CASE NUMBER:

99-149

Filed 6-14-99

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COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

FILED
JUN 14 1999
PUBLIC SERVICE COMMISSION

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC., AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER

CASE NO. 99-149

TRANSCRIPT OF EVIDENCE

DATE OF HEARING: MAY 28, 1999

CONNIE SEWELL
COURT REPORTER
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APPEARANCES

HON. B. J. HELTON, CHAIRWOMAN
HON. EDWARD J. HOLMES, VICE CHAIRMAN
HON. GARY GILLIS, COMMISSIONER

HON. RICHARD RAFF, COUNSEL FOR COMMISSION STAFF

FOR KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC., AND CENTRAL AND SOUTH WEST CORPORATION:
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FOR KENTUCKY ELECTRIC STEEL:
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FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS
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I N D E X

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CHAIRWOMAN HELTON:

We're here in the matter of the Joint Application of Kentucky Power Company, American Electric Power Company, Inc., and Central and South West Corporation regarding a proposed merger, Case No. 99-149. Could I have the appearances of the parties, please?

MR. OVERSTREET:

Thank you, Madam Chair. I'm Mark R. Overstreet, Stites & Harbison. I'm here on behalf of American Electric Power, Central and South West Corporation, and Kentucky Power, collectively. They are the joint applicants. With me is Mr. Edward Brady who is here on behalf of American Electric Power and Kentucky Power.

MR. BOEHM:

Good morning, Madam Chairman. I'm David Boehm of the law firm of Boehm, Kurtz & Lowry, and I'm here on behalf of Kentucky Industrial Utility Customers and specifically, in this case, Marathon Ashland Petroleum, AK Steel, and Calgon Carbon. Thank you.

MS. BLACKFORD:

Elizabeth Blackford here for the Attorney General's Office, 1024 Capital Center Drive, Frankfort.

CHAIRWOMAN HELTON:

Commission staff? I'm sorry. Mr. Taylor?

MR. TAYLOR:

That's all right. Richard S. Taylor, 315 High Street, Frankfort, Kentucky 40601, here on behalf of Kentucky Electric Steel.

MR. RAFF:

For the Commission and the staff, Richard Raff.

CHAIRWOMAN HELTON:

Is there anyone in the audience that would like to give public comment? There being no one, Mr. Overstreet, would you call your first witness?

MR. OVERSTREET:

Yes, Madam Chair. First, we would like to call Mr. Richard Munczinski. Madam Chair, as the Commission, undoubtedly, is aware, we have reached a unanimous settlement with all the parties to this proceeding, and Mr. Munczinski is here to testify in support of the Stipulation and Settlement Agreement. I think, before he is sworn, if I may, may I hand the Court Reporter the notices of publication so they can be entered into the record?

CHAIRWOMAN HELTON:

Yes.

APPLICANT EXHIBIT 1

WITNESS SWORN

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The witness, RICHARD E. MUNCZINSKI, after having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. OVERSTREET:

Q. Mr. Munczinski, would you please state your full name and position for the record, sir?

A. My name is Richard E. Munczinski. I'm Senior Vice President of Corporate Planning and Budgeting for American Electric Power Service Corporation.

Q. And your business address?

A. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Mr. Munczinski, have you sponsored testimony in this proceeding?

A. Yes, I have.

Q. And I believe you actually have sponsored two sets of testimony, sir. One was filed in connection with the original Joint Application, and the second was filed on May 26, Wednesday of this week, in support of the Stipulation and Settlement Agreement. Do you have any corrections to either of those prefiled testimonies?

A. I have one correction to the original filing, the direct testimony, and specifically . . .

Q. Before you start, let me pass this out so everyone has a copy of those. First of all, would you please

identify, sir, the document that I've passed out?
A. This is Exhibit REM-4, Page 1 of 1.
Q. And this is the Exhibit to which you want to make the correction?
A. Correct.
Q. And is this the corrected Page 1 of 1 to REM-4?
A. Yes.
Q. Okay. Now, would you explain to the Commission, Mr. Munczinski, what correction was made?
A. Okay. This is the allocation of fuel merger benefits to the jurisdictions of the current AEP companies, and it's listed going down by AEP companies starting with Appalachian Power Company or APCo, then Kentucky Power, Indiana, Michigan, Ohio, Columbus, and then it's jurisdictionalized into the state and federal jurisdictions. Under the company APCo or Appalachian Power Company, the sale that's marked "FERC" and then going all the way to the right total was just mathematically incorrect. The computer program added down on the total, and it should have added across, So the FERC jurisdiction for Appalachian, for Indiana, and for Ohio should be revised, and the numbers should add across and not down, and the revised Exhibit does that. I will point out that the correction does not at all affect Kentucky Power Company.

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Q. Thank you, Mr. Munczinski. Do you have any further corrections to your testimony?
A. No, I do not.
MR. OVERSTREET:
Okay. I tender the witness for cross examination.
CHAIRWOMAN HELTON:
Mr. Boehm?
MR. BOEHM:
No cross, Your Honor. Thank you.
MS. BLACKFORD:
No questions. Thank you.
MR. TAYLOR:
No cross.
CHAIRWOMAN HELTON:
Mr. Raff?
CROSS EXAMINATION
BY MR. RAFF:
Q. Good morning, Mr. Munczinski.
A. Good morning.
Q. In your revised testimony, supplemental testimony, Page 10, Lines 15 and 16, you state there that ". . . AEP agrees to maintain or improve the quality and reliability of retail electric service and to submit service reports to the Commission"?
A. Yes, sir.

Q. And there's a provision in the Settlement Agreement, Paragraph 9, that talks about adequacy and reliability of retail electric service?
A. Yes, sir.
Q. And that provision then refers to Attachment C which sets forth I guess it's six pages discussing certain service measures?
A. Yes, it does.
Q. Is this an AEP generic service quality plan or does it include provisions that are specific to Kentucky Power?
A. The foundation of it is a generic plan that we've adopted for much of the merger, but it does include some specifics for Kentucky Power. At least, it mentions some terms specifically for Kentucky Power.
Q. Could you tell us what is specific to Kentucky Power?
A. Well, to maintain the overall quality and reliability of electric service at levels no less than it has achieved in calendar years 1995-1998. It also makes mention that "These standards can be changed during the term of this agreement to reflect any performance-based ratemaking plans or rules which the Commission adopts either for AEP/Kentucky Power and/or generically for the electric utility industry." "In the event the Commission," meaning this Commission, "adopts industry generic rules concerning customer service standards,

AEP/Kentucky Power shall have at its option the right to incorporate them into this agreement." It talks about AEP/Kentucky representatives being left in the state.

Q. But I guess, then, it's not specific to Kentucky Power in the sense that anyone sat down and said, "Well, you know, Kentucky Power's service territory is somewhat different from Ohio or Indiana. So therefore we ought to have something specific in our plan here for Kentucky."

A. No. As I mentioned, the basic foundation is one that would be offered in Indiana and Ohio and in each of the current AEP states.

Q. Okay. And, in fact, has this same service quality plan been included in any of the settlements that you've already negotiated with other states?

A. I'm familiar with the Indiana settlement, and I have not checked word for word, but, again, the basic terms for both Indiana and Kentucky are similar.

Q. Okay. With reference to Page 1 of Attachment C under Section 2.a), . . .

A. Yes, sir.

Q. . . . is Kentucky Power willing and able to begin filing the performance measure reports referenced herein beginning in May of 2000 regardless of when the merger closes?

A. Well, the entire agreement is, as you know, based on the consummation of the merger. Our best guess is that, by May of 2000, the merger will have been consummated, and I guess that's - it's a difficult question to answer because we are putting together teams of people that will be basically putting together this information. We are going ahead under the assumption that the merger will be consummated actually prior to either the end of the year or the first of the year, but the commitment right now is based on the consummation of the merger.

Q. Okay. But your intent is that, as long as it closes by May of next year, that you will be able to have put that material together for 1999?

A. I think that was our intent.

Q. Okay. Can you give us a brief update of where you are in the settlements and negotiations with the other AEP and CSW states?

A. I certainly can. Let me first mention that there are four CSW states, and there are seven current AEP states. Let me list the activities in the four CSW states. Oklahoma and Arkansas, two of the four states in the CSW service territory, have granted approval of our merger. We have a pending merger settlement with key parties in Texas, a third CSW state, that awaits action of the Public Utility Commission of Texas, and hearings are scheduled for August. The majority of intervenors there have signed onto that stipulation. It includes the staff, the Attorney General, the consumer groups, low income. The only remaining parties that have not signed on are co-ops and power marketers. We are working with all parties in Louisiana, a fourth state, and we hope to settle there within a short period of time and that's the four CSW states. In the AEP states, I think you're aware that we have approval of the Indiana Utility Regulatory Commission. We have this current proceeding in Kentucky. Two states, the States of West Virginia and Tennessee, have not intervened either at the FERC or have called for a state case, which leaves us with ongoing negotiations with the States of Ohio, Michigan, and Virginia. We have settled with a number of key wholesale customers, and we've also reached an agreement with the International Brotherhood of Electrical Workers. Let me then add the most important one. Late last week we reached an agreement with FERC trial staff on a number of issues, including the market power issues, the transmission rate issue, and divestiture issues. The two open issues yet to be negotiated are the wholesale customer protection issues and issues related to the system integration agreements.

Q. It's my recollection there was an investigation opened by the Ohio Commission; is that correct?

A. The Ohio Commission has an investigation under the Public Interest Standards, and we have obviously been working closely with Ohio, as we did with the Kentucky group, both at the local level and at the federal level.

Q. And, in Michigan, is there any proceeding open there?

A. No. Michigan is an intervenor at the federal level, and we've been working with them on that level.

Q. And Virginia, is there any proceeding there?

A. Virginia has also intervened at the federal level and has no local case pending.

Q. Thank you. I have a couple of questions about the net merger savings for Kentucky Power customers, . . .

A. Yes, sir.

Q. . . . your Exhibit REM-3, Pages 2 and 4, from your direct testimony. Is it correct that, in AEP's Application, the nonfuel merger savings were to be provided over a ten year period with the associated merger costs-to-achieve and the change-in-control payments to be amortized over a five year period?

A. Yes.

Q. And, under the Stipulation and Settlement, the nonfuel merger savings are to be initially provided over an eight year period with the cost amortization also over eight years?

A. That is correct.

Q. And, after the initial eight year period, the eighth year level of nonfuel merger savings will continue until the next base rate case?

A. Well, what continues is the eighth year level minus the costs that have been amortized out. So, if you look at Attachment A, Page 1 of 1, you'll see that the parties have settled on an eight year plan and, if you look, the ninth and tenth years are not appreciably different than the eighth year, but, after an eight year plan or in the ninth year, the number noted here would change from the eighth year customer bill reduction of $4.626 million to $5.242 million. The difference is that, once the amortization of costs are off the books, then you're basically sharing the gross savings.

Q. And the split of the savings was proposed in the Application to be 52 percent to ratepayers, 48 percent to shareholders, but the Settlement Agreement provides for 55 percent for ratepayers and 45 percent to shareholders; is that correct?

A. Yes, 55 percent of the net merger savings listed there and 45 percent of the net merger savings listed there.
Q. Again, on your Exhibit REM-3, Page 2 of 4, at the bottom of the page under the AEP portion, is it correct that this schedule shows the shareholders bearing the full amount of the change-in-control payments?
A. The schedule shows that we would have achieved merger savings on the total existing AEP companies, and then it subtracts out the costs-to-achieve, which is not including change-in-control, to get to the net savings. What we were proposing in the original numbers, in the original offer filing, was that the customer would receive 50 percent of those net savings, and the shareholder would be receiving 50 percent of the net savings. However, there is a change-in-control issue with CSW management, and we were allocating recovery of the change-in-control to the shareholder's portion. So, on a net basis, instead of 50-50 sharing, we got to the 52-48 sharing by allocating change-in-control to recovery under the shareholder portion.
Q. Okay. Is it correct that this same approach is reflected in the calculations that support the amounts on Attachment A to the Stipulation and Settlement Agreement?
A. Well, the end result is that, once you take the gross

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savings minus the costs-to-achieve, minus the change-in-control payments, you get to the $51.571 million figure on Attachment A, and, if you take 55 percent of that number, you'll get the customer bill reduction, and, if you take 45 percent of that number, you'll get the shareholder bill reduction.

MR. RAFF:

Thank you, Mr. Munczinski. No further questions.

A. Thank you.

CHAIRWOMAN HELTON:

Mr. Gillis? Mr. Holmes?

EXAMINATION

BY CHAIRWOMAN HELTON:

Q. You answered Mr. Raff's question about the service quality, and this Commission has been concerned about that. In that there is the agreement in the Settlement Agreement, I would just ask you to also tell us if AEP is committed to making sure that the budgetary funds flow through to Kentucky Power to ensure that they're able to maintain the service quality that you have agreed to in the stipulation.

A. We certainly are.

CHAIRWOMAN HELTON:

Thank you. Mr. Overstreet, do you have anything?

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MR. OVERSTREET:

Thank you. Our next witness, Madam Chair, is Mr. Errol Wagner, a familiar face.

WITNESS SWORN

The witness, ERROL K. WAGNER, after having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. OVERSTREET:

Q. Mr. Wagner, would you please state your name and position for the record, sir?

A. Errol K. Wagner, and I'm Director of Regulatory Affairs.

Q. And your business address?

A. 1701 Central Avenue, Ashland, Kentucky 41101.

Q. And have you sponsored testimony in this proceeding, Mr. Wagner?

A. Yes, I have.

Q. When was that testimony filed?

A. May 26.

Q. Okay. Is that testimony in support of the Stipulation and Settlement Agreement?

A. Yes, it is.

Q. Do you have any changes to that testimony?

A. No, I don't.

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MR. OVERSTREET:

I'll tender the witness for cross examination.

CHAIRWOMAN HELTON:

Thank you.

MR. BOEHM:

No questions, Your Honor. Thank you.

CHAIRWOMAN HELTON:

Ms. Blackford?

MS. BLACKFORD:

I have no questions. Thank you.

CHAIRWOMAN HELTON:

Mr. Taylor?

MR. TAYLOR:

No questions.

CHAIRWOMAN HELTON:

Mr. Raff?

MR. RAFF:

One question.

CROSS EXAMINATION

BY MR. RAFF:

Q. Good morning, Mr. Wagner.

A. Good morning.

Q. In your direct testimony supporting the stipulation, Page 2, beginning on Line 21 and continuing on over to Page 4, is it correct that the calculation approach

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used to determine the ninth and subsequent years' merger savings for ratepayers is consistent with the approach used to determine the ratepayer amounts for the first eight years?

A. Is it consistent? No, it would not be consistent. For the first eight years, we used our forecasted kilowatt-hours, for the years 2000-2007, I believe. For the ninth year or the years after the eighth year period, we used the kilowatt-hours for the next, which will be 2008, and that's what we would be proposing to use until the next base rate case.

Q. Okay, but have you used the same percentage factor as shown at the top of Page 3 on Line 1, this 52.339 percent?

A. Yes. Yes. I'm sorry.

Q. So there has been no change in that?

A. There's no change in that percentage factor.

MR. RAFF:

Okay. Thank you, Mr. Wagner. No further questions.

A. Okay. Thank you.

CHAIRWOMAN HELTON:

Mr. Gillis? Mr. Holmes?

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EXAMINATION

BY CHAIRWOMAN HELTON:

Q. Mr. Wagner, there's going to be a three year freeze on rates, and I don't think there's any calculation in the Stipulation Agreement as to what that might have resulted in, in terms of savings to the ratepayer. Could you give us any thoughts as to how much that would have been if you had come in for a rate case and rates had been increased? Can you give us any ball park figures on that?

A. Yes, ma'am. Looking at our current return as basically in the vicinity of 8 and 9 percent, and let's just take 8.5 percent for easy calculations in my mind, and, in light of the fact that the Commission authorized this 11.5 percent in the most recent environmental proceedings, that's approximately a 3 percent return that we would be asking for, and, if you increase - each percent is approximately $4.4 million. So you're talking between $12 million and $14-$15 million that we would be coming in for a rate case, I believe, rather shortly if it wouldn't have been for this three year freeze. So just take the $12 million, for simple math, and then times three. You're talking just that alone is $36 million benefit to the ratepayer along with the merger savings credit that they'll be getting. So I believe that's - you can add those two together and you'll see that is a big benefit for the ratepayers in eastern Kentucky.

CHAIRWOMAN HELTON:

Thank you.

A. Okay.

MR. RAFF:

Well, let me ask.

CROSS EXAMINATION CONTINUED

BY MR. RAFF:

Q. Mr. Wagner, are you the company's chief accountant?

A. Not any more, sir. Accounting was relocated to Canton and Columbus, but I am responsible for the rate cases and things of that nature.

Q. All right. You used to be their chief accountant?

A. Yes.

Q. Do you believe that Kentucky Power can operate successfully over the next three years with a rate freeze and the merger credits that are going to be passed back to ratepayers?

A. Yes, and also the shareholders also keeping 45 percent of that. So that's going to be reinvested in the business also. So, with that extra 45 percent, I believe the company can operate. I mean, we're going to do everything humanly possible, not knowing, again,

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what the future holds for us, but I believe we can successfully operate, and I don't believe the ratepayers are going to see any detrimental service quality issues. I believe we can operate and provide satisfactory or improve our service to the ratepayers.

Q. There has been included in the Settlement Agreement a force majeure provision which would allow you to come in for a rate case under certain limited circumstances; is that correct?

A. That's correct, and most of those circumstances, you know, are basically beyond the control of the company, clean air things and tax issues. There are just certain things that, yes, we do have that flexibility.

Q. Besides the provisions that allow you to come in for change in taxes and changes for environmental costs, there's also provisions that talk about in the event that your bonds were to be downgraded to a level below investment grade . . .

A. That's correct.

Q. . . . and to the extent that there was, I believe it is, a 5 percent increase in your overall operating expenses. Can we assume that you currently believe that you can operate over the next three years, at least with what you know now, without triggering that force majeure provision?

A. Yes. There's no plan to file a case in the next three years. I'm not working on anything right now.

MR. RAFF:

Okay. Thank you. No further questions.

EXAMINATION

BY VICE CHAIRMAN HOLMES:

Q. That also includes continued improvements to the system that AEP has been working on with Kentucky Power?

A. Yes, it does, sir; yeah.

CHAIRWOMAN HELTON:

You're dismissed.

A. Thank you.

CHAIRWOMAN HELTON:

I don't think there are any other further matters to come before the Commission. Mr. Overstreet, do you have something?

MR. OVERSTREET:

No, Madam Chair. I was just going to say that was our final witness.

CHAIRWOMAN HELTON:

Okay. I would like to compliment the parties on working together to achieve a Settlement Agreement to present to this Commission which we can now look at and hopefully move the process faster than we would have if we had had to address all those

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issues in a hearing. So I do appreciate all the efforts that have gone into the informal conferences with the parties and our staff, and we do appreciate it when the parties do work toward Settlement Agreements and resolve these issues before it comes before us. So we do appreciate that. There being no further matters to come before us, this hearing is adjourned.

MR. OVERSTREET:

Thank you.

MR. BOEHM:

Thank you.

FURTHER THE WITNESSES SAITH NOT

HEARING ADJOURNED

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STATE OF KENTUCKY

COUNTY OF FRANKLIN

I, Connie Sewell, the undersigned Notary Public, in and for the State of Kentucky at Large, do hereby certify the foregoing transcript is a complete and accurate transcript, to the best of my ability, of the hearing taken down by me in this matter, as styled on the first page of this transcript; that said hearing was first taken down by me in shorthand and mechanically recorded and later transcribed under my supervision; that the witnesses were first duly sworn before testifying.

My commission will expire November 19, 2001.

Given under my hand at Frankfort, Kentucky, this the 13th day of June, 1999.

Connie Sewell

Connie Sewell, Notary Public
State of Kentucky at Large
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Frankfort, Kentucky 40601
Phone: (502) 875-4272

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NOTARIZED PROOF OF PUBLICATION

STATE OF KENTUCKY

COUNTY OF Franklin

Before me, a Notary Public, in and for said County and State, this 24th day of May, 1999, came Gloria Davis personally known to me, who being duly sworn, states as follows:

That she is Director of Sales of the Kentucky Press Service, and that the following publications ran the Notice of Public Hearing for American Electric Power:

Ashland Daily Independent, May 12; Booneville Sentinel, May 13; Grayson Journal Enquirer, May 12; Greenup News, May 13; Hazard Herald, May 12; Hindman Troublesome Creek Times, May 12; Hyden Leslie County News, May 13; Inez Mountain Citizen, May 12; Jackson Times, May 13; Louisa Big Sandy News, May 12; Manchester Enterprise, May 12; Martin County Sun, May 12; Morehead News, May 11; Paintsville Herald, May 12; Pikeville Appalachian News Express, May 12; Prestonsburg Floyd Co. Times, May 19; Salyersville Independent, May 13; Sandy Hook Elliott Co. News, May 14; Vanceburg Lewis Co. Herald, May 11; West Liberty Licking Valley Courier, May 13; and Whitesburg Mountain Eagle, May 12.

Gloria Davis

Gloria Davis, Director of Sales

Bonnie J. Howard

Notary Public

My commission expires 9-18-2000

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environmental impact statement be required. USDA/RUS has further determined that the location of the proposed construction would impact the 100-year floodplain. It has been determined that there is no practicable alternative to avoid this impact. The basis of this determination is as follows:

• The floodplain would be impacted by the proposed construction due to stream crossings.

• The proposed water and sewer system must be located within the floodplain in order to serve the proposed customers.

• The proposed action conforms to applicable state and local floodplain protection standards.

In order to avoid or minimize any adverse environmental impacts, the Rural Utilities Service will require the applicant to incorporate the following mitigation measures into the proposed project's design.

• The applicant will be required in the RUS Letter of Conditions to amend its bylaws whereby it will deny service to any new customer planning to build in a floodplain or identified wetland area.

• The water and sewer lines will be laid on public right-of-ways, where necessary to avoid impacts on any prime farmland and/or wetlands that may be in the vicinity.

Copies of the Environmental

James Newsome, Josephine Hall, T.B. Akers Estate, David R. Akers, Herbert & Lettie Mae Cordial Allan Conn, Brice Conn Estate, Emmin & Cynthia J. Akers, John D. & Emodel A. Boyd, James & Bertha Williams, Kenneth Spears, Norman & Mae Martin, Herman Conn, Bailey Crum, Mexico & Lizzie Spears, Alma Land Company.

The application has been filed for public inspection at the Department for Surface Mining Reclamation and Enforcement's Prestonsburg Office, 3410 South Lake Drive, Prestonsburg, KY 41653. Written comments, objections, or requests for a permit conference must be filed with the Director, Division of Permits, No. 2 Hudson Hollow, U.S. 127 South, Frankfort, Kentucky 40601.

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NOTICE OF INTENTION TO MINE

Pursuant to Application Number 836-0244, Major Revision 6

NOTICE OF INTENTION TO MINE

Pursuant to Application No. 636-8005, Renewal

In accordance with KRS 350.055, notice is hereby given that Lodestar Energy, Inc., 251 Tollage Creek, Pikeville, Kentucky 41501, has applied for renewal for a permit for an existing coal processing facility affecting 25.35 acres located 0.25 mile south of Ivel in Floyd County.

The proposed operation is approximately 0.25 mile south from US 23's junction with Ivy Creek Road and located 0.25 mile south of Levisa Fork of Big Sandy. The latitude is 37 deg. 35 min. 25 sec. The longitude is 82 deg. 34 min. 56 sec.

The proposed operation is located on the Harold U.S.G.S. 7 1/2 minute quadrangle map. The surface area is owned by Windell E. Stratton and J. K. Stratton Heirs.

The application has been filed for public inspection at the Department for Surface Mining Reclamation and Enforcement's Prestonsburg Regional Office, 2705 South Lake Drive, Prestonsburg, Kentucky 41653-1397. Written comments, objections, or requests for a permit conference must be filed with the Director of the Division of Permits, No. 2

to tender a proposal are required to visit the site and familiarize themselves with the conditions there. Submittal of a bid shall be construed as evidence that such a site visit was made.

Bidding Documents, including Drawing and Specifications, may be purchased for $15.00 per set cash or check, payable to Johnson-Romanowitz Architects, Inc. Payments for documents should be submitted directly to Lynn Blueprint & Supply Company, 328 Old East Vine Street, Lexington, KY 40507, (606) 255-1021.

Bids must be submitted, in duplicate originals, on Bid Form included in the Project Manual. Mailed Bids shall be addressed to the offices of the Floyd County School Board. Facsimile bids will not be accepted.

Immediately following the scheduled closing time for receiving the bids, all proposals which are completely filed out and have been properly submitted with the appropriate attachments in accordance with the Contract Documents, will be publicly opened and read allowed.

All bids shall be accompanied by a Bid Bond of not less than 5% of the amount of the total bid. A 100% Performance Bond and Payment Bond shall be required of the successful Bidder. All bonding and insurance requirements are contained in the instructions to Bidders

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opening. Should there
be reasons why the
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the bidder.

Bidders may satisfy themselves of the accuracy of the equipment specifications described in the bid schedule by examination of the specifications including agen-

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acres for a total proposed permit acreage of 585.18 acres located 1.00 mile east of Ivel in Floyd County.

The proposed major revision area is approximately 2.5 miles east from the Junction of US 23 and Ivy Creek Road and located 0.1 mile east of Mare Creek. The latitude is 37º 35' 52" and the longitude is 82º 37' 27".

The proposed operation is located on the Harold and Broad Bottom U.S.G.S. 7 1/2 minute quadrangle maps. The surface area to be affected by this major revision is owned by Mitchell Williams and Danny and Ronnie Stratton.

This major revision proposes a change in the post mining land use from a pre-mining land use of pasture land and forest land to a post mining land use of residential areas.

The major revision application has been filed for pubic inspection at the Department for Surface Mining Reclamation and Enforcement's Prestonsburg Regional Office, Bureau of Surface Mining Reclamation and Enforcement, 2705 South Lake Drive, Prestonsburg, KY 41653. Written comments, objections or requests for a permit conference must be filed with the Director of the Division of Permits, No. 2 Hudson Hollow, U.S. 127 South, Frankfort, KY 40601.

... Resource Drive, Prestonsburg, Kentucky 41653, until 1:00 p.m., May 25, 1999.

Lots for sale are Lot B4 (Old Community Building), Lot B6 (Old Theater Lot), Lot 16, Lot 273, and Lot 465.

Copies of bid forms and maps can be obtained at the Corporation's office located in Wheelwright City Hall. Bids must be sealed and marked "Lot Bid" clearly on the outside of the envelope.

The Corporation reserves the right to reject any and all bids.

"EQUAL HOUSING OPPORTUNITY"

ADVERTISEMENT FOR BIDS

For the Project Titled:
NEW PROTECTIVE COVER
BETSY LAYNE ELEMENTARY SCHOOL
FLOYD COUNTY SCHOOL BOARD
Prestonsburg, Kentucky

Sealed proposals will be received from qualified contractors by Floyd County School Board at their offices located at 69 North Arnold Avenue, Prestonsburg, Kentucky, until 2:00 p.m. local time, Thursday, May 27, 1999, for the construction of a new aluminum protective cover for Betsy Layne Elementary School. Bids received after the stated time will not be accepted and will be returned unopened to the bidder.

Contractors wishing reject any and all bids.

PROJECT DESCRIPTION:

The Project consists of the construction of a free-standing aluminum canopy connecting three buildings at Betsy Layne Elementary School, including concrete foundations, flashing to existing buildings and repair of work damaged by construction activities.

BIDS

The Floyd County Fiscal Court will receive sealed bids until 10 a.m., May 21, 1999, for the following: Twenty (20) Four wheel gas golf cars with sweater baskets, roofs and number decals (2).

Bids will be received by Floyd County Fiscal Court (herein called "OWNER"), at P.O. Box 789, Prestonsburg, Kentucky, 41653 until 10 a.m. May 21st, 1999, and then and then at said office publicly opened and read aloud at the regular meeting of the Floyd County Fiscal Court on May 21st, 1999, at 10 a.m.

Each bid must be submitted in a sealed envelope, addressed to Floyd County Fiscal Court at P.O. Box 789, Prestonsburg, Kentucky 41653. Each sealed envelope containing a bid must be plainly marked on the outside as bid for (20) four wheel gas golf cars to be used at Beaver Valley Golf describes, the equipment to be purchased. The bid documents contain the provisions required for the equipment. Information obtained from an officer, agent, or employee, or employee of the owner or any other person shall not affect the risks or obligations assumed by the bidder or relieve him from fulfilling any of the conditions of the contract.

The owner may make such investigations as he deems necessary to determine the ability of the bidder to provide the equipment, and the bidder shall furnish to the owner all such information and data for the purpose as the owner may request. The owner reserves the right to reject any bid if the evidence submitted by, or investigation of, such bidder fails to satisfy the owner that such bidder is properly qualified to carry out

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

Am Elect.

RATES
20 words or less
$5.00 a week
10 cents for every
word over 20
Deadline
12 noon on Friday
Call (606) 633-2252

Classified

BUSINESS OPPORTUNITY

TIRED OF WORKING 9 TO 5? — Tired of making money for someone else? Do you just need additional income? Then Avon may be the career you're searching for. For details call Lorie Rayburn, Avon Ind. Sales Rep., (606) 633-7740. (5-12-1p)

FOR RENT

ISOM STORAGE RENTALS — Located just off Highway 15, Garner Mountain at Isom. Good neighborhood, well lighted area. Sizes range from 5 x 10 up to 10 x 30. Rent by the month. Call 633-5961. (7-2-ufnb)

NOW RENTING STORAGE SPACE — Blair Self-Storage. For your residential and commercial storage needs. 606-633-7200. 7 days a week access. (7-9-ufnb)

NOW RENTING STORAGE!! — Storage Rentals of America. Located beside Food City in Whitesburg. No deposit required, you can call 24 hours a day, 7 days a week - Free!! $19.00 maximum security disc lock with any rental, yours to keep. Paved driveways for less dust on your contents. FREE!! report on 25 most helpful hints on self-storage. Prices start as low as $19.00 a month. Call now - move in now. Free call, 1-800-457-5678. (11-26-ufnb)

I HAVE A TWO-BEDROOM TRAILER — For rent located in McRoberts, KY. The trailer has electric heat, is fairly new and in very good condition. For more information, Monday through Friday during day hours call 606-832-9080, and evenings and weekends call 832-4363. (4-28-ufnb)

FOR RENT

1-BEDROOM APARTMENT — For rent, Isom, KY, 633-9930. (4-7-ufnb)

FOR RENT — 1-bedroom apartment. Call 633-9977. (5-12-1p)

SMALL ONE-BEDROOM HOUSE — Nearly new. Thornton area. Clean. Neat. Suitable for one or two people. No pets. Deposit and references required. 633-9208. (5-12-1p)

APARTMENT FOR RENT — On Church Street, 2 blocks from Main. Living room, bedroom, kitchen with dining area, bath with shower and tub. Completely furnished. $275. Now available, appointment only. Call or see Don Brown, Whitesburg, KY. (606) 633-0036. (5-12-1p)

FOR RENT/LEASE

1-BEDROOM APARTMENT — For rent or lease. References required. ALSO - 1 apartment, furnished, all utilities paid. 633-7665. (5-12-1b)

HELP WANTED

EXCELLENT EMPLOYMENT OPPORTUNITY — For single lady aged 39 - 70 who would live in with elderly couple at 525 Lakeside Drive, Jenkins, KY, and help with light housekeeping. For full particulars, please call 606-832-4306, ask for Bert or Greta. (3-3-ufnb)

POSITIONS AVAILABLE — For experienced heavy equipment operators and Class A CDL truck drivers. For more information please contact Millstone Construction Company, Inc., at (606) 633-1014 or (606) 633-9065. (4-17-ufnb)

HELP WANTED

HELP WANTED — Person needed to spray bushes and weeds around cemetery. Call 633-7523. (5-12-2p)

MISCELLANEOUS FOR SALE

KENTUCKY MOUNTAIN QUILTS — Send for list with prices and descriptions. The Cozy Corner, 116 Main Street, Whitesburg, KY 41858. Phone 606-633-9637. (ufn)

USED TIRES — For sale. Rt. 805, Whitaker, KY. Sergent's Used Tires. 855-4308. (12-9-ufnb)

FOR SALE — Nordic Track Cross-Country Ski machine. Very good condition. Paid $1,500, asking $800. Call 633-2042 evenings. (3-10-ufnb)

CAMPER/TRAILER FOR SALE — 24' pull type. Extra clean and nice. Like new condition. Extra low, reasonably priced. 633-3030. (5-5-2b)

HOUSEHOLD GOODS — Oak table and four chairs - $250.00, microwave with table, sofa/sleeper, waterbed frame, armchair, coffee table. Prices on items to be discussed. Person to contact - 633-2876 (leave message), best time to call - after 6 PM. (5-12-2p)

MOBILE HOMES

1978 2-BEDROOM MOBILE HOME — For sale. Completely remodeled. $5,000.00. 632-9195. (5-5-2p)

FOR SALE — 1988 Clayton mobile home. 14 x 52, 2 bedroom, 1 bath with shower stall. Comes with stove, refrigerator, 4 piece dinette, underpinning, power pole and 1.5 ton central air unit. Priced at $7,000.00 firm. Call 855-9917 from 8 AM - 4 PM, or 632-3603 from 4 PM - 9 PM. (5-5-

NOTICE

PUBLIC NOTICE FOR BLACK MOUNTAIN HEARING

The Department for Surface Mining Reclamation and Enforcement announces that the Black Mountain Lands Unsuitable Petition Hearing, scheduled for May 4-6, 1999, at Cawood High School, has been rescheduled. The following location, dates and times are now in effect: Location: Cawood High School, 279 Ballpark Road, Harlan, Kentucky. Date/Times: June 3, 6:30 p.m. June 4, 5:00 p.m. June 5, 9:00 a.m. (if needed). The purpose of the hearing is to receive public comments, pursuant to 405 KAR Chapter 24, on a petition to declare an area unsuitable for surface coal mining and reclamation operations. The petition area lies within the geographic region in Harlan and Letcher counties known as Black Mountain, and is approximately 2.5 miles southeast of Benham. The hearing will be legislative in nature, with no cross-examination of participants. For individuals who do not wish to make public comments, written comments may be submitted at the hearing or sent to the Department. Mailed written comments will be accepted through close of business June 14, 1999, and should be sent directly to: Kentucky Division of Permits, Department for Surface Mining Reclamation and Enforcement, Attention: Critical Resources Review Section, #2 Hudson Hollow, Frankfort, Kentucky 40601-4321. (5-5-2b)

REAL ESTATE

LOTS FOR SALE — To build homes. New subdivision, good neighborhood. Good sized lots located on Highway 588, near the mouth of Dry Fork. 633-7589-Frank Perry, or 633-5650-Sonny Frazier. (6-10-ufnb) seeding and mulching as of 1996 as per the provisions of KRS 350 and 405 KAR and permit conditions. Results achieved include revegetation of the area, water quality meets standards, and compliance with 405 KAR has been achieved.

Written comments, objections, and requests for a public hearing or informal conference must be filed with the Director, Division of Field Services, No. 2 Hudson Hollow, U.S. 127 South, Frankfort, Kentucky 40601 by June 25, 1999.

A public hearing on the application has been scheduled for June 29, 1999 at 9:00 a.m. at the Department for Surface Mining Reclamation and Enforcement's Pikeville Regional Office, 109 Mays Branch Road, Pikeville, Kentucky 41501. The hearing will be canceled if no request for a hearing or informal conference is received by June 25, 1999.

ADVERTISEMENT OF VACANCIES

The Letcher County School District anticipates job openings in the following areas. Applicants for the following positions are being accepted.

CERTIFIED POSITION

Extended School Service Teachers — Letcher County Schools

CLASSIFIED POSITIONS

Extended School Service Bus Drivers, Custodians, Cook, Instructional Assistants — Letcher County Schools

Applications and job descriptions for these positions may be obtained from:

The Office of the Superintendent
Letcher County Board of Education
1 Park Street
Whitesburg, KY 41858

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

NOTICE TO BID

The City of Whitesburg has declared that it ha... plus property located at Colson, KY and White... KY. The city will accept sealed bids on th... Whitesburg Airport property located at Colso... which includes 59 acres and the Old Whitesbu... Hall building, which includes first floor approxi... 2,856 sq. ft. includes garage, offices, storag... bathroom. Second floor approximately 2,856 ... includes bath, offices, kitchen, others. Baseme... proximately 2,856 sq. ft. includes furnace, st... (2). The bids must be submitted no later tha... 18, 1999 at 12:00 noon to the City Clerk's Offi... East Main Street, Whitesburg, Kentucky. Th... will be open at the City's council meeting M... 1999 at 6:30 p.m. The city retains the right to a... or reject any and all bids.

Nathan Baker

Creek Power

Schooling/ Training

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140 Legal Notices

I Richard A. Thompson ... Morehead, KY

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation, Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

140 Legal Notices

Located: 39 Church Rd. & US 60-Midland, KY, 4.5 Miles To I-64. 3.8 Miles To Cave Run Lake. Approx. 8 Miles West of Morehead
Building: New metal siding & doors, 4 overhead doors, 3 walk through doors, concrete floor, handicap bathrooms, water-sewer-electric, access to all sides.
Parking: Approx. 60'x200'.

Phone 606-683-5651
or
813-641-2846

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140 Legal Notices

I Richard A. Thompson, will not be responsible for any debts other than may own as of March 18, 1999.

140 Legal Notices

I, Harold L. Tolliver, P.O Box 2, Ontario, Ohio 44862, will not be responsible for any debts other than my own as of May 5, 1999.

140 Legal Notices

Notice Of Bond Sale

The County of Rowan, Kentucky acting by and through its Fiscal Court ("the county") will until 1:00 A.M., C.S.T. on Tuesday, May 18, 1999, receive at the offices of the County Judge/Executive, Rowan County Courthouse, 627 East Main Street, Morehead, Kentucky 40351, sealed competitive bids for two million thirty-five dollars ($2,035,000.00) (subject to an adjustment of up to $200,000.00) of its General obligation Bonds, Series 1999, dated May 1, 1999.

Bids must be on Official Bid Form contained in the Preliminary Official Statement, available from the undersigned or Ross, Sinclaire & Associates, Inc., 315 North Broadway, Lexington, Kentucky 40508, which has been deemed "final" by the Corporation within the meaning of Securities and Exchange Commission Rule 15c2-12. Reference is made to the Official Terms and Conditions of Bond Sale contained in the Preliminary Official Statement for details and bidding conditions.

Sale on tax-exempt basis, subject to approving legal opinion of Lewis, King, Krieg, Waldrop & Catron, P.C., Bond Counsel, Bowling Green, Kentucky. The Bonds are designated as "quali-

140 Legal Notices

Section 00020
Advertisement For Bids
Menifee, Morgan, Rowan, and Carter Regional
Industrial Development Authority
150 East First Street
Morehead, Kentucky 40351

Separate sealed bids for the construction of water distribution lines and oblatoid elevated water storage tank will be received by the Menifee, Morgan, Rowan, and Carter Regional Industrial Development Authority, Terry Ensor, Chairman, at their office located at 150 East First Street in Morehead, Kentucky until 11:00 am (Local Time) on May 21, 1999 at which time the sealed bids will be publicly opened and read aloud.

Contract 1 - will consist of the construction of one elevated water storage tank and potable waterline. The bid includes 1,000,000 gallon, 500,000 gallon and 400,000 gallon tank alternates on two alternate sites as follows:

Alternate 1

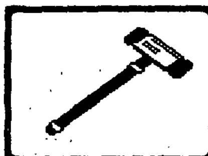
Site 1 - Construction of an elevated tank, approximately 6,000 feet of 16, 12 and 6 inch waterline and appurtenances. E x cavation is unclassified. Time of completion will be 270 days.

Alternate 2

Site 2 - Construction of an elevated tank, approximately 6,500 feet of 16 and 6 inch waterline and appurtenances. Excavation is unclassified. Time of Completion will be 270 days.

Contract Documents may be reviewed at the following locations:

Menifee, Morgan, Rowan and Carter Regional Industrial Development Authority, 150 East First Street, Morehead, Ken-



DISTRICT CO

Hon. Robert B. Conley, Judge

April 27, 1999

Randall Stacy Frazee. Show cause hearing. Money due, $641. Defendant to serve 30 days in lieu of fines and costs.

Wendell D. Cooper. Hon. Charles L. Douglas, Jr. Show cause hearing. Show proof of rehabilitation. Showed proof of rehabilitation.

Wendell D. Cooper. Hon. Thomas M. Bertram. Show cause hearing. Money due, $142. Reset for 7-27-99.

Randy Frazee. Hon. Thomas M. Bertram. Show cause hearing. Money due, $121. Defendant to serve seven days in lieu of fines and costs. Run consecutive to 96-F-034. Release for 24 hours to allow Defendant to take care of personal chores.

Wendall D. Cooper. Hon. Thomas M. Bertram. Show cause hearing. Money due, $111. Reset for 7-27-99.

Greg Bivens. Show cause hearing. Money due, $147. Reset for 7-27-99.

Wilma Bernice Cooley. Show cause hearing. Money due, $280.68. Show proof of alcohol rehabilitation. Defendant to serve 14 days and costs and fines and considered paid in full.

Becky D. Valentine. Show cause hearing. Restitution due, $289.40. Reset for 7-27-99.

Todd E. Monteith. Show cause hearing. Money due, $57. Show proof of 125 hours community labor. Reset for 6-29-99.

Brian Lykins. Hon. Thomas M. Bertram. Show cause hearing. Money due, $76. Restitution due, $140. Failed to appear, issue bench warrant.

Michael Brent Thomas. Show cause hearing. Money due, $73.25. Show cause issued 3-29-99. Defendant placed in jail for 48 hours in lieu of paying fines and costs.

Eric D. Clark. Review. Review/dismiss. Harassment. Dismissed.

Ruth Henderson. Motion hour. Motion, other, filed by Attorney-Public Advocate. Motion to declare proof of restitution. Show proof of 80 hours of community labor. Reset for 5-25-99.

Jason A. Highfield. Hon. William Knoebell. Show cause hearing. Show proof of restitution. Show proof of 80 hours of community labor. Reset for 5-25-99.

Douglas Landis, Jr. Show cause hearing. Bench warrant issued 3-23-98. Money due, $87.75. Cash bond posted 4-9-99. Defendant surrenders bond to pay fines and costs.

Clyde D. Hampton. Hon. Robert W. Miller. Show cause hearing. Show proof of home incarceration. Proof of 20 days home incarceration filed. Showed proof and paid in full. Dismissed.

Jamie Evins. Show cause hearing. Money due, $683. Failed to appear. Issue bench warrant and notify Frankfort.

Ruth Henderson. Other hearing. Contempt hearing money due, $309.50. Motion, other, filed by Attorney-Public Advocate. Motion to declare amount owed uncollectable. Motion sustained. Release.

Brian K. Stone. Show cause hearing. Money due, $653. Reset for 7-27-99.

Bron E. Rowe. Show cause hearing. Money due, $50. Failed to appear, notify Frankfort.

Robert L. Hurff. Show cause hearing. Money due, $323.25. Failed to appear. Notify Frankfort, issue bench warrant.

Katrina J. Mitchell. Show cause hearing. Money due, $348.25. Failed to appear. Notify Frankfort, issue bench warrant.

Mark A. Marschke. Show cause hearing. Money due, $197.85. Failed to appear. Notify Frankfort, issue bench warrant.

Britt A. Erwin. Show cause hearing. Money due, $279.50. Failed to appear. Notify Frankfort, issue bench warrant.

Benjamin Horsley. Show cause hearing. Money due, $398.25. Reset f... able costs. Paid in full.

Shirley K. Bennett. Arraignment. No insurance. PG. $500 fine, conditionally discharge $250.

Christopher C. Scott. Arraignment. (1) Speeding, 5 MPH over limit. Motion by County Attorney to amend to improper equipment KRS 189.020 violation code 00206. Fine $25 and costs. Suspend fine, 30 days to pay costs. (2) No insurance. Motion by County Attorney to dismiss, showed proof.

Barett G. Skarl. Arraignment. (1) Speeding, 7 MPH over limit. (2) No insurance. (3) No/expired registration receipt. (4) No Kentucky registration plates. Failed to appear, notify Frankfort.

Brandon A. Yates. Arraignment. (1) Reckless driving. (2) Operating on suspended license. (3) Attempting to elude police. PNG. Set for pre-trial 5-4-99.

Roger A. Bloomfield. Arraignment. (1) No operator's license. (2) No Kentucky registration plates. (3) No/expired registration receipt. (4) No insurance. Motion by County Attorney to dismiss, showed proof.

William C. Wisecup. Arraignment. (1) Speeding, 14 MPH over limit. (2) No insurance. Failed to appear, notify Frankfort.

Portia J. Howard. Arraignment. (1) Speeding, 20 MPH over limit. Amend to improper equipment. PG. $25 fine. Suspend fine, pay costs. (2) No Kentucky registration plates. (3) No/expired registration receipt. (4) No insurance. Dismissed on Commonwealth's motion, showed proof.

Douglas R. Kiser. Arraignment. (1) Disregarding stop sign. PG. $25 fine and costs. (2) Operating on suspended license. Dismissed on Commonwealth's motion.

Elizabeth Campbell. Arraignment. (1) Improper equipment. Dismissed, showed proof. (2) Failure to wear seatbelt. PG. $25 fine and costs.

Amanda Nicole Smith. Arraign-

...ry trial 6-29-99.

...orsley. Pre-trial conference. ...hol intoxication, 1st/2nd. (2) ...n of marijuana. (3) Drug ...nalia, use/possess, 1st. Reset ...ial on 5-18-99.

...y Evans. Pre-trial confer- ... Violation of Emergency ... Order. (2) Alcohol intoxi- .../2nd. Set for jury trial on 7- ...nmonwealth offers 60 days. ... days, conditionally dis- ...nce and work release.

...Carroll. Pre-trial confer- ...sault, 4th degree. On ...ealth's motion, charge is ...no prejudice.

... Jones. Pre-trial confer- ...by unlawful taking/disp., ... PNG (Pled Not Guilty). ...ial 6-1-99.

... Jones. Pre-trial con- ... by unlawful taking/ ...(M). PNG. Set for pre-

... Blevins. Hon. Thomas ... Pre-trial conference. ... Defender fund due. ...marijuana, <five plants, ... 30 days. Serve seven ...ally discharge balance ...it for one day already ...ed to possession of ...e Saturday 8:00 a.m. ...a.m. beginning 5-8- ...three consecutive

...re-trial conference. ...over for six months ...h's motion. Defen- ...ave no more prob- ...s.

...aster. Arraignment. ...r injury. PNG. Set ...

... Pre-trial confer- ...communications. ...s probable cause. ...'s motion, charge ...onths. If no other ...ged victim, then

...on. Thomas M. ...nference. $94.50 ... (1) Public in- ...d substance), ...ge into #2. (2) ...ana. Entered ... Serve seven ...arge balance,

Kendall Thurman. Pre-trial conference. (1) Operating motor vehicle under influence, 2nd. Set for jury trial 7-13-99. (2) Driving DUI suspended license, 1st. PG. 30 days. Serve seven days, conditionally discharge balance, two years. Serve Friday at 6:00 p.m. to Sunday 6:00 p.m. beginning 5-7-99 and repeat for three consecutive weekends. Credit for one day already served. (3) Failure to wear seatbelt. PG. $25 fine and costs. (1) Refusal to take alcohol/substance test. Set for jury trial 7-13-99. (2) Failure to illuminate head lamps. Amended to improper equipment. $25 fine.

Harry Steve Moore. Pre-trial conference. Operating motor vehicle under influence, 2nd. Blood alcohol content .222. Reset for 5-11-99.

Harrison Kennedy, Jr. Arraignment. (1) Operating motor vehicle under influence of intoxicant. PG. $200 fine, $200 SF. Attend alcohol rehabilitation. Seven days, conditionally discharge, two years. Treat as non-refusal. (1) No insurance. Dismissed, showed proof. (2) Failure to wear seatbelt. PG. $25. (3) Refusal to take alcohol/substance test. Merge with DUI. (1) Drink alcohol, public, 1st/2nd. Merge with DUI.

Carla S. Blevins. Arraignment. (1) Improper equipment. Dismissed, showed proof of repair. (2) Failure to wear seatbelt. PG. $25 fine.

Larry D. Cooper. Arraignment. No insurance. Dismissed, showed proof.

Michael W. Rodgers. Arraignment. (1) Speeding, 5 MPH over limit. PG. Motion by County Attorney to pay fines and costs. 60 days to pay. (2) No Kentucky registration plates. Motion by County Attorney to dismiss, showed proof. (3) No/expired registration receipt. Motion by County Attorney to dismiss, showed proof.

Melissa Bloomfield. Arraignment. (1) License to be in possession. Motion by County Attorney to dismiss, showed proof. (2) Failure to wear seatbelt. Motion by County Attorney, $25 fine and costs.

Matthew D. Willis. Arraignment. (1) Speeding, 25 MPH over limit. Motion by County Attorney to amend to 65/55. Pay fines and costs. Paid in full. (2) Operating on suspended license. Motion by County Attorney to dismiss, showed proof.

...paired, 3rd> offense within <five years. PNG. Set for preliminary hearing on 5-11-99. $1,000 unsecured to be signed by property owner.

Mark A. Flannery. Show cause hearing. Bench warrant issued, 4-12-99. Money due, $474. Bonded out of jail.

Robert Lightner. Arraignment. (1) Operating ATV on roadway. (2) Operating ATV without head gear. (3) No eye protective device MCY. (4) Operating motor vehicle controlled substance impaired, 3rd> offense within <five years. (1) Driving DUI suspended license, 2nd. PNG. Set for pre-trial on 6-1-99. License suspended until pre-trial. Appoint T. Bertram. Bond set at $4,000 cash.

Steven Leroy McCormick. Arraignment. Failure to appear 9-3-96, for arraignment. Resident hunt/fish/trap without license/stamp. PG. $25 fine and costs.

John Thomas. Arraignment. (1) Criminal trespassing, 3rd. (2) Menacing. Set for sentencing on 5-18-99. Stay away from complaining witness. Released on own recognizance.

William Wicker. Assault, 4th. PG. Six months, conditionally discharge, two years. 1.) Violate no law. 2.) Attend and complete counseling for domestic violence. 3.) Pay costs.

All information contained in the "Court News" is directly taken from the dockets of the Lewis County Circuit and District Court.

ered by HUD. No objection received after June 6, 1999 will be considered by HUD.

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

Am. El. Power.

NOTICE

The Clay County Board of Education will receive bids at 128 Richmond Road, Manchester, Kentucky for Office Supplies until 10:00 A.M. May 21, 1999. Specifications and bid forms may be obtained at the Clay County Board of Education office in Manchester, Kentucky. The Board reserves the right

tion will receive bids at 128 Richmond Road, Manchester, Kentucky for Custodial/Maintenance Uniforms until 1:00 P.M. May 25, 1999. Specifications and bid forms may be obtained at the Clay County Board of Education office in Manchester, Kentucky. The Board reserves the right to reject any or all bids.

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described above with HOME funds from the U.S. Department of Housing and Urban Development (HUD) under Title II of the National Affordable Housing Act of 1990. KHC is certifying that KHC as State Participating Jurisdiction consents to accept the jurisdiction of the Federal courts if an action is brought

Am. Elect. power

REAL ESTATE CLASSIFIEDS

REAL ESTATE

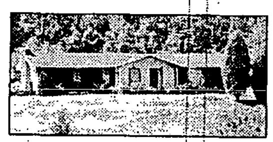
FOR SALE Four acres with 30X50 ft. Building, 2 sewers with city water. One mile from US 23 Louisa on Rt. 3 North. (606) 686-2469. 5/19.

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint *Application of Kentucky Power Company,* American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

FOR SALE 200 acres with mineral rights off paved raod. This property is minutes from Yatesville Lake, Louisa, and Fallsburg. Great buy for investment or farm. Hunters can appreciate the game available. Contact Betty Hager, Rt 5 Box 440, Louisa, Ky. 41230 (606) 638-4837 after 6:00 p.m or Wes Heston at (606) 638-4472. 5/19.



FOR SALE Over 2,000 sq. ft. living space, formal dining and living room. 3 br, 2 ba, lg walk in closets, breakfast area, huge family room, w/fireplace/gas logs and guest house, 4 acres one ml from courthouse on Murray Rd. Additional 8 acres also for sale. Call (606) 298-7578.

FOR SALE: 3 bd home, 2 ba., large living room, dining room, walk-in-closets, central heat/air. Heat pump, fireplace with gas logs. 1 mile from courthouse. 4 acres with new roof, 8 acres of additional land. Guest house with porch. Over 2,000 sq. ft House also has large front porch. Call (606) 298-7578 after 4 p.m. (tfn)

FOR SALE 97 acre farm in Lawrence county, Fallsburg area, 10 minutes from Yatesville Lake, with 5 year old 3 BR home, 2 1/2BA, family room, fireplace, heating/cooling, and a new 30X50 foot cattle and hay barn. Also has diesel International tractor and numerous farming implements included. Shown by appointment only and serious inquiries only. Call (606)686-3267 rtc

FOR SALE Lovely 2 story home on large corner lot on Lady Washington Street in Louisa. Downstairs has bedroom, large bath, huge kitchen with breakfast room, pantry/laundry room, large dining room. family room with gas logs *in fireplace and living room. Upstairs 4 bedrooms and a playroom or 5th bedroom, large bath with wide hallway and storage closet. Two large covered porches.* Contact Betty Hager, Rt 5 Box 440, Louisa, Ky. 41230, (606) 638-4837 after 6:00 p.m. or Wes Heston at (606) 638-4472. 5/19.

FOR SALE 12X65 2 BR Trailer

USED HOME for sale $1,800. **CASH ONLY.** Call Freedom Homes 492-1600 or (606) 478-8259.

PERMANENT AFFORDABLE HOUSING Latest building concept, financing available, we will work with you to overcome past credit problems, including bancrupcy. Contractor and dealer inquiries welcome. Call toll free 1-888-615-9988. 5/19

FOR SALE 14X70 mobile home, 3 BR, 2 BA, stove, refridgerator, washer, dryer, central heat and air, front deck. Located on Coldwater, close to all 3 schools. Price $7,900.00 cal.l(606) 298-7432. 5/19.

FOR SALE Farm on Collins Branch at Coldwater. 130 acres surface oil and gas 230 acres of coal. 3-4 acres of flat land ideal building site. Surface seam of coal leased to Martin County coal. Deep mining has not been leased. 1 or 2 active gas wells. Free gas for owner, also gas royalities. Hand dug well with ample supply of water. Will sell all including lease of coal and gas royalities. Asking *$200,000 (negotiable). If interested call (614)443-1054. (5/26)*

FOR SALE BY OWNER SPLIT LEVEL BRICK sits on 4 acres, with 3 bedrooms, 2 baths, large living room, dining room, kitchen and family room with fireplace, above ground pool with decking and out building. RT 3 N. Reduced to sell. Call 298-

FOR SALE 4 acres level property with house, 5 rooms, bath, free gass, good for trailer park or housing development on Rt 292 near Riverfront Mkt. Price $125,000 Call (606) 395-6231. 5/19

HOUSE FOR SALE on Main Street in Inez, 4 bedrooms, 1 1/2 baths, Central heat and air conditioning. Reduced to $39,000 Call (606) 623-5017. (rtc)

HOUSE FOR SALE 4 BR house, 1 /4 mile on Coldwater, at Lafferty/ Coldwater Lane. Living room, kitchen, utility room, and bath. New vinyl siding, central heat and air, large fenced yard, and 2 storage buildings, If interested call (606) 298-3809 after 4 p.m.

3 bedroom house in Louisa, well maintained, large garage, and tool room, conbination kitchen and dining area, large bedrooms, and closets. Must see to appreciate. Call (606) 638-0908

HOUSE FOR SALE Brick 3 BR, 2 BA small fenced yard. Above the 77 flood stage. 7 years old. In excellent shape, located in Warfield, Ky. Call (606) 395-7140. 5/12

FOR SALE *2 story country home near Yatesville Lake. One mile past Rt. 1185 on Rt. 3 North. 3 BR, BA, WBF 18 acres m/l wooded.* Price $74,500 Call (606) 686-2484. 5/26

FOR SALE Nice, 3 Br, 2 full bath bay ranch, large living room, formal dining, eat in kitchen, oak

WARD'S MINI STOR[A]... cated beside Ward Ch... Blacklog. 24 storage un... 8x12's, 10x12's, and 10x... 298-3561 (days) or 298-... ter 5 p.m.) rtc.

RENTAL SPECIA[L] **TWELVE OAKS** On... room apt. $400.00. mon... all utilities paid and 2 B... $250.00 monthly renter... utilities., $100.00 deposit... Call 298-3916 (tfn)

MOBILE HO...

NEW 14 wide 3 BR 2... $185 per mo. Free air. 1-... 6777.

4 BR HOUSE for rent re... completely, large living r... ing area, kitchen, cent... Plenty of garden space. $3... month. Deposit same as r... (614) 443-1054. 5/26

FOR SALE 14X70 mo... 2 BR, 1 BA, all electric, contidion. Can be s... *appoionment at Pointvi... Paintsville. Call (606) 2...*

NEW 4 BR 16 wide $50... $219 per mo. Free air. 1-80... 6777.

ZERO Down on land and ho... nancing package. Call Fre... Homes. 478-1600 or 1-800... 8259.

Am. Elect. power

(606)298-7570

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

NOTICE OF INTENTION TO MINE
Pursuant to Application Number 880-7012

In accordance with KRS 350.055, notice is hereby given that 17 West Mining, Inc., 1500 North Big Run Road, Ashland, Kentucky 41102, has applied for a permit for a surface coal mining and reclamation operation affecting 175.41 acres located 2 miles south of Moree in Martin County. The proposed operation will be located in both Pike and Martin Counties.

The proposed operation is approximately 1 mile south from Route 1439 junction with Lowgap Fork and located 0.10 miles east of Lowgap Fork. The Latitude is 37 degrees 41' 44" and the Longitude is 82 degrees 30' 31".

The proposed operation is located on the Thomas and Varney U.S.G.S. 7 1/2 minute quadrangle maps. The operation will be a haulroad permit only. The surface owners are Pocahontas Development Corporation, Price Rice, Oliver Brown, et. al., Denzel Lowe, and Clell Fraley.

The application has been filed for public inspection at the Department for Surface Mining Reclamation and Enforcement's Prestonsburg Office, 1346 South Lake Drive Prestonsburg, Kentucky 41653. Written comments, objections, or request for a permit conference must be filed with the Director, Division of Permits, #2 Hudson Hollow, US 127 South, Frankfort, Kentucky 40601.

This is the final advertisement of this application; all comments, objections, or requests for a permit conference must be received within thirty (30) days of this date.

NOTICE TO BID

a is owned by Pocahontas Development rporation and 17 West Mining Inc.

4) The application has been filed public inspection at the Department for rface Mining Reclamation and forcement's Prestonsburg Regional ice, 1346 South Lake Drive, stonsburg, Kentucky 41653. Written nments, objections or requests for a mit conference must be filed with the ector, Division of Permits, No. 2 dson Hollow, U.S. 127 South, Frankfort, ntucky 40601.

19, 20, 21 f.

NOTICE OF INTENTION TO MINE
Pursuant to Application Number 480-0046, Renewal

1) In accordance with KRS .055, notice is hereby given that 17 st Mining, Inc., 1500 North Big Run d, Ashland, KY 41102 has applied for wal of a permit for a surface coal ing and reclamation operation affecting 9 acres located 5 miles southwest of rim in Martin County.

2) The proposed operation is oximately 3.5 miles southwest from 1439 junction with KY 1714 (formerly and located 2.75 miles southwest of confluence of Petercave Fork and onroost Fork. The Latitude is 37° 44' and the Longitude is 82° 28' 58".

3) The proposed operation is ed on the Kermit and Varney U.S.G.S. 2 minute quadrangle maps. The ation will use the contour and ntaintop removal method of surface ng. The surface area is owned by hontas Development Corporation and est Mining, Inc.

4) The application has been filed ublic inspection at the Department for ace Mining Reclamation and rcement's Prestonsburg Regional e, 1346 South Lake Drive, onsburg, Kentucky 41653. Written nents, objections or requests for a it conference must be filed with the tor, Division of Permits, #2 Hudson ow, U.S. 127 South, Frankfort, ıcky 40601.

, 20, 21 f.

NOTICE OF BOND RELEASE

Lake Drive, Suite 6, Prestonsburg, Kentucky 41653-1410. The hearing will be canceled if no request for a public hearing or informal conference is received by 06/25/99.

18, 19, 20, 21f

NOTICE OF BOND RELEASE

(1) In accordance with KRS 350.093, notice is hereby given that Martin County Coal Corporation, P.O. Box 5002, Inez, Kentucky 41224 has applied for a Phase I bond release on permit no. 880-0109. Increment #7 which was last issued on 06/13/98. Increment #7 covers an area of approximately 74.80 acres, located 1.0 mile east of Preece Kentucky in Martin County.

(2) The permit area is approximately 1.0 mile east of KY Rt. 908's junction with Hurricane Branch Road and east of Cassady Branch. The latitude is 37° 48' 30". The longitude is 82° 29' 30".

(3) The bond now in effect for Increment #7 is a Surety bond in the amount of $265,500.00. Approximately 60% of the original bond amount of $265,600 is included in the application for release.

(4) Reclamation work performed includes; Backfilling, grading, seeking and mulching completed in the Spring of 1999.

(5) Written comments, objections and requests for a public hearing or informal conference must be filed with the Director, Division of Field Services, No. 2 Hudson Hollow, Frankfort, Kentucky 40601 by 06/25/99.

(6) A public hearing on the application has been scheduled for 06/28/99 at 9 a.m. at the Department for Surface Mining Reclamation and Enforcement's Prestonsburg Regional Office, 3140 South Lake Drive, Suite 6, Prestonsburg, Kentucky 41653. The hearing will be canceled if no request for a public hearing or informal conference is received by 06/25/99.

18, 19, 20, 21f

LEGAL NOTICE

The following cases will come on for hearing on 6-1-99 at 9:00 a.m. in the Martin District Courtroom, Courthouse Annex, Inez, Ky. before Hon. Daniel R. Sparks, Martin District Judge. Any objections should be filed before that date.

Freda Fannin, Guardian of the Minor Child Autumn Fannin, have filed

Am. Elect.

604 - AUTOMOBILES

FOR SALE
1994' Pontiac Grand-Am, 4-door, child safety, extended warranty, new tires, call **(606)639-2610.**

605 - HEAVY EQUIPMENT

1980 450C John Deere Dozer, good cond., central a/c, 432-3295 or 437-0681

620 - MOTORCYCLES

FOR SALE: 1996 Honda Magna 750, excellent condition 606-427-7355

622 - RECREATIONAL VEHICLES

Terry Travel Trailer, 29', exc. cond., fully equipped, C/H., A/C, blt.-in stereo, sleeps 6. $5,500. 432–9416

86 Kawasaki 185, 4 wheeler with reverse, needs repairs but you can still ride it, asking $650.00, 606-754-9556

650-LEGALS

NOTICE OF INTENTION TO MINE
Pursuant to Application Number 498-5411 Major Revision #7

In accordance with the provisions of KRS 350.070, notice is hereby treating substandard water, access to the tank sites, a slide area and dewatering borehold sites. This revision also proposed to permit a small area for underground mining operations. The major revision will affect an area within 100 feet of Mudlick Branch public road. The major revision will not involve relocation or closure of the public road.

The major revision application has been filed for public inspection at the Department for Surface Mining Reclamation and Enforcement's Pikeville Regional Office, 109 Mays Branch Road, Pikeville, Kentucky 41501-2289. Written comments, objections, or requests for a permit conference must be filed with the Director, Division of Permits, #2 Hudson Hollow, U.S. 127 South, Frankfort, Kentucky 40601.

This is the final adver-

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

to be disturbed is owned by Wolf Creek Collieries Company, Inc., Emma Goff Heirs, Kentucky State Department of Transportation, George Runyon, J. B. Goff Land Company, Howard and Nancy Pruitt, John Dove, John Henry Davis, Dennis and Lassie

tisement of the application. All comments, objections or requests for a permit conference must be received within thirty (30) days of today's date.

4-21-28-5-5-12-4tc

NOTICE OF BOND RELEASE

01192-052 the Commonwealth of Kentucky, Transportation Cabinet, Department of Highways has deemed it necessary to relocate one or more unidentified graves located in the community of Canada KY, more fully described as follows:

The Stottridge Cemetery; parcel 101 is located on the property of Bennett West et al; Parcel 42 and is found on the existing US 119, 0.7 mile north of the intersection of US 119 and Big Creek Road at Sidney. The cemetery contains nine (9) or more graves of which one grave (1) is identified by name.

REBECCA STOTTRIDGE 1806-1887

The Department of Highways hereby requests information from anyone having knowledge of the identity of the Unknown graves, next-of-kin, or family member having a legal interest in the remaining graves to be relocated.

PLEASE CONTACT:
Kentucky Department of Highways
Lanny R. Damron
Right of Way Agent, Pr.
P.O. Box 2468
Pikeville, Ky. 41502
(606) 433-7791 ext. 261
FAX: (606) 433-7765
E-mail: ldamron@mail.kytc.state.ky.us

cation for release Reclamation worl formed onIncreme 2 includes: backf final grading, se and mulching pleted in March of Written comments, tions, and request: public hearing or mal conference mi

Appl

blocked open.

Whenever changing your furnace filter be sure to replace your fan compartment door.

Never cover fresh air vents that supply air to your gas appliances.

Have all gas line alterations and appliance repairs performed by a professional

Before digging in your yard, be sure you know the location of underground gaslines. Call us:

Write your fire and police department phone numbers and our emergency service number in the front of your phone book.

Anytime you suspect a gas leak or potential gas emergency, call the hazard public work department. We respond to emergency calls. Telephone numbers to call:

City of Hazard, Ky. Maintenance Dept. 606-439-1863, Day

City of Hazard, Ky. Police Dept. 606-436-2222, Night.

1x-5/12-c-coh-25

PUBLIC HEARING

A public hearing will be held by the City of Hazard in the council chambers at City Hall on Tuesday, May 18, 1999, at 7:00 p.m. for the purpose of obtaining written or oral comments from citizens regarding the proposed use of municipal road aid funds and local government economic assistance funds for the upcoming fiscal year 1998-99. All interested citizens, groups, senior citizens, and organizations are invited to the public hearing to submit written and/or oral comments on the use of these funds. During the fiscal year 1999-2000 the City of Hazard expects to receive $90,000 in municipal road aid funds and $220,200 in local government economic assistance funds.

1x-5/12-c-coh-26

BUDGET HEARING

A public hearing will be held by the City of Hazard at City Hall on Tuesday May 18, 1999, at 7:00 p.m. for the purpose of obtaining written and oral comments from citizens regarding the proposed annual budget as summarized below:

General Fund, $3,123,800; Local Government Economic Assistance, $200,200; Road Aid Fund, $95,100; DARE Program, $25,600; Mayor/Commissioners Recreation Fund, $1,100; Fire Dept. Equipment Fund, $5,000; Jack Lot Hollow Dev. Trust, $50,000; Public Improvements Corp., $325,000; Pension Fund, $146,000; Lost Creek - Harveyton, $1,900,000; Gas Fund, $1,992,000; Garbage Fund, $650,000; Hazard Pavilion Fund, $220,000; Water Fund, $1,600,000; Sewer Fund, $1,167,000; Total All Funds, 11,500,800.

Road aid funds are to be appropriated to the road maintenance in the amount of $60,000. From LGEA funds.

Hudson Hollow, U.S. 127 South,
Frankfort, Kentucky 40601.

4x-5/12-6/2-c-gom-28

ACCEPTING BIDS

Law Books & Misc. Office Equipment. Peoples Bank & Trust Co. will be accepting bids as of 5-13-99 through 5-27-99. Contact Mike at 487-7232. Peoples Bank reserves the right to reject any and all bids.

2x-5/12-19-c-pb-29

ACCEPTING BIDS

1986 W900 Kenworth: Ser # 1XWD29X1G5330310. Peoples Bank & Trust Co. will be accepting bids as of 5-13-99 through 5-27-99. Contact Mike at 487-7232. Peoples Bank reserves the right to reject any and all bids.

2x-5/12-19-c-pb-31

NOTICE

I, Charles Moore, Jr., of Coal Ridge Trailer Park (Grapevine), will not be responsible for any debts incurred by anyone other than myself after this date, May 12, 1999.

1x-5/12-p-cmj-32

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

More Legals on Page 2C

Am. Elect
Dereck

Classified and Legal Notice

Ty Beanies

NOW OPEN
Marie's New & Used Novelties
New Shipment of
Beanie Buddies

Ty Beanie
Babies & Buddies
For Sale

Call: 642-3039 or leave a message located on Rt. 160, Litt Carr above Kings Odds & Ends, inside grey two car garage, trimmed in red. Look for NOW OPEN sign.

Services

I Repair Lawn Mowers, Tillers, Chain Saws and Weed Eaters. Over Ten Years Experience. I also Sell New & Used Parts.
Call 785-5423

AUTO SERVICE
Shadetree Auto. 24-hr. towing. Steam Genie Service (mobile). Now open at the mouth of Slone Fork on Route 550. Phone 785-5852.
886:5/12:4t:pd

PUBLISHER'S NOTICE: EQUAL HOUSING OPPORTUNITY
All real estate advertisements in this newspaper are subject to the Federal Fair Housing Act of 1968, which makes it illegal to advertise "any preference, limitation or national origin, or any intention to make any such preference, limitations or discrimination."

Miscellaneous

FOR SALE: Two tickets to Indianapolis 500.
Fourth turn seats. $50 each face value. Call Dan 251-3231 (days) or 251-3745 (evenings and weekends).
868:5/5:2t:pd

Resale Shop
Resale Shop with miscellaneous items has opened on Route 550 at the mouth of Slone Fork. Call 785-5862.
887:5/12:4t:pd

WHY PAY RETAIL??
Front Doors Are Our Specialty!
Factory Direct Pre-Hung Exterior Door Units....At Super Discounts!
Steel•Fiberglass•Mahogany•Teak
BRING A TRUCK!!

6 panel steel	$75
9 lite steel	$119
6 panel fiberglass	$149
5' steel patio	$275
3' oak	$395

Toll Free: 1-877-244-3667
REGENCY DOOR OUTLET
Tues.-Fri.: 9:30 AM-6PM
Saturday: 10 AM-5 PM
Sun. & Mon.: CLOSED
2519 Regency Rd.
Lexington, Ky.
Jim Calhoun - Owner/Manager

WANTED

WANTED 97 People!!!
We'll PAY you to lose up to 29 pounds!
CALL Toll FREE 1-800-378-4504
869:5/5:4t:pd

WANTED
Housekeeper/Babysitter. Must be dependable. 447-2496.
877:5/5:2t:pd

SUPER
$1000 Sign On Bonus For Experience!
Tractor trailer drivers needed for long distance

Buying Timberlands
We pay **top prices** for timberland ready to cut now **Or** ready to cut in 10 to 15 years **Or** timberland cut recently. We also buy timber on the stump. For more information. Call Toll Free, without obligation: 800-326-8325, ext. 366 or ext. 205.
Kentucky Bright Timberlands LLC
863:5/5:4t:bl

NOTICE OF PUBLIC HEARING
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Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

PETS

Needs a home
Found blind, white, male, Shitzu, on Knott/Floyd Co. between Bevinsville and Bypro, on Route 1091, near Route 122. We can not keep him. Call 368-2453.
890:5/12:2t:nc

Chihuahua puppies
Chihuahau puppies for sale. Call 606-886-2087.
892:5/12:1t:pd

Employment Opportunities

No door to door sales. Sell to family and friends. Can do parties and fundraisers. Call 785-5900 785-

Am. El. Power.

I, **Heath Waugh**, am no longer responsible for any debts other than my own.

867:5/5:3t:pd

Legal Notices

COMMONWEALTH OF KENTUCKY
KNOTT DISTRICT COURT
FILE NO. 99-P-00034

In the matter of the Estate of
Charles Osborne
NOTICE

Pursuant to KRS 424.340, notice is hereby given that Socie Osborne was on the 20th day of April, 1999 appointed Executrix of the estate of Charles Osborne, deceased, late of this county, and all persons having claims against said estate shall present same, verified according to law, to said Socie Osborne at her present address of 3296 Hwy. 7 South., Dema, Ky. 41859, not later than Oct. 20, 1999.

Carlos Huff
Clerk
Knott District Court

846:4/28:3t:pd

COMMONWEALTH OF KENTUCKY
KNOTT DISTRICT COURT
FILE NO. 99-P-00027

In the matter of the Estate of
Buena Gail Little
NOTICE

Pursuant to KRS 424.340, notice is hereby given that Stanley Little was on the 22nd day of April, 1999 appointed Administrator of the estate of Buena Gail Little, deceased, late of this county, and all persons having claims against said estate shall present same, verified according to law, to said Stanley Little at his present address of Box 39, Kite, Ky. 41828, not later than Oct. 22, 1999.

Carlos Huff
Clerk
Knott District Court

848:4/728:3t:pd

COMMONWEALTH OF KENTUCKY
KNOTT DISTRICT COURT
FILE NO. 99-P-00021

In the matter of the Estate of
Abel Kelley
NOTICE

Notice of Bond Release

NOTICE OF BOND RELEASE
Permit No. KY-065

In accordance with the provisions of KRS 350.083, notice is hereby given that Southeast Coal Co. PO Box 507, Isom, KY 41824, has applied for a Phase III bond release of Permit No. KY-065. The application covers a total area of 73.5 underground acres located near Red Fox, KY in Knott County.

The permit area is approximately 0.42 miles N. E. and 0.17 miles S. E. from KY 15 junction with Perkins Branch RD. and located 1.10 miles East and 1.02 miles S.E. of Red Fox, KY. The Latitude is 37 12' 50". The longitude is 82 55'18".

The bond now in effect for the permit is a surety bond in the amount of $10,000.

This is the final advertisement of the application. Written comments, objections and requests for a public hearing or informal conference must be filed with The Office of Surface Mining, 2675 Regency Road, Lexington, KY 40503 by June 11, 1999.

A public hearing on the application has been scheduled for June 14, 1999 at 10:00 am at the Office for Surface Mining, 2675 Regency Road, Lexington, KY 40503. The hearing will be canceled if no request for a hearing or informal conference is received by June 11, 1999.

834f:4/21:4t:pd

Mobile Homes

Mobile Home For Sale

Dutch Home 70 x 28, **REDUCED TO** $37,000. Only Two-Years Old. In Immaculate Condition. Large Bedrooms. Oak Cabinetry. Energy Efficient. Call 606-874-9777.

891:5/21:3t:wp

Class

recruiting, case management, maintaining files, administering assessment tools, leading job exploration workshops, and conducting client follow-ups. The position requires occasional travel and frequent contact with the public.

Applicants must have excellent verbal and written communication skills, a professional attitude, and the ability to work with a team. Applicants will benefit from knowledge of local labor markets and laborforce needs, facilitation techniques, and experience in career counseling.

A Bachelor's Degree from an accredited college or university is required; however, related work experience may be substituted for education at a two-to-one ratio (two years of related work experience for each one year of formal education).

Qualified applicants may submit resumes no later than May 21, 1999, to:

Marsha Ison
Personnel Director
Eastern Kentucky CEP, Inc.
941 N. Main Street
Hazard, KY 41701
Eastern Kentucky C.E.P., Inc. is an Equal Opportunity Employer.

STORE MANAGER

Fast-growing rental company looking for store manager. Must be energetic and motivated with a desire to succeed. Competitive salary and benefits. Apply in person at **A-Plus Rent to Own**, Pikeville.

WANTED: Avon Representatives. Must be 18 and above. Reward yourself with extra money and gifts. Call 297-6813.

UNEMPLOYED VETERANS
FREE JOB TRAINING
(CDL OR ANY SHORT-COURSE).
FIRST MONTH RENT,

Country (all by C. Mitchell Hall. Send offers to S.M. Castle, 2700 Cox Mill Road, Hopkinsville, KY 42240; phone 502-885-6389.

SERVICES

C&C TAX AND BOOKKEEPING SERVICE
5788 U.S. Highway 23 North
Approximately 2 miles north of W.R. Castle School
Nippa, KY 41240

Personal and business income tax returns, employee quarterly tax returns, sales tax, coal tax, highway usage tax, fuel tax. We offer electronic tax filing. We offer quick refund. You often receive your refund in 24 to 48 hours. Computerized bookkeeping, profit and loss statements, billing services and computerized payroll preparation. Phone 606-297-6217 or 606-297-6218; after hours call 606-297-3013.

ODD JOBS: Painting; lay plastic under dwellings; wash trailers, houses, windows; housework; light hauling; roofing. Free estimates. Experienced. Call 297-4016 or 788-0496.

FREE PAGER TO THOSE WHO QUALIFY! Long distance phone service for 7.9¢ per minute (pro rated to the second). Call 673-4361.

WOULD LIKE TO DO housekeeping and office cleaning Monday through Saturday. Reasonable rates. Please call 265-3516, ask for Barbara.

BACKHOE, DOZER AND DUMP TRUCK work at reasonable prices. Licensed installer for septic systems. Free estimates. Call 434-4063, anytime; 788-9113, days; or 789-7438 after 5:30 p.m.

COMBS' LAWN ...

Daniels. Anyone owing said estate shall pay promptly and all claims shall be filed within six months of date of notice.

Herbert Daniel
40 Riverdale Drive
Thelma, KY 41260

PROBATE CASE
CASE NO. 99-P-00065

Notice is hereby given that Doug Young has been appointed fiduciary of the estate of Lora Evangeline Young. Anyone owing said estate shall pay promptly and all claims shall be filed within six months of date of notice.

Doug Young
P.O. Box 97
Lowmansville, KY 41232

PROBATE CASE
CASE NO. 99-P-00067

Notice is hereby given that Joyce Vanhoose and Alton Fairchild have been appointed co-fiduciaries of the estate of Phyllis Grimm. Anyone owing said estate shall pay promptly and all claims shall be filed within six months of date of notice.

Joyce Vanhoose
615 Washington Avenue
Paintsville, KY 41240
Alton Fairchild
1136 Maple Street
Paintsville, KY 41240

PROBATE CASE
CASE NO. 99-P-00066

Notice is hereby given that Dottie Stamper has been appointed fiduciary of the estate of Luther Stamper. Anyone owing said estate shall pay promptly and all claims shall be filed within six months of date of notice.

Dottie Stamper
Box 658
West Van Lear, KY 41268

Gullett. Anyone owing said estate shall pay promptly and all claims shall be filed within six months of date of notice.

Flora Rose Kestner
P.O. Box 375
Hager Hill, KY 41222

PROBATE CASE
CASE NO. 99-P-00069

Notice is hereby given that Roy Douglas Blair has been appointed fiduciary of the estate of Dixie Ray Blair. Anyone owing said estate shall pay promptly and all claims shall be filed within six months of date of notice.

Roy Douglas Blair
4036 KY Hwy. 825
Denver, KY 41222

FINAL SETTLEMENT
CASE NO. 98-P-00170

Notice is hereby given that Emalene Mullins, fiduciary, has tendered final settlement to the Johnson County District Court, Probate Division, this 27th day of April, 1999, which settlement will be filed for exception in District Court, Probate Division, on the 1st day of June, 1999.

The estate of Dewey Mullins, deceased.

Vicki (Crace) Rice, Clerk
Johnson Circuit Court

FINAL SETTLEMENT
CASE NO. 98-P-00198

Notice is hereby given that Maxine Blair, fiduciary, has tendered final settlement to the Johnson County District Court, Probate Division, this 5th day of May, 1999, which settlement will be filed for exception in District Court, Probate Division, on the 7th day of June, 1999.

The estate of Marshall Blair, deceased.

Vicki (Crace) Rice, Clerk
Johnson Circuit Court

ifieds

Am. E. power

:ourt, Probate Division, iis 27th day of April, 1999, which settlement will be led for exception in District :ourt, Probate Division, on ie 1st day of June, 1999.

he estate of Reuben :oots, deceased.

Vicki (Crace) Rice, Clerk
Johnson Circuit Court

FINAL SETTLEMENT
:ASE NO. 97-P-00089

otice is hereby given that 'pal Daniels Ford, fiducia-, has tendered final settle-ient to the Johnson ounty District Court, robate Division, this 29th ay of April, 1999, which ettlement will be filed for xception in District Court, robate Division, on the 1st ay of June, 1999.

he estate of Asa Daniels, eceased.

Vicki (Crace) Rice, Clerk
Johnson Circuit Court

INVITATION TO BID

he Big Sandy Regional ail Authority will be renew-g contracts for fiscal year ily 1, 1999, through June), 2000, for the Big Sandy egional Detention Center.

ids will be received for nployee health insur-ice, an employee life surance for $10,000, iilding and liability insur-ice, Workers' ompensation insurance, ilk/dairy products, ead/bread products.

ds will also be received r snack cakes, chips, soft inks, individual candy irs, cigarettes (brand and eneric), tobacco products, ersonal hygiene items and paper writing products.

Bids will be received until May 31, 1999, and will be awarded on June 9, 1999. Specifications may be obtained by calling Ken O'Bryan, 606-297-5245, Monday-Friday, 8 a.m.-4 p.m.

Bids shall be mailed to: Big Sandy Regional Detention Center, Attn: Bid, P.O. Box 1390, Paintsville, KY 41240-5390.

Ken O'Bryan
Administrator
Big Sandy Regional
Detention Center

INVITATION TO BID

The Johnson County Board of Education will be accepting sealed bids on athletic equipment for the 1999-2000 school year.

Bids will be received until May 19, 1999 at 2:00 p.m. Specifications may be obtained by contacting Jeff Reed, Bid Coordinator, Johnson County Schools, 253 N. Mayo Trail, Paintsville, Kentucky 41240. Telephone 606-789-2530.

Orville L. Hamilton
Superintendent
Johnson County Schools

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

INVITATION TO BID

The Johnson County Board of Education will be accepting sealed bids on Health Items for the 1999-2000 school year.

Bids will be received until May 19, 1999 at 1:00 p.m. Specifications may be obtained by contacting Jeff Reed, Bid Coordinator, Johnson County Schools, 253 N. Mayo Trail, Paintsville, Kentucky 41240. Telephone 606-789-2530.

Orville L. Hamilton
Superintendent
Johnson County Schools

INVITATION TO BID

The Johnson County Board of Education is accepting sealed bids for the following school bus supplies: 1. Fuel & Lubricants; 2. Tires

CONTINUED...

YARD SALE

YARD SALE - May 13th, 14th & 15th; rain days will be May 20th, 21st & 22nd. Old Lick Road 1st turn on left past Dollar Store. First gray house on left across the creek. Big women and men's clothing, lots of Home Interior and other miscellaneous items. (5/12 pd)

****

FOR LEASE

WANTED

HELP WANTED - Computers Plus is seeking a regional sales associate for our Paintsville office. Must have minimum one-year sales experience preferably in service or contract sales. Some computer knowledge is necessary. Ideal candidate to have computer service sales experience. Fax resumes to 606-789-1126 or mail to 241 College Street, Paintsville, KY 41240. (4/14 TFN)

****

HELP WANTED - The Lexington Herald-Leader

Kentucky. 606-474-5118 or 1-800-880-6453. (TFN)

****

SPORTS, NEWS, AND ENTERTAINMENT HOT-LINE!! 24 hours, 7 days/week!! Call 1-900-226-8461 Ext. 3325. $2.99

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Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

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1999

QUOTABLE QUOTE

There are no unmotivated people, only unchallenging goals. Make your goals believable and exciting — and make sure that they challenge you without discouraging you. Set goals for health and vitality, and for improving relationships and character. Lackluster goals will remain on the shelf like a bad book. But powerful goals will ignite your hottest fires so that you get them done . . . now!

Eric Jensen

QUOTABLE QUOTE

It must be borne in mind that the tragedy of life doesn't lie in not reaching your goal. The tragedy lies in having no goal to reach. It isn't a calamity to die with dreams unfulfilled, but it is a calamity not to dream....It is not a disgrace not to reach the stars, but it is a disgrace to have no stars to reach for. Not failure, but low aim is sin.

Benjamin Mays

Classifieds Get Results!

drove back to Morehead to show Carrie all the beautiful scenery and flowering trees. It was fun for them. Thank you.

Curt and Freda Tussey were having dinner at the Frosty Freeze and visited with a lot of friends.

Tracey Elliott Stakelback of Tennessee recently visited with her parents, Sandy and Larry Elliott, of Paris. Tracey and Sandy visited with her grandmother, Loretta Gilliam, in Sandy Hook. Others dropping by were Myrtle and Loverta Dickerson, John, Linda, Lisa and Linsey May, Garnetta Fannin, Gloria and Jason

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Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
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CLASSIFIED ADS
RATE: 30¢ Per Word • $3 minimum
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SUBSCRIPTION RATES:
$14 in County; $16 in Kentucky; $17 Out of State
Poetry • Memorial Letters • Late Obituaries — $9
Card of Thanks — $8

THE ELLIOTT COUNTY NEWS does not knowingly accept help wanted ads that include a preference based on age from employers covered by the Age Discrimination in Employment Act. More information may be obtained from the Wage-Hour Office at 188 Fuller Building, 120 West Second Street, Lexington, KY 40507. Telephone 606-252-2312. Nor does THE ELLIOTT COUNTY NEWS knowingly publish real estate ads that show a preference based on sex, national origin, race, religion, etc.

CLASSIFIEDS

OR SALE — Two tanning beds. One unquest Pro 32XL, 36-bulb, $2,000; one un, 32-buld with radio/cassette player, 1,500. Call 606-668-6243 or 606-668-446.
5-13-TFJBS

OR SALE — 1973 12x65 trailer, partly ırnished, two bedroom, two baths. Call 58-6512.
5-13-1TPD

OR RENT — Two bedroom house on 'ells Creek. $250 a month plus $250 eposit. Call 738-5273 or 738-9655.
5-13-1TPD

OR SALE — 12x60 trailer. Asking ,600. Floor and wall tile. Asking $300. ıll 668-7133.
5-13-1TPD

OR SALE — 1991 Subaru Legacy, ur door, four-wheel drive, 243,000 iles, runs good. $700, or best offer. Call 3-2384.
5-13-1TPD

ARY'S FLORAL CREATIONS — lk flower arrangements for all occans. Located on KY-191, Hazel Green, ntucky. Call 662-9587.
5-13-3TPD

ANTING TO BUY — Land contract purchase 40 acres or more with or thout older home. Call 606-487-0048.
5-13-4TPD

NOW AVAILABLE — Two and three bedroom apartments. Central air and heat, 24-hour access to laundry facilities, free maintenance, water and garbage collection. Rent based on monthly income. No pets allowed. Contact the business manager during business hours, Monday through Friday, 9:00 am to 1:00 pm, at 668-3555 or TDD# 1-800-247-2510. Campton Methodist Housing. An Equal Housing Opportunity.
5-13-TFJBS

APARTMENTS NOW AVAILABLE — One bedroom apartments now available in the elderly section. Fully carpeted, electric heat and air conditioning, free maintenance and garbage collection, 24-hour laundry facility. Contact the business manager of Campton Methodist Housing, during regular business hours between 9:00 am and 1:00 pm, at 668-3555 or TDD# 1-800-247-2510. An Equal Housing Opportunity.
5-13-TFJBS

HANDY RENTALS, CONSTRUCTION TOOLS AND EQUIPMENT — John Deere 450G dozer; Thomas skid steers; portable restrooms. Call 606-780-0204 or 1-888-858-6300.
5-13-TF

FOR RENT — Mobile home and trailer lot. Call 743-4135.
5-13-TF

FOR SALE — Peavey PA system, consists of amplifier, six speakers, five mikes with cords, five adjustable floor mike stands. $2,000. Call 606-668-6243 or 606-668-3446.
5-13-TFJBS

MOUNTAINEERS — A sports history of Hazel Green Academy (1880-1983), 963 pages. $41 postpaid from author, Bob Bickers, 407 West 200 South, Hyrum, Utah 84319.
5-13-2TPD

FOR SALE — 105 acres (78 acres woodland, 27 acres cropland). Located in Magoffin County. Contact James Whitt at 614-876-0597.
5-13-2TPD

FOR SALE BY OWNER — 1980 Ford Fairmont Wagon, great condition, new tires, automatic, power steering, power brakes, air condition, $800; 1986 Oldsmobile Cutlass Cirea, automatic, power steering, power brakes, air condition, new vinyl top, excellent condition, $1,200. Call 606-738-9154 after 6:00 pm.
5-13-1TPD

FOR SALE — 1996 30 ft. Gulfstream, sleeps eight, completely furnished. Call 743-4494.
5-13-TF

FOR SALE — 1978 Show trailer, 14x70, three bedroom, 1-1/2 baths, gas furnace, washer and dryer. $6,800. Call 725-4740.
5-13-1TPD

FOR RENT — Two bedroom house in Elliott County off Route 504. Call 738-6246.
5-13-1TPD

FOR RENT — Two bedroom house at Bruin with garden. For more information call 606-325-0731.
5-13-1TPD

FOR RENT — Trailer. Good location. Married couple only. Call 662-6823.
5-13-1TPD

FOR SALE — Three bedroom frame house with living room, kitchen, one bath, large family room with hobby room, newly remodeled. Located in country setting. Priced to sell at $42,000. Gwen Hurst owner. Call Harold M. Hurst Realty, 175 Blackburn Street, Stanton, Kentucky 40380, at 606-663-4314 or 606-663-4591 for appointment.
5-13-1TJBS

LEGALS

tion 504 of the Rehabilitat 1973, as amended, the Age nation Act of 1975, as ame the rules and regulatio United States Department o ture which provide that no the United States on the bas color, national origin, age, cap shall be excluded fro pation in, admission or a denied the benefits of, or be subjected to discriminat any of this organization's or activities.

The person responsible dinating this organization's crimination compliance Dan McKenzie, General M

Any individual, or spec of individuals, who feels organization may obtain f formation about the statutes lations listed above from a a written complaint with th zation; or the Secretary, Uni Department of Agriculture, ton, DC 20250; or the Ad tor, Rural Utilities Service, ton, DC 20250.

Complaints must be fil 180 days after the alleged nation. Confidentiality will tained to the extent possibl

LES breakfa and lunch m

Monday, May 17
Breakfast — cereal, ba cuits, juice, milk.
Lunch — chicken nugg slaw, french fries, milk.

Tuesday, May 18
Breakfast — eggs, toa milk.
Lunch — pizza, corn, ch milk.

Wednesday, May 1
Breakfast — muffins juice, milk.
Lunch — pinto beans, sa potato wedges, cornbread milk.

Thursday, May 2
Breakfast — pancakes, juice, milk.
Lunch — hot dogs/bun french fries, grapes, milk

am. Electric

EDS

Deadline: Tuesday at 12 Noon
Call (606) 473-9851 • Fax (606) 473-7591
Call Stefanie for more information

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084 Mobile Homes for Sale

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Payments as low as $189 Mo. Call Today (606)623-1153.
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4 Bed. 2 Bath. Payments starting at $269 Mo. Call Now (606)623-1122.
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Refurbed. Like New. 2 & 3 Bedroom. We Finance. (606)623-1122.
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Only 4 Left at
$239/mo
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tfn

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New 3 BR, 2 Bath. $1000 Down, $248 Per/Mo. Free Air. 1-800-691-6777.
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3+2. Excellent condition. Must see to believe. Will finance Trailer Sales. Motor homes, travel trailers, tents, campers, fiberglass and ...

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c16-19

090 Apartments for Rent

TWO BEDROOM
Garage Apt. New carpet. 1408 Hickory St. Flatwoods. $350/Mo. Call (606)833-5651.
p19

092 Homes for Rent

THREE BEDROOM
1409 Mullins St. Flatwoods. Forced Air & Heat. $450/Mo. Call (606)833-5651.
p19

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Brighten any setting naturally- kitchens, hall- ...

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ADVERTISING REAL

NOTICE OF PUBLIC HEARING

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Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

Delinquent Property Taxes Cont.

2869	SMITH LOU ANNE	$42.13
2870	SMITH LUCY HRS	$168.72
2879	SMITH ROGER & GERALDINE	$67.17
2885	SMITH THURMAN & VICKI	$269.66
[redacted]		
2894	SNOWDEN NANNIE & ARCH HRS	$31.29
2900	SPENCE ELBY & DONNA	$360.66
[redacted]		
2908	SPENCER KENNETH	$888.57
2913	SPRUCE FORK MINING CO	$64.89
2922	STAMPER FLOYD & FLOSSIE	$301.50
[redacted]		
2939	STEPP RICHARD HRS	$25.07
[redacted]		
2984	STRUNK ARTHUR	$30.76
2987	STURGEON CREEK COAL CORP	$53.51
2988	STURGEON MINNG COMPANY INC	$12,594.79
2989	STURGILL ELIZABETH	$30.76
3018	TAYLOR FRED	$196.20
[redacted]		
3023	TAYLOR MARAGRET	$76.26
3028	TAYLOR ROBERT & MARGARET	$76.26
3035	TERRY GLEN	$178.65
[redacted]		
3040	TERRY JOEY	$155.90
3045	TERRY VIRGIL & GWENOLYN KAY	$202.89
3048	THARP NAOMI	$253.72
3050	THOMAS BOBBY JR	$149.08
3073	THOMAS RANDY & DEBBIE	$54.70
3082	THOMAS TISHA RENEE	$67.17
3083	THOMAS WALLACE & TISHA	$147.16
3084	THOMAS WALLACE & TISHA	$463.05
3086	THOMAS WILLARD & LINDA	$397.52
3088	THOMPSON RALPH	$23.93
3101	TIREY BERNICE	$30.76
3123	TURNER CAROL J	$211.06
3132	TURNER FREDA	$81.96
3133	TURNER FREDA & JAMES	$30.76
3179	GLENN, DON & PAMELA	$99.00
3182	UNKNOWN OWNER	$19.37
3183	UNKNOWN OWNER	$64.89
3206	WHEELWRIGHT ROBERT M	$50.03
3207	WHICKER JAMES	$121.76
3210	WHITTAKER LARRY L	$60.17
3211	WILDER BERNIE	$242.34
3217	WILDER EUGENE & ALIENE	$42.93
3219	WILDER GARY & MARY	$31.11
3222	WILDER HESTER HRS	

Location of gr

Dear Editor:

I am looking for the grave c
great grandfather, Elkaner S
who was buried in Owsley, L
a surrounding county.

Histories I have seen said he
born in 1834 and died in 187

A distant cousin of mine,
Ollie Brandenburg, told me
going from Booneville to
Owsley Co. Stockyards on Rt.
turn off toward Stay where I
cated two cemeteries. A la
nearby told me that one of
cemeteries with a long grave a
a short grave was the old Sm

THANK YOU

Mr. and Mrs. Michael Evans and family would like to express their thanks to everyone who has helped out in any way following the loss of our home to fire last week. Your kindness and thoughtfulness is appreciated.

The Michael Evans Family

DEAR GRANNIE ELLIE

Dear Grannie,

Well, they say beauty is in th
eye of the beholder, and it sur
must be true. I have a friend, wh
is quite a handsome fellow. W
grew up together and we alway
dated good looking gals. After w
got out of school, I live here and h

arx. elect.

of Elkaner Smith

Cemetery. The other cemetery close by had 25-30 graves in it.

If anyone has any information where Elkaner Smith is buried please call or write to me so I can go with you to locate his grave.

Elkaner's son was Squire Smith, my grandfather and my dad was Henry Smith. Elkaner was raised in Virginia, and moved to this area.

Please contact:
Harry Smith
4854 Hwy 30 West
Annville, KY 40402
or call 1-606-364-5789

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Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

LEGAL NOTICES

COMMONWEALTH OF KENTUCKY
23RD JUDICIAL CIRCUIT
OWSLEY CIRCUIT COURT
CIVIL ACTION NO. 98-C1-00094

PEOPLES EXCHANGE BANK A CORPORATION of Beattyville, Kentucky (PLAINTIFF) vs. NOTICE OF SALE DONALD BARKER, PEGGY T. BARKER, his wife (DEFENDANTS)

By virtue of Judgment and Order of Sale by the Owsley Circuit Court in the above cause, I will, on Saturday, May 22, 1999 at the hour of 10 o'clock a.m., at the Courthouse door in Booneville, Owsley County, Kentucky, offer the respective interests of the above parties in the following described property for sale at public auction, to-wit:

TRACT 1: BEGINNING at a planted stone near the Old Stephen Gumm graveyard and corner to Bent Lynch land; S 48 E 37 poles to a branch; thence N 60 E 1 poles and 2 L to a forked white oak on the East Side of the Branch; thence S 50 1/2 E 8 poles to a black oak; thence S 51 1/2 E 11 1/2 poles to the top of a ridge; thence with the top of the ridge S 51 W 5 poles S 63 W 10 poles to a small hickory; thence S 28 1/2 W 12 poles S 40 W 6 4/5 poles to a black oak; S 38 1/4 W 19 1/2 poles to a small white oak at a fence division corner between Sarah E. Price and Grant Lynch; thence N 58 1/4 W 30 poles to two white oaks at the Barker Lick Branch; corner to M.V. Barker land; S 26 1/2 W 16 1/2 poles to an elm tree; N 88 W 16 poles to two small white oaks and a small black oak division corner between Grant Lynch and Bent Lynch; thence with a line between them N 15 1/2 E 32 poles to a small hickory and rock; thence N 35 E 3 poles to two small white oaks on top of the cliff N 16 E 15 1/2 poles to an ash and black oak on the cliff, N 24 W 5 poles N 31 W 6 poles to a stake near a spring N 38 poles to a stake one pole above the fells of the falls of the branch, S 33 E 6 poles to a rock on the edge of the cliff, N 61 E 29 3/5 poles to the beginning, containing 21 7/8 acres, more or less. The oil, coal, and gas is excepted out an all minerals also.

TRACT 2: BEGINNING at a stone in the Ester Branch in the line of Sarah E. Price; thence westward with the branch

bush; thence S 26 1/2 W 10 poles and 11 links to a white oak or bush N 70 W 2 poles and 15 links to the beginning, containing 4 1/8 acres, more or less.

First parties reserved house, garden and orchard and so much of the land as is necessary for their own use during their natural lifetime.

TRACT 4: BEGINNING at a stone in the line of J.G. Rowlett; thence Westward to the creek; crossing the creek to the mouth of a small drain; thence up said drain to its source to a stone set in the ground; same course to a stone at the fence; thence Northward to a small dogwood marked as a corner; thence SW to a hickory marked as a corner; westward to a black oak in the Tackett line; thence Southward with the Tackett line to the line of David Flannery; thence with two small hickory on the top of a point; thence with a conditional line around the old corn field to the first branch; thence down said branch as it meanders to the creek; crossing the creek to a locust stump at the mouth of the Gumm Branch, also a corner to Jesse G. Rowlett; thence a straight line to the beginning, containing 31 1/2 acres, more or less.

There is reserved to party of the first part the use of the roads for Bruce Barker where they are now presently located and as they presently exist. There is expected out and not conveyed herein the following described tract of land: BEGINNING at a forked maple and running 126 feet S to Hwy #846; thence running E approximately 2/10 of a mile to the Eastis Branch; thence running N with Eastis Branch to Warren Eddie's line; thence running W Warren Eddie's line to a corner of Bruce Barker's line on top of the hill; thence running S down the hill with Bruce Barker's fence and line to the Gumm Road; thence running parallel with the Gumm Road to a rock in the road bank; thence running a straight line across the bottom with Bruce Barker's line to the beginning corner.

There is also excluded and not conveyed herein that certain tract which was conveyed to Bruce Barker and Ora Barker dated January 3, 1948, and recorded in Deed Book 17, page 203,

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power C-5-13-1T

Angie Keaton, of Flat G
The wedding will

Tra
new

Well, a lot of birth
come and gone since the
umn.

Those who recently
days were Chris J. Com
Dingus, Jessie Murrell
Luttie (Maw) Patrick.

Those who will be ce
their birthdays this week a
Young, Waylon Blanton a
Lykins. Sherrie Young a
Lykins will be turning a
hope they all have ma
birthdays and that their live
blessed.

Pray for Ora Dingu
said that she avoided th
winter and then caught i

ng thy light
here is sadness
bring joy.

ing to all, every-
ll are fine this 10th
ope all mothers had
rday.

of my ten children
five of them came
e. They brought
had a good visit.
Jim and Michael,
anita, Wanda and
an and Kelly and
Emma and Justin,
redith and their three
and Betty and R.T.,
nd Jason.
nd David took Trish
helped sing every
sung. She looked so
Penta and Hannah
had nine grands here
grands. They had a
lso had three grand
e had a good time.
Frank both called
me a happy Moth-
Farland called and

Henry Douglas Allen, son of Mr. and Mrs. James Phillip Allen, on Saturday, May 22, at 1 p.m., at the Faith Church in Salyersville.

Aaron is currently a senior at Magoffin County High School and is employed part-time at McDonald's in Salyersville.

Doug is a 1996 graduate of Magoffin County High School and is employed by the United Parcel Service in Allen.

The gracious custom of an open ceremony will be observed with all friends and family invited to attend. A reception will follow the ceremony at the Lloyd M. Hall Community Center.

The couple plans to reside on Craft Creek, in Salyersville.

HRMC births announced

Highlands Regional Medical

Montgomery's residence, Wayne Howard's residence, Royalton United Baptist Church and Royalton Post Office.

Monday, May 17 - Mouth of Jellico, Litteral Fork, Falcon Post Office, Collins' Grocery and Mash Fork Trailer Park.

Tuesday, May 18 - Birch Branch, Jim Arnett Branch, Ivyton Post Office, Marshalls' residence, Deans' residence, Calvin Cain Trailer Court and Faith Church parking lot.

Thursday, May 20 - Allen Drive Apartments, Pine Point Apartments, College Heights Apartments, Dixie: Pauline Prater's residence, Rescue Squad and Lee Prater Street.

Friday, May 21 - Howard Grocery, Carver, Ginger's Headquarters, Lakeville Road, Lakeville Freewill Baptist Church

Creek, Trinity Full Gospel Mission, T & J Grocery, Lake Front Church and Jarrell's B.P. Station.

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Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

am. elect. power.

SPORTS

Koch

FROM PAGE 16

but you're not featured enough, it's time to look around. And if you are the star player, the go-to guy, what's the sense of hanging around when you can go to the NBA and make millions?

This isn't unique to the Wildcats. Luke Recker has had it with Bobby Knight at Indiana. Chris Burgess doesn't want to play at Duke anymore. His teammates, Elton Brand and William Avery, are going to the NBA. Two years of ivy and academics, even in the hallowed halls of Duke University, are enough, thank you.

And at the University of Cincinnati, DerMarr Johnson hasn't even participated in his first practice and already everyone in town is bracing for his departure.

But when this sort of thing happens at UK, where the players are treated like gods, it's a little more disturbing, as if college sports as we know them will never be the same.

Brace yourself. They won't.

The Revenge of the Players has descended upon the NCAA at last.

For years, the NCAA has legislated against the student-athletes who bring in all the money. Coaches make hundreds of thousands of dollars a year, and that's not counting endorsements. Players, until recently, weren't even allowed to have a job during the school year.

Coaches can break contracts and leave at will, but players can't transfer without sitting out a year. Until recently, that was enough incentive to make most of the players stay put. Not ...

2. LEGAL NOTICES

NOTICE
OF PUBLIC SALE
First National Bank of Grayson will offer for Public Sale to the highest and best bidder the following vehicles, as is:
1994 Ford F150 SR# 1FTEF14N6RNA67170
1994 Ford Thunderbird S R# 1FALP62W3KHH8383
1989 Ford Tempo SR# 1FAPP31XXKK224476
1993 Pontiac Grand Am SR# 1G2NE5433PC740731
1995 Saturn SL SR 1G8ZH5Z8X5Z130098
1989 Pontiac Grand Prix SR# 1G2WJ14T6KF321921
1987 Oldsmobile Delta 88 SR# 1G3HY5130HW330117

The Sale will be held on Friday, May 14th, 1999 at 3:30PM at the First National Bank of Grayson, Depot Office located on Railroad Street, Olive Hill, KY. Terms of the Sale are cash and the Bank reserves the right to bid and the right to accept or reject any and all bids. Announcements the day of the Sale take precedence over printed material. First National Bank, Grayson, KY. 606-474-2000.
Published May 11, 12, 13, 1999.

3. AUCTIONS

SILOAM AUCTION— Siloam, KY Rt 23, 606-932-4990. Every Thurs. 11a.m. Sat. 5:00p.m, Auctioneer Geo. Madacsi.

TRI STATE AUCTION CENTER
Sale Every Sat. 7p.m.
1102 Vernon St. Huntington
PH: 1-304-429-3102

5. PUBLIC NOTICES

A BEAUTIFUL CANDLELIT...

24. MEDICAL HEL... WANTED

PARAMEDICS, E...
& MECHANIC A...
Due to expansion, Para... EMTs and Mechanic A... needed. Excellent pa... desirable schedule, ... medical and 401K avail... well as other benefits.
Call General Ambulanc...
Oak Hill, WV. 304-465-...

RN/LPN/CNA
Looking for work and no... another job? Challenging... rewarding career opportu... in geriatric nursing. ...petitive wages, health/d... plan, 401K.
Mariner Health Care
1720 17th Street
Huntington, WV 25701
EOE

RNs - Home Health...
King's Daughters' Med... Center is accepting app... tions for PRN RN positions... our Ashland and Gree... Home Health offices. Ap... cants must be licensed in... state of KY and OH and h... at least 2 years experience... a nurse in a hospital or p... vious home health experien... with cardiac nursing exp... ence preferred. Curr... driver's license and relia... vehicle required.
For immediate considerati... sumbit application or forw... resume to:
Human Resources Dept.
King's Daughters' Medical Center
2201 Lexington Ave.
Ashland, KY 41101
Fax: (606) 327-7480
EOE

SOUTH SHORE NURSING & REHABILITATION CENTE... is accepting applications the position of MDS/Care P... Coordinator. Must be an L... or RN licensed in Kentuc... Send resume with cover let... to S.S.N.R.C., P.O. Box 4... South Shore, KY 41175. EOE

STNA CLASS— Apply in per... Mon.-Fri., 9a.m-2p.m., Bry... Health Center, 5th & Clint... Ironton, OH.

25. HELP WANTED

ered that sitting out a year isn't so bad, after all, not if you're going to leave school early anyway. And the NBA is ready and willing to gobble up the elite players, even as it protests so righteously against it.

These players are making a big mistake, they say. They're not ready for the NBA. They should stay in school.

That's what they're telling the public. What they're saying to the kids is "Would a million dollars a year be enough until we can see how good you are?"

Things will work out at UK without Magloire, Hogan and Bradley. The blue-chip high school players will continue to arrive in droves and UK will continue to win.

But the players won't stay as long. The fans won't get to know many of them the way they used to. And it will become harder for Smith to find three seniors to pass along the UK tradition in a teary locker room after that final game each season.

Coaches often complain that their players don't listen to them.

Maybe so. But they're watching. And they've learned this much from their coaches: All that stuff about family that they spout to the boosters doesn't amount to much. In college athletics, as in so much of life, you go where the money is.

BILL KOCH writes for the Cincinnati Post.

▶Maynard

FROM **PAGE 16**

strikeouts per nine innings at 13.2.

Senior outfielder **Mark Dixon** broke **Denny Doyle's** record for stolen bases in a season last week. He leads the league in thefts, swiping 30 of 37.

MARK MAYNARD is sports editor of The Independent.

ate monitoring violations. For more information,
ant Operator, Doug Buckner. Phone No. 286-2618
c-19

143 Lost & Found

LOST
mixed breed female, brown, bobtail, name is
t. Call David Gee 286-5016.
p-19

tional Month

- A new web- been estab- Internet for want to learn sed container 1 set for con- 2000 General address is /kentucky- information f the current- bill" legisla- of the oppo- de Kentucky lers and suc- from other had the con- gislation for

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Toll-free number for tobacco transplants

FRANKFORT - Agriculture Commissioner Billy Ray Smith has announced that a toll-free number has been established to help Kentucky Farmers sell and buy Kentucky-grown tobacco transplants. The Kentucky Department of Agriculture is providing this toll-free assistance.

This service will link Kentucky transplant producers with those who wish to buy in-state plants.

Framers can call 1-888-531-8083 to provide information on tobacco transplants they have for sale or of any they wish to purchase.

The service is provided free of charge and has the potential to assist thousands of farmers.

Ashland urologist adds in-office urology analysis

ASHLAND - Urologist James explores the abdomen with a

Tips On Picking A Good Used Car

• **Do your homework**—Check all available resources and data, including consumer reports, and automotive magazines about the car you're planning to buy.

• **Lift the hood**—Check for leaky hoses, worn belts, and dirty oil. Transmission fluid should be clear and reddish, and not smell burned. Radiator water should have a light yellow or green color.

• **Take a seat**—Turn the ignition key to accessory and make sure all of the warning lights and gauges work. Start the car and check all lights and accessories and make sure no warning lights remain lit on the dashboard.

Am. elect.

MSU photo by Tim Holbrook

owcase talents

d sessions during the Phi
Showcase at Morehead
presenters were, from left,
man; Leanne McHenry,
a Opell, Louisa freshman.
"Friendship Through the
riendship in Aristotle's
fessions" to examine rela-
nds." The trio had previ-
sis during the Southern
onference in Little Rock,

Greenup Chapter to host Red Cross training

GREENUP - The Greenup County Chapter, American Red Cross, will be hosting several basic and intermediate disaster courses at the Mini-Disaster Institute, Friday, May 14 through Sunday, May 16, at Greenbo Lake State Resort Park in Greenup County.

The courses that will be offered on Friday, May 14, will be: Disaster Health Services I, 9 a.m. until 5 p.m.; Records and Reports I, 9 a.m. until 5 p.m.; Mass Care: An Overview, 9 a.m. until noon; and Shelter Operations, 1 p.m. until 4 p.m.

On Saturday, May 15, these classes will be offered: Administering a Small Disaster Administration, 9 a.m. until 5 p.m. (day 1); Emergency Assistance I, 9 a.m. until 5 p.m.; and Damage Assessment I, 9 a.m. until noon.

Sunday, May 16, will have the following classes: Administering a Small Disaster Operation, 9 a.m. until 5 p.m. (day 2); and Emergency Assistance II, 9 a.m. until 5 p.m.

You must pre-register for any of these classes. If you have any questions, you may contact Mary Hickey at Greenup County Chapter 473-9594 or Jesse Green in Field Services at 1-800-272-3635.

ar Corner

Good Used Car

• Take a seat—Turn the igni-
on key to accessory and make
ure all of the warning lights and
auges work. Start the car and
heck all lights and accessories
nd make sure no warning lights
emain lit on the dashboard.

NOTICE OF PUBLIC HEARING

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To Christine Jewell,

from your loving husband . . .
you are my world; without you
I don't exist!
Happy Late Mother's Day!

I love you forever
and always!

Riverside looks to graduation

On Sunday, May 16 at 3 p.m., the Baccalaureate service for Riverside Christian School's seniors and eighth graders will be held in the Dreshal Memorial Brethren Church Building (Campus Church).

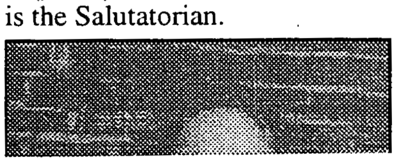
The featured speaker for this occasion will be Dr. Harold E. Barnett of Haddix. He and his wife, Doris, will also sing a duet. Harold is a graduate of Riverside and was also president of the school for 16 years.

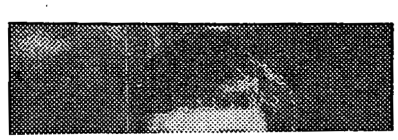
Commencement exercises will be on the following Friday, May 21, at 7 p.m. in the school gymnasium. The kindergartners will be graduating that night along with seniors and eighth graders.

The public is cordially invited to attend both functions.

Rebecca Thorpe, daughter of Ora and Diane Thorpe of Southfork, is the Valedictorian of the class of 1999. She has a 4.0 GPA.

John Paul Neace, son of John Paul and Shirley Neace of Lost Creek is the Salutatorian.





Legal

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31 Derickson Ro
Phone (606)
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Stanton Nursing Center has
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1. Inpatient and outp basis; all residents v race, color, creed, na
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3. Residents will nc room with a person c
4. Employees will be race, color, creed, na
5. Staff privileges w on the basis of race,
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SING CENTER
ton, Kentucky 40380-2153
• Fax (606) 663-8040
ATEMENT
GHTS ACT OF 1964

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Stanton Nursing Center Facility
5 May 99

icare® Facility

1TE-5-13

PUBLIC NOTICE

The Board of Directors of Appalachian Research and Defense Fund of Kentucky, Inc., will hold a regular quarterly meeting on Saturday, May 15, 1999, at 11:00 a.m. at its Jackson, KY office. The meeting is open to the public. 1TE-5-13

NOTICE OF PUBLIC HEARING

A public hearing will be held on May 28, 1999 at 10:00 a.m., Eastern Daylight Time, in Hearing Room 1 of the offices of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky for the purpose of cross-examination of witnesses of Applicants and Intervenors in the Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central South West Corporation Regarding a Proposed Merger.

Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

NOTICE OF INTENTION TO MINE[1]
Pursuant to Application Number 813-8009 Renewal

In accordance with KRS 350.055, notice is hereby given that Addington Mining, Inc., 1500 North Big Run Road, Ashland, Kentucky 41102, has applied for a renewal of a permit for an existing surface coal mining and reclamation operation affecting 20.0 surface acres.

The proposed operation is located .75 miles west of Evanston in Breathitt County. The operation is approximately 1.0 mile east from Kentucky Route 542's junction with KY Route 2465 and located 1.0 mile Northwest of Slusher Branch Road. The operation is located on the Tiptop U.S.G.S. 7 1/2 minute quadrangle map at latitude 37°32'40" and longitude 82°02'55".

The operation will be used to process coal. The surface area to be disturbed is owned by Western Pocahontas Land Corporation.

The application has been filed for public inspection at the Department for Surface Mining Reclamation and Enforcement's London Regional Office, 85 State Police Road, London, KY 40741. Written comments, objections, or requests for a permit conference must be filed with the Director, Division of Permits, #2 Hudson Hollow, US 127 South, Frankfort, Kentucky 40601.

4TE-6-3

Professional Business Directory

ers: Michael Callahan, Doug Wayne Hensley, Chuck Fugate, Lewis Fugate, Doug Wooton, and Rodney Pennington.

Mr. Levi Roark

Mr. Levi Roark, age 57 of London passed away May 4, 1999 at his residence in London, Kentucky. He was born in Leslie County, Kentucky the son of Will Roark and Goldie Sizemore Roark. He was retired from General Motors.

Mr. Levi Roark leaves surviving the following relatives: wife: Elsie and friends.

Funeral services for Mr. James F. Thacker were conducted Wednesday, May 5, 1999 at 2:00 p.m. at the Dwayne Walker Funeral Home Chapel, Hyden, with Thomas Smith officiating. Interment followed in the John R. Hendrix Cemetery, Wooton, under the direction of the Dwayne Walker Funeral Home, Hyden.

The following served as pallbearers: Scott Cornett, David Thacker, Doug Cornett, Josh Sturgill, Noah Family Cemetery Dryhill, under the direction of the Dwayne Walker Funeral Home, Hyden.

The following served as pallbearers: Russell Baker, Jimmy Turner, Gary Begley, Robert Brock, Justin Osborne, Josh and Robert Asher.

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Errol K. Wagner,
Director of Regulatory Affairs
Kentucky Power Company
d/b/a
American Electric Power

Send all church and events to
The Leslie County News
P.O. Box 967
Hyden, KY 41749

PUBLIC NOTICE
INVITATION TO BID

The fiscal court of Leslie County, Kentucky, will receive sealed bids for the following materials, services and supplies until 4:00 p.m., May 21, 1999. Bids will be opened at the regular fiscal court meeting to be held in the Leslie County Extension Office, Main Street, Hyden, Kentucky on May 26, 1999 at 10:00 a.m.

H

(1) Fuels, Oils, Lubricants and Anti-Freeze
(2) Drain Pipe
(3) Gravel at Quarry
(4) Gravel Haul
(5) Concrete Mix
(6) Asphalt
(7) Drilled Railroad Steel

2-6

Interested parties must obtain bid specifications from the office of the Leslie County Judge-Executive, Leslie County Courthouse, Main Street, Hyden, Kentucky.

Onzie Sizemore
County Judge-Executive
Leslie County Fiscal Court

Amer. Elec.

Mr. Ford Simpson

Ford Simpson born October 6, 1936 departed this life on April 30, 1999 at the Mary Breckinridge Hospital, Hyden, KY. He was 62 years, 6 months, and 24 days old. Ford was born at Asher, Kentucky, the son of Joe Simpson and the late Polly Bowling Simpson. He was a retired coal truck driver having been employed by C&S Trucking and Julie Trucking. Ford was affiliated with the Church of God and was a life-long resident of Leslie County residing at 45 Honey Lane, Cinda, Kentucky, at the time of his death. He was preceded in death by one daughter, Kimberly Lynn Maggard, his mother, Polly Bowling Simpson, and one son Terry. Mr. Ford Simpson leaves the following relatives surviving: wife: Alpha Lewis Simpson of Asher, Kentucky; father & step-mother: Joe and Elsie Simpson of Asher, Kentucky; one son: Jody Simpson of Bear Branch, Kentucky; one step-son: John Henry Sizemore of London; three step-daughters: Mildred Carol Sizemore of Texas, Maggie Sue Lewis of Lexington, KY, Rebecca Ann Mosley of Stinnett, KY; three brothers: Billy Simpson of Asher, Kentucky, Donnie Simpson of Chicago, Illinois, Eugene Simpson of Arthur, Tennessee; four sisters: Jewell Dean Morgan of Essie, Kentucky, Josephine Amos of Asher, Kentucky, Rozella Morgan of Asher, Kentucky, Betty Joyce Burkhart of Streamwood, Illinois; two grandchildren: Chelsa Simpson and Lowell Brandon Nantz; four step-grandchildren: Jonathan Brian Sizemore, Ashley Lynn Sizemore, Anthony Steven Lewis, & April Nicole Lewis.

Following the funeral service Mr. Ford Simpson will be laid to rest in the Hoskins Family Cemetery, Asher, Kentucky.

Funeral services for Mr. Ford Simpson were conducted Monday, May 03, 1999 at 1:00 p.m. at the Stinnett Gap Church of God, Stinnett, with Rev. Chad Hensley officiating. Interment followed in the Hoskins Cemetery, Asher, under the direction of the Dwayne Walker Funeral Home. The following served as pallbearers: Mitchell Mosley, Doyle Hoskins, Junior Bowling, Roy Gene Morgan, Freddie Wayne Hoskins, & Jimmy Helisek.

Mr. Sim Woods

Sim Woods born January 1930 departed this life on April 1999 at his home at Lick Bra Rd., Ball Creek, KY. Woods 69 years old. Woods was bor Leslie Co. KY, the son of the Tennessee Woods and the Allen Woods. He was a reti coal miner for Blue Diamond. was preceded in death by his ther, Tennessee Woods, and mother, Allen Woods. Mr. Wo leaves the following relatives viving: wife: Betty Willia Woods; five sons: Jr., Jo Sheldon, & Richard all of Flo and Danny Davidson of Haz KY; four daughters: Uleta Fre Donna Raymond, Charma Stringfellow all of Florida Becky Messer of Ary, KY; brother: Marcum Woods of C fornia; three sisters, Ada Hick Alabama, Sadie Eversole Confluence, KY, and Gert Francis of Ohio, and a host grandchildren, great grandc dren, and great-great grandc dren. Following the funeral ser Mr. Woods will be laid to res the Granville Eversole Cemet Confluence.

CASE NUMBER:

99-149

RECEIVED
APR 1 5 1999
PUBLIC SERVICE
COMMISSION

KNORR

RECEIVED
APR 1 5 1999
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

JOINT APPLICATION OF KENTUCKY POWER COMPANY,	)	
AMERICAN ELECTRIC POWER COMPANY, INC.	)	
AND CENTRAL AND SOUTH WEST CORPORATION	)	CASE NO. 99-
REGARDING A PROPOSED MERGER	)	

DIRECT TESTIMONY

OF

GERALD R. KNORR

APRIL 1999

TESTIMONY INDEX

EXHIBITS

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

JOINT APPLICATION OF KENTUCKY POWER COMPANY,	)	
AMERICAN ELECTRIC POWER COMPANY, INC.	)	
AND CENTRAL AND SOUTH WEST CORPORATION	)	CASE NO. 99-
REGARDING A PROPOSED MERGER	)	

DIRECT TESTIMONY

OF

GERALD R. KNORR

APRIL 1999

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Gerald R. Knorr and my business address is 1 Riverside Plaza, Columbus, Ohio 43215-2273. I am an assistant controller of American Electric Power Service Corporation (AEPSC), Kentucky Power Company (KPCO) and certain other American Electric Power Company, Inc. (AEP) companies.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH AEPSC?

A. As director of non-utility ledger accounting, I am responsible for the general ledgers, financial statements and reports, various statistical reports, and accounting practices of AEP, AEPSC, and all the direct non-utility subsidiaries of AEP and certain indirect subsidiaries. My responsibilities include the monthly service billings issued by AEPSC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Business Administration degree in Accounting from Hofstra University in Hempstead, New York. I am a certified public accountant in New York and a member of the American Institute of Certified Public Accountants and the New York State Society of Certified Public Accountants.

After graduation from Hofstra University I was employed for six years with a major public accounting firm. I began my employment with AEPSC in August 1971 and was elected assistant treasurer in 1974 and assistant controller in 1996. I have held various accounting positions with AEPSC since 1971, including my current position as director of non-utility ledger accounting beginning in 1998.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. No, I have not.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the ability of the Public Service Commission of the Commonwealth of Kentucky (Commission) to effectively regulate KPCO's operations, and generally describe the affiliate accounting practices and procedures of the merged AEP and Central and South West Corporation (CSW) entity, which will retain the name of American Electric Power Company, Inc. I will discuss the procedures to be used to account for and allocate costs generated by affiliate activity including service company work order procedures. I will also show how the non-fuel benefits shown in the Synergies Analysis are allocated among the subsidiaries of the merged company. The Synergies Analysis is discussed by Mr. Thomas J. Flaherty and is included in the filed workpapers.

III. AFFILIATE STRUCTURE OF MERGED ENTITY

Q. DESCRIBE THE STRUCTURE OF THE TWO MERGING ENTITIES, CSW AND AEP.

A. Both CSW and AEP are electric utility holding companies subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA).

Among its holdings, AEP owns seven electric utility operating companies: Appalachian Power Company (APCO), Columbus Southern Power Company (CSP), Indiana Michigan Power Company (I&M), KPCO, Kingsport Power Company (KgPCO), Ohio Power Company (OPCO) and Wheeling Power Company (WPCO). AEP also owns AEPSC, a service company that predominantly provides services to the electric utility operating companies. Among its holdings, CSW owns four electric utility operating companies, Southwestern Electric Power Company, Central Power and Light Company, Public Service Company of Oklahoma and West Texas Utilities Company. CSW also owns Central and South West Services, Inc. (CSWS), a service company whose primary business is to provide services to the four regulated electric operating companies.

Q. DESCRIBE THE AFFILIATE STRUCTURE THAT THE MERGED ORGANIZATION WILL ASSUME FOLLOWING APPROVAL OF THE PROPOSED MERGER.

A. Once the merger is closed, AEP will own CSW and its subsidiaries. Also, the functions of the two service companies will be performed by a single service company, AEPSC, with the same mission that the existing service companies now have; however, that mission will be performed for eleven electric utility operating companies. For the remainder of my testimony when I refer to the service company, unless I specifically indicate otherwise, I am referring to AEPSC, the service company after the merger.

Q. WILL THERE BE OTHER CHANGES TO THE AFFILIATED STRUCTURE IN ADDITION TO THE ONES YOU HAVE DESCRIBED?

A. At this time no other changes have been identified. Although, with time, there may be other changes to the affiliate structure that the management of the merged AEP determines to be appropriate in adapting to the requirements of the evolving business environment.

IV. TRANSACTIONS AMONG AFFILIATES

Q. WITH WHICH AFFILIATES WILL THE REGULATED ELECTRIC UTILITIES TRANSACT BUSINESS?

A. The great majority of affiliate transactions in which the regulated electric utilities participate will be service company transactions. As discussed below, a broad range of electric utility functions and activities have been and will continue to be performed for the operating companies by the service company. The electric operating companies can also be expected to continue to have transactions among themselves, including energy and transmission service transactions. They could also have regular and periodic transactions with the holding company concerning equity transfers. The regulated electric utilities will also participate in some transactions with non-regulated affiliates. Each of these groupings of affiliate transactions will be discussed separately.

A. Transactions with the Service Company

Q. WHAT AFFILIATE SERVICES ARE YOU ADDRESSING IN THIS SECTION OF YOUR TESTIMONY?

A. I am addressing the affiliate services, which will be provided in the merged entity by AEPSC. There are other companies within the AEP and CSW systems that provide specialized services to electric operating companies for each system. For example, within the AEP system, Ohio Power Company owns certain coal mining subsidiaries engaged in mining coal to fuel generating plants. While these other subsidiaries might in a general sense be considered limited purpose service companies, their activities are not addressed in this testimony because their operations will be unaffected by the merger.

Q. WHAT TYPES OF SERVICES WILL BE PROVIDED TO THE OPERATING COMPANIES OF THE MERGED ENTITY BY AEPSC?

A. AEPSC will provide the services previously provided by the two service companies, AEPSC and CSWS. Those companies were formed under the PUHCA to perform services primarily for the subsidiary electric utility operating companies of AEP and CSW. That will remain AEPSC's primary function. Because the electric operating companies are in the same business of providing regulated electric utility service, there are numerous essential activities that can be more efficiently and cost effectively provided for those companies jointly.

The services to be provided to the operating companies by AEPSC generally fall into the following categories: production services, transmission services, distribution services, customer services, marketing services, operational services, financial services, human resource services, information technology services, and other services. I will discuss these services in more detail later in my testimony.

Q. DO THE TYPES OF SERVICES YOU HAVE JUST DESCRIBED REPRESENT AN EXPANSION IN SERVICES PERFORMED BY AEPSC AND CSWS PRESENTLY?

A. No. The services described are the same services provided by the two service companies presently. However, it should also be recognized that some of the services may benefit only a limited number of subsidiaries of AEP or CSW. For example, AEPSC provides certain services related to coal mining activities and nuclear plant operations. Since CSW does not operate coal mines, and nuclear operation and maintenance activities for the South Texas Project (STP) are performed by STP Nuclear Operating Company, the costs of these services performed by AEPSC will only be allocated to the appropriate AEP subsidiaries that receive such services.

Q. HOW WILL TRANSACTIONS BETWEEN THE SERVICE COMPANY AND AFFILIATES BE ACCOUNTED FOR?

A. Both AEPSC and CSWS are regulated by the SEC under PUHCA and utilize a work order system to account for transactions as required by the SEC. The service company will continue to use a work order system following the merger.

Expenditures at the service company will be charged to work orders, which accumulate the charges for ultimate billing to the companies that benefit from the services. The accounting within each work order will be performed in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (FERC USA). By using the FERC USA, AEPSC can charge its costs to the same FERC account numbers that are presently used by the electric operating companies.

The costs for services which are performed 100 percent for the benefit of an individual company will be billed directly to that company. The costs for services which benefit more than one company will be allocated in accordance with an authorized SEC formula. As with the existing service company affiliated billings, no profit is to be charged.

Q. HAVE AEPSC AND CSWS HISTORICALLY USED FORMULAS OR ALLOCATION FACTORS TO ALLOCATE COSTS?

A. Yes, they have.

Q. IS IT PROPOSED THAT AEPSC WILL USE THOSE SAME ALLOCATION FACTORS TO ASSIGN COSTS TO THE SUBSIDIARIES OF THE MERGED ENTITY?

A. No. In connection with the merger approvals sought from the SEC, AEPSC has sought authorization from the SEC to use allocation factors developed through a joint effort of AEPSC and CSWS personnel familiar with SEC allocation rules and affiliate billings. As AEPSC's SEC contact for affiliate billings, I participated in the effort to develop these allocation factors. These allocation factors have received management's approval and have been presented to the SEC for approval.

Q. WHAT ALLOCATION FACTORS HAVE BEEN PROPOSED TO THE SEC FOR USE BY THE SERVICE COMPANY OF THE MERGED ENTITY?

A. EXHIBIT GRK-1 details the allocation factors that have been proposed to the SEC to be used by the service company to bill for services performed.

Q. PLEASE DESCRIBE THOSE ALLOCATION FACTORS.

A. First I wish to emphasize that it will be the policy of AEPSC to directly bill costs to the maximum extent possible. However, when costs cannot be directly billed, appropriate allocation factors will be used. The allocation factors included in EXHIBIT GRK-1 emphasize factors that correlate to the volume of activity that is generated in performing certain services and thereby emphasize cost causation factors.

A volume driven formula is used in all cases where the cost driver is volume based and the data for both companies is available and comparable. For example, in allocating costs for processing accounts payable, the number of vouchers is used; for printing customer electric bills, the number of customers is used; and for transmission engineering, the number of transmission pole miles is used.

If a work order does not have a direct volume based cost driver, the most representative factor for the service provided is used. For example, costs of accounting for investments and retirements of utility property are allocated based on total gross utility plant dollars; for audit service, total asset dollars will be used; for internal communication, number of employees will be used; for purchasing fuel, the past three months of fuel burns measured in million British Thermal Units (MMBtu) will be used.

Q. PREVIOUSLY, YOU LISTED BY MAJOR CATEGORY THE TYPES OF SERVICES TO BE PROVIDED BY AEPSC. DESCRIBE PRODUCTION SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Six major services are provided in the production category. I will briefly describe each.

Plant (fossil-fueled) services includes the provision of management services for power plants, training, unit commitment, maintenance scheduling, plant management and centralized maintenance crews that serve regional power plants. This service also provides new technology evaluation, Electric Power Research Institute support, asset evaluation studies, and performance testing guidelines. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are megawatt-generating capacity, average peak load over the past three years, total peak load, number of generating plant employees, and the production department's prior three month bill to subsidiaries.

Fuel supply services includes the provision of fuel procurement and production mining services, power marketing, contract administration, strategic fuel planning and analysis, fuel cost accounting and reporting, and regulatory compliance and reporting. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are MMBtu of all fuel burned, MMBtu of gas burned, MMBtu of coal burned, and megawatts (MW) of generating capacity.

Environmental services includes the provision of or administration of occupational health guidelines for employees, assures environmental compliance at company facilities and power plants for air, water and waste, and obtains needed permits for construction projects with potential environmental impacts. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are total peak load and average peak load over the last three years.

Q. PLEASE CONTINUE THE DISCUSSION OF PRODUCTION SERVICES.

A. Engineering services includes the provision of administrative and executive power plant support, overview of instrument and control upgrades at power plants and technology engineering to the power plants. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are megawatt-generating capacity, average peak load over the past three years, total peak load and the production department's prior three month bill to subsidiaries.

Nuclear services, while not impacting KPCO, includes the provision of management services, administrative support for the nuclear plants and maintenance scheduling. Nuclear services are primarily directly charged. Allocations will be based on the nuclear department's prior three months bill to subsidiaries.

Central dispatching services includes the provision of economic dispatching of power generation and the arrangement for the purchases and sales of power. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are average peak load over the past three years and the system operations department's prior three month bill to subsidiaries.

Q. DESCRIBE TRANSMISSION SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Transmission services includes the provision of project management, design and development of construction projects, drafting and engineering services, contract administration, development of standards associated with the evaluation of materials, forestry services and impact studies. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are transmission pole miles, transmission level of construction, and the transmission department's prior three month bill to subsidiaries.

Q. DESCRIBE DISTRIBUTION SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Distribution services includes the provision of mapping services, project management, design and development of construction projects, drafting and engineering services, contract administration, forestry services and administrative and planning services. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are number of electric customers, distribution level of construction, and the distribution department's prior three month bill to subsidiaries.

Q. DESCRIBE CUSTOMER SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Customer services includes the provision of printing, inserting and mailing of customers' bills and other required mailings for electric service customers, remittance processing, support services for the customer information system, credit and collections, customer accounting, call centers and power billing. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factor used for these services is number of electric customers. Other allocation factors to be used will be number of call center calls, number of bills printed, number of mailings, number of remittance items and the department's prior three months bill to subsidiaries.

Q. DESCRIBE MARKETING SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Marketing services includes the provision of centralized marketing program administration and development, coordination of marketing activity, demand side management, energy conservation, economic development, costing and pricing functions and consumer affairs activities. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are number of electric customers and the marketing department's prior three months bill to subsidiaries.

Q. DESCRIBE OPERATIONAL SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Operational services includes the provision of strategic and business planning and regulatory support. Strategic and business planning is coordinated on a system-wide basis to track the key issues facing the utility industry in both the short- and long-term and to facilitate the business planning efforts of the individual subsidiaries. Operational services provide a central management of the efforts necessary to prepare and present reviews and other regulatory matters for the electric operating companies. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are total assets and the department's prior three months bill to subsidiaries.

Q. DESCRIBE FINANCIAL SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Financial services includes the provision, to the affiliated utility companies, of a full array of accounting and financial services. In addition to accounting policy and research services, AEPSC will compile and maintain financial, statistical and regulatory records and reports, and provide accounting services that include payroll and accounts payable processing. AEPSC will support financing activities and provide investor relations services. Corporate planning and budgeting, including services related to strategic business planning, operational forecasting and construction budgeting, will be provided by AEPSC. The financial services area will guide rate proceeding activities and provide services in the areas of cash management, lease management, insurance, and investment of pension plan and trust funds. AEPSC will provide internal auditing functions and tax guidance and services. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are number of general ledger transactions, number of vendor payments, number of bank accounts, total assets, total gross utility plant, number of employees, and the department's prior three months bill to subsidiaries.

Q. DESCRIBE HUMAN RESOURCES SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Human resource services includes the provision of administration and coordination of the employee benefit plans, labor relations, coordination of certain aspects of training throughout the AEP System, and human resources management for the electric operating companies. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are number of employees, number of employees exclusive of certain union employees, and the human resource department's prior three months bill to subsidiaries.

Q. DESCRIBE INFORMATION TECHNOLOGY SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Information technology services includes the provision of research and administration of company-wide information technology standards and specifications for mainframe and PC-based hardware and software systems. In addition to providing and maintaining system infrastructure, user and application support services are provided. AEPSC also performs feasibility studies for new applications, develops new applications and provides enhancement of existing applications and related activities. These services are primarily charged to specific work orders through the use of computer resource units and are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are number of electric customers, number of employees, number of general ledger transactions, MW generating capacity, number of vendor payments, and the information services department's prior three months bill to subsidiaries.

Q. DESCRIBE OTHER SERVICES AND WHAT ALLOCATION FACTORS WILL BE USED TO ALLOCATE THE COST OF PROVIDING SERVICES WHICH CANNOT BE DIRECTLY CHARGED.

A. Other services provided by AEPSC include procurement, research and development, internal and external communication, building and lease services, fleet and equipment services, legal, governmental affairs, and special projects. These services are directly charged to the benefiting company whenever possible. If the service benefits more than one company, the most cost causative allocation factor will be used given the nature of the services performed. The primary cost causative allocation factors used for these services are number of purchase orders written, number of employees, total assets, number of vehicles, number of electric customers, and the departments' prior three months bill to subsidiaries.

Q. IN YOUR OPINION, ARE THE PROPOSED ALLOCATION FACTORS REASONABLE?

A. Yes. They are based on cost causative criteria which are indicators of the amount of activity within the companies that will receive allocations. Those factors greatly expand the available factors that can be used to allocate costs, enhancing the ability to assure that costs are allocated on the basis of specific company cost causative criteria which approximate the service recipients' activity levels and portion of services received.

Q. ARE YOU SEEKING ANY APPROVAL FROM THIS COMMISSION WITH RESPECT TO THE PROPOSED FORMULAS AND THEIR APPLICATION TO THE FUNCTIONAL CATEGORIES AND WORK ORDERS PRESENTED?

A. No. The merged entity will continue to be subject to SEC regulation under PUHCA, and approval of the factors has been sought from the SEC. However, it should be noted that the merger savings were allocated to each company by applying certain of the proposed factors to the anticipated savings. The proposed allocation factors provide a reasonable basis for identifying the merger savings for each subsidiary of the merged entity, and for determining a reasonable sharing of savings by company for purposes of the merger as I discuss below.

Q. WILL THE COMMISSION HAVE THE ABILITY IN RATE PROCEEDINGS TO REVIEW THE REASONABLENESS OF THE COSTS SUBJECT TO THE ALLOCATION FACTORS?

A. Yes, in determining rates, regulatory commissions will have the same opportunity they have had to determine whether costs are reasonably incurred, whether the services are necessary for providing regulated utility service, and whether expenditures meet other applicable statutory tests in providing service to the affected utility companies.

Q. WILL THE PARENT COMPANY SHARE IN THE COST ALLOCATION FROM THE SERVICES COMPANY?

A. Yes, the parent company will receive services from AEPSC and will be billed based on its proportionate share of costs, either directly or through an allocation in accordance with the approved SEC allocations. Costs billed to the parent company are not reallocated to other companies and are not paid by electric customers in any jurisdiction.

Q. WILL AEP'S NON-UTILITY SUBSIDIARIES RECEIVE ALLOCATIONS OF COSTS FROM THE SERVICE COMPANY?

A. Yes, all subsidiaries will receive allocations of costs for the services from which they receive a benefit.

Q. DOES THIS MEAN ALL SUBSIDIARIES PARTICIPATE IN THE ALLOCATION FACTORS FOR ALL WORK ORDERS THAT ARE ALLOCATED BY AN ALLOCATION FACTOR?

A. No, it does not. Only subsidiaries that benefit from the activities performed in an individual work order are included in the allocation of costs accumulated in that work order. The service company provides services under an SEC order for the primary benefit of the electric operating companies, and many of the services provided do not benefit other subsidiaries.

This is not to say that AEPSC will not provide services to the other subsidiaries. For example, a work order that accumulates costs for billing and mailing electric customer bills would not be shared by all subsidiaries. Only the subsidiaries with electric customers benefiting from the service would share such costs. These subsidiaries are historically the electric operating companies. On the other hand, a work order accumulating costs for vendor payments would be allocated to all subsidiaries receiving the service based on total number of vendor payments. This allocation could encompass all subsidiaries. Many of the services provided to the non-electric operating companies will be specialized in nature and, as with the specific services provided to the electric operating companies, will be directly charged 100% to the specific subsidiary.

Q. CAN ALL COSTS BE CHARGED DIRECTLY TO EACH COMPANY, RATHER THAN ALLOCATED THROUGH A FORMULA?

A. No. Certain costs are jointly incurred on behalf of one or more recipients and these costs must be allocated because the product or service provided is not reducible to discrete, easily divisible parts. However, providing services jointly can produce substantial savings compared to providing the service on a stand-alone basis.

When a joint service is provided, the task becomes to allocate the cost in a manner that allows for the reasonable sharing of the costs and benefits. If each affiliate were allocated costs based on its own cost to produce the service, more than the total cost incurred by the service company for providing the service would be charged.

When services are charged to a work order, they are charged at actual cost, which is then allocated to each company based on one of the several SEC-approved allocation factors. As previously noted, these allocation factors are designed to allocate costs based on specific company cost causative criteria which reasonably approximate each company's activity level and hence, proportion of services received.

B. Transactions with the Parent Company

Q. WHAT TRANSACTIONS WILL THE ELECTRIC OPERATING COMPANIES HAVE WITH THE PARENT?

A. The electric utility operating companies and other subsidiaries will transact business with the parent company for equity transfers (including the payment of common stock dividends and equity contributions) and possible short-term investments.

C. Transactions Among Operating Companies

Q. WHAT TRANSACTIONS ARE ANTICIPATED TO OCCUR AMONG THE ELECTRIC OPERATING COMPANIES?

A. Electric operating company transactions are expected to fall into two general categories. First, there will be power supply and transmission service arrangements for operating the combined company system in an integrated fashion. The power supply transactions will be conducted under the proposed AEP/CSW System Integration Agreement filed with the FERC and are addressed by Mr. J. Craig Baker. Second, certain operating companies may have other transactions among themselves whereby they provide certain services to achieve mutual benefit and meet the demands of certain circumstances. Examples of the second category of transactions include the temporary lease of available rail cars among operating companies or maintenance of such cars by one subsidiary for another; and, the sharing of line crews to address disaster or emergency conditions.

Q. WITH RESPECT TO THE SECOND CATEGORY OF TRANSACTIONS, HOW WILL TRANSACTIONS OCCUR AND COSTS BE CHARGED AMONG THE OPERATING COMPANIES?

A. If the services provided are tariffed services, the companies will charge the appropriate tariffed prices. Otherwise, transactions will occur as a result of contractual arrangements between the operating companies. Unless a waiver is granted by the SEC, these transactions will be at cost, as required by the SEC, and these costs will be directly assigned where possible. If an allocation of costs is required, a reasonable allocation basis will be used. For example, the costs of operating jointly-owned generating stations would be allocated among operating company participants based upon either their output from or ownership share in that station, depending upon the nature of the costs.

D. Transactions Between Operating Companies and Non-Regulated Affiliates

Q. IS IT ANTICIPATED THAT TRANSACTIONS WILL OCCUR BETWEEN THE ELECTRIC OPERATING COMPANIES AND NON-REGULATED AFFILIATES?

A. Yes. From time to time there may be transactions that occur between the electric operating companies and non-regulated affiliates other than AEPSC. These transactions can involve the sale of goods and services by a regulated affiliate to a non-regulated affiliate, or the sale of such items by a non-regulated affiliate to a regulated affiliate. In addition, there may be non-routine sales of property between regulated and non-regulated companies.

Q. WHAT TRANSACTIONS OF THIS TYPE ARE EXPECTED TO OCCUR WITHIN THE MERGED ENTITY?

A. All of the transactions which may occur are not presently known. To the extent that opportunities exist to engage in such transactions and provide economic benefit to both the operating companies and the non-regulated companies, they should be permitted to occur. The practice of the merged entity will be to permit such transactions to occur, subject to compliance with applicable statutes, rules and regulations, where the participants have determined that each will realize an economic benefit.

E. Ratepayer Assurances

Q. HOW WILL THE REGULATED ELECTRIC UTILITIES INSURE THAT THEY PROVIDE SERVICE TO THEIR CUSTOMERS AT REASONABLE COST WITH RESPECT TO AFFILIATE TRANSACTIONS?

A. As it pertains to affiliate transactions, this will be accomplished in a couple of different ways. For activities necessary to provide electric service that are not appropriate to be obtained on the open market, the electric operating companies and their responsible agents will continue to review those activities to determine which might be performed through the service company using standardized procedures and other approaches which can produce economies of scale and other benefits. By having such activities performed by the service company and allocating the costs among the recipients of such services, regulated customers obtain the benefits that are produced by affiliate transactions.

With respect to new contracts for services that can be obtained on the open market or through an affiliate, the electric utility operating companies will seek to obtain the service at the lowest reasonable cost and will select the best supplier to do so, regardless of affiliation, taking into account all circumstances surrounding its acquisition. With respect to the sale of services, the regulated electric utilities will protect the interests of their customers by making such sales at tariffed rates, or in the event no tariff exists for the service, as required by the SEC, at fully allocated costs to affiliates.

V. ALLOCATION OF MERGER SAVINGS AND COSTS AMONG AFFILIATES

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

A. I describe how annual merger savings and costs are distributed among the merged entity's subsidiaries.

Q. PLEASE EXPLAIN HOW YOUR ANALYSIS WAS DONE.

A. The Synergies Analysis groups savings by functional area. Those savings result from labor reductions, corporate program savings and non-fuel purchasing economies. A graphical overview of the type of information provided in the Synergies Analysis is found in Mr. Flaherty's EXHIBIT TJF-4. The analysis of merger benefits categorizes savings first by labor and non-labor. Based on the information from the synergies analysis, labor and non-labor savings were allocated to the subsidiaries based on further analysis as explained below.

Q. PLEASE EXPLAIN YOUR ANALYSIS AND ALLOCATION OF THE LABOR SAVINGS.

A. The Synergies Analysis identifies labor savings by functional area and sub-functional area for the Regulated-Direct and the Service Company. The Synergies Analysis identified no labor savings for Non-Regulated Direct. A synergy savings work order was established for each sub-category based on an analysis of companies benefiting from services provided by the affected group. An appropriate allocation factor was assigned to each work order based on an analysis of services provided by the functional group. By this means, the savings identified by work order and allocation factor were allocated to the appropriate subsidiaries.

For example, savings were identified for the finance area. Within the finance area, savings were sub-categorized by payroll, accounts payable, general accounting, and other activities. For each sub-category, a work order and the most representative allocation factor was assigned. To illustrate, the accounts payable work order was allocated based on the number of vendor payments. For general accounting, the allocation factor was based on the number of general ledger transactions. The savings identified as Regulated Direct were allocated to the electric operating companies only.

This process was used for every category and sub-category of labor savings. FERC accounts were assigned to each work order based on an analysis of historical services provided by the functional group.

Q. PLEASE EXPLAIN YOUR ANALYSIS AND ALLOCATION OF THE NON-LABOR SAVINGS.

A. The Synergies Analysis identifies non-labor savings by functional categories for the Non-Regulated Direct, Regulated-Direct and the Service Company. The functional categories identified in the Synergies Analysis are administration and general overhead, advertising, association dues, benefits, directors fees, insurance, telecommunication, credit facilities, information services, professional services, regulatory expenses, shareholder services, facilities, research and development costs, procurement, and inventory.

For categories covering multiple areas, a sub-category was assigned. For example, the savings for professional services are split into the sub-categories of legal, auditing, accounting and finance, engineering and other. A synergy savings work order was assigned to each category and sub-category based on an analysis of companies benefiting from each area of savings. An allocation factor was assigned to each work order based on an analysis of the savings. For example, professional service savings for production engineering used the allocation factor megawatts of generating capacity. Professional service savings for transmission engineering used the allocation factor transmission pole miles. The savings identified as Regulated Direct were allocated to the electric operating companies only. The savings identified as Non-Regulated Direct were allocated to the non-regulated subsidiaries only.

This process was used for every category and sub-category of non-labor savings. FERC accounts were assigned to each work order based on an analysis of historical account classifications of such costs. The savings identified by work order and allocation factor were allocated to the appropriate subsidiaries. Having performed this analysis, EXHIBIT GRK-2 shows the distribution of savings among the affiliated companies of the merged entity.

Q. MR. FLAHERTY STATES THE SYNERGIES SAVINGS ARE OFFSET BY THE COSTS TO ACHIEVE AND PRE-MERGER INITIATIVES. HOW WERE THE COSTS TO ACHIEVE, PRE-MERGER INITIATIVES, AND CHANGE IN CONTROL PAYMENTS ALLOCATED TO THE SUBSIDIARIES?

A. Consistent with the proposed regulatory plan in Mr. Munczinski's testimony, the costs to achieve and the change in control payments were distributed on a straight line basis over a five year period. These costs, as well as the pre-merger initiatives, were then allocated to all companies on a pro rata basis following gross savings. For example, if KPCO received 4% of the gross savings, then KPCO would receive 4% of the costs to achieve, change in control payments, and pre-merger initiatives.

Q. IN YOUR OPINION DOES THE PROCESS YOU HAVE DESCRIBED ABOVE PRODUCE A REASONABLE ALLOCATION OF MERGER SYNERGIES, COSTS TO ACHIEVE AND PRE-MERGER INITIATIVES AMONG THE AFFILIATES OF THE MERGED ENTITY?

A. Yes, it does. The basis for allocating merger savings generally follow how such anticipated savings will be experienced using the proposed allocation factors. Since the gross merger savings are a result of the costs to achieve and include the results of the pre-merger initiatives, it is reasonable to allocate the costs to achieve and pre-merger initiatives in proportion to the gross merger savings.

Q. WHAT DID YOU DO WITH THE RESULTS OF YOUR ALLOCATION TO COMPANIES?

A. The information has been provided to Mr. Munczinski to allocate to jurisdictions and to address the regulatory treatment of the savings and costs.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony demonstrates that the merger will preserve the Commission's ability to effectively regulate KPCO. The affiliate accounting policies under which the merged entity will operate are reasonable and appropriate. AEP will continue to perform services through its service company in a manner designed to capture the economies of scope and scale that occur with that type of operation. Allocation factors to be used by the service company of the merged entity are reasonable, fair, and equitable and a reasonable basis for allocating the cost of future shared services and merger savings. The savings produced, as a result of the merger, will provide benefits to affiliates, including the regulated utilities of AEP and CSW. As a result, affiliate operations of the merged entity will experience future cost reductions which will reduce costs for the regulated utilities. The accounting procedures I have discussed contribute to the ability of the Commission to properly regulate and oversee affiliate transactions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COUNTY OF BOYD

COMMONWEALTH OF KENTUCKY CASE NO. 99-

Affidavit

Gerald R. Knorr, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Gerald R. Knorr

Gerald R. Knorr

Subscribed and sworn to before me by Gerald R. Knorr this 7th day of April 1999.

Kathy L. Messer

Notary Public

My Commission Expires August 18, 2002

PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
1 NUMBER OF BANK ACCOUNTS	Number of Bank Accounts Per Company / Total Number of Bank Accounts
2 NUMBER OF CALL CENTER TELEPHONES	Number of Call Center Telephones Per Company / Total Number of Call Center Telephones
3 NUMBER OF CELL PHONES / PAGERS	Number of Cell Phones and Pagers Per Company / Total Number of Cell Phones and Pagers
4 NUMBER OF CHECKS PRINTED	Number of Checks Printed Per Company Per Month / Total Number of Checks Printed Per Month
5 NUMBER OF CIS CUSTOMER MAILINGS	Number of CIS Customer Mailings Per Company / Total Number of CIS Customer Mailings
6 NUMBER OF COMMERCIAL CUSTOMERS	Number of Commercial Customers Per Company / Total Number of Commercial Customers
7 NUMBER OF CREDIT CARDS	Number of Corporate Credit Cards Per Company / Total Number of Corporate Credit Cards
8 NUMBER OF ELECTRIC RETAIL CUSTOMERS	Number of Electric Retail Customers Per Company / Total Number of Electric Retail Customers
9 NUMBER OF EMPLOYEES	Number of Full-Time and Part-Time Employees Per Company / Total Number of Full-Time and Part-Time Employees
10 NUMBER OF GENERATING PLANT EMPLOYEES	Number of Generating Plant Employees Per Company / Total Number of Generating Plant Employees
11 NUMBER OF GL TRANSACTIONS	Number of Lines of Accounting Distribution Per Company / Total Number of Lines of Accounting Distribution
12 NUMBER OF HELP DESK CALLS	Number of Help Desk Calls Per Company / Total Number of Help Desk Calls

PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
13 NUMBER OF INDUSTRIAL CUSTOMERS	Number of Industrial Customers / Total Number of Industrial Customers
14 NUMBER OF JCA TRANSACTIONS	Number of Lines of Accounting Distribution on Job Cost Accounting Sub-System Per Company / Total Number of Lines of Accounting Distribution on Job Cost Accounting Sub-System
15 NUMBER OF NON-UMWA EMPLOYEES	Number of Non-UMWA Employees Per Company / Total Number of Non-UMWA Employees
16 NUMBER OF PHONE CENTER CALLS	Number of Phone Calls Per Phone Center Per Company / Total Number of Phone Center Phone Calls
17 NUMBER OF PURCHASE ORDERS WRITTEN	Number of Purchase Orders Written Per Company / Total Number of Purchase Orders Written
18 NUMBER OF RADIOS (BASE/MOBILE/HANDHELD)	Number of Radios (Base/Mobile/Handheld) Per Company / Total Number of Radios (Base/Mobile/Handheld)
19 NUMBER OF RAILCARS	Number of Rail Cars Per Company / Total Number of Rail Cars
20 NUMBER OF REMITTANCE ITEMS	Number of Electric Bill Payments Processed Per Company Per Month (non-lockbox) / Total Number of Electric Bill Payments Processed Per Company Per Month
21 NUMBER OF REMOTE TERMINAL UNITS	Number of Remote Terminal Units Per Company / Total Number of Remote Terminal Units
22 NUMBER OF RENTED WATER HEATERS	Number of Rented Water Heaters Per Company / Total Number of Rented Water Heaters
23 NUMBER OF RESIDENTIAL CUSTOMERS	Number of Residential Customers Per Company / Total Number of Residential Customers
24 NUMBER OF ROUTERS	Number of Routers Per Company / Total Number of Routers

PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
25 NUMBER OF SERVERS	Number of Servers Per Company Total Number of Servers
26 NUMBER OF STORES TRANSACTIONS	Number of Stores Transactions Per Company Total Number of Stores Transactions
27 NUMBER OF TELEPHONES	Number of Telephones Per Company (Includes all phone lines) Total Number of Telephones (includes all phone lines)
28 NUMBER OF TRANSMISSION POLE MILES	Number of Transmission Pole Miles Per Company Total Number of Transmission Pole Miles
29 NUMBER OF TRANSTEXT CUSTOMERS	Number of Transtext Customers Per Company Total Number of Transtext Customers
30 NUMBER OF TRAVEL TRANSACTIONS	Number of Travel Transactions Per Company Per Month Total Number of Travel Transactions Per Month
31 NUMBER OF VEHICLES	Number of Vehicles Per Company (Includes Fleet and Pool Cars) Total Number of Vehicles Per Company (Includes Fleet and Pool Cars)
32 NUMBER OF VENDOR INVOICE PAYMENTS	Number of Vendor Invoice Payments Per Company Per Month Total Number of Vendor Invoice Payments Per Month
33 NUMBER OF WORKSTATIONS	Number of Personal Computers Per Company Total Number of Personal Computers
34 ACTIVE OWNED OR LEASED COMMUNICATION CHANNELS	Number of Active Owned Or Leased Communication Channels Per Company Total Number of Active Owned Or Leased Communication Channels
35 AVG PEAK LOAD FOR PAST THREE YEARS	Average Peak Load for Past Three Years Per Company Total of Average Peak Load for Past Three Years
36 COAL PLANT COMBINATION	The Sum of Each Coal Company's Gross Payroll, Original Cost of Fixed Assets Original Cost of Leased Assets, and Gross Revenues for Last Twelve Months The Sum of the Same Factors for All Coal Companies

PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
37 AEPSC PAST 3 MONTHS TOTAL BILL DOLLARS	AEPSC Total Billed Amount for Past Three Months Per Company Total AEPSC Total Billed Amount for Past Three Months
38 AEPSC PRIOR MONTH TOTAL BILL DOLLARS	AEPSC Total Billed Amount for Prior Month Per Company AEPSC Total Billed Amount for Prior Month
39 DIRECT	100% to One Company
40 EQUAL SHARE RATIO	One (1) Total Number of Companies
41 FOSSIL PLANT COMBINATION	The Sum of (1) the Percentage Derived by Dividing the Total Megawatt Capability of All Fossil Generating Plants of Each Generating Company by the Total Megawatt Capability of All Fossil Plants Generating Plants of All Generating Companies (2) the Percentage Derived by Dividing the Total Scheduled Maintenance Outages of All Fossil Generating Plants of Each Generating Company For the Last Three Years by the Total Scheduled Maintenance of All Fossil Generating Plants at all Generating Companies During the Same Three Years Two (2)
42 FUNCTIONAL DEPARTMENT'S PAST 3 MONTHS TOTAL BILL DOLLARS	AEPSC Billed Amount for Past Three Months by Functional Category Per Company Total AEPSC Billed Amount for Past Three Months by Functional Category
43 KWH SALES	Number of KWH Sales Per Company Total Number of KWH Sales
44 LEVEL OF CONSTRUCTION – DISTRIBUTION	Construction Expenditures for All Distribution Plant Accounts Except Land and Land Rights, Services, Meters and Leased Property on Customers Premises, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC Are Being Made Separately, for Each Operating Company During the Last Twelve Months The Sum of the Same Factors for All Companies
45 LEVEL OF CONSTRUCTION – PRODUCTION	Construction Expenditures for All Production Plant Accounts Except Land and Land Rights, Nuclear Accounts, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, for Each Operating Company During the Last Twelve Months The Sum of the Same Factors for All Companies

PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
46 LEVEL OF CONSTRUCTION- TRANSMISSION	Construction Expenditures for All Transmission Plant Accounts Except Land and Land Rights and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, for Each Operating Company During the Last Twelve Months The Sum of the Same Factors for All Companies
47 LEVEL OF CONSTRUCTION-TOTAL	Construction Expenditures for ALL Plant Accounts Except Land and Land Rights, Line Transformers Services, Meters and Leased Property on Customers' Premises; and the Following General Plant Accounts: Structures and Improvements, Shop Equipment, Laboratory Equipment and Communication Equipment; And Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, for Each Operating Company During the Last Twelve Months The Sum of the Same Factors for All Companies
48 MW GENERATING CAPABILITY	Number of MWH Generation Capacity Per Company Total Number of MWH Generation Capacity
49 MWH 'S GENERATION	Number of MWH Generation Per Company Total Number of MWH Generation
50 OVERHEAD CLEARING	Budgeted AEPSC Payroll Dollars Billed Per Company Total AEPSC Payroll Dollars Billed
51 PAST 3 MO. MMBTU'S BURNED(ALL FUEL TYPES)	Past Three Months MMBTU's Burned Per Company (All Fuel Types) Total Number of MMBTU's Burned for Past Three Months (All Fuel Types)
52 PAST 3 MO. MMBTU'S BURNED(COAL ONLY)	Past Three Months MMBTU's Burned Per Company (Coal Only) Total Number of MMBTU's Burned for Past Three Months (Coal Only)
53 PAST 3 MO. MMBTU'S BURNED(GAS TYPE ONLY)	Past Three Months MMBTU's Burned Per Company (Gas Type Only) Total Number of MMBTU's Burned for Past Three Months (Gas Type Only)
54 PAST 3 MO. MMBTU'S BURNED(OIL TYPE ONLY)	Past Three Months MMBTU's Burned Per Company (Oil Type Only) Total Number of MMBTU's Burned for Past Three Months (Oil Type Only)
55 PAST 3 MO. MMBTU'S BURNED(SOLID FUELS ONLY)	Past Three Months MMBTU's Burned Per Company (Solid Fuels Only) Total Number of MMBTU's Burned for Past Three Months (Solid Fuels Only)

PROPOSED ALLOCATION FACTORS FOR AEPSC

DESCRIPTION	CALCULATION
56 PEAK LOAD/AVG # CUST/KWH SALES	Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers Per Company Total of Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers
57 TONS OF FUEL ACQUIRED	Number of Tons of Fuel Acquired Per Company Total Number of Tons of Fuel Acquired
58 TOTAL ASSETS	Total Asset Amount Per Company Total Asset Amount
59 TOTAL ASSETS LESS NUCLEAR PLANT	Total Asset Dollars Less Nuclear Per Company Total Asset Dollars Less Nuclear
60 TOTAL AEPSC BILLING LESS INDIRECT COST & INTEREST	Total Billing Amount Less Indirect Cost and Interest Per Company Total Billing Amount Less Indirect Cost and Interest
61 TOTAL FIXED ASSET	Total of Fixed Asset Amount Per Company Total of Fixed Asset Amount
62 TOTAL GROSS REVENUE	Total Gross Revenue Previous Four Quarters Per Company Total Gross Revenue Previous Four Quarters
63 TOTAL GROSS UTILITY PLANT(INCLUDES CWIP)	Gross Utility Plant Amount Per Company Total Gross Utility Plant Amount
64 TOTAL PEAK LOAD (PRIOR YEAR)	Total Peak Load for Prior Year Per Company Total Peak Load for Prior Year

DISTRIBUTION OF MERGER SAVINGS AMONG COMPANIES

GROSS SAVINGS
($000)

LINE	COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
1	APCO	(10947)	(25418)	(31544)	(37200)	(41187)	(44101)	(46936)	(48415)	(50033)	(51643)	(13151)	(400575)
2	KgPCO	(281)	(701)	(889)	(1063)	(1197)	(1250)	(1330)	(1326)	(1359)	(1377)	(351)	(11124)
3	CSP	(6233)	(14589)	(18129)	(21273)	(23623)	(24899)	(26487)	(26925)	(27815)	(28603)	(7284)	(225860)
4	I&M	(8131)	(18933)	(23398)	(27436)	(30221)	(32472)	(34525)	(35816)	(37052)	(38309)	(9756)	(296049)
5	KPCO	(2653)	(6022)	(7413)	(8637)	(9517)	(10231)	(10885)	(11303)	(11703)	(12133)	(3090)	(93588)
6	OPCO	(10841)	(24279)	(29907)	(34761)	(38384)	(41303)	(44020)	(45767)	(47486)	(49357)	(12569)	(378676)
7	WPCO	(294)	(722)	(911)	(1087)	(1219)	(1273)	(1354)	(1354)	(1391)	(1416)	(360)	(11382)
8	SUBTOTAL	(39380)	(90664)	(112191)	(131457)	(145348)	(155529)	(165537)	(170906)	(176839)	(182838)	(46561)	(1417254)
9	AEP-OTHER	(3997)	(7954)	(9364)	(10403)	(11150)	(12469)	(13131)	(14145)	(14521)	(15108)	(3848)	(116094)
10	TOTAL AEP	(43377)	(98618)	(121555)	(141860)	(156498)	(167998)	(178668)	(185051)	(191360)	(197946)	(50409)	(1533348)
11	CSW	(25096)	(57251)	(70409)	(81054)	(89258)	(95241)	(101277)	(104610)	(108410)	(112243)	(28584)	(873433)
12	TOTAL	(68473)	(155869)	(191964)	(222914)	(245756)	(263239)	(279945)	(289661)	(299770)	(310189)	(78993)	(2406781)
13	ROUNDING												35
14	TOTAL SAVINGS PER SYNERGIES ANALYSIS												(2406746)

DISTRIBUTION OF MERGER SAVINGS AMONG COMPANIES

AMORTIZATION OF COST TO ACHIEVE
($000)

LINE	COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
1	APCO	5,949	8,091	8,153	8,280	8,316	2,078	0	0	0	0	0	40,867
2	KgPCO	153	223	230	237	242	59	0	0	0	0	0	1,143
3	CSP	3,387	4,644	4,686	4,735	4,769	1,173	0	0	0	0	0	23,395
4	I&M	4,419	6,027	6,048	6,107	6,102	1,530	0	0	0	0	0	30,232
5	KPCO	1,442	1,917	1,916	1,923	1,921	482	0	0	0	0	0	9,601
6	OPCO	5,891	7,729	7,730	7,737	7,750	1,946	0	0	0	0	0	38,783
7	WPCO	160	230	235	242	246	60	0	0	0	0	0	1,173
8	SUBTOTAL	21,401	28,861	28,998	29,261	29,346	7,328	0	0	0	0	0	145,194
9	AEP-OTHER	2,174	2,531	2,419	2,316	2,250	590	0	0	0	0	0	12,279
10	TOTAL AEP	23,575	31,392	31,417	31,577	31,596	7,918	0	0	0	0	0	157,473
11	CSW	13,638	18,224	18,198	18,041	18,020	4,487	0	0	0	0	0	90,608
12	TOTAL	37,213	49,616	49,615	49,618	49,616	12,405	0	0	0	0	0	248,081
13	ROUNDING												-1
14	TOTAL SAVINGS PER SYNERGIES ANALYSIS												248,080

DISTRIBUTION OF MERGER SAVINGS AMONG COMPANIES

PRE-MERGER INITIATIVES
($000)

LINE	COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
1	APCO	248	709	1,220	1,843	2,580	3,381	4,223	5,051	5,547	5,888	1,562	32,251
2	KgPCO	6	20	34	53	75	96	120	138	151	157	41	891
3	CSP	141	407	701	1,054	1,480	1,909	2,383	2,809	3,084	3,261	865	18,094
4	I&M	184	528	905	1,359	1,893	2,490	3,107	3,736	4,108	4,368	1,159	23,836
5	KPCO	60	168	287	428	596	784	979	1,179	1,297	1,383	367	7,529
6	OPCO	245	677	1,157	1,722	2,404	3,167	3,961	4,774	5,264	5,628	1,493	30,492
7	WPCO	7	20	35	54	76	98	122	141	154	161	43	911
8	SUBTOTAL	891	2,529	4,339	6,513	9,104	11,925	14,895	17,828	19,605	20,846	5,530	114,004
9	AEP-OTHER	91	223	362	512	699	955	1,182	1,477	1,609	1,722	456	9,293
10	TOTAL AEP	982	2,752	4,701	7,025	9,803	12,880	16,077	19,305	21,214	22,568	5,986	123,297
11	CSW	568	1,597	2,723	4,014	5,591	7,302	9,113	10,913	12,019	12,798	3,395	70,032
12	TOTAL	1,550	4,349	7,424	11,039	15,394	20,182	25,190	30,218	33,233	35,366	9,381	193,329
13	ROUNDING												-2
14	TOTAL SAVINGS PER SYNERGIES ANALYSIS												193,327

DISTRIBUTION OF MERGER SAVINGS AMONG COMPANIES

GROSS SAVINGS LESS COST TO ACHIEVE AND PRE-MERGER INITIATIVES
($000)

LINE	COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
1	APCO	(4750)	(16618)	(22171)	(27077)	(30291)	(38642)	(42713)	(43364)	(44486)	(45755)	(11589)	(327457)
2	KgPCO	(122)	(458)	(625)	(773)	(880)	(1095)	(1210)	(1188)	(1208)	(1220)	(310)	(9090)
3	CSP	(2705)	(9538)	(12742)	(15484)	(17374)	(21817)	(24104)	(24116)	(24731)	(25342)	(6419)	(184371)
4	I&M	(3528)	(12378)	(16445)	(19970)	(22226)	(28452)	(31418)	(32080)	(32944)	(33941)	(8597)	(241981)
5	KPCO	(1151)	(3937)	(5210)	(6286)	(7000)	(8965)	(9906)	(10124)	(10406)	(10750)	(2723)	(76458)
6	OPCO	(4705)	(15873)	(21020)	(25302)	(28230)	(36190)	(40059)	(40993)	(42222)	(43729)	(11076)	(309401)
7	WPCO	(127)	(472)	(641)	(791)	(897)	(1115)	(1232)	(1213)	(1237)	(1255)	(317)	(9298)
8	SUBTOTAL	(17088)	(59274)	(78854)	(95683)	(106898)	(136276)	(150642)	(153078)	(157234)	(161992)	(41031)	(1158056)
9	AEP-OTHER	(1732)	(5200)	(6583)	(7575)	(8201)	(10924)	(11949)	(12668)	(12912)	(13386)	(3392)	(94522)
10	TOTAL AEP	(18820)	(64474)	(85437)	(103258)	(115099)	(147200)	(162591)	(165746)	(170146)	(175378)	(44423)	(1252578)
11	CSW	(10890)	(37430)	(49488)	(58999)	(65647)	(83452)	(92164)	(93698)	(96392)	(99445)	(25189)	(712793)
12	TOTAL	(29710)	(101904)	(134925)	(162257)	(180746)	(230652)	(254755)	(259444)	(266538)	(274823)	(69612)	(1965371)
13	ROUNDING												32
14	TOTAL SAVINGS PER SYNERGIES ANALYSIS												(1965339)

DISTRIBUTION OF MERGER SAVINGS AMONG COMPANIES

AMORTIZATION OF CHANGE IN CONTROL
($000)

LINE	COMPANY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
1	APCO	1,655	2,251	2,269	2,304	2,314	578	0	0	0	0	0	11,371
2	KgPCO	42	62	64	66	67	16	0	0	0	0	0	318
3	CSP	942	1,292	1,304	1,318	1,327	326	0	0	0	0	0	6,510
4	I&M	1,230	1,677	1,683	1,699	1,698	426	0	0	0	0	0	8,412
5	KPCO	401	533	533	535	535	134	0	0	0	0	0	2,672
6	OPCO	1,639	2,151	2,151	2,153	2,156	542	0	0	0	0	0	10,792
7	WPCO	44	64	65	67	69	17	0	0	0	0	0	326
8	SUBTOTAL	5,953	8,030	8,069	8,142	8,166	2,039	0	0	0	0	0	40,401
9	AEP-OTHER	604	702	672	644	625	163	0	0	0	0	0	3,416
10	TOTAL AEP	6,557	8,732	8,741	8,786	8,791	2,202	0	0	0	0	0	43,817
11	CSW	3,795	5,071	5,064	5,020	5,014	1,249	0	0	0	0	0	25,213
12	TOTAL	10,352	13,803	13,805	13,806	13,805	3,451	0	0	0	0	0	69,030
13	ROUNDING												0
14	TOTAL SAVINGS PER SYNERGIES ANALYSIS												69,030

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF :

JOINT APPLICATION OF KENTUCKY POWER COMPANY,	)	
AMERICAN ELECTRIC POWER COMPANY, INC.	)	
AND CENTRAL AND SOUTH WEST CORPORATION	)	CASE NO. 99-
REGARDING A PROPOSED MERGER	)	

DIRECT TESTIMONY

OF

WILLIAM H. HIERONYMUS

APRIL 1999

TESTIMONY INDEX

COMMONWEALTH OF KENTUCKY

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REGARDING A PROPOSED MERGER)

DIRECT TESTIMONY

OF

WILLIAM H. HIERONYMUS

APRIL 1999

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is William H. Hieronymus. My business address is Putnam, Hayes & Bartlett, Inc., One Memorial Drive, Cambridge, Massachusetts 02142.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am Senior Vice President of PHB Hagler Bailly, Inc., an international economic and management consulting firm created by the merger of Putnam, Hayes & Bartlett and Hagler Bailly, Inc. Hagler Bailly is a worldwide provider of consulting, research and other professional services to corporations and governments on energy, telecommunications, transportation, and the environment.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by American Electric Power Company, Inc. (AEP) and Central and South West Corporation (CSW) (collectively, the Applicants) to determine the potential competitive impact of their proposed merger on electricity markets. My analysis is conducted in a manner consistent with the Competitive Analysis Screen described in Appendix A to the Federal Energy Regulatory Commission (FERC) Merger Policy Statement (Order No. 592), which in turn is intended to comport with the Department of Justice and Federal Trade Commission (DOJ/FTC) Merger Guidelines (Guidelines). My analysis also responds to the FERC's Order setting this merger for hearing.[1] This testimony is fully consistent with my FERC testimony, and is based primarily on a subset of the analyses filed at the FERC.

Q. ARE YOU SUBMITTING A COPY OF YOUR FERC TESTIMONY IN THIS PROCEEDING?

A. Yes. I have attached as EXHIBIT WHH-1, a copy of my January 13, 1999 testimony before the FERC regarding the proposed merger. The analysis of market power presented in the FERC testimony applies equally to both the state and federal level. The conclusions that I reach, and the calculations that support those conclusions, are the same before this Commission and the FERC. If asked the same questions in Kentucky, I would provide the same answers as are presented in the FERC testimony. My additional testimony in Kentucky merely summarizes the particular findings in the FERC testimony relevant to Kentucky destination markets.

Q. PLEASE SUMMARIZE YOUR OVERALL CONCLUSIONS OF THE MARKET POWER ANALYSIS CONDUCTED AS PART OF YOUR FERC TESTIMONY.

A. With the mitigation measures proposed by Applicants (primarily near-term sale followed by divestiture of some CSW generation), the merger will not adversely affect competition in any of the numerous wholesale destination markets that I have analyzed.

The essential fact is that, historically, the utility subsidiaries of the two companies have not traded with each other, or with utilities that are reached through the

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[1] *American Electric Power Company and Central and South West Corporation*, 85 FERC ¶ 61,201(November 10, 1999).

transmission system of the other. The only overlap in wholesale sales of the two companies is in sales to utilities that lie between them, and in those cases the extent of the overlap is small.

Accordingly, the amount of competition eliminated by the merger is very small, and the mitigation measures proposed by Applicants are amply sufficient to assure that the merger will not adversely affect competition in wholesale, and relevant retail, electricity markets.

Q. WHAT CONCLUSION DO YOU REACH WITH REGARD TO WHETHER THIS MERGER WILL HAVE A COMPETITIVE IMPACT ON ELECTRICITY MARKETS IN KENTUCKY?

A. I conclude that the proposed merger does not pose any market power concerns in wholesale, and relevant retail, electricity markets in Kentucky. The merger is particularly unlikely to have an impact upon Kentucky given that CSW has no historical presence in the Kentucky markets.

III. FRAMEWORK OF THE ANALYSIS

Q. WHAT ARE THE GENERAL MARKET POWER ISSUES RAISED BY MERGER PROPOSALS?

A. Market power analysis of a merger proposal examines whether the merger would cause a material increase in the merging firms' market power or a significant reduction in the competitiveness of relevant markets. Market power is defined as the ability of a firm or group of firms to profitably sustain a significant increase in the price of their products above a competitive level.

In merger market power analyses, the critical issue is the effect of the merger on market competitiveness, as opposed to the competitiveness of the pre-merger market structure. While the pre-merger competitiveness of markets may, as under the DOJ/FTC Guidelines, affect the amount by which market structure may be allowed to change, the focus remains on the *change* in market competitiveness caused by the merger.

This focus on the effects of the merger means that the merger analysis examines those business areas where the merging firms are competitors. In most instances, the merger will not affect competition in markets in which only one of the merging firms is active but the applicants do not compete. Analysis of the effects of a merger on market power in businesses in which the merging firms both participate is sometimes referred to as horizontal market power assessment. In the proposed merger of AEP and CSW, therefore, the focus is properly on those markets in which both firms are actual or potential competitors.

Vertical market power relates to the effect of the merger on the merged firm's ability and incentives to use its market position in a related business to affect competition. For example, vertical market power could result if the merger of two electric utilities created an opportunity and incentive to operate transmission in a manner that created market power for the merged company's generation activity that did not exist previously. The FERC also has identified market power as arising from the ability to frustrate potential entry, such as by using dominant control over potential generation sites or over fuel supplies and delivery systems and, prior to Order No. 888, refusals to interconnect. These vertical barriers to entry could undercut the presumption that long-run generation markets are competitive.

Q. WHAT ARE THE MAIN ELEMENTS IN DEVELOPING A MARKET POWER ANALYSIS?

A. Understanding the competitive impact of a merger first requires defining the relevant market (or markets) in which the merging firms participate. Participants in a relevant market include all suppliers and, in some instances, potential suppliers who can compete to supply the products produced by the merging parties and whose ability to do so diminishes the ability of the merging parties to increase prices. Hence, determining the scope of a market is fundamentally an analysis of the potential for competitors to respond to an attempted price increase. Markets are defined in two dimensions: geographic and product. Thus, the relevant market is composed of companies that can supply a given product (or its close substitute) to customers in a given geographic area.

Q. PLEASE DESCRIBE THE ANALYTICAL FRAMEWORK ADOPTED BY FERC FOR EXAMINING PROPOSED MERGERS INVOLVING ELECTRIC UTILITIES.

A. With the issuance of Order No. 592 in December 1996, the FERC adopted a detailed analytic framework for assessing utility mergers. This framework is organized around a market concentration analysis prescribed in Appendix A to the Order. Appendix A (the "Competitive Analysis Screen") prescribes an analytic method that Applicants are required to follow in their applications and that the FERC will use in screening the competitive impact of mergers. This is the approach used by the FERC, for example, in approving the merger of Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E).

If a proposed merger raises no market power concerns (*i.e.*, passes the Appendix A screen), the inquiry is generally complete. If a proposed merger exceeds the Appendix screens in some markets, Order No. 592 invites the Applicants to propose mitigation measures targeted to reducing market concentration changes to safe harbor levels. In the alternative, Applicants can seek to establish that the merger does not cause competitive harm notwithstanding the unmitigated failure of the screen.

Q. UNDER THE FERC'S MERGER GUIDELINES, HOW IS THE APPENDIX A ANALYSIS TO BE CONDUCTED?

A. There are four steps: (1) identify the relevant products; (2) identify the relevant geographic markets; (3) identify potential suppliers of economic capacity in each relevant geographic market; and (4) assess market concentration.

Q. WHAT PRODUCTS HAS THE FERC GENERALLY CONSIDERED?

A. The FERC generally has defined the relevant product markets to be long-term capacity, short-term capacity ("Uncommitted Capacity"), and non-firm energy ("Available Economic Capacity" and "Economic Capacity"). The FERC has determined that long-term capacity markets are presumed to be competitive, unless special factors exist that limit the ability of new generation to be sited or receive fuel. (The discussion in the next section addresses the Economic Capacity and Available Economic Capacity measures. The Uncommitted Capacity analysis and the analysis of long-term capacity markets are discussed in the attached FERC testimony.)

Q. HOW HAS THE FERC ANALYZED GEOGRAPHIC MARKETS?

A. To examine geographic markets, the FERC has focused on the utilities that are directly interconnected to the applicant companies. This "destination market" approach was continued in Order No. 592 and in the Merger NOPR. Each utility that is directly interconnected to the Applicants is considered a separate "destination market." Additionally, the FERC has suggested that utilities who historically have been customers of Applicants are also potential "destination markets."

The supply alternatives to each destination market are defined using the "delivered price test," which identifies suppliers that can reach a destination market at a cost no more than 5 percent over the pre-merger market price. The supply is considered economic if a supplier's generation can be delivered to a destination market, including delivery costs (which include transmission rates, transmission losses and ancillary services), at a cost that is within 105 percent of the destination market price. Physical transmission constraints also are taken into consideration in determining the potential supply to the destination market. Competing suppliers are defined as those who have capacity (energy) that is physically and economically deliverable to the destination market. Their importance in the market (i.e., their market share) is determined by the amount of such capacity.

For each market in which Applicants participate, market shares and market concentration are calculated. In addition, Order No. 592 invites Applicants to consider whether competitive conditions in relevant markets differ by time of day or season.

Q. WHAT FRAMEWORK DOES THE FERC USE TO DETERMINE WHETHER A MERGER POSES POTENTIAL MARKET POWER CONCERNS?

A. In Order No. 592, the FERC adopted the DOJ/FTC Guidelines for measuring market concentration levels by the Herfindahl-Hirschman Index.[2] To determine whether a proposed merger will have a significant anti-competitive impact, the Commission will consider the level of the HHI after the merger (the post-merger HHI) and the change in the HHI that results from the merger. Markets with a post-merger HHI of less than 1000 are considered "unconcentrated." The DOJ and FTC generally consider mergers in such markets to have no anti-competitive impact. Markets with post-merger HHIs of 1000 to 1800 are considered "moderately concentrated." In those markets, mergers that result in an HHI change of 100 points or fewer are considered unlikely to have anti-competitive effects. Finally, post-merger HHIs of more than 1800 are considered to indicate "highly concentrated" markets. The Guidelines suggest that in these markets, mergers that increase the HHI by 50 points or fewer are unlikely to have a significant anti-competitive impact, while mergers that increase the HHI by more than 100 points are considered likely to reduce market competitiveness.

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2 The HHI is calculated as the sum of the squares of each company's market share, expressed in percentage terms. For example, a market with a single supplier with 100 percent market share has an HHI of 10000 (100*100), and a market with two suppliers of equal size has an HHI of 5000 (50*50+50*50).

IV. THE IMPACT OF THE MERGER ON RETAIL COMPETITION IN KENTUCKY

Q. WHAT ISSUES MUST BE ADDRESSED CONCERNING THE IMPACT OF THE MERGER ON RETAIL MARKETS IN KENTUCKY?

A. Fundamentally, a merger of two electric utilities can affect retail markets in one of two ways. First, it could adversely affect the wholesale power market from which energy sold at retail is purchased. Second, the merger of the retailing activities of two utilities might affect competition in the provision of retail services.

The FERC Appendix A analysis is designed to examine the first of these two issues: the effect of the merger on wholesale markets. For periods before retail access, a combination of the Economic Capacity and Available Economic Capacity analyses is used. After retail access, the Economic Capacity analysis (which assumes no native load obligations) is solely relevant.[3] This test was designed as part of FERC's expressed desire in Order No. 592 to be forward looking and take into account the ongoing restructuring of the electricity industry.

Q. WHAT GEOGRAPHIC MARKETS DID YOU EXAMINE RELEVANT TO KENTUCKY CUSTOMERS?

A. Among the relevant geographic markets I examined as part of my FERC analysis, were three destination markets wholly or partially in Kentucky: American Electric

[3] Economic Capacity is the amount of hourly energy that a supplier can deliver to the destination market on an economic basis, taking into account the busbar variable cost of the supplier's generation on a unit by unit basis, the cost of transmission and losses and the capacity of the transmission system linking the suppliers collectively to the destination market. The analysis of Available Economic Capacity is similar, except that a supplier's native load responsibility is subtracted from its potential supply to the destination market before assessing how much economic capacity is potentially available to compete in the destination market.

Power (AEP), which includes its subsidiary Kentucky Power; East Kentucky Power Cooperative (EKPC); and LG&E Energy (LGE). (The LGE destination market represents operations of both LG&E and KU). I evaluated market concentration in these markets pre- and post-merger for both the Economic Capacity and Available Economic Capacity measures described above. Exhibit AC-512 of my FERC testimony summarizes the results of the analysis of the impact of the merger, taking into consideration Applicants' proposed mitigation.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF THE ECONOMIC CAPACITY MEASURE FOR THE RELEVANT DESTINATION MARKETS?

A. Summarized below are the summary HHI results for the AEP, EKPC and LGE destination markets. Market structures are assessed for multiple time periods (i.e., summer, winter and shoulder peak and off-peak periods) in order to examine whether the effect of the merger on market structure differs significantly depending on seasonal or diurnal load levels. An additional peak time period, at a $35/MWh destination market price, was also analyzed.

In virtually all instances, the change in HHIs is zero or negative (indicating no change in concentration or reductions in concentration post-merger, post-mitigation). The negative HHI changes reflect that the merger results in a lower market concentration (as measured by HHIs) than existed pre-merger. In the Kentucky destination markets, the reduction in HHIs is due to AEP's declining market share which, in turn, results from the expectation that AEP will supply 250 MW of power to CSW as a consequence of the merger (as described in my FERC testimony).

AEP Market	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	37.10%	0.00%	1607	36.90%	1589	-18
Summer Super Peak	48.70%	0.00%	2557	48.40%	2531	-25
Summer Peak	51.30%	0.00%	2860	51.00%	2832	-29
Summer Off-Peak	40.00%	0.00%	1986	40.00%	1986	0
Winter Super Peak	51.80%	0.00%	2922	51.50%	2895	-27
Winter Peak	53.00%	0.00%	3074	52.70%	3045	-28
Winter Off-Peak	48.30%	0.00%	2649	47.90%	2617	-32
Shoulder Super Peak	41.80%	0.00%	1951	41.50%	1931	-20
Shoulder Peak	45.70%	0.00%	2333	45.40%	2309	-24
Shoulder Off-Peak	39.10%	0.00%	1905	38.80%	1880	-25

EKPC Market	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	6.40%	0.10%	2419	6.40%	2420	0
Summer Super Peak	9.90%	0.00%	2188	9.90%	2188	0
Summer Peak	3.90%	0.00%	1768	3.90%	1768	0
Summer Off-Peak	1.80%	0.00%	1516	1.80%	1516	0
Winter Super Peak	9.90%	0.00%	2317	9.90%	2316	-1
Winter Peak	3.70%	0.00%	2413	3.70%	2413	0
Winter Off-Peak	9.30%	0.00%	1841	9.30%	1841	0
Shoulder Super Peak	7.30%	0.30%	1868	7.50%	1871	4
Shoulder Peak	3.20%	0.00%	1757	3.20%	1757	0
Shoulder Off-Peak	1.60%	0.00%	1315	1.60%	1315	0

LGE Market	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	7.90%	0.10%	2987	7.90%	2988	1
Summer Super Peak	2.50%	0.00%	1379	2.50%	1379	0
Summer Peak	2.60%	0.00%	1702	2.60%	1702	0
Summer Off-Peak	5.20%	0.00%	1380	5.20%	1380	0
Winter Super Peak	1.20%	0.00%	1761	1.20%	1761	0
Winter Peak	1.30%	0.00%	1802	1.30%	1802	0
Winter Off-Peak	13.20%	0.00%	1097	13.20%	1097	0
Shoulder Super Peak	1.20%	0.00%	1739	1.20%	1739	0
Shoulder Peak	1.20%	0.00%	1747	1.20%	1747	0
Shoulder Off-Peak	2.10%	0.00%	1322	2.10%	1322	0

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF THE AVAILABLE ECONOMIC CAPACITY MEASURE FOR THE RELEVANT DESTINATION MARKETS?

A. These are summarized below. Again, in every instance, the change in HHIs is zero or negative.

AEP Market	Pre-Merger			Post-Merger (Post-Mitigation)		
Available Economic Capacity	**AEP Market Share**	**CSW Market Share**	**HHI**	**Merged Market Share**	**HHI**	**Delta HHI**
Summer Super Peak $35	35.50%	0.00%	1653	33.50%	1532	-121
Summer Super Peak	98.50%	0.00%	9697	98.30%	9670	-27
Summer Peak	99.80%	0.00%	9959	99.80%	9957	-2
Summer Off-Peak	0.00%	0.00%	10000	0.00%	10000	0
Winter Super Peak	99.70%	0.00%	9943	99.70%	9939	-5
Winter Peak	99.80%	0.00%	9959	99.80%	9956	-2
Winter Off-Peak	99.80%	0.00%	9970	99.80%	9965	-5
Shoulder Super Peak	85.50%	0.00%	7392	84.00%	7160	-232
Shoulder Peak	99.00%	0.00%	9803	98.90%	9790	-13
Shoulder Off-Peak	99.70%	0.00%	9935	99.60%	9912	-22

EKPC Market	Pre-Merger			Post-Merger (Post-Mitigation)		
Available Economic Capacity	**AEP Market Share**	**CSW Market Share**	**HHI**	**Merged Market Share**	**HHI**	**Delta HHI**
Summer Super Peak $35	51.40%	0.00%	2959	49.90%	2818	-141
Summer Super Peak	87.80%	0.00%	7754	87.80%	7754	0
Summer Peak	0.00%	0.00%	0	0.00%	0	0
Summer Off-Peak	0.00%	0.00%	0	0.00%	0	0
Winter Super Peak	32.30%	0.00%	2278	32.30%	2278	0
Winter Peak	0.00%	0.00%	10000	0.00%	10000	0
Winter Off-Peak	0.00%	0.00%	10000	0.00%	10000	0
Shoulder Super Peak	26.70%	0.00%	1852	24.40%	1803	-49
Shoulder Peak	0.00%	0.00%	10000	0.00%	10000	0
Shoulder Off-Peak	0.00%	0.00%	10000	0.00%	10000	0

LGE Market	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	54.00%	0.00%	3187	51.40%	2939	-248
Summer Super Peak	0.00%	0.00%	0	0.00%	0	0
Summer Peak	0.00%	0.00%	0	0.00%	0	0
Summer Off-Peak	0.00%	0.00%	10000	0.00%	10000	0
Winter Super Peak	0.00%	0.00%	10000	0.00%	10000	0
Winter Peak	0.00%	0.00%	10000	0.00%	10000	0
Winter Off-Peak	0.00%	0.00%	8415	0.00%	8415	0
Shoulder Super Peak	0.00%	0.00%	0	0.00%	0	0
Shoulder Peak	0.00%	0.00%	10000	0.00%	10000	0
Shoulder Off-Peak	0.00%	0.00%	10000	0.00%	10000	0

Q. THE TABLES ABOVE SHOW SOME ENTRIES OF "0" AND "10000". WHAT DOES THIS MEAN?

A. A zero HHI means that there are no suppliers to the destination market for the relevant time period. The combination of destination market prices during that time period and load obligations of suppliers means that there are no additional economic supply during that period. In each of those instances, the merger has no impact; that is, if there is no available economic supply pre-merger, there also is no available economic supply post-merger.

At the other extreme, a 10000 HHI means that there is a single supplier with 100 percent market share. In all of the instances of a 10000 HHI shown in the table above neither Applicant is the single supplier, and the merger has no impact; that is, the sole supplier pre-merger is the same sole supplier post-merger.

Q. WILL THE MERGER ADVERSELY EFFECT COMPETITION IN RETAIL MARKETS IN KENTUCKY?

A. No. First, the Commission concluded in its September 12, 1997 Order approving the merger of Louisville Gas & Electric Company and Kentucky Utilities Company, P.S.C. 97-300, that "at the present time, regulation, not competition, determines prices, service territories and market share in the retail market [in Kentucky].... The total absence of direct competition in Kentucky's existing retail electric markets makes implausible any attempt to prove market power and obviates the need, at this time, to consider the issue." Commission Order at 7-8. I have reviewed retail access-related events in Kentucky for the period since that order. Nothing has changed in the intervening nineteen months to diminish the accuracy of the Commission's finding.

Second, within the limits described above, if and when retail competition does come to Kentucky, the merger will not affect the retail market. Retailing consists of the buying of power at wholesale and reselling it to retail customers. As explained in detail in the attached testimony, and summarized above, the merger will not affect the bulk power market from which retailers will require access in an environment of retail competition. Hence, it will not affect the ability of competitive retailers to purchase power. Regarding the sale of electricity to retail customers, the competitive retailing of electricity is a very new business. Neither AEP nor CSW have any significant experience or market presence in this new business in America. Nor is there even any basis for assuming that, absent the merger, CSW would have been a participant in the Kentucky retail electricity market. Thus, the merger eliminates neither an actual nor a potential competitor.

Q. IS IT YOUR TESTIMONY THAT THE MERGER WILL NOT ADVERSELY AFFECT WHOLESALE COMPETITION OR RETAIL COMPETITION, IF AND WHEN IT COMES TO KENTUCKY?

A. Yes.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COUNTY OF BOYD

COMMONWEALTH OF KENTUCKY CASE NO. 99-

Affidavit

William H. Hieronymus, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

William H. Hieronymus
William H. Hieronymus

Subscribed and sworn to before me by William H. Hieronymus, this 6TH day of April 1999.

Elizabeth W. Trimber
Notary Public

My Commission Expires ____________________

Elizabeth W. Trimber
Notary Public
District of Columbia
My Commission Expires Jan 1, 2003

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

DIRECT TESTIMONY OF
WILLIAM H. HIERONYMUS
FILED ON BEHALF OF
AMERICAN ELECTRIC POWER COMPANY, INC.
AND
CENTRAL AND SOUTH WEST CORPORATION

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS FILED ON BEHALF OF AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION

I. INTRODUCTION

1. **Q. Please state your name and business address.**

A. My name is William H. Hieronymus. My business address is Putnam, Hayes & Bartlett, Inc., One Memorial Drive, Cambridge, Massachusetts 02142.

2. **Q. By whom are you employed?**

A. I am Senior Vice President of Putnam, Hayes & Bartlett, Inc. ("PHB"), a subsidiary of Hagler Bailly, Inc. Hagler Bailly is a worldwide provider of consulting, research and other professional services to corporations and governments on energy, telecommunication, transportation, and the environment.

3. **Q. What is your educational background and work experience?**

A. I received my Bachelor's degree from the University of Iowa in 1965, my Master's degree in economics in 1967 and a Doctoral degree in economics in 1969 from the University of Michigan, where I was a Woodrow Wilson Fellow and National Science Foundation Fellow. After serving in the U.S. Army, I began my consulting career. In 1973, I joined Charles River Associates Inc. as a specialist in antitrust economics. By the mid-1970s my focus was principally on the economics of energy and network industries. In 1978, I joined PHB, where my consulting practice has focused almost exclusively on network industries, particularly electric utilities.

During the past 23 years, I have completed numerous assignments for electric utilities; state and federal government agencies and regulatory bodies; energy and equipment companies; research organizations and trade associations; independent power producers and investors; international aid and lending agencies; and foreign governments. While I have worked on most economics-related aspects of the utility sector, a major theme has been public policies and their relation to the operation of utility companies.

Since about 1988, the main focus of my consulting has been on electric utility industry restructuring, regulatory innovation and privatization. In that year, I began work on the restructuring and privatization of the electric utility industry of the United Kingdom, an assignment on which I worked nearly full time through the completion of the restructuring in 1990. I also led a major study of the reorganization of the New Zealand electricity sector, focusing mainly on competition issues in the generating sector. Following privatization of the U.K. industry, I continued to work in the United Kingdom for electricity clients based there and I was also involved in restructuring studies concerning the former Soviet Union, Eastern Europe, the European Union and specific European countries.

Late in 1993, I returned to the United States, where I have worked on restructuring, regulatory reform and, increasingly, the competitive future of the U.S. electricity industry. In this context, I have testified before FERC and state commissions on market power issues concerned with several mergers, power pools and market rate applications. More generally, I have testified before state and federal regulatory commissions, federal and state courts and legislatures on numerous matters concerning the electric utility and other network industries. My resume is included as Exhibit No. AC-501.

II. PURPOSE AND SUMMARY OF TESTIMONY

PURPOSE

4. Q. **What is the purpose of your testimony?**

A. I have been asked by American Electric Power Company, Inc. ("AEP") and Central and South West Corporation ("CSW") (collectively, the "Applicants") to determine the potential competitive impact of their proposed merger on electricity markets. My analysis is conducted in a manner consistent with the Competitive Analysis Screen described in Appendix A to the Commission's Merger Policy Statement ("Order No. 592"), which in turn is intended to comport with the Department of Justice and Federal Trade Commission ("DOJ/FTC") Merger Guidelines ("Guidelines"). My analysis also responds to the Commission's Order setting this merger for hearing.[1]

SUMMARY OF CONCLUSIONS

5. Q. **Please summarize the results of your analysis of the effect of combining the generation resources of the two companies under a single ownership.**

A. With the mitigation measures that I describe below, the merger will not adversely affect competition in any of the numerous wholesale destination markets that I have analyzed.

The essential fact is that, historically, the utility subsidiaries of the two companies have not traded with each other, or with utilities that are reached through the transmission system of the other. The only overlap in wholesale sales of the two companies is in sales to utilities that lie between them, and in those cases the extent of the overlap is small.

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[1] *American Electric Power Company and Central and Southwest Corporation*, 85 FERC ¶ 61.201(November 10, 1999).

Accordingly, the amount of competition eliminated by the merger is very small, and the mitigation measures proposed by Applicants are amply sufficient to assure that the merger will not adversely affect competition in wholesale, and relevant retail, electricity markets.

6. Q. **How did you approach your analysis of the relevant electricity generation markets for short term power and energy?**

A. I performed a market concentration analysis for each potentially relevant destination market, using the methodology prescribed in Order 592. As directed by the Commission's Hearing Order in this case, I used the latest available data and expanded the analysis to include all of the conceivably relevant destination markets that I could identify. I analyzed economic capacity and available economic capacity separately.

7. Q. **What judgment or assumption was most important in influencing the outcome of this analysis?**

A. The most important judgment that I made involved the 250 MW firm transmission path from AEP to CSW that the Applicants have purchased from Ameren in anticipation of the merger for the period until May 31, 2003. I treated this as a merger-related increase in Applicants' market share in both CSW's SPP and ERCOT control areas, and a merger-related elimination of 250 MW of transmission capacity between Ameren and CSW's SPP control area that otherwise would have been available for certain wholesale customers to reach competing suppliers.

8. Q. **Do you regard this treatment as conservative?**

A. Yes. The principal competitive concern about a merger is that, by combining two sellers into one firm, it eliminates a competitor and concentrates the market. The question is whether supply will be withheld from the market after the merger in order to raise prices. In this case, however, AEP has not historically sold any significant amount of power to destination markets in the states where CSW operates. Indeed, the transfer of 250 MW of previously unavailable economic capacity from AEP to CSW actually *increases supply* in the area where CSW operates, which ordinarily would be expected to lower, rather than raise, prices.

Moreover, the Applicants' use of the 250 MW of transmission service provided by Ameren is merger-related only in the sense that the merger prompted the Applicants to purchase the transmission service. The service is being purchased under Ameren's open access transmission tariff and would have been available to any other participant in the market that chose to apply for it.

Essentially, the 250 MW transfer from AEP to CSW represents an increase in economic activity that results from the merger. Where, as here, the increase is based upon the purchase of an input (transmission service) that was available on the open market, such an action is pro-competitive rather than anti-competitive. The concept that unclaimed transmission capacity must remain unclaimed and idle to avoid even very small change in competitive conditions is a perverse application of antitrust policy, which is intended to promote rather than restrict increased economic activity.

9. Q. What are the results of the market concentration analysis required by Order No. 592 for Economic Capacity?

A. When Applicants' mitigation proposal is taken into account, the merger significantly deconcentrates the CSW SPP and ERCOT markets, and results in HHI changes below the Order 592 threshold in all but a handful of destination markets. The exceptions involve destination markets in which the merged company will have a miniscule market share but where the Applicants' use of the 250 MW of transmission capacity for the transfer of power from AEP to CSW serves to increase the already very high market share of one or more incumbent sellers that are unrelated to either Applicant.

10. Q. What are the results of the analysis for Available Economic Capacity?

A. They are substantially similar. For the most part, CSW's SPP and ERCOT markets are deconcentrated. The AEP market is either deconcentrated or reflects zero HHI changes in all time periods. The HHI changes for almost all of the other relevant destination markets and time periods are below the Order No. 592 threshold or are zero or negative (meaning that the market is deconcentrated). The few exceptions are in destination markets in which the Applicants have little or no post-merger market share.

11. Q. What do you conclude with respect to these few markets in which the Order No. 592 HHI change thresholds are exceeded?

A. I believe that they represent anomalies which should not affect the Commission's decision on the merger. On a post-mitigation basis, the combination of Applicants' generation shares does not cause screen failures in any market in any time period. In a majority of cases, the merger has a deconcentrating effect, i.e., makes the market more competitive. These screen failures do not result from combining the Applicants as wholesale sellers. In most instances they would be produced by anyone's purchase of firm transmission capacity, whether or not AEP and CSW were to merge. In a few instances, they result from the cessation of CSW's purchases from third party sellers, purchases that will be replaced by the 250 MW from AEP. When CSW ceases these purchases, the analysis returns the capacity to the seller and adds to the seller's already very high market share in its "home" destination market. These HHI increases do not reflect increased market power on the part of the merged company. Moreover, as these HHI increases are not the result of the market share of the merged company, they cannot practically be eliminated by divestiture of generation.

12. Q. The Hearing Order suggested that a proper analysis should take into account the effects of loop flow associated with the 250 MW transfer of power from

AEP to CSW. Does your analysis include consideration of these loop flow effects?

A. Yes. I have performed a sensitivity analysis that incorporates the loop flow study that Mr. Malizewski performed, and which is described in his testimony. Given Applicants' proposed mitigation, this sensitivity analysis reflects no HHI changes in excess of the screening threshold in the overwhelming majority of the destination markets. In the vast majority of destination markets analyzed, the merger, with mitigation, is deconcentrating. To the extent that there are failures in some of the destination markets between AEP and CSW, they are caused by marginal reductions in market size and increases in market shares of the respective incumbent local utilities, not Applicants' market share. This would be the effect of any other transmission reservation of comparable terms, whether or not AEP and CSW were to merge.

13. Q. Did you test your Base Case analysis using sensitivity analyses?

A. Yes. As noted in the Hearing Order, intervenors have suggested that reducing assumed transmission rates and/or increasing Available Transmission Capability ("ATC") over some paths might affect the results of the analysis. It was suggested that these cases might reflect a broadening of the market in the future, which might occur if transmission were priced regionally at losses or if transfer capability were expanded. I conducted sensitivity studies for each of these cases, examining the effect of the merger on market concentration if transmission were priced regionally at losses or if the measure of transfer capability were Total Transfer Capability ("TTC") rather than ATC. I found that the Base Case results were not significantly changed. I also performed a sensitivity analysis with an alternative market organization (AEP joining the MISO) and found that the Base Case results were not significantly affected.

14. Q. How does the Applicants' mitigation proposal relate to your analysis?

A. Applicants propose to divest 50 percent (250 MW) of a 500 MW generating unit being built by CSW Energy within the Electric Reliability Council of Texas ("ERCOT") and 300 MW of the Northeastern baseload coal generation capacity located in Oklahoma in the Southwest Power Pool ("SPP"). The Northeastern sale will consist of two equal size shares (i.e., 150 MW each). In the interim until divestiture can be accomplished, Applicants propose power sale arrangements that are designed to be the economic equivalent of divestiture, while preserving CSW's ability to meet native load reliability requirements in the SPP and preserving the pooling of interest accounting treatment for the merger. The divestiture results in the merged company having reduced generation capacity in the post-merger case and this reduces the effect of the merger on market concentration. Indeed, in the majority of destination markets, the merger, with the proposed mitigation, will have a deconcentrating effect.

15. Q. Do Applicants propose any other mitigation measures?

A. Yes. Applicants have committed not to increase their reservation of firm transmission service from the East Zone to the West Zone (whether through Ameren or any other intermediate transmission provider) above 250 MW unless authorized to do so by the Commission. Applicants also have committed to waive native load priority with respect to use of CSW's interconnections.

16. Q. Is it appropriate to take into account the mitigation proposed by Applicants in evaluating whether the merger meets the merger approval criteria set forth in Order No. 592?

A. Yes. Under Order 592 and the Merger Guidelines, the post-mitigation HHI screen results should create a strong presumption that the merger will not have significant adverse effects on horizontal competition. The divestitures proposed by the Applicants, combined with the sales of power in the interim prior to divestiture, represent changes in the structure of the market. They are an integral part of the merger proposal. Under both the Commission's policies and the Department of Justice Merger Guidelines, if the merger as proposed passes the screening analysis it is presumed not to have an adverse effect on competition. The principles that underlie this policy apply equally when, as here, the modified proposal is submitted after a hearing has been ordered and when the mitigation proposal is submitted in an initial application for merger approval.

17. Q. Did you consider the effect of the merger on the market for capacity?

A. Yes. I found that the market for capacity is unconcentrated, with an HHI based on uncommitted capacity of considerably less than 1,000 in the relevant destination markets.

18. Q. What did your analysis show with respect to long term market for generation capacity?

A. The Commission has found the long term market for generation capacity to be presumptively competitive, unless there is evidence that the merged company has the ability to impede entry by new generators, such as control of desirable sites for new generation facilities or control over key inputs such as fuel supply. I examined the ability of new generators to enter the relevant geographic markets in this case. I found that the merged company will not be able to control desirable sites or other critical inputs, and that a number of new entrants are at various stages of the process of entering these markets.

19. Q. **The Hearing Order directs Applicants to analyze the vertical competitive effect of the merged company's control of the Louisiana Interstate Gas Company ("LIG"). Have you performed this analysis?**

A. Yes. I analyzed whether the merged company's ownership of LIG would provide it with the ability to affect competition in electricity markets by withholding natural gas from, or increasing the price of natural gas to, competing electricity generators. Nearly all generators connected to LIG have alternatives to gas delivery through LIG. When I treated all electric generation served solely by LIG as if it were acquired by AEP as a result of the LIG purchase, my analysis of the horizontal effects of the merger remains valid.

20. Q. **The Hearing Order also sets for hearing the issue of whether the merged company, by virtue of its control of transmission, is able to affect competition in generation markets in a way that may not be reflected in a horizontal market concentration analysis. How do Applicants address this issue?**

A. Applicants' witness Dr. Henderson is submitting testimony addressing this issue. I have reviewed his testimony and find it consistent with my own analyses in all respects.

21. Q. **What is your ultimate recommendation with respect to this merger proposal?**

A. I have concluded that the merger should be approved without condition other than the mitigation measures proposed in the testimony of Applicants' witness Mr. Jones.

ORGANIZATION OF TESTIMONY

22. Q. **How is the remainder of your testimony organized?**

A. In Section III, I outline the Applicants' business operations. Section IV describes the economic framework used in the analysis as set out in the Commission's

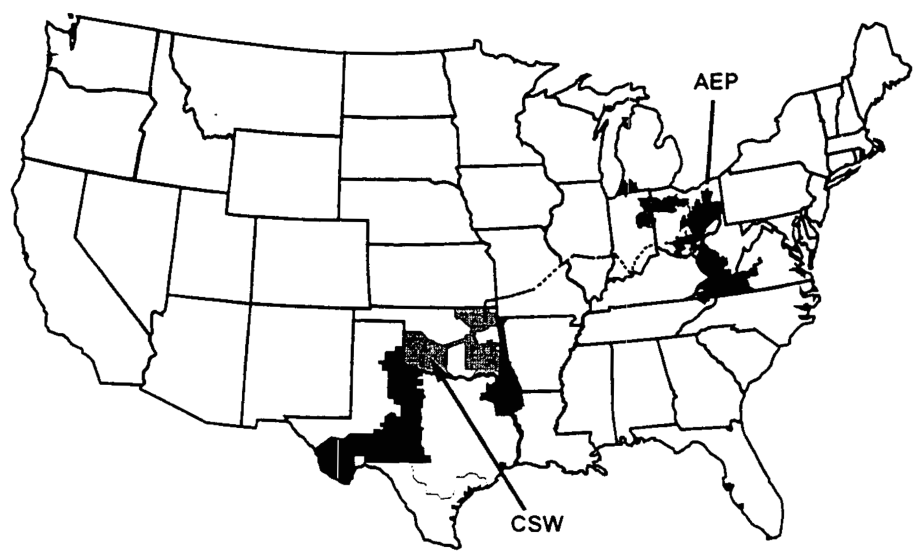
Order No. 592. A description of the methodology I used in conducting the analysis is included in Section V. Section VI describes Applicants' proposed mitigation measures. My analysis of the merger's impact on competition is included in Sections VII-IX.

III. DESCRIPTION OF THE PARTIES

GEOGRAPHIC LOCATION

23. Q. Where are Applicants located?

A. The service territories of Applicants' respective systems and the contract path connecting the two systems are depicted on the map below:



The two nearest generating stations in Applicants' East and West Zones are AEP's Rockport station in southern Indiana and CSW's Northeastern plant in northeastern Oklahoma.

LACK OF SIGNIFICANT COMPETITIVE OVERLAPS BETWEEN APPLICANTS

24. Q. **You mentioned that Applicants have not sold material amounts of energy to common distribution markets. Please explain.**

A. AEP and CSW are not significant competitors and do not sell material amounts of energy to common buyers. I examined data for 1997 and year-to-date 1998 and found that both AEP and CSW sold non-firm energy only to the following companies:[2] Ameren, Associated Electric Cooperative, Central Louisiana Electric Company, Entergy, Illinois Power, Missouri Public Service, Southern Company and Western Resources. The degree of actual competitive overlap even among these few companies is quite small since only one of the Applicants had a material share of the sales to each of these companies, as shown in Exhibit No. AC-502. In sum, historically, the competitive overlap between AEP and CSW is *de minimis*, amounting to very small shares of sales to a few large utilities.

I recognize that wholesale markets are becoming more competitive and the reduction of pancaked transmission rates and improved access may change trading patterns somewhat. However, these changes cannot alter the fundamental economics of the wholesale market that result in AEP selling chiefly east of the Mississippi and CSW selling chiefly in the SPP and ERCOT. More than 96 percent of AEP's non-firm wholesale sales in 1997 were to utilities east of the Mississippi, and 99 percent of CSW's sales were to utilities west of the Mississippi. These expectations are confirmed by the sensitivity analysis presented later in my testimony, which shows that the market concentration measures would not materially change even if transmission were priced across the region at zero costs other than transmission losses. As would be expected given

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[2] The data cover January-September 1998 for AEP and January-October 1998 for CSW. I excluded sales to power marketers and sales aggregating to less than $100,000 to a single utility. These figures also exclude sales made by Applicants' power marketing affiliates from generation owned by other companies, and in the control of those companies. Data for 1995 and 1996 show even lower levels of overlap and identify no additional overlap customers.

their respective locations, Applicants are not significant actual or potential competitors.

DESCRIPTION OF APPLICANTS' SYSTEMS

25. Q. Please describe AEP.

A. AEP is a registered public utility holding company with seven principal utility operating companies: Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co. and Wheeling Power Co. AEP subsidiaries include American Electric Power Service Corporation, a service company; AEP Generating Company, a wholesale generator; AEP Resources, Inc. AEP Resources has a 50 percent ownership in Yorkshire Electricity Group, a regional electricity company in the United Kingdom; owns an interest in existing and planned generating facilities in China; recently purchased an equity interest in Pacific Hydro Ltd., an Australian company that develops and operates hydroelectric facilities; and recently purchased certain assets of Equitable Resources, Inc., including the LIG Pipeline, four related natural gas processing plants, a salt dome storage facility, and an energy trading and marketing business.

AEP, through other subsidiaries, owns and operates coal mines that supply coal to AEP generating plants and leases transport facilities for delivery of purchased coal to its generating facilities. In 1996, AEP subsidiaries supplied 13 percent of the total coal delivered to AEP-operated plants.

AEP's utility operating companies serve customers in Ohio, Indiana, West Virginia, Virginia, Kentucky, Michigan and Tennessee. AEP has approximately 23,500 MW of installed generating capacity, and its projected net peak load requirement is about 20,500 MW in 1999.

AEP is directly interconnected to other utilities in the East Central Area Reliability Coordination Agreement ("ECAR") (Allegheny Power System, Cinergy, Consumers Power, Dayton Power & Light, Duquesne Light, East Kentucky Power Coop, FirstEnergy, Indianapolis Power & Light, LG&E Energy Corp., Ohio Valley Electric Corp and Northern Indiana Public Service); utilities in the Southern Electric Reliability Council ("SERC") (Carolina Power & Light, Duke Power, Tennessee Valley Authority and Virginia Power); and utilities in the Mid-America Interconnected Network ("MAIN") (Ameren, Commonwealth Edison and Illinois Power).

26. Q. Please describe CSW.

A. CSW is a registered public utility holding company and the parent of four utility operating companies (Central Power & Light Company ("CPL"), West Texas Utilities Company ("WTU"), Public Service Company of Oklahoma ("PSO") and Southwestern Electric Power Company ("SWEPCO")). Other subsidiaries include Central and South West Services, Inc., a service company; CSW Energy, Inc. ("CSWE"), a developer of cogeneration and non-utility generation; and CSW Energy Services, Inc., a seller of power and energy to retail customers. CSW Power Marketing, Inc., a wholesale power marketer, is a subsidiary of CSWE. CSW controls SEEBOARD, a regional electricity company in the United Kingdom. CSW also has additional non energy-related domestic subsidiaries.

SWEPCO serves customers in northwestern Louisiana, northeastern Texas and western Arkansas. PSO serves customers in eastern and southwestern Oklahoma. CSW's SPP operations are directly interconnected with other SPP utilities (Arkansas Electric Cooperative, Central Louisiana Electric, Empire District Electric, Grand River Dam Authority, KAMO Electric Cooperative, Oklahoma Gas and Electric, Southwestern Power Administration, Southwestern Public Service, Western Farmers Electric Coop and Western Resources); with Entergy and Associated Electric Cooperative in SERC; and with Ameren in MAIN. PSO is interconnected with WTU in ERCOT via an HVDC tie and SWEPCO is interconnected with Texas Utilities in ERCOT via an HVDC tie.[3]

CPL and WTU serve customers in Texas (southern Texas and central and west Texas, respectively). Within ERCOT, CSW is directly interconnected to the City of Brownsville, City Public Service of San Antonio, Houston Lighting & Power, Lower Colorado River Authority, South Texas and Medina Electric Coop and Texas Utilities Electric. Unlike other regional reliability council areas, ERCOT utilities engage primarily in operations within Texas.

CSW has approximately 8,300 MW of total generating capability in SPP and 5,800 MW in ERCOT. Its projected 1999 peak load requirement is about 7,500 MW in SPP and 5,500 MW in ERCOT.[4] CSW is short of capacity in both SPP and ERCOT, other than the uncommitted merchant capacity of CSWE-owned generation in Texas. CSWE owns three projects in Texas: Newgulf (85 MW) and Sweeny (165 MW, which represents CSWE's 50 percent share), both in operation since 1997, and Frontera (500 MW), scheduled to come on-line in 1999.

IV. FRAMEWORK FOR THE ANALYSIS

27. Q. **What are the general market power issues raised by merger proposals?**

A. Market power analysis of a merger proposal examines whether the merger would cause a material increase in the merging firms' market power or a significant reduction in the competitiveness of relevant markets. Market power is defined as

[3] The two HVDC tie lines are the North HVDC Tie, a 220 MW HVDC interconnection between WTU and PSO; and the East HVDC Tie, a 600 MW HVDC interconnection between Texas Utilities and SWEPCO.

[4] In addition to the generation owned and controlled by CSW's operating companies, CSWE also owns generation in Florida, Colorado and Texas. My understanding is that virtually all of the capability of the Colorado and Florida units is committed under long-term contracts, but that 205 MW of the capacity in Texas is uncommitted. See Central and South West Services, Inc. Application for Blanket Authorizations and for Certain Waivers of the Commission's Regulations and Request for Expedited Consideration," Docket No. ER98-542-000 ("CSW Market-Based Rate Application"). The CSWE-owned Frontera plant will create an additional 500 MW of uncommitted capacity sometime in 1999.

the ability of a firm or group of firms to profitably sustain a significant increase in the price of their products above a competitive level.

In merger market power analyses, the critical issue is the effect of the merger on market competitiveness, as opposed to the competitiveness of the pre-merger market structure. While the pre-merger competitiveness of markets may, as under the DOJ/FTC Guidelines, affect the amount by which market structure may be allowed to change, the focus remains on the change in market competitiveness caused by the merger.

This focus on the effects of the merger means that the merger analysis examines those business areas where the merging firms are competitors. In most instances, the merger will not affect competition in markets in which only one of the merging firms is active but the applicants do not compete. Analysis of the effects of a merger on market power in businesses in which the merging firms both participate is sometimes referred to as horizontal market power assessment. In the proposed merger of AEP and CSW, therefore, the focus is properly on those markets in which both firms are actual or potential competitors.

Vertical market power relates to the effect of the merger on the merged firm's ability and incentives to use its market position in a related business to affect competition. For example, vertical market power could result if the merger of two electric utilities created an opportunity and incentive to operate transmission in a manner that created market power for the merged company's generation activity that did not exist previously. The Commission also has identified market power as arising from the ability to frustrate potential entry, such as by using dominant control over potential generation sites or over fuel supplies and delivery systems and, prior to Order No. 888, refusals to interconnect. These vertical barriers to entry could undercut the presumption that long-run generation markets are competitive.

28. Q. What are the main elements in developing a market power analysis?

A. Understanding the competitive impact of a merger first requires defining the relevant market (or markets) in which the merging firms participate. Participants in a relevant market include all suppliers and, in some instances, potential suppliers who can compete to supply the products produced by the merging parties and whose ability to do so diminishes the ability of the merging parties to increase prices. Hence, determining the scope of a market is fundamentally an analysis of the potential for competitors to respond to an attempted price increase. Markets are defined in two dimensions: geographic and product. Thus, the relevant market is composed of companies that can supply a given product (or its close substitute) to customers in a given geographic area.

29. Q. Has the Commission prescribed an analytical framework for examining proposed mergers involving electric utilities?

A. Yes. With the issuance of Order No. 592 in December 1996, the Commission adopted a detailed analytic framework for assessing utility mergers. This framework is organized around a market concentration analysis prescribed in Appendix A to the Order. Appendix A (the "Competitive Analysis Screen") prescribes an analytic method that Applicants are required to follow in their applications and that the Commission will use in screening the competitive impact of mergers.

If a proposed merger raises no market power concerns (*i.e.*, passes the Appendix A screen), the inquiry is generally complete. If a proposed merger exceeds the Appendix screens in some markets, Order No. 592 invites the Applicants to propose mitigation measures targeted to reducing market concentration changes to safe harbor levels. In the alternative, Applicants can seek to establish that the merger does not cause competitive harm notwithstanding the unmitigated failure of the screen.[5]

30. Q. Under the Commission's Merger Guidelines how is the Appendix A analysis to be conducted?

A. There are four steps: (1) identify the relevant products; (2) identify the relevant geographic markets; (3) identify potential suppliers of economic capacity in each relevant geographic market; and (4) assess market concentration.

31. Q. What products has the Commission generally considered?

A. The Commission generally has defined the relevant product markets to be long-term capacity, short-term capacity ("Uncommitted Capacity"),[6] and non-firm energy ("Available Economic Capacity" and "Economic Capacity"). The Commission has determined that long-term capacity markets are presumed to be competitive, unless special factors exist that limit the ability of new generation to be sited or receive fuel.

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[5] As stated in the Merger NOPR, "Where the competitive screen analysis indicates concentration results that exceed the thresholds but mitigation measures are not proposed, applicants must provide additional analysis. The Guidelines describe four additional factors to examine in situations where merger-induced concentration exceeds specified thresholds." The Merger NOPR goes on to describe the four additional factors contained in the DOJ/FTC Horizontal Merger Guidelines, two of which relate to market power. The other two (efficiencies not achievable without a merger and the likely business failure of one of the applicants absent a merger) are potential counterweights to market power concerns. The two market power-related issues are, first, other market factors (besides concentration) that may affect market power, and, second, the ease and sufficiency of entry. The "other factors" section of the Guidelines focuses on product and market conditions that facilitate coordinated interaction among market participants or, contrarily, its detection; and product characteristics (i.e., uniquely close substitutes) that make unilateral exercise of market power more likely.

[6] While I refer to Uncommitted Capacity as a short-term capacity measure, it addresses capacity of approximately one year or more; this has sometimes been termed intermediate capacity. I use the term "short-term" to distinguish it from "long-term" which, in terms of a capacity measure, is deemed to be long enough to build new capacity (i.e., attract entry).

32. Q. How has the Commission analyzed geographic markets?

A. To examine geographic markets, the Commission has focused on the utilities that are directly interconnected to the applicant companies. This "destination market" approach was continued in Order No. 592 and in the Merger NOPR. Each utility that is directly interconnected to the Applicants is considered a separate "destination market." Additionally, the Commission has suggested that utilities who historically have been customers of Applicants are also potential "destination markets."

The supply alternatives to each destination market are defined using the "delivered price test," which identifies suppliers that can reach a destination market at a cost no more than 5 percent over the pre-merger market price. The supply is considered economic if a supplier's generation can be delivered to a destination market, including delivery costs (which include transmission rates, transmission losses and ancillary services), at a cost that is within 105 percent of the destination market price. Physical transmission constraints also are taken into consideration in determining the potential supply to the destination market. Competing suppliers are defined as those who have capacity (energy) that is physically and economically deliverable to the destination market. Their importance in the market (i.e., their market share) is determined by the amount of such capacity.

For each market in which Applicants participate, market shares and market concentration are calculated. In addition, Order No. 592 invites Applicants to consider whether competitive conditions in relevant markets differ by time of day or season.

33. Q. What framework does the Commission use to determine whether a merger poses potential market power concerns?

A. In Order No. 592, the Commission adopted the DOJ/FTC Guidelines for measuring market concentration levels by the Herfindahl-Hirschman Index.[7] To determine whether a proposed merger will have a significant anti-competitive impact, the Commission will consider the level of the HHI after the merger (the post-merger HHI) and the change in the HHI that results from the merger. Markets with a post-merger HHI of less than 1000 are considered "unconcentrated." The DOJ and FTC generally consider mergers in such markets to have no anti-competitive impact. Markets with post-merger HHIs of 1000 to 1800 are considered "moderately concentrated." In those markets, mergers that result in an HHI change of 100 points or fewer are considered unlikely to have anti-competitive effects. Finally, post-merger HHIs of more than 1800 are considered to indicate "highly concentrated" markets. The Guidelines suggest that in these markets, mergers that increase the HHI by 50 points or fewer are unlikely to have a significant anti-competitive impact, while mergers that increase the HHI by more than 100 points are considered likely to reduce market competitiveness.

34. Q. Has the Commission addressed whether and how to evaluate the effect of mitigation on market concentration?

A. In its pending merger NOPR, the Commission has said that: "If applicants propose mitigation measures, the screen analysis should also take into account the effect of the remedy on market concentration to the extent possible."

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7 The HHI is calculated as the sum of the squares of each company's market share, expressed in percentage terms. For example, a market with a single supplier with 100 percent market share has an HHI of 10000 (100*100), and a market with two suppliers of equal size has an HHI of 5000 (50*50+50*50).

V. DESCRIPTION OF APPENDIX A ANALYSIS

OVERVIEW

35. Q. Please describe the overall approach you utilized.

A. Consistent with the Hearing Order in this case, I first performed a revised Base Case Appendix A analysis that uses the most up-to-date data available. This analysis takes into account the issues raised by the Commission in its Order: (1) taking into consideration proposed changes in market organization, such as Commission approval of a Midwest ISO and the ERCOT ISO; (2) using the most current data available; (3) including additional destination markets in the study; (4) expanding upon the time periods analyzed in order to capture sufficient differences in load levels and take into consideration time zone differences; (5) incorporating mileage-based transmission rates in the relevant regions and reflecting systematically discounted rates. I also revised the method of allocating available transmission capacity to more closely conform to the Commission's methodology used in post-Order No. 592 analyses and in response to some intervenors' criticism of the method used in my April 1998 analysis.[8]

Second, as suggested in the Hearing Order, I conducted sensitivity analyses to test the robustness of the analysis and to investigate the impact of various alternative scenarios including: (1) consideration of loop flow impacts, specifically the impact of the 250 MW reservation on other parties' import capability; (2) the prospect that regionalization of the transmission grid could lead to lower transmission prices; (3) the possibility that transmission transfer capability will be expanded beyond current posted ATCs; and (4) the prospect that AEP might join the MISO. These sensitivities provide "boundary" measures that reveal whether

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[8] This methodology is discussed in my exhibits.

or not the merger's effect on concentration would change materially if the market develops differently than the Commission's baseline Appendix A analysis.

Third, I worked with Applicants and their counsel to develop proposed mitigation measures. These measures were designed to contain HHI changes caused by the merger of Applicants' generation to below the Merger Guidelines' limits in all markets, and to deconcentrate the majority of affected markets. I analyzed market concentration taking into account the proposed mitigation measures to confirm their sufficiency. I also examined the mitigation measures to ensure that they appropriately address the "effectiveness" issues raised on the Hearing Order and confirmed that they will be in place effectively and permanently.

APPENDIX A ANALYSIS

36. Q. Please describe the nature of the analysis undertaken to complete the Appendix A competitive analysis screen.

A. PHB has developed the Competitive Analysis Screening model ("CASm") to facilitate Appendix A analyses. This model implements the delivered price test and other calculations required in Appendix A by determining potential supply both pre- and post-merger for each (i) destination market, (ii) relevant time period and (iii) relevant supply measure. From these results, the model also calculates pre- and post-merger HHIs. The relevant geographic market is determined based on the economics of supply (including generation costs, transmission rates, losses and ancillary services) and the physical transmission capacity available to the competing suppliers on an open access basis. In CASm, each transmission path has a fixed maximum capacity. In addition, CASm incorporates simultaneous transmission constraints. To determine the potential supply to a destination market, the model determines an economic delivery route for supply that meets the delivered price test via existing transmission paths, each of which has a capability, transmission rate and transmission losses associated with it. CASm determines the supply that can be delivered to the destination market within the parameters of the delivered price test. The model is described in Exhibit AC-503.

37. Q. **What data are required to conduct a competitive analysis screen?**

A. The key data requirements for implementing the screening analysis include:

- Generating capability
- Capacity purchases and sales
- Variable costs of generation
- Transmission capability
- Transmission rates
- Transmission line losses
- Native loads
- Market prices

To the maximum practical extent, I have used the most recent publicly available data consistent with those detailed in Appendix B of Order No. 592. These have been supplemented, where appropriate, with more recent data supplied by Applicants. My study is intended to approximate a 1999 time period. 1999 is the only period for which forward-looking ATC data are available. To the extent I have had to rely on historic data, those data are for the most recent available time period. Historic data (e.g., loads, lambdas and generating costs) are projected to 1999 levels.

38. Q. **Did you prepare an Exhibit to your testimony that explains the data you relied on and how the data were applied in the Appendix A analysis?**

A. Yes. Exhibit AC-504, and accompanying Exhibits No. AC-505 through AC-507, describe the data I utilized and the approach I took to calculate each of the inputs enumerated above for my Base Case analysis. Electronic and other workpapers supplement this appendix. For the most part, these inputs are specifically prescribed in Appendices to Order No. 592. Where the Hearing Order contained specific suggestions (*e.g.*, taking into account the MISO tariffed transmission rates), I followed those suggestions.

DESTINATION MARKETS AND MARKET STRUCTURE

39. Q. What destination markets did you analyze?

A. Consistent with Order No. 592, in identifying destination markets, I included each of Applicants' direct interconnections as well as utilities with which Applicants have been trading partners based on historic data.

With respect to direct interconnections, I included the following destination markets:[9]

- Direct interconnections of AEP: Ameren, Allegheny Power System ("APS"), Carolina Power & Light, Cinergy, Commonwealth Edison, Consumers Power, Dayton Power & Light, Duke Power, Duquesne Light ("DQE"), East Kentucky Power Coop, FirstEnergy, Illinois Power, Indianapolis Power & Light, Louisville Gas & Electric Energy, Northern Indiana Public Service, Tennessee Valley Authority and Virginia Power.[10]
- Direct interconnections of CSW-SPP: AECI, Ameren, Central Louisiana Electric, Empire District Electric, Entergy, Grand River Dam Authority, Oklahoma Gas and Electric, Southwestern Power Administration,

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[9] I have used the terms "CSW-SPP" and "CSW-ERCOT" to refer to the two control areas operated by CSW in the SPP and ERCOT, respectively.

[10] AEP is also interconnected with Ohio Valley Electric Corp (OVEC), of which AEP is a 44 percent joint owner. OVEC supplies the power requirements of a DOE uranium enrichment facility in Ohio. OVEC's capacity is under contract to DOE until 2005, subject to early termination by DOE; to the extent power is not required by DOE, AEP can receive OVEC surplus power and can also receive firm entitlement to such power. I have not treated OVEC as a separate destination market. However, I have estimated the amount of capacity and energy which AEP (and the other owners of OVEC) potentially has control over and allocated those MW to AEP (and the other owners). I based this estimate on OVEC's generating capacity in excess of its load requirement.

Southwestern Public Service, Western Farmers Electric Coop and Western Resources.[11]

- Direct interconnections of CSW-ERCOT: City of Brownsville, City Public Service of San Antonio ("CPST"), Houston Lighting & Power ("HL&P"), Lower Colorado River Authority ("LCRA"), South Texas & Medina Coop and Texas Utilities ("TU").[12]

I analyzed the AEP, CSW-SPP and CSW-ERCOT markets as proxies for their Transmission Dependent Utility ("TDU") markets. Similarly, other utility destination markets can be considered proxies for their own TDUs.

I analyzed additional destination markets that represent historic customers of Applicants. I determined these markets based on Applicants' sales of non-firm energy in 1997 and 1998 year-to-date.[13] These include (in addition to those customers already included as destination markets because they are direct interconnections of Applicants):

- Customers of AEP: Alliant (East), Central Illinois Light, Detroit Edison, Hoosier Electric, Missouri Public Service, Northern States Power, South Carolina Gas & Electric, Southern Indiana Gas & Electric, Southern Company, Wisconsin Electric Power and Wisconsin Public Power.
- Customers of CSW-SPP: Arkansas Electric Coop, City of Lafayette, and Kansas City Power & Light ("KCPL"). (Missouri Public Service was also a customer of CSW-SPP in 1998.)
- Other ERCOT utilities: City of Austin, City of Brazos, City of Bryan, Texas Municipal Power Pool ("TMPP") and Texas-New Mexico Power ("TNP").

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11 CSW is also interconnected with KAMO Electric Cooperative, which is in the control area of Grand River Dam Authority.

12 As discussed below, because ERCOT has defined zones based on Available Transmission Capability ("ATC") which are subsets of control areas, the actual destination markets analyzed in ERCOT correspond to the ATC zones.

13 My April 1998 analysis included those customers to whom Applicants sold in either 1995 and 1996. At the time, these were the most recently available published data. Failure to analyze some destination markets defined by sales in 1997 was one of the criticisms of that analysis in the Hearing Order. The analysis presented herein includes customers to which Applicants sold in 1997, as shown in their FERC Form 1s. I also have included customers to which they sold year-to-date in 1998 (through September for AEP and through October for CSW). These 1998 customers are based on data provided by Applicants.

This universe of destination markets not only includes the Applicants' direct interconnections and historic customers,[14] but also should amply demonstrate that competition in any other potential destination markets will not be affected by the merger. To the extent that there are other potential customers of Applicants that were not analyzed, they are remote from at least one of the Applicants and thus are less likely to be supplied by more than one of the Applicants in an Appendix A analysis than are the customers that are analyzed.[15] Exhibit No. AC-505 provides the list of utilities and abbreviations included in my analysis and shows destination markets being analyzed in bold type face.

40. Q. Are there any other pertinent assumptions in your treatment of potential competitors?

A. For modeling purposes, I excluded most small municipalities and cooperatives, other than those that would be considered Applicants' TDUs or direct interconnections. Further, to the extent Applicants' TDUs own or control capacity, they are combined and treated as a single TDU supplier. Both of these assumptions are conservative in that they tend to increase HHIs.

I modeled both the Pennsylvania-New Jersey-Maryland Interconnection ("PJM") and New York Power Pool ("NYPP") as single suppliers.[16] I limited the ability of Tennessee Valley Authority ("TVA") to sell power into the competitive market, consistent with its "inside-the-fence" limits as a government power marketing

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[14] I also analyzed additional destination markets in Missouri, as part of the Missouri retail market study undertaken.

[15] The customers that are analyzed include all of the major utilities that are located between AEP and CSW.

[16] Although PJM and NYPP also have been historic customers of AEP, I did not analyze them as destination markets. They are so remote from CSW that they are unlikely to be supplied by both Applicants even in an Appendix A analysis. AEP can access PJM and NYPP only through intervening utilities (FirstEnergy, APS and Virginia Power), each of which I have modeled as destination markets.

agency.[17] These assumptions also tend to increase market concentration and thus are conservative.

Utilities whose mergers have been completed have been modeled as single entities. These include Ameren (Union Electric and Central Illinois Public Service), FirstEnergy (Ohio Edison and Centerior), Louisville Gas & Electric Energy (Louisville Gas & Electric and Kentucky Utilities), and Alliant (Interstate Power, IES Utilities and Wisconsin Power & Light).[18] I have not included other planned mergers.[19]

In nearly all cases, the operating companies of holding companies are combined and treated as single suppliers. For example, there is a single node for all AEP operating companies. The exception is where a part of the utility is in the Eastern Interconnection and a part is not. Thus, there are separate nodes for CSW's SPP operations and CSW's ERCOT operations.

41. Q. **Why did you analyze CSW-SPP and CSW-ERCOT as separate destination markets?**

A. I analyzed separate destination markets for the SPP and ERCOT operations of CSW because the SPP and ERCOT TDUs generally have different supply alternatives. ERCOT and the SPP are interconnected only via two DC ties. In

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[17] TVA can sell to its direct interconnections (AEP, Carolina Power & Light, Southern Company, LG&E Energy, Illinois Power, Entergy, East Kentucky Power Coop, Duke and Electric Energy) with the exception of AECI and Big Rivers Electric Coop.

[18] I have modeled Alliant East and Alliant West as separate nodes, since Wisconsin Power & Light is not directly interconnected with Interstate Power or IES. I add their supply together before calculating market shares.

[19] There are two other potentially relevant mergers in the regions being analyzed: Western Resources/ KCPL and APS/DQE. The Western Resource/KCPL merger has not yet been approved by the Commission, and applicants have just recently re-filed their competition analysis. While the APS/DQE merger has been conditionally approved by both the Commission and the Pennsylvania Public Utilities Commission, DQE has terminated the merger agreement and the merger is now subject to a lawsuit pending in federal court.

fact, because of the manner in which transmission capability data are reported in ERCOT, I analyzed three separate CSW destination markets in ERCOT.

ERCOT reports Available Transmission Capability ("ATC") based on zones that are subsets of control areas. For example, although CSW-ERCOT is a single control area ("CSWS" as reported by ERCOT), its operations fall into three ATC zones:[20] North & Middle Central Power & Light ("CBEN"), South Central Power & Light ("VALC") and West Texas Utilities ("WTU"). ERCOT also reports an ATC zone for the City of Brownsville ("VALP") which, combined with VALC, forms the Rio Grande Valley zone ("VALL"). Although no separate ATC data are reported for the overall Rio Grande Valley zone, I have examined that area as a relevant destination market because it is sometimes separated from the rest of ERCOT by a north to south transmission constraint.[21,22]

42. Q. **Have you defined other ERCOT destination markets consistent with the ERCOT ATC zones?**

A. Yes, as with the CSW-ERCOT destination markets, I based my definition of destination markets on the ATC zones. I examined the following ATC zones: Brazos Electric Coop; City of Bryan; City of Austin; City Public Service of San Antonio; Cities of Denton, Garland and Greenville; HL&P; LCRA; South Texas Electric Coop; Texas Municipal Power Pool; Texas New Mexico Power; and TU.

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20 ERCOT also defines the DC Tie East ("DC-E") and the DC Tie North ("DC-N") as ATC zones.

21 The Rio Grande Valley includes certain generation and load for a portion of CPL, certain generation and all load for the City of Brownsville ("Brownsville") and load for Magic Valley Electric Coop, a full-requirements customer of CPL. MVEC's contract ends July 23, 2001, and they have given termination notice. Although there are other potentially constrained areas within Texas, the Rio Grande Valley is the constrained area in which Applicants own the most significant generation.

22 CSWE's planned Frontera project is located in the Rio Grande Valley.

43. Q. **Does the manner in which you have analyzed ERCOT destination markets imply that these areas are "markets"?**

A. No, the approach I used was dictated by two factors: first, the Commission's destination market approach and, second, the manner in which transmission data are posted based on ATC zones. Given the existence of the ERCOT ISO, in the absence of internal ERCOT transmission constraints, I would have modeled an overall ERCOT market for purposes of my analysis. Using the ERCOT zones permits me to take the transmission availability in ERCOT into account. As noted above, I also examined the Valley zone since it is a constrained area in which Applicants own significant generation.

44. Q. **Please provide more detail on how you treated TDUs.**

A. A number of full- and partial-requirements customers, some of which own their own generating capacity, are located in the Applicants' control areas. These customers include cooperatives and municipal power authorities with only a portion of their load within the control areas of Applicants and other load located in the control areas of other utilities.

I analyzed a single CSW-SPP and single AEP destination market to reflect both the TDUs and the retail customers of Applicants. I also modeled additional areas in Texas; however, Applicants' TDUs in Texas would similarly be covered by the Applicants' destination markets. To the extent Applicants' TDUs owned generating capacity, I included this capacity in the Applicants' respective destination markets as capacity controlled by the TDUs collectively.

45. Q. **What did your analysis assume about ISOs?**

A. In the Base Case, I took into account the PJM and NYPP ISOs and the Midwest ISO ("MISO"), all of which have been approved by the Commission, as well as the ERCOT ISO. My analysis also takes the SPP transmission tariff into account.

I also considered an alternative market organization in a sensitivity analyses in which AEP is a participant in the MISO.

DEFINITION OF TIME PERIODS

46. Q. How did you define the periods that you evaluated?

A. Recognizing the fact that both electricity supply and demand conditions change throughout the year, I evaluated nine different time periods. These time periods were selected to reflect the fact that both load and available generation vary during the year and load varies during the time of day. Specifically, I evaluated a Super Peak, Peak and Off-peak period for the Summer, Winter, and Shoulder seasons.[23] I added a tenth time period, defined as the summer super peak period but with a $35/MWh price for all destination markets.[24]

The Super Peak period for each season is defined as the top 150 load hours that were recorded during the peak hours for either CSW-SPP or AEP. I used CSW-SPP's hours to define the Super Peak period when I was analyzing destination markets for utilities in the Central Time Zone, and AEP's hours when I was analyzing destination markets for utilities in the Eastern Time Zone.[25] This period was chosen to reflect the highest load hours for each season. The Peak and Off-peak periods correspond with on- and off-peak time-of-day definitions provided

[23] In its Order setting this merger for hearing, the Commission criticized my choice of time periods ("Applicants define time periods by hour, as opposed to load level, which may mask important merger-related effects that occur within long time periods and those due to the fact that the merging companies are located in different time zones.") (footnote 78). My time periods were intended to reflect varying load levels, taking into consideration that loads vary both by season and time of day. If I used load levels to the exclusion of considering seasons, differences in generation availability would have to be ignored, thereby masking changes in supply conditions. In my current analysis, as discussed herein, I have ensured that the time periods I use reflect appropriate load levels.

[24] As discussed in Exhibit No. AC-504, this additional time period was analyzed to ensure that my analysis covered a fully representative range of price levels.

[25] See workpapers.

by NERC.[26] I chose this approach after I evaluated load profiles for various utilities and found that the load pattern in 1997 appeared to closely correspond with on and off-peak definitions provided by NERC. Therefore, I used the NERC definition to group the on-peak and off-peak hours.[27] Because I added a third time period, Super Peak, the Peak period hours are the subset of on-peak hours other than those that correspond with CSW-SPP's top 150 load hours.

I considered the alternative of defining periods based exclusively on load rather than season or time of day; for example, considering the top X load hours whenever they occurred during the year as one period, the next X load hours another period and so on. This methodology, however, defines periods based only on demand conditions and ignores the fact that supply alternatives may be very different on a seasonal basis. For example, the available supply response in the shoulder months is presumably less than during other months since many units are on scheduled maintenance during this time period. Also, generator ratings can differ by season. In summary, I evaluated the following nine time periods:

SUMMER (June-July-August).

Super Peak (Top 150 load hours)

Peak (Hour ending ("HE") 8 to HE 22 EST; HE 7 to HE 21 CST, excluding hours used in Super Peak)

Off-peak (HE 1 to HR 7 and HE 23 to HE 24 EST; HE 1 to HE 6 and HE 22 to HE 24 CST)

WINTER (December-January-February).

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26 Based on the NERC definition, the Peak period for each season consists of the hour ending 8 to hour ending 22 for utilities in the Eastern Standard Time zone, and hour ending 7 to hour ending 21 for utilities in the Central Standard Time zone. The off-peak period is defined as the remaining hours. I took into account the time zone in which each utility is located. These definitions of on-peak and off-peak also correspond with the time periods defined in individual utility's OATT tariffs. See workpapers.

Super Peak (Top 150 load hours)

Peak (HE 8 to HE 22 EST; HE 7 to HE 21 CST, excluding hours used in Super Peak)

Off-peak (HE 1 to HR 7 and HE 23 to HE 24 EST; HE 1 to HE 6 and HE 22 to HE 24 CST)

SHOULDER (March-April-May-September-October-November).

Super Peak (Top 150 load hours)

Peak (HE 8 to HE 22 EST; HE 7 to HE 21 CST, excluding hours used in Super Peak)

Off-peak (HE 1 to HR 7 and HE 23 to HE 24 EST; HE 1 to HE 6 and HE 22 to HE 24 CST)

These load data are summarized in Exhibit No. AC-508.

THE 250 MW PATH

47. Q. **Please describe the 250 MW East-to-West reserved contract transmission path that Applicants have established between AEP and CSW.**

A. This path from AEP to CSW through Ameren and the arrangements established to create it are described in detail in Mr. Maliszewski's testimony. In developing my analysis, I relied on the information, as detailed in Mr. Maliszewski's testimony, which Ameren provided to Applicants in response to PSO's request for a 250 MW firm point-to-point reservation, updated to reflect underlying assumptions currently being applied to develop OASIS postings.

Ameren performed a system impact study on the basis of which it concluded that it could accommodate the full 250 MW reservation from AEP to Ameren during

[27] One exception is that, based on a review of the load data, I considered only the non-holiday weekdays to have peak hours, whereas the NERC definition includes Saturdays as well.

all periods of the year except when its load is within 90 percent of the annual peak. Citing a transformer constraint at its Albion substation, Ameren informed Applicants that it could accommodate only 150 MW of the 250 MW request during that period for the AEP-to-CSW path without enhancing the substation's transfer capability. The upgrade has since been accomplished.

48. Q. **How did you incorporate this information in your analysis?**

A. My understanding is that current ATC postings on OASIS reflect both the firm reservation (beginning in June 1999) and the transformer upgrade. In analyzing pre-merger conditions, I adjusted the ATC to take out the transformer upgrade and AEP's 250 MW reservations.

VI. APPLICANTS' PROPOSED MITIGATION

49. Q **Please summarize Applicants' proposed mitigation measures.**

A. The testimony of Mr. Stephen B. Jones sets out the proposed mitigation measure in detail. The key elements are:

- Applicants will divest 50 percent (250 MW) of the 500 MW Frontera plant as soon as feasible upon approval of the merger. Frontera is a baseload combined cycle plant located in southern Texas that is owned by CSW's affiliate CSWE and will be energized in 1999. It is anticipated that the divestiture process will be initiated two years after consummation of the merger.
- Applicants also will divest an additional 300 MW of the Northeastern baseload coal generation capacity located in Oklahoma (CSW-SPP). The Northeastern plant is owned by PSO. The Northeastern shares will be sold in two equal-sized pieces. As Mr. Jones testifies, the capacity of this plant currently is required to meet PSO's native load reliability obligations in the SPP. The divestiture of the Northeastern shares will take place as soon as (1) the progress of retail restructuring programs permits the transfer without

impairing PSO's reliability obligations and (2) divestiture can be accomplished without jeopardizing pooling of interest accounting treatment. Oklahoma's retail access statute provides for retail access by July 1, 2002, and the divestiture process is expected to begin soon thereafter.

- Only buyers (or in the case of the SPP divestiture, a combination of buyers) that can meet the Appendix A screens will be permitted by CSW to purchase the divested properties. That is, a condition of each divestiture will be that the sale of the divested interests will not cause the post-merger HHIs in any CSW destination markets or contiguous destination markets to violate the Appendix A screening criteria.

- In the interim before each of the divestitures is completed, Applicants will conduct interim energy sales in SPP and ERCOT, respectively. As with the divestiture sales, a condition of the energy sales will be that the sales will not cause the post-merger HHIs in any CSW destination markets or contiguous destination markets to violate the Appendix A screening criteria.

- In the SPP area, Applicants will undertake a system sale or sales of 300 MWh of financially firm energy. The minimum bid amount will be 50 MW and no buyer will be allowed to purchase more than 150 MW in any sale period. The energy entitlement will be priced at $14/MWh. That price reasonably assures that the contracted energy will be economic in all of the time periods that I have analyzed. CSW may recall all or a portion of the energy sold in the interim sale of energy if CSW declares a generation emergency pursuant to the terms and conditions of the SPP operating rules and the CSW operating agreement. Thus, any callback will take place only if absolutely essential for CSW to maintain power supplies for native-load and other firm customers, and after CSW has exhausted other alternatives such as cutting interruptible load and discontinuing discretionary, non-firm, energy sales. In the event that

CSW declares a generation emergency, it will make the energy sold in the interim sale financially firm to the buyer(s) affected.

- In the ERCOT area, the interim energy sale will be a unit power sale of 250 MW of capacity and associated energy from the Frontera plant. The energy entitlement will be priced at the running rate for the Frontera plant, which is expected to be about $17/MWh. That price reasonably assures that the contracted energy will be economic in all of the time periods that I have analyzed.
- In order to ensure that the effects of the merger will not exceed the effects examined in my analysis, Applicants have undertaken not to contract for more than 250 MW of firm transmission from the East Zone to the West Zone unless the Commission authorizes them to do so.
- Applicants also have agreed to waive certain AES-TVA priority rights to use of CSW's interconnections and to schedule available capacity on the HVDC ties on a first-in-line basis.

50. Q. **Do these mitigation measures satisfy the concerns expressed in the Hearing Order vis-a-vis the need for an effective, long-term solution?**

A. Yes, they do. In relevant part, the Commission's Order stated:

> Moreover, Applicants' short-term sales proposal for remedying merger-related competitive harm in markets adversely affected by the proposed merger is likely to be ineffective. The primary reason for this is that the merged company would retain control over the capacity that Applicants purportedly would relinquish. Moreover, the short-term proposal attempts to cure a structural problem – one that Applicants have not demonstrated will be eliminated by entry or other means by the end of the term of the sales proposal.

Applicants have taken this as a strong message that the Commission is seeking a structural solution to structural problems. For this reason, Applicants have focused on divestiture, a permanent structural remedy, as the main method for mitigating market power concerns. As described in detail below, Applicants' proposed divestiture is far larger than the 250 MW integration of the two companies that is the main source of pre-mitigation failure of the market power screen, and it results in market concentrations that are below pre-merger levels in most markets and time periods.

51. Q. What is the basis for the interim mitigation proposal?

A. In Order No. 592, the Commission recognized that mitigation measures cannot be put into action instantaneously. In the case of Frontera, the only lag is the time necessary to accomplish the divestiture while maintaining pooling of interest accounting treatment. In the case of the Northeastern capacity, the divestiture also will be delayed due to CSW-SPP's continuing need to meet its reserve responsibility for serving native load until such time that its native load responsibility is reduced by retail access. The State of Oklahoma, in which the Northeastern plant is located, has set a statutory goal of full retail access by July 1, 2002.

The Commission has indicated that interim measures to bridge the gap prior to the effectiveness of permanent solutions must be fully effective. Applicants' mitigation is designed to meet the objections to its earlier mitigation stated in the Order and, indeed, most of the objections of intervenors. The interim mitigation proposal is far stronger that their initial proposal, indeed, stronger than Applicants' amended proposal propounded in their Answer in this docket.

The power sale is structured to achieve its purpose of retaining the right to the "pure capacity" associated with the system power sales while not retaining economic energy from the sold capacity under any but unusual and transitory circumstances. Moreover, since CSW can exercise the recall rights only when it declares a generation emergency because the power is needed to meet native load, such load being served at regulated rates, it cannot profit from any theoretical ability to increase prices with respect to recalled energy.

52. **Q. Does the mitigation sale satisfy the Commission's criteria set out in the Allegheny Energy Inc.-DQE Inc. merger (Docket No. EC97-47-000 et al.)?**

A. In that proceeding, the applicants had proposed a unit sale from the Cheswick power station as interim mitigation until ISO membership and changes in market conditions would mitigate market power concerns. The Commission ordered that applicants commit to divest the Cheswick station. In stating its reasons for conditioning its acceptance of the merger on this divestiture, the Commission cited applicants' continuing control over the unit. It stated, however, that its "primary concern" was that the power sale might not be fully subscribed due to reservations contained in the proposed offering and to transmission limitations. The Commission reasoned that any unsold energy would remain in applicants' control.

Applicants in this case already have proposed divestiture as the market power remedy. What is at potential issue is the interim, pre-divestiture, remedy.[28] There is no likelihood that the contracts will not be fully subscribed. The entitlement price for energy in the SPP contract is $14 per MWh, well below market prices in SPP. The strike price of the Frontera unit sale is well below the market price (as represented by system lambda) in ERCOT in all time periods, including off-peak periods. No economic reservations as part of the auction process are proposed by Applicants. For the SPP firm energy sale, there is no transmission access issue, since the proposal would allow the buyer to take delivery at any CSW point of interconnection within the relevant power pool or any major generator bus within its SPP service area. The ERCOT ISO will ensure transmission access for the ERCOT energy sale.

[28] No interim mitigation was required in the Commission's Allegheny order.

53. Q. **Will the merged company maintain operating control of the Frontera and Northeastern plants after divestiture of the undivided ownership interests described above is completed?**

A. Yes. However this should not be a basis for concern. Applicants have agreed that the purchasers of the divested capacity will have the right to have their capacity operated and dispatched anytime that the unit can be made available for operation, and that scheduled outages for maintenance and the like will be coordinated among the owners. In addition, at any time when CSW is not dispatching the subject units up to its ownership interests in them, the purchasers will have the right to purchase any remaining energy from the units at the units' marginal cost. Failing to carry out their obligations in good faith would subject the merged company to liability to its owners.

54. Q. **What analytical approach did you use to demonstrate that mitigation is sufficient?**

A. I undertook a two-part analysis. First, in order to assist Applicants in determining the requisite amount of mitigation to ensure that the Appendix A screen is passed, I analyzed the pre-mitigation results and determined the hypothetical level and type of mitigation required to eliminate the screen failures. Second, once the mitigation was chosen, I reflected it in the inputs to the CASm model and re-ran the analyses to calculate post-merger, post-mitigation HHIs. In assessing mitigation, I used the permanent divestiture of the units, rather than the interim mitigation. This is conservative, since generating units are derated for outages; whereas the SPP interim Northeastern contracts are 100 percent firm, the reduction in applicants' share under the interim mitigation is larger.

VII. THE IMPACT OF THE MERGER ON COMPETITION – HORIZONTAL MARKET POWER ANALYSIS

PRODUCT MARKETS AND SUPPLY MEASURES

55. Q. Please identify the relevant product markets you analyzed.

A. Consistent with the product markets the Commission has typically evaluated in the context of mergers, I considered the relevant product markets to be long-term capacity, short-term capacity and non-firm energy. Consistent with Commission guidance, the product measures on which I concentrated were deliverable Economic Capacity and Available Economic Capacity. These are used to measure market structure in energy markets, and are also used by the Commission as measures of short-term capacity markets. Consistent with Commission guidance, I also considered Uncommitted and Total Capacity measures.

Because the Commission has determined that long-term capacity markets are presumed to be competitive, and because neither Applicant has control over sites for new generation or fuel supplies, I did not conduct any quantitative analysis of long-term capacity markets. I discuss ease of entry later in my testimony.

TOTAL CAPACITY

56. Q. Did you analyze Total Capacity?

A. Yes. As a threshold matter, the method appropriate for defining the scope of the geographic market for purposes of a Total Capacity (or, for that matter, an Uncommitted Capacity) analysis is not addressed in Order No. 592. Because of the location of the Applicants and the fact that their historic trading partners do not overlap, any analysis that puts them into the same geographic market necessarily assumes a large geographic market.

For the purposes of the Total Capacity analysis, I defined the relevant geographic market as consisting of all utilities directly interconnected with either of the

Applicants. Consistent with Commission guidance, this is an estimate intended to provide a "sense of the overall size of a supplier" to be included in the market.[29]

I examined Total Capacity for 1999-2001, and included as part of the market new merchant capacity planned in the area.[30]

57. Q. **What does the Total Capacity analysis show for the market consisting of Applicants' direct interconnects?**

A. The overall size of the market so defined is in excess of 340,000 MW in 1999, growing to almost 360,000 MW in 2001. AEP has approximately 24,000 MW of capacity and CSW has approximately 15,000 MW of capacity, including capacity of its unregulated subsidiary, CSWE, located within Texas. AEP's and CSW's market shares are 7 percent and 5 percent, respectively. The market is unconcentrated (an HHI of less than 1000), and the merger thus has no anti-competitive impact. This conclusion is relevant to the effect of the merger on all the Applicants' customers whether located in AEP, CSW-SPP or CSW-ERCOT. Had I performed an analysis centered on individual destination markets, the amount of competing capacity would have been still larger, since the market would contain additional suppliers beyond those that are first tier to Applicants and able to reach the destination market using Applicants' open access tariffs. A summary table for 1999 is shown below and results for 2000 and 2001 are included in Exhibit No. AC-509.[31]

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[29] Order No. 592, page 65.

[30] I have presumed that the EIA-411 data on which I rely captures planned capacity additions by traditional utilities in their own control areas. I have additionally included in the Total Capacity and Uncommitted Capacity analyses capacity that includes plants being developed by independent power producers or unregulated utility subsidiaries or plants whose total output is not fully committed to serve native load. See workpapers.

[31] See workpapers.

Total Capacity: AEP and CSW Direct Interconnections			
	1999		
	MW	Market Share	HHI
AEP	23540	6.9%	47
CSW-SPP	8488	2.5%	NA
CSW-ERCOT	6069	1.8%	NA
CSWE	750	0.2%	NA
CSW Subtotal	15307	4.5%	20
TOTAL	341736	100.0%	694
Post-Merger HHI			756
Delta HHI			62

UNCOMMITTED CAPACITY

58. Q. Did you analyze Uncommitted Capacity?

A. Yes. I considered Uncommitted Capacity to be the relevant measure for assessing short- (or intermediate-) term capacity markets. I concluded that the merger does not have an adverse effect. "Uncommitted" capacity for purposes of this calculation is simply installed capacity (plus net firm purchases) minus net peak load and capacity reserve requirements. By this measure, CSW has negative uncommitted capacity in both SPP and ERCOT. However, CSWE has 705 MW of uncommitted capacity.[32] The combination of this 705 MW of uncommitted capacity with AEP's 495 MW of uncommitted capacity in 1999 still represents less than a 15 percent combined market share. This analysis is conservative in

[32] As cited earlier, CSWE has 205 MW of existing uncommitted capacity in Texas, plus an additional 500 MW from the Frontera plant in Texas, which expected to come on-line in 1999.

that it would be logical to net CSWE's uncommitted merchant capacity against the shortfall of capacity for CSW's utility subsidiaries.

As shown below, the market for Uncommitted Capacity is unconcentrated and mergers in such markets are presumed to have no anti-competitive impact. Exhibit No. AC-510 provides results as well for 2000 and 2001.

Uncommitted Capacity: AEP and CSW Direct Interconnections			
	1999		
	MW	Market Share	HHI
AEP	495	5.9%	34
CSW-SPP	0	0.0%	NA
CSW-ERCOT	0	0.0%	NA
CSWE	705	8.4%	NA
CSW Subtotal	705	8.4%	70
TOTAL	8435	100.0%	491
Post-Merger HHI			589
Delta HHI			98

ECONOMIC CAPACITY

59. Q. What did your analysis show for Economic Capacity?

A. The most important conclusion to be drawn from the Economic Capacity analysis is that it confirms, with very few exceptions, the conclusion that would be drawn from an analysis of the historic transactions data: the Applicants serve separate markets with only minimal overlap. This conclusion is particularly striking since the deliverable economic capacity test does not take into account the opportunity cost that keeps AEP energy in ECAR, MAIN and points east and CSW energy in the SPP and ERCOT markets.

A review of the market shares – pre- and post-merger – that are shown in Exhibit AC-511,[33] demonstrates that CSW has almost no share in any of the markets in MAIN, ECAR, eastern SERC or MAPP. AEP has very small shares in the SPP, SERC, MAPP (where neither is a factor) and no measurable share in ERCOT.

For this reason, it is unsurprising that the screen is passed in nearly all markets. Failures are restricted primarily to the CSW markets (primarily CSW-SPP). Despite the small shares of the Applicants, a few other markets fail the screen because the market is already concentrated due to the share of the local utilities.

60. Q. Please describe the results for the CSW-SPP market.

A. Consistent with current plans, and as described in Mr. Smith's testimony, 150 MW of the 250 MW of AEP power will replace some of CSW-SPP's existing firm purchases and the remaining 100 MW will be delivered to WTU, where it also replaces an existing contract. In the CSW-SPP market, without the 250 MW transfer, AEP's pre-merger share generally is less than one percent and more frequently at or below 0.5 percent. AEP's share is lowest when CSW's share is highest. The 150 MW delivered from AEP to CSW-SPP represents 1 to 2 percent of the post-merger market. Hence, Applicants' post-merger market share increases by 1 to 3 percentage points above CSW's pre-merger share and the change in HHI ranges from 147 to 307. Most of this increase is due to the transmission reservation between AEP and CSW.

61. Q. Do the HHI results for the CSW market properly indicate a potentially adverse impact of the merger on the current wholesale customers in the CSW area?

A. No. The main effect of the integration of the Applicants on CSW's TDUs is to make 150 MW of low-cost AEP energy available to serve loads in the CSW-SPP

[33] Detailed market share reports are included in electronic workpapers.

market, where most of this energy otherwise would not have been sold. Use of the transmission system to import this energy from AEP does not simply displace other supplies since CSW-SPP's transmission capability to import from other systems is not fully used at all times. An increase in low-cost supply should reduce, rather than increase, prices.

Further, the only current wholesale customers in the CSW-SPP area, other than CSW itself, are CSW's SPP TDUs. Their aggregate potential demands are small relative to the amount of energy from non-CSW/AEP sources that can reach them using available transmission capacity. Moreover, most of these TDU loads are served under multi-year contracts which insulate the TDUs from any potential increase in market price due to the hypothetically enhanced ability of CSW to raise prices post-merger.[34] Also, insofar as these customers are under contract, their ability to access competing suppliers is theoretical, and the "market" to sell energy to them is not relevant. It will become relevant only when existing contracts can be terminated which, for most customers, is well in the future. TDUs will be able to arrange contracts for future power supplies, including contracts with new power sources, well before their current contracts expire, and the Commission already has determined that the long-term market for new supplies is competitive.

While the transmission entitlement reduces the potential ability of other sellers to compete with the Applicants when transmission capacity is scarce, the transmission capacity that remains available is more than sufficient to support vigorous competition for the wholesale sales that can use competitive power sources, even if new merchant plant construction and new generation owned by TDUs inside CSW's control area are ignored. As is discussed below, Applicants' mitigation will eliminate any even theoretically adverse competitive effect.

[34] I am aware that an open season has been offered to CSW wholesale customers, but they are under no obligation to elect to terminate existing contracts.

62. Q. What are the results for Economic Capacity for the CSW-ERCOT destination markets?

A. The Appendix A screen is passed pre-mitigation in all the CSW-ERCOT destination markets (i.e., the CPL, WTU and Rio Grande Valley markets), except for two summer time periods in the CBEN market (North and Middle CPL). AEP has no pre-merger market share in these time periods, and the HHI increase is caused entirely by the post-merger delivery of AEP energy into the ERCOT market. The changes in HHIs are 174 and 176 points in the summer super peak and summer peak periods, respectively.[35]

63. Q. Please describe how Applicants' proposed mitigation affects the HHI results for Economic Capacity in the CSW markets.

A. With mitigation, all of the HHI increases resulting from the merger are eliminated in the CSW's own destination markets in the SPP and Texas. Indeed, with mitigation, the effect of the merger is to deconcentrate these destination markets in virtually every time period. The results for all destination markets are included in Exhibit No. AC-512.

[35] These screen failures arise from the fact that there are multiple feasible prorations of transmission capability of economic capacity in a large, complex network. Changes to transmission capability in one part of the market (such as AEP to Ameren) can change the allocation of shares, and, hence HHIs, even in remote destination markets. Some pre- to post-merger HHI changes are a result of somewhat different feasible prorations than in the pre-merger case, despite that different proration is not per se required by a merger-related event. In the CBEN market, the post-merger proration shows CSW "bumping" another supplier's share, despite the fact that the pre-merger allocation remains economically and electronically feasible. Such screen failures do not demonstrate that the more competitively favorable allocation is not feasible after the merger.

CSW-SPP Market	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	0.20%	63.40%	4114	62.60%	4009	-105
Summer Super Peak	0.30%	62.00%	3937	61.10%	3832	-105
Summer Peak	0.30%	53.30%	3049	52.60%	2970	-87
Summer Off-Peak	0.40%	49.00%	2645	48.00%	2556	-88
Winter Super Peak	0.40%	56.50%	3306	56.00%	3247	-60
Winter Peak	0.70%	37.60%	1649	37.20%	1620	-29
Winter Off-Peak	0.90%	37.80%	1658	37.60%	1641	-17
Shoulder Super Peak	0.50%	50.60%	2714	50.20%	2671	-44
Shoulder Peak	0.90%	36.50%	1561	36.70%	1575	14
Shoulder Off-Peak	1.50%	32.00%	1313	32.60%	1335	21

CSW-ERCOT Market "CBEN" (North & Middle CPL)	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	0.00%	66.80%	4691	64.10%	4339	-352
Summer Super Peak	0.00%	64.00%	4371	62.00%	4134	-237
Summer Peak	0.00%	61.30%	4117	59.30%	3872	-245
Summer Off-Peak	0.00%	54.80%	3435	50.80%	3023	-412
Winter Super Peak	0.00%	72.00%	5336	69.20%	4939	-397
Winter Peak	0.00%	69.10%	5005	64.80%	4454	-551
Winter Off-Peak	0.00%	68.40%	4927	64.10%	4372	-555
Shoulder Super Peak	0.00%	55.50%	3415	52.50%	3102	-313
Shoulder Peak	0.00%	54.00%	3332	50.70%	3000	-332
Shoulder Off-Peak	0.00%	44.10%	2534	40.20%	2218	-316

CSW-ERCOT Market "Valley" (Rio Grande Valley)	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	**AEP Market Share**	**CSW Market Share**	**HHI**	**Merged Market Share**	**HHI**	**Delta HHI**
Summer Super Peak $35	0.00%	78.00%	6177	64.60%	4437	-1739
Summer Super Peak	0.00%	77.80%	6138	63.50%	4321	-1816
Summer Peak	0.00%	79.20%	6339	64.50%	4447	-1891
Summer Off-Peak	0.00%	75.80%	5864	60.50%	4014	-1849
Winter Super Peak	0.00%	75.50%	5868	62.70%	4255	-1613
Winter Peak	0.00%	79.50%	6398	64.20%	4433	-1965
Winter Off-Peak	0.00%	79.90%	6459	64.60%	4482	-1977
Shoulder Super Peak	0.00%	70.00%	5057	56.20%	3505	-1552
Shoulder Peak	0.00%	70.20%	5078	55.20%	3427	-1650
Shoulder Off-Peak	0.00%	69.80%	5039	54.30%	3357	-1683

CSW-ERCOT Market "WTU"	Pre-Merger			Post-Merger (Post-Mitigation)		
Economic Capacity	**AEP Market Share**	**CSW Market Share**	**HHI**	**Merged Market Share**	**HHI**	**Delta HHI**
Summer Super Peak $35	0.00%	41.20%	2374	40.90%	2352	-23
Summer Super Peak	0.00%	33.00%	1995	32.50%	1971	-24
Summer Peak	0.00%	31.40%	2431	30.90%	2406	-25
Summer Off-Peak	0.00%	19.10%	2259	21.10%	2223	-36
Winter Super Peak	0.00%	49.00%	4019	48.90%	4014	-4
Winter Peak	0.00%	38.70%	3768	38.60%	3766	-2
Winter Off-Peak	0.00%	38.80%	3782	38.70%	3780	-2
Shoulder Super Peak	0.00%	33.90%	2227	33.50%	2198	-29
Shoulder Peak	0.00%	27.40%	2077	26.80%	2051	-26
Shoulder Off-Peak	0.00%	23.00%	2055	22.40%	2030	-25

64. Q. Was the Appendix A screen passed for Economic Capacity in other Texas destination markets?

A. Yes, each of the ten other ERCOT destination markets I analyzed readily passed the HHI screen, and are generally deconcentrated.

65. Q. Was the Appendix A screen passed for Economic Capacity in the AEP destination market?

A. Yes. CSW does not have Economic Capacity that reaches the AEP market. Thus, the screening criteria are not violated.[36]

66. Q. You mentioned there were a few minor exceptions to passing the screen for Economic Capacity before mitigation outside of CSW. What are they?

A. The only screen failures pre-mitigation are two time periods in two markets: Oklahoma Gas & Electric ("OKGE") and Western Farmers ("WEFA"), and a single time period in Missouri Public Service ("MPS"). AEP's pre-merger share in all four markets is less than one percent. The OKGE and WEFA failures are in the summer peak and off-peak periods. For the WEFA failures and the OKGE summer peak failure, the HHI increases barely exceed the safe harbor level of the Merger Guidelines (HHI change of 57-70 in a highly concentrated market versus a safe harbor of 50) and are well below the HHI change of 100 deemed likely to be a problem. Only the OKGE summer off-peak market clearly fails the upper end of the screen. The screen failure is due to a combination of an increase in CSW's share (which is about 20 percent post-merger) as a result of the AEP power transfer and, more importantly, an increase in the local utility's share (i.e., OKGE) due to the market shrinkage caused by the 250 MW path.

[36] Indeed, since 250 MW of AEP supply is effectively "transferred" out of the AEP market for Appendix A purposes to CSW, the merger deconcentrates the AEP market.

The HHI increase in the MPS market (in the summer super peak $35 period) clearly does not indicate a market power problem. It is caused by the termination of a contract, the result of which is to increase MPS's economic capacity in its own market. PSO's 50 MW firm purchase from Utilicorp (which was modeled as a purchase from Utilicorp's subsidiary, MPS) is assumed to be controlled by CSW pre-merger. Post-merger, that 50 MW contract is not renewed but is replaced by the AEP contract. When the capacity is returned to the seller, MPS's market share in its own market increases, resulting in an increase in the HHI. Because the contract is for high-priced energy, it affects the MPS market only in the highest-priced time period.

This increase in MPS market share assumes that MPS does not make a substitute sale of the 50 MW to a buyer outside of the MPS destination market. If such a sale is made, the termination of PSO's purchase has no effect on the MPS market share and does not increase concentration in the MPS market.

67. Q. Does Applicants' proposed mitigation eliminate these screen failures in Economic Capacity?

A. Yes, all except the one time period failure that I describe above with respect to MPS. That clearly does not indicate a market power problem. Indeed, in the majority of cases, the mitigation measures reduce market concentration.

AVAILABLE ECONOMIC CAPACITY

68. Q. Does your analysis of Available Economic Capacity indicate similar results to the Economic Capacity analysis?

A. Broadly, yes. In the pre-mitigation analysis, the merger has no effect on the HHIs for Available Economic Capacity in most of the markets analyzed, as is shown in Exhibit No. AC-511, although there are a few other markets in which the HHI screen is failed for a single or few time periods.

69. Q. **Please describe the results of your Available Economic Capacity analysis for the CSW markets.**

A. Pre-mitigation, the changes in HHIs are below the screening threshold in the CSW-SPP and CSW-ERCOT destination markets in all time periods except in three time periods in the CSW-SPP market and one time period in the CBEN market. Each of the CSW-SPP failures is in a moderately concentrated market. The CBEN failure is in a highly concentrated market and is due solely to the AEP contract.

Post-mitigation, the Appendix A screen is passed in the CSW-SPP and CSW-ERCOT destination markets (i.e., CSW-SPP, CBEN, WTU and Valley) and, in most instances, the markets are substantially deconcentrated as shown below and in Exhibit No. AC-512).

CSW-SPP Market	**Pre-Merger**			**Post-Merger (Post-Mitigation)**		
Available Economic Capacity	**AEP Market Share**	**CSW Market Share**	**HHI**	**Merged Market Share**	**HHI**	**Delta HHI**
Summer Super Peak $35	8.50%	6.90%	656	13.50%	679	23
Summer Super Peak	22.40%	13.50%	1101	25.50%	1126	25
Summer Peak	0.00%	18.30%	1002	6.90%	782	-219
Summer Off-Peak	7.10%	0.00%	866	4.30%	837	-29
Winter Super Peak	3.10%	26.30%	1095	26.00%	1092	-3
Winter Peak	0.00%	0.00%	959	0.00%	781	-179
Winter Off-Peak	0.00%	0.00%	969	0.90%	784	-185
Shoulder Super Peak	6.10%	11.50%	711	12.10%	677	-35
Shoulder Peak	0.00%	12.60%	591	5.10%	480	-111
Shoulder Off-Peak	0.00%	0.00%	1270	0.00%	1122	-149

CSW-ERCOT Market "CBEN" (North & Middle CPL)	Pre-Merger			Post-Merger (Post-Mitigation)		
Available Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	0.00%	54.70%	3787	46.50%	3028	-759
Summer Super Peak	0.00%	66.80%	4961	54.30%	3588	-1373
Summer Peak	0.00%	68.70%	5231	54.10%	3361	-1870
Summer Off-Peak	0.00%	55.90%	3718	35.30%	2077	-1640
Winter Super Peak	0.00%	46.10%	3081	41.30%	2683	-398
Winter Peak	0.00%	67.90%	4790	58.00%	3605	-1185
Winter Off-Peak	0.00%	63.50%	4303	55.10%	3354	-949
Shoulder Super Peak	0.00%	61.40%	4155	47.00%	2679	-1476
Shoulder Peak	0.00%	51.40%	2971	42.60%	2205	-766
Shoulder Off-Peak	0.00%	45.20%	2650	29.20%	1571	-1079

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CSW-ERCOT Market "Valley" (Rio Grande Valley)	Pre-Merger			Post-Merger (Post-Mitigation)		
Available Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	0.00%	64.30%	4642	44.90%	2900	-1743
Summer Super Peak	0.00%	69.70%	5360	50.20%	3403	-1957
Summer Peak	0.00%	57.10%	3898	37.70%	2438	-1460
Summer Off-Peak	0.00%	59.50%	4020	40.00%	2460	-1559
Winter Super Peak	0.00%	56.40%	3673	38.20%	2288	-1384
Winter Peak	0.00%	62.40%	4289	43.00%	2622	-1667
Winter Off-Peak	0.00%	64.10%	4473	44.70%	2739	-1734
Shoulder Super Peak	0.00%	61.20%	3997	41.90%	2351	-1646
Shoulder Peak	0.00%	48.60%	3068	29.50%	1944	-1123
Shoulder Off-Peak	0.00%	51.60%	3306	32.50%	2064	-1242

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CSW-ERCOT Market "WTU"	Pre-Merger			Post-Merger (Post-Mitigation)		
Available Economic Capacity	AEP Market Share	CSW Market Share	HHI	Merged Market Share	HHI	Delta HHI
Summer Super Peak $35	0.00%	31.90%	2618	30.10%	2503	-115
Summer Super Peak	0.00%	45.50%	3314	25.90%	1888	-1426
Summer Peak	0.00%	31.10%	5058	21.70%	2099	-2959
Summer Off-Peak	0.00%	39.40%	2724	20.30%	1529	-1196
Winter Super Peak	0.00%	29.40%	4788	28.90%	4789	1
Winter Peak	0.00%	12.70%	4990	12.40%	4996	6
Winter Off-Peak	0.00%	16.20%	5133	15.90%	5147	14
Shoulder Super Peak	0.00%	46.80%	2989	37.10%	1991	-998
Shoulder Peak	0.00%	23.40%	1214	20.00%	1041	-174
Shoulder Off-Peak	0.00%	28.40%	2245	22.80%	1935	-310

70. Q. Was the Appendix A screen passed for Available Economic Capacity in other Texas destination markets?

A. Yes. On a pre-mitigation basis and with one exception, the other ERCOT destination markets I analyzed readily passed the HHI screen, and are generally deconcentrated. The change in HHI in the winter peak period for the City of Bryan is only 59 points. Post-mitigation, the screen is passed in all the non-CSW Texas markets, as shown in Exhibit No. AC-512.

71. Q. Please summarize the Available Economic Capacity results in other markets.

A. Pre-mitigation, there are six markets for which the HHI screen is exceeded (and four others where the HHI change is above 50, but well below 100), generally for only a single time period. None shows a significant market power problem. The Detroit Edison market fails in one period because the AEP contract reduces AEP's minority share of the market. The CELE, OKGE, SWEPA and WEFA markets all fail the HHI screen despite the Applicants' zero share both before and after the merger. The SWPS failure is due to its capacity being returned when it is replaced by the AEP contract.

None of these screen failures is caused by the Applicants having or acquiring market power. None causes a significant adverse impact on competition. Finally, even pre-mitigation the merger is as commonly deconcentrating as it is concentrating and the post-mitigation results are overwhelmingly to deconcentrate the market.

72. Q. **Did you prepare exhibits that summarize the post-mitigation results?**

A. Yes. Exhibit No. AC-512 summarizes the post-mitigation results of the Economic Capacity and the Available Economic Capacity analyses.

SENSITIVITIES

Overview

73. Q. **You indicated earlier that you undertook a number of sensitivities to corroborate your Base Case results. Please summarize the sensitivities you conducted.**

A. I conducted the following sensitivity analyses:

- Market organization – AEP is a participant in the MISO.
- Transmission pricing – elimination of all transmission rates (only transmission losses occur).
- Transmission capability – (i) use of TTCs instead of ATCs; and (ii) adjustments to reflect loop flow effect

Given the extraordinarily large number of destination markets I examined in the Base Case, I limited the sensitivity analyses (other than the loop flow sensitivity) to only the subset of the destination markets most likely to be affected by the merger. These broadly included AEP and CSW-SPP and all the utilities "in-between" AEP and CSW, which I identified to include all Ameren's direct interconnections that I analyzed as destination markets in my Base Case.[37] In all cases, my analysis takes Applicants' proposed mitigation into account. Thus, these sensitivities test whether the proposed mitigation remains robust under the changed circumstances represented by the sensitivity analyses.

74. Q. **Did the results of these sensitivities change any of your conclusions?**

A. No, they do not. The sensitivity analyses corroborated the Base Case results. A summary of these results are included in Exhibit Nos. AC-513 to AC-515 and Exhibit No. AC-517.

Market Organization

75. Q. **Please describe the results of your sensitivity analyses with respect to market organization.**

A. Recall that in the Base Case, I assumed that there was a MISO, but that AEP was not a member of it. This sensitivity assesses the effects on the horizontal market power analysis of AEP's participation in the MISO. This analysis is not meant to suggest that joining MISO is the only possible outcome of AEP's commitment to join a Regional Transmission Organization (RTO) that independently controls transmission activities.[38] Rather, I analyze this option to answer the contention in some of the protests of intervenors that AEP's membership in MISO would amplify the supposed adverse horizontal effects of the merger.

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[37] The markets analyzed for these sensitivities thus include: AEP, CSW-SPP, AECI, Alliant East, Ameren, Cinergy, Commonwealth Edison, Entergy, Illinois Power, KCPL, Louisville Gas & Electric, MPS, Northern Indiana Public Service, SWEPA, STJO, TVA and Western Resources. I also included the OKGE destination market.

[38] Indeed, as described in Mr. Baker's testimony, AEP is participating in the process for formation of the Alliance RTO.

AEP's hypothetical participation in the MISO had a minimal effect on the overall horizontal market power analyses. In all of the destination markets analyzed, the screen was passed for both the Economic Capacity and Available Economic Capacity measures in all time periods, with only one exception: the same high-priced $35/MWh market for MPS, where the failure relates to a pre- to post-merger contract change in which MPS reacquires capacity it had previously sold outside of its destination market. In general, the effects of the merger are to deconcentrate these markets. The summary results are included in Exhibit No. AC-513.

76. Q. **Did you consider whether the results of your analysis would be affected if AEP participates in the Alliance RTO?**

A. Yes. AEP's participation in the Alliance RTO could not adversely affect the results of my analysis and in fact could be expected to have a small deconcentrating effect in some destination markets. The other participants in the Alliance are located to the east of AEP. Since energy from CSW does not reach AEP in my current analysis, bringing firms located to the east of AEP into the AEP destination market will not produce a greater concentrating effect for the merger in these eastern destination markets. However, reducing the pancaked rates these eastern utilities pay to destination markets that lie between AEP and CSW could have a small deconcentrating effect on those destination markets. This is confirmed by an analysis performed on the subset of markets that most likely would be adversely affected by AEP's membership in the RTO. This analysis is contained in my workpapers.

Zero Transmission Costs

77. Q. **What is the purpose of your sensitivity analysis that assumes no transmission costs other than losses?**

A. This is intended to be a limiting case showing the effects of market enlargement on the competitive effects of the merger. Since distant generation pays only losses, it is the equivalent of a single "postage stamp" tariff covering the entire area included in my analyses. If the merger creates no incremental competitive problems when transmission is priced at zero, it follows that no lesser level of discounting would cause it to be anticompetitive.

78. Q. **What does the zero transmission cost sensitivity show?**

A. As with the other sensitivities, the results in terms of the screen are the same as in the Base Case: the HHI screen is passed in all instances but the usual one time period in the MPS market. The summary results are included in Exhibit No. AC-514.

TTCs

79. Q. **Please describe the results of your sensitivity analysis with respect to use of TTCs.**

A. In the Base Case, I relied on non-firm ATCs as the basis for determining transmission capability into a destination market, limited by any simultaneous constraint on imports. At an earlier stage in this proceeding, some intervenors contended that using ATCs to size transmission capability might mask adverse effects of this merger on the theory that changes in market institutions or FERC rules might remove restrictions on transmission availability. The reductions in ATCs to reflect transmission providers' reservations for Capacity Benefit Margin ("CBM") and Transmission Reliability Margin ("TRM") were cited specifically. To check the validity of this concern, I substituted TTCs for the non-firm ATCs I used in my Base Case analysis.[39] For this purpose, as with my ATC analysis, I used the lower of the reported values in instances where two parties post different capabilities for the same path.[40]

Use of TTCs did not substantively change the results in terms of the HHI screen, although there were some numerical changes (some slightly lessening and some slightly increasing the change in the HHIs). There was only one screen failure. The MPS market had a one-time period failure – the same time period that failed in my Base Case, due again, not to enhanced market power but to the increase in MPS's capability when the AEP contract replaces it.. The summary results are included in Exhibit No. AC-515.

Loop Flow

80. Q. Do the Base Case data on transmission capability take into account loop flow?

A. Yes, to the extent the OASIS-posted ATCs take into consideration loop flow in the individual utilities' determinations of transmission availability. ATCs generally are based on load flow studies. Assuming that they are conducted properly, these will reflect loop flows. Contract path ATCs should, therefore, reflect the effects of loop flows and power distribution factors based on the amount of inter-control area transmission capacity cannot be made available for purchase on a contract path basis.[41] In my Base Case, I modeled merger-related

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39 This sensitivity using TTCs is also relevant to expansion of transmission capability more generally, such as the concern that posted ATCs reflect native load obligations, whereas under retail access, native loads might not receive priority.

40 To the extent simultaneous constraints had been placed on import capability, these were also adjusted. It is incorrect to assume that simultaneous import capability differs depending on whether transfer capability is based on ATCs or TTCs. However, given the methodology to determine simultaneous limits (i.e., that the maximum import capability into a given market was no greater than the maximum of the individual paths subject to a common limiting facility), the results can yield different simultaneous import constraints depending upon whether the maximum of the individual paths is based on ATCs or TTCs.

41 My analysis takes into account loop flow effects through recognition of joint transmission constraints, which I developed in accordance with the Commission's approach outlined in the *FirstEnergy* decision. This method limits flows into an area from multiple adjacent areas based on a common limiting element,

changes as adjustments to a contract path, from AEP to Ameren and Ameren to CSW.

At my request, Applicants' transmission planning personnel undertook an additional analysis in order to determine the effects of the 250 MW path reservation on transmission availability on paths other than the contract path. This load flow analysis, described in Mr. Maliszewski's testimony, responds to the Hearing Order's concern (expressed in footnote 79 of the Order) that Applicants' analysis left open the possibility that the changed loading of Applicants' generation could adversely affect competitors' ability to reach some customers. From this analysis, I was provided estimates of pre- and post-merger summer, winter and fall/spring First Contingency Incremental Transmission Capacity ("FCITC") between a large number of affected control areas. FCITCs differ from ATCs (the data posted on the OASIS, which I used) to the extent CBM and TRM (which I described earlier) are taken into consideration in the ATC data; therefore, FCITC data are not a direct substitute for ATC data. In consultation with Mr. Maliszewski, I decided the best approach to using the data developed in his load flow analysis was to apply the change in FCITC from pre- to post-merger load flow cases to the ATC data that I relied on in my Base Case analysis. The load flow analysis covers those paths most likely to be affected by the 250 MW flow; all other ATCs remain the same as in my Base Case. The analysis focused solely on the impact of redispatching 250 MW from AEP for delivery to CSW as compared to a pre-merger situation.

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which is generally identified in various NERC transmission assessment reports. I used the most recent reports available for this analysis. For those instances where a common facility limits imports over multiple paths, I assumed that the maximum import capability was no greater than the maximum of the individual path limits. A summary of the simultaneous limits is shown in Exhibit No. AC-516. Thus, for example, the availability of 250 MW on an AEP to CSW contract path does not mean that the lines compressing that path can accept an additional 250 MW. Rather, it means that an additional 250 MW injection in AEP and off-take for CSW can be accommodated on the various transmission lines and transformers affected by the change in power flows.

81. Q. Please describe the results of your sensitivity analysis that takes into account the impact of loop flow on transmission capability.

A. Even taking into consideration changes in the transmission network reflecting loop flow effects of the 250 MW AEP to CSW transfer, the merger (with mitigation) has no impact on the concentration in most of the markets I examined. There are some exceptions but, on the whole, the merger (post-mitigation) has a deconcentrating effect on market structure.

With respect to Economic Capacity, the HHI screen is easily passed in all the CSW-SPP and CSW-ERCOT destination markets (i.e., CSW-SPP, CBEN, WTU and Valley) and, in virtually all instances, the market is deconcentrated.

For the other Texas markets, the HHI screen is passed in all markets.

There are screen failures for several of the non-CSW markets in the Eastern Interconnection. Setting aside the few random cases that barely exceed our HHI change of 50, these are located primarily in Oklahoma and Missouri. GRRD and KACY fail in summer periods; SPRM and WEFA fail in summer and winter, and OKGE and SWPS fail in all three seasons.[42]

In no case is the failure due to Applicants either having or acquiring market power. Rather, the increase in HHIs is entirely due to the effects of the power contract on the size of the markets. For those markets for which inbound transmission is reduced by the contract, the main result is that the market share of the local utility (most of whose generation is inside the control area) increases. Since the local utility has the largest market share, the HHI is increased even when the reduction in inbound transmission is modest.

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[42] MPS fails in the super peak for the same reason as in all other cases.

82. Q. **Can you demonstrate that the increase is HHIs is not due to the Applicants' market power?**

A. Yes. For GRRD in the summer peak seasons, Applicants combined pre-merger share is less than 0.5 percent pre-merger and zero post-merger (and post-integration); Applicants' post-merger share in summer off-peak is only 3 percent. For KACY, Applicants' share is less than one percent pre- and post- merger. For OKGE, AEP's pre-merger share is less than one percent. CSW has shares ranging from zero to 21 percent. However, the Applicants' post-merger, post-integration share is less than CSW's pre-merger share in all time periods. For SPRM, Applicants' share is below one percent in all but one time period; in that period, their share falls from 2.0 to 1.2 percent. For SWPS, AEP has a share of about zero pre-merger and CSW's shares range up to 3.4 percent. Post-merger their combined share falls to a maximum of 1.8 percent. In the time periods when the WEFA market screen is failed, Applicants' combined pre-merger share is at most 7 percent; it declines as a result of the merger and associated divestiture.

83. Q. **Is it appropriate to require that the Applicants mitigate these increases in market concentration?**

A. No. Clearly the increases in market concentration in these destination markets is not due to combining Applicants' generation assets. Rather, it is due to CSW arranging transmission to bring power in from somewhere beyond Ameren. FERC does not require that users of open access transmission mitigate the effects of their use on the competitive alternatives facing other utilities that did not elect to use the transmission system.

Moreover and as a practical matter, it is not clear how a utility whose lawful use of open access transmission affects the market structure in third party markets could mitigate this consequence. At least in the case of this merger, asset divestiture cannot "mitigate" these consequences, since Applicants already have very small market shares.

The Available Economic Capacity results can be similarly characterized. In the CSW-SPP market, there is one time period in which the HHI screen is marginally exceeded (change in HHI of 108 in a moderately concentrated, 1208 HHI, market). In no other case does the market failure result from the combination of the two companies, as distinct from the effects of the CSW reservation of the transmission path. Since, for the reasons described earlier in my testimony, CSW's TDUs have more competitive alternatives than they can make use of, the only buyer potentially "harmed" by this small increase in concentration is CSW. While this might be a concern in the context of retail access, retail access by definition eliminates the relevance of my Available Economic Capacity analyses.

The summary results are included in Exhibit No. AC-517.

84. Q. What do you conclude from these results?

A. The CSW reservation of a 250 MW transmission path, which I treat as merger-related, does have some adverse market structure impacts in Oklahoma and Missouri. They are not, however, a result of a merger-related creation or enhancement of Applicants' market power. Rather, they demonstrate that the use of transmission by any party can affect the competitive options facing a number buyers in adjacent market participants, positively or negatively. However, if the consequences of transmission use are adverse, the answer cannot be to ban it, whether associated with a merger or otherwise.

VIII. THE IMPACT OF THE MERGER ON RETAIL COMPETITION IN MISSOURI

85. Q. What issues must be addressed concerning the impact of the merger on retail competition in Missouri?

A. Since this issue is included at the request of the Missouri Public Service Commission ("MPSC"), I presume that the issues to be addressed are those retail competition-related issues that are contained in the Protest filed by the MPSC. In relevant part, that Protest asserts: "[T]he merged company might enter retail markets should the State determine that retail competition is appropriate. Moreover, as noted in the previous section, the merged company intends to use limited Ameren transmission capacity that otherwise could be used by other market participants."[43]

86. Q. Have you considered the assertion that the merged firm might enter competitive retail markets in Missouri should such markets come into existence?

A. Yes. As the Protest concedes, there is no retail competition in Missouri and Applicants have no retail customers in the state. Hence, the only possible competitive harm is the loss of one potential entrant into the retailing of electricity, assuming that each would have entered separately but for the merger. Such entry is at best conjectural. There is no reason to assume that both would have chosen to enter the hypothetical Missouri competitive retail market.

More importantly, there is no reason to assume that the loss of one such potential competitor harms retail competition in Missouri. Neither Applicant is a

[43] *Notice of Intervention, Protest and Request for Hearing of the Missouri Public Service Commission*, p. 10. The Protest also contends that Applicants' reservation may exceed 250 MW, principally on the basis that the SEC might require additional interconnection between the merging parties. In keeping with Applicants' commitment to limit its reservation, I have assumed that the reservation is restricted to 250 MW.

substantial retailer in those markets that have been opened to retail competition. Neither has any particular advantage in serving the Missouri market. There are a large number of firms actively engaged in retailing electricity and the loss of one of the Applicants as a potential competitor will not diminish the competitiveness of the retail competition market.

87. Q. Does the fact that the Applicants are large generators and transmission providers make them more important potential entrants?

A. No. Retailing involves buying wholesale energy and transmission and marketing and reselling it, perhaps packaged with non-energy goods and services, to retail customers. Some retailers have chosen to integrate backward into owning generating facilities. However, these are Exempt Wholesale Generating (EWG) facilities, which sell to their affiliated power marketers. Affiliate dealing restrictions severely inhibit the use of generation that is owned by a conventionally regulated utility to support the activities of a competitive retailing activity. Transmission ownership is similarly ineffective in conferring competitive advantages on a competitive retail activity.

88. Q. The MPSC's second concern was that Applicants' use of transmission to integrate their systems would use transmission capability in Missouri that otherwise would be available to support retail competition in Missouri. How does this concern relate to the analysis of this merger?

A. The general area of concern expressed goes to the question of whether Applicants' use of transmission will reduce the competitiveness of the bulk power market in Missouri. The MPSC does not express a concern that Applicants will have market power in the Missouri bulk power market. Rather, their concern is that Applicants' use of transmission will concentrate such markets, with the possible effect that a more dominant generator, presumably a generator serving presently regulated retail customers in Missouri, may be able to exercise market power.

As I described in the summary of my testimony, the main effect of the merger is the impact of the Applicants' reservation of the 250 MW path. This is particularly true for Missouri, the area of concern to the MPSC. From a Missouri perspective, it matters little that the transmission reservation through Ameren is a result of this merger. The "harm" to wholesale competition in Missouri would be the same if, for example, Oklahoma Gas and Electric had contracted for 250 MW of firm transmission through Ameren in order to buy electricity from Illinois Power. While Missouri's desire to hold open the maximum amount of transmission capability to support a possible future retail access market is understandable, this does not mean that any transaction that uses such transmission capability should be halted. The real issue, when and if Missouri moves to retail access, is that incumbent generators in Missouri have quite high market shares.[44]

This being said, I have analyzed the effect of the merger on the structure of the wholesale power market in Missouri.

89. Q. **Is the framework required to develop an analysis of bulk power markets in a retail access context different than that required for a wholesale market power analysis?**

A. No. The methodology used to evaluate wholesale market power is the same as is required to analyze the effects of the merger on the bulk power market that would underpin a competitive retail market in Missouri.

The market power tests adopted by Commission in Order No. 592 in December 1996, and that dictated the nature of my analysis, were expressly designed to be

[44] In Missouri destination markets, the MPSC and/or the Missouri legislature will have the opportunity to address this issue directly at the appropriate time.

forward looking and to take into account the ongoing restructuring of the electricity industry. The Commission directed merger applicants to perform analyses of a merger's competitive effects under two quite different environments concerning the degree to which retail power markets are deregulated. The Economic Capacity analysis is precisely the right analysis to use under the assumption of 100 percent retail access. In the Economic Capacity analysis, we assume that all capacity is available to serve loads in the destination markets; none is reserved to meet native load.

90. Q. At what stage is retail competition in Missouri?

A. I am not an expert on the status of retail competition in Missouri. To the best of my knowledge, while the legislature has held hearings on a task force report of the Public Service Commission and a restructuring proposal submitted by the PSC staff, no action has been taken.[45]

On this basis, it seems likely that Missouri will not be among the earliest states in the central United States to open up its markets to competition. Hence, it is reasonable to assume for purposes of analysis that by the time that there is full retail access in Missouri, there also will be substantial retail access in many of the surrounding states in which Applicants' and other competitors' generation is located.

91. Q. Please describe your analysis of the effects of the merger on competition in bulk power markets in Missouri in the context of retail access.

A. I have considered the impact of the merger, and specifically the 250 MW East to West transmission reservation, on the Missouri retail market in terms of its impact

[45] Indeed, one press report indicated that electricity restructuring will not be a priority in the 1999 session and that prospects are uncertain for electricity restructuring bills that are introduced. *Retail Wheeling & Restructuring Report*, Edison Electric Institute, 3rd Quarter 1998.

on import capability into Missouri, the shares of Applicants in that market and, more generally, the effects of the merger on the competitive structure of the bulk power market available to retail access providers in Missouri. For the reason discussed immediately above, I have focused on an analysis of Economic Capacity. Consistent with the rest of my analysis, I focus first on the Base Case, including Applicants' proposed mitigation. Because the MPSC concerns are due to transmission, and include concerns about load flow effects, I also have used the information provided by the Applicants on the load flow effects of the merger in my analysis to examine the Missouri situation. As I discussed earlier in my testimony, I used the load flow study conducted by Applicants' transmission engineers to estimate changes in FCITCs arising from use of the 250 MW firm transmission reservation and applied this change to the Base Case transmission values based on the OASIS ATCs. Finally, results for Missouri control areas for my sensitivity studies can be seen in the relevant exhibits and workpapers.

A. I analyzed as destination markets the following control areas in Missouri: AECI; Ameren, SPRM; EDE; Independence Power & Light ("CIMO"); KCPL; MPS; and STJO.

92. Q. What are the results of your study?

A. In the Base Case (with mitigation), all of the Missouri destination markets readily pass the HHI screen for Economic Capacity, with the lone exception of the usual one time period in the MPS market which, as I described earlier, relates to termination of a 50 MW contract between Utilicorp and CSW. The merger generally deconcentrates the relevant destination markets.

93. Q. How does the load flow analysis affect the Missouri markets?

A. The analyses, which are described in Mr. Maliszewski's testimony, indicate that use of the 250 MW reservation between AEP and CSW results in a relatively small reduction in transfer capability (less than 10 percent) on most of the

Missouri markets in most time periods. The exceptions are in the summer into Ameren and out of KCPL.

94. Q. **What did your analysis of the load flows indicate about the effects of the 250 MW reservation on bulk power competition in the context of retail access in Missouri?**

A. In some of these markets, there is an adverse effect on market concentration from the transmission reservation (even with mitigation). As described earlier, this arises from the reductions in the size of some transmission paths. In turn, these reduce the size of some markets, causing corresponding increases in the market shares of the incumbent local utility and, hence, HHI changes that exceed the screen.

This occurs for one time period in the Ameren market (delta HHI of 59, with Applicants' combined share of less than 3 percent); EDE market (delta HHI of 90, and HHI at 1803); MPS (Applicants' combined share of 0.8 percent); and six time periods for SPRM (Applicants' combined share of 1.2 percent or less).

These results are summarized in Exhibit No. AC-517.

95. Q. **What do you conclude based on this analysis?**

A. I conclude that these instances of screen failure in Missouri should not affect the Commission's disposition of this merger application. The pre-mitigation failures do not result from combining the Applicants' market share in these markets, but rather from transmission reservations of the types that are permitted, indeed encouraged, by this Commission's policies. It is neither practical nor sound regulatory policy to require that inter-regional transmission capacity that can be used for efficient transactions remain uncommitted so that Missouri can effect a transition to retail access without addressing the high "home market" shares of some of its utilities. To the extent that a problem exists at such time as it moves to retail access, the State of Missouri can address the fundamental cause of it – high market share for incumbents – as part of the transition process, as other states have.

IX. THE IMPACT OF THE MERGER ON COMPETITION -- VERTICAL MARKET POWER ANALYSIS

96. Q. **Are there any other issues that would affect competition in the relevant markets?**

A. As noted earlier, I have not formally analyzed competition in long-term markets which FERC has found to be presumptively competitive (although I discuss entry in this section as well). The possible exceptions to this presumption arise from vertical market power issues -- control over transmission, sites or fuels supplies, that might block entry in the long term.

97. Q. **What is the issue concerning an applicant's control over essential fuels or delivery systems?**

A. In the context of long term capacity markets, the issue is whether applicants can foreclose or impede the entry of competing generators.

98. Q. **Do these Applicants have the ability to frustrate entry due to their control over fuels or fuel delivery systems?**

A. No. Applicants' only potentially relevant activities arise from the purchase of the LIG pipeline. As discussed more fully below, Applicants lack a concerning degree of control over fuels supplies. Neither controls gas production facilities. An entrant into generation in the regions in which they are located would have no difficulty in purchasing commodity gas from a multiplicity of sellers. Applicants do not control long distance gas transmission facilities that arguably might be used to disadvantage entrants. Applicants cannot use their role as owner of the LIG intrastate pipeline to impede entry.

Further, as discussed below in the context of existing generating facilities, direct connection to an alternative transmission pipeline is feasible and relatively inexpensive. Hence, even if Applicants were to somehow deny service from the LIG pipeline to entrants on a reasonable basis, the entrants likely could bypass Applicants, taking service from another gas supplier directly.

99. Q. Are there any other vertical market power issues of concern in this merger?

A. No. This merger should raise no other vertical market power concerns. As I noted previously, AEP and CSW are not transmission competitors, so there are no horizontal transmission market power issues. As shown by the historic data on transactions, AEP pre-merger did not sell into or through CSW, nor did CSW sell into or through AEP. Hence, neither is in a position to favor the other by preferential treatment in allocating or scheduling its transmission system. Further, Commission Orders No. 888 and 889 ensure that transmission owners such as Applicants will not be able to foreclose access to any essential transmission facilities, including connecting new merchant plants to their grids.

The Commission's Order, as noted earlier, expressed concern that the merged firm might somehow use transmission to frustrate competitors' access to relevant markets. Their concern was specifically expressed in the context of how the merger could change flows on adjacent systems. This concern has been addressed in my discussion of the loop flow sensitivity and in Mr. Maliszewski's testimony on load flow impacts of the merger. Additionally, the testimony of Dr. Henderson addresses other vertical market power concerns with respect to Applicants' use of transmission facilities.

LIG ACQUISITION

100. Q. Please describe the LIG transaction.

A. AEP Resources, Inc, a subsidiary of AEP, is purchasing the Gulf Coast, natural gas midstream operations of Equitable Resources, Inc ("Midstream Operations"). The principal assets that AEP will acquire include the LIG Pipeline, four related natural gas processing plants, a salt dome storage facility, and an energy trading and marketing business.

The LIG Pipeline consists of about 2,000 miles of pipeline with roughly 750 receipt and delivery points and over 100 connections with 12 interstate and 24 intrastate pipeline systems. It has a throughput of 600 MMcf per day, of which about 330 MMcf per day are transportation volumes. Nearly 80 percent of the company's major end-user customers are Mississippi River industrial firms, such as Borden and Dow Chemical. The pipeline is connected to one investor-owned utility (Central Louisiana Electric Company, "CELE"), a number of municipalities (Cities of Alexandria, Lafayette, Natchitoches, Morgan and Terrebonne Parish) and one state system (Louisiana Energy & Power Authority).[46] Notably, less than 10 percent of the pipeline's delivery volumes are for electric generators.

The Processing Plants have a total natural gas processing capacity of roughly 460 MMcf per day. They are located near St. Landry, Plaquemine, Franklin and Gibson, Louisiana. The Jefferson Island salt-dome storage facility is directly connected to the Henry Hub complex. It has approximately 5.0 Bcf of total

[46] The generating units served by LIG include CELE's Rodemacher (440 MW), Teche (407 MW) and Coughlin (334 MW) plants; the City of Alexandria's DG Hunter Units 1-4 (157 MW); and the City of Natchitoches's Natchitoches Unit (54 MW); City of Morgan's Morgan City plant (62 MW); Terrebonne Parish's Houma plant (62 MW); and LEPA's Plaquemine plant (41 MW). In addition, several cogen plants are supplied by LIG. See workpapers.

storage capacity (3.5 Bcf of working capacity) and 180 MMcf per day of injection capacity and 360 MMcf per day of withdrawal capacity.

Midstream Operation's Supply and Trading Group is located in Houston, Texas and Calgary, Canada. The group participates in wholesale trading and marketing of both natural gas and electricity. The trading group currently trades approximately 1.7 Bcf of natural gas and 23,300 MWh of electricity per day.

101. Q. What issues have arisen in the context of convergence mergers involving gas pipelines and electricity generators?

A. The Commission has indicated that under some circumstances a merger involving an electricity generator and a supplier of generating fuels could give rise to vertical concerns. Potential market power arising from gas operations is discussed by the Commission in its final order on the Enova/Pacific Enterprises merger in 1997,[47] and the recent FERC Notice of Proposed Rulemaking (NOPR) on mergers.[48]

Briefly, the main areas of concern are the creation of incentives for the upstream activities (i.e., gas-related) to raise rivals costs,[49] facilitate coordination of pricing

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47 Order in Docket No. EC-97-12-001 *et al.* (Enova-Pacific Enterprises).

48 Notice of Proposed Rulemaking on Revised Filing Requirements Under Part 33 of the Federal Power Act, Docket No. RM98-4-000.

49 Foreclosure (or raising rivals' costs) refers to the situation in which a vertically integrated firm withholds inputs that are produced by the upstream portion of the firm from rivals in the downstream market. The goal of this strategy is to increase the production costs of the downstream rivals and create a market advantage for the downstream portion of the firm.

Provided that competitors in the downstream market have adequate alternative sources of the input in question, foreclosure will not have anti-competitive effects. However, if the loss of the upstream supplier permits firms in the upstream input market to exercise market power, either unilaterally or in a coordinated manner, the costs of the firm's rivals in the downstream market could be increased. Such an attempt to raise rivals' costs can only be successful if the upstream market is susceptible to market power.

in upstream or downstream markets[50] or evade regulation,[51] primarily through self dealing. As discussed below, none of these concerns is relevant here.

In order for a vertical market power strategy to be successful, a number of structural conditions are necessary: (1) gas transportation alternatives must be absent or limited; (2) enough generating capacity must be affected so that market prices are impacted; (3) existing regulatory constraints must not be effective; and (4) both the upstream and downstream markets must be conducive to the exercise of market power. Given these conditions, a final consideration is whether or not the strategy would be profitable (i.e., whether the gain on electricity profits outweighs the lost profits on natural gas sales and transportation).

102. Q. Please summarize your conclusions with respect to the potential competitive impact of the LIG acquisition.

A. I conclude that the combination of the Midstream Operations and Applicants will not create or enhance the combined companies' ability to exercise market power. The principal bases for this conclusion are:

The electric generating capacity supplied by the LIG Pipeline has sufficient alternatives to defeat any attempt to manipulate gas deliveries or their costs. Nearly all of the capacity is directly connected to another natural gas

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50 Facilitating coordination concerns arise if the combination either positively affects the ability of competing firms to agree to raise prices (or restrict output) or decreases the incentive for firms to compete aggressively on price or service. As with foreclosure, whether this is an issue depends upon the competitive conditions in the relevant upstream and downstream markets.

51 Regulatory evasion concerns may be relevant if one of the consolidating firms is partially regulated and partially market oriented. In such a case, the combined firm may be able to transfer costs to a regulated affiliate, thereby creating a competitive advantage for its non-regulated entity while imposing higher costs on the regulated sector. An additional concern is whether the new vertical relationship would impede regulatory review of the sale or transfer of intermediary goods (i.e., goods and services that are a final product in the upstream market, but are inputs to the downstream market).

transportation system and that which is not has nearby alternatives.[52] There is an abundance of natural gas transporters and natural gas providers in Louisiana.

The small amount of generation capacity that is not directly connected to another transportation system (two stations comprising nine small units totaling about 210 MW) has high variable costs and thus is generally not economic and operates at very low capacity factors. Thus, any attempt by the LIG Pipeline to affect the price of electricity could have no material effect and, at worst, could not have a sustainable impact.

The combination of the generating facilities served solely by the LIG Pipeline and those of Applicants does not exceed the HHI thresholds in any relevant destination market by an amount sufficient to create a perception of adverse competitive effects.[53] In time periods when the capacity served by LIG is economic, AEP has only trivial amounts of economic capacity in the relevant downstream electric markets with the units served by the LIG Pipeline and cannot benefit from higher wholesale electricity prices. CSW has a less trivial share of these markets in relevant time periods, but the combination of these assets has a very small effect on concentration.

103. Q. What analysis did you conduct with respect to the potential competitive impact of the LIG acquisition?

A. The relevant market power concern in this case stems from the vertical combination of the electric generating facilities owned by Applicants and the natural gas transportation system of the Midstream Operations. Specifically, the

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52 Indeed, one of the two stations not currently committed to another pipeline is within two miles of an alternative pipeline.

53 As I discuss below, this analysis assumes that Applicants' ownership of a pipeline that serves electricity generators somehow gives them control over those generators in a manner similar to direct ownership of them. I do not agree with this assumption, but I have conformed with the analysis that I understand is the intent of the Commission's NOPR.

issue is whether Applicants would be able to use their control of the LIG Pipeline in a manner that would adversely impact competitive conditions in the downstream electric generation market where either Applicant competes.

To the extent there is a relevant concern, it is whether the LIG Pipeline can withhold or impair service to generating facilities in a manner that increases prices received by its own generation. The relevant geographic area to consider is the overlap, if any, between the markets where AEP and CSW operate and the markets where the generators served by the LIG Pipeline operate.

The Commission has proposed an explicit methodology to analyze competitive conditions in the downstream electricity market, based on the delivered price test used to calculate market concentration statistics in the Commission's horizontal market power analysis. The analysis makes the very strong assumption that generating capacity served by the upstream supplier is controlled by the supplier (if an Applicant) rather than the actual owner of the generating plant.

104. Q. What are the relevant markets?

A. In the upstream natural gas market, the relevant product market is natural gas transportation, which consists of delivering gas supplies from gas-producing regions and remote storage facilities into the market area. While the product market could potentially be defined by type of transportation service, there is no reason to do so in this instance because both firm and non-firm transportation is available on the LIG Pipeline and competing pipelines and all of the services are generally discounted.

The geographic market for natural gas transportation services can be defined fairly broadly to include, a minimum, most of the state of Louisiana because the LIG Pipeline provides transportation service throughout many areas in Louisiana and competes directly with pipelines throughout the state. Since one theoretical concern is the extent to which the LIG Pipeline dominates competition in the relevant natural gas transportation market, this market definition is relevant for discussing overall competitive conditions in the market and whether the LIG Pipeline might be able to hinder new entry by electric generators. On the other hand, from the perspective of the individual consumer (i.e., a generator), the geographic market consists only of the region in which the individual consumer can seek alternative supplies. This narrower perspective requires a direct examination of the supply alternatives available to each individual customer.

The relevant downstream product market is bulk (or wholesale) electric energy, specifically non-firm capacity (energy) and short-term capacity. The relevant geographic market consists of the area in which those generators served by the LIG Pipeline compete. As with the horizontal market power analysis described in the preceding sections, I performed a delivered price test in the relevant destination markets, as discussed below.

105. Q. Did you evaluate the upstream natural gas transportation markets?

A. Not to any great extent, because it is generally accepted that transportation markets in the Gulf are competitive. There are more than two dozen interstate and intrastate pipelines in the state and "Pipeline Alley" runs through a portion of the state where generating units served by the LIG Pipeline are located. By any definition, LIG has a very small share of the market. There are other factors that make this market competitive: connection costs are low; units are physically located on top of natural gas reserves; major pipelines who are picking up supplies and heading North could deliver into the areas through which they pass; and Henry Hub and other types of supply arrangements are present.

The majority of the capacity served by the LIG Pipeline takes deliveries under interruptible transportation service. The competitiveness of that service is illustrated by the fact that essentially all of the service provided by LIG Pipeline is discounted;[54,55] both of these factors imply that transportation is not scarce in the region. All of the major generating facilities served by LIG have competing pipeline alternatives; the CELE facilities that generate most of the electricity produced in LIG-served units actually take the majority of gas from competing pipelines.

106. Q. Did you consider supply alternatives for the affected customers of the LIG Pipeline?

A. Yes, consistent with the Commission's guidance in the context of the ability of the merged firm to raise rivals' costs, I considered supply alternatives with respect to both existing generating facilities and new pipeline entry.

Exhibit No. AC-518 summarizes supply alternatives for the electric generating facilities currently served by the LIG Pipeline, along with some other relevant plant statistics.

As noted earlier, the LIG Pipeline directly serves a total of 1,800 MW of electric generation of CELE, LEPA and several municipal utilities. Collectively, the electric generating plants served by the LIG Pipeline are connected with eight other pipelines (Columbia Gulf Transmission, Trunkline Gas Company, ANR Pipeline Company, Texas Gas Transmission, Koch Gateway Pipeline, Arcadian Gas Pipeline, Texas Eastern and Louisiana Resources Company) and two others are nearby (Union Gas and TCP). All but two of the plants (City of Alexandria's Hunter and City of Natchitoches's Natchitoches) are connected to at least one other pipeline. My understanding is that even these two plants have relatively nearby alternatives and, further, these plants operate at very low capacity factors (2 percent for Hunter and, although there are no data for Natchitoches, it is

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54 CELE recently changed its service from firm to interruptible. I also understand that there are two generating units that receive firm deliveries under the Lafayette Utilities System contract.

55 See workpapers.

believed to be near zero for the last several years), so that even a strategy that successfully forces this capacity from the market would likely have a *de minimis* effect on market prices.

107. Q. **Could LIG control or impede gas supply alternatives for future generating facilities?**

A. No. There is no opportunity for LIG to exercise vertical market power that would foreclose gas transportation to potential entrants even in a tightly defined area. Even if the relevant geographic market is defined very narrowly, the LIG Pipeline does not dominate gas transportation. Under such circumstances, foreclosure by withholding of gas transportation service seems highly unlikely.

Additionally, new entrants can choose locations to build new power plants that are served by any gas pipeline in the region and potentially sell power anywhere in the region if electricity transmission service is available at reasonable terms and rates. The Commission's open access Order No. 888 reasonably assures that electricity connection and transmission access will not unduly limit the siting decisions of entrant gas-fired generating. Any attempt to foreclose gas transportation service to a new entrant could be defeated by its choosing a location with alternative gas supply arrangements.

108. Q. **Did you evaluate the effect of the LIG acquisition in the downstream market for electricity using the method proposed by the Commission?**

A. Yes, my analysis uses the assumption proposed in the merger NOPR that Applicants, in effect, controlled the generating capacity served by the LIG Pipeline. Starting with the Base Case results of my horizontal market power analyses described earlier, I re-ran the analysis assuming that AEP controlled a share of the natural gas fired units served solely by the LIG Pipeline. I evaluated the destination markets most likely to be affected by the addition of the LIG-served generation to that controlled by Applicants: CELE, City of Lafayette, CSW-SPP, and Entergy. These markets should be representative of the impact of the LIG acquisition on existing customers of LIG and on nearby markets.

Notably, the dispatch costs of the generating units served by the LIG Pipeline are high with the result that energy from the units is economic only in high-price periods, a fact corroborated by the low capacity factor of these units.[56] The results are shown in Exhibit No. AC-519, and summarized below.

The HHI screen is fully passed in all markets and time periods except for two high-price periods for the CELE market. In these two periods, when the Hunter (both cases) and Natchitoches (one case) units are economic. In these two periods the HHI deltas are on the Merger Guidelines' gray area, at 69 and 71, respectively.

109. Q. Do you think that an analysis that treats the electric generation facilities served by LIG as if they were owned by AEP accurately assesses the competitive impact of this merger?

A. No. Conducting the analysis that way provides, at least in this case, results that are much too conservative, and indeed unrealistic. AEP does not own the generating plants at issue here. They are owned by independent utilities, who are served by LIG—an interstate natural gas company that is governed by the Commission's open access requirements. Communications between LIG and its affiliates are governed by the Commission's codes of conduct. Therefore, under any circumstances, the risk that LIG and its electric affiliates can coordinate their actions to raise prices in electric markets is very small.

Here, the two plants in issue operate only a small fraction of the hours in any year. The merged company's share (counting the LIG-served generation as AEP's) of the two markets in which the calculated HHI changes slightly exceed the

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[56] All other generating units are connected to alternative pipeline suppliers and are assumed to be controlled by their owners

threshold levels is below 20 percent, the safe harbor adopted by the Commission for market-based pricing authorization. The risk that AEP's control of LIG will translate into the exercise of market power in electricity markets as a result of this merger is virtually nil.

110. Q. Will the LIG acquisition help facilitate anticompetitive coordination?

A. No. I find no evidence that the acquisition will have an increased ability to facilitate collusive or parallel pricing behavior because of the vertical relationship of the LIG Pipeline and Applicants. The upstream wellhead gas market, in which LIG participates only as a small buyer, has been found workably competitive by the Commission and my analysis shows that the LIG Pipeline cannot exercise vertical market power from its control of gas transportation assets into the downstream electric generation market. Thus, it cannot, for example, facilitate coordination by rationing gas transportation availability or access to low cost gas supplies. Nor does it provide transportation services to sufficient economic capacity to meaningfully facilitate "coordination" with Applicants' electric generating facilities, even absent code of conduct restrictions. Accordingly, there is no vertical combination of upstream wellhead gas or pipeline market activity with downstream electricity market activity associated with the combination that facilitates coordinated pricing behavior.

ENTRY

111. Q. Do Applicants exercise control over the available generation sites?

A. No. I have discussed this with Applicants. AEP informs me that in recent years they have sold a number of sites that they previously had acquired for future generation facilities. CSW pointed to the substantial number of generating facilities being built by entrants in SPP and ERCOT as evidence that there are no special barriers to entry.

More generally, the geographic area that must be included in any market that must be included in any market that contains both Applicants includes many control areas. Entrants who could compete in areas potentially affected by this merger would not need to locate new facilities in Applicants' service areas or connect to Applicants' transmission systems.

112. Q. **Earlier, you stated that the Commission has found long-term markets to be presumptively competitive. Please elaborate.**

A. In Order No. 888, the Commission in referring to a decision in *Entergy Services, Inc.*, noted that "after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets."[57] In the Merger NOPR, the Commission stated that "[a]s restructuring in the wholesale and retail electricity markets progresses, short-term markets appear to be growing in importance. The role of long-term capacity markets appears to be diminishing."[58]

113. Q. **Is there any evidence that there will be entry into the SPP and ERCOT markets within the next few years?**

A. Yes. First, entry <u>can</u> be accomplished in far shorter periods of time than were required with the large coal and nuclear generation facilities that used to be the chosen technology. According to the Department of Energy, conventional and advanced combined cycle generating units have a lead time of three years, and combustion turbines (i.e., peaking capacity) have a lead time of only two years.[59]

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57 Order No. 888 at 31,649 n.86 (citation omitted).

58 Merger NOPR, *op. cit.*, at 20.

59 Assumptions to the Annual Energy Outlook 1998, Energy Information Administration, U.S. Department of Energy, December 1997, p. 67.

Recent experience substantiates the reasonableness of EIA's determination. In the summer of 1998, Calpine Energy brought its Pasadena 1 unit on line, a 240 MW combined cycle unit. Plans for this unit were first announced in 1996, construction began in 1997 and the plant was on-line by 1998. In 1996, Tenaska completed its Tenaska IV Texas Partners plant, a 258 MW combined cycle unit, for which a power sale agreement was first announced in 1993.

As another example, in June 1998, PSO received responses to a request for proposals for procurement of up to 280 MW of capacity and energy to serve PSO native load. The 27 bids received, in the aggregate, offered approximately 1,800 MW of capacity and ranged in size from 1 MW of distributed generation to 500 MW from greenfield combined cycle units to be located within or adjacent to the service areas of PSO and SWEPCO. The bidders propose to make the new capacity available as early as June 1, 2001, and no later than June 1, 2002.[60]

Notably, exempt wholesale generators building merchant plants are not required to obtain certificates of convenience and necessity in Oklahoma, Texas or Louisiana. In addition, as the deregulation process unfolds over the next few years, permits should be easier to obtain as regulators will no longer have to determine the need for new generation from the perspective of captive ratepayers

Second, there is substantial evidence that additional entry <u>will</u> occur. Merchant activity is particularly strong in Texas, where more than 8,000 MW of new capacity is planned to come on line between 1999 and 2002. The fact that much of this planned capacity is not yet in the construction phase demonstrates that the near term prospect of opening up competition in generation, a recent phenomenon, is a major spur to the development of new merchant capacity. Projects actually under active construction exceed 1,000 MW. In SPP, there is 330 MW of capacity under construction, another 200 MW for which construction

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[60] *Electric Utility Week*, July 6, 1998, at 13.

is supposed to commence in January 1999,[61] and 825 MW located just south of PSO's service territory that is in the planning stage.[62] Particularly noteworthy is an 800 MW merchant plant in Grimes County, Texas that will be capable of selling into both ERCOT and the Eastern Interconnection.[63] (See Exhibit No. AC-520.)

114. Q. **In reaching your conclusion that this merger poses no harm to competition, are you relying on entry to mitigate potential harmful competitive effects?**

A. No. As I discussed previously, the principal potential competitive harm is mitigated by Applicants' divestiture and other undertakings. However, it is relevant that the entry of merchant plants will deconcentrate markets increasingly as the utility industry is restructured. Moreover, it also is instructive that entry can be massive and quick in response to high prices. The leading example is New England, where the amount of new entry announced in the past two years exceeds the total load in the region. As the DOJ recognizes, the threat of entry, even when entry can take more than the two years suggested in the *Merger Guidelines* (as supplemented by committed entry taking a longer time),[64] can constrain the exercise of market power.

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[61] Application for Determination of Exempt Wholesale Generator Status, Koch Power Louisiana, L.L.C., Docket No. EG99-XX, November 18, 1998.

[62] *Tulsa World*, December 22, 1998.

[63] *Power Generation Markets Quarterly*, McGraw-Hill Companies, Third Quarter 1998, p. 153.

[64] "In order to deter or counteract the competitive effects of concern, entrants quickly must achieve a significant impact on price in the relevant market. The Agency generally will consider timely only those committed entry alternatives that can be achieved within two years from initial planning to significant market impact..." (Footnote: "Firms which have committed to entering the market prior to the merger generally will be included in the measurement of the market. Only committed entry or adjustments to pre-existing entry plans that are induced by the merger will be considered as possibly deterring or counteracting the competitive effects of concern.") In my analysis, I have not included any post-1999 entry in my analysis, despite this invitation to do so.

LACK OF CONTROL OVER FUEL SUPPLIES

115. Q. Do AEP or CSW own fuel supplies that are essential to market entrants?

A. No. AEP owns coal mines and reserves and CSW owns lignite mines. However, neither is capable of supplying all of its own needs, much less withholding essential supplies from others. Each of them also must obtain coal supply from non-captive sources: AEP uses Appalachian coal and Powder River Basin ("PRB") coal; CSW purchases PRB coal and coal from Utah.

With respect to captive coal supply, as I noted earlier, AEP obtained only 13 percent of its 1996 coal requirements from its coal mining subsidiaries. AEP's estimated coal requirements for the remainder of the useful lives of its coal generating plants total almost 2 billion tons. In contrast, AEP's coal-mining subsidiaries own or control about 205 million tons of clean recoverable coal in Ohio and about 105 million tons of clean recoverable coal in West Virginia which can be mined without substantial additional development. An additional 113 million tons of recoverable coal in Ohio would require substantial development.[65] About 2 million of the approximately 10 million tons of coal from its own mines in 1997 was sold to third parties. I understand that AEP may shut down its three mines in 1999, 2000 and 2001, respectively. CSW's two lignite coal mines are dedicated to the supply of the Pirkey and Dolet Hills plants.

In any case, the control over coal supplies, even if far more substantial than Applicants possess, would not be very relevant. The fuel of choice for new entrants in their market areas, as elsewhere in the United States, is natural gas. Control over modest amounts of coal cannot meaningfully impede entry by new generation.

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[65] American Electric Power Company, Inc., Form 10-K for the fiscal year ended December 31, 1996.

116. Q. Do AEP or CSW own fuels delivery systems?

A. I already have discussed the LIG pipeline acquisition. Applicants' other fuels delivery capabilities are limited. AEP purchases western coal, transports it by rail to the Ohio River and loads the coal onto barges for delivery to generating stations. AEP's subsidiaries lease approximately 3500 coal hopper cars for train transport, 14 towboats, 295 jumbo barges and 184 standard barges.[66]

CSW's coal supplies are primarily from Wyoming and Colorado mines, and are generally transported by common carrier. PSO owns sufficient rail cars and spares for the operation of six unit trains to deliver coal for its Northeastern Station coal units. SWEPCO owns sufficient rail cars and spares for the operation of twelve unit trains to deliver coal for its Welsh and Flint Creek units.[67]

The merger has no market power implications with respect to control of rail cars or delivery systems. Based on published data, the market is unconcentrated, and the combination of AEP and CSW is unlikely to have more than a small impact on market concentration.[68] AEP and CSW own or lease about 6200 coal hopper cars out of a U.S. fleet in excess of 45,000.[69] Further, there is no impediment that would limit entrants' ability to buy new cars from manufacturers. Also, as discussed in the context of their ownership of coal reserves, control over limited coal facilities cannot impede entry when the fuel of choice is natural gas.

117. Q. Does this complete your testimony?

A. Yes it does.

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66 Ibid.

67 Central and South West, Form 10-K for the fiscal year ended December 31, 1997.

68 *Progressive Railroading* reports fleet statistics for railcars. These data are from the April 1997 issue, which includes a listing of ownership of "private cars".

69 Ibid.

AFFIDAVIT

DISTRICT OF COLUMBIA §
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WILLIAM H. HIERONYMUS, being duly sworn, deposes and states: that he prepared the Direct Testimony and Exhibits of William H. Hieronymus and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of his knowledge and belief.

William H. Hieronymus

William H. Hieronymus

SUBSCRIBED AND SWORN TO BEFORE ME, this the 11th day of January, 1999.

Janet P. Cashion

Notary Public, District of Columbia

Printed Name: Janet P. Cashion

My Commission Expires: July 14, 2002

EXHIBITS

Exhibit No. AC-501	Resume of William H. Hieronymus
Exhibit No. AC-502	Customers of Applicants Wholesale
Exhibit No. AC-503	Description of CASm Model
Exhibit No. AC-504	Appendix: Data and Methodology
Exhibit No. AC-505	List of Utilities and Abbreviations
Exhibit No. AC-506	Lambda Data
Exhibit No. AC-507	Transmission Capacity (ATC data)
Exhibit No. AC-508	Load Data
Exhibit No. AC-509	Total Capacity
Exhibit No. AC-510	Uncommitted Capacity
Exhibit No. AC-511	Base Case (Pre-Mitigation)
Exhibit No. AC-512	Base Case (Post-Mitigation)
Exhibit No. AC-513	Sensitivity: AEP in MISO
Exhibit No. AC-514	Sensitivity: No Transmission Costs
Exhibit No. AC-515	Sensitivity: TTCs
Exhibit No. AC-516	Simultaneous Transfer Limits
Exhibit No. AC-517	Sensitivity: Loop Flow Impact
Exhibit No. AC-518	Electric Generating Facilities Served by LIG Pipeline
Exhibit No. AC-519	LIG Pipeline Analysis
Exhibit No. AC-520	Planned New Generating Capacity

WILLIAM H. HIERONYMUS **Managing Director**

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators and policy makers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy and regulatory issues. He has spent the last several years working on restructuring and privatization of utility systems internationally and on changing regulatory systems and management strategies in mature electricity systems. In his twenty-plus years of consulting to this sector he also has performed a number of more specific functional tasks including the selection of investments, determining procedures for contracting with independent power producers, assistance in contract negotiation, tariff formation, demand forecasting and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of utility clients before regulatory bodies, federal courts and legislative bodies in the United States and United Kingdom. Since joining Putnam, Hayes & Bartlett, Inc. (PHB) he has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Assignments

- Dr. Hieronymus served as an advisor to a western electric utility on restructuring and related regulatory issues and has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment he helped develop, and testified respecting, a settlement with the state regulatory commission staff that provides, among other things, for accelerated recovery of strandable assets. He also prepared numerous briefings for the senior management group on various topics related to restructuring.

- For several utilities seeking merger approval he has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The analyses he has sponsored cover the destination market-oriented traditional FERC tests, Justice Department-oriented market structure tests similar to the Order 592 required analyses, behavioral tests of the ability to raise prices and examination of vertical market power arising from ownership of transmission and generation and from ownership of distribution facilities in the context of retail access. The mergers on which he has testified include both electricity mergers and combination mergers involving electricity and gas companies.

- For utilities and power pools preparing structural reforms, he has assisted in examining various facets of proposed reforms. This analysis has included both features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For the New England Power Pool he examined the issue of market power in connection with its movement to market-based pricing for energy, capacity and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.

- As part of a large PHB team he assisted a midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to PHB's activities in the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

- He has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of the utilities' assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which the utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs and assisted companies in internal stranded cost and asset valuation studies.

- He has contributed to the development of benchmarking analyses for U.S. utilities. These have been used in work with PHB's clients to develop regulatory proposals, set cost reduction targets, restructure internal operations and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package that PHB has tailored to region-specific applications. He and other PHB personnel have provided numerous multi-day training sessions using the package to help our utility clients in educating management personnel in the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- Dr. Hieronymus has made numerous presentations to U.S. utility managements on the U.K. electricity system and has arranged meetings with senior executives and regulators in the U.K. for the senior managements of U.S. utilities.

- For a task force of utilities, regulators, legislators and other interested parties created by the Governor's office of a northeastern state he prepared background and briefing papers as part of a PHB assignment to assist in developing a consensus proposal for electricity industry restructuring.

WILLIAM H. HIERONYMUS
Managing Director

- For an East Coast electricity holding company, he prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand management programs.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico and before the Federal Energy Regulatory Commission in plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant cost for tariff setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that are currently under construction. His testimony has covered the likely cost of plant completion, forecasts of operating performance and extensive analyses of ratepayer and shareholder impacts of completion, deferral and cancellation.

- For utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning continuing the construction projects. Areas of inquiry included plant cost, financial feasibility, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers and evaluation of offers to purchase partially completed facilities.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major midwestern utility, he headed a team that assisted senior management in devising its strategic plans including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition and diversification opportunities.

- On behalf of two West Coast utilities, he testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

WILLIAM H. HIERONYMUS
Managing Director

- For a large western combination utility, Dr. Hieronymus participated in a major 18-month effort to provide it with an integrated planning and rate case management system. His specific responsibilities included assisting the client in design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts and forecasts of the impacts of conservation and load management programs.

- For two midwestern utilities, he prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee..

- For a major combination electric and gas utility, he directed the adaptation of a PHB-developed financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the White Paper setting out the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional electricity councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, he assisted several of the U.K. individual electricity companies in understanding the evolving system, in development of use of system tariffs, and in developing strategic plans and management and technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for an 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- He also has consulted on the separate reorganization and privatization of the Scottish electricity sector. PHB's role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation and company strategy.

- He has assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment have been policy issues such as incentives for economic purchasing of power, the scope of the price control, and the use of comparisons among companies as a basis for price regulation. His model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus has assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment includes advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development he performed analyses of least cost power options, evaluation of the return on a major plant investment that the Bank was considering and forecasts of electricity prices in support of assessment of a major investment in an electricity intensive industrial plant.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, he developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command and control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which is to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization will be based on regional electricity companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, he continued to advise the Russian energy and power ministry and government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company he analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electric generating and electricity distribution industries in New Zealand, he undertook an analysis of industry structure and regulatory alternatives for achieving economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.

- For EPRI, he directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, Dr. Hieronymus developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, he filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines on fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guideline on cost-of-service standards.
- For private utility clients, he assisted in the preparation of comments on draft Federal Energy Regulatory Commission (FERC) regulations and in preparing their compliance plans for PURPA Section l33.
- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For the DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, he assisted in preparation of briefing papers, lines of questioning and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES
FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force and formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, he developed a load forecasting model designed to interface with the utility's revenue forecasting system- planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For the DOE, he directed the development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and constructed a forecasting model for their interim use.

- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a midwestern electric utility, he has provided consulting assistance in improving its load forecast and has testified in defense of the revised forecasting models.

- For an East Coast gas utility, he testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These include both Sherman Act Section One and Two cases, contract negotiations, generic rate hearings, ITC hearings and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor he has testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, he is assisting clients in responding to the Antitrust Division of the U.S. Department of Justice's Hart-Scott-Rodino requests.

- For a private client, he headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For a industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, he developed an estimate of the potential market for the system by geographic area.

- For the U.S. Environmental Protection Agency (EPA), Dr. Hieronymus was the principal investigator in a series of studies for forecasting future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation and utility-related opportunities for investment bankers.

Before joining PHB, Dr. Hieronymus was program manager for Energy Market Analysis at Charles River Associates. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving in the U.S. Army. He is a present or past member of the American Economics Association and the International Association of Energy Economists, and a past member of the Task Force on Coal Supply of the New England Energy Policy Commission. He is the author of a number of reports in the field of energy economics and has been an invited speaker at numerous conferences.

Dr. Hieronymus received a B.A. from the University of Iowa and M.A. and Ph.D. degrees in economics from the University of Michigan.

Summary of Applicants' (Non-Firm) Sales, 1997
Total Charges ($)

	AEP	CSW	Total
Total Non-Firm Sales	567,065,101	47,780,368	614,845,469
Sales to Common Customers			
Ameren	818,442	6,020,128	6,838,570
Entergy	9,229,867	2,023,976	11,253,843
Sales to Common Customers, as a Percent of Total Non-Firm Sales			
Ameren	0.14%	12.60%	1.11%
Entergy	1.63%	4.24%	1.83%
Total Non-Firm Purchases			
Ameren			176,630,357
Entergy			1,063,428,865
Non-Firm Sales to Common Customers as a Percent of Customer's Total Non-Firm Purchases			
Ameren	0.46%	3.41%	3.87%
Entergy	0.87%	0.19%	1.06%

Summary of Applicants' (Non-Firm) Sales, 1997
MWH

	AEP	CSW	Total
Total Non-Firm Sales	28,986,730	1,625,694	30,612,424
Sales to Common Customers			
Ameren	25,992	159,786	185,778
Entergy	334,037	57,294	391,331
Sales to Common Customers, as a Percent of Total Non-Firm Sales			
Ameren	0.09%	9.83%	0.61%
Entergy	1.15%	3.52%	1.28%
Total Non-Firm Purchases			
Ameren			7,790,731
Entergy			24,926,235
Non-Firm Sales to Common Customers as a Percent of Customer's Total Non-Firm Purchases			
Ameren	0.33%	2.05%	2.38%
Entergy	1.34%	0.23%	1.57%

SOURCE: 1997 RDI Database and 1997 FERC Form 1.
NOTES: Excludes intra-company transactions.

Exhibit No. AC-502

Summary of Applicants' (Total) Sales, 1998 YTD

Total Charges ($)

	AEP	CSW	Total
Total Sales	5,485,395,969	36,097,681	5,521,493,650
Sales to Common Customers			
Ameren	2,657,221	2,449,168	5,106,389
Associated Electric Cooperative	102,389	685,283	787,672
Central Louisiana Electric Company	252,576	1,351,293	1,603,870
Entergy	14,419,291	1,537,192	15,956,483
Illinois Power	38,830,288	178,550	39,008,838
Missouri Public Service	262,938	438,875	701,813
Southern Company	4,494,647	243,312	4,737,959
Western Resources	13,426,827	2,602,549	16,029,376
Sales to Common Customers as a Percent of Total Sales			
Ameren	0.05%	6.78%	0.09%
Associated Electric Cooperative	0.00%	1.90%	0.01%
Central Louisiana Electric Company	0.00%	3.74%	0.03%
Entergy	0.26%	4.26%	0.29%
Illinois Power	0.71%	0.49%	0.71%
Missouri Public Service	0.00%	1.22%	0.01%
Southern Company	0.08%	0.67%	0.09%
Western Resources	0.24%	7.21%	0.29%

Summary of Applicants' (Total) Sales, 1998 YTD

MWH

	AEP	CSW	Total
Total Sales			
Ameren	61,875	49,025	110,900
Associated Electric Cooperative	3,272	15,852	19,124
Central Louisiana Electric Company	7,675	56,537	64,212
Entergy	598,080	27,808	625,888
Illinois Power	855,219	400	855,619
Missouri Public Service	7,024	6,825	13,849
Southern Company	91,960	5,242	97,202
Western Resources	406,777	44,756	451,533

[1] Data for Jan-Sept for AEP and Jan-Oct for CSW.

SOURCE: Company data.

COMPETITIVE ANALYSIS SCREENING MODEL (CASm)

Putnam Hayes & Bartlett developed the Competitive Analysis Screening model (CASm) with the specific purpose of performing analyses related to Appendix A of the FERC Merger Policy Statement, Order No. 592 ("Appendix A"). Appendix A requires the analysis of market concentration for a large number of markets under a number of different conditions.

The primary requirement of Appendix A is to assess potential suppliers to a market using a "delivered price test" This test involves comparing variable generation costs plus delivery costs (transmission rates, transmission losses and ancillary services) to a "market price." If the delivered cost of generation is less than 105 percent of the market price, the generation is considered economic. Economic generation is further limited to the amount that can be delivered into the market, given transmission capability and constraints.

CASm implements the prescribed delivered price test by determining -- for each destination market, for each relevant time period, and for each relevant supply measure -- potential supply to the destination market both pre- and post-merger. In effect, CASm determines the relevant geographic market by applying the delivered price test, based on the economics of production and delivery (transmission rates, transmission losses and ancillary services), and also based on the physical transmission capacity available to the competing suppliers on an open access basis. This requires a delivery route for the energy on the established transmission paths, each of which has a capability, transmission rate and transmission losses associated with it. CASm finds the supply that can be delivered to the destination market consistent with cost minimization and the delivered price test.

As a formal matter, CASm minimizes the production and transmission costs of supplying demand in the destination market. Any shortfall in demand is filled by a hypothetical generator located in the destination market that can produce an unlimited amount of energy at 105 percent of the market price. On this basis, any supplier who can profitably supply energy to the destination market will do so, to the maximum extent that their cost structure and the transmission system allow. This formulation ensures that no supplied generation is uneconomic; the hypothetical generator will undercut all such suppliers.

CASm can be used to determine both economic measures of supply, and the non-economic supply measures, using total system capacity and peak load projections, instead of the supply curve and load data by time period.

CASm determines pre- and post-merger market shares and calculates concentration (as measured by the measured by the Herfindahl-Hirschman Index, or HHI) and the change in HHIs.

To undertake these analyses, CASm solves a series of scenarios involving a network of interconnected suppliers. By limiting suppliers based on the economics of generation and delivery, or by limiting the interconnections between those suppliers based on the transmission capability, each Appendix A analysis can be completed. CASm includes a simplified depiction of the transmission system, essentially a system of "pipes" with independent, fixed capacity between and among utilities.

The following sections describe:

- What data inputs are required to operate CASm
- How different analyses are undertaken in CASm
- What outputs CASm produces; and
- How CASm is implemented.

INPUT DATA

Market Participants

The largest element of the required data for CASm relates to individual market participants, which are utilities with generation capacity and load. In addition, there are some market participants (for example, transmission dependent utilities, or TDUs) that may have load but no generation. CASm regards all distinct market participants as having the ability to both supply and consume electricity. The particular circumstances of each analysis will determine the extent to which each activity is possible.

Nodes

In CASm, a node is a location where electricity is generated, or consumed, or where it may "split" or change direction. All market participants are defined as having a unique node, and hence unique location in the transportation network. Total simultaneous import limits can be imposed at each node to mirror reliability restrictions.

Output Capability

Each market participant may have generating ability. This is defined generically in terms of any number of "tranches" of generation, having both a quantity and a price. This output capability may differ over time, either because of availability of fuel, or because of planned and unplanned outage rates. CASm has a number of data inputs available for modifying the underlying physical availability of generating assets to get the correct "supply curve" for any given model period.

Native Load & Reserve Requirements

Each market participant may have native load or reserve requirements. As with output capability, these requirements may change over time. Note that not all Appendix A analyses consider native load or reserve requirements.

System Lambda

For each destination market, a system lambda, or prevailing market price, can be defined. The lambda values are used to calculate a threshold price which potential suppliers must meet to be included in the market for economic-based analyses (that is, the "delivered price test").

Interconnections

Interconnections represent the network that links market participants together. These interconnections are currently represented as a "transportation" network, where flows are specifically directed. A network with electrical properties could be added to CASm.

Lines

A line between two nodes in CASm may represent either a single line, or the combined effect of a number of lines. Each line has an upper limit on the flow, and losses may occur on the line. Since capacity on the line may represent physical limits, less firm commitments, limits are allowed to be different, depending on the direction of the flow. Limits on the simultaneous flow on combinations of lines can be imposed to simulate the effect of loopflow or reliability constraints.

Scenarios

The final input area for CASm is related to scenario definition. Scenarios define which parties are considering merging, which load periods are relevant, and so on. In effect, the scenarios define a number of individual analyses to be performed, and how they should be compared to each other for reporting purposes.

REQUIRED CALCULATIONS

Appendix A defines analyses of four different supply measures that should be performed:

- **Total Capacity** represents all potential supply to a destination market without regard to generation or transportation economics.
- **Uncommitted Capacity** is a measure of Total Capacity less native load and net firm contractual obligations.
- **Economic Capacity** is the amount of capacity that can reach a market at a cost (including transmission rates, transmission losses and ancillary services) no more than 105 percent of the destination market price.
- **Available Economic Capacity** is the amount of Economic Capacity that is available after serving native load and other net firm commitments with the lowest cost units. This measure is useful for evaluating energy markets.

CASm focuses on Economic Capacity and Available Economic Capacity measures, but with modification could also be used to calculate Total Capacity and Uncommitted Capacity.

For every analysis, the following process is undertaken:

First, the solution of a Linear Programming (LP) problem. The LP is slightly different, depending on the underlying assumptions of each of the supply measures. CASm includes two options for allocating scarce transmission capacity. CASm has a "proration" option, which is called "squeeze-down." Where available supply exceeds the ability of the network to deliver that capacity to the destination market, suppliers are allocated shares at each node, and hence each outgoing line, based on the results of an algorithm that considers both supply and transfer capability at each node. Starting at the "outside" of the network, CASm calculates a share at each node that is based on a proportion of the incoming transfer capability (and the share of that capability allocated to each supplier), and the maximum economic supply available at that node. When the algorithm reaches the destination market, a total share of the incoming transfer capability has been determined.[1] This is described in more detail below.

Another option for proration is an economic allocation of limited transfer capability. Under this option, where available supply exceeds the ability of the network to deliver that capacity to the destination market, the least-cost supply is allocated the available transmission capacity.

A final step involves calculating what can be delivered to the destination market, after accounting for line losses. CASm allocates total system losses amongst suppliers on the basis on how much they injected, and how far away (how many wheels) they are from the destination market.

Maximum Supply Calculation

The maximum supply quantities can be found by solving, for each supplier, an LP exactly the same as those described below, except that no other supplier is allowed to inject. For economic supply calculations, the quantity found will be the maximum economic supply possible.

Economic Capacity

For the Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

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1 CASm can be modified to apply different proration methods when appropriate for some analyses.

supply < quantity (less outage rate), for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

The objective is slightly different when transmission capacity is to be prorated. The objective then becomes:

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

Available Economic Capacity

For the Available Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity (less native load commitments, reserve requirements and outage rates), for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

This is different from the economic capacity analysis only to the extent that suppliers must meet their own native load and reserve requirements.

When transmission capacity is to be prorated the objective becomes:

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

OUTPUTS

The primary output from CASm is a report that summarizes the results of different analyses. For each destination market, load period and FERC analysis type, CASm reports the following for both pre- and post-merger:

- Available Supplies in MWs
- Supplied MWs
- Market Share
- HHIs

CASm also reports the change in HHIs post-merger compared to pre-merger.

CASm produces a transmission report that shows the detail of each node, and the injections and flows between them.

Supply quantities, shares and transmission flows may be displayed in graphical form, via a windows-based viewing application.

"SQUEEZE-DOWN" PRORATION

In the "squeeze-down" proration algorithm, prorated shares on each line are based on the weighted shares of deliverable energy at the source node for that line. As noted above, weighted shares at the destination market node are calculated by a recursive algorithm that starts at the "outside" of the network, calculating shares on each line until it reaches the "middle".

This algorithm requires that all possible paths are simultaneously feasible, which, in turn, requires that each line be assigned a unique "direction". The steps of the proration algorithm include:

1. A C++ program enumerates all possible paths to the destination, the cost of transmission on each path and the maximum possible flow on the path. A "wheel limit", or maximum number of point-to-point links, may be imposed on paths.
2. The minimum "entry cost" for each supplier is calculated. This cost is the injection cost of the cheapest generator that has capacity for possible delivery to the destination.
3. Paths for which the entry cost plus the transmission cost are higher than 105% of the destination market price are rejected as being uneconomic.
4. To the extent remaining paths are not simultaneously feasible (because, for example, suppliers can seek to use the paths in both directions), a series of decision rules for determining the direction of the line are undertaken (in the following order):

- Instructions can be manually input as to the chosen direction of a line.
- Merger-case decisions should be consistent with base-case decisions.
- The direction of the line as determined in an economic allocation of available transmission is applied.
- The direction heading toward a destination market, if it is clear, is chosen.
- The direction that retains the maximum potential volume-weighted flow on the line (calculated from the paths that depend on this line) is chosen.
- The direction on which the maximum number of economic paths depend is chosen.

If these other options fail to reach a feasible solution, manual input will be required.

5. Proration begins at nodes furthest from the destination market (where only exports, and no imports are being attempted). Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability.
6. Proration continues at the next set of nodes, that should consist only of nodes with inflows from "resolved" nodes from step 5. Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability. Suppliers from the "resolved" nodes have their shares scaled down to match the transmission capacity into the node.
7. To the extent an iteration of the algorithm does not resolve any additional nodes and the destination market has not yet been reached (i.e., a loop is detected), flow is disallowed from any unresolved node to the furthest and smallest node affected by a loop.
8. The proration has been completed when the destination market node has been resolved. At that point, the "shares" at the destination market represent the prorated shares of deliverable energy.
9. Injections for each supplier are "capped" at the calculated shares, and these injections are then checked for economic feasibility. While suppliers need not deliver their energy to the destination in exactly the way that their share was calculated, the solution is still both economically and physically feasible. The final solution represents the least-cost method of delivering these supplies.

CASM IMPLEMENTATION

CASm has been implemented using GAMS (Generalized Algebraic Modeling System), release 2.25. GAMS is a programming language which supports both data manipulation and calls to many mainstream mathematical modeling systems. The linear programming problems generated by CASm are solved by BDMLP. The path enumeration program has been written in Microsoft Visual C++ version 5.

APPENDIX: DATA AND METHODOLOGY

UTILITIES INCLUDED

Q. What utilities did you include in your data set?

A. I included most of the utilities in the following NERC regions:

- ECAR
- ERCOT
- MAIN
- Mid-Atlantic Area Council ("MAAC")
- Mid-Continent Area Power Pool ("MAPP")
- Northeast Power Coordinating Council ("NPCC") New York Power Pool Only
- SERC
- SPP

The list of utilities (and corresponding abbreviations used in other exhibits) is included in Exhibit No. AC-505.

I should emphasize that the broad geographic area of candidate suppliers does not pre-judge the question of the geographic scope of the specific destination market. Potential competitors were restricted in two ways. First, consistent with the Commission's guidance, the number of potential suppliers is limited by the number of wheels.[1] Second, CASm determines, through application of the delivered price test, which of these candidate suppliers, and to what degree, are competitors to serve a particular destination customer.

GENERATION AND PURCHASES AND SALES

Q. What sources did you use for generating capability data?

A. Data on generating plant capability (winter and summer capacity), including non-utility generators ("NUGs"), were obtained from Form EIA-411s published in 1998. For jointly owned plants, I assigned shares to respective owners based on data reported in Form EIA-411. I took into account planned retirements and capacity additions through 1999.

I included as capacity additions during 1999 not only those units identified in the Form EIA-411, but also other utility and merchant plants that are already under construction and scheduled to enter service during 1999.

Q. How did you rate the production capacity of generators?

A. Production capacity was based on both the summer and winter ratings of the generators. When appropriate for the particular supply measure (i.e., Economic Capacity and Available Economic Capacity), I assumed that generation capacity would be unavailable during some hours of the year for either (planned) maintenance or forced (unplanned) outages. I assumed that maintenance would be scheduled during the non-peak seasons and forced outages would occur uniformly throughout the year. For this purpose, I used data reported in the most recent Generating

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[1] In *FirstEnergy*, the Commission limited the number of wheels "a supplier could reasonably travel to reach the destination market," recognizing that "[m]ore distant suppliers would face considerable losses and transmission costs." 80 FERC ¶61,039 at 61,104. In *FirstEnergy*, the Commission limited the potential suppliers to those within four wheels. Ibid. The recently issued request for comments on the use of computer models in merger analysis suggests that "three wheels has been deemed adequate." *Inquiry concerning the Commission's Policy On the Use of Computer Models in Merger Analysis*, Notice of Request for Written Comments and intent to Convene a Technical Conference, Docket No. PL98-6-000, April 16, 1998, page 24. I included as potential suppliers those that were three wheels from the destination market. In the instant case, this allows potential suppliers to move a significant distance, yet eliminates supply sources too remote to affect prices in the destination market.

Availability Data System for the average equivalent availability factor to estimate total outages, and the average equivalent forced outage rate to estimate forced outages for fossil and nuclear plants. These data were supplemented, where necessary, by data from other public sources such as NERC and Electric Power Research Institute.

Q. What did you assume about reserve margin requirements?

A. Reserve margin requirements are necessary for calculating results for the Uncommitted Capacity measure.[2]

For SPP companies, including CSW, I used a reserve margin of 13.6 percent, equivalent to the minimum required capacity margin of 12 percent.[3] Even though the CSW operating companies use a minimum planning reserve margin of 15 percent, as reported in its Joint Resource Plan, I applied the 13.6 percent reserve margin to CSW as well to be conservative. I separately included as uncommitted capacity CSWE's merchant generation not committed to long-term contracts.

For ERCOT companies, I used a reserve margin of 15 percent, based on their Capacity, Demand and Resources plan. For ECAR companies, I used a reserve margin of 12 percent, based on the planning margin used by AEP.[4] For other regions, I used a reserve margin assumption of between 15 and 18 percent, depending on the reserve requirements for their NERC region.

Q. How did you treat purchases and sales?

A. Data on long-term capacity purchase and sales were obtained primarily from FERC Form 1 and EIA Form 412 (or databases based on these forms), Form EIA-411, individual utility resource plans, or NERC's Electricity Supply and Demand

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2 The Economic Capacity and Available Economic Capacity supply measures use capacity as a proxy for energy, but reserves are not held on energy.

3 *Capacity Margin Criteria Recommendation* to SPP Board dated May 1, 1998.

4 ECAR does not have a reserve margin criterion (but uses Dependence on Supplemental Capacity Resources ("DSCR") for its reliability standard), which is not readily translated into a specific reserve margin.

("ES&D") database. These transactions are intended to represent long-term (one year or more) firm sales.

To the extent a utility has sold capacity under a long-term agreement, ownership over that resource is assumed to pass to the buyer.[5] Accordingly, I adjusted generation ownership to reflect the transfer of control by assuming that the sale resulted in a decrease in capacity for the seller and a corresponding increase in capacity for the buyer. Consistent with Appendix A, for the Economic Capacity and Available Economic Capacity measures, I assumed that system power sales were comprised of the lowest-cost supply for the seller.[6] Therefore, the seller's lowest-cost supply was reduced by the amount of the sale and the buyer's supply was increased by the amount of the purchase. To the extent that long-term sales could be identified specifically as unit sales, I have tied the sale to the capacity of a specific generating unit. I assumed this was the case with respect to AEP's unit sale of Rockport capacity to Virginia Power and Carolina Power & Light. Finally, I based the dispatch price of purchases on the energy price reported for long-term purchases in the FERC Form 1.[7]

Q. What purchases or sales did you reflect for Applicants?

A. AEP has three long-term sales contracts totaling 955 MW: the sale referenced above of Rockport capacity to Virginia Power (500 MW) and Carolina Power & Light (250 MW), plus a 205 MW sale to North Carolina Electric Membership Coop. AEP has no long-term purchases.

Because CSW is short of capacity in 1999, it is purchasing capacity under several contracts:

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5 Consistent with this assumption, NUGs were assumed to be under the control of the purchasing utility.

6 "[T]he lowest running cost units are used to serve native load and other firm contractual obligations" (Appendix A, p. 11). I used the lowest-cost supply that was available year-round, i.e., excluding hydro.

7 Footnote 78 of the Commission's Order incorrectly states that "Applicants also assume that purchases enter the generation 'stack' as least cost resources." As noted, I used the energy cost reported in the FERC Form 1 as a proxy for the dispatch price. In instances where I could not match up the capacity purchases from the EIA-411 or ES&D, I estimated the dispatch price based on the capacity factor of the purchase.

- PSO has three contracts totaling 125 MW: 50 MW from Utilicorp, 25 MW from Nebraska Public Power District ("NPPD") and 50 MW from Western Resources. The Western Resources and NPPD contracts are each for one year starting January 1, 1999. The Utilicorp contract, which is still under negotiation as of December 1998, is a four-month contract covering the summer period in 1999. Additionally, PSO is gaining 22 MW from the refurbishment of the Weleetka generating unit. This capacity, totaling 147 MW, replaces the non-specific purchases anticipated in the July 1998 Joint Resource Plan.[8]
- CPL has a 65 MW contract with Formosa (reflected in the July 1998 Joint Resource Plan), plus an expected 21 MW contract with Aquila, a power marketer which has contracted with CSWE's Frontera project. The Aquila purchase replaces an unspecified 49 MW wholesale purchase in the July 1998 Joint Resource Plan. CPL also is gaining a capacity credit of 18 MW from a load interruption program.
- WTU is purchasing 255 MW: 54 MW from Aquila,[9] 25 MW from Williams, 100 MW from Southwestern Public Service, 76 MW via a capacity commitment from Swepco (from the Knox Lee 5 unit). WTU is also crediting 7 MW from a load interruption program.

Given the expectation (based on the 1998 Joint Resource Plan as well as more updated information) that CSW will continue to be short of capacity in the absence of the merger (see Testimony of Wayman Smith), I reflected these contracts as dispatchable energy under the control of CSW pre-merger. With respect to the PSO contract with Utilicorp, I reflected it as a summer-only purchase. My understanding is that the energy prices of these contracts range from $24/MWh and up, and I have modeled them accordingly. Further, while some of these contract details have not been finalized at the time I am conducting my analysis, I believe these assumptions broadly reflect what ultimately will be done and I have used the best information available at the time of my analysis.

Post-merger, many of these contracts (or equivalent ones substituting from them) would be eliminated, replaced with the 250 MW path purchase from AEP. I have assumed that CPL's contract with Formosa (65 MW) and Aquila (21 MW), or

[8] I understand that PSO is also in the process of negotiating a contract to replace 57 MW that it had expected to obtain from the refurbishment of Tulsa #3. I have not included this additional capacity in my analysis.

[9] Because I have modeled separate destination markets for CSW ERCOT operations, I have counted the 54 MW WTU purchase from Aquila as a transfer from CPL (Frontera) to WTU.

their equivalents, will remain in effect. I also assumed that WTU's contracts with Aquila (54 MW) and Williams (25 MW), or their equivalents, will remain in effect, as will the capacity commitment from Swepco to WTU (76 MW). Consistent with current plans, 150 MW of the 250 MW of AEP power would replace PSO's existing 125 MW of firm purchases plus at least an additional 25 MW of other firm purchases required. The remaining 100 MW will be delivered to WTU, where it replaces the Southwestern Public Service contract. Thus, my post-merger analysis assumes the expected pattern of deliveries in 1999: 100 MW to WTU and 150 MW to PSO.

Q. What sources did you use for the cost of generation?

A. I used data from several sources to estimate the incremental cost of generation; these sources were the most recent available.

- Heat rates from EIA Form 860, supplemented in a few instances by data from Form OE-411.
- Fuel costs from Form 423, supplemented by data from other sources, mainly RDI's COALDAT®. I based the estimated dispatch cost on spot or interruptible fuel prices for 1997, the last complete year for which data were available. To the extent all fuel purchases in that period had been made under contract rather than at spot prices, I estimated an incremental price based on reported spot or interruptible prices in the relevant region. I escalated the fuel price to 1999 based on EIA forecasts.
- An estimate for variable O&M (by type of unit) and an SO_2 adder that is the same for all similar units.[10]
- For NUGs, I set the variable costs at zero, in effect assuming NUGs were must-run, except in instances where I could confirm the NUGs as dispatchable. Where I could identify a dispatchable NUG, I estimated the variable cost based on the energy price reported in relevant regulatory filings.
- To the extent new merchant capacity is expected to be on-line by 1999, I priced it on the basis of a heat rate of 10,000 Btu/kWh for combustion turbines and 7,000 btu/kWh for combined cycle plants and the incremental cost of natural gas. I also included variable O&M consistent with my assumptions for existing units.

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[10] I used an estimate for variable O&M of $1/MWh for gas and oil steam units, $3/MWh for scrubbed coal-fired units and $2/MWh for other coal-fired units. I estimated SO_2 costs based on 1998 year-to-date allowance prices. See workpapers.

TRANSMISSION RATES AND LOSSES

Q. What sources did you use for transmission rates?

A. Unless otherwise described below, consistent with Order No. 592 I used the ceiling rates in Exhibit 8 (Non-Firm Point-to-Point Transmission Service) of each utility's Order No. 888 filings.[11] If a utility reports on-peak and off-peak ceiling rates in its Order No. 888 filing, I used the applicable transmission rate for the on- and off-peak periods. To these transmission rates, I added ancillary services charges from Exhibits 1 (Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage Control from Generation Sources Service) of Order No. 888 filings.

In all relevant instances, I assumed transmission charges would be incurred for the transmission system where the generator is located and for wheeling the power through intermediate systems, but not for the destination market.

Rates for transfers within, into or out of ERCOT, MAPP, SPP and the Midwest ISO reflect the regional transmission arrangements for members. I used ERCOT rates posted on its OASIS page for transmission costs to export to the SPP via the East DC tie or the North DC tie.[12] For imports into ERCOT and unplanned (economy) transactions within ERCOT, transmission rates are effectively zero; only losses are charged.[13]

The MAPP and SPP regions have adopted transmission pricing regimes that allow utilities to trade using distance-sensitive rates on file with the Commission. I

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11 In instances where transmission data were not reported in dollars per MWh, I converted the $/MW rates to $/MWh rates using the "Appalachian" method. 39 FERC ¶ 61,296 at 61,965.

12 See workpapers.

13 All transmission service in ERCOT is either planned or unplanned. Planned service is to a specified load from designated resources and is for a term greater than 30 days. Unplanned service is between a specified load and specified resource, but is for a less than 30 days. Unplanned service is available subject to the availability of transmission capacity over that required for planned service.

Planned service is paid for by the load and the applicable charge is made up of a load ratio formula (70% of the charge) and a distance impact formula (30% of the charge). Unplanned service pays only a nominal scheduling fee to the ISO ($0.15/MWh) and losses.

have incorporated these rates in my analysis in order to reflect the lower cost of transmission that is available in these regions.

Q. Please describe how you implemented the MAPP rates.

A. In MAPP, the regional tariff ("Schedule F") allows parties to transact using rates based on the impact of each trade on various transmission facilities throughout the affected network, rather than the traditional contract path methodology. The basic MAPP schedule rates are determined by the facilities that are used when moving power between any two points within the region and are calculated on a seasonal basis. The resulting rates are discounted by various amounts depending upon three factors: (1) the type of service (firm vs. non-firm); (2) the time of service (peak vs. off-peak); and (3) the duration of service (monthly vs. hourly).

I used the hourly non-firm on and off-peak rates for the most recent period posted.[14] These hourly rates are derived from the basic MAPP $MW-mile program, but are discounted during both the peak and off-peak periods.[15]

The Schedule F rates are applicable only for trades within MAPP; for trades from a MAPP utility to a utility outside of MAPP, the Schedule F tariff would apply until the MAPP border company was reached, at which point the border company's Order 888 rate would apply. Similarly, for trades into MAPP the Order 888 rates are applicable until the MAPP region is actually entered.

While MAPP's Schedule F tariff are listed for any two points within MAPP regardless of the actual interconnections, transmission capacity is still posted assuming a contract path basis (i.e., by Control Areas). Thus, I implemented the MAPP rate structure in CASm by assuming that the MAPP utilities scheduled and paid for transmission service under the Schedule F tariff on a contract path basis.[16]

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[14] Calculated October 15, 1998 and applicable for the Winter 1998 period.

[15] Off-Peak rates are half of on-peak rates. I have observed that discounts do not vary by season for the MAPP rates.

[16] In some instances, this implementation methodology means that utilities may pay a slightly different rate to trade within MAPP than is actually possible under MAPP's Schedule F tariff. Still, this result is consistent

Q. Please describe how you implemented the SPP rates.

A. I also modeled the SPP's distance sensitive rates, which were filed with the Commission on June 1, 1998. The SPP tariff is similar to the MAPP Schedule F and I have implemented it in a similar fashion.[17] There are two key areas, however, in which the SPP tariff differs from MAPP's Schedule F. First, the eligibility requirements under the SPP tariff allow any SPP member or utilities first tier to the SPP to transact under the tariff.[18] Second, the SPP posts discounts for non-firm service over specific paths (currently on a monthly basis, but such postings may be made more frequently in the future). I applied the discounts implemented thus far, which appear to vary by season, to the appropriate season analyzed.[19]

Q. What transmission rate structure did you assume for the MISO, which you said earlier you included in your Base Case?

A. I assumed that the MISO membership consists of those utilities that are currently committed to the ISO: Cinergy, Commonwealth Edison, Illinois Power, Wisconsin Electric Power, Ameren, Louisville Gas & Electric Energy, Hoosier Energy and Central Illinois Light.[20,21]

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with the Appendix A instructions to use maximum-filed transmission rates and the resulting rates are low enough that this does not impact the amount of capacity that is included in the market. For example, transactions from Minnesota Power & Light to Northern States Power would pay $7.73/MWh under MP's Order 888 tariff, whereas the rate under the MAPP Schedule F tariff is less than $0.30/MWh. The methodology that I have used reflects the availability of the lower Schedule F rates.

17 Four companies are eligible to trade under either the SPP or the MAPP tariff (KCPL, Sunflower Electric Coop, Missouri Public Service and West Plains). For these utilities, I assumed that the SPP rates applied when they were trading with SPP companies and that the MAPP rates applied when they were trading with MAPP utilities.

18 The SPP tariff's definition of eligible customers is the same as that found in the Commission's Pro Forma Order 888 tariff.

19 The monthly discounts implemented thus far are shown in the workpapers. I used August 1998 rates for Summer (15 percent discount), December 1998 rates for Winter (25 percent discount) and October 1998 rates for Shoulder (50 percent discount). (Discounts do not apply to all trades within SPP.) A workpaper shows the cost for CSW to reach various markets under the SPP matrix, using SPP rates on a point-to-point basis, and under the Order 888 rates.

20 Wabash Valley Power also has committed to the MISO, but is not modeled in the analysis.

21 While APS and DQE committed to join the MISO as part of their merger application, I have not included them as are part of the MISO for two main reasons; (1) the merger's status is in flux (as I described in an

I have incorporated the rate structure that the MISO filed with the Commission. Under this structure, there are two applicable rates: An average tariff rate for trades through and out of the MISO, and a zonal rate for trades into and within the MISO. I calculated the average MISO rate using data from the MISO filing and the individual company's Order 888 tariffs.[22]

Q. What did you assume about transmission losses?

A. I assumed that losses average 2.8 percent per wheel, based on Order No. 888 filings.[23]

Q. What data sources did you use for native loads?

A. For the Available Economic Capacity measure, I generally used hourly load data from FERC Form 714 for 1997 (the most recent data available).[24] For the few utilities that do not file Form 714s (e.g., some cooperatives and municipal utilities) or whose data were otherwise unavailable, I used data from the EIA-411 along with a load shape based on those of similar utilities for which data were available.

Q. Did you make any changes in the 1997 load data for purposes of your analysis?

A. Yes. Since my analysis is intended to reflect 1999 conditions, 1997 load data were escalated to 1999, based on the projected energy growth rate reported in the EIA-411 or FERC Form 714. For utilities for which such data were not available, I used a regional growth rates reported for the relevant NERC region.

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earlier footnote); and (2) without AEP as a MISO participant, APS and DQE would not be physically interconnected with the other MISO members and could not transact with the other MISO utilities without also paying the AEP transmission rates. More recently, a news report indicated that APS and DQE are re-evaluating their status in the MISO. I believe the assumption to exclude APS and DQE from the MISO is conservative: including them would not the lower the cost of AEP to get to any of the affected markets and, while excluding APS and DQE raises their transmission cost, it simply reduces potential competition from them in the affected markets.

22 See workpapers.

23 See workpapers.

24 I asked Applicants to provide me with hourly load data for year-to-date 1998, and compared these to 1997 data to investigate whether the patterns were similar. The overall patterns in 1998 are not dramatically different than those in 1997. See workpapers.

COMPETITIVE MARKET PRICES

Q. How did you determine competitive market prices in the destination markets you analyzed?

A. I based my estimate of market prices on 1997 system lambda data from the FERC Forms 714. This is the suggestion made in Order No. 592 and the basis for most market price estimates in post-Order No. 592 applications. Because I have escalated fuels prices from 1997 to 1999, it was necessary to also escalate system lambdas in order to maintain consistency.[25]

I recognize limitations to using system lambdas as a basis for competitive prices. Utilities do not necessarily apply the same methodology to calculate system lambdas, there are frequently reporting errors, and neighboring utilities can report varying system lambdas.[26] This can lead to inconsistencies between the system lambda prices and the fuel costs used to determine what generation is economic relative to 105 percent of those prices.

There are, however, no good alternatives. In some instances, and certainly increasingly so in the future, price data published by some independent source, such as *Power Markets Week*, might be reasonably relied upon to determine competitive market prices in relevant regions. At present, *Power Markets Week*, which reports daily prices and a weekly range of low and high on- and off-peak prices for certain delivery points, represents a fairly limited number of trades in relevant regions.[27] Even if these data represented more than thinly-traded markets, it is unlikely that the data used in the Appendix A analysis are consistent with the actual market assumptions; for example, in the Appendix A analysis, transmission rates are

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[25] Fortuitously, both coal and gas are forecast by the EIA to decline by 6 percent over the two year period. Since system lambda almost always is set by either coal or gas-fired generation, it is appropriate to change the system lambdas by this same amount, which I have done.

[26] See, for example, 80 FERC ¶61,039 at 61,105. The average system lambda data presented in Exhibit No. AC-506 suggest that data for adjacent markets in this particular instance generally do not differ significantly.

[27] For example, current *Power Markets Week* data report an ECAR price that tends to represent prices into Cinergy.

assumed to be the maximum filed-rates, while the market prices would reflect actual transmission costs incurred. In any case, there are far fewer pricing "hubs" for reported market data than there are destination markets.

Another alternative would be to use a dispatch model to calculate market-clearing prices. The main advantage of this approach is that the underlying data (e.g., generation and transmission costs) would be consistent with that used in the Appendix A delivered price test. Its disadvantages are the dependence on complex modeling to "make up" market prices and the fact that the type of model that would be required is different from the type of model that can be used to prepare the analysis specified in Order No. 592.[28]

Given the lack of truly good options, it is fortunate that the source for market prices in destination markets is not very important, at least in determining the amount of deliverable economic capacity. Under the economic capacity test, in which native load responsibility is ignored, all that matters is the level of prices and, to a lesser extent, the season.[29] So long as the competitive price conditions analyzed reasonably span the likely range of prices under non-transitory conditions, the analysis is sufficient to determine whether the merger is problematic. Hence, one can evaluate results at different price levels independently from season or from on-peak and off-peak conditions.

That being said, I looked to both system lambda data and reported market price data in developing my Base Case prices and related sensitivities. I started with system lambda data as summarized in Exhibit No. AC-506.[30,31] I compared these

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28 A dispatch model that could be used to forecast market prices would necessarily contain all loads and resources in the relevant area. In this type of model, the concept of shares in selling to a destination market cannot be implemented. Conversely, a model that can be used for an Order No. 592 application must eliminate all loads except that of the destination market.

29 As I noted earlier, there is also some seasonal difference in the amount of energy available, relating to different assumptions about outages.

30 For merged companies or for companies whose operating subsidiaries report separate system lambdas (including CSW-SPP), I used a load-weighted average. (I did not need to make this assumption for CSW-ERCOT markets because I used ATC zones to define the destination markets, which placed WTU and CPL in separate zones.)

data to the average 1997 prices for wholesale purchases in the relevant destination markets and to *Power Markets Week* data.[32] In the Base Case, in addition to the nine time periods, I also analyzed a summer super peak period with a $35/MWh price for all destination markets.[33]

TRANSMISSION CAPABILITY

Q. What sources did you use to determine transmission capability?

A. I determined transmission capability primarily based on postings on OASIS (Open Access Same-Time Information System). OASIS reports Total Transmission Capability ("TTC"), firm Available Transmission Capability ("ATC") and non-firm ATC. Data generally are provided monthly for a twelve-month period starting with the next month.

For the Economic Capacity and Available Economic Capacity measures, I used monthly non-firm ATCs for seasonal periods based on OASIS postings. Generally, I relied on OASIS postings reported in the fourth quarter of 1998 (covering the period December 1998 through November 1999). Non-firm ATCs are the appropriate input assumption for transfer capability since Economic Capacity and Available Economic Capacity are intended to reflect competition in non-firm energy. In reviewing the OASIS data for selected utilities, I also found that utilities frequently post the same value for both firm and non-firm ATCs,[34] even though one would expect that non-firm ATCs would be higher than firm-ATCs.

CSW does not include variable O&M in its dispatch of generating units and, therefore, CSW's system lambdas do not reflect variable O&M. In order to place CSW's lambdas on the same basis as generating costs in the model, I added an estimate for variable O&M to CSW's system lambdas. This has the effect of raising the market prices used to analyze the CSW destination market by about $1-2/MWh. Based on discussions with CSW personnel, for the Valley I used the reported CPL lambda plus $2/MWh.

31 I also compared Applicants' 1998 year-to-date lambda data to 1997 data. See workpapers.

32 See workpapers.

33 In instances where system lambda data were unavailable, missing values or otherwise deemed inadequate for use in my analysis, I used as a proxy lambda data from an interconnected or nearby utility.

34 See workpapers.

In order to capture the seasonal differences in transmission capability, I generally used the average of June-August data to represent a summer capability; the average of December-February data to represent a winter capability; and the average of remaining months to represent a shoulder capability. In instances in which postings were not available for all months in a season, I used the available monthly posting for the whole season.[35]

In instances where two parties post different capability for the same path, I generally used the lower of the reported values. (I did not consider third-party postings, i.e., ATCs from one utility to another utility that it is not directly interconnected with, in this assessment.) I made this assumption on the basis that if a party sought use of a particular path, the lower of the reported values would be applicable unless the utilities at both the receipt and delivery points could agree differently.

The ATC data are shown in Exhibit AC-507.

Q. Were you able to use OASIS data for all the relevant geographic areas?

A. No, not for the SPP. My understanding is that SPP is now providing the OASIS postings for its member companies. However, SPP is posting information on the basis of Flowgates rather than posting point-to-point ATCs, even though they continue to calculate ATCs and provide the calculations to its members. I was unable to use this Flowgate information directly in my analysis because it is not readily translated into control area-to-control area ATCs, such as are being posted elsewhere and which form the basis for my Order No. 592 modeling. I discuss below the data I used for transmission capability within the SPP.

Q. What data did you use to determine transmission capability for the SPP?

A. I used ATC data compiled by the SPP. SPP has continued to report to its member companies "default values" (subject to adjustment by the reporting company) for

[35] The ERCOT OASIS provided data for four seasons of 1998 and Winter 1999. I used the Winter 1999 data and 1998 data for the remaining seasons. See workpapers.

ATCs among SPP utilities and between SPP utilities and utilities in other NERC regions. Input data for the analyses are provided by member companies and SPP calculates ATCs using both a linear load flow and an AC analysis. Prior to the flowgate information being posted on OASIS, this was the model SPP used to calculate ATCs for OASIS postings.

At my request, CSW asked the SPP to undertake a special ATC analysis. The only difference between this analysis and the one they normally undertake is that it eliminates the reserved 250 MW transmission path between Ameren and CSW which is to begin in the summer of 1999. I used these results for an approximation of pre-merger transmission conditions.

Q. What did this SPP analysis assume about other CSW capacity purchases?

A. My understanding is that the SPP analysis assumes 199 MW of capacity purchases for PSO, a figure that is consistent with the July 1998 CSW Joint Resource Plan. The SPP transmission analysis assumes that half of these purchases are supplied from a utility in SERC and the other half by a utility in MAPP. Because of this assumption, my pre-merger analysis has a transmission representation that does not match precisely the CSW's power purchase contracts as CSW presently anticipates them or as I have modeled them.

Whereas my analysis assumes that PSO is purchasing 225 MW of firm capacity purchases (25 MW from NPPD, 50 MW from Western Resources and 50 MW from Utilicorp) and that WTU is purchasing 100 MW from Southwestern Public Service), the transmission ATCs reported by the SPP reflect 199 MW purchased from SERC and MAPP in the 1999 summer peak and shoulder periods.

Q. What pricing assumption did you make for AEP's use of this contract path?

A. I assumed that post-merger Applicants will not incur any additional transmission costs other than incremental losses for use of this path. The contract requires a fixed price payment with no associated variable costs based on usage. My assumption maximizes Applicants' use of the 250 MW reservation.

Treatment of this transmission path as a resource with zero incremental cost ignores the opportunity cost which Applicants incur in using the 250 MW transmission path. Since Applicants could re-sell their firm transmission rights even if at a discount relative to filed rates, the resale value for use of this line is the opportunity cost. By ignoring opportunity cost, I have overstated the extent to which AEP has economic capacity available to serve the CSW market.

Q. What did you assume about post-merger ATCs?

A. The only adjustment I made to the ATCs for purposes of my post-merger analysis was to assume that the 250 MW AEP to CSW transfer occurs along a contract path from AEP to Ameren and Ameren to CSW. Because 100 MW of the 250 MW is intended to supply WTU, I also made the appropriate downward adjustments in ATCs from CSW to the North DC Tie. (However, the pre- and post-merger reservation of the North DC Tie does not change.) Finally, I eliminated the adjustment I had made to the AEP-Ameren path to reflect the pre-merger elimination of the transformer upgrade.

ALLOCATION OF LIMITED TRANSMISSION

Q. What methods did you consider to allocate limited transmission capacity?

A. Appendix A notes that there are various methods for allocating transmission, and that Applicants should support the method used.[36] There are two basic approaches to allocating limited transmission capacity: economic and pro rata, both of which I considered. Under an economic allocation, available transmission is assigned on the basis of the cost of the capacity (energy) competing to use limited transmission capability. The lowest cost capacity is assumed to have a priority in using the transmission. Higher cost generation is excluded, despite its having costs below 105

[36] Order No. 592, ¶31,044 at 30,133. ("In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated among the potential suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used.")

percent of the destination market price. In contrast, pro rata methods of allocation treat all generation that meets the delivered price test equally in allocating scarce transmission. There are a number of methods by which one can apply a pro rata allocation to available transmission, as I discuss below. I determined that a pro rata method is appropriate in the case of this merger.

Q. Why did you determine that an economic allocation was not appropriate?

A. While economic allocation might be a sensible method in some instances, its major flaw is that it would continually reallocate the same low cost energy, principally hydro and nuclear energy (and non-dispatchable NUG capacity) over and over to each destination market,[37] since Appendix A does not take into consideration the opportunity cost of supplying alternative markets to the destination market being analyzed.[38] This repeated allocation of the same energy is particularly troublesome given the large area involved in the analysis in the instant case

Q. Why are there multiple methods of prorating available transmission?

A. The paradigm lying behind the proration required by the Order No. 592 delivered price test (whether economic or pro rata methods are used) can be likened to a tree, for which the root is the destination market. At the furthest extremes are small branches, each one of which is connected to a single larger branch and so on until the trunk and root are reached. There is no ambiguity concerning the path. Hence, at every node (joining with a large branch), all of the capacity that can access the limited capacity of the branch can be calculated; each small branch's capacity is reduced proportionately to the capacity of the branch. This can be repeated successively, moving inward to the destination market.

Even taking into account the simplifications required by a "transportation" representation of transmission, real world transmission systems are more complex.

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[37] This flaw is less serious in the Available Economic Capacity test.

[38] Indeed, if opportunity costs were taken into account, and one was considering a regional dispatch, available transmission capacity appropriately would be allocated on the basis of economics.

The "small branch" distant utilities have multiple paths by which a destination market can be reached. In some cases, paths may first be in a direction away from the destination market, looping around onto another path to it. An analysis that takes this important complexity into account is computationally very difficult. Proration methods differ primarily in terms of how the problem is simplified in order to make computation tractable.

Q. What are the various versions of pro rata methods of allocation?

A. I have considered three such methods, which I have termed "single-path", "theoretical maximum" and "squeeze-down". I ultimately determined that a "squeeze-down" proration was the most appropriate to use, as I describe below. I have also developed a simplified numerical example that compares these various methods of proration as well as the economic allocation.

Q. Please explain the "single-path" method of allocation.

A. The single path method is an approach frequently used to allocate scarce transmission capacity, most likely because it is relatively easy to implement. It assumes that each supplier seeks to use the single least expensive path to the destination market regardless of the availability or the costs of using competing paths. At its worst, without complicated decision rules or human intervention, a model that relies on a single path methodology, for example, would force several utilities compete to use a particular low-cost path that is significantly smaller than one that has a slightly higher cost but offers substantially more transmission capability, leaving the larger and only slightly more expensive path unutilized.

Given the complexity and scope of the network that must be analyzed in this merger , I determined that this simplified methodology was not appropriate.

Q. Please explain the "theoretical maximum" method of allocation.

A. The "theoretical maximum" methodology is so named because it is based on the maximum amount of energy that any particular supplier can economically and physically deliver to a destination market. This is the method that I used in my April1998 testimony in this proceeding.

PHB developed this methodology specifically to take into consideration the complexity and scope of the network involved in this merger. For each destination market, a determination is made of the maximum amount of energy that each potential supplier could economically and physically supply to the destination market over all of the paths, assuming no other suppliers are competing for these paths. This determination for each supplier takes into consideration transmission charges and losses along the way, and all individual and joint transmission limitations encountered throughout the network. By this process, the amount of deliverable capacity for any individual supplier is limited by both the delivered price test as well as any transmission constraints. The amount that any supplier can theoretically sell into a destination market also is limited to the simultaneous import capability into that market.

The next step is to assign a share of supply into the destination market to each supplier based on its theoretical maximum relative to the theoretical maximums of other suppliers competing to use the transmission network. For example, if supplier A's theoretical maximum supply to destination market X is 1000, and supplier B's theoretical maximum supply to destination market X is 500, and the simultaneous import limitation into destination market X is 1000, supplier A was assigned 667 MW and supplier B was assigned 333 MW. In assigning shares, this method seeks the best pro rata solution consistent with economically and physically feasible paths from suppliers to the destination markets. Thus, deliveries as they occur through the network are all economically feasible (i.e., meet the delivered price test) and physically feasible (i.e., all transmission constraints, including simultaneous limits, are satisfied).

While I believe this methodology is a reasonable approach for proration in this merger, it has one potential weakness (relative to the "squeeze-down" methodology described below), namely that capacity that meets the delivered price test is not prorated at each node of the transmission system. Since the filing of my testimony in

April, PHB has developed another method, which I believe to be superior and which meets many of the criticisms of the theoretical maximum method.[39]

Q. **Please explain the "squeeze-down" method of allocation.**

A. This is the method used in this analysis. I believe it to be the closest approximation to what the Commission applied in the FirstEnergy merger[40] that is computationally feasible. The particular method the Commission described in that Order is what I have termed "squeeze down" because it seeks to prorate capacity at each node.

Under this method, shares of available transmission are allocated at each interface, diluting as they get closer to the destination market. When there is economic supply (i.e., having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

Q. **Please provide more details on how you allocated limited transmission capacity using the squeeze-down method.**

A. The methodology is detailed in Exhibit No. AC-503, but I have summarized some of the more salient points below.

Shares on each transmission path are based on the shares of deliverable energy at the source node for the particular path being analyzed. The calculations start at the outside of a network defined with the destination market as its center and end at the

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[39] Indeed, in Applicants' *Answer to Motion for Rejection of Merger Filing and for Other Relief* (page 9), Applicants, at my direction, noted that "the argument that available capacity should be prorated at each node of the transmission system would have some merit in the unique circumstance in which all connections linking suppliers to the destination market are direct (*i.e.*, radial). However, when a large, interactive and complex transmission system separates a power supplier from the destination market, such a proration method is unrealistic. In complex transmission systems, the supplier connections to the market are not radial because alternative transmission paths intersect with the consequence that power from any given supplier flows over many paths to the purchaser."

[40] *Ohio Edison Company, et al.*, 80 FERC ¶ 61,039 at 61,107. ("When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface.")

destination market itself. A series of decision rules are required to accomplished this proration. The purpose of these decision rules is limited to assigning a unique power flow direction to each link for any given destination market analysis. Once the links are given a direction, the complex network can be solved. CASm implements a series of rules to determine the direction of the path. The first rule (and the one expected to be applied most frequently) is based on the direction of the flow under an economic allocation of transmission capacity. Other options take into consideration the predominant flow on the line based on desired volume (the amount of economic capacity seeking to reach the destination market, the number of participants seeking to use a path in a particular direction and the path direction that points toward the destination market.

The model proceeds to assign each supplier at each node a share equal to their maximum supply capability. At each node, "new" suppliers (those located at the node outside of the next interface) are given a share equal to their supply capability and the shares of more distant suppliers (those who have had to pass through interfaces more remote from the destination market in order to reach the node) are scaled down to match the line capacity into the node. Ultimately, the shares at the destination market represent the prorated shares of economic capacity that is economically and physically feasible.

Q. Did you apply this same methodology to allocating transmission on the DC ties into and out of ERCOT?

A. Yes, I assumed that all participants including CSW have equal access through open access tariffs to the two DC ties out of ERCOT into the SPP.[41] Energy from the

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[41] Although the North HVDC tie line might be considered "internal" to CSW (in that it is a direct interconnection between PSO and WTU), it is available under an open access tariff subject to Order No. 888, and its transfer capability is posted on OASIS. (The capacity on the North HVDC tie that CSW has reserved for transmission of Oklaunion generation is accounted for in the ATC figures used in my analysis and by counting Oklaunion capacity as owned by PSO and Oklahoma Municipal Power Authority.) As discussed in Mr. Jones's testimony, Applicants have committed to waive for a stated period priority for scheduling transfers of non-firm energy into and out of ERCOT over the North HVDC tie.

Eastern Interconnection can flow into CSW-ERCOT or the rest of ERCOT through the available capacity on the DC ties.

Utilities Included in Analysis
(Destination Markets are Shown in Bold)

NERC Region	Node	Full Name
SERC	**AECI**	**Associated Electric Cooperative**
ECAR	**AEP**	**American Electric Power**
ECAR	AEP_TDU	AEP Transmission Dependant Utilities
SERC	ALEC	Alabama Electric Cooperative
SPP	ALEX	Alexandria, LA, City of
MAIN	**ALLIANT_E**	**Alliant - East**
MAPP	ALLIANT_W	Alliant - West
MAIN	**AMEREN**	**Ameren**
ECAR	**APS**	**Allegheny Power Systems**
ERCOT	**BEC**	**Brazos Electric Cooperative**
MAPP	BEPC	Basin Electric Power Cooperative
ECAR	BREC	Big Rivers Electric Cooperative
ERCOT	**BRYN**	**Bryan, City of**
SPP	CAJN	Cajun Electric Power Cooperative
ERCOT	CAL	Calpine Corp.
SERC	**CAPO**	**Carolina Power and Light**
ERCOT	**CBEN**	**North and Middle Central Power and Light**
SPP	**CELE**	**Central Louisiana Electric Co.**
MAIN	CILCO	Central Illinois Light Company
SPP	**CIMO**	**Independence, MO, City Power and Light**
ECAR	**CIN**	**Cinergy**
ERCOT	**COA**	**Austin, TX, City of**
MAIN	**COMED**	**Commonwealth Edison Company**
ECAR	**CP**	**Consumers Power**
ERCOT	**CPS**	**San Antonio, City Public Service of**
SPP	**CSW_SPP**	**Central and South West - SPP**
SPP	CSW_TDU	CSW Transmission Dependant Utility
ERCOT	FRONTERA	CSW Energy
MAIN	CWL	Columbia, MO Water and Light Department
MAIN	CWLP	Springfield, IL, City Water Light and Power
ERCOT	DC_E	HV-DC East Tie between ERCOT and SPP
ERCOT	DC_N	HV-DC North Tie between ERCOT and SPP
ECAR	**DECO**	**Detroit Edison**
ERCOT	**DGG**	**Cities of Denton, Garland & Greenville**
ECAR	**DLCO**	**Duquesne Light**
MAPP	DPC	Dairyland Power Cooperative
ECAR	**DPL**	**Dayton Power and Light**
SERC	**DUKE**	**Duke Power**
SPP	**EDE**	**Empire District Electric**
MAIN	EEI	Electric Energy, Inc.
ECAR	**EKPC**	**East Kentucky Power Cooperative**
SERC	**ENT**	**Entergy**
SPP	ENT_TDU	Entergy Transmission Dependant Utilities
ECAR	**FENER**	**First Energy**
SPP	**GRRD**	**Grand River Dam Authority**
ERCOT	GSEC	Golden Spread Elec. Coop.
ECAR	**HEC**	**Hoosier Electric**
ERCOT	**HLP**	**Houston Light and Power**
MAIN	**IP**	**Illinois Power**
ECAR	**IPL**	**Indianapolis Power and Light**
SPP	**KACY**	**Kansas City, MO, Board of Public Utilities**
SPP	KAMO	KAMO Electric Cooperative
SPP/MAPP	**KCPL**	**Kansas City Power and Light**
SPP	**LAFA**	**Lafayette, LA, City of**
ERCOT	**LCRA**	**Lower Colorado River Authority**
SPP	LEPA	Louisiana Energy and Power Authority
MAPP	LES	Lincoln Electric System
ECAR	**LGE**	**Louisville Gas and Electric Energy**
MAIN	MGE	Madison Gas and Electric
MAPP	MIDAM	MidAmerican Energy
SPP	MIDW	Midwest Energy, Inc.
MAPP	MP	Minnesota Power and Light
MAPP	MPC	Minnkota Power Cooperative

Utilities Included in Analysis
(Destination Markets are Shown in Bold)

NERC Region	Node	Full Name
SPP/MAPP	**MPS**	**Missouri Public Service**
ECAR	**NIPS**	**Northern Indiana Public Service**
MAPP	NPPD	Nebraska Public Power District
MAPP	**NSP**	**Northern States Power Company**
MAPP	NSPI	NSP Independent
NPCC	NYPP	New York Power Pool
SPP	**OKGE**	**Oklahoma Gas and Electric Company**
SPP	OKGE_TDU	OKGE Transmission Dependent Utility
MAPP	OPPD	Omaha Public Power District
MAPP	OTP	Otter Tail Power Company
ECAR	OVEC	Ohio Valley Electric Cooperative
MAAC	PJM	PJM Pool
SERC	**SCEG**	**South Carolina Electric and Gas Corporation**
SERC	SCPSA	South Carolina Public Service Authority
SPP/MAPP	SEC	Sunflower Electric Cooperative
SERC	SEPA	Southeastern Power Administration
ECAR	**SIGE**	**Southern Indiana Gas and Electric**
SPP	SIKE	Sikeston, MO, City of
MAIN	SIPC	Southern Illinois Power Cooperative
SERC	SMEPA	South Mississippi Electric Power Assn.
MAPP	SMMP	Southern Minnesota Municipal Power
SERC	**SOCO**	**Southern Company**
SPP	**SPRM**	**Springfield, MO City Utilities**
ERCOT	**STEC**	**South Texas Electric Coop**
SPP	**STJO**	**St. Joseph Light and Power**
SPP	**SWEPA**	**Southwestern Power Administration**
SPP	**SWPS**	**Southwestern Public Service Company**
ERCOT	**TMPA**	**Texas Municipal Power Agency Gibbons Creek Plant**
ERCOT	**TNMP**	**Texas New Mexico Power**
ERCOT	**TU**	**Texas Utilities Electric Co.**
SERC	**TVA**	**Tennessee Valley Authority**
ERCOT	VALC	South Central Power and Light
ERCOT	**VALLEY**	**Valley Destination Market**
ERCOT	VALP	Brownsville, TX, City of
SERC	**VP**	**Virginia Electric Power**
MAPP	WAPA	Western Area Power Authority
SPP	**WEFA**	**Western Farmers Electric Cooperative**
MAIN	**WEP**	**Wisconsin Electric Power**
SPP/MAPP	**WEPL**	**West Plains Energy**
MAIN	WPPI	Wisconsin Public Power
MAIN	WPS	Wisconsin Public Service
SPP	**WR**	**Western Resources**
ERCOT	**WTU**	**West Texas Utilities**
SERC	ALA	Air Luquide America
MAIN	ALLIANT	Combined Alliant Node for Reporting Purposes
ECAR/ERCOT/SP	CSW+AEP	Merged Entity of CSW and AEP
ERCOT/SPP	CSW-CSW	Combined CSW Node for Reporting Purposes
SPP	DUK_GL	Duke Energy (Glennonville - Missouri)
MAPP	ENR_FPL	Enron Wind/FPL (Buena Vista)
SERC	ENRON	Enron (SERC)
MAIN	HIPG	Houston Industries Power Generation
SERC	KOCH	Koch Energy
ERCOT/SPP	NEWGULF	CSWE's Newgulf Unit
MAIN	NRG	NRG Energy
MAIN	POL	Polsky Energy
ERCOT/SPP	SWEENY	CSWE's Sweeny Unit
SERC	TENG	Tengasco
SPP/MAPP	UTILCOR	Reporting Node for West Plains and Missouri Public Service
SERC	WES	World Energy Systems

Exhibit No. AC-506

1997 Lambdas
(Central Time Zone Based upon CSW (SPP) Top 150 Hours)

	Summer			Winter			Shoulder		
Node	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak
AECI	23.52	21.70	18.56	30.84	23.06	20.25	27.58	22.51	20.18
AEP	17.03	14.20	11.87	15.00	13.94	12.72	16.99	14.67	12.62
ALEX	23.52	21.70	18.56	30.84	23.06	20.25	27.58	22.51	20.18
ALLIANT_E	24.95	19.14	12.57	33.15	21.11	14.02	21.75	19.63	12.15
AMEREN	50.24	26.69	15.60	26.85	21.91	12.79	31.01	21.40	12.43
APS	17.63	16.88	14.48	20.44	17.23	16.41	22.32	21.04	16.74
BEC	24.09	21.51	19.86	35.13	20.52	22.08	29.93	21.80	19.85
BRYN	24.09	21.51	19.86	35.13	20.52	22.08	29.93	21.80	19.85
CAPO	29.60	18.02	13.84	18.83	14.42	13.70	24.19	15.77	12.59
CBEN	28.17	26.03	24.31	37.00	25.49	25.24	33.23	26.54	24.77
CELE	23.52	21.70	18.56	30.84	23.06	20.25	27.58	22.51	20.18
CIMO	19.56	17.34	15.17	14.63	14.71	13.79	15.51	13.61	12.94
CIN	15.03	13.79	13.05	16.28	13.76	13.90	14.13	14.03	13.11
COA	23.16	21.87	20.50	32.74	21.21	19.08	28.27	22.66	19.54
COMED	25.92	15.78	12.96	23.49	15.11	13.52	22.07	18.76	13.41
CP	34.47	19.82	14.81	30.08	23.29	17.16	22.40	22.40	14.77
CPS	24.63	23.00	21.43	21.99	16.37	14.32	29.57	23.21	18.84
CSW_SPP	27.32	23.16	19.52	32.05	20.49	19.27	31.02	23.26	19.32
DECO	34.47	19.82	14.81	30.08	23.29	17.16	22.40	22.40	14.77
DGG	24.09	21.51	19.86	35.13	20.52	22.08	29.93	21.80	19.85
DLCO	33.87	22.48	16.85	21.94	19.85	17.57	21.17	21.98	16.39
DPL	16.00	14.79	13.32	15.14	14.11	13.23	15.18	14.65	13.42
DUKE	16.27	13.91	12.24	16.24	13.97	13.20	16.35	13.83	11.95
EDE	41.79	24.35	18.97	36.94	24.42	18.88	29.04	24.21	17.01
EKPC	18.72	14.42	13.05	20.03	15.79	14.41	20.37	15.48	13.49
ENT	23.52	21.70	18.56	30.84	23.06	20.25	27.58	22.51	20.18
FENER	17.63	16.88	14.48	20.44	17.23	16.41	22.32	21.04	16.74
GRRD	26.19	19.65	14.41	27.21	19.19	13.72	35.24	20.98	13.56
HEC	23.91	16.97	12.67	22.02	16.01	12.97	18.57	16.28	12.86
HLP	23.16	21.87	20.50	32.74	21.21	19.08	28.27	22.66	19.54
IP	29.43	21.54	16.43	22.79	18.20	15.94	25.56	17.84	14.86
IPL	15.46	11.08	9.53	12.88	10.99	9.51	11.82	11.71	9.62
KACY	24.46	15.81	13.21	14.65	13.05	11.78	20.14	15.82	13.21
KCPL	50.24	26.69	15.60	26.85	21.91	12.79	31.01	21.40	12.43
LAFA	23.52	21.70	18.56	30.84	23.06	20.25	27.58	22.51	20.18
LCRA	19.10	17.35	14.90	29.01	20.09	18.22	21.46	19.92	17.99
LGE	15.10	12.76	11.97	14.91	12.38	12.04	13.99	12.85	11.75
MPS	19.56	17.34	15.17	14.63	14.71	13.79	15.51	13.61	12.94
NIPS	12.93	12.77	12.64	12.75	13.11	13.02	13.32	14.27	13.15
NSP	11.02	9.58	8.57	14.58	9.81	9.34	8.59	8.71	8.28
OKGE	26.19	19.65	14.41	27.21	19.19	13.72	35.24	20.98	13.56
SCEG	25.18	25.47	25.60	26.70	34.21	37.14	27.63	33.20	37.46
SIGE	23.91	16.97	12.67	22.02	16.01	12.97	18.57	16.28	12.86
SOCO	23.34	21.32	21.49	20.19	22.39	21.06	20.23	22.57	19.30
SPRM	19.56	17.34	15.17	14.63	14.71	13.79	15.51	13.61	12.94
STEC	29.62	20.87	14.79	28.17	9.46	12.56	31.38	13.65	12.67
STJO	50.24	26.69	15.60	26.85	21.91	12.79	31.01	21.40	12.43
SWEPA	25.95	20.94	17.28	28.29	17.73	16.11	28.81	20.24	16.63
SWPS	23.93	21.58	16.64	32.61	20.04	16.17	28.87	22.75	17.73
TMPA	24.09	21.51	19.86	35.13	20.52	22.08	29.93	21.80	19.85
TNMP	23.45	22.23	19.75	37.23	22.93	21.51	28.86	23.10	20.44
TU	23.45	22.23	19.75	37.23	22.93	21.51	28.86	23.10	20.44
TVA	29.45	14.53	12.37	15.64	11.86	11.53	24.53	12.35	11.13
VALLEY	32.17	30.03	28.31	41.00	29.49	29.24	37.23	30.54	28.77
VP	23.24	19.15	15.87	19.98	16.22	15.19	24.21	17.40	14.76
WEFA	19.51	17.79	16.96	15.26	14.03	13.88	19.90	16.74	15.47
WEP	24.95	19.14	12.57	33.15	21.11	14.02	21.75	19.63	12.15
WEPL	20.57	15.43	12.92	16.09	14.79	13.76	20.26	15.49	13.39
WR	20.57	15.43	12.92	16.09	14.79	13.76	20.26	15.49	13.39
WTU	27.24	25.67	24.18	38.25	26.33	26.82	33.24	26.97	25.57

Source:
1997 FERC Form 714 Data before adjustment.
For utilities where data were not available, lambdas were based on nearby utilities.

Exhibit No. AC-506

1997 Lambdas
(Eastern Time Zone Based upon AEP Top 150 Hours)

	Summer			Winter			Shoulder		
Node	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak
AECI	23.34	21.73	18.56	29.55	23.28	20.25	29.36	22.37	20.18
AEP	17.57	14.11	11.87	15.35	13.89	12.72	17.49	14.63	12.62
ALEX	23.34	21.73	18.56	29.55	23.28	20.25	29.36	22.37	20.18
ALLIANT_E	30.10	18.28	12.57	30.03	21.62	14.02	22.18	19.60	12.15
AMEREN	57.44	25.51	15.60	25.72	22.10	12.79	35.76	21.02	12.43
APS	26.02	15.46	14.48	21.61	17.03	16.41	33.98	20.13	16.74
BEC	23.01	21.69	19.86	33.24	20.83	22.08	27.76	21.97	19.85
BRYN	23.01	21.69	19.86	33.24	20.83	22.08	27.76	21.97	19.85
CAPO	34.53	17.19	13.84	19.62	14.28	13.70	25.16	15.69	12.59
CBEN	27.16	26.20	24.31	36.06	25.65	25.24	31.93	26.64	24.77
CELE	23.34	21.73	18.56	29.55	23.28	20.25	29.36	22.37	20.18
CIMO	19.39	17.36	15.17	14.63	14.71	13.79	14.96	13.65	12.94
CIN	15.29	13.75	13.05	16.27	13.76	13.90	14.15	14.03	13.11
COA	22.34	22.01	20.50	31.67	21.39	19.08	27.07	22.76	19.54
COMED	34.75	14.30	12.96	23.95	15.03	13.52	30.56	18.10	13.41
CP	46.51	17.79	14.81	28.99	23.47	17.16	25.91	22.13	14.77
CPS	23.88	23.13	21.43	17.80	17.07	14.32	25.58	23.51	18.84
CSW_SPP	26.93	23.23	19.52	31.44	20.59	19.27	29.72	23.36	19.32
DECO	46.51	17.79	14.81	28.99	23.47	17.16	25.91	22.13	14.77
DGG	23.01	21.69	19.86	33.24	20.83	22.08	27.76	21.97	19.85
DLCO	28.74	23.34	16.85	22.37	19.78	17.57	31.10	21.20	16.39
DPL	16.51	14.71	13.32	15.13	14.11	13.23	15.30	14.64	13.42
DUKE	16.47	13.88	12.24	16.68	13.90	13.20	16.22	13.84	11.95
EDE	43.74	24.02	18.97	36.23	24.53	18.88	35.40	23.72	17.01
EKPC	20.89	14.06	13.05	20.96	15.64	14.41	26.72	14.98	13.49
ENT	23.34	21.73	18.56	29.55	23.28	20.25	29.36	22.37	20.18
FENER	26.02	15.46	14.48	21.61	17.03	16.41	33.98	20.13	16.74
GRRD	23.62	20.08	14.41	25.55	19.46	13.72	27.67	21.57	13.56
HEC	35.93	14.94	12.67	26.12	15.33	12.97	21.60	16.05	12.86
HLP	22.34	22.01	20.50	31.67	21.39	19.08	27.07	22.76	19.54
IP	38.38	20.03	16.43	22.15	18.31	15.94	30.59	17.45	14.86
IPL	16.36	10.93	9.53	13.38	10.91	9.51	13.83	11.55	9.62
KACY	24.43	15.82	13.21	13.68	13.21	11.78	25.19	15.43	13.21
KCPL	57.44	25.51	15.60	25.72	22.10	12.79	35.76	21.02	12.43
LAFA	23.34	21.73	18.56	29.55	23.28	20.25	29.36	22.37	20.18
LCRA	19.09	17.36	14.90	29.40	20.03	18.22	25.05	19.64	17.99
LGE	11.24	11.05	10.79	12.62	12.23	12.23	11.98	11.85	11.38
MPS	19.39	17.36	15.17	14.63	14.71	13.79	14.96	13.65	12.94
NIPS	12.91	12.77	12.64	12.92	13.08	13.02	14.30	14.19	13.15
NSP	12.75	9.29	8.57	14.24	9.87	9.34	9.20	8.66	8.28
OKGE	23.62	20.08	14.41	25.55	19.46	13.72	27.67	21.57	13.56
SCEG	24.12	25.65	25.60	28.55	33.91	37.14	33.00	32.74	37.46
SIGE	35.93	14.94	12.67	26.12	15.33	12.97	21.60	16.05	12.86
SOCO	20.80	21.75	21.49	20.39	22.35	21.06	22.35	22.41	19.30
SPRM	19.39	17.36	15.17	14.63	14.71	13.79	14.96	13.65	12.94
STEC	25.12	21.63	14.79	22.42	10.41	12.56	15.70	14.86	12.67
STJO	57.44	25.51	15.60	25.72	22.10	12.79	35.76	21.02	12.43
SWEPA	25.52	21.01	17.28	27.97	17.78	16.11	27.29	20.36	16.63
SWPS	23.30	21.69	16.64	31.77	20.18	16.17	28.50	22.78	17.73
TMPA	23.01	21.69	19.86	33.24	20.83	22.08	27.76	21.97	19.85
TNMP	22.82	22.33	19.75	35.32	23.25	21.51	28.84	23.10	20.44
TU	22.82	22.33	19.75	35.32	23.25	21.51	28.84	23.10	20.44
TVA	30.18	14.41	12.37	16.40	11.73	11.53	20.05	12.70	11.13
VALLEY	31.16	30.20	28.31	40.06	29.65	29.24	35.93	30.64	28.77
VP	25.20	18.82	15.87	21.47	15.98	15.19	22.35	17.55	14.76
WEFA	18.54	17.96	16.96	15.26	14.03	13.88	20.31	16.71	15.47
WEP	30.10	18.28	12.57	30.03	21.62	14.02	22.18	19.60	12.15
WEPL	19.71	15.57	12.92	15.68	14.86	13.76	21.95	15.36	13.39
WR	19.71	15.57	12.92	15.68	14.86	13.76	21.95	15.36	13.39
WTU	26.72	25.75	24.18	37.27	26.49	26.82	32.31	27.04	25.57

Source:
1997 FERC Form 714 Data before adjustment.
For utilities where data were not available, lambdas were based on nearby utilities.

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
AECI	AMEREN	1,000	630	1,000	630	1,000	630	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
AECI	CSW_SPP	628	58	8	796	8	796	374	796	374	796	374	796	369	796	369	796	369	796
AECI	EDE	131	145	-	189	-	189	437	166	437	166	437	166	66	171	66	171	66	171
AECI	ENT	619	55	619	55	619	55	619	93	619	93	619	93	478	93	478	93	478	93
AECI	GRRD	-	262	-	266	-	266	253	192	253	192	253	192	127	219	127	219	127	219
AECI	KCPL	647	638	-	466	-	466	720	1,009	720	1,009	720	1,009	369	727	369	727	369	727
AECI	LES	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
AECI	MIDAM	142	142	142	142	142	142	142	142	142	142	142	142	150	146	150	146	150	146
AECI	MPS	95	293	-	289	-	289	275	468	275	468	275	468	138	450	138	450	138	450
AECI	NPPD	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
AECI	OPPD	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
AECI	STJO	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	352	843	352	843	352	843
AECI	SWEPA	-	336	-	584	-	584	536	522	536	522	536	522	332	332	332	332	332	332
AECI	TVA	298	298	298	298	298	298	300	395	300	395	300	395	150	150	150	150	150	150
AECI	WAPA	150	150	150	150	150	150	150	150	150	150	150	150	239	412	239	412	239	412
AECI	WR	378	299	-	412	-	412	477	-	477	-	477	-	630	1,000	630	1,000	630	1,000
AEP	AMEREN	630	1,000	630	1,000	630	1,000	630	1,000	630	1,000	630	1,000	2,710	2,719	2,710	2,719	2,710	2,719
AEP	APS	3,000	3,837	3,000	3,837	3,000	3,837	3,000	3,000	3,000	3,000	3,000	3,000	1,019	1,700	1,019	1,700	1,019	1,700
AEP	CAPO	500	1,880	500	1,880	500	1,880	1,403	1,900	1,403	1,900	1,403	1,900	3,090	2,306	3,090	2,306	3,090	2,306
AEP	CIN	3,090	1,750	3,090	1,750	3,090	1,750	3,090	3,418	3,090	3,418	3,090	3,418	3,967	3,000	3,967	3,000	3,967	3,000
AEP	COMED	3,043	3,000	3,043	3,000	3,043	3,000	4,000	3,000	4,000	3,000	4,000	3,000	4,740	5,000	4,740	5,000	4,740	5,000
AEP	CP	3,103	5,000	3,103	5,000	3,103	5,000	4,800	5,000	4,800	5,000	4,800	5,000	1,540	1,540	1,540	1,540	1,540	1,540
AEP	DLCO	1,510	1,510	1,510	1,510	1,510	1,510	1,500	1,500	1,500	1,500	1,500	1,500	2,200	2,157	2,200	2,157	2,200	2,157
AEP	DPL	2,200	2,150	2,200	2,150	2,200	2,150	2,200	2,000	2,200	2,000	2,200	2,000	1,835	2,000	1,835	2,000	1,835	2,000
AEP	DUKE	1,835	2,000	1,835	2,000	1,835	2,000	1,835	2,000	1,835	2,000	1,835	2,000	410	420	410	420	410	420
AEP	EKPC	400	410	400	410	400	410	400	400	400	400	400	400	4,430	3,045	4,430	3,045	4,430	3,045
AEP	FENER	2,791	1,173	2,791	1,173	2,791	1,173	-	2,800	-	2,800	-	2,800	960	960	960	960	960	960
AEP	IP	860	860	860	860	860	860	900	900	900	900	900	900	3,120	3,022	3,120	3,022	3,120	3,022
AEP	IPL	2,723	2,823	2,723	2,823	2,723	2,823	3,100	3,000	3,100	3,000	3,100	3,000	2,530	2,530	2,530	2,530	2,530	2,530
AEP	NIPS	2,173	2,510	2,173	2,510	2,173	2,510	2,500	2,500	2,500	2,500	2,500	2,500	3,640	3,178	3,640	3,178	3,640	3,178
AEP	OVEC	3,530	3,377	3,530	3,377	3,530	3,377	3,500	3,000	3,500	3,000	3,500	3,000	3,000	2,233	3,000	2,233	3,000	2,233
AEP	TVA	3,000	2,200	3,000	2,200	3,000	2,200	3,000	2,200	3,000	2,200	3,000	2,200	336	1,690	336	1,690	336	1,690
AEP	VP	1,205	1,240	1,205	1,240	1,205	1,240	150	1,700	150	1,700	150	1,700	ML	ML	ML	ML	ML	ML
AEP_TDU	AEP	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
ALA	ENT	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	1,500	1,210	1,500	1,210	1,500	1,210
ALLIANT_E	AMEREN	1,500	390	1,500	390	1,500	390	1,500	1,100	1,500	1,100	1,500	1,100	1,215	845	1,215	845	1,215	845
ALLIANT_E	COMED	340	1,100	340	1,100	340	1,100	700	770	700	770	700	770	700	700	700	700	700	700
ALLIANT_E	DPC	700	330	700	330	700	330	700	420	700	420	700	420	275	260	275	260	275	260
ALLIANT_E	MGE	70	260	70	260	70	260	250	260	250	260	250	260						

Exhibit No. AC-507

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
ALLIANT_E	NSP	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
ALLIANT_E	WEP	560	500	560	500	560	500	920	1,000	920	1,000	920	1,000	1,100	1,250	1,100	1,250	1,100	1,250
ALLIANT_E	WPS	230	480	230	480	230	480	220	810	220	810	220	810	1,065	1,000	1,065	1,000	1,065	1,000
ALLIANT_W	AECI	270	390	270	390	270	390	270	1,100	270	1,100	270	1,100	270	1,210	270	1,210	270	1,210
ALLIANT_W	AMEREN	1,000	570	1,000	570	1,000	570	1,000	1,000	1,000	1,000	1,000	1,000	1,050	800	1,050	800	1,050	800
ALLIANT_W	COMED	1,100	590	1,100	590	1,100	590	1,100	1,500	1,100	1,500	1,100	1,500	1,450	565	1,450	565	1,450	565
ALLIANT_W	DPC	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
ALLIANT_W	MIDAM	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
ALLIANT_W	NSP	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
ALLIANT_W	SMMP	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
ALLIANT_W	WAPA	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
AMEREN	CILCO	450	450	450	450	450	450	450	450	450	450	450	450	450	475	450	475	450	475
AMEREN	CIN	598	603	598	603	598	603	598	603	598	603	598	603	598	603	598	603	598	603
AMEREN	COMED	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
AMEREN	CSW_SPP	510	1,000	510	1,000	510	1,000	1,000	1,000	1,000	1,000	1,000	1,000	765	1,000	765	1,000	765	1,000
AMEREN	CWLP	140	170	140	170	140	170	140	350	140	350	140	350	320	320	320	320	320	320
AMEREN	EEI	1,000	-	1,000	-	1,000	-	1,000	330	1,000	330	1,000	330	1,000	500	1,000	500	1,000	500
AMEREN	ENT	50	760	50	760	50	760	400	800	400	800	400	800	451	945	451	945	451	945
AMEREN	IP	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
AMEREN	KCPL	350	1,000	350	1,000	350	1,000	1,000	1,000	1,000	1,000	1,000	1,000	945	1,000	945	1,000	945	1,000
AMEREN	MIDAM	770	800	770	800	770	800	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,050	1,000	1,050	1,000	1,050
AMEREN	MPS	280	950	280	950	280	950	880	930	880	930	880	930	860	1,000	860	1,000	860	1,000
AMEREN	NIPS	115	180	115	180	115	180	115	180	115	180	115	180	115	180	115	180	115	180
AMEREN	SIPC	300	-	300	-	300	-	300	300	300	300	300	300	300	300	300	300	300	300
AMEREN	STJO	350	200	350	200	350	200	1,000	200	1,000	200	1,000	200	945	200	945	200	945	200
AMEREN	SWEPA	300	1,000	300	1,000	300	1,000	680	1,000	680	1,000	680	1,000	1,000	1,000	1,000	1,000	1,000	1,000
AMEREN	TVA	1,000	650	1,000	650	1,000	650	1,000	1,000	1,000	1,000	1,000	1,000	790	1,000	790	1,000	790	1,000
AMEREN	WR	420	650	420	650	420	650	500	1,000	500	1,000	500	1,000	500	630	500	630	500	630
APS	DLCO	345	406	345	406	345	406	400	406	400	406	400	406	425	406	425	406	425	406
APS	FENER	344	970	344	970	344	970	800	970	800	970	800	970	805	970	805	970	805	970
APS	PJM	2,358	3,932	2,358	3,932	2,358	3,932	2,000	4,000	2,000	4,000	2,000	4,000	1,702	4,000	1,702	4,000	1,702	4,000
APS	VP	77	2,265	77	2,265	77	2,265	300	2,200	300	2,200	300	2,200	353	2,278	353	2,278	353	2,278
BEC	BRYN	187	39	187	39	187	39	275	-	275	-	275	-	320	147	320	147	320	147
BEC	DGG	380	732	380	732	380	732	262	832	262	832	262	832	431	948	431	948	431	948
BEC	LCRA	407	650	407	650	407	650	279	-	279	-	279	-	462	950	462	950	462	950
BEC	TMPA	399	374	399	374	399	374	274	141	274	141	274	141	454	742	454	742	454	742
BEC	TNMP	402	340	402	340	402	340	276	-	276	-	276	-	456	778	456	778	456	778
BEC	TU	399	1,374	399	1,374	399	1,374	276	1,207	276	1,207	276	1,207	461	1,233	461	1,233	461	1,233
BEC	WTU	457	613	457	613	457	613	324	643	324	643	324	643	538	789	538	789	538	789

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
BREC	HEC	-	250	-	250	-	250	69	250	69	250	69	250	138	250	138	250	138	250
BREC	SIGE	207	180	207	180	207	180	207	180	207	180	207	180	173	180	173	180	173	180
BREC	SIPC	17	290	17	290	17	290	240	290	240	290	240	290	162	290	162	290	162	290
BREC	TVA	17	1,080	17	1,080	17	1,080	250	1,080	250	1,080	250	1,080	216	1,080	216	1,080	216	1,080
BRYN	DGG	38	183	38	183	38	183	-	291	-	291	-	291	140	314	140	314	140	314
BRYN	TMPA	51	214	51	214	51	214	19	332	19	332	19	332	187	390	187	390	187	390
CAL	HLP	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
CAPO	DUKE	1,500	529	1,500	529	1,500	529	1,500	712	1,500	712	1,500	712	1,500	712	1,500	712	1,500	712
CAPO	SCEG	980	196	980	196	980	196	980	851	980	851	980	851	817	600	817	600	817	600
CAPO	SCPSA	1,304	181	1,304	181	1,304	181	1,300	704	1,300	704	1,300	704	1,449	500	1,449	500	1,449	500
CAPO	TVA	335	335	335	335	335	335	335	335	335	335	335	335	279	279	279	279	279	279
CAPO	VP	1,916	215	1,916	215	1,916	215	600	787	600	787	600	787	717	598	717	598	717	598
CBEN	CPS	262	436	262	436	262	436	-	737	-	737	-	737	415	1,003	415	1,003	415	1,003
CBEN	HLP	256	440	256	440	256	440	715	-	715	-	715	-	603	870	603	870	603	870
CBEN	LCRA	267	629	267	629	267	629	-	616	-	616	-	616	599	812	599	812	599	812
CBEN	STEC	144	910	144	910	144	910	-	1,026	-	1,026	-	1,026	462	1,167	462	1,167	462	1,167
CBEN	VALLEY	787	787	787	787	787	787	787	787	787	787	787	787	787	787	787	787	787	787
CBEN	WTU	254	461	254	461	254	461	-	492	-	492	-	492	615	681	615	681	615	681
CELE	ALEX	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575
CELE	CSW_SPP	-	170	-	7	-	7	243	311	243	311	243	311	162	159	162	159	162	159
CELE	LAFA	49	66	94	25	94	25	39	80	39	80	39	80	37	82	37	82	37	82
CILCO	COMED	450	450	450	450	450	450	450	450	450	450	450	450	725	705	725	705	725	705
CILCO	CWLP	170	130	170	130	170	130	180	310	180	310	180	310	305	295	305	295	305	295
CILCO	IP	450	450	450	450	450	450	450	450	450	450	450	450	875	450	875	450	875	450
CIMO	AECI	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
CIMO	KCPL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CIMO	MPS	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CIN	DPL	1,625	2,467	1,625	2,467	1,625	2,467	2,375	2,500	2,375	2,500	2,375	2,500	2,375	2,500	2,375	2,500	2,375	2,500
CIN	EKPC	311	311	311	311	311	311	349	349	349	349	349	349	317	317	317	317	317	317
CIN	HEC	2,265	1,090	2,265	1,090	2,265	1,090	2,265	1,780	2,265	1,780	2,265	1,780	2,228	1,272	2,228	1,272	2,228	1,272
CIN	IPL	1,430	1,160	1,430	1,160	1,430	1,160	1,300	2,050	1,300	2,050	1,300	2,050	1,408	1,457	1,408	1,457	1,408	1,457
CIN	NIPS	768	1,064	768	1,064	768	1,064	900	1,300	900	1,300	900	1,300	719	1,161	719	1,161	719	1,161
CIN	OVEC	1,860	1,860	1,860	1,860	1,860	1,860	1,897	1,860	1,897	1,860	1,897	1,860	1,866	1,866	1,866	1,866	1,866	1,866
CIN	SIGE	299	299	299	299	299	299	358	350	358	350	358	350	309	309	309	309	309	309
COA	HLP	1,206	466	1,206	466	1,206	466	1,346	-	1,346	-	1,346	-	978	654	978	654	978	654
COA	LCRA	1,287	1,217	1,287	1,217	1,287	1,217	1,465	992	1,465	992	1,465	992	1,225	795	1,225	795	1,225	795
COMED	IP	2,500	1,500	2,500	1,500	2,500	1,500	2,500	1,500	2,500	1,500	2,500	1,500	1,950	1,500	1,950	1,500	1,950	1,500
COMED	MIDAM	1,102	855	1,102	855	1,102	855	1,235	855	1,235	855	1,235	855	1,169	855	1,169	855	1,169	855
COMED	NIPS	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500

Exhibit No. AC-507

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
COMED	WEP	540	500	540	500	540	500	680	720	680	720	680	720	1,200	1,300	1,200	1,300	1,200	1,300
CP	DECO	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
CP	NIPS	60	60	60	60	60	60	60	60	60	60	60	60	66	64	66	64	66	64
CPS	HLP	1,000	609	1,000	609	1,000	609	1,276	-	1,276	-	1,276	-	1,018	967	1,018	967	1,018	967
CPS	LCRA	1,015	711	1,015	711	1,015	711	-	776	-	776	-	776	1,116	767	1,116	767	1,116	767
CPS	STEC	320	663	320	663	320	663	737	735	737	735	737	735	773	664	773	664	773	664
CSW_SPP	DC_E	206	467	564	600	564	600	564	600	564	600	564	600	563	600	563	600	563	600
CSW_SPP	DC_N	-	-	-	36	-	36	-	35	-	35	-	35	-	36	-	36	-	36
CSW_SPP	EDE	118	157	8	201	8	201	419	178	419	178	419	178	329	183	329	183	329	183
CSW_SPP	ENT	50	22	50	22	50	22	1,500	400	1,500	400	1,500	400	1,891	876	1,891	876	1,891	876
CSW_SPP	GRRD	-	293	259	293	259	293	433	208	433	208	433	208	301	420	301	420	301	420
CSW_SPP	OKGE	202	798	1,465	798	1,465	798	702	945	702	945	702	945	696	1,165	696	1,165	696	1,165
CSW_SPP	SWEPA	125	353	-	353	-	353	909	539	909	539	909	539	1,008	860	1,008	860	1,008	860
CSW_SPP	SWPS	207	194	133	-	133	-	188	219	188	219	188	219	154	228	154	228	154	228
CSW_SPP	WEFA	242	223	573	189	573	189	239	354	239	354	239	354	353	242	353	242	353	242
CSW_SPP	WR	174	365	406	406	406	406	406	406	406	406	406	406	203	406	203	406	203	406
CSW_TDU	CSW_SPP	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
CWL	AECI	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
CWL	AMEREN	380	350	380	350	380	350	380	1,000	380	1,000	380	1,000	340	945	340	945	340	945
DC_E	TU	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
DC_N	WTU	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38	38
DGG	TMPA	606	347	606	347	606	347	831	135	831	135	831	135	831	714	831	714	831	714
DLCO	FENER	2,017	2,744	2,017	2,744	2,017	2,744	2,000	4,000	2,000	4,000	2,000	4,000	2,338	4,416	2,338	4,416	2,338	4,416
DPC	NSP	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
DPL	FENER	550	675	550	675	550	675	600	760	600	760	600	760	651	761	651	761	651	761
DPL	OVEC	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
DUK_GL	AMEREN	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
DUKE	SCEG	524	504	524	504	524	504	524	504	524	504	524	504	524	504	524	504	524	504
DUKE	SCPSA	765	600	765	600	765	600	765	800	765	800	765	800	765	836	765	836	765	836
DUKE	SEPA	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
DUKE	SOCO	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
DUKE	TVA	217	217	217	217	217	217	217	217	217	217	217	217	117	217	117	217	117	217
EDE	ENT	325	161	325	161	325	161	161	161	161	161	161	161	161	161	161	161	161	161
EDE	GRRD	134	257	178	28	178	28	155	278	155	278	155	278	160	271	160	271	160	271
EDE	KCPL	157	141	201	-	201	-	178	79	178	79	178	79	183	41	183	41	183	41
EDE	SWEPA	157	199	201	-	201	-	178	449	178	449	178	449	183	359	183	359	183	359
EDE	WR	157	339	149	11	149	11	178	264	178	264	178	264	183	372	183	372	183	372
EEI	TVA	1,837	1,837	1,837	1,837	1,837	1,837	1,800	1,800	1,800	1,800	1,800	1,800	1,865	1,865	1,865	1,865	1,865	1,865
EKPC	TVA	982	982	982	982	982	982	1,000	1,000	1,000	1,000	1,000	1,000	1,029	1,029	1,029	1,029	1,029	1,029

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
ENR_FPL	ALLIANT_W	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
ENRON	TVA	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
ENT	CAJN	1,409	1,397	1,409	1,397	1,409	1,397	1,409	1,397	1,409	1,397	1,409	1,397	1,409	1,397	1,409	1,397	1,409	1,397
ENT	CELE	25	999	25	999	25	999	300	999	300	999	300	999	471	999	471	999	471	999
ENT	LAFA	-	292	-	292	-	292	292	292	292	292	292	292	292	292	292	292	292	292
ENT	LEPA	-	-	-	-	-	-	50	100	50	100	50	100	71	100	71	100	71	100
ENT	OKGE	135	200	135	200	135	200	350	500	350	500	350	500	356	754	356	754	356	754
ENT	SMEPA	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
ENT	SOCO	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
ENT	SWEPA	-	-	-	-	-	-	150	800	150	800	150	800	493	854	493	854	493	854
ENT	TVA	1,507	1,900	1,507	1,900	1,507	1,900	500	1,000	500	1,000	500	1,000	1,277	1,842	1,277	1,842	1,277	1,842
ENT_TDU	ENT	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
FENER	DECO	945	2,200	945	2,200	945	2,200	1,500	1,500	1,500	1,500	1,500	1,500	1,527	1,522	1,527	1,522	1,527	1,522
FENER	PJM	1,643	183	1,643	183	1,643	183	1,401	900	1,401	900	1,401	900	1,401	968	1,401	968	1,401	968
FRONTERA	VALC	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
GRRD	KAMO	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
GRRD	WEFA	262	-	293	165	293	165	208	375	208	375	208	375	368	296	368	296	368	296
GSEC	SWPS	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
HEC	IPL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
HEC	SIGE	250	263	250	263	250	263	250	263	250	263	250	263	257	263	257	263	257	263
HIPG	IP	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
HLP	STEC	330	1,226	330	1,226	330	1,226	-	1,341	-	1,341	-	1,341	1,155	1,100	1,155	1,100	1,155	1,100
HLP	TMPA	1,900	1,421	1,900	1,421	1,900	1,421	1,217	-	1,217	-	1,217	-	1,871	1,562	1,871	1,562	1,871	1,562
HLP	TNMP	665	340	665	340	665	340	577	562	577	562	577	562	795	828	795	828	795	828
HLP	TU	378	1,267	378	1,267	378	1,267	-	2,396	-	2,396	-	2,396	895	1,410	895	1,410	895	1,410
IP	CWLP	160	140	160	140	160	140	160	350	160	350	160	350	320	320	320	320	320	320
IP	EEI	1,400	-	1,400	-	1,400	-	1,200	330	1,200	330	1,200	330	1,450	625	1,450	625	1,450	625
IP	SIPC	350	190	350	190	350	190	340	310	340	310	340	310	400	380	400	380	400	380
IP	TVA	409	409	409	409	409	409	400	409	400	409	400	409	420	420	420	420	420	420
IPL	SIGE	275	286	275	286	275	286	275	286	275	286	275	286	281	286	281	286	281	286
KACY	WR	211	-	143	-	143	-	117	114	117	114	117	114	185	114	185	114	185	114
KCPL	KACY	132	211	170	179	170	179	336	117	336	117	336	117	301	214	301	214	301	214
KCPL	MIDAM	142	92	142	92	142	92	142	117	142	117	142	117	142	105	142	105	142	105
KCPL	MPS	122	308	534	304	534	304	697	483	697	483	697	483	644	457	644	457	644	457
KCPL	STJO	20	106	-	158	-	158	-	259	-	259	-	259	-	173	-	173	-	173
KCPL	WR	414	364	551	651	551	651	1,051	-	1,051	-	1,051	-	769	711	769	711	769	711
KOCH	ENT	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
LCRA	HLP	789	637	789	637	789	637	-	-	-	-	-	-	715	1,336	715	1,336	715	1,336
LCRA	STEC	313	1,529	313	1,529	313	1,529	1,121	1,309	1,121	1,309	1,121	1,309	1,023	1,520	1,023	1,520	1,023	1,520

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
LCRA	TMPA	1,146	474	1,146	474	1,146	474	979	234	979	234	979	234	821	972	821	972	821	972
LCRA	TU	821	572	821	572	821	572	-	582	-	582	-	582	911	757	911	757	911	757
LCRA	WTU	645	459	645	459	645	459	-	488	-	488	-	488	501	682	501	682	501	682
LES	NPPD	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
LES	OPPD	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
LGE	AEP	1,392	1,392	1,392	1,392	1,392	1,392	1,400	1,350	1,400	1,350	1,400	1,350	1,397	1,397	1,397	1,397	1,397	1,397
LGE	BREC	646	19	646	19	646	19	646	180	646	180	646	180	646	174	646	174	646	174
LGE	CIN	1,510	1,950	1,510	1,950	1,510	1,950	1,800	1,635	1,800	1,635	1,800	1,635	1,822	1,850	1,822	1,850	1,822	1,850
LGE	EEI	307	307	307	307	307	307	300	307	300	307	300	307	312	312	312	312	312	312
LGE	EKPC	567	433	567	433	567	433	500	350	500	350	500	350	683	533	683	533	683	533
LGE	OVEC	277	277	277	277	277	277	280	270	280	270	280	270	279	279	279	279	279	279
LGE	SIGE	143	140	143	140	143	140	143	140	143	140	143	140	143	142	143	142	143	142
LGE	TVA	1,497	1,316	1,497	1,316	1,497	1,316	1,500	1,000	1,500	1,000	1,500	1,000	1,504	1,501	1,504	1,501	1,504	1,501
MGE	WEP	200	90	200	90	200	90	200	230	200	230	200	230	800	840	800	840	800	840
MIDAM	IP	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201
MIDAM	LES	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107
MIDAM	NPPD	1,026	380	1,026	380	1,026	380	1,053	542	1,053	542	1,053	542	1,041	461	1,041	461	1,041	461
MIDAM	NSP	946	694	946	694	946	694	946	998	946	998	946	998	947	846	947	846	947	846
MIDAM	OPPD	1,074	409	1,074	409	1,074	409	1,064	409	1,064	409	1,064	409	1,069	409	1,069	409	1,069	409
MIDAM	STJO	247	309	247	309	247	309	272	309	272	309	272	309	260	309	260	309	260	309
MIDW	SEC	116	57	103	250	103	250	165	143	165	143	165	143	80	254	80	254	80	254
MIDW	WR	-	127	-	151	-	151	-	148	-	148	-	148	221	182	221	182	221	182
MP	MPC	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
MP	NSP	2,169	1,000	2,169	1,000	2,169	1,000	2,169	1,000	2,169	1,000	2,169	1,000	2,169	1,000	2,169	1,000	2,169	1,000
MP	OTP	907	200	907	200	907	200	907	200	907	200	907	200	907	200	907	200	907	200
MPC	WAPA	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
MPS	WR	308	97	144	234	144	234	400	235	400	235	400	235	400	235	400	235	400	235
NEWGULF	CBEN	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
NPPD	BEPC	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850
NPPD	OPPD	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
NPPD	SEC	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
NPPD	STJO	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
NPPD	WAPA	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NRG	COMED	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
NSP	OTP	36	133	36	133	36	133	36	133	36	133	36	133	36	133	36	133	36	133
NSP	WEP	330	500	330	500	330	500	420	956	420	956	420	956	676	956	676	956	676	956
NSP	WPS	330	440	330	440	330	440	420	870	420	870	420	870	1,300	720	1,300	720	1,300	720
NSPI	NSP	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
OKGE	GRRD	97	206	97	206	97	206	97	208	97	208	97	208	97	206	97	206	97	206

Exhibit No. AC-507

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
OKGE	SWEPA	604	317	604	-	604	-	604	539	604	539	604	539	604	436	604	436	604	436
OKGE	WEFA	360	223	567	189	567	189	579	399	579	399	579	399	469	363	469	363	469	363
OKGE	WR	474	358	152	422	152	422	-	484	-	484	-	484	835	570	835	570	835	570
OKGE_TDU	OKGE	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
OPPD	STJO	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
OPPD	WR	321	200	321	200	321	200	321	200	321	200	321	200	321	200	321	200	321	200
OTP	MPC	133	942	133	942	133	942	133	942	133	942	133	942	133	942	133	942	133	942
OTP	WAPA	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
PJM	NYPP	3,100	2,150	3,100	2,150	3,100	2,150	3,100	2,150	3,100	2,150	3,100	2,150	3,100	2,150	3,100	2,150	3,100	2,150
PJM	VP	133	2,250	133	2,250	133	2,250	1,000	2,000	1,000	2,000	1,000	2,000	1,090	2,446	1,090	2,446	1,090	2,446
POL	WPS	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
SCEG	SCPSA	503	285	503	285	503	285	500	500	500	500	500	500	562	535	562	535	562	535
SCEG	SOCO	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
SCPSA	SOCO	900	1,015	900	1,015	900	1,015	900	1,000	900	1,000	900	1,000	1,013	915	1,013	915	1,013	915
SEPA	SCEG	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
SEPA	SCPSA	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
SEPA	SOCO	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
SIKE	SWEPA	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
SMEPA	ALEC	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
SMMP	DPC	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
SMMP	NSP	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
SOCO	ALEC	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
SOCO	SMEPA	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
SOCO	TVA	1,700	2,200	1,700	2,200	1,700	2,200	2,000	1,600	2,000	1,600	2,000	1,600	2,133	2,067	2,133	2,067	2,133	2,067
SON_CAL	SOCO	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
SPRM	AECI	16	-	5	-	5	-	157	339	157	339	157	339	163	151	163	151	163	151
SPRM	SWEPA	16	353	6	353	6	353	121	350	121	350	121	350	126	344	126	344	126	344
SWEENY	CBEN	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
SWEPA	GRRD	237	249	-	280	-	280	507	195	507	195	507	195	455	433	455	433	455	433
SWEPA	WEFA	353	212	-	178	-	178	467	388	467	388	467	388	413	352	413	352	413	352
SWPS	WEPL	103	75	103	75	103	75	103	75	103	75	103	75	103	75	103	75	103	75
TENG	TVA	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
TMPA	STEC	329	1,258	329	1,258	329	1,258	249	1,244	249	1,244	249	1,244	808	1,121	808	1,121	808	1,121
TNMP	WTU	340	443	340	443	340	443	-	471	-	471	-	471	777	621	777	621	777	621
TU	TMPA	629	357	629	357	629	357	946	139	946	139	946	139	957	740	957	740	957	740
TU	TNMP	615	340	615	340	615	340	557	-	557	-	557	-	764	817	764	817	764	817
TU	WTU	1,028	468	1,028	468	1,028	468	1,322	501	1,322	501	1,322	501	1,099	707	1,099	707	1,099	707
VALC	VALLEY	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML
VALP	VALLEY	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML

Exhibit No. AC-507

Transmission Capacity (ATC Data)

From	To	Summer						Winter						Shoulder					
		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak		Super Peak		Peak		Off Peak	
Node	Node	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
WAPA	BEPC	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
WAPA	MIDAM	608	793	608	793	608	793	686	793	686	793	686	793	675	793	675	793	675	793
WAPA	NSP	1,284	1,284	1,284	1,284	1,284	1,284	1,307	1,307	1,307	1,307	1,307	1,307	1,296	1,296	1,296	1,296	1,296	1,296
WAPA	SWEPA	30	138	30	138	30	138	40	138	40	138	40	138	42	138	42	138	42	138
WEP	WPPI	250	200	250	200	250	200	250	200	250	200	250	200	250	200	250	200	250	200
WEP	WPS	230	430	230	430	230	430	210	810	210	810	210	810	3,060	3,000	3,060	3,000	3,060	3,000
WEPL	SEC	177	57	244	180	244	180	309	59	309	59	309	59	344	175	344	175	344	175
WEPL	WR	146	132	146	244	146	244	194	200	194	200	194	200	315	100	315	100	315	100
WES	SOCO	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML	ML

NOTES:
[1] ML = Modeling Line.
[2] The Merger ATC Value is equal to the Base ATC Value for all interconnections, except those listed below.
(i) AEP to Ameren: the Merger ATC Value equals the Base ATC Value plus 370.
(ii) Ameren to CSW (SPP): the Merger ATC Value equals the Base ATC Value less 250.

Exhibit No. AC-508

1997 Load
Central Time Zone Based upon CSW (SPP)

	Summer			Winter			Shoulder		
Node	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak
AECI	2,268	1,780	1,492	2,070	1,641	1,527	2,104	1,377	1,216
AEP	16,554	14,764	11,875	16,970	15,099	13,475	14,943	13,941	11,610
ALEC	1,191	950	791	924	754	749	1,085	720	632
ALEX	124	95	76	87	75	64	104	69	56
ALLIANT_E	1,799	1,677	1,293	1,763	1,656	1,306	1,637	1,565	1,208
ALLIANT_W	2,753	2,753	2,753	2,753	2,753	2,753	2,753	2,753	2,753
AMEREN	8,564	6,888	5,906	7,191	6,141	5,727	7,060	5,563	4,911
APS	6,075	5,521	4,872	6,487	5,867	5,515	5,504	5,320	4,761
BEC	1,058	793	663	929	613	613	967	542	490
BEPC	1,313	1,292	1,201	1,338	1,314	1,243	1,263	1,250	1,168
BREC	1,106	1,014	942	1,070	992	970	1,050	947	906
BRYN	209	165	133	145	110	100	195	116	96
CAPO	9,053	7,601	5,981	7,447	6,611	5,888	7,827	6,128	5,011
CBEN	2,686	2,339	1,998	2,197	1,691	1,537	2,555	1,825	1,543
CELE	1,389	1,161	946	1,043	863	800	1,286	894	767
CILCO	911	802	675	806	732	632	803	701	583
CIMO	210	156	125	121	109	90	170	104	84
CIN	8,652	7,294	5,840	7,942	6,890	6,031	7,338	6,354	5,196
COA	1,693	1,411	1,127	1,210	973	855	1,603	1,035	847
COMED	13,972	12,206	9,561	12,492	11,435	9,301	12,069	10,680	8,274
CP	5,727	5,133	4,342	5,256	4,927	4,262	5,098	4,776	4,044
CPS	3,052	2,544	2,048	2,009	1,613	1,402	2,866	1,789	1,445
CSW_SPP	7,516	5,863	4,763	5,433	4,510	3,991	6,581	4,422	3,708
CWL	218	166	133	153	132	113	183	121	98
CWLP	328	263	214	275	235	207	270	213	176
DECO	7,832	6,876	5,816	6,743	6,367	5,499	6,865	6,217	5,254
DGG	720	558	449	511	393	347	650	395	324
DLCO	2,076	1,838	1,447	1,818	1,698	1,397	1,810	1,617	1,279
DPC	674	578	458	557	511	415	582	493	384
DPL	2,375	2,027	1,610	2,313	2,010	1,720	2,050	1,855	1,474
DUKE	14,973	12,753	10,996	12,608	11,298	10,504	13,159	10,687	9,307
EDE	774	598	465	692	550	484	650	484	385
EKPC	1,337	1,070	867	1,505	1,200	1,163	1,102	999	863
ENT	18,331	15,646	13,254	13,664	12,072	11,056	16,925	12,533	10,925
FENER	9,469	8,473	6,698	9,185	8,425	6,993	8,431	7,977	6,329
GRRD	1,007	747	740	723	590	553	847	567	610
HEC	669	532	429	700	569	531	525	475	401
HLP	12,136	10,304	8,661	8,490	7,243	6,418	11,278	7,857	6,678
IP	3,222	2,815	2,205	2,881	2,637	2,145	2,783	2,463	1,908
IPL	2,275	1,893	1,499	2,124	1,809	1,584	1,925	1,627	1,313
KACY	403	342	289	311	279	239	358	273	227
KAMO	410	313	251	288	248	213	344	227	185
KCPL	2,597	2,078	1,675	1,807	1,614	1,366	2,241	1,538	1,239
LAFA	373	309	233	255	204	172	346	223	171
LCRA	1,928	1,565	1,287	1,739	1,191	1,162	1,774	1,125	976
LEPA	200	166	130	122	102	86	189	115	91
LES	503	408	315	366	331	269	420	314	242
LGE	5,073	4,136	3,211	4,312	3,653	3,180	4,173	3,376	2,696
MGE	464	411	309	391	373	290	415	361	277
MIDAM	3,081	2,643	2,093	2,547	2,337	1,898	2,659	2,253	1,753
MIDW	148	121	103	102	97	85	123	93	81
MP	1,245	1,226	1,139	1,269	1,246	1,179	1,198	1,186	1,108
MPC	308	290	219	531	467	438	300	358	304
MPS	930	711	569	653	563	483	782	515	419
NIPS	2,214	2,032	1,720	2,111	1,947	1,733	2,019	1,860	1,587
NPPD	1,699	1,392	1,200	1,402	1,232	1,083	1,241	1,143	955
NSP	5,991	5,497	4,197	5,403	5,071	4,035	5,414	4,841	3,693
NYPP	23,330	20,601	16,660	21,214	19,220	16,725	20,007	17,093	14,974
OKGE	4,479	3,489	2,869	3,245	2,759	2,406	4,012	2,681	2,247
OPPD	1,516	1,252	1,006	1,119	1,014	856	1,281	968	787
OTP	438	421	316	577	526	450	382	436	343
PJM	38,230	33,758	27,307	34,763	31,495	27,412	32,785	28,010	24,543
SCEG	3,322	2,726	2,387	2,486	2,234	2,213	2,858	2,170	2,014
SCPSA	3,031	2,488	2,178	2,269	2,039	2,020	2,608	1,980	1,838

Exhibit No. AC-508

1997 Load
Central Time Zone Based upon CSW (SPP)

	Summer			Winter			Shoulder		
Node	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak
SEC	286	241	209	201	197	173	249	206	180
SIGE	959	794	633	767	694	594	869	680	552
SIKE	55	42	34	39	33	29	46	31	25
SIPC	178	138	117	180	143	139	142	119	107
SMEPA	887	757	642	661	584	535	819	607	529
SMMP	380	334	254	327	308	233	343	299	220
SOCO	33,663	28,731	24,338	25,091	22,169	20,303	31,081	23,016	20,063
SPRM	508	390	307	345	309	252	438	300	236
STEC	206	174	154	186	121	124	190	119	109
STJO	287	235	188	261	220	189	246	192	153
SWPS	3,434	2,897	2,561	2,639	2,450	2,222	2,994	2,452	2,192
TMPA	2,021	1,547	1,272	1,609	1,141	1,081	1,857	1,081	935
TNMP	1,286	1,107	938	947	777	727	1,197	846	750
TU	18,793	15,092	11,982	14,503	11,206	10,112	17,269	11,130	9,243
TVA	24,392	20,205	17,041	21,701	18,053	17,223	20,814	16,745	14,747
VALC	1,131	985	841	925	712	647	1,076	769	650
VALP	168	140	112	110	89	77	157	98	79
VP	11,999	10,461	8,782	10,767	9,573	9,029	10,328	8,592	7,507
WEFA	746	605	524	687	556	522	708	484	434
WEP	4,253	3,961	3,125	3,955	3,806	3,059	4,047	3,768	2,969
WEPL	380	308	257	273	252	214	334	252	209
WPPI	477	445	343	468	439	346	434	415	320
WPS	1,617	1,508	1,163	1,586	1,489	1,174	1,472	1,407	1,086
WR	3,932	3,217	2,622	2,518	2,483	2,116	3,595	2,530	2,112
WTU	1,157	978	846	929	801	733	1,127	795	701

Source:
1997 FERC Form 714 Data (before adjustment for load growth to 1999)
For utilities where data were not available, energy and peak figures were applied to load shapes of nearby utilities.

Exhibit No. AC-508

1997 Load
Eastern Time Zone Based upon AEP

	Summer			Winter			Shoulder		
Node	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak
AECI	2,214	1,789	1,492	2,030	1,647	1,527	1,826	1,399	1,216
AEP	17,623	14,584	11,875	17,296	15,045	13,475	16,024	13,857	11,610
ALEC	1,127	961	791	956	749	749	901	734	632
ALEX	123	95	76	85	75	64	86	70	56
ALLIANT_E	1,938	1,654	1,293	1,762	1,656	1,306	1,753	1,556	1,208
ALLIANT_W	2,897	2,434	2,025	2,539	2,346	1,992	2,524	2,262	1,851
AMEREN	8,893	6,832	5,906	7,107	6,155	5,727	6,680	5,593	4,911
APS	6,518	5,447	4,872	6,594	5,849	5,515	6,039	5,279	4,761
BEC	971	808	663	841	627	613	734	560	490
BEPC	1,319	1,291	1,201	1,339	1,314	1,243	1,311	1,247	1,168
BREC	1,109	1,014	942	1,071	991	970	1,031	949	906
BRYN	197	167	133	136	112	100	139	120	96
CAPO	9,084	7,595	5,981	7,763	6,559	5,888	7,457	6,157	5,011
CBEN	2,550	2,362	1,998	2,076	1,711	1,537	1,978	1,870	1,543
CELE	1,317	1,173	946	1,024	866	800	1,014	915	767
CILCO	981	790	675	801	732	632	791	702	583
CIMO	209	156	125	120	109	90	131	107	84
CIN	9,238	7,195	5,840	7,990	6,882	6,031	7,420	6,347	5,196
COA	1,596	1,427	1,127	1,147	983	855	1,181	1,068	847
COMED	15,753	11,906	9,561	12,439	11,444	9,301	11,905	10,692	8,274
CP	6,199	5,054	4,342	5,264	4,925	4,262	5,236	4,765	4,044
CPS	2,840	2,580	2,048	1,906	1,630	1,402	2,004	1,856	1,445
CSW_SPP	7,099	5,933	4,763	5,259	4,538	3,991	5,314	4,521	3,708
CWL	216	167	133	150	132	113	152	123	98
CWLP	340	261	214	272	235	207	255	214	176
DECO	8,712	6,728	5,816	6,762	6,363	5,499	6,712	6,229	5,254
DGG	668	567	449	480	398	347	477	408	324
DLCO	2,289	1,802	1,447	1,842	1,694	1,397	1,780	1,620	1,279
DPC	718	571	458	554	512	415	556	495	384
DPL	2,565	1,995	1,610	2,332	2,007	1,720	2,151	1,848	1,474
DUKE	15,238	12,709	10,996	13,008	11,231	10,504	12,735	10,720	9,307
EDE	755	601	465	671	553	484	600	488	385
EKPC	1,374	1,064	867	1,555	1,192	1,163	1,300	983	863
ENT	17,623	15,765	13,254	13,519	12,096	11,056	13,871	12,771	10,925
FENER	10,429	8,311	6,698	9,230	8,418	6,993	8,828	7,946	6,329
GRRD	943	757	740	697	594	657	709	578	610
HEC	720	523	429	706	568	531	608	468	401
HLP	11,507	10,410	8,661	8,167	7,296	6,418	8,569	8,067	6,678
IP	3,633	2,745	2,205	2,868	2,639	2,145	2,745	2,466	1,908
IPL	2,430	1,867	1,499	2,125	1,809	1,584	1,913	1,628	1,313
KACY	407	341	289	306	280	239	310	277	227
KAMO	406	314	251	283	249	213	286	231	185
KCPL	2,582	2,081	1,675	1,774	1,620	1,366	1,845	1,569	1,239
LAFA	356	312	233	249	205	172	247	231	171
LCRA	1,801	1,586	1,287	1,614	1,212	1,162	1,378	1,156	976
LEPA	190	168	130	120	102	86	129	120	91
LES	502	408	315	362	332	269	364	318	242
LGE	5,235	4,108	3,211	4,371	3,643	3,180	4,055	3,385	2,696
MGE	497	405	309	392	373	290	393	363	271
MIDAM	3,280	2,609	2,093	2,532	2,340	1,898	2,539	2,263	1,753
MIDW	147	121	103	101	97	85	105	95	81
MP	1,251	1,225	1,139	1,270	1,246	1,179	1,244	1,183	1,108
MPC	308	290	219	521	469	438	424	349	304
MPS	921	712	569	642	565	483	650	525	419
NIPS	2,396	2,001	1,720	2,121	1,945	1,733	1,993	1,862	1,587
NPPD	1,655	1,400	1,200	1,382	1,235	1,083	1,312	1,138	955
NSP	6,333	5,439	4,197	5,385	5,074	4,035	5,308	4,849	3,693
NYPP	25,240	20,279	16,660	21,421	19,186	16,725	17,901	17,257	14,974
OKGE	4,214	3,534	2,869	3,135	2,777	2,406	3,230	2,741	2,247
OPPD	1,531	1,249	1,006	1,107	1,016	856	1,119	981	787
OTP	464	416	316	569	527	450	465	430	343
PJM	41,360	33,231	27,307	35,101	31,439	27,412	29,333	28,278	24,543
SCEG	3,223	2,742	2,387	2,606	2,215	2,213	2,581	2,191	2,014
SCPSA	2,942	2,503	2,178	2,378	2,021	2,020	2,356	1,999	1,838

1997 Load
Eastern Time Zone Based upon AEP

	Summer			Winter			Shoulder		
Node	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak	Super Peak	Peak	Off Peak
SEC	276	243	209	201	197	173	224	208	180
SIGE	994	788	633	780	691	594	786	686	552
SIKE	55	42	34	38	33	29	38	31	25
SIPC	183	138	117	179	143	139	153	118	107
SMEPA	853	763	642	654	586	535	671	618	529
SMMP	398	331	254	326	308	233	328	301	220
SOCO	32,362	28,950	24,338	24,826	22,213	20,303	25,473	23,452	20,063
SPRM	498	392	307	341	310	252	360	306	236
STEC	193	176	154	168	124	124	141	123	109
STJO	290	235	188	255	221	189	232	193	153
SWPS	3,341	2,913	2,561	2,591	2,458	2,222	2,642	2,479	2,192
TMPA	1,866	1,573	1,272	1,482	1,162	1,081	1,389	1,117	935
TNMP	1,239	1,115	938	908	784	727	942	866	750
TU	17,623	15,289	11,982	13,630	11,351	10,112	13,277	11,440	9,243
TVA	24,281	20,223	17,041	21,851	18,028	17,223	20,018	16,807	14,747
VALC	1,074	995	841	874	720	647	833	787	650
VALP	156	142	112	105	90	77	110	102	79
VP	12,802	10,326	8,782	11,105	9,517	9,029	10,373	8,588	7,507
WEFA	737	607	524	655	561	522	611	492	434
WEP	4,565	3,908	3,125	3,936	3,809	3,059	4,049	3,768	2,969
WEPL	366	311	257	270	253	214	295	255	209
WPPI	514	439	343	467	439	346	465	413	320
WPS	1,742	1,487	1,163	1,584	1,489	1,174	1,576	1,399	1,086
WR	3,773	3,244	2,622	2,501	2,486	2,116	2,993	2,577	2,112
WTU	1,090	989	846	894	807	733	919	811	701

Source:
1997 FERC Form 714 Data (before adjustment for load growth to 1999)
For utilities where data were not available, energy and peak figures were applied to load shapes of nearby utilities.

Exhibit No. AC-509

Total Capacity
(AEP and CSW Direct Interconnections)

Node	1999 Pre-Merger Total Capacity	Pre-Merger Market Share	Pre-Merger HHI	Post-Merger Total Capacity	Post-Merger Market Share	Post-Merger HHI
Applicants						
AEP	23,540	6.9%	47	NA	NA	NA
CSW *	15,307	4.5%	20	NA	NA	NA
AEP + CSW	NA	NA	NA	38,847	11.4%	129
Direct Interconnections						
AMEREN	11,109	3.3%	11	11,109	3.3%	11
APS	8,914	2.6%	7	8,914	2.6%	7
CELE	1,862	0.5%	0	1,862	0.5%	0
CIN	10,936	3.2%	10	10,936	3.2%	10
COA	2,329	0.7%	0	2,329	0.7%	0
COMED	21,941	6.4%	41	21,941	6.4%	41
CPS	4,515	1.3%	2	4,515	1.3%	2
DLCO	2,668	0.8%	1	2,668	0.8%	1
DPL	3,274	1.0%	1	3,274	1.0%	1
EDE	977	0.3%	0	977	0.3%	0
EKPC	2,538	0.7%	1	2,538	0.7%	1
Entergy Subregion (1)	27,004	7.9%	62	27,004	7.9%	62
FENER	12,944	3.8%	14	12,944	3.8%	14
GRRD	967	0.3%	0	967	0.3%	0
HLP	14,540	4.3%	18	14,540	4.3%	18
IP	4,950	1.4%	2	4,950	1.4%	2
IPL	2,956	0.9%	1	2,956	0.9%	1
LCRA	2,667	0.8%	1	2,667	0.8%	1
LGE	7,160	2.1%	4	7,160	2.1%	4
MECS (2)	20,196	5.9%	35	20,196	5.9%	35
NIPS	3,392	1.0%	1	3,392	1.0%	1
OKGE	6,199	1.8%	3	6,199	1.8%	3
STEC	389	0.1%	0	389	0.1%	0
SWEPA	209	0.1%	0	209	0.1%	0
SWPS	4,145	1.2%	1	4,145	1.2%	1
TMPA	2,880	0.8%	1	2,880	0.8%	1
TNMP	1,084	0.3%	0	1,084	0.3%	0
TU	22,367	6.5%	43	22,367	6.5%	43
TVA	29,754	8.7%	76	29,754	8.7%	76
VACAR Subregion (3)	57,981	17.0%	288	57,981	17.0%	288
VALP	232	0.1%	0	232	0.1%	0
WEFA	1,226	0.4%	0	1,226	0.4%	0
WR	5,035	1.5%	2	5,035	1.5%	2
New Merchant Capacity						
Total Merchant Capacity	3,549	1.0%	0	3,549	1.0%	0
Total:	341,736	100.0%	694	341,736	100.0%	756
Change in HHI:						62

(1) Includes AECI, ENT and CAJN.
(2) Includes CP and DECO.
(3) Includes: CAPO, DUKE, SCEG, SCPSA, SEPA and VP.
* Value represents CSWE's Total Capacity plus 750 MW Merchant Plant Capacity.

Total Capacity
(AEP and CSW Direct Interconnections)

Node	2000					
	Pre-Merger			Post-Merger		
	Total Capacity	Market Share	HHI	Total Capacity	Market Share	HHI
Applicants						
AEP	23,595	6.7%	44	NA	NA	NA
CSW *	15,097	4.3%	18	NA	NA	NA
AEP + CSW	NA	NA	NA	38,692	10.9%	120
Direct Interconnections						
AMEREN	11,526	3.3%	11	11,526	3.3%	11
APS	9,044	2.6%	7	9,044	2.6%	7
CELE	1,908	0.5%	0	1,908	0.5%	0
CIN	10,886	3.1%	9	10,886	3.1%	9
COA	2,436	0.7%	0	2,436	0.7%	0
COMED	22,331	6.3%	40	22,331	6.3%	40
CPS	4,515	1.3%	2	4,515	1.3%	2
DLCO	2,668	0.8%	1	2,668	0.8%	1
DPL	3,274	0.9%	1	3,274	0.9%	1
EDE	1,009	0.3%	0	1,009	0.3%	0
EKPC	2,473	0.7%	0	2,473	0.7%	0
Entergy Subregion (1)	27,825	7.9%	62	27,825	7.9%	62
FENER	13,456	3.8%	14	13,456	3.8%	14
GRRD	967	0.3%	0	967	0.3%	0
HLP	14,540	4.1%	17	14,540	4.1%	17
IP	4,847	1.4%	2	4,847	1.4%	2
IPL	2,956	0.8%	1	2,956	0.8%	1
LCRA	2,764	0.8%	1	2,764	0.8%	1
LGE	7,357	2.1%	4	7,357	2.1%	4
MECS (2)	20,480	5.8%	33	20,480	5.8%	33
NIPS	3,392	1.0%	1	3,392	1.0%	1
OKGE	6,199	1.8%	3	6,199	1.8%	3
STEC	400	0.1%	0	400	0.1%	0
SWEPA	209	0.1%	0	209	0.1%	0
SWPS	4,091	1.2%	1	4,091	1.2%	1
TMPA	2,937	0.8%	1	2,937	0.8%	1
TNMP	1,097	0.3%	0	1,097	0.3%	0
TU	22,780	6.4%	41	22,780	6.4%	41
TVA	30,386	8.6%	74	30,386	8.6%	74
VACAR Subregion (3)	58,076	16.4%	269	58,076	16.4%	269
VALP	240	0.1%	0	240	0.1%	0
WEFA	1,226	0.3%	0	1,226	0.3%	0
WR	4,968	1.4%	2	4,968	1.4%	2
New Merchant Capacity						
Total Merchant Capacity	11,888	3.4%	1	11,888	3.4%	1
Total:	353,843	100.0%	661	353,843	100.0%	718
Change in HHI:						57

(1) Includes AECI, ENT and CAJN.
(2) Includes CP and DECO.
(3) Includes: CAPO, DUKE, SCEG, SCPSA, SEPA and VP.
* Value represents CSWE's Total Capacity plus 750 MW Merchant Plant Capacity.

Total Capacity
(AEP and CSW Direct Interconnections)

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Node	2001					
	Pre-Merger			Post-Merger		
	Total Capacity	Market Share	HHI	Total Capacity	Market Share	HHI
Applicants						
AEP	23,611	7%	42	NA	NA	NA
CSW *	15,527	4%	18	NA	NA	NA
AEP + CSW	NA	NA	NA	39,138	11%	116
Direct Interconnections						
AMEREN	11,619	3%	10	11,619	3%	10
APS	8,984	2%	6	8,984	2%	6
CELE	1,950	1%	0	1,950	1%	0
CIN	10,886	3%	9	10,886	3%	9
COA	2,543	1%	0	2,543	1%	0
COMED	22,511	6%	38	22,511	6%	38
CPS	4,515	1%	2	4,515	1%	2
DLCO	2,668	1%	1	2,668	1%	1
DPL	3,274	1%	1	3,274	1%	1
EDE	979	0%	0	979	0%	0
EKPC	2,553	1%	0	2,553	1%	0
Entergy Subregion (1)	28,073	8%	60	28,073	8%	60
FENER	14,274	4%	15	14,274	4%	15
GRRD	967	0%	0	967	0%	0
HLP	14,540	4%	16	14,540	4%	16
IP	4,847	1%	2	4,847	1%	2
IPL	2,956	1%	1	2,956	1%	1
LCRA	2,882	1%	1	2,882	1%	1
LGE	7,475	2%	4	7,475	2%	4
MECS (2)	20,958	6%	33	20,958	6%	33
NIPS	3,392	1%	1	3,392	1%	1
OKGE	6,218	2%	3	6,218	2%	3
STEC	403	0%	0	403	0%	0
SWEPA	240	0%	0	240	0%	0
SWPS	4,070	1%	1	4,070	1%	1
TMPA	2,997	1%	1	2,997	1%	1
TNMP	1,111	0%	0	1,111	0%	0
TU	23,224	6%	41	23,224	6%	41
TVA	31,131	9%	73	31,131	9%	73
VACAR Subregion (3)	59,739	16%	270	59,739	16%	270
VALP	252	0%	0	252	0%	0
WEFA	1,226	0%	0	1,226	0%	0
WR	5,040	1%	2	5,040	1%	2
New Merchant Capacity						
Total Merchant Capacity	15,603	4%	1	15,603	4%	1
Total:	363,238	100%	654	363,238	100%	709
Change in HHI:						56

(1) Includes AECI, ENT and CAJN.
(2) Includes CP and DECO.
(3) Includes: CAPO, DUKE, SCEG, SCPSA, SEPA and VP.
* Value represents CSWE's Total Capacity plus 750 MW Merchant Plant Capacity.

Uncommitted Capacity
(AEP and CSW Direct Interconnections)

Node	1999					
	Pre-Merger			Post-Merger		
	Uncommitted Capacity	Market Share	HHI	Uncommitted Capacity	Market Share	HHI
Applicants						
AEP	495	5.9%	34	NA	NA	NA
CSW*	705	8.4%	70	NA	NA	NA
AEP + CSW	NA	NA	NA	1,200	14.2%	202
Direct Interconnections						
AMEREN	0	0.0%	0	0	0.0%	0
APS	139	1.6%	3	139	1.6%	3
CELE	0	0.0%	0	0	0.0%	0
CIN	0	0.0%	0	0	0.0%	0
COA	0	0.0%	0	0	0.0%	0
COMED	0	0.0%	0	0	0.0%	0
CPS	313	3.7%	14	313	3.7%	14
DLCO	0	0.0%	0	0	0.0%	0
DPL	88	1.0%	1	88	1.0%	1
EDE	0	0.0%	0	0	0.0%	0
EKPC	540	6.4%	41	540	6.4%	41
Entergy Subregion (1)	103	1.2%	1	103	1.2%	1
FENER	0	0.0%	0	0	0.0%	0
GRRD	0	0.0%	0	0	0.0%	0
HLP	262	3.1%	10	262	3.1%	10
IP	409	4.9%	24	409	4.9%	24
IPL	0	0.0%	0	0	0.0%	0
LCRA	111	1.3%	2	111	1.3%	2
LGE	141	1.7%	3	141	1.7%	3
MECS (2)	309	3.7%	13	309	3.7%	13
NIPS	295	3.5%	12	295	3.5%	12
OKGE	491	5.8%	34	491	5.8%	34
STEC	11	0.1%	0	11	0.1%	0
SWEPA	0	0.0%	0	0	0.0%	0
SWPS	149	1.8%	3	149	1.8%	3
TMPA	212	2.5%	6	212	2.5%	6
TNMP	0	0.0%	0	0	0.0%	0
TU	603	7.2%	51	603	7.2%	51
TVA	0	0.0%	0	0	0.0%	0
VACAR Subregion (3)	0	0.0%	0	0	0.0%	0
VALP	2	0.0%	0	2	0.0%	0
WEFA	81	1.0%	1	81	1.0%	1
WR	182	2.2%	5	182	2.2%	5
New Merchant Capacity						
Total Merchant Capacity	2,796	33.1%	163	2,796	33.1%	163
Total:	8,435	100.0%	491	8,435	100.0%	589
Change in HHI:						98

(1) Includes AECI, ENT and CAJN.
(2) Includes CP and DECO.
(3) Includes: CAPO, DUKE, SCEG, SCPSA, SEPA and VP.
* Value represents CSWE's Uncommitted Merchant Plant Capacity. Both CSW_SPP and CSW_ERCOT have negative uncommitted capacity.

Uncommitted Capacity
(AEP and CSW Direct Interconnections)

	2001					
	Pre-Merger			Post-Merger		
Node	Uncommitted Capacity	Market Share	HHI	Uncommitted Capacity	Market Share	HHI
Applicants						
AEP	701	4%	17	NA	NA	NA
CSW*	705	4%	17	NA	NA	NA
AEP + CSW	NA	NA	NA	1,406	8%	67
Direct Interconnections						
AMEREN	113	1%	0	113	1%	0
APS	0	0%	0	0	0%	0
CELE	0	0%	0	0	0%	0
CIN	0	0%	0	0	0%	0
COA	90	1%	0	90	1%	0
COMED	0	0%	0	0	0%	0
CPS	40	0%	0	40	0%	0
DLCO	0	0%	0	0	0%	0
DPL	113	1%	0	113	1%	0
EDE	0	0%	0	0	0%	0
EKPC	245	1%	2	245	1%	2
Entergy Subregion (1)	294	2%	3	294	2%	3
FENER	757	4%	19	757	4%	19
GRRD	0	0%	0	0	0%	0
HLP	7	0%	0	7	0%	0
IP	0	0%	0	0	0%	0
IPL	0	0%	0	0	0%	0
LCRA	100	1%	0	100	1%	0
LGE	149	1%	1	149	1%	1
MECS (2)	211	1%	2	211	1%	2
NIPS	227	1%	2	227	1%	2
OKGE	286	2%	3	286	2%	3
STEC	1	0%	0	1	0%	0
SWEPA	0	0%	0	0	0%	0
SWPS	110	1%	0	110	1%	0
TMPA	134	1%	1	134	1%	1
TNMP	13	0%	0	13	0%	0
TU	530	3%	9	530	3%	9
TVA	0	0%	0	0	0%	0
VACAR Subregion (3)	0	0%	0	0	0%	0
VALP	1	0%	0	1	0%	0
WEFA	39	0%	0	39	0%	0
WR	2	0%	0	2	0%	0
New Merchant Capacity						
Total Merchant Capacity	12,331	72%	257	12,331	72%	257
Total:	17,198	100%	334	17,198	100%	367
Change in HHI:						33

(1) Includes AECI, ENT and CAJN.
(2) Includes CP and DECO.
(3) Includes: CAPO, DUKE, SCEG, SCPSA, SEPA and VP.
* Value represents CSWE's Uncommitted Merchant Plant Capacity. Both CSW_SPP and CSW_ERCOT have negative uncommitted capacity.

Base Case (Pre-Mitigation)

Exhibit No. AC-511

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CSW_SPP	Economic Capacity	S_35	0.20%	63.40%	4,114	65.00%	4,311	198
CSW_SPP	Economic Capacity	S_SP	0.30%	62.00%	3,937	63.60%	4,140	203
CSW_SPP	Economic Capacity	S_P	0.30%	53.30%	3,049	56.10%	3,352	303
CSW_SPP	Economic Capacity	S_OP	0.40%	49.00%	2,645	52.00%	2,952	307
CSW_SPP	Economic Capacity	W_SP	0.40%	56.50%	3,306	58.10%	3,488	182
CSW_SPP	Economic Capacity	W_P	0.70%	37.60%	1,649	40.30%	1,852	203
CSW_SPP	Economic Capacity	W_OP	0.90%	37.80%	1,658	40.70%	1,877	218
CSW_SPP	Economic Capacity	SH_SP	0.50%	50.60%	2,714	52.10%	2,862	148
CSW_SPP	Economic Capacity	SH_P	0.90%	36.50%	1,561	39.10%	1,757	196
CSW_SPP	Economic Capacity	SH_OP	1.50%	32.00%	1,313	35.20%	1,507	193
CBEN	Economic Capacity	S_35	0.00%	66.80%	4,691	66.80%	4,690	-1
CBEN	Economic Capacity	S_SP	0.00%	64.00%	4,371	65.30%	4,545	174
CBEN	Economic Capacity	S_P	0.00%	61.30%	4,117	62.80%	4,293	176
CBEN	Economic Capacity	S_OP	0.00%	54.80%	3,435	55.10%	3,460	25
CBEN	Economic Capacity	W_SP	0.00%	72.00%	5,336	72.00%	5,335	-1
CBEN	Economic Capacity	W_P	0.00%	69.10%	5,005	69.10%	5,004	-1
CBEN	Economic Capacity	W_OP	0.00%	68.40%	4,927	68.40%	4,926	-1
CBEN	Economic Capacity	SH_SP	0.00%	55.50%	3,415	55.50%	3,414	-1
CBEN	Economic Capacity	SH_P	0.00%	54.00%	3,332	54.00%	3,331	-1
CBEN	Economic Capacity	SH_OP	0.00%	44.10%	2,534	44.10%	2,534	0
VALLEY	Economic Capacity	S_35	0.00%	78.00%	6,177	78.00%	6,176	0
VALLEY	Economic Capacity	S_SP	0.00%	77.80%	6,138	77.80%	6,137	0
VALLEY	Economic Capacity	S_P	0.00%	79.20%	6,339	79.20%	6,339	0
VALLEY	Economic Capacity	S_OP	0.00%	75.80%	5,864	75.80%	5,863	0
VALLEY	Economic Capacity	W_SP	0.00%	75.50%	5,868	75.50%	5,868	0
VALLEY	Economic Capacity	W_P	0.00%	79.50%	6,398	79.50%	6,397	0
VALLEY	Economic Capacity	W_OP	0.00%	79.90%	6,459	79.90%	6,458	-1
VALLEY	Economic Capacity	SH_SP	0.00%	70.00%	5,057	70.00%	5,056	-1
VALLEY	Economic Capacity	SH_P	0.00%	70.20%	5,078	70.20%	5,077	-1
VALLEY	Economic Capacity	SH_OP	0.00%	69.80%	5,039	69.80%	5,039	-1
WTU	Economic Capacity	S_35	0.00%	41.20%	2,374	41.20%	2,370	-4
WTU	Economic Capacity	S_SP	0.00%	33.00%	1,995	32.90%	1,992	-3
WTU	Economic Capacity	S_P	0.00%	31.40%	2,431	31.30%	2,431	0
WTU	Economic Capacity	S_OP	0.00%	19.10%	2,259	21.70%	2,248	-11
WTU	Economic Capacity	W_SP	0.00%	49.00%	4,019	49.00%	4,017	-2
WTU	Economic Capacity	W_P	0.00%	38.70%	3,768	38.60%	3,771	2
WTU	Economic Capacity	W_OP	0.00%	38.80%	3,782	38.70%	3,785	2
WTU	Economic Capacity	SH_SP	0.00%	33.90%	2,227	33.90%	2,224	-2
WTU	Economic Capacity	SH_P	0.00%	27.40%	2,077	27.30%	2,076	-1
WTU	Economic Capacity	SH_OP	0.00%	23.00%	2,055	22.90%	2,055	0

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			Base Case (Pre-Mitigation)				MERGER	
				BASE				
Market	Analysis	Period	AEP Mkt Share	CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	HHI Post-Merger	HHI Change
AECI	Economic Capacity	S_35	0.60%	0.90%	1,139	1.60%	1,140	1
AECI	Economic Capacity	S_SP	1.00%	1.00%	1,206	[illegible] 10%	1,208	2
AECI	Economic Capacity	S_P	0.40%	4.40%	1,073	5.10%	1,078	5
AECI	Economic Capacity	S_OP	1.10%	3.80%	1,081	5.20%	1,090	9
AECI	Economic Capacity	W_SP	0.90%	5.90%	1,261	6.90%	1,273	11
AECI	Economic Capacity	W_P	1.20%	4.80%	1,395	6.10%	1,407	12
AECI	Economic Capacity	W_OP	1.60%	2.80%	1,459	4.50%	1,468	9
AECI	Economic Capacity	SH_SP	1.00%	3.40%	782	4.60%	788	6
AECI	Economic Capacity	SH_P	1.10%	2.70%	791	4.10%	796	5
AECI	Economic Capacity	SH_OP	1.60%	2.70%	813	4.60%	822	9
AEP	Economic Capacity	S_35	37.10%	0.00%	1,607	36.90%	1,589	-18
AEP	Economic Capacity	S_SP	48.70%	0.00%	2,557	48.40%	2,531	-25
AEP	Economic Capacity	S_P	51.30%	0.00%	2,860	51.00%	2,832	-29
AEP	Economic Capacity	S_OP	40.00%	0.00%	1,986	40.00%	1,986	0
AEP	Economic Capacity	W_SP	51.80%	0.00%	2,922	51.50%	2,895	-27
AEP	Economic Capacity	W_P	53.00%	0.00%	3,074	52.70%	3,045	-28
AEP	Economic Capacity	W_OP	48.30%	0.00%	2,649	47.90%	2,617	-32
AEP	Economic Capacity	SH_SP	41.80%	0.00%	1,951	41.50%	1,931	-20
AEP	Economic Capacity	SH_P	45.70%	0.00%	2,333	45.40%	2,309	-24
AEP	Economic Capacity	SH_OP	39.10%	0.00%	1,905	38.80%	1,880	-25
ALLIANT_E	Economic Capacity	S_35	1.70%	0.00%	2,599	1.80%	2,599	-1
ALLIANT_E	Economic Capacity	S_SP	2.20%	0.00%	2,398	2.20%	2,398	0
ALLIANT_E	Economic Capacity	S_P	1.70%	0.00%	2,423	1.70%	2,424	1
ALLIANT_E	Economic Capacity	S_OP	0.30%	0.00%	1,695	0.30%	1,680	-15
ALLIANT_E	Economic Capacity	W_SP	1.80%	0.00%	1,743	1.90%	1,741	-2
ALLIANT_E	Economic Capacity	W_P	1.00%	0.00%	1,795	1.10%	1,792	-2
ALLIANT_E	Economic Capacity	W_OP	0.20%	0.00%	1,307	0.20%	1,307	0
ALLIANT_E	Economic Capacity	SH_SP	1.10%	0.00%	1,592	1.20%	1,587	-5
ALLIANT_E	Economic Capacity	SH_P	1.40%	0.00%	1,507	1.40%	1,505	-2
ALLIANT_E	Economic Capacity	SH_OP	0.40%	0.00%	1,249	0.30%	1,257	8
AMEREN	Economic Capacity	S_35	2.00%	2.70%	2,491	4.20%	2,499	7
AMEREN	Economic Capacity	S_SP	1.90%	2.70%	2,500	4.40%	2,508	8
AMEREN	Economic Capacity	S_P	0.50%	2.30%	2,535	2.60%	2,535	0
AMEREN	Economic Capacity	S_OP	0.20%	0.00%	2,813	0.20%	2,802	-10
AMEREN	Economic Capacity	W_SP	2.20%	0.70%	2,299	4.00%	2,239	-59
AMEREN	Economic Capacity	W_P	0.60%	0.00%	2,511	0.60%	2,510	-2
AMEREN	Economic Capacity	W_OP	0.30%	0.00%	2,261	0.30%	2,258	-3
AMEREN	Economic Capacity	SH_SP	2.60%	2.70%	1,743	6.00%	1,746	3
AMEREN	Economic Capacity	SH_P	3.40%	2.00%	1,816	5.30%	1,818	2
AMEREN	Economic Capacity	SH_OP	0.30%	0.00%	1,671	0.30%	1,673	2
APS	Economic Capacity	S_35	8.70%	0.00%	2,282	8.70%	2,281	-1
APS	Economic Capacity	S_SP	9.30%	0.00%	2,213	9.30%	2,212	-1
APS	Economic Capacity	S_P	6.20%	0.00%	2,194	6.20%	2,194	0
APS	Economic Capacity	S_OP	7.90%	0.00%	2,232	7.90%	2,232	0
APS	Economic Capacity	W_SP	8.60%	0.00%	2,474	8.60%	2,474	0
APS	Economic Capacity	W_P	3.30%	0.00%	2,518	3.30%	2,518	0
APS	Economic Capacity	W_OP	8.80%	0.00%	2,371	8.70%	2,370	-1
APS	Economic Capacity	SH_SP	8.00%	0.00%	2,220	8.00%	2,219	0
APS	Economic Capacity	SH_P	10.20%	0.00%	2,256	10.10%	2,254	-2
APS	Economic Capacity	SH_OP	10.50%	0.00%	2,297	10.50%	2,296	-1
BEC	Economic Capacity	S_35	0.00%	6.20%	2,254	6.20%	2,254	0
BEC	Economic Capacity	S_SP	0.00%	5.60%	2,068	5.50%	2,070	1
BEC	Economic Capacity	S_P	0.00%	5.10%	2,014	6.40%	2,006	-7
BEC	Economic Capacity	S_OP	0.00%	5.80%	2,034	8.00%	2,038	3
BEC	Economic Capacity	W_SP	0.00%	17.40%	2,367	17.40%	2,367	0
BEC	Economic Capacity	W_P	0.00%	14.20%	2,999	17.40%	2,909	-89
BEC	Economic Capacity	W_OP	0.00%	14.60%	3,009	17.70%	2,921	-88
BEC	Economic Capacity	SH_SP	0.00%	9.20%	1,610	9.20%	1,611	1
BEC	Economic Capacity	SH_P	0.00%	6.30%	1,838	6.90%	1,817	-21
BEC	Economic Capacity	SH_OP	0.00%	7.50%	1,954	8.10%	1,933	-21
BRYN	Economic Capacity	S_35	0.00%	7.90%	1,226	7.90%	1,226	0
BRYN	Economic Capacity	S_SP	0.00%	14.30%	1,435	15.20%	1,435	0
BRYN	Economic Capacity	S_P	0.00%	14.50%	1,411	15.40%	1,414	2
BRYN	Economic Capacity	S_OP	0.00%	15.20%	1,438	16.10%	1,443	5
BRYN	Economic Capacity	W_SP	0.00%	0.60%	2,118	0.60%	2,118	1
BRYN	Economic Capacity	W_P	0.00%	1.20%	2,437	1.20%	2,446	9
BRYN	Economic Capacity	W_OP	0.00%	0.60%	2,491	0.60%	2,498	7
BRYN	Economic Capacity	SH_SP	0.00%	14.50%	1,279	14.50%	1,280	0
BRYN	Economic Capacity	SH_P	0.00%	15.60%	1,547	16.20%	1,546	-1
BRYN	Economic Capacity	SH_OP	0.00%	20.00%	1,643	20.50%	1,652	8

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Base Case (Pre-Mitigation)

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CAPO	Economic Capacity	S_35	2.10%	0.00%	6,821	2.10%	6,821	0
CAPO	Economic Capacity	S_SP	2.20%	0.00%	6,797	2.20%	6,797	0
CAPO	Economic Capacity	S_P	0.60%	0.00%	6,750	0.60%	6,750	0
CAPO	Economic Capacity	S_OP	1.70%	0.00%	3,900	1.70%	3,900	0
CAPO	Economic Capacity	W_SP	5.80%	0.00%	4,220	5.70%	4,220	-1
CAPO	Economic Capacity	W_P	4.00%	0.00%	2,397	4.00%	2,397	0
CAPO	Economic Capacity	W_OP	3.80%	0.00%	2,143	3.80%	2,143	0
CAPO	Economic Capacity	SH_SP	3.80%	0.00%	4,561	3.80%	4,561	0
CAPO	Economic Capacity	SH_P	1.30%	0.00%	4,474	1.30%	4,474	0
CAPO	Economic Capacity	SH_OP	0.60%	0.00%	2,265	0.60%	2,265	0
CELE	Economic Capacity	S_35	0.00%	5.10%	6,627	5.20%	6,628	1
CELE	Economic Capacity	S_SP	0.20%	10.10%	4,390	10.90%	4,406	16
CELE	Economic Capacity	S_P	0.10%	0.60%	8,017	0.80%	8,017	0
CELE	Economic Capacity	S_OP	0.30%	0.70%	7,949	1.00%	7,949	0
CELE	Economic Capacity	W_SP	0.20%	7.30%	4,716	7.70%	4,721	5
CELE	Economic Capacity	W_P	0.90%	10.60%	2,229	12.10%	2,261	32
CELE	Economic Capacity	W_OP	0.80%	12.50%	2,210	14.10%	2,249	39
CELE	Economic Capacity	SH_SP	0.80%	1.90%	4,442	2.90%	4,446	4
CELE	Economic Capacity	SH_P	2.10%	3.70%	2,342	6.30%	2,360	19
CELE	Economic Capacity	SH_OP	2.10%	5.40%	2,346	8.00%	2,374	28
CIMO	Economic Capacity	S_35	0.50%	0.90%	1,349	1.50%	1,353	3
CIMO	Economic Capacity	S_SP	0.60%	1.00%	1,121	1.80%	1,122	1
CIMO	Economic Capacity	S_P	0.10%	0.00%	1,312	0.10%	1,309	-3
CIMO	Economic Capacity	S_OP	1.00%	0.00%	1,339	1.30%	1,336	-3
CIMO	Economic Capacity	W_SP	0.50%	0.00%	862	0.50%	862	0
CIMO	Economic Capacity	W_P	0.40%	0.00%	1,101	0.40%	1,101	0
CIMO	Economic Capacity	W_OP	3.30%	0.00%	876	4.20%	872	-4
CIMO	Economic Capacity	SH_SP	0.20%	0.00%	1,223	0.20%	1,216	-7
CIMO	Economic Capacity	SH_P	0.40%	0.00%	990	0.40%	982	-8
CIMO	Economic Capacity	SH_OP	2.50%	0.00%	979	3.50%	956	-22
CIN	Economic Capacity	S_35	14.10%	0.10%	2,104	14.10%	2,104	1
CIN	Economic Capacity	S_SP	7.90%	0.00%	2,913	7.90%	2,913	0
CIN	Economic Capacity	S_P	3.80%	0.00%	1,830	3.80%	1,830	0
CIN	Economic Capacity	S_OP	14.00%	0.00%	1,552	14.00%	1,552	0
CIN	Economic Capacity	W_SP	7.20%	0.00%	2,696	7.20%	2,696	0
CIN	Economic Capacity	W_P	1.10%	0.00%	1,700	1.10%	1,700	0
CIN	Economic Capacity	W_OP	13.10%	0.00%	1,737	13.10%	1,737	0
CIN	Economic Capacity	SH_SP	2.90%	0.00%	2,085	2.90%	2,085	0
CIN	Economic Capacity	SH_P	2.70%	0.00%	2,035	2.70%	2,035	0
CIN	Economic Capacity	SH_OP	11.10%	0.00%	1,415	11.10%	1,415	0
COA	Economic Capacity	S_35	0.00%	3.30%	3,464	3.30%	3,464	0
COA	Economic Capacity	S_SP	0.00%	5.20%	1,981	5.50%	1,977	-4
COA	Economic Capacity	S_P	0.00%	5.50%	1,975	5.80%	1,971	-4
COA	Economic Capacity	S_OP	0.00%	5.40%	1,977	5.80%	1,973	-4
COA	Economic Capacity	W_SP	0.00%	3.20%	4,718	3.20%	4,718	0
COA	Economic Capacity	W_P	0.00%	6.30%	2,954	7.60%	2,940	-14
COA	Economic Capacity	W_OP	0.00%	6.50%	2,955	7.90%	2,942	-14
COA	Economic Capacity	SH_SP	0.00%	5.60%	3,172	5.60%	3,172	0
COA	Economic Capacity	SH_P	0.00%	8.00%	1,986	8.40%	1,980	-6
COA	Economic Capacity	SH_OP	0.00%	9.50%	2,075	10.00%	2,067	-8
COMED	Economic Capacity	S_35	0.60%	0.00%	5,681	0.60%	5,681	0
COMED	Economic Capacity	S_SP	0.40%	0.00%	5,597	0.40%	5,596	0
COMED	Economic Capacity	S_P	0.40%	0.00%	5,023	0.40%	5,023	0
COMED	Economic Capacity	S_OP	0.20%	0.00%	4,156	0.20%	4,156	0
COMED	Economic Capacity	W_SP	9.20%	0.40%	3,775	9.70%	3,789	14
COMED	Economic Capacity	W_P	1.90%	0.00%	4,046	2.00%	4,043	-4
COMED	Economic Capacity	W_OP	3.70%	0.00%	3,027	3.80%	3,030	4
COMED	Economic Capacity	SH_SP	9.80%	0.40%	2,933	10.30%	2,946	12
COMED	Economic Capacity	SH_P	9.10%	0.00%	3,144	9.00%	3,142	-1
COMED	Economic Capacity	SH_OP	2.80%	0.00%	2,342	2.80%	2,343	1
CP	Economic Capacity	S_35	8.50%	0.00%	2,976	8.40%	2,975	-1
CP	Economic Capacity	S_SP	8.30%	0.00%	3,038	8.30%	3,038	-1
CP	Economic Capacity	S_P	6.20%	0.00%	2,637	6.20%	2,637	0
CP	Economic Capacity	S_OP	12.00%	0.00%	2,982	12.00%	2,982	0
CP	Economic Capacity	W_SP	12.10%	0.00%	2,295	12.10%	2,294	-1
CP	Economic Capacity	W_P	14.40%	0.00%	2,323	14.30%	2,321	-2
CP	Economic Capacity	W_OP	16.00%	0.00%	2,238	15.90%	2,236	-3
CP	Economic Capacity	SH_SP	12.20%	0.00%	2,164	12.10%	2,164	0
CP	Economic Capacity	SH_P	15.00%	0.00%	2,217	14.90%	2,215	-2
CP	Economic Capacity	SH_OP	10.10%	0.00%	2,310	10.10%	2,310	0

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Base Case (Pre-Mitigation)

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CPS	Economic Capacity	S_35	0.00%	4.80%	5,445	4.80%	5,445	0
CPS	Economic Capacity	S_SP	0.00%	7.80%	3,462	7.80%	3,462	0
CPS	Economic Capacity	S_P	0.00%	6.70%	3,455	6.70%	3,455	0
CPS	Economic Capacity	S_OP	0.00%	6.70%	3,468	6.70%	3,469	0
CPS	Economic Capacity	W_SP	0.00%	0.00%	5,303	0.00%	5,303	1
CPS	Economic Capacity	W_P	0.00%	0.10%	2,959	0.10%	2,961	2
CPS	Economic Capacity	W_OP	0.00%	0.10%	2,934	0.10%	2,936	2
CPS	Economic Capacity	SH_SP	0.00%	9.90%	3,323	9.90%	3,323	0
CPS	Economic Capacity	SH_P	0.00%	12.40%	2,113	12.60%	2,111	-3
CPS	Economic Capacity	SH_OP	0.00%	14.80%	1,812	15.30%	1,804	-8
DECO	Economic Capacity	S_35	5.60%	0.00%	4,058	5.60%	4,058	0
DECO	Economic Capacity	S_SP	5.20%	0.00%	4,158	5.20%	4,158	0
DECO	Economic Capacity	S_P	0.60%	0.00%	3,861	0.60%	3,861	0
DECO	Economic Capacity	S_OP	0.30%	0.00%	3,917	0.30%	3,917	0
DECO	Economic Capacity	W_SP	7.60%	0.00%	3,732	7.50%	3,732	0
DECO	Economic Capacity	W_P	6.80%	0.00%	3,632	6.80%	3,632	0
DECO	Economic Capacity	W_OP	7.40%	0.00%	3,431	7.40%	3,431	0
DECO	Economic Capacity	SH_SP	11.80%	0.00%	3,364	11.70%	3,363	0
DECO	Economic Capacity	SH_P	4.00%	0.00%	3,481	4.00%	3,481	0
DECO	Economic Capacity	SH_OP	0.30%	0.00%	3,749	0.30%	3,749	0
DGG	Economic Capacity	S_35	0.00%	6.00%	2,399	6.00%	2,399	0
DGG	Economic Capacity	S_SP	0.00%	12.10%	1,258	12.70%	1,258	0
DGG	Economic Capacity	S_P	0.00%	13.80%	1,411	14.60%	1,412	1
DGG	Economic Capacity	S_OP	0.00%	14.40%	1,440	15.20%	1,444	4
DGG	Economic Capacity	W_SP	0.00%	3.60%	3,785	3.60%	3,785	0
DGG	Economic Capacity	W_P	0.00%	5.10%	3,120	6.00%	3,051	-69
DGG	Economic Capacity	W_OP	0.00%	5.50%	3,124	6.30%	3,057	-67
DGG	Economic Capacity	SH_SP	0.00%	12.40%	1,509	12.40%	1,509	0
DGG	Economic Capacity	SH_P	0.00%	15.10%	1,565	15.70%	1,564	-1
DGG	Economic Capacity	SH_OP	0.00%	19.50%	1,668	20.00%	1,675	7
DLCO	Economic Capacity	S_35	11.50%	0.00%	1,968	11.50%	1,967	-1
DLCO	Economic Capacity	S_SP	11.60%	0.00%	1,999	11.60%	1,998	-1
DLCO	Economic Capacity	S_P	15.00%	0.00%	2,142	14.90%	2,140	-2
DLCO	Economic Capacity	S_OP	18.20%	0.00%	2,067	18.10%	2,065	-2
DLCO	Economic Capacity	W_SP	9.10%	0.00%	2,317	9.00%	2,316	-1
DLCO	Economic Capacity	W_P	8.50%	0.00%	2,275	8.40%	2,273	-1
DLCO	Economic Capacity	W_OP	9.20%	0.00%	2,162	9.20%	2,162	0
DLCO	Economic Capacity	SH_SP	12.60%	0.00%	1,638	12.60%	1,637	-1
DLCO	Economic Capacity	SH_P	14.50%	0.00%	1,883	14.50%	1,883	0
DLCO	Economic Capacity	SH_OP	14.60%	0.00%	1,794	14.50%	1,791	-4
DPL	Economic Capacity	S_35	16.20%	0.00%	1,635	16.10%	1,633	-1
DPL	Economic Capacity	S_SP	7.60%	0.00%	1,636	7.60%	1,636	0
DPL	Economic Capacity	S_P	5.70%	0.00%	1,677	5.70%	1,677	0
DPL	Economic Capacity	S_OP	9.80%	0.00%	1,577	9.80%	1,577	0
DPL	Economic Capacity	W_SP	1.80%	0.00%	1,818	1.80%	1,818	0
DPL	Economic Capacity	W_P	2.10%	0.00%	1,877	2.10%	1,877	0
DPL	Economic Capacity	W_OP	12.80%	0.00%	1,575	12.80%	1,575	0
DPL	Economic Capacity	SH_SP	4.60%	0.00%	1,479	4.60%	1,479	0
DPL	Economic Capacity	SH_P	1.70%	0.00%	1,749	1.70%	1,749	0
DPL	Economic Capacity	SH_OP	9.20%	0.00%	1,501	9.20%	1,501	0
DUKE	Economic Capacity	S_35	3.50%	0.00%	4,438	3.50%	4,438	0
DUKE	Economic Capacity	S_SP	0.50%	0.00%	4,612	0.50%	4,612	0
DUKE	Economic Capacity	S_P	2.10%	0.00%	3,548	2.10%	3,548	0
DUKE	Economic Capacity	S_OP	2.90%	0.00%	2,599	2.90%	2,599	0
DUKE	Economic Capacity	W_SP	1.70%	0.00%	4,402	1.70%	4,402	0
DUKE	Economic Capacity	W_P	1.40%	0.00%	3,451	1.40%	3,451	0
DUKE	Economic Capacity	W_OP	2.10%	0.00%	3,157	2.10%	3,157	0
DUKE	Economic Capacity	SH_SP	0.60%	0.00%	4,108	0.60%	4,108	0
DUKE	Economic Capacity	SH_P	0.90%	0.00%	3,078	0.90%	3,078	0
DUKE	Economic Capacity	SH_OP	1.90%	0.00%	2,071	1.90%	2,071	0
EDE	Economic Capacity	S_35	0.40%	4.00%	1,653	4.50%	1,657	4
EDE	Economic Capacity	S_SP	0.30%	3.90%	1,713	4.40%	1,717	4
EDE	Economic Capacity	S_P	0.80%	0.90%	4,496	1.70%	4,502	6
EDE	Economic Capacity	S_OP	2.20%	2.00%	2,848	4.30%	2,857	9
EDE	Economic Capacity	W_SP	0.50%	12.50%	1,111	13.30%	1,130	19
EDE	Economic Capacity	W_P	0.70%	10.30%	651	11.70%	675	24
EDE	Economic Capacity	W_OP	0.90%	11.90%	596	13.60%	626	30
EDE	Economic Capacity	SH_SP	0.90%	2.00%	2,144	3.50%	2,148	4
EDE	Economic Capacity	SH_P	1.40%	2.50%	1,421	4.90%	1,425	3
EDE	Economic Capacity	SH_OP	2.00%	0.00%	1,129	2.90%	1,091	-37

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			Base Case (Pre-Mitigation)					
				BASE			MERGER	
Market	Analysis	Period	AEP Mkt.Share	CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	HHI Post-Merger	HHI Change
EKPC	Economic Capacity	S_35	6.40%	0.10%	2,419	6.40%	2,420	0
EKPC	Economic Capacity	S_SP	9.90%	0.00%	2,188	9.90%	2,188	0
EKPC	Economic Capacity	S_P	3.90%	0.00%	1,768	3.90%	1,768	0
EKPC	Economic Capacity	S_OP	1.80%	0.00%	1,516	1.80%	1,516	0
EKPC	Economic Capacity	W_SP	9.90%	0.00%	2,317	9.90%	2,316	-1
EKPC	Economic Capacity	W_P	3.70%	0.00%	2,413	3.70%	2,413	0
EKPC	Economic Capacity	W_OP	9.30%	0.00%	1,841	9.30%	1,841	0
EKPC	Economic Capacity	SH_SP	7.30%	0.30%	1,868	7.50%	1,871	4
EKPC	Economic Capacity	SH_P	3.20%	0.00%	1,757	3.20%	1,757	0
EKPC	Economic Capacity	SH_OP	1.60%	0.00%	1,315	1.60%	1,315	0
ENT	Economic Capacity	S_35	0.20%	0.20%	5,427	0.40%	5,427	0
ENT	Economic Capacity	S_SP	0.60%	0.20%	2,728	0.80%	2,729	0
ENT	Economic Capacity	S_P	0.20%	0.90%	2,768	1.10%	2,770	3
ENT	Economic Capacity	S_OP	0.80%	0.70%	2,991	1.50%	2,992	1
ENT	Economic Capacity	W_SP	0.20%	3.50%	5,220	3.70%	5,223	3
ENT	Economic Capacity	W_P	0.40%	2.00%	2,699	2.80%	2,701	2
ENT	Economic Capacity	W_OP	0.70%	2.70%	2,719	3.80%	2,727	8
ENT	Economic Capacity	SH_SP	0.30%	3.90%	3,749	4.40%	3,753	3
ENT	Economic Capacity	SH_P	0.60%	4.80%	1,620	5.70%	1,625	6
ENT	Economic Capacity	SH_OP	1.10%	5.90%	1,676	7.50%	1,707	31
FENER	Economic Capacity	S_35	8.20%	0.00%	3,359	8.20%	3,358	0
FENER	Economic Capacity	S_SP	8.80%	0.00%	3,341	8.70%	3,340	-1
FENER	Economic Capacity	S_P	6.70%	0.00%	3,420	6.70%	3,420	0
FENER	Economic Capacity	S_OP	8.20%	0.00%	3,082	8.20%	3,082	0
FENER	Economic Capacity	W_SP	4.70%	0.00%	4,363	4.70%	4,362	-1
FENER	Economic Capacity	W_P	3.10%	0.00%	4,538	3.10%	4,538	0
FENER	Economic Capacity	W_OP	3.30%	0.00%	4,493	3.30%	4,493	0
FENER	Economic Capacity	SH_SP	11.90%	0.00%	2,390	11.80%	2,389	-1
FENER	Economic Capacity	SH_P	11.70%	0.00%	2,631	11.60%	2,629	-2
FENER	Economic Capacity	SH_OP	8.90%	0.00%	2,736	8.90%	2,732	-5
GRRD	Economic Capacity	S_35	0.10%	0.20%	3,297	0.30%	3,297	0
GRRD	Economic Capacity	S_SP	0.10%	0.30%	3,053	0.50%	3,053	0
GRRD	Economic Capacity	S_P	0.00%	12.10%	2,938	12.90%	2,964	26
GRRD	Economic Capacity	S_OP	0.20%	1.00%	2,789	1.90%	2,788	-1
GRRD	Economic Capacity	W_SP	0.30%	16.20%	1,152	17.20%	1,183	31
GRRD	Economic Capacity	W_P	0.40%	11.90%	1,280	13.10%	1,303	23
GRRD	Economic Capacity	W_OP	1.00%	0.00%	1,772	1.30%	1,756	-16
GRRD	Economic Capacity	SH_SP	0.40%	12.00%	1,607	12.80%	1,625	18
GRRD	Economic Capacity	SH_P	0.50%	7.50%	1,351	8.70%	1,363	13
GRRD	Economic Capacity	SH_OP	1.10%	0.00%	1,854	1.50%	1,849	-5
HEC	Economic Capacity	S_35	7.20%	0.10%	1,679	7.20%	1,680	1
HEC	Economic Capacity	S_SP	7.20%	0.10%	1,679	7.20%	1,680	1
HEC	Economic Capacity	S_P	3.10%	0.00%	2,225	3.10%	2,225	0
HEC	Economic Capacity	S_OP	20.00%	0.00%	1,294	20.00%	1,294	0
HEC	Economic Capacity	W_SP	10.40%	0.10%	1,821	10.50%	1,822	1
HEC	Economic Capacity	W_P	3.70%	0.00%	2,367	3.70%	2,367	0
HEC	Economic Capacity	W_OP	20.60%	0.00%	1,875	20.60%	1,875	0
HEC	Economic Capacity	SH_SP	17.80%	0.10%	1,673	17.80%	1,675	2
HEC	Economic Capacity	SH_P	3.50%	0.00%	2,285	3.50%	2,285	0
HEC	Economic Capacity	SH_OP	20.70%	0.00%	1,200	20.70%	1,200	0
HLP	Economic Capacity	S_35	0.00%	2.70%	5,011	2.70%	5,011	0
HLP	Economic Capacity	S_SP	0.00%	7.10%	2,748	7.70%	2,740	-8
HLP	Economic Capacity	S_P	0.00%	6.10%	2,573	6.50%	2,556	-17
HLP	Economic Capacity	S_OP	0.00%	6.10%	2,586	6.50%	2,568	-17
HLP	Economic Capacity	W_SP	0.00%	3.50%	4,642	3.50%	4,642	0
HLP	Economic Capacity	W_P	0.00%	5.90%	2,630	6.40%	2,628	-2
HLP	Economic Capacity	W_OP	0.00%	6.00%	2,671	6.60%	2,668	-4
HLP	Economic Capacity	SH_SP	0.00%	4.90%	4,431	4.90%	4,432	0
HLP	Economic Capacity	SH_P	0.00%	10.00%	2,516	10.90%	2,501	-16
HLP	Economic Capacity	SH_OP	0.00%	10.20%	2,605	11.20%	2,585	-21
IP	Economic Capacity	S_35	4.70%	0.50%	1,929	5.10%	1,933	4
IP	Economic Capacity	S_SP	4.80%	0.40%	2,014	5.20%	2,018	4
IP	Economic Capacity	S_P	4.80%	0.50%	1,906	5.20%	1,913	7
IP	Economic Capacity	S_OP	6.40%	0.50%	2,030	7.10%	2,035	5
IP	Economic Capacity	W_SP	6.20%	0.60%	1,905	6.90%	1,914	9
IP	Economic Capacity	W_P	3.20%	0.00%	2,082	3.10%	2,080	-2
IP	Economic Capacity	W_OP	5.60%	0.00%	1,973	5.80%	1,972	-1
IP	Economic Capacity	SH_SP	5.20%	0.70%	1,549	6.00%	1,556	8
IP	Economic Capacity	SH_P	1.10%	0.00%	1,697	1.10%	1,699	2
IP	Economic Capacity	SH_OP	6.10%	0.00%	1,108	5.90%	1,106	-2

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Base Case (Pre-Mitigation)

Market	Analysis	Period	BASE AEP Mkt Share	BASE CSW Mkt Share	BASE HHI Pre-Merger	MERGER Merged Mkt Share	MERGER HHI Post-Merger	MERGER HHI Change
IPL	Economic Capacity	S_35	16.30%	0.10%	1,834	16.20%	1,833	-1
IPL	Economic Capacity	S_SP	6.40%	0.00%	1,848	6.40%	1,848	0
IPL	Economic Capacity	S_P	2.70%	0.00%	2,175	2.70%	2,175	0
IPL	Economic Capacity	S_OP	1.10%	0.00%	2,624	1.10%	2,624	0
IPL	Economic Capacity	W_SP	1.10%	0.00%	1,941	1.10%	1,941	0
IPL	Economic Capacity	W_P	3.10%	0.00%	1,778	3.10%	1,778	0
IPL	Economic Capacity	W_OP	1.10%	0.00%	2,598	1.10%	2,598	0
IPL	Economic Capacity	SH_SP	12.30%	0.00%	1,505	12.30%	1,505	0
IPL	Economic Capacity	SH_P	1.40%	0.00%	1,425	1.40%	1,425	0
IPL	Economic Capacity	SH_OP	1.00%	0.00%	1,752	1.00%	1,752	0
KACY	Economic Capacity	S_35	0.10%	0.30%	5,983	0.30%	5,983	0
KACY	Economic Capacity	S_SP	0.10%	0.30%	5,971	0.40%	5,971	0
KACY	Economic Capacity	S_P	0.00%	0.00%	4,425	0.00%	4,425	0
KACY	Economic Capacity	S_OP	0.60%	0.00%	3,567	0.90%	3,565	-2
KACY	Economic Capacity	W_SP	0.20%	0.00%	2,210	0.20%	2,208	-3
KACY	Economic Capacity	W_P	0.50%	0.00%	1,662	0.50%	1,662	0
KACY	Economic Capacity	W_OP	0.20%	0.00%	1,333	0.20%	1,331	-2
KACY	Economic Capacity	SH_SP	0.30%	2.30%	2,681	2.80%	2,682	1
KACY	Economic Capacity	SH_P	0.10%	0.00%	2,837	0.10%	2,837	0
KACY	Economic Capacity	SH_OP	1.40%	0.00%	1,699	2.10%	1,685	-14
KCPL	Economic Capacity	S_35	0.60%	0.40%	2,626	1.10%	2,626	0
KCPL	Economic Capacity	S_SP	0.50%	0.40%	3,051	1.00%	3,051	0
KCPL	Economic Capacity	S_P	0.50%	1.30%	2,409	1.90%	2,410	1
KCPL	Economic Capacity	S_OP	0.50%	0.00%	2,570	0.50%	2,572	2
KCPL	Economic Capacity	W_SP	1.10%	3.00%	1,670	4.30%	1,676	5
KCPL	Economic Capacity	W_P	1.40%	3.60%	1,889	5.10%	1,898	9
KCPL	Economic Capacity	W_OP	1.00%	0.00%	1,604	1.00%	1,597	-7
KCPL	Economic Capacity	SH_SP	1.00%	1.90%	1,461	3.00%	1,463	2
KCPL	Economic Capacity	SH_P	1.30%	1.70%	1,371	3.20%	1,373	2
KCPL	Economic Capacity	SH_OP	2.30%	0.00%	1,059	2.40%	1,049	-10
LAFA	Economic Capacity	S_35	0.00%	0.40%	8,668	0.40%	8,668	0
LAFA	Economic Capacity	S_SP	0.00%	1.90%	7,159	2.00%	7,159	0
LAFA	Economic Capacity	S_P	0.00%	0.20%	5,960	0.20%	5,960	0
LAFA	Economic Capacity	S_OP	0.00%	0.20%	5,957	0.20%	5,957	0
LAFA	Economic Capacity	W_SP	0.40%	1.50%	4,656	1.90%	4,657	1
LAFA	Economic Capacity	W_P	0.80%	3.00%	2,514	4.10%	2,520	6
LAFA	Economic Capacity	W_OP	1.10%	3.80%	2,457	5.10%	2,466	9
LAFA	Economic Capacity	SH_SP	1.00%	1.80%	3,914	2.90%	3,918	4
LAFA	Economic Capacity	SH_P	1.10%	3.10%	2,221	4.40%	2,228	7
LAFA	Economic Capacity	SH_OP	2.30%	3.30%	2,227	5.80%	2,243	16
LCRA	Economic Capacity	S_35	0.00%	8.30%	1,558	8.30%	1,558	0
LCRA	Economic Capacity	S_SP	0.00%	7.20%	1,909	7.70%	1,893	-15
LCRA	Economic Capacity	S_P	0.00%	7.10%	1,926	7.60%	1,911	-15
LCRA	Economic Capacity	S_OP	0.00%	7.20%	2,238	7.60%	2,211	-27
LCRA	Economic Capacity	W_SP	0.00%	4.90%	2,366	4.90%	2,366	0
LCRA	Economic Capacity	W_P	0.00%	3.50%	2,174	4.10%	2,143	-31
LCRA	Economic Capacity	W_OP	0.00%	3.50%	2,170	4.10%	2,138	-31
LCRA	Economic Capacity	SH_SP	0.00%	6.90%	2,182	7.20%	2,166	-16
LCRA	Economic Capacity	SH_P	0.00%	6.50%	2,198	6.90%	2,181	-17
LCRA	Economic Capacity	SH_OP	0.00%	6.40%	2,438	6.80%	2,419	-19
LGE	Economic Capacity	S_35	7.90%	0.10%	2,987	7.90%	2,988	1
LGE	Economic Capacity	S_SP	2.50%	0.00%	1,379	2.50%	1,379	0
LGE	Economic Capacity	S_P	2.60%	0.00%	1,702	2.60%	1,702	0
LGE	Economic Capacity	S_OP	5.20%	0.00%	1,380	5.20%	1,380	0
LGE	Economic Capacity	W_SP	1.20%	0.00%	1,761	1.20%	1,761	0
LGE	Economic Capacity	W_P	1.30%	0.00%	1,802	1.30%	1,802	0
LGE	Economic Capacity	W_OP	13.20%	0.00%	1,097	13.20%	1,097	0
LGE	Economic Capacity	SH_SP	1.20%	0.00%	1,739	1.20%	1,739	0
LGE	Economic Capacity	SH_P	1.20%	0.00%	1,747	1.20%	1,747	0
LGE	Economic Capacity	SH_OP	2.10%	0.00%	1,322	2.10%	1,322	0
MPS	Economic Capacity	S_35	0.70%	0.00%	4,591	0.80%	4,714	124
MPS	Economic Capacity	S_SP	0.70%	0.00%	3,805	0.70%	3,801	-4
MPS	Economic Capacity	S_P	0.80%	0.00%	2,573	0.90%	2,574	1
MPS	Economic Capacity	S_OP	1.10%	0.00%	2,023	1.10%	2,017	-6
MPS	Economic Capacity	W_SP	0.40%	0.00%	1,017	0.40%	1,006	-10
MPS	Economic Capacity	W_P	0.30%	0.00%	839	0.30%	832	-8
MPS	Economic Capacity	W_OP	2.90%	0.00%	840	3.00%	829	-11
MPS	Economic Capacity	SH_SP	1.70%	0.00%	1,384	1.80%	1,375	-9
MPS	Economic Capacity	SH_P	0.40%	0.00%	984	0.40%	967	-17
MPS	Economic Capacity	SH_OP	2.00%	0.00%	1,123	2.00%	1,099	-24

Base Case (Pre-Mitigation) **Exhibit No. AC-511**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
NIPS	Economic Capacity	S_35	13.50%	0.10%	1,981	13.50%	1,982	1
NIPS	Economic Capacity	S_SP	0.90%	0.00%	1,441	0.90%	1,441	0
NIPS	Economic Capacity	S_P	0.90%	0.00%	1,342	0.90%	1,342	0
NIPS	Economic Capacity	S_OP	0.80%	0.00%	1,174	0.80%	1,174	0
NIPS	Economic Capacity	W_SP	1.00%	0.00%	1,259	1.00%	1,259	0
NIPS	Economic Capacity	W_P	1.00%	0.00%	1,259	1.00%	1,259	0
NIPS	Economic Capacity	W_OP	0.70%	0.00%	1,212	0.70%	1,212	0
NIPS	Economic Capacity	SH_SP	7.50%	0.00%	1,183	7.50%	1,183	0
NIPS	Economic Capacity	SH_P	7.50%	0.00%	1,196	7.50%	1,196	0
NIPS	Economic Capacity	SH_OP	4.60%	0.00%	1,071	4.60%	1,071	0
NSP	Economic Capacity	S_35	0.40%	0.10%	2,412	0.50%	2,412	0
NSP	Economic Capacity	S_SP	0.00%	0.00%	2,129	0.00%	2,129	0
NSP	Economic Capacity	S_P	0.00%	0.00%	1,873	0.00%	1,873	0
NSP	Economic Capacity	S_OP	0.90%	0.00%	2,391	0.90%	2,391	0
NSP	Economic Capacity	W_SP	0.50%	0.00%	2,926	0.50%	2,926	0
NSP	Economic Capacity	W_P	0.00%	0.00%	1,529	0.00%	1,529	0
NSP	Economic Capacity	W_OP	1.00%	0.00%	1,903	1.00%	1,903	0
NSP	Economic Capacity	SH_SP	0.00%	0.00%	1,889	0.00%	1,889	0
NSP	Economic Capacity	SH_P	0.00%	0.00%	1,878	0.00%	1,878	0
NSP	Economic Capacity	SH_OP	0.50%	0.00%	2,405	0.50%	2,405	0
OKGE	Economic Capacity	S_35	0.10%	2.50%	5,724	2.70%	5,725	1
OKGE	Economic Capacity	S_SP	0.20%	2.30%	5,826	2.60%	5,827	1
OKGE	Economic Capacity	S_P	0.30%	20.60%	2,458	22.20%	2,524	66
OKGE	Economic Capacity	S_OP	0.80%	14.30%	2,437	17.80%	2,613	175
OKGE	Economic Capacity	W_SP	0.20%	6.10%	4,085	6.50%	4,090	5
OKGE	Economic Capacity	W_P	0.50%	11.60%	2,126	12.80%	2,150	24
OKGE	Economic Capacity	W_OP	0.90%	0.00%	2,393	0.90%	2,376	-16
OKGE	Economic Capacity	SH_SP	0.20%	6.10%	3,795	6.60%	3,799	5
OKGE	Economic Capacity	SH_P	0.50%	7.30%	1,809	8.30%	1,819	10
OKGE	Economic Capacity	SH_OP	0.80%	3.30%	2,117	4.90%	2,109	-8
SCEG	Economic Capacity	S_35	1.30%	0.00%	2,814	1.30%	2,814	0
SCEG	Economic Capacity	S_SP	2.20%	0.00%	2,730	2.20%	2,730	0
SCEG	Economic Capacity	S_P	2.10%	0.00%	2,698	2.10%	2,698	0
SCEG	Economic Capacity	S_OP	1.90%	0.00%	2,697	1.80%	2,697	0
SCEG	Economic Capacity	W_SP	2.40%	0.00%	2,660	2.40%	2,661	0
SCEG	Economic Capacity	W_P	1.90%	0.00%	2,694	1.90%	2,695	0
SCEG	Economic Capacity	W_OP	1.80%	0.00%	2,638	1.80%	2,638	0
SCEG	Economic Capacity	SH_SP	2.00%	0.00%	2,490	2.00%	2,491	0
SCEG	Economic Capacity	SH_P	2.10%	0.00%	2,489	2.10%	2,490	0
SCEG	Economic Capacity	SH_OP	1.70%	0.00%	2,506	1.70%	2,506	0
SIGE	Economic Capacity	S_35	5.80%	0.00%	2,463	5.80%	2,463	0
SIGE	Economic Capacity	S_SP	5.90%	0.00%	2,465	5.90%	2,465	0
SIGE	Economic Capacity	S_P	2.40%	0.00%	3,399	2.40%	3,399	0
SIGE	Economic Capacity	S_OP	1.50%	0.00%	2,272	1.50%	2,272	0
SIGE	Economic Capacity	W_SP	6.30%	0.00%	2,335	6.30%	2,336	0
SIGE	Economic Capacity	W_P	2.30%	0.00%	2,847	2.30%	2,847	0
SIGE	Economic Capacity	W_OP	1.70%	0.00%	2,199	1.70%	2,199	0
SIGE	Economic Capacity	SH_SP	4.60%	0.00%	2,313	4.60%	2,313	0
SIGE	Economic Capacity	SH_P	1.50%	0.00%	2,734	1.50%	2,734	0
SIGE	Economic Capacity	SH_OP	1.60%	0.00%	2,096	1.60%	2,096	0
SOCO	Economic Capacity	S_35	0.50%	0.00%	6,169	0.50%	6,169	0
SOCO	Economic Capacity	S_SP	0.70%	0.00%	6,234	0.70%	6,234	0
SOCO	Economic Capacity	S_P	0.20%	0.00%	6,355	0.20%	6,355	0
SOCO	Economic Capacity	S_OP	0.90%	0.00%	6,118	0.90%	6,119	0
SOCO	Economic Capacity	W_SP	0.40%	0.00%	6,430	0.40%	6,430	0
SOCO	Economic Capacity	W_P	0.40%	0.00%	6,339	0.40%	6,340	0
SOCO	Economic Capacity	W_OP	1.20%	0.00%	6,366	1.20%	6,366	0
SOCO	Economic Capacity	SH_SP	0.30%	0.00%	5,817	0.30%	5,817	0
SOCO	Economic Capacity	SH_P	0.70%	0.00%	5,785	0.70%	5,785	0
SOCO	Economic Capacity	SH_OP	1.10%	0.00%	5,759	1.10%	5,760	0
SPRM	Economic Capacity	S_35	0.10%	1.90%	5,150	2.00%	5,150	0
SPRM	Economic Capacity	S_SP	0.00%	0.70%	3,817	0.90%	3,817	0
SPRM	Economic Capacity	S_P	0.10%	0.00%	3,934	0.10%	3,934	0
SPRM	Economic Capacity	S_OP	0.50%	0.00%	3,523	0.80%	3,522	-1
SPRM	Economic Capacity	W_SP	0.50%	0.00%	2,186	0.50%	2,186	0
SPRM	Economic Capacity	W_P	0.50%	0.00%	2,186	0.50%	2,186	0
SPRM	Economic Capacity	W_OP	1.40%	0.00%	1,740	1.80%	1,724	-16
SPRM	Economic Capacity	SH_SP	0.10%	1.20%	2,886	1.80%	2,875	-10
SPRM	Economic Capacity	SH_P	0.30%	0.00%	2,541	0.30%	2,541	0
SPRM	Economic Capacity	SH_OP	1.80%	0.00%	2,066	2.50%	2,059	-7

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Market	Analysis	Period	Base Case (Pre-Mitigation) BASE AEP Mkt Share	CSW Mkt Share	HHI Pre-Merger	MERGER Merged Mkt Share	HHI Post-Merger	HHI Change
STEC	Economic Capacity	S_35	0.00%	0.00%	4,613	0.00%	4,613	0
STEC	Economic Capacity	S_SP	0.00%	0.00%	4,508	0.00%	4,508	0
STEC	Economic Capacity	S_P	0.00%	0.30%	6,001	0.30%	6,000	0
STEC	Economic Capacity	S_OP	0.00%	15.80%	2,472	15.80%	2,472	0
STEC	Economic Capacity	W_SP	0.00%	3.60%	2,100	3.60%	2,101	0
STEC	Economic Capacity	W_P	0.00%	0.00%	4,723	0.00%	4,723	0
STEC	Economic Capacity	W_OP	0.00%	0.00%	4,594	0.00%	4,594	0
STEC	Economic Capacity	SH_SP	0.00%	15.60%	1,581	15.60%	1,581	0
STEC	Economic Capacity	SH_P	0.00%	9.50%	4,755	10.90%	4,597	-159
STEC	Economic Capacity	SH_OP	0.00%	8.30%	4,908	9.30%	4,828	-80
STJO	Economic Capacity	S_35	1.30%	0.90%	1,133	2.30%	1,136	2
STJO	Economic Capacity	S_SP	1.10%	0.90%	1,172	2.10%	1,175	3
STJO	Economic Capacity	S_P	1.40%	3.00%	1,136	4.60%	1,144	8
STJO	Economic Capacity	S_OP	1.30%	0.00%	996	1.30%	993	-3
STJO	Economic Capacity	W_SP	2.20%	2.70%	725	5.20%	731	7
STJO	Economic Capacity	W_P	2.30%	2.10%	762	4.70%	768	5
STJO	Economic Capacity	W_OP	1.20%	0.00%	828	1.20%	825	-3
STJO	Economic Capacity	SH_SP	1.40%	3.60%	542	5.10%	550	8
STJO	Economic Capacity	SH_P	1.50%	2.20%	668	3.90%	674	5
STJO	Economic Capacity	SH_OP	3.70%	0.00%	880	3.70%	872	-7
SWEPA	Economic Capacity	S_35	0.50%	5.10%	1,423	5.70%	1,428	5
SWEPA	Economic Capacity	S_SP	0.50%	5.50%	1,278	6.30%	1,280	1
SWEPA	Economic Capacity	S_P	0.60%	0.00%	1,510	0.70%	1,509	-1
SWEPA	Economic Capacity	S_OP	0.80%	15.90%	959	17.00%	991	32
SWEPA	Economic Capacity	W_SP	0.90%	11.00%	709	12.30%	734	25
SWEPA	Economic Capacity	W_P	1.30%	6.80%	749	8.70%	765	16
SWEPA	Economic Capacity	W_OP	2.50%	7.80%	579	11.10%	622	42
SWEPA	Economic Capacity	SH_SP	1.70%	0.00%	1,084	1.80%	1,088	5
SWEPA	Economic Capacity	SH_P	2.40%	0.00%	940	2.60%	934	-6
SWEPA	Economic Capacity	SH_OP	1.00%	0.00%	735	1.10%	731	-3
SWPS	Economic Capacity	S_35	0.00%	3.00%	7,903	3.00%	7,942	39
SWPS	Economic Capacity	S_SP	0.00%	3.40%	6,736	3.60%	6,737	1
SWPS	Economic Capacity	S_P	0.00%	2.00%	7,089	2.20%	7,089	0
SWPS	Economic Capacity	S_OP	0.10%	1.70%	8,409	2.00%	8,410	1
SWPS	Economic Capacity	W_SP	0.00%	2.40%	7,952	2.40%	7,991	39
SWPS	Economic Capacity	W_P	0.00%	2.60%	6,631	2.80%	6,631	1
SWPS	Economic Capacity	W_OP	0.10%	2.30%	7,953	2.50%	7,954	2
SWPS	Economic Capacity	SH_SP	0.00%	1.40%	8,122	1.40%	8,162	40
SWPS	Economic Capacity	SH_P	0.00%	0.50%	7,154	0.70%	7,154	0
SWPS	Economic Capacity	SH_OP	0.00%	0.00%	8,496	0.20%	8,495	0
TMPA	Economic Capacity	S_35	0.00%	8.50%	1,628	8.50%	1,628	0
TMPA	Economic Capacity	S_SP	0.00%	5.40%	1,728	6.50%	1,707	-22
TMPA	Economic Capacity	S_P	0.00%	9.60%	1,627	10.20%	1,624	-3
TMPA	Economic Capacity	S_OP	0.00%	6.40%	1,658	7.60%	1,633	-25
TMPA	Economic Capacity	W_SP	0.00%	3.80%	1,455	3.80%	1,455	0
TMPA	Economic Capacity	W_P	0.00%	3.30%	2,104	3.80%	2,076	-28
TMPA	Economic Capacity	W_OP	0.00%	3.60%	2,098	4.00%	2,071	-28
TMPA	Economic Capacity	SH_SP	0.00%	4.00%	1,859	4.10%	1,859	0
TMPA	Economic Capacity	SH_P	0.00%	3.70%	1,914	4.00%	1,903	-10
TMPA	Economic Capacity	SH_OP	0.00%	3.90%	2,057	4.20%	2,045	-12
TNMP	Economic Capacity	S_35	0.00%	1.40%	2,017	1.40%	2,017	0
TNMP	Economic Capacity	S_SP	0.00%	1.40%	1,702	1.40%	1,704	3
TNMP	Economic Capacity	S_P	0.00%	2.30%	1,630	2.10%	1,640	9
TNMP	Economic Capacity	S_OP	0.00%	2.60%	1,781	2.50%	1,803	22
TNMP	Economic Capacity	W_SP	0.00%	0.80%	2,558	0.80%	2,559	1
TNMP	Economic Capacity	W_P	0.00%	2.50%	2,320	2.60%	2,319	-1
TNMP	Economic Capacity	W_OP	0.00%	2.20%	2,320	2.40%	2,319	0
TNMP	Economic Capacity	SH_SP	0.00%	3.10%	2,057	3.10%	2,058	1
TNMP	Economic Capacity	SH_P	0.00%	2.60%	1,916	2.50%	1,922	6
TNMP	Economic Capacity	SH_OP	0.00%	2.90%	1,942	2.90%	1,948	7
TU	Economic Capacity	S_35	0.00%	2.80%	7,591	2.80%	7,591	0
TU	Economic Capacity	S_SP	0.00%	6.70%	5,358	7.10%	5,332	-26
TU	Economic Capacity	S_P	0.00%	8.30%	5,039	8.80%	5,019	-20
TU	Economic Capacity	S_OP	0.00%	8.50%	5,079	8.80%	5,076	-3
TU	Economic Capacity	W_SP	0.00%	3.50%	8,687	3.50%	8,687	0
TU	Economic Capacity	W_P	0.00%	6.40%	7,324	7.60%	7,188	-136
TU	Economic Capacity	W_OP	0.00%	6.40%	7,325	7.50%	7,188	-136
TU	Economic Capacity	SH_SP	0.00%	7.50%	5,462	7.50%	5,462	0
TU	Economic Capacity	SH_P	0.00%	9.60%	3,414	10.30%	3,411	-4
TU	Economic Capacity	SH_OP	0.00%	10.20%	3,772	11.20%	3,733	-39

Base Case (Pre-Mitigation) | Exhibit No. AC-511

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
TVA	Economic Capacity	S_35	13.30%	0.00%	829	13.30%	829	0
TVA	Economic Capacity	S_SP	13.30%	0.00%	801	13.30%	801	0
TVA	Economic Capacity	S_P	9.00%	0.00%	841	9.00%	841	0
TVA	Economic Capacity	S_OP	10.30%	0.00%	963	10.30%	963	0
TVA	Economic Capacity	W_SP	4.50%	0.00%	672	4.50%	672	0
TVA	Economic Capacity	W_P	1.00%	0.00%	718	1.00%	718	0
TVA	Economic Capacity	W_OP	6.80%	0.00%	813	6.80%	813	0
TVA	Economic Capacity	SH_SP	13.00%	1.20%	688	14.10%	718	30
TVA	Economic Capacity	SH_P	0.60%	0.00%	862	0.60%	862	0
TVA	Economic Capacity	SH_OP	10.00%	0.00%	894	10.00%	894	0
VP	Economic Capacity	S_35	2.90%	0.00%	6,769	2.80%	6,769	0
VP	Economic Capacity	S_SP	3.50%	0.00%	6,453	3.50%	6,453	-1
VP	Economic Capacity	S_P	5.40%	0.00%	5,844	5.40%	5,842	-2
VP	Economic Capacity	S_OP	5.90%	0.00%	5,767	5.90%	5,766	-2
VP	Economic Capacity	W_SP	1.10%	0.00%	7,048	1.10%	7,048	0
VP	Economic Capacity	W_P	1.10%	0.00%	7,050	1.10%	7,050	0
VP	Economic Capacity	W_OP	1.90%	0.00%	6,921	1.90%	6,921	0
VP	Economic Capacity	SH_SP	0.80%	0.00%	6,914	0.80%	6,914	0
VP	Economic Capacity	SH_P	1.70%	0.00%	6,498	1.70%	6,498	0
VP	Economic Capacity	SH_OP	3.10%	0.00%	5,853	3.10%	5,853	0
WEFA	Economic Capacity	S_35	0.10%	6.90%	3,071	7.20%	3,076	4
WEFA	Economic Capacity	S_SP	0.10%	5.00%	2,071	5.50%	2,072	2
WEFA	Economic Capacity	S_P	0.00%	17.90%	1,769	19.70%	1,825	57
WEFA	Economic Capacity	S_OP	0.20%	20.40%	1,841	22.40%	1,911	70
WEFA	Economic Capacity	W_SP	0.50%	0.00%	2,518	0.40%	2,506	-12
WEFA	Economic Capacity	W_P	0.00%	0.00%	1,968	0.00%	1,970	2
WEFA	Economic Capacity	W_OP	1.50%	0.00%	1,930	2.10%	1,863	-67
WEFA	Economic Capacity	SH_SP	0.30%	8.60%	1,621	10.10%	1,634	13
WEFA	Economic Capacity	SH_P	0.10%	0.00%	1,731	0.10%	1,705	-26
WEFA	Economic Capacity	SH_OP	0.60%	0.50%	1,693	2.60%	1,667	-26
WEP	Economic Capacity	S_35	0.80%	0.00%	5,051	0.80%	5,051	0
WEP	Economic Capacity	S_SP	1.10%	0.00%	4,678	1.10%	4,678	0
WEP	Economic Capacity	S_P	1.40%	0.00%	5,182	1.40%	5,182	0
WEP	Economic Capacity	S_OP	1.70%	0.00%	2,089	1.70%	2,090	1
WEP	Economic Capacity	W_SP	1.00%	0.10%	3,988	1.20%	3,988	0
WEP	Economic Capacity	W_P	1.60%	0.00%	3,737	1.60%	3,742	4
WEP	Economic Capacity	W_OP	0.80%	0.00%	2,818	0.80%	2,827	9
WEP	Economic Capacity	SH_SP	1.00%	0.00%	2,044	1.00%	2,045	2
WEP	Economic Capacity	SH_P	1.00%	0.00%	2,119	1.00%	2,120	0
WEP	Economic Capacity	SH_OP	1.00%	0.00%	1,497	1.00%	1,500	3
WEPL	Economic Capacity	S_35	0.00%	0.50%	5,520	0.60%	5,521	1
WEPL	Economic Capacity	S_SP	0.00%	0.00%	4,889	0.00%	4,879	-9
WEPL	Economic Capacity	S_P	0.10%	0.00%	2,937	0.10%	2,937	0
WEPL	Economic Capacity	S_OP	0.00%	0.00%	1,599	0.00%	1,555	-44
WEPL	Economic Capacity	W_SP	0.00%	0.00%	3,563	0.00%	3,547	-16
WEPL	Economic Capacity	W_P	0.00%	0.00%	3,696	0.00%	3,675	-21
WEPL	Economic Capacity	W_OP	0.20%	0.00%	3,600	0.40%	3,563	-37
WEPL	Economic Capacity	SH_SP	0.00%	0.20%	3,478	0.20%	3,477	0
WEPL	Economic Capacity	SH_P	0.00%	0.00%	3,686	0.00%	3,686	0
WEPL	Economic Capacity	SH_OP	0.30%	0.00%	1,725	0.40%	1,751	26
WR	Economic Capacity	S_35	0.30%	0.70%	4,684	1.00%	4,710	25
WR	Economic Capacity	S_SP	0.20%	0.80%	3,505	1.10%	3,505	0
WR	Economic Capacity	S_P	0.10%	0.80%	3,882	0.60%	3,879	-3
WR	Economic Capacity	S_OP	1.00%	0.00%	2,068	1.00%	2,069	1
WR	Economic Capacity	W_SP	0.10%	0.90%	2,554	1.10%	2,553	-1
WR	Economic Capacity	W_P	0.10%	0.00%	2,826	0.10%	2,828	2
WR	Economic Capacity	W_OP	0.60%	0.00%	2,890	0.60%	2,886	-4
WR	Economic Capacity	SH_SP	0.50%	1.60%	2,380	2.10%	2,381	1
WR	Economic Capacity	SH_P	0.10%	0.00%	2,256	0.10%	2,253	-3
WR	Economic Capacity	SH_OP	0.60%	0.00%	1,829	0.60%	1,818	-11

Base Case (Pre-Mitigation) **Exhibit No. AC-511**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CSW_SPP	Available Economic Capacity	S_35	8.30%	8.10%	678	15.70%	800	122
CSW_SPP	Available Economic Capacity	S_SP	22.40%	13.50%	1,101	36.20%	1,775	675
CSW_SPP	Available Economic Capacity	S_P	0.00%	18.30%	1,002	21.50%	1,129	127
CSW_SPP	Available Economic Capacity	S_OP	7.10%	0.00%	866	5.60%	947	81
CSW_SPP	Available Economic Capacity	W_SP	3.10%	26.30%	1,095	30.30%	1,321	226
CSW_SPP	Available Economic Capacity	W_P	0.00%	0.00%	959	0.00%	918	-42
CSW_SPP	Available Economic Capacity	W_OP	0.00%	0.00%	969	1.00%	897	-72
CSW_SPP	Available Economic Capacity	SH_SP	6.10%	11.50%	711	18.10%	878	167
CSW_SPP	Available Economic Capacity	SH_P	0.00%	12.60%	591	13.60%	619	28
CSW_SPP	Available Economic Capacity	SH_OP	0.00%	0.00%	1,270	0.00%	1,281	11
CBEN	Available Economic Capacity	S_35	0.00%	54.70%	3,787	54.60%	3,785	-2
CBEN	Available Economic Capacity	S_SP	0.00%	66.80%	4,961	66.70%	4,952	-9
CBEN	Available Economic Capacity	S_P	0.00%	68.70%	5,231	73.20%	5,678	447
CBEN	Available Economic Capacity	S_OP	0.00%	55.90%	3,718	55.90%	3,708	-10
CBEN	Available Economic Capacity	W_SP	0.00%	46.10%	3,081	46.10%	3,082	1
CBEN	Available Economic Capacity	W_P	0.00%	67.90%	4,790	67.90%	4,776	-14
CBEN	Available Economic Capacity	W_OP	0.00%	63.50%	4,303	63.50%	4,293	-10
CBEN	Available Economic Capacity	SH_SP	0.00%	61.40%	4,155	61.20%	4,103	-52
CBEN	Available Economic Capacity	SH_P	0.00%	51.40%	2,971	51.40%	2,960	-10
CBEN	Available Economic Capacity	SH_OP	0.00%	45.20%	2,650	45.20%	2,600	-50
VALLEY	Available Economic Capacity	S_35	0.00%	64.30%	4,642	64.30%	4,640	-2
VALLEY	Available Economic Capacity	S_SP	0.00%	69.70%	5,360	69.70%	5,357	-3
VALLEY	Available Economic Capacity	S_P	0.00%	57.10%	3,898	57.10%	3,909	11
VALLEY	Available Economic Capacity	S_OP	0.00%	59.50%	4,020	59.50%	4,023	4
VALLEY	Available Economic Capacity	W_SP	0.00%	56.40%	3,673	56.40%	3,673	0
VALLEY	Available Economic Capacity	W_P	0.00%	62.40%	4,289	62.40%	4,288	-2
VALLEY	Available Economic Capacity	W_OP	0.00%	64.10%	4,473	64.10%	4,474	1
VALLEY	Available Economic Capacity	SH_SP	0.00%	61.20%	3,997	61.10%	3,972	-24
VALLEY	Available Economic Capacity	SH_P	0.00%	48.60%	3,068	48.60%	3,067	-1
VALLEY	Available Economic Capacity	SH_OP	0.00%	51.60%	3,306	51.70%	3,310	4
WTU	Available Economic Capacity	S_35	0.00%	31.90%	2,618	31.70%	2,614	-4
WTU	Available Economic Capacity	S_SP	0.00%	45.50%	3,314	45.50%	3,314	0
WTU	Available Economic Capacity	S_P	0.00%	31.10%	5,058	45.20%	4,328	-730
WTU	Available Economic Capacity	S_OP	0.00%	39.40%	2,724	39.40%	2,703	-21
WTU	Available Economic Capacity	W_SP	0.00%	29.40%	4,788	29.40%	4,805	17
WTU	Available Economic Capacity	W_P	0.00%	12.70%	4,990	12.40%	5,010	20
WTU	Available Economic Capacity	W_OP	0.00%	16.20%	5,133	15.90%	5,154	21
WTU	Available Economic Capacity	SH_SP	0.00%	46.80%	2,989	46.60%	2,899	-90
WTU	Available Economic Capacity	SH_P	0.00%	23.40%	1,214	23.10%	1,191	-24
WTU	Available Economic Capacity	SH_OP	0.00%	28.40%	2,245	28.40%	2,228	-17

Exhibit No. AC-511

			Base Case (Pre-Mitigation)				MERGER	
				BASE				
Market	Analysis	Period	AEP Mkt Share	CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	HHI Post-Merger	HHI Change
AECI	Available Economic Capacity	S_35	11.20%	0.00%	1,544	11.60%	1,462	-83
AECI	Available Economic Capacity	S_SP	0.00%	0.00%	950	0.00%	950	0
AECI	Available Economic Capacity	S_P	0.00%	0.00%	1,575	0.00%	1,499	-77
AECI	Available Economic Capacity	S_OP	0.00%	0.00%	1,485	0.00%	1,485	0
AECI	Available Economic Capacity	W_SP	7.60%	0.00%	804	8.00%	800	-5
AECI	Available Economic Capacity	W_P	0.00%	0.00%	986	0.00%	986	0
AECI	Available Economic Capacity	W_OP	1.10%	0.00%	1,088	1.40%	1,084	-4
AECI	Available Economic Capacity	SH_SP	19.30%	0.80%	903	20.80%	957	54
AECI	Available Economic Capacity	SH_P	0.00%	0.00%	1,044	0.00%	1,044	0
AECI	Available Economic Capacity	SH_OP	9.10%	0.00%	971	9.90%	975	5
AEP	Available Economic Capacity	S_35	35.50%	0.00%	1,653	33.60%	1,550	-103
AEP	Available Economic Capacity	S_SP	98.50%	0.00%	9,697	98.30%	9,670	-27
AEP	Available Economic Capacity	S_P	99.80%	0.00%	9,959	99.80%	9,957	-2
AEP	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
AEP	Available Economic Capacity	W_SP	99.70%	0.00%	9,943	99.70%	9,939	-5
AEP	Available Economic Capacity	W_P	99.80%	0.00%	9,959	99.80%	9,956	-2
AEP	Available Economic Capacity	W_OP	99.80%	0.00%	9,970	99.80%	9,965	-5
AEP	Available Economic Capacity	SH_SP	85.50%	0.00%	7,392	84.00%	7,160	-232
AEP	Available Economic Capacity	SH_P	99.00%	0.00%	9,803	98.90%	9,790	-13
AEP	Available Economic Capacity	SH_OP	99.70%	0.00%	9,935	99.60%	9,912	-22
ALLIANT_E	Available Economic Capacity	S_35	8.30%	0.00%	912	1.60%	895	-17
ALLIANT_E	Available Economic Capacity	S_SP	0.00%	0.00%	1,839	0.00%	1,819	-20
ALLIANT_E	Available Economic Capacity	S_P	0.00%	0.00%	1,619	0.00%	1,619	0
ALLIANT_E	Available Economic Capacity	S_OP	0.00%	0.00%	7,083	0.00%	7,083	0
ALLIANT_E	Available Economic Capacity	W_SP	7.60%	0.00%	1,035	5.20%	1,060	25
ALLIANT_E	Available Economic Capacity	W_P	0.00%	0.00%	1,756	0.00%	1,756	0
ALLIANT_E	Available Economic Capacity	W_OP	0.00%	0.00%	8,511	0.00%	8,511	0
ALLIANT_E	Available Economic Capacity	SH_SP	0.00%	0.00%	1,993	0.00%	1,993	0
ALLIANT_E	Available Economic Capacity	SH_P	0.00%	0.00%	2,283	0.00%	2,283	0
ALLIANT_E	Available Economic Capacity	SH_OP	0.00%	0.00%	7,132	0.00%	7,132	0
AMEREN	Available Economic Capacity	S_35	24.10%	0.00%	1,231	25.70%	1,287	56
AMEREN	Available Economic Capacity	S_SP	6.50%	1.10%	399	8.50%	422	23
AMEREN	Available Economic Capacity	S_P	3.40%	0.00%	1,093	2.20%	1,097	4
AMEREN	Available Economic Capacity	S_OP	0.00%	0.00%	2,683	0.00%	2,632	-50
AMEREN	Available Economic Capacity	W_SP	3.10%	0.00%	938	3.10%	946	8
AMEREN	Available Economic Capacity	W_P	6.30%	0.00%	1,254	6.20%	1,254	-1
AMEREN	Available Economic Capacity	W_OP	0.00%	0.00%	2,600	0.00%	2,600	0
AMEREN	Available Economic Capacity	SH_SP	11.30%	0.40%	574	13.90%	630	56
AMEREN	Available Economic Capacity	SH_P	8.70%	0.00%	1,225	8.60%	1,223	-2
AMEREN	Available Economic Capacity	SH_OP	0.00%	0.00%	4,776	0.00%	4,776	0
APS	Available Economic Capacity	S_35	53.20%	0.00%	3,660	48.20%	3,223	-438
APS	Available Economic Capacity	S_SP	98.80%	0.00%	9,764	98.70%	9,744	-20
APS	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
APS	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
APS	Available Economic Capacity	W_SP	83.80%	0.00%	7,155	82.50%	6,967	-187
APS	Available Economic Capacity	W_P	0.00%	0.00%	7,739	0.00%	7,739	0
APS	Available Economic Capacity	W_OP	71.40%	0.00%	5,919	69.50%	5,758	-161
APS	Available Economic Capacity	SH_SP	22.00%	0.00%	2,233	20.00%	2,208	-25
APS	Available Economic Capacity	SH_P	47.80%	0.00%	3,253	40.40%	2,891	-362
APS	Available Economic Capacity	SH_OP	76.90%	0.00%	6,448	76.90%	6,448	0
BEC	Available Economic Capacity	S_35	0.00%	34.30%	2,500	34.10%	2,494	-5
BEC	Available Economic Capacity	S_SP	0.00%	78.00%	6,563	78.00%	6,563	0
BEC	Available Economic Capacity	S_P	0.00%	78.00%	6,563	78.00%	6,563	0
BEC	Available Economic Capacity	S_OP	0.00%	27.70%	3,728	27.90%	2,717	-1,011
BEC	Available Economic Capacity	W_SP	0.00%	27.80%	3,112	27.80%	3,121	9
BEC	Available Economic Capacity	W_P	0.00%	45.70%	3,142	45.70%	3,142	0
BEC	Available Economic Capacity	W_OP	0.00%	10.20%	2,300	10.20%	1,975	-324
BEC	Available Economic Capacity	SH_SP	0.00%	51.60%	3,522	51.40%	3,509	-13
BEC	Available Economic Capacity	SH_P	0.00%	48.00%	3,540	48.00%	3,540	0
BEC	Available Economic Capacity	SH_OP	0.00%	32.00%	2,707	32.00%	2,707	0

Base Case (Pre-Mitigation) **Exhibit No. AC-511**

			BASE			MERGER		
Market	**Analysis**	**Period**	**AEP Mkt Share**	**CSW Mkt Share**	**HHI Pre-Merger**	**Merged Mkt Share**	**HHI Post-Merger**	**HHI Change**
BRYN	Available Economic Capacity	S_35	0.00%	46.10%	3,196	46.00%	3,193	-3
BRYN	Available Economic Capacity	S_SP	0.00%	79.20%	6,700	79.20%	6,700	0
BRYN	Available Economic Capacity	S_P	0.00%	79.20%	6,700	79.20%	6,700	0
BRYN	Available Economic Capacity	S_OP	0.00%	36.80%	2,907	37.00%	2,844	-63
BRYN	Available Economic Capacity	W_SP	0.00%	21.80%	1,977	20.20%	2,036	59
BRYN	Available Economic Capacity	W_P	0.00%	0.00%	3,366	0.00%	3,366	0
BRYN	Available Economic Capacity	W_OP	0.00%	0.00%	7,228	0.00%	6,668	-560
BRYN	Available Economic Capacity	SH_SP	0.00%	53.30%	3,658	53.10%	3,619	-39
BRYN	Available Economic Capacity	SH_P	0.00%	49.20%	3,686	49.20%	3,686	0
BRYN	Available Economic Capacity	SH_OP	0.00%	31.60%	2,348	31.60%	2,218	-129
CAPO	Available Economic Capacity	S_35	88.20%	0.00%	7,797	87.60%	7,694	-103
CAPO	Available Economic Capacity	S_SP	87.50%	0.00%	7,689	86.80%	7,572	-117
CAPO	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	SH_SP	84.40%	0.00%	7,177	78.40%	6,230	-948
CAPO	Available Economic Capacity	SH_P	0.00%	0.00%	10,000	0.00%	10,000	0
CAPO	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
CELE	Available Economic Capacity	S_35	2.20%	4.30%	1,619	6.50%	1,650	31
CELE	Available Economic Capacity	S_SP	0.00%	0.00%	2,741	0.00%	3,614	873
CELE	Available Economic Capacity	S_P	0.00%	0.00%	2,015	0.00%	2,117	102
CELE	Available Economic Capacity	S_OP	0.00%	0.00%	3,493	0.00%	3,717	224
CELE	Available Economic Capacity	W_SP	1.70%	7.60%	1,804	10.10%	1,850	46
CELE	Available Economic Capacity	W_P	0.00%	0.00%	1,518	0.00%	1,489	-28
CELE	Available Economic Capacity	W_OP	15.10%	0.00%	1,091	11.80%	928	-163
CELE	Available Economic Capacity	SH_SP	9.10%	0.30%	1,211	10.10%	1,270	59
CELE	Available Economic Capacity	SH_P	0.00%	0.00%	4,545	0.00%	4,276	-269
CELE	Available Economic Capacity	SH_OP	24.00%	0.00%	1,871	24.50%	1,816	-55
CIMO	Available Economic Capacity	S_35	7.10%	0.00%	944	8.60%	922	-22
CIMO	Available Economic Capacity	S_SP	0.00%	0.00%	5,255	0.00%	5,255	0
CIMO	Available Economic Capacity	S_P	0.00%	0.00%	9,519	0.00%	9,519	0
CIMO	Available Economic Capacity	S_OP	0.00%	0.00%	6,784	0.00%	6,784	0
CIMO	Available Economic Capacity	W_SP	0.00%	0.00%	9,205	0.00%	9,205	0
CIMO	Available Economic Capacity	W_P	0.00%	0.00%	4,759	0.00%	4,759	0
CIMO	Available Economic Capacity	W_OP	0.00%	0.00%	4,993	0.00%	4,993	0
CIMO	Available Economic Capacity	SH_SP	0.00%	0.00%	4,774	0.00%	4,774	0
CIMO	Available Economic Capacity	SH_P	0.00%	0.00%	6,240	0.00%	6,240	0
CIMO	Available Economic Capacity	SH_OP	0.00%	0.00%	5,700	0.00%	5,700	0
CIN	Available Economic Capacity	S_35	50.60%	0.00%	2,809	46.60%	2,447	-362
CIN	Available Economic Capacity	S_SP	0.00%	0.00%	3,882	0.00%	3,882	0
CIN	Available Economic Capacity	S_P	0.00%	0.00%	3,260	0.00%	3,260	0
CIN	Available Economic Capacity	S_OP	0.00%	0.00%	5,151	0.00%	5,151	0
CIN	Available Economic Capacity	W_SP	0.00%	0.00%	2,356	0.00%	2,356	0
CIN	Available Economic Capacity	W_P	0.00%	0.00%	3,254	0.00%	3,254	0
CIN	Available Economic Capacity	W_OP	0.00%	0.00%	3,180	0.00%	3,180	0
CIN	Available Economic Capacity	SH_SP	0.00%	0.00%	3,973	0.00%	3,973	0
CIN	Available Economic Capacity	SH_P	0.00%	0.00%	3,266	0.00%	3,266	0
CIN	Available Economic Capacity	SH_OP	0.00%	0.00%	4,306	0.00%	4,306	0
COA	Available Economic Capacity	S_35	0.00%	34.90%	3,355	34.90%	3,355	0
COA	Available Economic Capacity	S_SP	0.00%	77.40%	6,501	77.40%	6,501	0
COA	Available Economic Capacity	S_P	0.00%	77.40%	6,501	77.40%	6,501	0
COA	Available Economic Capacity	S_OP	0.00%	76.00%	6,352	76.00%	6,352	0
COA	Available Economic Capacity	W_SP	0.00%	15.80%	2,405	15.70%	2,405	0
COA	Available Economic Capacity	W_P	0.00%	0.00%	5,068	0.00%	5,068	0
COA	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
COA	Available Economic Capacity	SH_SP	0.00%	81.20%	6,942	81.20%	6,942	0
COA	Available Economic Capacity	SH_P	0.00%	72.60%	5,661	72.60%	5,661	0
COA	Available Economic Capacity	SH_OP	0.00%	0.00%	5,010	0.00%	5,010	0

Base Case (Pre-Mitigation) | Exhibit No. AC-511

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Available Economic Capacity	S_35	30.30%	0.00%	2,064	30.30%	2,068	4
COMED	Available Economic Capacity	S_SP	29.00%	0.00%	2,050	29.30%	2,066	16
COMED	Available Economic Capacity	S_P	0.00%	0.00%	2,308	0.00%	2,308	0
COMED	Available Economic Capacity	S_OP	0.00%	0.00%	5,397	0.00%	5,397	0
COMED	Available Economic Capacity	W_SP	38.30%	0.00%	2,123	37.60%	2,084	-39
COMED	Available Economic Capacity	W_P	0.00%	0.00%	2,058	0.00%	2,058	0
COMED	Available Economic Capacity	W_OP	0.00%	0.00%	2,742	0.00%	2,742	0
COMED	Available Economic Capacity	SH_SP	41.30%	0.00%	2,010	39.80%	1,903	-107
COMED	Available Economic Capacity	SH_P	0.00%	0.00%	1,744	0.00%	1,744	0
COMED	Available Economic Capacity	SH_OP	0.00%	0.00%	2,081	0.00%	2,081	0
CP	Available Economic Capacity	S_35	55.80%	0.00%	3,380	53.80%	3,190	-190
CP	Available Economic Capacity	S_SP	58.30%	0.00%	3,613	56.50%	3,423	-190
CP	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
CP	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
CP	Available Economic Capacity	W_SP	27.80%	0.00%	1,415	26.70%	1,369	-46
CP	Available Economic Capacity	W_P	77.70%	0.00%	6,301	77.60%	6,278	-23
CP	Available Economic Capacity	W_OP	87.70%	0.00%	7,767	87.70%	7,767	0
CP	Available Economic Capacity	SH_SP	79.10%	0.00%	6,412	77.30%	6,148	-263
CP	Available Economic Capacity	SH_P	96.00%	0.00%	9,238	95.80%	9,195	-44
CP	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
CPS	Available Economic Capacity	S_35	0.00%	39.10%	3,436	38.90%	3,434	-2
CPS	Available Economic Capacity	S_SP	0.00%	78.00%	6,563	78.00%	6,563	0
CPS	Available Economic Capacity	S_P	0.00%	78.00%	6,563	78.00%	6,563	0
CPS	Available Economic Capacity	S_OP	0.00%	78.00%	6,563	78.00%	6,563	0
CPS	Available Economic Capacity	W_SP	0.00%	50.00%	5,000	50.00%	5,000	0
CPS	Available Economic Capacity	W_P	0.00%	0.00%	10,000	0.00%	10,000	0
CPS	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
CPS	Available Economic Capacity	SH_SP	0.00%	74.20%	5,844	74.20%	5,844	0
CPS	Available Economic Capacity	SH_P	0.00%	73.10%	5,729	73.10%	5,729	0
CPS	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
DECO	Available Economic Capacity	S_35	97.40%	0.00%	9,492	97.20%	9,449	-43
DECO	Available Economic Capacity	S_SP	64.40%	0.00%	4,519	62.80%	4,354	-165
DECO	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
DECO	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
DECO	Available Economic Capacity	W_SP	63.40%	0.00%	4,673	61.90%	4,540	-133
DECO	Available Economic Capacity	W_P	0.00%	0.00%	4,019	0.00%	4,019	0
DECO	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
DECO	Available Economic Capacity	SH_SP	32.00%	0.00%	3,643	0.00%	5,663	2,020
DECO	Available Economic Capacity	SH_P	0.00%	0.00%	6,219	0.00%	6,219	0
DECO	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
DGG	Available Economic Capacity	S_35	0.00%	45.80%	3,198	45.70%	3,196	-2
DGG	Available Economic Capacity	S_SP	0.00%	78.00%	6,563	78.00%	6,563	0
DGG	Available Economic Capacity	S_P	0.00%	78.00%	6,563	78.00%	6,563	0
DGG	Available Economic Capacity	S_OP	0.00%	34.40%	2,832	34.80%	2,747	-85
DGG	Available Economic Capacity	W_SP	0.00%	28.80%	1,169	28.80%	1,169	0
DGG	Available Economic Capacity	W_P	0.00%	25.00%	2,500	25.00%	2,500	0
DGG	Available Economic Capacity	W_OP	0.00%	20.00%	1,200	20.00%	1,200	0
DGG	Available Economic Capacity	SH_SP	0.00%	53.20%	3,652	53.00%	3,613	-39
DGG	Available Economic Capacity	SH_P	0.00%	48.70%	3,630	48.70%	3,630	0
DGG	Available Economic Capacity	SH_OP	0.00%	33.20%	2,722	33.20%	2,517	-204
DLCO	Available Economic Capacity	S_35	90.80%	0.00%	8,273	89.80%	8,083	-189
DLCO	Available Economic Capacity	S_SP	100.00%	0.00%	10,000	100.00%	10,000	0
DLCO	Available Economic Capacity	S_P	43.90%	0.00%	3,148	43.90%	3,148	0
DLCO	Available Economic Capacity	S_OP	66.80%	0.00%	5,565	66.80%	5,565	0
DLCO	Available Economic Capacity	W_SP	71.40%	0.00%	5,515	71.40%	5,515	0
DLCO	Available Economic Capacity	W_P	67.80%	0.00%	5,631	62.20%	5,296	-335
DLCO	Available Economic Capacity	W_OP	64.50%	0.00%	5,419	64.50%	5,419	0
DLCO	Available Economic Capacity	SH_SP	56.60%	0.00%	4,042	53.80%	3,832	-210
DLCO	Available Economic Capacity	SH_P	83.70%	0.00%	7,275	83.70%	7,275	0
DLCO	Available Economic Capacity	SH_OP	69.90%	0.00%	5,793	69.90%	5,793	0

Base Case (Pre-Mitigation) Exhibit No. AC-511

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
DPL	Available Economic Capacity	S_35	64.20%	0.00%	4,282	62.00%	4,026	-256
DPL	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
DPL	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
DPL	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
DPL	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
DUKE	Available Economic Capacity	S_35	78.30%	0.00%	6,271	76.10%	5,970	-301
DUKE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
EDE	Available Economic Capacity	S_35	10.60%	0.00%	714	12.40%	726	12
EDE	Available Economic Capacity	S_SP	6.50%	1.90%	785	9.70%	829	44
EDE	Available Economic Capacity	S_P	0.00%	0.00%	3,441	0.00%	3,442	1
EDE	Available Economic Capacity	S_OP	0.00%	0.00%	9,842	0.00%	9,834	-8
EDE	Available Economic Capacity	W_SP	2.50%	10.20%	691	13.90%	755	64
EDE	Available Economic Capacity	W_P	0.00%	0.00%	1,656	0.00%	1,652	-3
EDE	Available Economic Capacity	W_OP	0.00%	0.00%	1,293	0.00%	1,298	5
EDE	Available Economic Capacity	SH_SP	0.00%	0.00%	2,661	0.00%	2,733	72
EDE	Available Economic Capacity	SH_P	0.00%	0.00%	2,266	0.00%	2,178	-88
EDE	Available Economic Capacity	SH_OP	0.00%	0.00%	2,965	0.00%	2,926	-39
EKPC	Available Economic Capacity	S_35	51.40%	0.00%	2,959	49.90%	2,818	-141
EKPC	Available Economic Capacity	S_SP	87.80%	0.00%	7,754	87.80%	7,754	0
EKPC	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
EKPC	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
EKPC	Available Economic Capacity	W_SP	32.30%	0.00%	2,278	32.30%	2,278	0
EKPC	Available Economic Capacity	W_P	0.00%	0.00%	10,000	0.00%	10,000	0
EKPC	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
EKPC	Available Economic Capacity	SH_SP	26.70%	0.00%	1,852	24.40%	1,803	-49
EKPC	Available Economic Capacity	SH_P	0.00%	0.00%	10,000	0.00%	10,000	0
EKPC	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
ENT	Available Economic Capacity	S_35	13.50%	0.00%	2,045	13.50%	2,063	17
ENT	Available Economic Capacity	S_SP	0.00%	0.00%	3,586	0.00%	3,586	0
ENT	Available Economic Capacity	S_P	0.00%	0.00%	2,351	0.00%	2,351	0
ENT	Available Economic Capacity	S_OP	0.00%	0.00%	7,306	0.00%	7,306	0
ENT	Available Economic Capacity	W_SP	3.80%	0.00%	3,892	3.90%	3,953	61
ENT	Available Economic Capacity	W_P	0.00%	0.00%	1,013	0.00%	1,000	-13
ENT	Available Economic Capacity	W_OP	0.00%	0.00%	993	0.00%	1,003	10
ENT	Available Economic Capacity	SH_SP	33.80%	0.60%	1,495	33.50%	1,488	-7
ENT	Available Economic Capacity	SH_P	0.00%	0.00%	1,566	0.00%	1,573	7
ENT	Available Economic Capacity	SH_OP	0.00%	0.00%	1,258	0.00%	1,272	14
FENER	Available Economic Capacity	S_35	70.60%	0.00%	5,121	68.10%	4,801	-320
FENER	Available Economic Capacity	S_SP	97.10%	0.00%	9,426	96.90%	9,395	-31
FENER	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
FENER	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
FENER	Available Economic Capacity	W_SP	0.00%	0.00%	3,549	0.00%	3,549	0
FENER	Available Economic Capacity	W_P	0.00%	0.00%	8,113	0.00%	8,113	0
FENER	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
FENER	Available Economic Capacity	SH_SP	28.10%	0.00%	1,478	25.60%	1,382	-97
FENER	Available Economic Capacity	SH_P	46.30%	0.00%	2,922	39.00%	2,521	-401
FENER	Available Economic Capacity	SH_OP	62.00%	0.00%	5,287	60.30%	5,214	-73

Base Case (Pre-Mitigation) **Exhibit No. AC-511**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
GRRD	Available Economic Capacity	S_35	2.20%	0.00%	1,137	3.20%	1,136	-1
GRRD	Available Economic Capacity	S_SP	0.00%	0.00%	2,372	0.00%	2,372	0
GRRD	Available Economic Capacity	S_P	0.00%	0.00%	7,713	0.00%	7,720	8
GRRD	Available Economic Capacity	S_OP	0.00%	0.00%	8,560	0.00%	8,560	0
GRRD	Available Economic Capacity	W_SP	0.00%	0.00%	1,351	0.00%	1,367	15
GRRD	Available Economic Capacity	W_P	0.00%	0.00%	2,517	0.00%	2,529	12
GRRD	Available Economic Capacity	W_OP	0.00%	0.00%	3,866	0.00%	3,866	0
GRRD	Available Economic Capacity	SH_SP	4.10%	0.20%	893	5.60%	928	35
GRRD	Available Economic Capacity	SH_P	0.00%	0.00%	3,705	0.00%	3,729	24
GRRD	Available Economic Capacity	SH_OP	0.00%	0.00%	5,331	0.00%	5,331	0
HEC	Available Economic Capacity	S_35	67.60%	0.00%	4,887	66.20%	4,736	-151
HEC	Available Economic Capacity	S_SP	68.70%	0.00%	4,988	67.10%	4,805	-183
HEC	Available Economic Capacity	S_P	0.00%	0.00%	5,045	0.00%	5,045	0
HEC	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
HEC	Available Economic Capacity	W_SP	37.00%	0.00%	1,985	35.90%	1,917	-67
HEC	Available Economic Capacity	W_P	0.00%	0.00%	2,752	0.00%	2,752	0
HEC	Available Economic Capacity	W_OP	0.00%	0.00%	9,002	0.00%	9,002	0
HEC	Available Economic Capacity	SH_SP	14.90%	0.00%	1,511	7.00%	1,553	42
HEC	Available Economic Capacity	SH_P	0.00%	0.00%	2,296	0.00%	2,296	0
HEC	Available Economic Capacity	SH_OP	0.00%	0.00%	7,852	0.00%	7,852	0
HLP	Available Economic Capacity	S_35	0.00%	31.70%	2,264	31.60%	2,259	-5
HLP	Available Economic Capacity	S_SP	0.00%	77.40%	6,499	77.40%	6,499	0
HLP	Available Economic Capacity	S_P	0.00%	77.40%	6,499	77.40%	6,499	0
HLP	Available Economic Capacity	S_OP	0.00%	36.40%	2,659	36.40%	2,540	-119
HLP	Available Economic Capacity	W_SP	0.00%	8.50%	2,516	8.50%	2,525	9
HLP	Available Economic Capacity	W_P	0.00%	54.10%	3,400	54.10%	3,400	0
HLP	Available Economic Capacity	W_OP	0.00%	0.00%	3,136	0.00%	2,926	-210
HLP	Available Economic Capacity	SH_SP	0.00%	43.30%	3,131	43.30%	3,095	-36
HLP	Available Economic Capacity	SH_P	0.00%	40.80%	3,620	42.30%	3,568	-52
HLP	Available Economic Capacity	SH_OP	0.00%	32.10%	2,451	32.10%	2,363	-88
IP	Available Economic Capacity	S_35	23.70%	0.00%	1,002	24.40%	1,032	29
IP	Available Economic Capacity	S_SP	40.70%	0.00%	1,948	41.40%	2,001	53
IP	Available Economic Capacity	S_P	28.80%	0.00%	1,448	27.50%	1,379	-69
IP	Available Economic Capacity	S_OP	22.90%	0.00%	1,770	23.50%	1,765	-5
IP	Available Economic Capacity	W_SP	34.00%	0.00%	1,637	34.10%	1,649	12
IP	Available Economic Capacity	W_P	0.00%	0.00%	1,674	0.00%	1,674	0
IP	Available Economic Capacity	W_OP	15.60%	0.00%	1,724	11.40%	1,753	29
IP	Available Economic Capacity	SH_SP	27.40%	0.00%	1,205	27.20%	1,203	-3
IP	Available Economic Capacity	SH_P	0.00%	0.00%	2,051	0.00%	2,051	0
IP	Available Economic Capacity	SH_OP	0.00%	0.00%	2,426	0.00%	2,426	0
IPL	Available Economic Capacity	S_35	62.70%	0.00%	4,104	61.20%	3,932	-172
IPL	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
KACY	Available Economic Capacity	S_35	3.30%	0.00%	1,448	4.80%	1,349	-99
KACY	Available Economic Capacity	S_SP	0.00%	0.00%	1,907	0.00%	1,907	0
KACY	Available Economic Capacity	S_P	0.00%	0.00%	6,711	0.00%	6,711	0
KACY	Available Economic Capacity	S_OP	0.00%	0.00%	8,194	0.00%	8,194	0
KACY	Available Economic Capacity	W_SP	0.00%	0.00%	10,000	0.00%	10,000	0
KACY	Available Economic Capacity	W_P	0.00%	0.00%	6,651	0.00%	6,651	0
KACY	Available Economic Capacity	W_OP	0.00%	0.00%	5,629	0.00%	5,629	0
KACY	Available Economic Capacity	SH_SP	0.00%	0.00%	2,736	0.00%	2,736	0
KACY	Available Economic Capacity	SH_P	0.00%	0.00%	4,225	0.00%	4,225	0
KACY	Available Economic Capacity	SH_OP	0.00%	0.00%	4,859	0.00%	4,859	0

Exhibit No. AC-511

Base Case (Pre-Mitigation)

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
KCPL	Available Economic Capacity	S_35	13.80%	0.00%	1,133	14.00%	1,126	-7
KCPL	Available Economic Capacity	S_SP	6.60%	0.00%	771	6.80%	756	-15
KCPL	Available Economic Capacity	S_P	0.00%	0.00%	1,588	0.00%	1,434	-154
KCPL	Available Economic Capacity	S_OP	0.00%	0.00%	1,792	0.00%	1,792	0
KCPL	Available Economic Capacity	W_SP	10.50%	0.00%	722	10.80%	711	-12
KCPL	Available Economic Capacity	W_P	0.00%	0.00%	932	0.00%	933	2
KCPL	Available Economic Capacity	W_OP	0.00%	0.00%	5,213	0.00%	5,213	0
KCPL	Available Economic Capacity	SH_SP	8.70%	0.00%	884	9.50%	884	1
KCPL	Available Economic Capacity	SH_P	0.00%	0.00%	2,366	0.00%	2,366	0
KCPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5,725	0.00%	5,725	0
LAFA	Available Economic Capacity	S_35	0.00%	0.00%	6,843	0.00%	6,842	-2
LAFA	Available Economic Capacity	S_SP	0.00%	0.00%	8,702	0.00%	8,702	0
LAFA	Available Economic Capacity	S_P	0.00%	0.00%	3,333	0.00%	3,333	0
LAFA	Available Economic Capacity	S_OP	0.00%	0.00%	9,999	0.00%	9,999	0
LAFA	Available Economic Capacity	W_SP	2.20%	5.20%	3,016	8.10%	3,044	28
LAFA	Available Economic Capacity	W_P	0.00%	0.00%	2,882	0.00%	2,759	-123
LAFA	Available Economic Capacity	W_OP	0.70%	0.00%	2,100	0.60%	1,933	-166
LAFA	Available Economic Capacity	SH_SP	23.30%	0.00%	1,478	23.20%	1,478	-1
LAFA	Available Economic Capacity	SH_P	0.00%	0.00%	3,266	0.00%	2,977	-289
LAFA	Available Economic Capacity	SH_OP	0.80%	0.00%	1,966	1.30%	1,716	-250
LCRA	Available Economic Capacity	S_35	0.00%	35.20%	2,665	35.00%	2,659	-6
LCRA	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
LCRA	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
LCRA	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
LCRA	Available Economic Capacity	W_SP	0.00%	5.10%	2,399	5.00%	2,400	1
LCRA	Available Economic Capacity	W_P	0.00%	0.00%	5,056	0.00%	5,056	0
LCRA	Available Economic Capacity	W_OP	0.00%	0.00%	5,642	0.00%	5,642	0
LCRA	Available Economic Capacity	SH_SP	0.00%	81.60%	6,997	81.60%	6,997	0
LCRA	Available Economic Capacity	SH_P	0.00%	66.50%	5,008	66.50%	5,008	0
LCRA	Available Economic Capacity	SH_OP	0.00%	0.00%	6,074	0.00%	6,074	0
LGE	Available Economic Capacity	S_35	54.00%	0.00%	3,187	51.40%	2,939	-248
LGE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
LGE	Available Economic Capacity	W_SP	0.00%	0.00%	10,000	0.00%	10,000	0
LGE	Available Economic Capacity	W_P	0.00%	0.00%	10,000	0.00%	10,000	0
LGE	Available Economic Capacity	W_OP	0.00%	0.00%	8,415	0.00%	8,415	0
LGE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	SH_P	0.00%	0.00%	10,000	0.00%	10,000	0
LGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
MPS	Available Economic Capacity	S_35	13.80%	0.00%	1,054	13.70%	1,013	-41
MPS	Available Economic Capacity	S_SP	0.00%	0.00%	2,221	0.00%	2,221	0
MPS	Available Economic Capacity	S_P	0.00%	0.00%	2,484	0.00%	2,484	0
MPS	Available Economic Capacity	S_OP	0.00%	0.00%	3,438	0.00%	3,438	0
MPS	Available Economic Capacity	W_SP	0.00%	0.00%	4,129	0.00%	4,129	0
MPS	Available Economic Capacity	W_P	0.00%	0.00%	4,071	0.00%	4,071	0
MPS	Available Economic Capacity	W_OP	0.00%	0.00%	2,856	0.00%	2,856	0
MPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3,168	0.00%	3,168	0
MPS	Available Economic Capacity	SH_P	0.00%	0.00%	8,266	0.00%	8,266	0
MPS	Available Economic Capacity	SH_OP	0.00%	0.00%	6,140	0.00%	6,140	0
NIPS	Available Economic Capacity	S_35	28.40%	0.00%	1,337	27.60%	1,303	-34
NIPS	Available Economic Capacity	S_SP	0.00%	0.00%	10,000	0.00%	10,000	0
NIPS	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
NIPS	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
NIPS	Available Economic Capacity	W_SP	0.00%	0.00%	10,000	0.00%	10,000	0
NIPS	Available Economic Capacity	W_P	0.00%	0.00%	10,000	0.00%	10,000	0
NIPS	Available Economic Capacity	W_OP	0.00%	0.00%	9,560	0.00%	9,560	0
NIPS	Available Economic Capacity	SH_SP	0.00%	0.00%	10,000	0.00%	10,000	0
NIPS	Available Economic Capacity	SH_P	0.00%	0.00%	5,985	0.00%	5,985	0
NIPS	Available Economic Capacity	SH_OP	0.00%	0.00%	9,677	0.00%	9,677	0

Exhibit No. AC-511

Base Case (Pre-Mitigation)

Market	Analysis	Period	BASE AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
NSP	Available Economic Capacity	S_35	9.90%	0.00%	970	10.80%	992	23
NSP	Available Economic Capacity	S_SP	0.00%	0.00%	7,387	0.00%	7,387	0
NSP	Available Economic Capacity	S_P	0.00%	0.00%	7,387	0.00%	7,387	0
NSP	Available Economic Capacity	S_OP	0.00%	0.00%	7,094	0.00%	7,094	0
NSP	Available Economic Capacity	W_SP	0.00%	0.00%	3,275	0.00%	3,275	0
NSP	Available Economic Capacity	W_P	0.00%	0.00%	4,849	0.00%	4,849	0
NSP	Available Economic Capacity	W_OP	0.00%	0.00%	8,518	0.00%	8,518	0
NSP	Available Economic Capacity	SH_SP	0.00%	0.00%	7,387	0.00%	7,387	0
NSP	Available Economic Capacity	SH_P	0.00%	0.00%	7,387	0.00%	7,387	0
NSP	Available Economic Capacity	SH_OP	0.00%	0.00%	8,207	0.00%	8,207	0
OKGE	Available Economic Capacity	S_35	4.60%	0.00%	1,182	5.30%	1,204	22
OKGE	Available Economic Capacity	S_SP	0.00%	0.00%	3,464	0.00%	3,383	-81
OKGE	Available Economic Capacity	S_P	0.00%	0.00%	3,213	0.00%	3,213	0
OKGE	Available Economic Capacity	S_OP	0.00%	0.00%	7,022	0.00%	7,022	0
OKGE	Available Economic Capacity	W_SP	0.00%	0.00%	1,831	0.00%	1,816	-15
OKGE	Available Economic Capacity	W_P	0.00%	0.00%	1,736	0.00%	1,752	16
OKGE	Available Economic Capacity	W_OP	0.00%	0.00%	4,550	0.00%	4,550	0
OKGE	Available Economic Capacity	SH_SP	5.90%	0.20%	776	6.90%	778	2
OKGE	Available Economic Capacity	SH_P	0.00%	0.00%	2,271	0.00%	2,482	211
OKGE	Available Economic Capacity	SH_OP	0.00%	0.00%	5,869	0.00%	5,869	0
SCEG	Available Economic Capacity	S_35	94.10%	0.00%	8,865	93.10%	8,671	-194
SCEG	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
SCEG	Available Economic Capacity	S_P	99.90%	0.00%	9,986	99.90%	9,986	0
SCEG	Available Economic Capacity	S_OP	42.20%	0.00%	3,714	42.10%	3,711	-2
SCEG	Available Economic Capacity	W_SP	67.20%	0.00%	4,822	67.20%	4,822	0
SCEG	Available Economic Capacity	W_P	18.50%	0.00%	1,795	18.20%	1,796	0
SCEG	Available Economic Capacity	W_OP	7.40%	0.00%	1,805	7.30%	1,805	0
SCEG	Available Economic Capacity	SH_SP	65.10%	0.00%	4,555	64.00%	4,452	-103
SCEG	Available Economic Capacity	SH_P	44.30%	0.00%	2,509	44.00%	2,485	-24
SCEG	Available Economic Capacity	SH_OP	10.20%	0.00%	1,522	10.00%	1,523	1
SIGE	Available Economic Capacity	S_35	79.70%	0.00%	6,412	78.90%	6,292	-120
SIGE	Available Economic Capacity	S_SP	86.20%	0.00%	7,454	85.90%	7,397	-56
SIGE	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
SIGE	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
SIGE	Available Economic Capacity	W_SP	28.50%	0.00%	1,961	27.60%	1,934	-28
SIGE	Available Economic Capacity	W_P	0.00%	0.00%	10,000	0.00%	10,000	0
SIGE	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
SIGE	Available Economic Capacity	SH_SP	0.00%	0.00%	2,002	0.00%	2,002	0
SIGE	Available Economic Capacity	SH_P	0.00%	0.00%	10,000	0.00%	10,000	0
SIGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
SOCO	Available Economic Capacity	S_35	76.80%	0.00%	5,964	76.80%	5,956	-8
SOCO	Available Economic Capacity	S_SP	0.00%	0.00%	4,302	0.00%	4,302	0
SOCO	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
SOCO	Available Economic Capacity	S_OP	81.40%	0.00%	6,756	81.40%	6,754	-2
SOCO	Available Economic Capacity	W_SP	0.00%	0.00%	5,000	0.00%	5,000	0
SOCO	Available Economic Capacity	W_P	0.00%	0.00%	3,166	0.00%	3,166	0
SOCO	Available Economic Capacity	W_OP	34.40%	0.00%	3,683	32.50%	3,703	19
SOCO	Available Economic Capacity	SH_SP	0.00%	0.00%	10,000	0.00%	10,000	0
SOCO	Available Economic Capacity	SH_P	0.00%	0.00%	4,085	0.00%	4,085	0
SOCO	Available Economic Capacity	SH_OP	85.40%	0.00%	7,347	85.40%	7,347	0
SPRM	Available Economic Capacity	S_35	3.00%	0.00%	2,500	4.40%	2,518	18
SPRM	Available Economic Capacity	S_SP	0.00%	0.00%	5,000	0.00%	5,000	0
SPRM	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
SPRM	Available Economic Capacity	S_OP	0.00%	0.00%	6,993	0.00%	6,993	0
SPRM	Available Economic Capacity	W_SP	0.00%	0.00%	8,188	0.00%	8,188	0
SPRM	Available Economic Capacity	W_P	0.00%	0.00%	4,718	0.00%	4,718	0
SPRM	Available Economic Capacity	W_OP	0.00%	0.00%	3,645	0.00%	3,645	0
SPRM	Available Economic Capacity	SH_SP	0.00%	0.00%	5,743	0.00%	5,743	0
SPRM	Available Economic Capacity	SH_P	0.00%	0.00%	3,868	0.00%	3,868	0
SPRM	Available Economic Capacity	SH_OP	0.00%	0.00%	9,913	0.00%	9,913	0

Base Case (Pre-Mitigation) **Exhibit No. AC-511**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
STEC	Available Economic Capacity	S_35	0.00%	54.10%	4,054	54.10%	4,054	0
STEC	Available Economic Capacity	S_SP	0.00%	80.30%	6,662	80.20%	6,657	-5
STEC	Available Economic Capacity	S_P	0.00%	65.00%	5,449	65.00%	5,449	0
STEC	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
STEC	Available Economic Capacity	W_SP	0.00%	6.00%	3,473	5.50%	3,504	31
STEC	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
STEC	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
STEC	Available Economic Capacity	SH_SP	0.00%	77.70%	6,249	77.60%	6,232	-18
STEC	Available Economic Capacity	SH_P	0.00%	0.00%	10,000	0.00%	10,000	0
STEC	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
STJO	Available Economic Capacity	S_35	11.30%	0.00%	1,391	11.60%	1,392	1
STJO	Available Economic Capacity	S_SP	6.30%	0.00%	817	6.50%	809	-8
STJO	Available Economic Capacity	S_P	0.00%	0.00%	1,177	0.00%	1,172	-5
STJO	Available Economic Capacity	S_OP	0.00%	0.00%	2,288	0.00%	2,288	0
STJO	Available Economic Capacity	W_SP	0.00%	0.00%	984	0.00%	973	-11
STJO	Available Economic Capacity	W_P	0.00%	0.00%	1,392	0.00%	1,392	0
STJO	Available Economic Capacity	W_OP	0.00%	0.00%	4,757	0.00%	4,757	0
STJO	Available Economic Capacity	SH_SP	9.60%	0.00%	826	10.40%	832	6
STJO	Available Economic Capacity	SH_P	0.00%	0.00%	1,058	0.00%	1,058	0
STJO	Available Economic Capacity	SH_OP	0.00%	0.00%	5,099	0.00%	5,099	0
SWEPA	Available Economic Capacity	S_35	4.90%	0.30%	907	6.20%	922	16
SWEPA	Available Economic Capacity	S_SP	17.10%	0.00%	2,396	16.00%	2,363	-33
SWEPA	Available Economic Capacity	S_P	0.00%	0.00%	3,332	0.00%	3,332	0
SWEPA	Available Economic Capacity	S_OP	0.00%	0.00%	2,701	0.00%	2,994	294
SWEPA	Available Economic Capacity	W_SP	0.00%	0.00%	1,142	0.00%	1,122	-20
SWEPA	Available Economic Capacity	W_P	0.00%	0.00%	1,923	0.00%	1,959	36
SWEPA	Available Economic Capacity	W_OP	0.00%	0.00%	1,540	0.00%	1,548	8
SWEPA	Available Economic Capacity	SH_SP	0.00%	0.50%	911	0.80%	862	-48
SWEPA	Available Economic Capacity	SH_P	0.00%	0.00%	2,069	0.00%	2,043	-26
SWEPA	Available Economic Capacity	SH_OP	0.00%	0.00%	1,484	0.00%	1,483	-1
SWPS	Available Economic Capacity	S_35	0.80%	0.00%	3,998	0.60%	4,282	283
SWPS	Available Economic Capacity	S_SP	0.00%	0.00%	6,116	0.00%	6,116	0
SWPS	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
SWPS	Available Economic Capacity	S_OP	0.00%	0.00%	7,503	0.00%	7,503	0
SWPS	Available Economic Capacity	W_SP	0.20%	2.50%	5,860	2.80%	6,016	156
SWPS	Available Economic Capacity	W_P	0.00%	0.00%	2,802	0.00%	2,802	0
SWPS	Available Economic Capacity	W_OP	0.00%	0.00%	4,074	0.00%	4,074	0
SWPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3,993	0.00%	4,331	338
SWPS	Available Economic Capacity	SH_P	0.00%	0.00%	4,123	0.00%	4,123	0
SWPS	Available Economic Capacity	SH_OP	0.00%	0.00%	5,050	0.00%	5,050	0
TMPA	Available Economic Capacity	S_35	0.00%	20.20%	2,485	20.10%	2,486	0
TMPA	Available Economic Capacity	S_SP	0.00%	78.00%	6,563	78.00%	6,563	0
TMPA	Available Economic Capacity	S_P	0.00%	78.00%	6,563	78.00%	6,563	0
TMPA	Available Economic Capacity	S_OP	0.00%	27.70%	3,728	27.90%	2,717	-1,011
TMPA	Available Economic Capacity	W_SP	0.00%	14.20%	2,480	14.20%	2,486	6
TMPA	Available Economic Capacity	W_P	0.00%	0.00%	3,365	0.00%	3,365	0
TMPA	Available Economic Capacity	W_OP	0.00%	0.00%	2,704	0.00%	2,699	-5
TMPA	Available Economic Capacity	SH_SP	0.00%	51.60%	3,522	51.40%	3,509	-13
TMPA	Available Economic Capacity	SH_P	0.00%	48.00%	3,540	48.00%	3,540	0
TMPA	Available Economic Capacity	SH_OP	0.00%	32.30%	2,735	32.30%	2,735	0
TNMP	Available Economic Capacity	S_35	0.00%	43.60%	3,959	43.40%	3,959	0
TNMP	Available Economic Capacity	S_SP	0.00%	78.00%	6,563	78.00%	6,563	0
TNMP	Available Economic Capacity	S_P	0.00%	78.00%	6,563	78.00%	6,563	0
TNMP	Available Economic Capacity	S_OP	0.00%	34.30%	2,745	34.40%	2,685	-60
TNMP	Available Economic Capacity	W_SP	0.00%	11.20%	3,331	11.20%	3,354	23
TNMP	Available Economic Capacity	W_P	0.00%	0.00%	3,056	0.00%	3,056	0
TNMP	Available Economic Capacity	W_OP	0.00%	0.00%	2,006	0.00%	1,901	-105
TNMP	Available Economic Capacity	SH_SP	0.00%	55.60%	3,800	55.60%	3,781	-19
TNMP	Available Economic Capacity	SH_P	0.00%	48.90%	3,433	48.90%	3,358	-75
TNMP	Available Economic Capacity	SH_OP	0.00%	38.20%	2,207	38.20%	2,160	-47

Base Case (Pre-Mitigation) **Exhibit No. AC-511**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
TU	Available Economic Capacity	S_35	0.40%	36.20%	2,717	36.40%	2,735	18
TU	Available Economic Capacity	S_SP	0.00%	59.90%	4,147	59.90%	4,147	0
TU	Available Economic Capacity	S_P	0.00%	43.70%	3,030	43.70%	3,028	-2
TU	Available Economic Capacity	S_OP	3.00%	27.30%	1,558	28.90%	1,709	151
TU	Available Economic Capacity	W_SP	0.10%	8.30%	6,106	8.60%	6,113	7
TU	Available Economic Capacity	W_P	0.00%	0.00%	1,542	0.00%	1,566	24
TU	Available Economic Capacity	W_OP	1.70%	0.00%	946	2.20%	933	-13
TU	Available Economic Capacity	SH_SP	3.00%	46.20%	2,487	49.20%	2,799	312
TU	Available Economic Capacity	SH_P	0.00%	40.30%	2,435	40.30%	2,442	6
TU	Available Economic Capacity	SH_OP	0.90%	31.70%	1,651	32.70%	1,726	75
TVA	Available Economic Capacity	S_35	38.80%	0.00%	1,870	37.70%	1,791	-79
TVA	Available Economic Capacity	S_SP	47.90%	0.00%	2,632	47.90%	2,632	0
TVA	Available Economic Capacity	S_P	0.00%	0.00%	10,000	0.00%	10,000	0
TVA	Available Economic Capacity	S_OP	0.00%	0.00%	10,000	0.00%	10,000	0
TVA	Available Economic Capacity	W_SP	0.00%	0.00%	10,000	0.00%	10,000	0
TVA	Available Economic Capacity	W_P	0.00%	0.00%	10,000	0.00%	10,000	0
TVA	Available Economic Capacity	W_OP	0.00%	0.00%	10,000	0.00%	10,000	0
TVA	Available Economic Capacity	SH_SP	49.70%	0.00%	2,666	48.00%	2,511	-155
TVA	Available Economic Capacity	SH_P	0.00%	0.00%	10,000	0.00%	10,000	0
TVA	Available Economic Capacity	SH_OP	0.00%	0.00%	10,000	0.00%	10,000	0
VP	Available Economic Capacity	S_35	67.00%	0.00%	4,948	65.90%	4,811	-137
VP	Available Economic Capacity	S_SP	100.00%	0.00%	10,000	100.00%	10,000	0
VP	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	S_OP	100.00%	0.00%	10,000	100.00%	10,000	0
VP	Available Economic Capacity	W_SP	100.00%	0.00%	10,000	100.00%	10,000	0
VP	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	SH_SP	80.40%	0.00%	6,853	80.40%	6,853	0
VP	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	S_35	2.50%	0.00%	2,057	3.20%	2,070	13
WEFA	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	S_OP	0.00%	0.00%	3,595	0.00%	4,498	903
WEFA	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	W_OP	0.00%	0.00%	5,089	0.00%	5,089	0
WEFA	Available Economic Capacity	SH_SP	0.00%	0.00%	2,554	0.00%	2,554	0
WEFA	Available Economic Capacity	SH_P	0.00%	0.00%	5,673	0.00%	5,673	0
WEFA	Available Economic Capacity	SH_OP	0.00%	0.00%	3,675	0.00%	3,675	0
WEP	Available Economic Capacity	S_35	8.50%	0.00%	1,584	1.90%	1,561	-23
WEP	Available Economic Capacity	S_SP	12.70%	0.00%	1,200	1.00%	1,172	-29
WEP	Available Economic Capacity	S_P	0.00%	0.00%	1,171	0.00%	1,171	0
WEP	Available Economic Capacity	S_OP	0.00%	0.00%	4,199	0.00%	4,199	0
WEP	Available Economic Capacity	W_SP	9.00%	0.00%	1,274	6.30%	1,279	5
WEP	Available Economic Capacity	W_P	0.00%	0.00%	1,631	0.00%	1,621	-10
WEP	Available Economic Capacity	W_OP	0.00%	0.00%	2,901	0.00%	2,901	0
WEP	Available Economic Capacity	SH_SP	6.70%	0.00%	1,149	5.20%	1,160	11
WEP	Available Economic Capacity	SH_P	0.00%	0.00%	1,142	0.00%	1,142	0
WEP	Available Economic Capacity	SH_OP	0.00%	0.00%	4,256	0.00%	4,256	0
WEPL	Available Economic Capacity	S_35	0.60%	0.00%	3,495	0.80%	3,556	61
WEPL	Available Economic Capacity	S_SP	0.00%	0.00%	3,847	0.00%	3,847	0
WEPL	Available Economic Capacity	S_P	0.00%	0.00%	4,606	0.00%	4,606	0
WEPL	Available Economic Capacity	S_OP	0.00%	0.00%	7,604	0.00%	7,604	0
WEPL	Available Economic Capacity	W_SP	0.00%	0.00%	4,480	0.00%	4,480	0
WEPL	Available Economic Capacity	W_P	0.00%	0.00%	3,466	0.00%	3,466	0
WEPL	Available Economic Capacity	W_OP	0.00%	0.00%	3,655	0.00%	3,655	0
WEPL	Available Economic Capacity	SH_SP	0.00%	0.00%	2,997	0.00%	2,997	0
WEPL	Available Economic Capacity	SH_P	0.00%	0.00%	3,680	0.00%	3,680	0
WEPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5,186	0.00%	5,186	0

Exhibit No. AC-511

Base Case (Pre-Mitigation)

Market	Analysis	Period	BASE AEP Mkt Share	BASE CSW Mkt Share	BASE HHI Pre-Merger	MERGER Merged Mkt Share	MERGER HHI Post-Merger	MERGER HHI Change
WR	Available Economic Capacity	S_35	8.10%	0.00%	1,289	8.10%	1,335	46
WR	Available Economic Capacity	S_SP	0.00%	0.00%	3,003	0.00%	3,003	0
WR	Available Economic Capacity	S_P	0.00%	0.00%	4,154	0.00%	4,154	0
WR	Available Economic Capacity	S_OP	0.00%	0.00%	7,480	0.00%	7,480	0
WR	Available Economic Capacity	W_SP	0.00%	0.00%	1,876	0.00%	1,876	0
WR	Available Economic Capacity	W_P	0.00%	0.00%	3,205	0.00%	3,205	0
WR	Available Economic Capacity	W_OP	0.00%	0.00%	3,305	0.00%	3,305	0
WR	Available Economic Capacity	SH_SP	0.00%	0.00%	1,787	0.00%	1,791	4
WR	Available Economic Capacity	SH_P	0.00%	0.00%	2,466	0.00%	2,466	0
WR	Available Economic Capacity	SH_OP	0.00%	0.00%	5,121	0.00%	5,121	0

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
BRYN	Economic Capacity	S_35	0.00%	7.90%	1226	7.80%	1225	-1
BRYN	Economic Capacity	S_SP	0.00%	14.30%	1435	14.40%	1413	-22
BRYN	Economic Capacity	S_P	0.00%	14.50%	1411	14.50%	1387	-24
BRYN	Economic Capacity	S_CP	0.00%	15.20%	1438	15.00%	1412	-26
BRYN	Economic Capacity	W_SP	0.00%	0.60%	2118	0.60%	2118	1
BRYN	Economic Capacity	W_P	0.00%	1.20%	2437	1.20%	2446	9
BRYN	Economic Capacity	W_OP	0.00%	0.60%	2491	0.60%	2498	7
BRYN	Economic Capacity	SH_SP	0.00%	14.50%	1279	14.10%	1269	-10
BRYN	Economic Capacity	SH_P	0.00%	15.60%	1547	14.80%	1503	-44
BRYN	Economic Capacity	SH_OP	0.00%	20.00%	1643	18.40%	1575	-69
CAPO	Economic Capacity	S_35	2.10%	0.00%	6821	2.10%	6821	0
CAPO	Economic Capacity	S_SP	2.20%	0.00%	6797	2.20%	6797	0
CAPO	Economic Capacity	S_P	0.60%	0.00%	6750	0.60%	6750	0
CAPO	Economic Capacity	S_OP	1.70%	0.00%	3900	1.70%	3900	0
CAPO	Economic Capacity	W_SP	5.80%	0.00%	4220	5.70%	4220	-1
CAPO	Economic Capacity	W_P	4.00%	0.00%	2397	4.00%	2397	0
CAPO	Economic Capacity	W_OP	3.80%	0.00%	2143	3.80%	2143	0
CAPO	Economic Capacity	SH_SP	3.80%	0.00%	4561	3.80%	4561	0
CAPO	Economic Capacity	SH_P	1.30%	0.00%	4474	1.30%	4474	0
CAPO	Economic Capacity	SH_OP	0.60%	0.00%	2265	0.60%	2265	0
CELE	Economic Capacity	S_35	0.00%	5.10%	6627	5.00%	6626	-1
CELE	Economic Capacity	S_SP	0.20%	10.10%	4390	10.10%	4389	-1
CELE	Economic Capacity	S_P	0.10%	0.60%	8017	0.80%	8017	0
CELE	Economic Capacity	S_OP	0.30%	0.70%	7949	0.90%	7949	0
CELE	Economic Capacity	W_SP	0.20%	7.30%	4716	7.40%	4717	1
CELE	Economic Capacity	W_P	0.90%	10.60%	2229	11.20%	2242	13
CELE	Economic Capacity	W_OP	0.80%	12.50%	2210	13.10%	2222	13
CELE	Economic Capacity	SH_SP	0.80%	1.90%	4442	2.90%	4446	4
CELE	Economic Capacity	SH_P	2.10%	3.70%	2342	6.30%	2361	19
CELE	Economic Capacity	SH_OP	2.10%	5.40%	2346	8.00%	2374	28
CIMO	Economic Capacity	S_35	0.50%	0.90%	1349	1.50%	1353	3
CIMO	Economic Capacity	S_SP	0.60%	1.00%	1121	1.70%	1122	1
CIMO	Economic Capacity	S_P	0.10%	0.00%	1312	0.10%	1309	-3
CIMO	Economic Capacity	S_OP	1.00%	0.00%	1339	1.30%	1336	-3
CIMO	Economic Capacity	W_SP	0.50%	0.00%	862	0.50%	862	0
CIMO	Economic Capacity	W_P	0.40%	0.00%	1101	0.40%	1101	0
CIMO	Economic Capacity	W_OP	3.30%	0.00%	876	4.20%	872	-4
CIMO	Economic Capacity	SH_SP	0.20%	0.00%	1223	0.20%	1216	-7
CIMO	Economic Capacity	SH_P	0.40%	0.00%	990	0.40%	982	-8
CIMO	Economic Capacity	SH_OP	2.50%	0.00%	979	3.50%	956	-22
CIN	Economic Capacity	S_35	14.10%	0.10%	2104	14.10%	2104	1
CIN	Economic Capacity	S_SP	7.90%	0.00%	2913	7.90%	2913	0
CIN	Economic Capacity	S_P	3.80%	0.00%	1830	3.80%	1830	0
CIN	Economic Capacity	S_OP	14.00%	0.00%	1552	14.00%	1552	0
CIN	Economic Capacity	W_SP	7.20%	0.00%	2696	7.20%	2696	0
CIN	Economic Capacity	W_P	1.10%	0.00%	1700	1.10%	1700	0
CIN	Economic Capacity	W_OP	13.10%	0.00%	1737	13.10%	1737	0
CIN	Economic Capacity	SH_SP	2.90%	0.00%	2085	2.90%	2085	0
CIN	Economic Capacity	SH_P	2.70%	0.00%	2035	2.70%	2035	0
CIN	Economic Capacity	SH_OP	11.10%	0.00%	1415	11.10%	1415	0
COA	Economic Capacity	S_35	0.00%	3.30%	3464	3.20%	3464	0
COA	Economic Capacity	S_SP	0.00%	5.20%	1981	5.30%	1975	-7
COA	Economic Capacity	S_P	0.00%	5.50%	1975	5.60%	1969	-7
COA	Economic Capacity	S_OP	0.00%	5.40%	1977	5.60%	1970	-7
COA	Economic Capacity	W_SP	0.00%	3.20%	4718	3.20%	4718	0
COA	Economic Capacity	W_P	0.00%	6.30%	2954	7.60%	2940	-14
COA	Economic Capacity	W_OP	0.00%	6.50%	2955	7.90%	2942	-14
COA	Economic Capacity	SH_SP	0.00%	5.60%	3172	5.50%	3171	-1
COA	Economic Capacity	SH_P	0.00%	8.00%	1986	8.10%	1974	-12
COA	Economic Capacity	SH_OP	0.00%	9.50%	2075	9.70%	2055	-21

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Economic Capacity	S_35	0.60%	0.00%	5681	0.60%	5681	0
COMED	Economic Capacity	S_SP	0.40%	0.00%	5597	0.40%	5596	0
COMED	Economic Capacity	S_P	0.40%	0.00%	5023	0.40%	5023	0
COMED	Economic Capacity	S_OP	0.20%	0.00%	4156	0.20%	4156	0
COMED	Economic Capacity	W_SP	9.20%	0.40%	3775	9.70%	3789	13
COMED	Economic Capacity	W_P	1.90%	0.00%	4046	2.00%	4043	-4
COMED	Economic Capacity	W_OP	3.70%	0.00%	3027	3.80%	3030	4
COMED	Economic Capacity	SH_SP	9.80%	0.40%	2933	10.20%	2946	12
COMED	Economic Capacity	SH_P	9.10%	0.00%	3144	9.00%	3142	-1
COMED	Economic Capacity	SH_OP	2.80%	0.00%	2342	2.80%	2343	1
CP	Economic Capacity	S_35	8.50%	0.00%	2976	8.40%	2975	-1
CP	Economic Capacity	S_SP	8.30%	0.00%	3038	8.30%	3038	-1
CP	Economic Capacity	S_P	6.20%	0.00%	2637	6.20%	2637	0
CP	Economic Capacity	S_OP	12.00%	0.00%	2982	12.00%	2982	0
CP	Economic Capacity	W_SP	12.10%	0.00%	2295	12.10%	2294	-1
CP	Economic Capacity	W_P	14.40%	0.00%	2323	14.30%	2321	-2
CP	Economic Capacity	W_OP	16.00%	0.00%	2238	15.90%	2236	-3
CP	Economic Capacity	SH_SP	12.20%	0.00%	2164	12.10%	2164	-1
CP	Economic Capacity	SH_P	15.00%	0.00%	2217	14.90%	2215	-2
CP	Economic Capacity	SH_OP	10.10%	0.00%	2310	10.10%	2310	0
CPS	Economic Capacity	S_35	0.00%	4.80%	5445	4.80%	5445	0
CPS	Economic Capacity	S_SP	0.00%	7.80%	3462	7.80%	3462	0
CPS	Economic Capacity	S_P	0.00%	6.70%	3455	6.70%	3456	1
CPS	Economic Capacity	S_OP	0.00%	6.70%	3468	6.70%	3469	1
CPS	Economic Capacity	W_SP	0.00%	0.00%	5303	0.00%	5303	1
CPS	Economic Capacity	W_P	0.00%	0.10%	2959	0.10%	2961	2
CPS	Economic Capacity	W_OP	0.00%	0.10%	2934	0.10%	2936	2
CPS	Economic Capacity	SH_SP	0.00%	9.90%	3323	9.40%	3314	-10
CPS	Economic Capacity	SH_P	0.00%	12.40%	2113	11.10%	2077	-37
CPS	Economic Capacity	SH_OP	0.00%	14.80%	1812	14.00%	1810	-2
DECO	Economic Capacity	S_35	5.60%	0.00%	4058	5.60%	4058	0
DECO	Economic Capacity	S_SP	5.20%	0.00%	4158	5.20%	4158	0
DECO	Economic Capacity	S_P	0.60%	0.00%	3861	0.60%	3861	0
DECO	Economic Capacity	S_OP	0.30%	0.00%	3917	0.30%	3917	0
DECO	Economic Capacity	W_SP	7.60%	0.00%	3732	7.50%	3732	0
DECO	Economic Capacity	W_P	6.80%	0.00%	3632	6.80%	3632	0
DECO	Economic Capacity	W_OP	7.40%	0.00%	3431	7.40%	3431	0
DECO	Economic Capacity	SH_SP	11.80%	0.00%	3364	11.70%	3363	0
DECO	Economic Capacity	SH_P	4.00%	0.00%	3481	4.00%	3481	0
DECO	Economic Capacity	SH_OP	0.30%	0.00%	3749	0.30%	3749	0
DGG	Economic Capacity	S_35	0.00%	6.00%	2399	6.00%	2399	-1
DGG	Economic Capacity	S_SP	0.00%	12.10%	1258	12.10%	1242	-16
DGG	Economic Capacity	S_P	0.00%	13.80%	1411	13.70%	1388	-23
DGG	Economic Capacity	S_OP	0.00%	14.40%	1440	14.30%	1415	-25
DGG	Economic Capacity	W_SP	0.00%	3.60%	3785	3.60%	3785	0
DGG	Economic Capacity	W_P	0.00%	5.10%	3120	5.80%	3054	-66
DGG	Economic Capacity	W_OP	0.00%	5.50%	3124	6.20%	3058	-66
DGG	Economic Capacity	SH_SP	0.00%	12.40%	1509	12.00%	1501	-8
DGG	Economic Capacity	SH_P	0.00%	15.10%	1565	14.30%	1524	-42
DGG	Economic Capacity	SH_OP	0.00%	19.50%	1668	17.90%	1602	-66
DLCO	Economic Capacity	S_35	11.50%	0.00%	1968	11.50%	1967	-1
DLCO	Economic Capacity	S_SP	11.60%	0.00%	1999	11.60%	1998	-1
DLCO	Economic Capacity	S_P	15.00%	0.00%	2142	14.90%	2140	-2
DLCO	Economic Capacity	S_OP	18.20%	0.00%	2067	18.10%	2065	-2
DLCO	Economic Capacity	W_SP	9.10%	0.00%	2317	9.00%	2316	-1
DLCO	Economic Capacity	W_P	8.50%	0.00%	2275	8.40%	2273	-1
DLCO	Economic Capacity	W_OP	9.20%	0.00%	2162	9.20%	2162	0
DLCO	Economic Capacity	SH_SP	12.60%	0.00%	1638	12.60%	1637	-1
DLCO	Economic Capacity	SH_P	14.50%	0.00%	1883	14.50%	1883	0
DLCO	Economic Capacity	SH_OP	14.60%	0.00%	1794	14.50%	1791	-4

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
DPL	Economic Capacity	S_35	16.20%	0.00%	1635	16.10%	1633	-1
DPL	Economic Capacity	S_SP	7.60%	0.00%	1636	7.60%	1636	0
DPL	Economic Capacity	S_P	5.70%	0.00%	1677	5.70%	1677	0
DPL	Economic Capacity	S_OP	9.80%	0.00%	1577	9.80%	1577	0
DPL	Economic Capacity	W_SP	1.80%	0.00%	1818	1.80%	1818	0
DPL	Economic Capacity	W_P	2.10%	0.00%	1877	2.10%	1877	0
DPL	Economic Capacity	W_OP	12.80%	0.00%	1575	12.80%	1575	0
DPL	Economic Capacity	SH_SP	4.60%	0.00%	1479	4.60%	1479	0
DPL	Economic Capacity	SH_P	1.70%	0.00%	1749	1.70%	1749	0
DPL	Economic Capacity	SH_OP	9.20%	0.00%	1501	9.20%	1501	0
DUKE	Economic Capacity	S_35	3.50%	0.00%	4438	3.50%	4438	0
DUKE	Economic Capacity	S_SP	0.50%	0.00%	4612	0.50%	4612	0
DUKE	Economic Capacity	S_P	2.10%	0.00%	3548	2.10%	3548	0
DUKE	Economic Capacity	S_OP	2.90%	0.00%	2599	2.90%	2599	0
DUKE	Economic Capacity	W_SP	1.70%	0.00%	4402	1.70%	4402	0
DUKE	Economic Capacity	W_P	1.40%	0.00%	3451	1.40%	3451	0
DUKE	Economic Capacity	W_OP	2.10%	0.00%	3157	2.10%	3157	0
DUKE	Economic Capacity	SH_SP	0.60%	0.00%	4108	0.60%	4108	0
DUKE	Economic Capacity	SH_P	0.90%	0.00%	3078	0.90%	3078	0
DUKE	Economic Capacity	SH_OP	1.90%	0.00%	2071	1.90%	2071	0
EDE	Economic Capacity	S_35	0.40%	4.00%	1653	4.30%	1656	3
EDE	Economic Capacity	S_SP	0.30%	3.90%	1713	4.20%	1716	3
EDE	Economic Capacity	S_P	0.80%	0.90%	4496	1.70%	4502	6
EDE	Economic Capacity	S_OP	2.20%	2.00%	2848	4.10%	2855	8
EDE	Economic Capacity	W_SP	0.50%	12.50%	1111	12.90%	1118	7
EDE	Economic Capacity	W_P	0.70%	10.30%	651	10.90%	656	5
EDE	Economic Capacity	W_OP	0.90%	11.90%	596	12.70%	602	5
EDE	Economic Capacity	SH_SP	0.90%	2.00%	2144	3.50%	2148	4
EDE	Economic Capacity	SH_P	1.40%	2.50%	1421	4.90%	1425	3
EDE	Economic Capacity	SH_OP	2.00%	0.00%	1129	2.90%	1092	-37
EKPC	Economic Capacity	S_35	6.40%	0.10%	2419	6.40%	2420	0
EKPC	Economic Capacity	S_SP	9.90%	0.00%	2188	9.90%	2188	0
EKPC	Economic Capacity	S_P	3.90%	0.00%	1768	3.90%	1768	0
EKPC	Economic Capacity	S_OP	1.80%	0.00%	1516	1.80%	1516	0
EKPC	Economic Capacity	W_SP	9.90%	0.00%	2317	9.90%	2316	-1
EKPC	Economic Capacity	W_P	3.70%	0.00%	2413	3.70%	2413	0
EKPC	Economic Capacity	W_OP	9.30%	0.00%	1841	9.30%	1841	0
EKPC	Economic Capacity	SH_SP	7.30%	0.30%	1868	7.50%	1871	4
EKPC	Economic Capacity	SH_P	3.20%	0.00%	1757	3.20%	1757	0
EKPC	Economic Capacity	SH_OP	1.60%	0.00%	1315	1.60%	1315	0
ENT	Economic Capacity	S_35	0.20%	0.20%	5427	0.40%	5427	0
ENT	Economic Capacity	S_SP	0.60%	0.20%	2728	0.80%	2729	0
ENT	Economic Capacity	S_P	0.20%	0.90%	2768	1.00%	2770	3
ENT	Economic Capacity	S_OP	0.80%	0.70%	2991	1.40%	2992	1
ENT	Economic Capacity	W_SP	0.20%	3.50%	5220	3.40%	5233	14
ENT	Economic Capacity	W_P	0.40%	2.00%	2699	1.40%	2741	43
ENT	Economic Capacity	W_OP	0.70%	2.70%	2719	2.60%	2745	27
ENT	Economic Capacity	SH_SP	0.30%	3.90%	3749	4.20%	3751	1
ENT	Economic Capacity	SH_P	0.60%	4.80%	1620	5.30%	1621	1
ENT	Economic Capacity	SH_OP	1.10%	5.90%	1676	7.10%	1700	24
FENER	Economic Capacity	S_35	8.20%	0.00%	3359	8.20%	3358	0
FENER	Economic Capacity	S_SP	8.80%	0.00%	3341	8.70%	3340	-1
FENER	Economic Capacity	S_P	6.70%	0.00%	3420	6.70%	3420	0
FENER	Economic Capacity	S_OP	8.20%	0.00%	3082	8.20%	3082	0
FENER	Economic Capacity	W_SP	4.70%	0.00%	4363	4.70%	4362	-1
FENER	Economic Capacity	W_P	3.10%	0.00%	4538	3.10%	4538	0
FENER	Economic Capacity	W_OP	3.30%	0.00%	4493	3.30%	4493	0
FENER	Economic Capacity	SH_SP	11.90%	0.00%	2390	11.80%	2389	-1
FENER	Economic Capacity	SH_P	11.70%	0.00%	2631	11.60%	2629	-2
FENER	Economic Capacity	SH_OP	8.90%	0.00%	2736	8.90%	2732	-5

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
GRRD	Economic Capacity	S_35	0.10%	0.20%	3297	0.30%	3297	0
GRRD	Economic Capacity	S_SP	0.10%	0.30%	3053	0.40%	3053	0
GRRD	Economic Capacity	S_P	0.00%	12.10%	2938	11.70%	2936	-2
GRRD	Economic Capacity	S_OP	0.20%	1.00%	2789	1.90%	2788	-1
GRRD	Economic Capacity	W_SP	0.30%	16.20%	1152	16.20%	1149	-3
GRRD	Economic Capacity	W_P	0.40%	11.90%	1280	11.60%	1274	-6
GRRD	Economic Capacity	W_OP	1.00%	0.00%	1772	1.30%	1755	-17
GRRD	Economic Capacity	SH_SP	0.40%	12.00%	1607	12.40%	1613	7
GRRD	Economic Capacity	SH_P	0.50%	7.50%	1351	8.10%	1353	2
GRRD	Economic Capacity	SH_OP	1.10%	0.00%	1854	1.50%	1848	-6
HEC	Economic Capacity	S_35	7.20%	0.10%	1679	7.20%	1680	1
HEC	Economic Capacity	S_SP	7.20%	0.10%	1679	7.20%	1680	1
HEC	Economic Capacity	S_P	3.10%	0.00%	2225	3.10%	2225	0
HEC	Economic Capacity	S_OP	20.00%	0.00%	1294	20.00%	1294	0
HEC	Economic Capacity	W_SP	10.40%	0.10%	1821	10.50%	1822	1
HEC	Economic Capacity	W_P	3.70%	0.00%	2367	3.70%	2367	0
HEC	Economic Capacity	W_OP	20.60%	0.00%	1875	20.60%	1875	0
HEC	Economic Capacity	SH_SP	17.80%	0.10%	1673	17.80%	1675	2
HEC	Economic Capacity	SH_P	3.50%	0.00%	2285	3.50%	2285	0
HEC	Economic Capacity	SH_OP	20.70%	0.00%	1200	20.70%	1200	0
HLP	Economic Capacity	S_35	0.00%	2.70%	5011	2.60%	5011	0
HLP	Economic Capacity	S_SP	0.00%	7.10%	2748	7.30%	2734	-14
HLP	Economic Capacity	S_P	0.00%	6.10%	2573	6.40%	2558	-16
HLP	Economic Capacity	S_OP	0.00%	6.10%	2586	6.50%	2570	-16
HLP	Economic Capacity	W_SP	0.00%	3.50%	4642	3.30%	4641	-1
HLP	Economic Capacity	W_P	0.00%	5.90%	2630	5.90%	2622	-8
HLP	Economic Capacity	W_OP	0.00%	6.00%	2671	6.30%	2682	11
HLP	Economic Capacity	SH_SP	0.00%	4.90%	4431	4.70%	4430	-2
HLP	Economic Capacity	SH_P	0.00%	10.00%	2516	10.60%	2494	-22
HLP	Economic Capacity	SH_OP	0.00%	10.20%	2605	11.20%	2584	-22
IP	Economic Capacity	S_35	4.70%	0.50%	1929	5.10%	1932	4
IP	Economic Capacity	S_SP	4.80%	0.40%	2014	5.20%	2018	4
IP	Economic Capacity	S_P	4.80%	0.50%	1906	5.20%	1912	6
IP	Economic Capacity	S_OP	6.40%	0.50%	2030	7.00%	2034	4
IP	Economic Capacity	W_SP	6.20%	0.60%	1905	6.90%	1914	9
IP	Economic Capacity	W_P	3.20%	0.00%	2082	3.10%	2080	-2
IP	Economic Capacity	W_OP	5.60%	0.00%	1973	5.80%	1972	-1
IP	Economic Capacity	SH_SP	5.20%	0.70%	1549	6.00%	1556	8
IP	Economic Capacity	SH_P	1.10%	0.00%	1697	1.10%	1698	1
IP	Economic Capacity	SH_OP	6.10%	0.00%	1108	6.00%	1106	-2
IPL	Economic Capacity	S_35	16.30%	0.10%	1834	16.20%	1833	-1
IPL	Economic Capacity	S_SP	6.40%	0.00%	1848	6.40%	1848	0
IPL	Economic Capacity	S_P	2.70%	0.00%	2175	2.70%	2175	0
IPL	Economic Capacity	S_OP	1.10%	0.00%	2624	1.10%	2624	0
IPL	Economic Capacity	W_SP	1.10%	0.00%	1941	1.10%	1941	0
IPL	Economic Capacity	W_P	3.10%	0.00%	1778	3.10%	1778	0
IPL	Economic Capacity	W_OP	1.10%	0.00%	2598	1.10%	2598	0
IPL	Economic Capacity	SH_SP	12.30%	0.00%	1505	12.30%	1505	0
IPL	Economic Capacity	SH_P	1.40%	0.00%	1425	1.40%	1425	0
IPL	Economic Capacity	SH_OP	1.00%	0.00%	1752	1.00%	1752	0
KACY	Economic Capacity	S_35	0.10%	0.30%	5983	0.30%	5983	0
KACY	Economic Capacity	S_SP	0.10%	0.30%	5971	0.40%	5971	0
KACY	Economic Capacity	S_P	0.00%	0.00%	4425	0.00%	4425	0
KACY	Economic Capacity	S_OP	0.60%	0.00%	3567	0.90%	3565	-2
KACY	Economic Capacity	W_SP	0.20%	0.00%	2210	0.20%	2208	-3
KACY	Economic Capacity	W_P	0.50%	0.00%	1662	0.50%	1662	0
KACY	Economic Capacity	W_OP	0.20%	0.00%	1333	0.20%	1331	-2
KACY	Economic Capacity	SH_SP	0.30%	2.30%	2681	2.80%	2682	1
KACY	Economic Capacity	SH_P	0.10%	0.00%	2837	0.10%	2825	-12
KACY	Economic Capacity	SH_OP	1.40%	0.00%	1699	2.10%	1685	-14

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
KCPL	Economic Capacity	S_35	0.60%	0.40%	2626	1.10%	2626	0
KCPL	Economic Capacity	S_SP	0.50%	0.40%	3051	1.00%	3051	0
KCPL	Economic Capacity	S_P	0.50%	1.30%	2409	1.80%	2410	1
KCPL	Economic Capacity	S_OP	0.50%	0.00%	2570	0.50%	2571	1
KCPL	Economic Capacity	W_SP	1.10%	3.00%	1670	4.10%	1674	4
KCPL	Economic Capacity	W_P	1.40%	3.60%	1889	4.90%	1896	7
KCPL	Economic Capacity	W_OP	1.00%	0.00%	1604	1.00%	1597	-7
KCPL	Economic Capacity	SH_SP	1.00%	1.90%	1461	2.90%	1462	2
KCPL	Economic Capacity	SH_P	1.30%	1.70%	1371	3.10%	1373	2
KCPL	Economic Capacity	SH_OP	2.30%	0.00%	1059	2.40%	1049	-10
LAFA	Economic Capacity	S_35	0.00%	0.40%	8668	0.40%	8668	0
LAFA	Economic Capacity	S_SP	0.00%	1.90%	7159	1.90%	7159	-1
LAFA	Economic Capacity	S_P	0.00%	0.20%	5960	0.20%	5960	0
LAFA	Economic Capacity	S_OP	0.00%	0.20%	5957	0.20%	5957	0
LAFA	Economic Capacity	W_SP	0.40%	1.50%	4656	1.80%	4656	1
LAFA	Economic Capacity	W_P	0.80%	3.00%	2514	3.80%	2518	4
LAFA	Economic Capacity	W_OP	1.10%	3.80%	2457	4.80%	2464	7
LAFA	Economic Capacity	SH_SP	1.00%	1.80%	3914	2.80%	3918	3
LAFA	Economic Capacity	SH_P	1.10%	3.10%	2221	4.20%	2226	5
LAFA	Economic Capacity	SH_OP	2.30%	3.30%	2227	5.50%	2240	13
LCRA	Economic Capacity	S_35	0.00%	8.30%	1558	8.10%	1555	-3
LCRA	Economic Capacity	S_SP	0.00%	7.20%	1909	7.20%	1903	-6
LCRA	Economic Capacity	S_P	0.00%	7.10%	1926	7.60%	1913	-13
LCRA	Economic Capacity	S_OP	0.00%	7.20%	2238	7.60%	2218	-20
LCRA	Economic Capacity	W_SP	0.00%	4.90%	2366	4.90%	2366	0
LCRA	Economic Capacity	W_P	0.00%	3.50%	2174	4.00%	2145	-29
LCRA	Economic Capacity	W_OP	0.00%	3.50%	2170	4.00%	2140	-29
LCRA	Economic Capacity	SH_SP	0.00%	6.90%	2182	6.40%	2157	-25
LCRA	Economic Capacity	SH_P	0.00%	6.50%	2198	6.00%	2173	-25
LCRA	Economic Capacity	SH_OP	0.00%	6.40%	2438	6.70%	2422	-17
LGE	Economic Capacity	S_35	7.90%	0.10%	2987	7.90%	2988	1
LGE	Economic Capacity	S_SP	2.50%	0.00%	1379	2.50%	1379	0
LGE	Economic Capacity	S_P	2.60%	0.00%	1702	2.60%	1702	0
LGE	Economic Capacity	S_OP	5.20%	0.00%	1380	5.20%	1380	0
LGE	Economic Capacity	W_SP	1.20%	0.00%	1761	1.20%	1761	0
LGE	Economic Capacity	W_P	1.30%	0.00%	1802	1.30%	1802	0
LGE	Economic Capacity	W_OP	13.20%	0.00%	1097	13.20%	1097	0
LGE	Economic Capacity	SH_SP	1.20%	0.00%	1739	1.20%	1739	0
LGE	Economic Capacity	SH_P	1.20%	0.00%	1747	1.20%	1747	0
LGE	Economic Capacity	SH_OP	2.10%	0.00%	1322	2.10%	1322	0
MPS	Economic Capacity	S_35	0.70%	0.00%	4591	0.80%	4714	124
MPS	Economic Capacity	S_SP	0.70%	0.00%	3805	0.70%	3801	-4
MPS	Economic Capacity	S_P	0.80%	0.00%	2573	0.90%	2574	1
MPS	Economic Capacity	S_OP	1.10%	0.00%	2023	1.10%	2015	-8
MPS	Economic Capacity	W_SP	0.40%	0.00%	1017	0.40%	1006	-10
MPS	Economic Capacity	W_P	0.30%	0.00%	839	0.30%	832	-8
MPS	Economic Capacity	W_OP	2.90%	0.00%	840	3.00%	829	-11
MPS	Economic Capacity	SH_SP	1.70%	0.00%	1384	1.80%	1377	-7
MPS	Economic Capacity	SH_P	0.40%	0.00%	984	0.40%	967	-17
MPS	Economic Capacity	SH_OP	2.00%	0.00%	1123	2.00%	1099	-24
NIPS	Economic Capacity	S_35	13.50%	0.10%	1981	13.50%	1982	1
NIPS	Economic Capacity	S_SP	0.90%	0.00%	1441	0.90%	1441	0
NIPS	Economic Capacity	S_P	0.90%	0.00%	1342	0.90%	1342	0
NIPS	Economic Capacity	S_OP	0.80%	0.00%	1174	0.80%	1174	0
NIPS	Economic Capacity	W_SP	1.00%	0.00%	1259	1.00%	1259	0
NIPS	Economic Capacity	W_P	1.00%	0.00%	1259	1.00%	1259	0
NIPS	Economic Capacity	W_OP	0.70%	0.00%	1212	0.70%	1212	0
NIPS	Economic Capacity	SH_SP	7.50%	0.00%	1183	7.50%	1183	0
NIPS	Economic Capacity	SH_P	7.50%	0.00%	1196	7.50%	1196	0
NIPS	Economic Capacity	SH_OP	4.60%	0.00%	1071	4.60%	1071	0

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
NSP	Economic Capacity	S_35	0.40%	0.10%	2412	0.50%	2412	0
NSP	Economic Capacity	S_SP	0.00%	0.00%	2129	0.00%	2129	0
NSP	Economic Capacity	S_P	0.00%	0.00%	1873	0.00%	1873	0
NSP	Economic Capacity	S_OP	0.90%	0.00%	2391	0.90%	2391	0
NSP	Economic Capacity	W_SP	0.50%	0.00%	2926	0.50%	2926	0
NSP	Economic Capacity	W_P	0.00%	0.00%	1529	0.00%	1529	0
NSP	Economic Capacity	W_OP	1.00%	0.00%	1903	1.00%	1903	0
NSP	Economic Capacity	SH_SP	0.00%	0.00%	1889	0.00%	1889	0
NSP	Economic Capacity	SH_P	0.00%	0.00%	1878	0.00%	1878	0
NSP	Economic Capacity	SH_OP	0.50%	0.00%	2405	0.50%	2405	0
OKGE	Economic Capacity	S_35	0.10%	2.50%	5724	2.60%	5724	0
OKGE	Economic Capacity	S_SP	0.20%	2.30%	5826	2.50%	5826	0
OKGE	Economic Capacity	S_P	0.30%	20.60%	2458	20.50%	2452	-5
OKGE	Economic Capacity	S_OP	0.80%	14.30%	2435	13.70%	2412	-23
OKGE	Economic Capacity	W_SP	0.20%	6.10%	4085	6.20%	4086	1
OKGE	Economic Capacity	W_P	0.50%	11.60%	2126	11.90%	2127	1
OKGE	Economic Capacity	W_OP	0.90%	0.00%	2393	0.90%	2376	-16
OKGE	Economic Capacity	SH_SP	0.20%	6.10%	3795	6.30%	3796	2
OKGE	Economic Capacity	SH_P	0.50%	7.30%	1809	7.70%	1810	1
OKGE	Economic Capacity	SH_OP	0.80%	3.30%	2117	4.10%	2101	-16
SCEG	Economic Capacity	S_35	1.30%	0.00%	2814	1.30%	2814	0
SCEG	Economic Capacity	S_SP	2.20%	0.00%	2730	2.20%	2730	0
SCEG	Economic Capacity	S_P	2.10%	0.00%	2698	2.10%	2698	0
SCEG	Economic Capacity	S_OP	1.90%	0.00%	2697	1.80%	2697	0
SCEG	Economic Capacity	W_SP	2.40%	0.00%	2660	2.40%	2661	0
SCEG	Economic Capacity	W_P	1.90%	0.00%	2694	1.90%	2695	0
SCEG	Economic Capacity	W_OP	1.80%	0.00%	2638	1.80%	2638	0
SCEG	Economic Capacity	SH_SP	2.00%	0.00%	2490	2.00%	2491	0
SCEG	Economic Capacity	SH_P	2.10%	0.00%	2489	2.10%	2490	0
SCEG	Economic Capacity	SH_OP	1.70%	0.00%	2506	1.70%	2506	0
SIGE	Economic Capacity	S_35	5.80%	0.00%	2463	5.80%	2463	0
SIGE	Economic Capacity	S_SP	5.90%	0.00%	2465	5.90%	2465	0
SIGE	Economic Capacity	S_P	2.40%	0.00%	3399	2.40%	3399	0
SIGE	Economic Capacity	S_OP	1.50%	0.00%	2272	1.50%	2272	0
SIGE	Economic Capacity	W_SP	6.30%	0.00%	2335	6.30%	2336	0
SIGE	Economic Capacity	W_P	2.30%	0.00%	2847	2.30%	2847	0
SIGE	Economic Capacity	W_OP	1.70%	0.00%	2199	1.70%	2199	0
SIGE	Economic Capacity	SH_SP	4.60%	0.00%	2313	4.60%	2313	0
SIGE	Economic Capacity	SH_P	1.50%	0.00%	2734	1.50%	2734	0
SIGE	Economic Capacity	SH_OP	1.60%	0.00%	2096	1.60%	2096	0
SOCO	Economic Capacity	S_35	0.50%	0.00%	6169	0.50%	6169	0
SOCO	Economic Capacity	S_SP	0.70%	0.00%	6234	0.70%	6234	0
SOCO	Economic Capacity	S_P	0.20%	0.00%	6355	0.20%	6355	0
SOCO	Economic Capacity	S_OP	0.90%	0.00%	6118	0.90%	6119	0
SOCO	Economic Capacity	W_SP	0.40%	0.00%	6430	0.40%	6430	0
SOCO	Economic Capacity	W_P	0.40%	0.00%	6339	0.40%	6339	-1
SOCO	Economic Capacity	W_OP	1.20%	0.00%	6366	1.20%	6366	0
SOCO	Economic Capacity	SH_SP	0.30%	0.00%	5817	0.30%	5817	0
SOCO	Economic Capacity	SH_P	0.70%	0.00%	5785	0.70%	5785	0
SOCO	Economic Capacity	SH_OP	1.10%	0.00%	5759	1.10%	5760	0
SPRM	Economic Capacity	S_35	0.10%	1.90%	5150	2.00%	5150	0
SPRM	Economic Capacity	S_SP	0.00%	0.70%	3817	0.70%	3817	-1
SPRM	Economic Capacity	S_P	0.10%	0.00%	3934	0.10%	3934	0
SPRM	Economic Capacity	S_OP	0.50%	0.00%	3523	0.80%	3522	-1
SPRM	Economic Capacity	W_SP	0.50%	0.00%	2186	0.50%	2186	0
SPRM	Economic Capacity	W_P	0.50%	0.00%	2186	0.50%	2186	0
SPRM	Economic Capacity	W_OP	1.40%	0.00%	1740	1.80%	1724	-16
SPRM	Economic Capacity	SH_SP	0.10%	1.20%	2886	1.90%	2875	-10
SPRM	Economic Capacity	SH_P	0.30%	0.00%	2541	0.30%	2541	0
SPRM	Economic Capacity	SH_OP	1.80%	0.00%	2066	2.50%	2059	-7

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
STEC	Economic Capacity	S_35	0.00%	0.00%	4613	0.00%	4613	0
STEC	Economic Capacity	S_SP	0.00%	0.00%	4508	0.00%	4508	0
STEC	Economic Capacity	S_P	0.00%	0.30%	6001	0.30%	6001	0
STEC	Economic Capacity	S_OP	0.00%	15.80%	2472	15.80%	2472	0
STEC	Economic Capacity	W_SP	0.00%	3.60%	2100	3.60%	2101	0
STEC	Economic Capacity	W_P	0.00%	0.00%	4723	0.00%	4723	0
STEC	Economic Capacity	W_OP	0.00%	0.00%	4594	0.00%	4594	0
STEC	Economic Capacity	SH_SP	0.00%	15.60%	1581	14.90%	1558	-22
STEC	Economic Capacity	SH_P	0.00%	9.50%	4755	10.90%	4597	-159
STEC	Economic Capacity	SH_OP	0.00%	8.30%	4908	9.30%	4828	-80
STJO	Economic Capacity	S_35	1.30%	0.90%	1133	2.30%	1136	2
STJO	Economic Capacity	S_SP	1.10%	0.90%	1172	2.10%	1175	2
STJO	Economic Capacity	S_P	1.40%	3.00%	1136	4.60%	1144	8
STJO	Economic Capacity	S_OP	1.30%	0.00%	996	1.30%	993	-3
STJO	Economic Capacity	W_SP	2.20%	2.70%	725	5.10%	731	6
STJO	Economic Capacity	W_P	2.30%	2.10%	762	4.40%	766	3
STJO	Economic Capacity	W_OP	1.20%	0.00%	828	1.20%	825	-3
STJO	Economic Capacity	SH_SP	1.40%	3.60%	542	5.00%	549	7
STJO	Economic Capacity	SH_P	1.50%	2.20%	668	3.80%	673	5
STJO	Economic Capacity	SH_OP	3.70%	0.00%	880	3.70%	872	-7
SWEPA	Economic Capacity	S_35	0.50%	5.10%	1423	5.50%	1426	3
SWEPA	Economic Capacity	S_SP	0.50%	5.50%	1278	6.00%	1275	-3
SWEPA	Economic Capacity	S_P	0.60%	0.00%	1510	0.70%	1509	-1
SWEPA	Economic Capacity	S_OP	0.80%	15.90%	959	14.60%	922	-37
SWEPA	Economic Capacity	W_SP	0.90%	11.00%	709	11.70%	722	13
SWEPA	Economic Capacity	W_P	1.30%	6.80%	749	7.70%	750	1
SWEPA	Economic Capacity	W_OP	2.50%	7.80%	579	10.00%	598	19
SWEPA	Economic Capacity	SH_SP	1.70%	0.00%	1084	1,80%	1089	5
SWEPA	Economic Capacity	SH_P	2.40%	0.00%	940	2.60%	934	-6
SWEPA	Economic Capacity	SH_OP	1.00%	0.00%	735	1.10%	731	-3
SWPS	Economic Capacity	S_35	0.00%	3.00%	7903	2.90%	7942	38
SWPS	Economic Capacity	S_SP	0.00%	3.40%	6736	3.30%	6735	-1
SWPS	Economic Capacity	S_P	0.00%	2.00%	7089	1.90%	7088	-1
SWPS	Economic Capacity	S_OP	0.10%	1.70%	8409	1.50%	8408	-1
SWPS	Economic Capacity	W_SP	0.00%	2.40%	7952	2.30%	7991	38
SWPS	Economic Capacity	W_P	0.00%	2.60%	6631	2.50%	6630	-1
SWPS	Economic Capacity	W_OP	0.10%	2.30%	7953	2.20%	7953	0
SWPS	Economic Capacity	SH_SP	0.00%	1.40%	8122	1.30%	8162	40
SWPS	Economic Capacity	SH_P	0.00%	0.50%	7154	0.70%	7154	0
SWPS	Economic Capacity	SH_OP	0.00%	0.00%	8496	0.20%	8495	0
TMPA	Economic Capacity	S_35	0.00%	8.50%	1628	8.50%	1628	0
TMPA	Economic Capacity	S_SP	0.00%	5.40%	1728	6.50%	1707	-22
TMPA	Economic Capacity	S_P	0.00%	9.60%	1627	10.10%	1623	-4
TMPA	Economic Capacity	S_OP	0.00%	6.40%	1658	7.50%	1633	-24
TMPA	Economic Capacity	W_SP	0.00%	3.80%	1455	3.80%	1455	0
TMPA	Economic Capacity	W_P	0.00%	3.30%	2104	3.60%	2077	-27
TMPA	Economic Capacity	W_OP	0.00%	3.60%	2098	3.90%	2071	-27
TMPA	Economic Capacity	SH_SP	0.00%	4.00%	1859	3.90%	1858	-1
TMPA	Economic Capacity	SH_P	0.00%	3.70%	1914	3.60%	1901	-12
TMPA	Economic Capacity	SH_OP	0.00%	3.90%	2057	4.10%	2045	-12
TNMP	Economic Capacity	S_35	0.00%	1.40%	2017	1.40%	2017	0
TNMP	Economic Capacity	S_SP	0.00%	1.40%	1702	1.40%	1704	3
TNMP	Economic Capacity	S_P	0.00%	2.30%	1630	2.10%	1640	9
TNMP	Economic Capacity	S_OP	0.00%	2.60%	1781	2.50%	1804	23
TNMP	Economic Capacity	W_SP	0.00%	0.80%	2558	0.80%	2559	1
TNMP	Economic Capacity	W_P	0.00%	2.50%	2320	2.50%	2320	1
TNMP	Economic Capacity	W_OP	0.00%	2.20%	2320	2.30%	2320	1
TNMP	Economic Capacity	SH_SP	0.00%	3.10%	2057	3.10%	2059	1
TNMP	Economic Capacity	SH_P	0.00%	2.60%	1916	2.50%	1922	6
TNMP	Economic Capacity	SH_OP	0.00%	2.90%	1942	2.80%	1949	7

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
TU	Economic Capacity	S_35	0.00%	2.80%	7591	2.80%	7591	0
TU	Economic Capacity	S_SP	0.00%	6.70%	5358	6.80%	5327	-31
TU	Economic Capacity	S_P	0.00%	8.30%	5039	8.40%	5011	-28
TU	Economic Capacity	S_OP	0.00%	8.50%	5079	8.60%	5073	-7
TU	Economic Capacity	W_SP	0.00%	3.50%	8687	3.50%	8686	0
TU	Economic Capacity	W_P	0.00%	6.40%	7324	7.40%	7185	-139
TU	Economic Capacity	W_OP	0.00%	6.40%	7325	7.30%	7185	-139
TU	Economic Capacity	SH_SP	0.00%	7.50%	5462	7.30%	5459	-3
TU	Economic Capacity	SH_P	0.00%	9.60%	3414	9.50%	3395	-19
TU	Economic Capacity	SH_OP	0.00%	10.20%	3772	10.20%	3712	-60
TVA	Economic Capacity	S_35	13.30%	0.00%	829	13.30%	829	0
TVA	Economic Capacity	S_SP	13.30%	0.00%	801	13.30%	801	0
TVA	Economic Capacity	S_P	9.00%	0.00%	841	9.00%	841	0
TVA	Economic Capacity	S_OP	10.30%	0.00%	963	10.30%	963	0
TVA	Economic Capacity	W_SP	4.50%	0.00%	672	4.50%	672	0
TVA	Economic Capacity	W_P	1.00%	0.00%	718	1.00%	718	0
TVA	Economic Capacity	W_OP	6.80%	0.00%	813	6.80%	813	0
TVA	Economic Capacity	SH_SP	13.00%	1.20%	688	14.00%	716	27
TVA	Economic Capacity	SH_P	0.60%	0.00%	862	0.60%	862	0
TVA	Economic Capacity	SH_OP	10.00%	0.00%	894	10.00%	894	0
VP	Economic Capacity	S_35	2.90%	0.00%	6769	2.80%	6769	0
VP	Economic Capacity	S_SP	3.50%	0.00%	6453	3.50%	6453	-1
VP	Economic Capacity	S_P	5.40%	0.00%	5844	5.40%	5842	-2
VP	Economic Capacity	S_OP	5.90%	0.00%	5767	5.90%	5766	-2
VP	Economic Capacity	W_SP	1.10%	0.00%	7048	1.10%	7048	0
VP	Economic Capacity	W_P	1.10%	0.00%	7050	1.10%	7050	0
VP	Economic Capacity	W_OP	1.90%	0.00%	6921	1.90%	6921	0
VP	Economic Capacity	SH_SP	0.80%	0.00%	6914	0.80%	6914	0
VP	Economic Capacity	SH_P	1.70%	0.00%	6498	1.70%	6498	0
VP	Economic Capacity	SH_OP	3.10%	0.00%	5853	3.10%	5853	0
WEFA	Economic Capacity	S_35	0.10%	6.90%	3071	7.00%	3072	1
WEFA	Economic Capacity	S_SP	0.10%	5.00%	2071	5.30%	2071	0
WEFA	Economic Capacity	S_P	0.00%	17.90%	1769	16.80%	1721	-47
WEFA	Economic Capacity	S_OP	0.20%	20.40%	1841	19.40%	1793	-48
WEFA	Economic Capacity	W_SP	0.50%	0.00%	2518	0.40%	2507	-11
WEFA	Economic Capacity	W_P	0.00%	0.00%	1968	0.00%	1970	2
WEFA	Economic Capacity	W_OP	1.50%	0.00%	1930	2.10%	1861	-68
WEFA	Economic Capacity	SH_SP	0.30%	8.60%	1621	8.60%	1609	-12
WEFA	Economic Capacity	SH_P	0.10%	0.00%	1731	0.10%	1705	-26
WEFA	Economic Capacity	SH_OP	0.60%	0.50%	1693	2.40%	1670	-23
WEP	Economic Capacity	S_35	0.80%	0.00%	5051	0.80%	5051	0
WEP	Economic Capacity	S_SP	1.10%	0.00%	4678	1.10%	4678	0
WEP	Economic Capacity	S_P	1.40%	0.00%	5182	1.40%	5182	0
WEP	Economic Capacity	S_OP	1.70%	0.00%	2089	1.70%	2090	1
WEP	Economic Capacity	W_SP	1.00%	0.10%	3988	1.20%	3988	0
WEP	Economic Capacity	W_P	1.60%	0.00%	3737	1.60%	3742	4
WEP	Economic Capacity	W_OP	0.80%	0.00%	2818	0.80%	2826	8
WEP	Economic Capacity	SH_SP	1.00%	0.00%	2044	1.00%	2045	2
WEP	Economic Capacity	SH_P	1.00%	0.00%	2119	1.00%	2120	0
WEP	Economic Capacity	SH_OP	1.00%	0.00%	1497	1.00%	1500	3
WEPL	Economic Capacity	S_35	0.00%	0.50%	5520	0.50%	5521	1
WEPL	Economic Capacity	S_SP	0.00%	0.00%	4889	0.00%	4879	-9
WEPL	Economic Capacity	S_P	0.10%	0.00%	2937	0.10%	2937	0
WEPL	Economic Capacity	S_OP	0.00%	0.00%	1599	0.00%	1555	-44
WEPL	Economic Capacity	W_SP	0.00%	0.00%	3563	0.00%	3547	-16
WEPL	Economic Capacity	W_P	0.00%	0.00%	3696	0.00%	3675	-21
WEPL	Economic Capacity	W_OP	0.20%	0.00%	3600	0.40%	3563	-37
WEPL	Economic Capacity	SH_SP	0.00%	0.20%	3478	0.20%	3477	0
WEPL	Economic Capacity	SH_P	0.00%	0.00%	3686	0.00%	3686	0
WEPL	Economic Capacity	SH_OP	0.30%	0.00%	1725	0.40%	1751	26

Exhibit No. AC-512

Base Case (Post Mitigation)

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
WR	Economic Capacity	S_35	0.30%	0.70%	4684	1.00%	4710	25
WR	Economic Capacity	S_SP	0.20%	0.80%	3505	1.10%	3505	0
WR	Economic Capacity	S_P	0.10%	0.80%	3882	0.60%	3879	-3
WR	Economic Capacity	S_OP	1.00%	0.00%	2068	1.00%	2069	1
WR	Economic Capacity	W_SP	0.10%	0.90%	2554	1.10%	2553	-1
WR	Economic Capacity	W_P	0.10%	0.00%	2826	0.10%	2828	3
WR	Economic Capacity	W_OP	0.60%	0.00%	2890	0.60%	2886	-4
WR	Economic Capacity	SH_SP	0.50%	1.60%	2380	2.00%	2380	0
WR	Economic Capacity	SH_P	0.10%	0.00%	2256	0.10%	2253	-3
WR	Economic Capacity	SH_OP	0.60%	0.00%	1829	0.60%	1818	-11

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CSW_SPP	Available Economic Capacity	S_35	8.50%	6.90%	656	13.50%	679	23
CSW_SPP	Available Economic Capacity	S_SP	22.40%	13.50%	1101	25.50%	1126	25
CSW_SPP	Available Economic Capacity	S_P	0.00%	18.30%	1002	6.90%	782	-219
CSW_SPP	Available Economic Capacity	S_OP	7.10%	0.00%	866	4.30%	837	-29
CSW_SPP	Available Economic Capacity	W_SP	3.10%	26.30%	1095	26.00%	1092	-3
CSW_SPP	Available Economic Capacity	W_P	0.00%	0.00%	959	0.00%	781	-179
CSW_SPP	Available Economic Capacity	W_OP	0.00%	0.00%	969	0.90%	784	-185
CSW_SPP	Available Economic Capacity	SH_SP	6.10%	11.50%	711	12.10%	677	-35
CSW_SPP	Available Economic Capacity	SH_P	0.00%	12.60%	591	5.10%	480	-111
CSW_SPP	Available Economic Capacity	SH_OP	0.00%	0.00%	1270	0.00%	1122	-149
CBEN	Available Economic Capacity	S_35	0.00%	54.70%	3787	46.50%	3028	-759
CBEN	Available Economic Capacity	S_SP	0.00%	66.80%	4961	54.30%	3588	-1373
CBEN	Available Economic Capacity	S_P	0.00%	68.70%	5231	54.10%	3361	-1870
CBEN	Available Economic Capacity	S_OP	0.00%	55.90%	3718	35.30%	2077	-1640
CBEN	Available Economic Capacity	W_SP	0.00%	46.10%	3081	41.30%	2683	-398
CBEN	Available Economic Capacity	W_P	0.00%	67.90%	4790	58.00%	3605	-1185
CBEN	Available Economic Capacity	W_OP	0.00%	63.50%	4303	55.10%	3354	-949
CBEN	Available Economic Capacity	SH_SP	0.00%	61.40%	4155	47.00%	2679	-1476
CBEN	Available Economic Capacity	SH_P	0.00%	51.40%	2971	42.60%	2205	-766
CBEN	Available Economic Capacity	SH_OP	0.00%	45.20%	2650	29.20%	1571	-1079
VALLEY	Available Economic Capacity	S_35	0.00%	64.30%	4642	44.90%	2900	-1743
VALLEY	Available Economic Capacity	S_SP	0.00%	69.70%	5360	50.20%	3403	-1957
VALLEY	Available Economic Capacity	S_P	0.00%	57.10%	3898	37.70%	2438	-1460
VALLEY	Available Economic Capacity	S_OP	0.00%	59.50%	4020	40.00%	2460	-1559
VALLEY	Available Economic Capacity	W_SP	0.00%	56.40%	3673	38.20%	2288	-1384
VALLEY	Available Economic Capacity	W_P	0.00%	62.40%	4289	43.00%	2622	-1667
VALLEY	Available Economic Capacity	W_OP	0.00%	64.10%	4473	44.70%	2739	-1734
VALLEY	Available Economic Capacity	SH_SP	0.00%	61.20%	3997	41.90%	2351	-1646
VALLEY	Available Economic Capacity	SH_P	0.00%	48.60%	3068	29.50%	1944	-1123
VALLEY	Available Economic Capacity	SH_OP	0.00%	51.60%	3306	32.50%	2064	-1242
WTU	Available Economic Capacity	S_35	0.00%	31.90%	2618	30.10%	2503	-115
WTU	Available Economic Capacity	S_SP	0.00%	45.50%	3314	25.90%	1888	-1426
WTU	Available Economic Capacity	S_P	0.00%	31.10%	5058	21.70%	2099	-2959
WTU	Available Economic Capacity	S_OP	0.00%	39.40%	2724	20.30%	1529	-1196
WTU	Available Economic Capacity	W_SP	0.00%	29.40%	4788	28.90%	4789	1
WTU	Available Economic Capacity	W_P	0.00%	12.70%	4990	12.40%	4996	6
WTU	Available Economic Capacity	W_OP	0.00%	16.20%	5133	15.90%	5147	14
WTU	Available Economic Capacity	SH_SP	0.00%	46.80%	2989	37.10%	1991	-998
WTU	Available Economic Capacity	SH_P	0.00%	23.40%	1214	20.00%	1041	-174
WTU	Available Economic Capacity	SH_OP	0.00%	28.40%	2245	22.80%	1935	-310

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Available Economic Capacity	S_35	11.20%	0.00%	1544	11.60%	1450	-95
AECI	Available Economic Capacity	S_SP	0.00%	0.00%	950	0.00%	840	-109
AECI	Available Economic Capacity	S_P	0.00%	0.00%	1575	0.00%	1312	-263
AECI	Available Economic Capacity	S_OP	0.00%	0.00%	1485	0.00%	1326	-159
AECI	Available Economic Capacity	W_SP	7.60%	0.00%	804	7.90%	782	-22
AECI	Available Economic Capacity	W_P	0.00%	0.00%	986	0.00%	932	-54
AECI	Available Economic Capacity	W_OP	1.10%	0.00%	1088	1.30%	1028	-60
AECI	Available Economic Capacity	SH_SP	19.30%	0.80%	903	19.20%	852	-51
AECI	Available Economic Capacity	SH_P	0.00%	0.00%	1044	0.00%	959	-85
AECI	Available Economic Capacity	SH_OP	9.10%	0.00%	971	9.50%	909	-61
AEP	Available Economic Capacity	S_35	35.50%	0.00%	1653	33.50%	1532	-121
AEP	Available Economic Capacity	S_SP	98.50%	0.00%	9697	98.30%	9670	-27
AEP	Available Economic Capacity	S_P	99.80%	0.00%	9959	99.80%	9957	-2
AEP	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
AEP	Available Economic Capacity	W_SP	99.70%	0.00%	9943	99.70%	9939	-5
AEP	Available Economic Capacity	W_P	99.80%	0.00%	9959	99.80%	9956	-2
AEP	Available Economic Capacity	W_OP	99.80%	0.00%	9970	99.80%	9965	-5
AEP	Available Economic Capacity	SH_SP	85.50%	0.00%	7392	84.00%	7160	-232
AEP	Available Economic Capacity	SH_P	99.00%	0.00%	9803	98.90%	9790	-13
AEP	Available Economic Capacity	SH_OP	99.70%	0.00%	9935	99.60%	9912	-22
ALLIANT_E	Available Economic Capacity	S_35	8.30%	0.00%	912	1.00%	893	-20
ALLIANT_E	Available Economic Capacity	S_SP	0.00%	0.00%	1839	0.00%	1693	-145
ALLIANT_E	Available Economic Capacity	S_P	0.00%	0.00%	1619	0.00%	1619	0
ALLIANT_E	Available Economic Capacity	S_OP	0.00%	0.00%	7083	0.00%	7083	0
ALLIANT_E	Available Economic Capacity	W_SP	7.60%	0.00%	1035	5.00%	1052	18
ALLIANT_E	Available Economic Capacity	W_P	0.00%	0.00%	1756	0.00%	1692	-64
ALLIANT_E	Available Economic Capacity	W_OP	0.00%	0.00%	8511	0.00%	8511	0
ALLIANT_E	Available Economic Capacity	SH_SP	0.00%	0.00%	1993	0.00%	1741	-252
ALLIANT_E	Available Economic Capacity	SH_P	0.00%	0.00%	2283	0.00%	1978	-305
ALLIANT_E	Available Economic Capacity	SH_OP	0.00%	0.00%	7132	0.00%	7132	0
AMEREN	Available Economic Capacity	S_35	24.10%	0.00%	1231	25.40%	1254	24
AMEREN	Available Economic Capacity	S_SP	6.50%	1.10%	399	8.40%	410	11
AMEREN	Available Economic Capacity	S_P	3.40%	0.00%	1093	1.20%	1080	-14
AMEREN	Available Economic Capacity	S_OP	0.00%	0.00%	2683	0.00%	2394	-288
AMEREN	Available Economic Capacity	W_SP	3.10%	0.00%	938	3.10%	940	1
AMEREN	Available Economic Capacity	W_P	6.30%	0.00%	1254	6.10%	1212	-43
AMEREN	Available Economic Capacity	W_OP	0.00%	0.00%	2600	0.00%	2600	0
AMEREN	Available Economic Capacity	SH_SP	11.30%	0.40%	574	13.40%	603	29
AMEREN	Available Economic Capacity	SH_P	8.70%	0.00%	1225	8.30%	1150	-75
AMEREN	Available Economic Capacity	SH_OP	0.00%	0.00%	4776	0.00%	4776	0
APS	Available Economic Capacity	S_35	53.20%	0.00%	3660	48.20%	3223	-438
APS	Available Economic Capacity	S_SP	98.80%	0.00%	9764	98.70%	9744	-20
APS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
APS	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
APS	Available Economic Capacity	W_SP	83.80%	0.00%	7155	82.50%	6967	-187
APS	Available Economic Capacity	W_P	0.00%	0.00%	7739	0.00%	7739	0
APS	Available Economic Capacity	W_OP	71.40%	0.00%	5919	69.50%	5758	-161
APS	Available Economic Capacity	SH_SP	22.00%	0.00%	2233	20.00%	2208	-25
APS	Available Economic Capacity	SH_P	47.80%	0.00%	3253	40.40%	2891	-362
APS	Available Economic Capacity	SH_OP	76.90%	0.00%	6448	76.90%	6448	0
BEC	Available Economic Capacity	S_35	0.00%	34.30%	2500	29.20%	2204	-296
BEC	Available Economic Capacity	S_SP	0.00%	78.00%	6563	24.80%	2305	-4258
BEC	Available Economic Capacity	S_P	0.00%	78.00%	6563	22.60%	2132	-4430
BEC	Available Economic Capacity	S_OP	0.00%	27.70%	3728	2.60%	1961	-1767
BEC	Available Economic Capacity	W_SP	0.00%	27.80%	3112	27.40%	3100	-12
BEC	Available Economic Capacity	W_P	0.00%	45.70%	3142	8.60%	1780	-1361
BEC	Available Economic Capacity	W_OP	0.00%	10.20%	2300	5.80%	1531	-769
BEC	Available Economic Capacity	SH_SP	0.00%	51.60%	3522	35.00%	2011	-1511
BEC	Available Economic Capacity	SH_P	0.00%	48.00%	3540	22.90%	1702	-1838
BEC	Available Economic Capacity	SH_OP	0.00%	32.00%	2707	13.10%	1651	-1056

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
BRYN	Available Economic Capacity	S_35	0.00%	46.10%	3196	42.50%	2889	-307
BRYN	Available Economic Capacity	S_SP	0.00%	79.20%	6700	34.70%	2388	-4312
BRYN	Available Economic Capacity	S_P	0.00%	79.20%	6700	33.40%	2312	-4388
BRYN	Available Economic Capacity	S_OP	0.00%	36.80%	2907	15.10%	1578	-1329
BRYN	Available Economic Capacity	W_SP	0.00%	21.80%	1977	20.00%	1980	3
BRYN	Available Economic Capacity	W_P	0.00%	0.00%	3366	0.00%	3415	50
BRYN	Available Economic Capacity	W_OP	0.00%	0.00%	7228	0.00%	3873	-3355
BRYN	Available Economic Capacity	SH_SP	0.00%	53.30%	3658	36.50%	2156	-1502
BRYN	Available Economic Capacity	SH_P	0.00%	49.20%	3686	23.20%	1827	-1859
BRYN	Available Economic Capacity	SH_OP	0.00%	31.60%	2348	13.00%	1404	-943
CAPO	Available Economic Capacity	S_35	88.20%	0.00%	7797	87.60%	7694	-103
CAPO	Available Economic Capacity	S_SP	87.50%	0.00%	7689	86.80%	7572	-117
CAPO	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	SH_SP	84.40%	0.00%	7177	78.40%	6230	-948
CAPO	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
CAPO	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
CELE	Available Economic Capacity	S_35	2.20%	4.30%	1619	6.00%	1622	4
CELE	Available Economic Capacity	S_SP	0.00%	0.00%	2741	0.00%	2414	-327
CELE	Available Economic Capacity	S_P	0.00%	0.00%	2015	0.00%	1829	-186
CELE	Available Economic Capacity	S_OP	0.00%	0.00%	3493	0.00%	3325	-167
CELE	Available Economic Capacity	W_SP	1.70%	7.60%	1804	8.20%	1818	14
CELE	Available Economic Capacity	W_P	0.00%	0.00%	1518	0.00%	1284	-234
CELE	Available Economic Capacity	W_OP	15.10%	0.00%	1091	11.20%	839	-252
CELE	Available Economic Capacity	SH_SP	9.10%	0.30%	1211	7.10%	1101	-110
CELE	Available Economic Capacity	SH_P	0.00%	0.00%	4545	0.00%	3793	-753
CELE	Available Economic Capacity	SH_OP	24.00%	0.00%	1871	22.50%	1604	-267
CIMO	Available Economic Capacity	S_35	7.10%	0.00%	944	8.60%	918	-26
CIMO	Available Economic Capacity	S_SP	0.00%	0.00%	5255	0.00%	4112	-1143
CIMO	Available Economic Capacity	S_P	0.00%	0.00%	9519	0.00%	9519	0
CIMO	Available Economic Capacity	S_OP	0.00%	0.00%	6784	0.00%	6784	0
CIMO	Available Economic Capacity	W_SP	0.00%	0.00%	9205	0.00%	9205	0
CIMO	Available Economic Capacity	W_P	0.00%	0.00%	4759	0.00%	4759	0
CIMO	Available Economic Capacity	W_OP	0.00%	0.00%	4993	0.00%	4993	0
CIMO	Available Economic Capacity	SH_SP	0.00%	0.00%	4774	0.00%	4774	0
CIMO	Available Economic Capacity	SH_P	0.00%	0.00%	6240	0.00%	6240	0
CIMO	Available Economic Capacity	SH_OP	0.00%	0.00%	5700	0.00%	5700	0
CIN	Available Economic Capacity	S_35	50.60%	0.00%	2809	46.60%	2446	-363
CIN	Available Economic Capacity	S_SP	0.00%	0.00%	3882	0.00%	3882	0
CIN	Available Economic Capacity	S_P	0.00%	0.00%	3260	0.00%	3260	0
CIN	Available Economic Capacity	S_OP	0.00%	0.00%	5151	0.00%	5151	0
CIN	Available Economic Capacity	W_SP	0.00%	0.00%	2356	0.00%	2334	-21
CIN	Available Economic Capacity	W_P	0.00%	0.00%	3254	0.00%	3254	0
CIN	Available Economic Capacity	W_OP	0.00%	0.00%	3180	0.00%	3089	-91
CIN	Available Economic Capacity	SH_SP	0.00%	0.00%	3973	0.00%	2216	-1757
CIN	Available Economic Capacity	SH_P	0.00%	0.00%	3266	0.00%	3266	0
CIN	Available Economic Capacity	SH_OP	0.00%	0.00%	4306	0.00%	2787	-1519
COA	Available Economic Capacity	S_35	0.00%	34.90%	3355	31.70%	3149	-206
COA	Available Economic Capacity	S_SP	0.00%	77.40%	6501	34.00%	3551	-2950
COA	Available Economic Capacity	S_P	0.00%	77.40%	6501	34.00%	3551	-2950
COA	Available Economic Capacity	S_OP	0.00%	76.00%	6352	30.80%	3581	-2771
COA	Available Economic Capacity	W_SP	0.00%	15.80%	2405	15.70%	2405	0
COA	Available Economic Capacity	W_P	0.00%	0.00%	5068	0.00%	5068	0
COA	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
COA	Available Economic Capacity	SH_SP	0.00%	81.20%	6942	45.50%	3704	-3238
COA	Available Economic Capacity	SH_P	0.00%	72.60%	5661	40.70%	3077	-2584
COA	Available Economic Capacity	SH_OP	0.00%	0.00%	5010	0.00%	3654	-1356

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Available Economic Capacity	S_35	30.30%	0.00%	2064	30.30%	2061	-3
COMED	Available Economic Capacity	S_SP	29.00%	0.00%	2050	28.40%	2018	-32
COMED	Available Economic Capacity	S_P	0.00%	0.00%	2308	0.00%	2120	-188
COMED	Available Economic Capacity	S_OP	0.00%	0.00%	5397	0.00%	5397	0
COMED	Available Economic Capacity	W_SP	38.30%	0.00%	2123	37.60%	2083	-40
COMED	Available Economic Capacity	W_P	0.00%	0.00%	2058	0.00%	2058	0
COMED	Available Economic Capacity	W_OP	0.00%	0.00%	2742	0.00%	2742	0
COMED	Available Economic Capacity	SH_SP	41.30%	0.00%	2010	39.50%	1876	-135
COMED	Available Economic Capacity	SH_P	0.00%	0.00%	1744	0.00%	1708	-36
COMED	Available Economic Capacity	SH_OP	0.00%	0.00%	2081	0.00%	1819	-262
CP	Available Economic Capacity	S_35	55.80%	0.00%	3380	53.80%	3190	-190
CP	Available Economic Capacity	S_SP	58.30%	0.00%	3613	56.50%	3423	-190
CP	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
CP	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
CP	Available Economic Capacity	W_SP	27.80%	0.00%	1415	26.70%	1369	-46
CP	Available Economic Capacity	W_P	77.70%	0.00%	6301	77.60%	6278	-23
CP	Available Economic Capacity	W_OP	87.70%	0.00%	7767	87.70%	7767	0
CP	Available Economic Capacity	SH_SP	79.10%	0.00%	6412	77.30%	6148	-263
CP	Available Economic Capacity	SH_P	96.00%	0.00%	9238	95.80%	9195	-44
CP	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
CPS	Available Economic Capacity	S_35	0.00%	39.10%	3436	33.50%	3069	-367
CPS	Available Economic Capacity	S_SP	0.00%	78.00%	6563	34.20%	3572	-2991
CPS	Available Economic Capacity	S_P	0.00%	78.00%	6563	34.20%	3572	-2991
CPS	Available Economic Capacity	S_OP	0.00%	78.00%	6563	34.20%	3572	-2991
CPS	Available Economic Capacity	W_SP	0.00%	50.00%	5000	20.00%	2000	-3000
CPS	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
CPS	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
CPS	Available Economic Capacity	SH_SP	0.00%	74.20%	5844	45.30%	3230	-2614
CPS	Available Economic Capacity	SH_P	0.00%	73.10%	5729	41.00%	3104	-2625
CPS	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	5417	-4583
DECO	Available Economic Capacity	S_35	97.40%	0.00%	9492	97.20%	9449	-43
DECO	Available Economic Capacity	S_SP	64.40%	0.00%	4519	62.80%	4354	-165
DECO	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
DECO	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
DECO	Available Economic Capacity	W_SP	63.40%	0.00%	4673	61.90%	4540	-133
DECO	Available Economic Capacity	W_P	0.00%	0.00%	4019	0.00%	4019	0
DECO	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
DECO	Available Economic Capacity	SH_SP	32.00%	0.00%	3643	0.00%	5663	2020
DECO	Available Economic Capacity	SH_P	0.00%	0.00%	6219	0.00%	6219	0
DECO	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
DGG	Available Economic Capacity	S_35	0.00%	45.80%	3198	42.10%	2887	-312
DGG	Available Economic Capacity	S_SP	0.00%	78.00%	6563	29.20%	2255	-4308
DGG	Available Economic Capacity	S_P	0.00%	78.00%	6563	29.40%	2209	-4354
DGG	Available Economic Capacity	S_OP	0.00%	34.40%	2832	10.40%	1627	-1205
DGG	Available Economic Capacity	W_SP	0.00%	28.80%	1169	25.20%	946	-223
DGG	Available Economic Capacity	W_P	0.00%	25.00%	2500	14.30%	1429	-1071
DGG	Available Economic Capacity	W_OP	0.00%	20.00%	1200	15.40%	888	-312
DGG	Available Economic Capacity	SH_SP	0.00%	53.20%	3652	36.50%	2153	-1500
DGG	Available Economic Capacity	SH_P	0.00%	48.70%	3630	23.50%	1759	-1871
DGG	Available Economic Capacity	SH_OP	0.00%	33.20%	2722	13.60%	1549	-1173
DLCO	Available Economic Capacity	S_35	90.80%	0.00%	8273	89.80%	8083	-189
DLCO	Available Economic Capacity	S_SP	100.00%	0.00%	10000	100.00%	10000	0
DLCO	Available Economic Capacity	S_P	43.90%	0.00%	3148	43.90%	3148	0
DLCO	Available Economic Capacity	S_OP	66.80%	0.00%	5565	66.80%	5565	0
DLCO	Available Economic Capacity	W_SP	71.40%	0.00%	5515	71.40%	5515	0
DLCO	Available Economic Capacity	W_P	67.80%	0.00%	5631	62.20%	5296	-335
DLCO	Available Economic Capacity	W_OP	64.50%	0.00%	5419	64.50%	5419	0
DLCO	Available Economic Capacity	SH_SP	56.60%	0.00%	4042	53.80%	3832	-210
DLCO	Available Economic Capacity	SH_P	83.70%	0.00%	7275	83.70%	7275	0
DLCO	Available Economic Capacity	SH_OP	69.90%	0.00%	5793	69.90%	5793	0

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
DPL	Available Economic Capacity	S_35	64.20%	0.00%	4282	62.00%	4026	-256
DPL	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
DPL	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
DPL	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
DPL	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
DUKE	Available Economic Capacity	S_35	78.30%	0.00%	6271	76.10%	5970	-301
DUKE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
EDE	Available Economic Capacity	S_35	10.60%	0.00%	714	12.00%	701	-13
EDE	Available Economic Capacity	S_SP	6.50%	1.90%	785	9.30%	795	10
EDE	Available Economic Capacity	S_P	0.00%	0.00%	3441	0.00%	2432	-1010
EDE	Available Economic Capacity	S_OP	0.00%	0.00%	9842	0.00%	7938	-1904
EDE	Available Economic Capacity	W_SP	2.50%	10.20%	691	12.20%	712	22
EDE	Available Economic Capacity	W_P	0.00%	0.00%	1656	0.00%	1546	-109
EDE	Available Economic Capacity	W_OP	0.00%	0.00%	1293	0.00%	1162	-130
EDE	Available Economic Capacity	SH_SP	0.00%	0.00%	2661	0.00%	2360	-301
EDE	Available Economic Capacity	SH_P	0.00%	0.00%	2266	0.00%	2063	-203
EDE	Available Economic Capacity	SH_OP	0.00%	0.00%	2965	0.00%	2458	-507
EKPC	Available Economic Capacity	S_35	51.40%	0.00%	2959	49.90%	2818	-141
EKPC	Available Economic Capacity	S_SP	87.80%	0.00%	7754	87.80%	7754	0
EKPC	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
EKPC	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
EKPC	Available Economic Capacity	W_SP	32.30%	0.00%	2278	32.30%	2278	0
EKPC	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
EKPC	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
EKPC	Available Economic Capacity	SH_SP	26.70%	0.00%	1852	24.40%	1803	-49
EKPC	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
EKPC	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
ENT	Available Economic Capacity	S_35	13.50%	0.00%	2045	13.40%	2010	-35
ENT	Available Economic Capacity	S_SP	0.00%	0.00%	3586	0.00%	2329	-1257
ENT	Available Economic Capacity	S_P	0.00%	0.00%	2351	0.00%	1704	-647
ENT	Available Economic Capacity	S_OP	0.00%	0.00%	7306	0.00%	5774	-1532
ENT	Available Economic Capacity	W_SP	3.80%	0.00%	3892	3.80%	3827	-65
ENT	Available Economic Capacity	W_P	0.00%	0.00%	1013	0.00%	958	-54
ENT	Available Economic Capacity	W_OP	0.00%	0.00%	993	0.00%	834	-159
ENT	Available Economic Capacity	SH_SP	33.80%	0.60%	1495	31.50%	1339	-156
ENT	Available Economic Capacity	SH_P	0.00%	0.00%	1566	0.00%	1428	-138
ENT	Available Economic Capacity	SH_OP	0.00%	0.00%	1258	0.00%	1193	-65
FENER	Available Economic Capacity	S_35	70.60%	0.00%	5121	68.10%	4801	-320
FENER	Available Economic Capacity	S_SP	97.10%	0.00%	9426	96.90%	9395	-31
FENER	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
FENER	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
FENER	Available Economic Capacity	W_SP	0.00%	0.00%	3549	0.00%	3549	0
FENER	Available Economic Capacity	W_P	0.00%	0.00%	8113	0.00%	8113	0
FENER	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
FENER	Available Economic Capacity	SH_SP	28.10%	0.00%	1478	25.60%	1382	-97
FENER	Available Economic Capacity	SH_P	46.30%	0.00%	2922	39.00%	2521	-401
FENER	Available Economic Capacity	SH_OP	62.00%	0.00%	5287	60.30%	5214	-73

Base Case (Post Mitigation) **Exhibit No. AC-512**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
GRRD	Available Economic Capacity	S_35	2.20%	0.00%	1137	3.20%	1101	-36
GRRD	Available Economic Capacity	S_SP	0.00%	0.00%	2372	0.00%	1880	-491
GRRD	Available Economic Capacity	S_P	0.00%	0.00%	7713	0.00%	3573	-4140
GRRD	Available Economic Capacity	S_OP	0.00%	0.00%	8560	0.00%	4808	-3752
GRRD	Available Economic Capacity	W_SP	0.00%	0.00%	1351	0.00%	1238	-113
GRRD	Available Economic Capacity	W_P	0.00%	0.00%	2517	0.00%	1889	-627
GRRD	Available Economic Capacity	W_OP	0.00%	0.00%	3866	0.00%	2243	-1623
GRRD	Available Economic Capacity	SH_SP	4.10%	0.20%	893	5.40%	866	-27
GRRD	Available Economic Capacity	SH_P	0.00%	0.00%	3705	0.00%	3517	-188
GRRD	Available Economic Capacity	SH_OP	0.00%	0.00%	5331	0.00%	2771	-2560
HEC	Available Economic Capacity	S_35	67.60%	0.00%	4887	66.20%	4736	-151
HEC	Available Economic Capacity	S_SP	68.70%	0.00%	4988	67.10%	4805	-183
HEC	Available Economic Capacity	S_P	0.00%	0.00%	5045	0.00%	5045	0
HEC	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
HEC	Available Economic Capacity	W_SP	37.00%	0.00%	1985	35.90%	1917	-67
HEC	Available Economic Capacity	W_P	0.00%	0.00%	2752	0.00%	2752	0
HEC	Available Economic Capacity	W_OP	0.00%	0.00%	9002	0.00%	9002	0
HEC	Available Economic Capacity	SH_SP	14.90%	0.00%	1511	7.00%	1553	42
HEC	Available Economic Capacity	SH_P	0.00%	0.00%	2296	0.00%	2296	0
HEC	Available Economic Capacity	SH_OP	0.00%	0.00%	7852	0.00%	7852	0
HLP	Available Economic Capacity	S_35	0.00%	31.70%	2264	23.90%	1887	-376
HLP	Available Economic Capacity	S_SP	0.00%	77.40%	6499	24.70%	2250	-4250
HLP	Available Economic Capacity	S_P	0.00%	77.40%	6499	22.50%	2127	-4373
HLP	Available Economic Capacity	S_OP	0.00%	36.40%	2659	14.90%	1473	-1186
HLP	Available Economic Capacity	W_SP	0.00%	8.50%	2516	8.10%	2501	-15
HLP	Available Economic Capacity	W_P	0.00%	54.10%	3400	24.00%	1436	-1964
HLP	Available Economic Capacity	W_OP	0.00%	0.00%	3136	0.00%	1806	-1330
HLP	Available Economic Capacity	SH_SP	0.00%	43.30%	3131	24.40%	1782	-1350
HLP	Available Economic Capacity	SH_P	0.00%	40.80%	3620	23.00%	1894	-1726
HLP	Available Economic Capacity	SH_OP	0.00%	32.10%	2451	13.10%	1489	-962
IP	Available Economic Capacity	S_35	23.70%	0.00%	1002	24.40%	1030	28
IP	Available Economic Capacity	S_SP	40.70%	0.00%	1948	41.10%	1971	23
IP	Available Economic Capacity	S_P	28.80%	0.00%	1448	27.60%	1373	-74
IP	Available Economic Capacity	S_OP	22.90%	0.00%	1770	23.50%	1752	-18
IP	Available Economic Capacity	W_SP	34.00%	0.00%	1637	33.90%	1635	-2
IP	Available Economic Capacity	W_P	0.00%	0.00%	1674	0.00%	1651	-23
IP	Available Economic Capacity	W_OP	15.60%	0.00%	1724	11.40%	1733	9
IP	Available Economic Capacity	SH_SP	27.40%	0.00%	1205	27.20%	1193	-12
IP	Available Economic Capacity	SH_P	0.00%	0.00%	2051	0.00%	1971	-80
IP	Available Economic Capacity	SH_OP	0.00%	0.00%	2426	0.00%	2349	-77
IPL	Available Economic Capacity	S_35	62.70%	0.00%	4104	61.20%	3932	-172
IPL	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
KACY	Available Economic Capacity	S_35	3.30%	0.00%	1448	4.80%	1349	-99
KACY	Available Economic Capacity	S_SP	0.00%	0.00%	1907	0.00%	1907	0
KACY	Available Economic Capacity	S_P	0.00%	0.00%	6711	0.00%	6711	0
KACY	Available Economic Capacity	S_OP	0.00%	0.00%	8194	0.00%	8194	0
KACY	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
KACY	Available Economic Capacity	W_P	0.00%	0.00%	6651	0.00%	6651	0
KACY	Available Economic Capacity	W_OP	0.00%	0.00%	5629	0.00%	5629	0
KACY	Available Economic Capacity	SH_SP	0.00%	0.00%	2736	0.00%	2476	-260
KACY	Available Economic Capacity	SH_P	0.00%	0.00%	4225	0.00%	3702	-524
KACY	Available Economic Capacity	SH_OP	0.00%	0.00%	4859	0.00%	4859	0

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
KCPL	Available Economic Capacity	S_35	13.80%	0.00%	1133	13.90%	1110	-23
KCPL	Available Economic Capacity	S_SP	6.60%	0.00%	771	6.80%	750	-21
KCPL	Available Economic Capacity	S_P	0.00%	0.00%	1588	0.00%	1182	-406
KCPL	Available Economic Capacity	S_OP	0.00%	0.00%	1792	0.00%	1420	-372
KCPL	Available Economic Capacity	W_SP	10.50%	0.00%	722	11.70%	669	-53
KCPL	Available Economic Capacity	W_P	0.00%	0.00%	932	0.00%	916	-15
KCPL	Available Economic Capacity	W_OP	0.00%	0.00%	5213	0.00%	5213	0
KCPL	Available Economic Capacity	SH_SP	8.70%	0.00%	884	9.40%	819	-64
KCPL	Available Economic Capacity	SH_P	0.00%	0.00%	2366	0.00%	1921	-445
KCPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5725	0.00%	5725	0
LAFA	Available Economic Capacity	S_35	0.00%	0.00%	6843	0.00%	6824	-19
LAFA	Available Economic Capacity	S_SP	0.00%	0.00%	8702	0.00%	3943	-4759
LAFA	Available Economic Capacity	S_P	0.00%	0.00%	3333	0.00%	5000	1666
LAFA	Available Economic Capacity	S_OP	0.00%	0.00%	9999	0.00%	3460	-6539
LAFA	Available Economic Capacity	W_SP	2.20%	5.20%	3016	5.60%	3024	8
LAFA	Available Economic Capacity	W_P	0.00%	0.00%	2882	0.00%	2450	-432
LAFA	Available Economic Capacity	W_OP	0.70%	0.00%	2100	0.60%	1699	-401
LAFA	Available Economic Capacity	SH_SP	23.30%	0.00%	1478	21.60%	1346	-133
LAFA	Available Economic Capacity	SH_P	0.00%	0.00%	3266	0.00%	2582	-684
LAFA	Available Economic Capacity	SH_OP	0.80%	0.00%	1966	1.20%	1538	-428
LCRA	Available Economic Capacity	S_35	0.00%	35.20%	2665	31.50%	2432	-233
LCRA	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	3945	-6055
LCRA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	5000	-5000
LCRA	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	5000	-5000
LCRA	Available Economic Capacity	W_SP	0.00%	5.10%	2399	5.00%	2394	-5
LCRA	Available Economic Capacity	W_P	0.00%	0.00%	5056	0.00%	2563	-2492
LCRA	Available Economic Capacity	W_OP	0.00%	0.00%	5642	0.00%	2926	-2715
LCRA	Available Economic Capacity	SH_SP	0.00%	81.60%	6997	34.00%	2384	-4613
LCRA	Available Economic Capacity	SH_P	0.00%	66.50%	5008	19.20%	1879	-3129
LCRA	Available Economic Capacity	SH_OP	0.00%	0.00%	6074	0.00%	3309	-2766
LGE	Available Economic Capacity	S_35	54.00%	0.00%	3187	51.40%	2939	-248
LGE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_OP	0.00%	0.00%	8415	0.00%	8415	0
LGE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
MPS	Available Economic Capacity	S_35	13.80%	0.00%	1054	13.50%	992	-62
MPS	Available Economic Capacity	S_SP	0.00%	0.00%	2221	0.00%	2080	-142
MPS	Available Economic Capacity	S_P	0.00%	0.00%	2484	0.00%	2484	0
MPS	Available Economic Capacity	S_OP	0.00%	0.00%	3438	0.00%	2501	-937
MPS	Available Economic Capacity	W_SP	0.00%	0.00%	4129	0.00%	4129	0
MPS	Available Economic Capacity	W_P	0.00%	0.00%	4071	0.00%	4071	0
MPS	Available Economic Capacity	W_OP	0.00%	0.00%	2856	0.00%	2856	0
MPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3168	0.00%	1986	-1182
MPS	Available Economic Capacity	SH_P	0.00%	0.00%	8266	0.00%	8266	0
MPS	Available Economic Capacity	SH_OP	0.00%	0.00%	6140	0.00%	6140	0
NIPS	Available Economic Capacity	S_35	28.40%	0.00%	1337	27.60%	1300	-36
NIPS	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_OP	0.00%	0.00%	9560	0.00%	9560	0
NIPS	Available Economic Capacity	SH_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	SH_P	0.00%	0.00%	5985	0.00%	5985	0
NIPS	Available Economic Capacity	SH_OP	0.00%	0.00%	9677	0.00%	9677	0

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
NSP	Available Economic Capacity	S_35	9.90%	0.00%	970	10.80%	992	23
NSP	Available Economic Capacity	S_SP	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	S_P	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	S_OP	0.00%	0.00%	7094	0.00%	7094	0
NSP	Available Economic Capacity	W_SP	0.00%	0.00%	3275	0.00%	3275	0
NSP	Available Economic Capacity	W_P	0.00%	0.00%	4849	0.00%	4849	0
NSP	Available Economic Capacity	W_OP	0.00%	0.00%	8518	0.00%	8518	0
NSP	Available Economic Capacity	SH_SP	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	SH_P	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	SH_OP	0.00%	0.00%	8207	0.00%	8207	0
OKGE	Available Economic Capacity	S_35	4.60%	0.00%	1182	5.20%	1107	-75
OKGE	Available Economic Capacity	S_SP	0.00%	0.00%	3464	0.00%	2842	-622
OKGE	Available Economic Capacity	S_P	0.00%	0.00%	3213	0.00%	1964	-1250
OKGE	Available Economic Capacity	S_OP	0.00%	0.00%	7022	0.00%	3275	-3747
OKGE	Available Economic Capacity	W_SP	0.00%	0.00%	1831	0.00%	1797	-34
OKGE	Available Economic Capacity	W_P	0.00%	0.00%	1736	0.00%	1415	-322
OKGE	Available Economic Capacity	W_OP	0.00%	0.00%	4550	0.00%	2565	-1985
OKGE	Available Economic Capacity	SH_SP	5.90%	0.20%	776	6.60%	739	-37
OKGE	Available Economic Capacity	SH_P	0.00%	0.00%	2271	0.00%	2245	-26
OKGE	Available Economic Capacity	SH_OP	0.00%	0.00%	5869	0.00%	2526	-3343
SCEG	Available Economic Capacity	S_35	94.10%	0.00%	8865	93.10%	8671	-194
SCEG	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	5000	-5000
SCEG	Available Economic Capacity	S_P	99.90%	0.00%	9986	99.90%	9986	0
SCEG	Available Economic Capacity	S_OP	42.20%	0.00%	3714	42.10%	3711	-2
SCEG	Available Economic Capacity	W_SP	67.20%	0.00%	4822	67.20%	4822	0
SCEG	Available Economic Capacity	W_P	18.50%	0.00%	1795	18.20%	1796	0
SCEG	Available Economic Capacity	W_OP	7.40%	0.00%	1805	7.30%	1805	0
SCEG	Available Economic Capacity	SH_SP	65.10%	0.00%	4555	64.00%	4452	-103
SCEG	Available Economic Capacity	SH_P	44.30%	0.00%	2509	44.00%	2485	-24
SCEG	Available Economic Capacity	SH_OP	10.20%	0.00%	1522	10.00%	1523	1
SIGE	Available Economic Capacity	S_35	79.70%	0.00%	6412	78.90%	6292	-120
SIGE	Available Economic Capacity	S_SP	86.20%	0.00%	7454	85.90%	7397	-56
SIGE	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	W_SP	28.50%	0.00%	1961	27.60%	1934	-28
SIGE	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	SH_SP	0.00%	0.00%	2002	0.00%	2002	0
SIGE	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
SOCO	Available Economic Capacity	S_35	76.80%	0.00%	5964	76.80%	5954	-10
SOCO	Available Economic Capacity	S_SP	0.00%	0.00%	4302	0.00%	3113	-1189
SOCO	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	3752	-6248
SOCO	Available Economic Capacity	S_OP	81.40%	0.00%	6756	81.40%	6754	-1
SOCO	Available Economic Capacity	W_SP	0.00%	0.00%	5000	0.00%	5000	0
SOCO	Available Economic Capacity	W_P	0.00%	0.00%	3166	0.00%	3132	-35
SOCO	Available Economic Capacity	W_OP	34.40%	0.00%	3683	32.40%	3681	-2
SOCO	Available Economic Capacity	SH_SP	0.00%	0.00%	10000	0.00%	3480	-6520
SOCO	Available Economic Capacity	SH_P	0.00%	0.00%	4085	0.00%	3965	-120
SOCO	Available Economic Capacity	SH_OP	85.40%	0.00%	7347	85.40%	7340	-7
SPRM	Available Economic Capacity	S_35	3.00%	0.00%	2500	4.40%	2472	-28
SPRM	Available Economic Capacity	S_SP	0.00%	0.00%	5000	0.00%	2552	-2448
SPRM	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
SPRM	Available Economic Capacity	S_OP	0.00%	0.00%	6993	0.00%	6993	0
SPRM	Available Economic Capacity	W_SP	0.00%	0.00%	8188	0.00%	8188	0
SPRM	Available Economic Capacity	W_P	0.00%	0.00%	4718	0.00%	4718	0
SPRM	Available Economic Capacity	W_OP	0.00%	0.00%	3645	0.00%	3645	0
SPRM	Available Economic Capacity	SH_SP	0.00%	0.00%	5743	0.00%	4420	-1323
SPRM	Available Economic Capacity	SH_P	0.00%	0.00%	3868	0.00%	3868	0
SPRM	Available Economic Capacity	SH_OP	0.00%	0.00%	9913	0.00%	9913	0

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
STEC	Available Economic Capacity	S_35	0.00%	54.10%	4054	36.50%	2771	-1282
STEC	Available Economic Capacity	S_SP	0.00%	80.30%	6662	56.00%	3941	-2722
STEC	Available Economic Capacity	S_P	0.00%	65.00%	5449	0.00%	5456	7
STEC	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	5000	-5000
STEC	Available Economic Capacity	W_SP	0.00%	6.00%	3473	5.50%	3504	31
STEC	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
STEC	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
STEC	Available Economic Capacity	SH_SP	0.00%	77.70%	6249	53.80%	3678	-2571
STEC	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
STEC	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
STJO	Available Economic Capacity	S_35	11.30%	0.00%	1391	11.40%	1387	-3
STJO	Available Economic Capacity	S_SP	6.30%	0.00%	817	6.50%	803	-14
STJO	Available Economic Capacity	S_P	0.00%	0.00%	1177	0.00%	1127	-50
STJO	Available Economic Capacity	S_OP	0.00%	0.00%	2288	0.00%	1761	-527
STJO	Available Economic Capacity	W_SP	0.00%	0.00%	984	0.00%	921	-63
STJO	Available Economic Capacity	W_P	0.00%	0.00%	1392	0.00%	1319	-73
STJO	Available Economic Capacity	W_OP	0.00%	0.00%	4757	0.00%	4757	0
STJO	Available Economic Capacity	SH_SP	9.60%	0.00%	826	9.90%	801	-26
STJO	Available Economic Capacity	SH_P	0.00%	0.00%	1058	0.00%	997	-60
STJO	Available Economic Capacity	SH_OP	0.00%	0.00%	5099	0.00%	5099	0
SWEPA	Available Economic Capacity	S_35	4.90%	0.30%	907	4.90%	832	-74
SWEPA	Available Economic Capacity	S_SP	17.10%	0.00%	2396	15.40%	1231	-1165
SWEPA	Available Economic Capacity	S_P	0.00%	0.00%	3332	0.00%	2006	-1326
SWEPA	Available Economic Capacity	S_OP	0.00%	0.00%	2701	0.00%	1773	-928
SWEPA	Available Economic Capacity	W_SP	0.00%	0.00%	1142	0.00%	959	-183
SWEPA	Available Economic Capacity	W_P	0.00%	0.00%	1923	0.00%	1637	-286
SWEPA	Available Economic Capacity	W_OP	0.00%	0.00%	1540	0.00%	1288	-251
SWEPA	Available Economic Capacity	SH_SP	0.00%	0.50%	911	3.70%	723	-188
SWEPA	Available Economic Capacity	SH_P	0.00%	0.00%	2069	0.00%	1795	-273
SWEPA	Available Economic Capacity	SH_OP	0.00%	0.00%	1484	0.00%	1409	-76
SWPS	Available Economic Capacity	S_35	0.80%	0.00%	3998	0.50%	4272	274
SWPS	Available Economic Capacity	S_SP	0.00%	0.00%	6116	0.00%	3519	-2597
SWPS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	4636	-5364
SWPS	Available Economic Capacity	S_OP	0.00%	0.00%	7503	0.00%	3081	-4421
SWPS	Available Economic Capacity	W_SP	0.20%	2.50%	5860	2.20%	6014	154
SWPS	Available Economic Capacity	W_P	0.00%	0.00%	2802	0.00%	2660	-142
SWPS	Available Economic Capacity	W_OP	0.00%	0.00%	4074	0.00%	3191	-883
SWPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3993	0.00%	4322	329
SWPS	Available Economic Capacity	SH_P	0.00%	0.00%	4123	0.00%	3871	-252
SWPS	Available Economic Capacity	SH_OP	0.00%	0.00%	5050	0.00%	3122	-1928
TMPA	Available Economic Capacity	S_35	0.00%	20.20%	2485	18.60%	2399	-86
TMPA	Available Economic Capacity	S_SP	0.00%	78.00%	6563	24.80%	2305	-4258
TMPA	Available Economic Capacity	S_P	0.00%	78.00%	6563	22.60%	2132	-4430
TMPA	Available Economic Capacity	S_OP	0.00%	27.70%	3728	2.60%	1961	-1767
TMPA	Available Economic Capacity	W_SP	0.00%	14.20%	2480	13.80%	2482	2
TMPA	Available Economic Capacity	W_P	0.00%	0.00%	3365	0.00%	2037	-1328
TMPA	Available Economic Capacity	W_OP	0.00%	0.00%	2704	0.00%	2352	-352
TMPA	Available Economic Capacity	SH_SP	0.00%	51.60%	3522	35.00%	2021	-1501
TMPA	Available Economic Capacity	SH_P	0.00%	48.00%	3540	23.10%	1721	-1819
TMPA	Available Economic Capacity	SH_OP	0.00%	32.30%	2735	13.20%	1802	-933
TNMP	Available Economic Capacity	S_35	0.00%	43.60%	3959	41.40%	3774	-185
TNMP	Available Economic Capacity	S_SP	0.00%	78.00%	6563	24.80%	2258	-4304
TNMP	Available Economic Capacity	S_P	0.00%	78.00%	6563	22.80%	2143	-4420
TNMP	Available Economic Capacity	S_OP	0.00%	34.30%	2745	3.20%	1920	-825
TNMP	Available Economic Capacity	W_SP	0.00%	11.20%	3331	11.00%	3322	-9
TNMP	Available Economic Capacity	W_P	0.00%	0.00%	3056	0.00%	2095	-962
TNMP	Available Economic Capacity	W_OP	0.00%	0.00%	2006	0.00%	1720	-286
TNMP	Available Economic Capacity	SH_SP	0.00%	55.60%	3800	34.10%	2124	-1676
TNMP	Available Economic Capacity	SH_P	0.00%	48.90%	3433	27.60%	1835	-1599
TNMP	Available Economic Capacity	SH_OP	0.00%	38.20%	2207	15.60%	1372	-835

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
TU	Available Economic Capacity	S_35	0.40%	36.20%	2717	33.00%	2506	-211
TU	Available Economic Capacity	S_SP	0.00%	59.90%	4147	24.60%	2063	-2083
TU	Available Economic Capacity	S_P	0.00%	43.70%	3030	16.60%	1529	-1501
TU	Available Economic Capacity	S_OP	3.00%	27.30%	1558	3.90%	1316	-241
TU	Available Economic Capacity	W_SP	0.10%	8.30%	6106	8.20%	6105	-1
TU	Available Economic Capacity	W_P	0.00%	0.00%	1542	0.00%	1384	-158
TU	Available Economic Capacity	W_OP	1.70%	0.00%	946	1.90%	897	-49
TU	Available Economic Capacity	SH_SP	3.00%	46.20%	2487	31.00%	1615	-872
TU	Available Economic Capacity	SH_P	0.00%	40.30%	2435	22.70%	1536	-899
TU	Available Economic Capacity	SH_OP	0.90%	31.70%	1651	13.90%	1149	-503
TVA	Available Economic Capacity	S_35	38.80%	0.00%	1870	37.70%	1776	-94
TVA	Available Economic Capacity	S_SP	47.90%	0.00%	2632	47.10%	2537	-95
TVA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_SP	49.70%	0.00%	2666	46.30%	2346	-320
TVA	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
VP	Available Economic Capacity	S_35	67.00%	0.00%	4948	65.90%	4811	-137
VP	Available Economic Capacity	S_SP	100.00%	0.00%	10000	100.00%	10000	0
VP	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	S_OP	100.00%	0.00%	10000	100.00%	10000	0
VP	Available Economic Capacity	W_SP	100.00%	0.00%	10000	100.00%	10000	0
VP	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	SH_SP	80.40%	0.00%	6853	80.40%	6853	0
VP	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	S_35	2.50%	0.00%	2057	3.10%	1984	-73
WEFA	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	5000	-5000
WEFA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	5000	-5000
WEFA	Available Economic Capacity	S_OP	0.00%	0.00%	3595	0.00%	2730	-865
WEFA	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	5000	-5000
WEFA	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	W_OP	0.00%	0.00%	5089	0.00%	2760	-2330
WEFA	Available Economic Capacity	SH_SP	0.00%	0.00%	2554	0.00%	1927	-627
WEFA	Available Economic Capacity	SH_P	0.00%	0.00%	5673	0.00%	2920	-2754
WEFA	Available Economic Capacity	SH_OP	0.00%	0.00%	3675	0.00%	2764	-911
WEP	Available Economic Capacity	S_35	8.50%	0.00%	1584	1.90%	1561	-23
WEP	Available Economic Capacity	S_SP	12.70%	0.00%	1200	1.00%	1172	-29
WEP	Available Economic Capacity	S_P	0.00%	0.00%	1171	0.00%	1171	0
WEP	Available Economic Capacity	S_OP	0.00%	0.00%	4199	0.00%	4199	0
WEP	Available Economic Capacity	W_SP	9.00%	0.00%	1274	6.30%	1279	5
WEP	Available Economic Capacity	W_P	0.00%	0.00%	1631	0.00%	1621	-10
WEP	Available Economic Capacity	W_OP	0.00%	0.00%	2901	0.00%	2901	0
WEP	Available Economic Capacity	SH_SP	6.70%	0.00%	1149	5.20%	1160	11
WEP	Available Economic Capacity	SH_P	0.00%	0.00%	1142	0.00%	1142	0
WEP	Available Economic Capacity	SH_OP	0.00%	0.00%	4256	0.00%	4256	0
WEPL	Available Economic Capacity	S_35	0.60%	0.00%	3495	0.80%	3585	90
WEPL	Available Economic Capacity	S_SP	0.00%	0.00%	3847	0.00%	1972	-1875
WEPL	Available Economic Capacity	S_P	0.00%	0.00%	4606	0.00%	4606	0
WEPL	Available Economic Capacity	S_OP	0.00%	0.00%	7604	0.00%	7604	0
WEPL	Available Economic Capacity	W_SP	0.00%	0.00%	4480	0.00%	4480	0
WEPL	Available Economic Capacity	W_P	0.00%	0.00%	3466	0.00%	3466	0
WEPL	Available Economic Capacity	W_OP	0.00%	0.00%	3655	0.00%	3655	0
WEPL	Available Economic Capacity	SH_SP	0.00%	0.00%	2997	0.00%	2857	-140
WEPL	Available Economic Capacity	SH_P	0.00%	0.00%	3680	0.00%	3104	-576
WEPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5186	0.00%	5186	0

Base Case (Post Mitigation)

Exhibit No. AC-512

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
WR	Available Economic Capacity	S_35	8.10%	0.00%	1289	8.00%	1312	23
WR	Available Economic Capacity	S_SP	0.00%	0.00%	3003	0.00%	2089	-913
WR	Available Economic Capacity	S_P	0.00%	0.00%	4154	0.00%	2295	-1859
WR	Available Economic Capacity	S_OP	0.00%	0.00%	7480	0.00%	7480	0
WR	Available Economic Capacity	W_SP	0.00%	0.00%	1876	0.00%	1448	-428
WR	Available Economic Capacity	W_P	0.00%	0.00%	3205	0.00%	2274	-931
WR	Available Economic Capacity	W_OP	0.00%	0.00%	3305	0.00%	2813	-492
WR	Available Economic Capacity	SH_SP	0.00%	0.00%	1787	0.00%	1481	-305
WR	Available Economic Capacity	SH_P	0.00%	0.00%	2466	0.00%	1741	-725
WR	Available Economic Capacity	SH_OP	0.00%	0.00%	5121	0.00%	3541	-1580

Sensitivity: AEP in MISO **Exhibit No. AC-513**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Economic Capacity	S_35	0.70%	0.80%	1192	1.50%	1192	1
AECI	Economic Capacity	S_SP	1.10%	0.90%	1263	2.00%	1265	1
AECI	Economic Capacity	S_P	1.10%	4.30%	1087	5.40%	1094	7
AECI	Economic Capacity	S_OP	1.30%	3.70%	1166	5.00%	1173	7
AECI	Economic Capacity	W_SP	1.10%	5.90%	1268	6.80%	1277	10
AECI	Economic Capacity	W_P	1.60%	4.80%	1394	6.10%	1404	10
AECI	Economic Capacity	W_OP	1.80%	6.70%	1476	8.10%	1491	15
AECI	Economic Capacity	SH_SP	1.00%	3.40%	787	4.40%	791	4
AECI	Economic Capacity	SH_P	1.50%	2.70%	796	4.30%	801	5
AECI	Economic Capacity	SH_OP	1.70%	2.70%	815	4.50%	823	8
AEP	Economic Capacity	S_35	37.10%	0.00%	1607	36.90%	1589	-18
AEP	Economic Capacity	S_SP	48.70%	0.00%	2554	48.40%	2529	-25
AEP	Economic Capacity	S_P	48.20%	0.00%	2541	47.90%	2514	-27
AEP	Economic Capacity	S_OP	37.20%	0.00%	1760	37.20%	1760	0
AEP	Economic Capacity	W_SP	48.60%	0.00%	2595	48.30%	2570	-25
AEP	Economic Capacity	W_P	48.10%	0.00%	2553	47.80%	2527	-26
AEP	Economic Capacity	W_OP	43.90%	0.00%	2212	43.50%	2183	-29
AEP	Economic Capacity	SH_SP	41.70%	0.20%	1948	41.60%	1940	-8
AEP	Economic Capacity	SH_P	42.00%	0.00%	2002	41.70%	1980	-21
AEP	Economic Capacity	SH_OP	37.00%	0.00%	1675	36.60%	1651	-24
ALLIANT_E	Economic Capacity	S_35	1.70%	0.00%	2582	1.70%	2581	-1
ALLIANT_E	Economic Capacity	S_SP	2.20%	0.00%	2384	2.20%	2384	-1
ALLIANT_E	Economic Capacity	S_P	2.20%	0.00%	2423	2.20%	2423	0
ALLIANT_E	Economic Capacity	S_OP	1.80%	0.00%	1099	1.80%	1089	-10
ALLIANT_E	Economic Capacity	W_SP	1.80%	0.00%	1730	1.90%	1728	-2
ALLIANT_E	Economic Capacity	W_P	2.40%	0.00%	1755	2.50%	1753	-2
ALLIANT_E	Economic Capacity	W_OP	10.00%	0.00%	973	10.00%	972	-1
ALLIANT_E	Economic Capacity	SH_SP	2.80%	0.00%	1584	3.00%	1580	-4
ALLIANT_E	Economic Capacity	SH_P	3.80%	0.00%	1478	4.00%	1476	-2
ALLIANT_E	Economic Capacity	SH_OP	9.20%	0.00%	1264	11.50%	1236	-28
AMEREN	Economic Capacity	S_35	1.90%	2.30%	2482	4.80%	2494	12
AMEREN	Economic Capacity	S_SP	1.90%	2.40%	2490	4.70%	2501	11
AMEREN	Economic Capacity	S_P	2.00%	3.50%	2435	5.90%	2452	17
AMEREN	Economic Capacity	S_OP	4.80%	0.00%	2612	6.00%	2596	-15
AMEREN	Economic Capacity	W_SP	1.80%	0.60%	2265	3.10%	2202	-62
AMEREN	Economic Capacity	W_P	2.00%	0.00%	2427	2.70%	2342	-85
AMEREN	Economic Capacity	W_OP	5.90%	0.00%	2274	7.00%	2171	-103
AMEREN	Economic Capacity	SH_SP	3.10%	2.70%	1767	6.40%	1749	-18
AMEREN	Economic Capacity	SH_P	3.20%	2.00%	1852	5.80%	1846	-6
AMEREN	Economic Capacity	SH_OP	0.90%	0.00%	1683	0.70%	1683	0
CIN	Economic Capacity	S_35	14.00%	0.10%	2096	14.00%	2096	1
CIN	Economic Capacity	S_SP	10.10%	0.00%	2683	10.10%	2677	-6
CIN	Economic Capacity	S_P	13.50%	0.00%	1628	13.50%	1629	1
CIN	Economic Capacity	S_OP	14.90%	0.00%	1544	14.90%	1545	2
CIN	Economic Capacity	W_SP	9.70%	0.00%	2837	9.70%	2832	-5
CIN	Economic Capacity	W_P	8.00%	0.00%	1627	7.80%	1626	-1
CIN	Economic Capacity	W_OP	13.90%	0.00%	2073	13.70%	2070	-3
CIN	Economic Capacity	SH_SP	10.30%	0.00%	1897	10.30%	1898	0
CIN	Economic Capacity	SH_P	10.40%	0.00%	1848	10.40%	1849	0
CIN	Economic Capacity	SH_OP	12.10%	0.00%	1410	12.10%	1410	1

Sensitivity: AEP in MISO

Exhibit No. AC-513

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Economic Capacity	S_35	5.60%	0.00%	5698	5.60%	5698	0
COMED	Economic Capacity	S_SP	5.70%	0.00%	5617	5.70%	5617	0
COMED	Economic Capacity	S_P	4.30%	0.00%	5086	4.20%	5088	1
COMED	Economic Capacity	S_OP	4.60%	0.00%	4155	4.50%	4154	-1
COMED	Economic Capacity	W_SP	6.60%	0.40%	3724	6.90%	3728	4
COMED	Economic Capacity	W_P	8.70%	0.00%	3525	8.60%	3524	-1
COMED	Economic Capacity	W_OP	10.00%	0.00%	3119	9.90%	3118	-1
COMED	Economic Capacity	SH_SP	9.30%	0.30%	2929	9.60%	2934	5
COMED	Economic Capacity	SH_P	11.00%	0.00%	3074	11.00%	3074	0
COMED	Economic Capacity	SH_OP	12.30%	0.00%	2451	12.30%	2450	-1
CSW_SPP	Economic Capacity	S_35	0.20%	63.40%	4114	62.60%	4009	-105
CSW_SPP	Economic Capacity	S_SP	0.30%	62.00%	3936	61.10%	3831	-106
CSW_SPP	Economic Capacity	S_P	0.30%	53.40%	3057	52.50%	2967	-89
CSW_SPP	Economic Capacity	S_OP	0.40%	49.00%	2645	48.00%	2557	-88
CSW_SPP	Economic Capacity	W_SP	0.40%	56.50%	3306	56.00%	3246	-60
CSW_SPP	Economic Capacity	W_P	0.80%	37.70%	1654	37.50%	1636	-18
CSW_SPP	Economic Capacity	W_OP	0.90%	37.80%	1661	37.70%	1644	-17
CSW_SPP	Economic Capacity	SH_SP	0.60%	50.60%	2703	50.30%	2671	-32
CSW_SPP	Economic Capacity	SH_P	0.90%	36.50%	1560	36.60%	1571	10
CSW_SPP	Economic Capacity	SH_OP	1.20%	33.10%	1363	33.50%	1386	23
ENT	Economic Capacity	S_35	0.20%	0.40%	5419	0.70%	5419	0
ENT	Economic Capacity	S_SP	0.70%	1.10%	2659	1.80%	2661	1
ENT	Economic Capacity	S_P	0.80%	0.90%	2770	1.70%	2773	4
ENT	Economic Capacity	S_OP	1.00%	0.00%	3027	1.00%	3027	0
ENT	Economic Capacity	W_SP	0.20%	3.50%	5283	3.50%	5292	8
ENT	Economic Capacity	W_P	0.60%	0.00%	2752	0.70%	2767	14
ENT	Economic Capacity	W_OP	0.80%	1.50%	2830	1.90%	2851	20
ENT	Economic Capacity	SH_SP	0.40%	5.90%	3729	6.20%	3731	2
ENT	Economic Capacity	SH_P	0.90%	7.60%	1663	8.50%	1673	10
ENT	Economic Capacity	SH_OP	1.20%	5.90%	1685	7.10%	1697	12
IP	Economic Capacity	S_35	4.70%	0.50%	1928	5.10%	1932	4
IP	Economic Capacity	S_SP	4.70%	0.40%	1960	5.10%	1964	4
IP	Economic Capacity	S_P	5.50%	0.50%	1853	5.90%	1858	6
IP	Economic Capacity	S_OP	7.30%	0.40%	1993	7.60%	1999	5
IP	Economic Capacity	W_SP	5.20%	0.60%	1809	5.80%	1816	6
IP	Economic Capacity	W_P	6.40%	0.00%	2035	6.30%	2035	0
IP	Economic Capacity	W_OP	7.30%	0.00%	1844	7.30%	1843	0
IP	Economic Capacity	SH_SP	5.00%	0.70%	1579	5.60%	1586	7
IP	Economic Capacity	SH_P	5.80%	0.40%	1605	6.20%	1610	4
IP	Economic Capacity	SH_OP	5.60%	0.00%	1202	5.60%	1203	0
KCPL	Economic Capacity	S_35	0.60%	0.40%	2625	1.10%	2625	0
KCPL	Economic Capacity	S_SP	0.50%	0.40%	3052	1.00%	3051	0
KCPL	Economic Capacity	S_P	0.50%	1.30%	2409	1.80%	2410	0
KCPL	Economic Capacity	S_OP	1.20%	0.00%	2547	1.40%	2548	1
KCPL	Economic Capacity	W_SP	1.10%	1.90%	1667	3.00%	1669	1
KCPL	Economic Capacity	W_P	1.40%	2.10%	1925	3.50%	1930	5
KCPL	Economic Capacity	W_OP	4.90%	0.00%	1557	4.70%	1558	1
KCPL	Economic Capacity	SH_SP	1.00%	2.00%	1465	3.00%	1467	2
KCPL	Economic Capacity	SH_P	1.20%	1.80%	1363	3.10%	1364	1
KCPL	Economic Capacity	SH_OP	6.30%	0.00%	778	6.50%	772	-6

Sensitivity: AEP in MISO **Exhibit No. AC-513**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
LGE	Economic Capacity	S_35	8.00%	0.10%	2995	8.00%	2996	1
LGE	Economic Capacity	S_SP	11.20%	0.00%	913	11.20%	913	0
LGE	Economic Capacity	S_P	9.50%	0.00%	955	9.50%	955	0
LGE	Economic Capacity	S_OP	6.60%	0.00%	885	6.60%	885	0
LGE	Economic Capacity	W_SP	22.40%	0.00%	1898	22.20%	1891	-7
LGE	Economic Capacity	W_P	22.50%	0.00%	1994	22.50%	1994	0
LGE	Economic Capacity	W_OP	20.80%	0.00%	1218	20.80%	1218	0
LGE	Economic Capacity	SH_SP	20.20%	0.00%	1555	20.20%	1555	0
LGE	Economic Capacity	SH_P	20.20%	0.00%	1607	20.20%	1607	0
LGE	Economic Capacity	SH_OP	7.30%	0.00%	919	7.30%	919	0
MPS	Economic Capacity	S_35	0.70%	0.00%	4590	0.80%	4714	123
MPS	Economic Capacity	S_SP	1.40%	0.00%	3805	1.60%	3802	-3
MPS	Economic Capacity	S_P	1.60%	0.00%	2560	1.90%	2556	-4
MPS	Economic Capacity	S_OP	2.10%	0.00%	2022	2.40%	2014	-7
MPS	Economic Capacity	W_SP	4.50%	0.00%	1002	5.00%	991	-11
MPS	Economic Capacity	W_P	4.00%	0.00%	830	4.40%	823	-7
MPS	Economic Capacity	W_OP	6.00%	0.00%	861	6.50%	855	-6
MPS	Economic Capacity	SH_SP	3.30%	0.00%	1383	3.80%	1377	-6
MPS	Economic Capacity	SH_P	6.40%	0.00%	963	7.20%	951	-12
MPS	Economic Capacity	SH_OP	9.90%	0.00%	1073	10.70%	1055	-18
NIPS	Economic Capacity	S_35	13.50%	0.10%	1981	13.50%	1982	1
NIPS	Economic Capacity	S_SP	10.00%	0.00%	1237	10.00%	1237	0
NIPS	Economic Capacity	S_P	11.50%	0.00%	1219	11.50%	1219	0
NIPS	Economic Capacity	S_OP	11.30%	0.00%	1207	11.30%	1207	0
NIPS	Economic Capacity	W_SP	11.00%	0.00%	1089	11.00%	1089	0
NIPS	Economic Capacity	W_P	9.70%	0.00%	1095	9.70%	1095	0
NIPS	Economic Capacity	W_OP	11.40%	0.00%	1124	11.40%	1124	0
NIPS	Economic Capacity	SH_SP	6.70%	0.00%	1220	6.70%	1220	0
NIPS	Economic Capacity	SH_P	6.70%	0.00%	1227	6.70%	1227	0
NIPS	Economic Capacity	SH_OP	7.50%	0.00%	1109	7.50%	1109	0
OKGE	Economic Capacity	S_35	0.10%	2.50%	5724	2.60%	5724	0
OKGE	Economic Capacity	S_SP	0.20%	2.30%	5825	2.50%	5825	0
OKGE	Economic Capacity	S_P	0.40%	20.60%	2458	20.60%	2456	-1
OKGE	Economic Capacity	S_OP	1.00%	14.30%	2444	14.00%	2426	-18
OKGE	Economic Capacity	W_SP	0.20%	6.10%	4085	6.20%	4086	1
OKGE	Economic Capacity	W_P	0.60%	11.60%	2126	12.00%	2129	3
OKGE	Economic Capacity	W_OP	1.40%	0.00%	2402	1.70%	2383	-19
OKGE	Economic Capacity	SH_SP	0.20%	6.10%	3795	6.30%	3797	2
OKGE	Economic Capacity	SH_P	0.70%	7.30%	1808	8.00%	1812	4
OKGE	Economic Capacity	SH_OP	1.70%	2.90%	2113	5.30%	2109	-4
STJO	Economic Capacity	S_35	1.30%	0.90%	1134	2.30%	1137	2
STJO	Economic Capacity	S_SP	1.10%	0.90%	1175	2.10%	1177	2
STJO	Economic Capacity	S_P	1.40%	3.50%	1139	4.90%	1147	8
STJO	Economic Capacity	S_OP	3.50%	0.00%	1037	3.80%	1024	-13
STJO	Economic Capacity	W_SP	2.30%	3.10%	727	5.60%	735	8
STJO	Economic Capacity	W_P	2.50%	2.50%	765	5.00%	771	6
STJO	Economic Capacity	W_OP	11.40%	0.00%	840	11.50%	835	-5
STJO	Economic Capacity	SH_SP	1.50%	2.50%	567	4.10%	570	3
STJO	Economic Capacity	SH_P	1.70%	1.40%	673	3.20%	676	2
STJO	Economic Capacity	SH_OP	7.50%	0.00%	912	7.60%	905	-7

Sensitivity: AEP in MISO **Exhibit No. AC-513**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
SWEPA	Economic Capacity	S_35	0.40%	5.10%	1423	5.50%	1426	3
SWEPA	Economic Capacity	S_SP	0.50%	5.50%	1278	5.90%	1275	-3
SWEPA	Economic Capacity	S_P	0.60%	0.00%	1509	0.70%	1509	0
SWEPA	Economic Capacity	S_OP	0.90%	9.90%	892	9.60%	884	-9
SWEPA	Economic Capacity	W_SP	0.90%	11.00%	709	11.80%	723	13
SWEPA	Economic Capacity	W_P	2.40%	6.80%	753	9.00%	769	16
SWEPA	Economic Capacity	W_OP	2.90%	13.30%	630	15.60%	664	34
SWEPA	Economic Capacity	SH_SP	1.70%	0.00%	1080	1.80%	1081	1
SWEPA	Economic Capacity	SH_P	2.50%	0.00%	934	2.70%	933	-1
SWEPA	Economic Capacity	SH_OP	4.30%	0.00%	724	4.60%	710	-14
TVA	Economic Capacity	S_35	14.40%	0.00%	845	14.30%	843	-2
TVA	Economic Capacity	S_SP	14.60%	0.20%	820	14.70%	823	3
TVA	Economic Capacity	S_P	6.60%	0.00%	973	6.60%	973	0
TVA	Economic Capacity	S_OP	6.30%	0.00%	1253	6.30%	1254	1
TVA	Economic Capacity	W_SP	9.10%	0.00%	826	9.10%	826	0
TVA	Economic Capacity	W_P	0.80%	0.00%	746	0.80%	746	0
TVA	Economic Capacity	W_OP	0.40%	0.00%	931	0.40%	950	20
TVA	Economic Capacity	SH_SP	14.50%	1.00%	735	15.40%	761	27
TVA	Economic Capacity	SH_P	11.10%	0.00%	1008	11.20%	1011	3
TVA	Economic Capacity	SH_OP	0.40%	0.00%	1186	0.40%	1193	8
WR	Economic Capacity	S_35	0.30%	0.70%	4684	1.00%	4709	25
WR	Economic Capacity	S_SP	0.50%	0.80%	3505	1.40%	3505	0
WR	Economic Capacity	S_P	1.10%	0.80%	3863	1.70%	3879	16
WR	Economic Capacity	S_OP	1.40%	0.00%	2069	1.40%	2070	1
WR	Economic Capacity	W_SP	2.10%	1.30%	2585	3.40%	2590	5
WR	Economic Capacity	W_P	2.80%	0.00%	2671	2.90%	2671	0
WR	Economic Capacity	W_OP	3.30%	0.00%	2910	3.50%	2908	-2
WR	Economic Capacity	SH_SP	0.50%	1.60%	2366	2.00%	2367	1
WR	Economic Capacity	SH_P	1.80%	0.00%	2251	2.00%	2247	-4
WR	Economic Capacity	SH_OP	3.50%	0.00%	1815	3.80%	1802	-13

Sensitivity: AEP in MISO

Exhibit No. AC-513

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Available Economic Capacity	S_35	11.90%	0.00%	1310	12.10%	1272	-38
AECI	Available Economic Capacity	S_SP	37.30%	0.00%	1971	33.60%	1666	-305
AECI	Available Economic Capacity	S_P	19.10%	0.00%	1423	14.50%	1220	-203
AECI	Available Economic Capacity	S_OP	8.50%	0.00%	1534	8.60%	1369	-165
AECI	Available Economic Capacity	W_SP	7.80%	0.00%	807	8.00%	784	-23
AECI	Available Economic Capacity	W_P	11.10%	0.00%	908	11.40%	899	-9
AECI	Available Economic Capacity	W_OP	3.90%	0.00%	1053	4.30%	1033	-20
AECI	Available Economic Capacity	SH_SP	40.40%	0.30%	1934	39.70%	1862	-72
AECI	Available Economic Capacity	SH_P	13.60%	0.00%	1056	13.50%	977	-79
AECI	Available Economic Capacity	SH_OP	5.80%	0.00%	970	6.20%	899	-71
AEP	Available Economic Capacity	S_35	34.70%	0.00%	1556	32.80%	1447	-109
AEP	Available Economic Capacity	S_SP	96.50%	0.00%	9315	87.50%	7697	-1618
AEP	Available Economic Capacity	S_P	86.60%	0.00%	7563	86.00%	7453	-111
AEP	Available Economic Capacity	S_OP	0.00%	0.00%	9406	0.00%	9406	0
AEP	Available Economic Capacity	W_SP	69.70%	0.00%	5053	63.90%	4291	-761
AEP	Available Economic Capacity	W_P	75.00%	0.00%	5794	73.90%	5646	-148
AEP	Available Economic Capacity	W_OP	56.50%	0.00%	3664	52.80%	3344	-320
AEP	Available Economic Capacity	SH_SP	42.80%	0.00%	2534	39.50%	2251	-283
AEP	Available Economic Capacity	SH_P	70.40%	0.00%	5118	65.80%	4504	-614
AEP	Available Economic Capacity	SH_OP	58.20%	0.00%	4175	50.90%	3676	-498
ALLIANT_E	Available Economic Capacity	S_35	39.40%	0.00%	1969	39.70%	1981	12
ALLIANT_E	Available Economic Capacity	S_SP	79.50%	0.00%	6395	79.70%	6433	38
ALLIANT_E	Available Economic Capacity	S_P	70.50%	0.00%	5205	70.30%	5190	-15
ALLIANT_E	Available Economic Capacity	S_OP	0.00%	0.00%	7083	0.00%	7083	0
ALLIANT_E	Available Economic Capacity	W_SP	12.40%	0.00%	1025	12.60%	1027	2
ALLIANT_E	Available Economic Capacity	W_P	38.40%	0.00%	2043	38.90%	2074	31
ALLIANT_E	Available Economic Capacity	W_OP	0.00%	0.00%	8511	0.00%	8511	0
ALLIANT_E	Available Economic Capacity	SH_SP	74.00%	0.00%	5634	74.10%	5640	7
ALLIANT_E	Available Economic Capacity	SH_P	68.10%	0.00%	4840	64.80%	4409	-431
ALLIANT_E	Available Economic Capacity	SH_OP	0.00%	0.00%	7070	0.00%	7070	0
AMEREN	Available Economic Capacity	S_35	18.10%	0.00%	706	18.90%	712	7
AMEREN	Available Economic Capacity	S_SP	5.70%	1.00%	393	7.40%	396	3
AMEREN	Available Economic Capacity	S_P	22.10%	0.00%	1160	18.90%	1011	-149
AMEREN	Available Economic Capacity	S_OP	24.80%	0.00%	2523	28.50%	2476	-47
AMEREN	Available Economic Capacity	W_SP	4.70%	0.00%	656	5.80%	630	-26
AMEREN	Available Economic Capacity	W_P	6.70%	0.00%	1108	7.90%	1029	-79
AMEREN	Available Economic Capacity	W_OP	30.50%	0.00%	2262	22.80%	2110	-151
AMEREN	Available Economic Capacity	SH_SP	25.40%	0.30%	990	26.70%	1025	35
AMEREN	Available Economic Capacity	SH_P	15.30%	0.00%	1326	17.40%	1323	-3
AMEREN	Available Economic Capacity	SH_OP	0.00%	0.00%	4776	0.00%	4776	0
CIN	Available Economic Capacity	S_35	50.50%	0.00%	2895	46.60%	2536	-360
CIN	Available Economic Capacity	S_SP	97.50%	0.00%	9499	97.30%	9461	-38
CIN	Available Economic Capacity	S_P	79.10%	0.00%	6401	78.20%	6287	-113
CIN	Available Economic Capacity	S_OP	82.40%	0.00%	6956	81.10%	6765	-191
CIN	Available Economic Capacity	W_SP	47.40%	0.00%	2780	46.00%	2655	-125
CIN	Available Economic Capacity	W_P	66.00%	0.00%	4745	63.60%	4484	-261
CIN	Available Economic Capacity	W_OP	69.30%	0.00%	5066	68.10%	4926	-140
CIN	Available Economic Capacity	SH_SP	0.00%	0.00%	3973	0.00%	2216	-1757
CIN	Available Economic Capacity	SH_P	72.90%	0.00%	5554	70.70%	5277	-277
CIN	Available Economic Capacity	SH_OP	62.40%	0.00%	4483	57.60%	3806	-677

Sensitivity: AEP in MISO

Exhibit No. AC-513

Market	Analysis	Period	BASE AEP Mkt Share	BASE CSW Mkt Share	BASE HHI Pre-Merger	MERGER Merged Mkt Share	MERGER HHI Post-Merger	MERGER HHI Change
COMED	Available Economic Capacity	S_35	26.60%	0.00%	1896	26.40%	1881	-15
COMED	Available Economic Capacity	S_SP	42.50%	0.00%	2966	41.70%	2891	-76
COMED	Available Economic Capacity	S_P	64.00%	0.00%	4597	64.00%	4597	0
COMED	Available Economic Capacity	S_OP	77.90%	0.00%	6329	76.10%	6094	-235
COMED	Available Economic Capacity	W_SP	19.40%	0.00%	964	18.80%	944	-20
COMED	Available Economic Capacity	W_P	46.00%	0.00%	2594	45.60%	2557	-37
COMED	Available Economic Capacity	W_OP	50.00%	0.00%	3144	48.60%	3061	-83
COMED	Available Economic Capacity	SH_SP	31.60%	0.00%	1307	30.50%	1242	-65
COMED	Available Economic Capacity	SH_P	25.10%	0.00%	1403	24.50%	1371	-33
COMED	Available Economic Capacity	SH_OP	58.30%	0.00%	3759	55.90%	3492	-268
CSW_SPP	Available Economic Capacity	S_35	8.30%	8.10%	676	13.80%	688	12
CSW_SPP	Available Economic Capacity	S_SP	26.10%	12.90%	1239	25.80%	1147	-93
CSW_SPP	Available Economic Capacity	S_P	7.40%	17.10%	909	10.80%	797	-112
CSW_SPP	Available Economic Capacity	S_OP	6.60%	0.00%	859	3.80%	834	-25
CSW_SPP	Available Economic Capacity	W_SP	3.30%	26.60%	1076	26.30%	1069	-7
CSW_SPP	Available Economic Capacity	W_P	11.10%	0.00%	1285	9.70%	1106	-179
CSW_SPP	Available Economic Capacity	W_OP	5.40%	0.00%	897	5.40%	767	-131
CSW_SPP	Available Economic Capacity	SH_SP	17.70%	11.70%	839	22.10%	889	50
CSW_SPP	Available Economic Capacity	SH_P	6.70%	8.50%	1492	9.30%	1317	-174
CSW_SPP	Available Economic Capacity	SH_OP	6.30%	0.00%	1157	6.10%	1076	-81
ENT	Available Economic Capacity	S_35	13.50%	0.00%	2066	13.40%	2021	-45
ENT	Available Economic Capacity	S_SP	18.60%	0.00%	2783	0.00%	2366	-417
ENT	Available Economic Capacity	S_P	1.00%	0.00%	2384	0.80%	1706	-678
ENT	Available Economic Capacity	S_OP	2.70%	0.00%	6980	2.30%	5536	-1443
ENT	Available Economic Capacity	W_SP	3.70%	0.00%	3933	3.70%	3872	-61
ENT	Available Economic Capacity	W_P	17.20%	0.00%	1077	17.50%	1044	-34
ENT	Available Economic Capacity	W_OP	1.60%	0.00%	922	2.10%	826	-95
ENT	Available Economic Capacity	SH_SP	25.50%	0.70%	1162	25.60%	1119	-42
ENT	Available Economic Capacity	SH_P	34.60%	0.00%	1649	33.30%	1520	-128
ENT	Available Economic Capacity	SH_OP	2.70%	0.00%	972	2.90%	885	-36
IP	Available Economic Capacity	S_35	16.40%	0.00%	773	15.90%	755	-18
IP	Available Economic Capacity	S_SP	21.30%	0.00%	947	20.70%	913	-34
IP	Available Economic Capacity	S_P	26.40%	0.00%	1321	27.50%	1356	35
IP	Available Economic Capacity	S_OP	22.60%	0.00%	1708	22.30%	1671	-38
IP	Available Economic Capacity	W_SP	18.70%	0.00%	886	18.20%	866	-19
IP	Available Economic Capacity	W_P	21.00%	0.00%	1293	20.60%	1264	-29
IP	Available Economic Capacity	W_OP	24.60%	0.00%	1497	24.30%	1473	-24
IP	Available Economic Capacity	SH_SP	45.30%	0.00%	2372	43.20%	2192	-180
IP	Available Economic Capacity	SH_P	31.40%	0.00%	1925	30.60%	1839	-87
IP	Available Economic Capacity	SH_OP	40.10%	0.00%	2407	39.60%	2319	-88
KCPL	Available Economic Capacity	S_35	13.70%	0.00%	1060	14.30%	1032	-28
KCPL	Available Economic Capacity	S_SP	7.40%	0.00%	692	7.70%	682	-10
KCPL	Available Economic Capacity	S_P	12.60%	0.00%	1136	12.10%	948	-188
KCPL	Available Economic Capacity	S_OP	29.60%	0.00%	2282	27.70%	1889	-393
KCPL	Available Economic Capacity	W_SP	13.80%	0.00%	801	13.70%	735	-66
KCPL	Available Economic Capacity	W_P	7.30%	0.00%	796	8.30%	769	-27
KCPL	Available Economic Capacity	W_OP	0.00%	0.00%	5213	0.00%	5213	0
KCPL	Available Economic Capacity	SH_SP	14.20%	0.00%	1001	14.30%	933	-68
KCPL	Available Economic Capacity	SH_P	15.90%	0.00%	1908	17.30%	1644	-264
KCPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5725	0.00%	5725	0

Sensitivity: AEP in MISO

Exhibit No. AC-513

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
LGE	Available Economic Capacity	S_35	54.50%	0.00%	3238	52.10%	3008	-230
LGE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_OP	0.00%	0.00%	8409	0.00%	8409	0
LGE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
MPS	Available Economic Capacity	S_35	13.80%	0.00%	1058	13.40%	993	-65
MPS	Available Economic Capacity	S_SP	83.40%	0.00%	7097	84.10%	7159	62
MPS	Available Economic Capacity	S_P	41.70%	0.00%	2984	42.20%	3018	33
MPS	Available Economic Capacity	S_OP	33.00%	0.00%	3933	34.50%	3253	-680
MPS	Available Economic Capacity	W_SP	0.00%	0.00%	4129	0.00%	4129	0
MPS	Available Economic Capacity	W_P	0.00%	0.00%	4071	0.00%	4071	0
MPS	Available Economic Capacity	W_OP	0.00%	0.00%	2856	0.00%	2856	0
MPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3168	0.00%	1986	-1182
MPS	Available Economic Capacity	SH_P	0.00%	0.00%	8266	0.00%	8266	0
MPS	Available Economic Capacity	SH_OP	0.00%	0.00%	6140	0.00%	6140	0
NIPS	Available Economic Capacity	S_35	51.10%	0.00%	2883	49.80%	2756	-127
NIPS	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	SH_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
OKGE	Available Economic Capacity	S_35	4.60%	0.00%	1182	5.20%	1107	-75
OKGE	Available Economic Capacity	S_SP	24.60%	0.00%	3123	24.70%	2611	-512
OKGE	Available Economic Capacity	S_P	39.40%	0.00%	2789	26.80%	1832	-957
OKGE	Available Economic Capacity	S_OP	0.00%	0.00%	7022	0.00%	3275	-3747
OKGE	Available Economic Capacity	W_SP	3.70%	0.00%	1748	4.20%	1707	-40
OKGE	Available Economic Capacity	W_P	15.70%	0.00%	1508	16.20%	1298	-209
OKGE	Available Economic Capacity	W_OP	0.00%	0.00%	4550	0.00%	2565	-1985
OKGE	Available Economic Capacity	SH_SP	5.70%	0.20%	855	6.50%	806	-48
OKGE	Available Economic Capacity	SH_P	4.80%	0.00%	1482	6.40%	1377	-104
OKGE	Available Economic Capacity	SH_OP	0.00%	0.00%	5869	0.00%	2526	-3343
STJO	Available Economic Capacity	S_35	11.40%	0.00%	1177	11.50%	1162	-14
STJO	Available Economic Capacity	S_SP	7.10%	0.00%	619	7.40%	603	-16
STJO	Available Economic Capacity	S_P	8.40%	0.00%	1160	8.50%	1098	-63
STJO	Available Economic Capacity	S_OP	13.90%	0.00%	2247	12.00%	1745	-502
STJO	Available Economic Capacity	W_SP	13.00%	0.00%	952	13.10%	871	-81
STJO	Available Economic Capacity	W_P	9.70%	0.00%	1138	10.10%	1063	-75
STJO	Available Economic Capacity	W_OP	0.00%	0.00%	4757	0.00%	4757	0
STJO	Available Economic Capacity	SH_SP	15.60%	0.00%	1000	15.10%	952	-48
STJO	Available Economic Capacity	SH_P	10.10%	0.00%	1029	10.20%	973	-57
STJO	Available Economic Capacity	SH_OP	0.00%	0.00%	5099	0.00%	5099	0

Sensitivity: AEP in MISO

Exhibit No. AC-513

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
SWEPA	Available Economic Capacity	S_35	4.90%	0.30%	907	4.90%	833	-75
SWEPA	Available Economic Capacity	S_SP	24.40%	0.00%	2464	22.00%	1420	-1044
SWEPA	Available Economic Capacity	S_P	18.10%	0.00%	3408	12.10%	2034	-1373
SWEPA	Available Economic Capacity	S_OP	8.90%	0.00%	2546	7.50%	1710	-836
SWEPA	Available Economic Capacity	W_SP	7.90%	0.00%	1110	7.50%	933	-177
SWEPA	Available Economic Capacity	W_P	26.70%	0.00%	1763	24.90%	1519	-244
SWEPA	Available Economic Capacity	W_OP	18.10%	0.00%	1459	17.90%	1238	-220
SWEPA	Available Economic Capacity	SH_SP	23.70%	0.50%	1277	22.00%	1053	-224
SWEPA	Available Economic Capacity	SH_P	20.30%	0.00%	1290	18.70%	1155	-135
SWEPA	Available Economic Capacity	SH_OP	22.10%	0.00%	1564	20.30%	1417	-147
TVA	Available Economic Capacity	S_35	40.90%	0.00%	2027	39.70%	1924	-103
TVA	Available Economic Capacity	S_SP	55.70%	0.00%	3391	52.30%	3025	-367
TVA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_SP	47.20%	0.00%	2487	43.90%	2196	-291
TVA	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
WR	Available Economic Capacity	S_35	8.00%	0.00%	1317	7.90%	1325	9
WR	Available Economic Capacity	S_SP	63.90%	0.00%	4572	47.00%	2770	-1802
WR	Available Economic Capacity	S_P	0.00%	0.00%	4154	0.00%	2295	-1859
WR	Available Economic Capacity	S_OP	0.00%	0.00%	7480	0.00%	7480	0
WR	Available Economic Capacity	W_SP	0.00%	0.00%	1876	0.00%	1448	-428
WR	Available Economic Capacity	W_P	0.00%	0.00%	3205	0.00%	2274	-931
WR	Available Economic Capacity	W_OP	0.00%	0.00%	3305	0.00%	2813	-492
WR	Available Economic Capacity	SH_SP	40.00%	0.00%	2483	36.30%	2085	-398
WR	Available Economic Capacity	SH_P	23.40%	0.00%	1994	6.40%	1567	-427
WR	Available Economic Capacity	SH_OP	0.00%	0.00%	5121	0.00%	3541	-1580

Sensitivity: No Transmission Costs **Exhibit No. AC-514**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Economic Capacity	S_35	0.90%	0.60%	1064	1.70%	1063	-1
AECI	Economic Capacity	S_SP	1.10%	0.70%	1091	1.90%	1090	-1
AECI	Economic Capacity	S_P	0.90%	3.80%	898	4.70%	900	2
AECI	Economic Capacity	S_OP	1.10%	3.60%	914	4.70%	917	4
AECI	Economic Capacity	W_SP	1.00%	4.80%	1103	5.80%	1110	8
AECI	Economic Capacity	W_P	1.10%	3.40%	1091	4.80%	1095	4
AECI	Economic Capacity	W_OP	1.00%	3.90%	1131	4.80%	1137	6
AECI	Economic Capacity	SH_SP	1.20%	3.90%	780	5.10%	787	7
AECI	Economic Capacity	SH_P	1.30%	2.70%	778	4.10%	783	4
AECI	Economic Capacity	SH_OP	1.70%	2.30%	766	4.10%	769	3
AEP	Economic Capacity	S_35	37.10%	0.10%	1590	37.00%	1579	-11
AEP	Economic Capacity	S_SP	37.00%	0.10%	1586	36.80%	1573	-13
AEP	Economic Capacity	S_P	35.70%	0.00%	1506	35.50%	1488	-18
AEP	Economic Capacity	S_OP	29.00%	0.00%	1201	29.00%	1201	0
AEP	Economic Capacity	W_SP	36.70%	0.00%	1576	36.40%	1559	-17
AEP	Economic Capacity	W_P	37.30%	0.00%	1629	37.10%	1610	-19
AEP	Economic Capacity	W_OP	34.70%	0.00%	1517	34.40%	1496	-21
AEP	Economic Capacity	SH_SP	32.00%	0.10%	1272	31.90%	1267	-5
AEP	Economic Capacity	SH_P	31.70%	0.20%	1252	31.60%	1251	-1
AEP	Economic Capacity	SH_OP	29.30%	0.00%	1172	29.00%	1153	-18
ALLIANT_E	Economic Capacity	S_35	1.70%	0.00%	2582	1.70%	2581	-1
ALLIANT_E	Economic Capacity	S_SP	2.20%	0.00%	2384	2.20%	2384	-1
ALLIANT_E	Economic Capacity	S_P	2.20%	0.00%	2423	2.20%	2423	0
ALLIANT_E	Economic Capacity	S_OP	1.80%	0.00%	1099	1.80%	1089	-10
ALLIANT_E	Economic Capacity	W_SP	1.80%	0.00%	1730	1.90%	1728	-2
ALLIANT_E	Economic Capacity	W_P	2.40%	0.00%	1755	2.50%	1753	-2
ALLIANT_E	Economic Capacity	W_OP	10.00%	0.00%	973	10.00%	972	-1
ALLIANT_E	Economic Capacity	SH_SP	2.80%	0.00%	1584	3.00%	1580	-4
ALLIANT_E	Economic Capacity	SH_P	3.80%	0.00%	1478	4.00%	1476	-2
ALLIANT_E	Economic Capacity	SH_OP	9.20%	0.00%	1264	11.50%	1236	-28
AMEREN	Economic Capacity	S_35	2.10%	3.30%	2453	6.00%	2471	18
AMEREN	Economic Capacity	S_SP	2.00%	3.30%	2456	6.00%	2473	17
AMEREN	Economic Capacity	S_P	2.10%	3.70%	2401	6.50%	2422	21
AMEREN	Economic Capacity	S_OP	4.20%	2.30%	2316	5.80%	2326	10
AMEREN	Economic Capacity	W_SP	1.70%	3.20%	2079	5.40%	2029	-51
AMEREN	Economic Capacity	W_P	1.80%	2.40%	2039	4.80%	1986	-53
AMEREN	Economic Capacity	W_OP	3.60%	0.00%	1503	4.40%	1458	-45
AMEREN	Economic Capacity	SH_SP	3.00%	3.80%	1720	7.00%	1739	20
AMEREN	Economic Capacity	SH_P	3.30%	2.60%	1642	6.50%	1660	18
AMEREN	Economic Capacity	SH_OP	8.00%	2.60%	1110	10.10%	1120	9
CIN	Economic Capacity	S_35	14.10%	0.10%	2095	14.10%	2095	0
CIN	Economic Capacity	S_SP	17.50%	0.10%	1519	17.50%	1518	-1
CIN	Economic Capacity	S_P	22.80%	0.10%	1114	22.80%	1114	0
CIN	Economic Capacity	S_OP	24.20%	0.00%	1113	24.00%	1105	-8
CIN	Economic Capacity	W_SP	11.20%	0.10%	1881	11.30%	1882	1
CIN	Economic Capacity	W_P	13.50%	0.20%	906	13.60%	909	3
CIN	Economic Capacity	W_OP	16.00%	0.20%	1115	16.10%	1117	3
CIN	Economic Capacity	SH_SP	20.20%	0.20%	1136	20.20%	1138	2
CIN	Economic Capacity	SH_P	20.50%	0.20%	1123	20.60%	1124	2
CIN	Economic Capacity	SH_OP	22.40%	0.30%	1004	22.50%	1008	3
COMED	Economic Capacity	S_35	5.60%	0.00%	5693	5.60%	5693	0
COMED	Economic Capacity	S_SP	5.80%	0.00%	5613	5.80%	5613	0
COMED	Economic Capacity	S_P	6.40%	0.00%	5038	6.40%	5038	0
COMED	Economic Capacity	S_OP	5.30%	0.00%	4107	5.20%	4106	-1

Sensitivity: No Transmission Costs **Exhibit No. AC-514**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Economic Capacity	W_SP	7.80%	0.40%	3670	8.20%	3676	6
COMED	Economic Capacity	W_P	9.10%	0.70%	3306	9.70%	3316	10
COMED	Economic Capacity	W_OP	10.00%	0.40%	2911	10.30%	2918	7
COMED	Economic Capacity	SH_SP	7.30%	0.40%	2535	7.70%	2541	6
COMED	Economic Capacity	SH_P	7.40%	0.40%	2541	7.80%	2547	6
COMED	Economic Capacity	SH_OP	9.70%	1.10%	1863	10.80%	1883	20
CSW_SPP	Economic Capacity	S_35	0.20%	63.40%	4108	62.50%	4004	-104
CSW_SPP	Economic Capacity	S_SP	0.30%	61.90%	3925	61.00%	3818	-107
CSW_SPP	Economic Capacity	S_P	0.30%	52.50%	2969	51.60%	2882	-87
CSW_SPP	Economic Capacity	S_OP	0.30%	49.00%	2661	48.00%	2569	-93
CSW_SPP	Economic Capacity	W_SP	0.40%	56.40%	3294	55.90%	3232	-62
CSW_SPP	Economic Capacity	W_P	0.60%	37.50%	1601	37.10%	1563	-38
CSW_SPP	Economic Capacity	W_OP	0.80%	37.70%	1656	37.40%	1627	-29
CSW_SPP	Economic Capacity	SH_SP	0.40%	50.50%	2708	50.00%	2662	-46
CSW_SPP	Economic Capacity	SH_P	0.80%	35.90%	1485	36.00%	1496	10
CSW_SPP	Economic Capacity	SH_OP	1.00%	33.20%	1363	33.40%	1376	12
ENT	Economic Capacity	S_35	0.20%	0.20%	5425	0.40%	5425	0
ENT	Economic Capacity	S_SP	0.50%	1.20%	2633	1.70%	2634	1
ENT	Economic Capacity	S_P	0.50%	0.80%	2704	1.30%	2705	1
ENT	Economic Capacity	S_OP	0.60%	1.00%	2851	1.50%	2852	1
ENT	Economic Capacity	W_SP	0.20%	3.20%	5154	3.10%	5161	8
ENT	Economic Capacity	W_P	0.40%	4.20%	2360	4.60%	2373	12
ENT	Economic Capacity	W_OP	0.50%	6.30%	2345	6.70%	2363	18
ENT	Economic Capacity	SH_SP	0.30%	4.50%	3587	4.70%	3589	2
ENT	Economic Capacity	SH_P	0.60%	4.70%	1590	5.30%	1593	3
ENT	Economic Capacity	SH_OP	0.60%	7.80%	1600	8.30%	1605	5
IP	Economic Capacity	S_35	4.60%	0.50%	1898	5.10%	1902	4
IP	Economic Capacity	S_SP	4.70%	0.50%	1906	5.10%	1909	4
IP	Economic Capacity	S_P	5.00%	0.50%	1728	5.50%	1733	5
IP	Economic Capacity	S_OP	5.40%	0.40%	1822	5.80%	1826	4
IP	Economic Capacity	W_SP	4.90%	0.80%	1643	5.60%	1650	7
IP	Economic Capacity	W_P	5.10%	0.80%	1770	5.90%	1777	8
IP	Economic Capacity	W_OP	5.60%	0.60%	1501	6.10%	1507	6
IP	Economic Capacity	SH_SP	4.80%	0.70%	1397	5.40%	1404	6
IP	Economic Capacity	SH_P	5.60%	0.50%	1354	6.00%	1359	5
IP	Economic Capacity	SH_OP	7.30%	0.50%	830	7.70%	836	7
KCPL	Economic Capacity	S_35	0.60%	0.50%	2622	1.10%	2622	0
KCPL	Economic Capacity	S_SP	0.50%	0.40%	3049	1.00%	3049	0
KCPL	Economic Capacity	S_P	0.50%	1.40%	2418	1.90%	2419	1
KCPL	Economic Capacity	S_OP	0.70%	1.80%	2445	2.50%	2446	1
KCPL	Economic Capacity	W_SP	1.10%	2.20%	1634	3.30%	1636	2
KCPL	Economic Capacity	W_P	1.10%	1.80%	1632	2.90%	1633	1
KCPL	Economic Capacity	W_OP	3.30%	2.90%	1281	6.20%	1290	10
KCPL	Economic Capacity	SH_SP	1.00%	1.00%	1469	2.10%	1469	0
KCPL	Economic Capacity	SH_P	1.20%	1.00%	1320	2.20%	1320	-1
KCPL	Economic Capacity	SH_OP	3.10%	7.90%	671	7.30%	688	16
LGE	Economic Capacity	S_35	6.70%	0.10%	2944	6.80%	2945	1
LGE	Economic Capacity	S_SP	3.90%	0.00%	1070	3.90%	1070	0
LGE	Economic Capacity	S_P	2.80%	0.00%	1067	2.80%	1067	0
LGE	Economic Capacity	S_OP	6.50%	0.00%	983	6.50%	983	0
LGE	Economic Capacity	W_SP	18.20%	0.00%	911	18.00%	904	-7
LGE	Economic Capacity	W_P	17.70%	0.00%	906	17.70%	906	0
LGE	Economic Capacity	W_OP	17.90%	0.00%	890	17.90%	890	0
LGE	Economic Capacity	SH_SP	16.60%	0.00%	910	16.60%	910	0

Sensitivity: No Transmission Costs **Exhibit No. AC-514**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
LGE	Economic Capacity	SH_P	16.90%	0.00%	930	16.90%	930	0
LGE	Economic Capacity	SH_OP	11.40%	0.00%	900	11.40%	900	0
MPS	Economic Capacity	S_35	0.70%	0.00%	4592	0.80%	4715	123
MPS	Economic Capacity	S_SP	1.00%	0.00%	3798	1.10%	3795	-3
MPS	Economic Capacity	S_P	0.70%	0.00%	2768	0.90%	2766	-2
MPS	Economic Capacity	S_OP	1.40%	0.00%	2059	1.60%	2057	-2
MPS	Economic Capacity	W_SP	1.80%	2.20%	836	4.00%	838	2
MPS	Economic Capacity	W_P	1.90%	2.80%	819	4.60%	824	5
MPS	Economic Capacity	W_OP	2.90%	2.50%	779	5.30%	783	5
MPS	Economic Capacity	SH_SP	2.40%	0.00%	1325	2.70%	1318	-8
MPS	Economic Capacity	SH_P	4.10%	0.00%	983	4.50%	969	-14
MPS	Economic Capacity	SH_OP	4.80%	0.00%	894	5.30%	879	-15
NIPS	Economic Capacity	S_35	13.40%	0.10%	1979	13.40%	1980	1
NIPS	Economic Capacity	S_SP	18.50%	0.30%	1083	18.50%	1086	3
NIPS	Economic Capacity	S_P	19.60%	0.30%	950	19.70%	954	4
NIPS	Economic Capacity	S_OP	21.30%	0.40%	929	21.40%	936	7
NIPS	Economic Capacity	W_SP	20.00%	0.40%	1029	20.10%	1036	7
NIPS	Economic Capacity	W_P	19.90%	0.40%	1025	20.10%	1032	7
NIPS	Economic Capacity	W_OP	20.00%	0.40%	1027	20.10%	1035	7
NIPS	Economic Capacity	SH_SP	18.00%	0.20%	1170	18.10%	1174	4
NIPS	Economic Capacity	SH_P	17.90%	0.30%	1164	18.00%	1169	4
NIPS	Economic Capacity	SH_OP	19.10%	0.40%	932	19.30%	939	7
OKGE	Economic Capacity	S_35	0.10%	2.50%	5724	2.60%	5724	0
OKGE	Economic Capacity	S_SP	0.10%	2.60%	5752	2.70%	5753	1
OKGE	Economic Capacity	S_P	0.30%	20.10%	2397	20.00%	2390	-6
OKGE	Economic Capacity	S_OP	0.50%	17.30%	2502	17.00%	2489	-12
OKGE	Economic Capacity	W_SP	0.20%	9.20%	4123	9.20%	4124	0
OKGE	Economic Capacity	W_P	0.30%	11.70%	1938	11.70%	1938	-1
OKGE	Economic Capacity	W_OP	0.70%	8.70%	1984	8.60%	1972	-12
OKGE	Economic Capacity	SH_SP	0.20%	6.40%	3805	6.50%	3806	2
OKGE	Economic Capacity	SH_P	0.60%	6.90%	1663	7.40%	1668	5
OKGE	Economic Capacity	SH_OP	1.10%	3.70%	1803	4.70%	1803	0
STJO	Economic Capacity	S_35	1.20%	0.00%	1140	1.30%	1140	0
STJO	Economic Capacity	S_SP	1.10%	0.00%	1183	1.20%	1183	0
STJO	Economic Capacity	S_P	1.30%	0.00%	773	1.40%	771	-2
STJO	Economic Capacity	S_OP	2.30%	0.00%	860	2.50%	859	-1
STJO	Economic Capacity	W_SP	2.10%	2.50%	733	4.80%	738	5
STJO	Economic Capacity	W_P	2.10%	2.40%	732	4.70%	736	4
STJO	Economic Capacity	W_OP	4.40%	0.00%	774	4.60%	770	-4
STJO	Economic Capacity	SH_SP	1.40%	3.80%	537	5.20%	545	7
STJO	Economic Capacity	SH_P	1.50%	2.90%	534	4.40%	539	5
STJO	Economic Capacity	SH_OP	3.70%	5.20%	633	8.10%	659	25
SWEPA	Economic Capacity	S_35	0.40%	5.00%	1421	5.40%	1424	3
SWEPA	Economic Capacity	S_SP	0.50%	5.20%	1340	5.60%	1343	3
SWEPA	Economic Capacity	S_P	0.50%	6.20%	1308	6.60%	1307	-1
SWEPA	Economic Capacity	S_OP	0.60%	10.20%	889	10.70%	887	-2
SWEPA	Economic Capacity	W_SP	0.90%	11.60%	728	12.30%	741	13
SWEPA	Economic Capacity	W_P	1.00%	8.20%	663	9.10%	672	9
SWEPA	Economic Capacity	W_OP	1.40%	7.30%	605	8.50%	608	3
SWEPA	Economic Capacity	SH_SP	1.60%	9.90%	942	9.40%	942	0
SWEPA	Economic Capacity	SH_P	2.10%	10.00%	864	5.80%	846	-18
SWEPA	Economic Capacity	SH_OP	2.60%	11.50%	756	8.00%	725	-31
TVA	Economic Capacity	S_35	14.70%	0.00%	839	14.80%	838	-1

Sensitivity: No Transmission Costs

Exhibit No. AC-514

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
TVA	Economic Capacity	S_SP	14.90%	0.00%	842	15.00%	841	-1
TVA	Economic Capacity	S_P	14.90%	0.00%	781	14.90%	780	-2
TVA	Economic Capacity	S_OP	14.20%	0.00%	740	14.20%	737	-3
TVA	Economic Capacity	W_SP	19.20%	0.00%	984	19.30%	987	3
TVA	Economic Capacity	W_P	9.50%	0.00%	695	9.50%	696	0
TVA	Economic Capacity	W_OP	11.60%	0.00%	704	11.70%	706	2
TVA	Economic Capacity	SH_SP	12.20%	1.10%	576	13.30%	603	27
TVA	Economic Capacity	SH_P	15.30%	1.00%	580	16.10%	605	26
TVA	Economic Capacity	SH_OP	5.70%	0.00%	556	5.70%	556	0
WR	Economic Capacity	S_35	0.30%	2.10%	4672	2.30%	4698	26
WR	Economic Capacity	S_SP	0.40%	2.00%	3485	2.30%	3486	1
WR	Economic Capacity	S_P	0.40%	2.90%	3504	3.20%	3504	0
WR	Economic Capacity	S_OP	1.00%	4.00%	1790	4.60%	1790	-1
WR	Economic Capacity	W_SP	0.60%	1.90%	2555	2.50%	2556	0
WR	Economic Capacity	W_P	0.70%	1.90%	2391	2.60%	2393	1
WR	Economic Capacity	W_OP	0.90%	1.60%	2660	2.40%	2660	1
WR	Economic Capacity	SH_SP	0.70%	3.10%	2308	3.70%	2310	2
WR	Economic Capacity	SH_P	1.00%	3.00%	2158	3.90%	2161	3
WR	Economic Capacity	SH_OP	2.10%	4.10%	1575	5.70%	1582	6

Sensitivity: No Transmission Costs **Exhibit No. AC-514**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Available Economic Capacity	S_35	8.90%	0.20%	914	9.50%	889	-24
AECI	Available Economic Capacity	S_SP	34.50%	0.00%	1523	33.60%	1445	-78
AECI	Available Economic Capacity	S_P	5.50%	0.00%	851	5.60%	779	-73
AECI	Available Economic Capacity	S_OP	4.60%	0.00%	804	4.70%	758	-46
AECI	Available Economic Capacity	W_SP	6.00%	1.60%	711	7.10%	709	-3
AECI	Available Economic Capacity	W_P	4.30%	0.00%	728	4.30%	703	-25
AECI	Available Economic Capacity	W_OP	2.30%	0.00%	748	2.40%	708	-40
AECI	Available Economic Capacity	SH_SP	13.20%	0.60%	855	13.10%	803	-51
AECI	Available Economic Capacity	SH_P	8.40%	0.40%	735	8.50%	696	-39
AECI	Available Economic Capacity	SH_OP	5.80%	0.10%	901	6.00%	869	-32
AEP	Available Economic Capacity	S_35	20.20%	0.00%	933	18.80%	890	-43
AEP	Available Economic Capacity	S_SP	59.30%	0.00%	3779	55.80%	3389	-389
AEP	Available Economic Capacity	S_P	75.40%	0.00%	5759	72.00%	5259	-500
AEP	Available Economic Capacity	S_OP	0.00%	0.00%	4232	0.00%	4232	0
AEP	Available Economic Capacity	W_SP	53.80%	0.00%	3115	50.70%	2804	-311
AEP	Available Economic Capacity	W_P	64.70%	0.00%	4373	62.20%	4053	-320
AEP	Available Economic Capacity	W_OP	39.10%	0.00%	2094	34.80%	1815	-279
AEP	Available Economic Capacity	SH_SP	28.00%	0.00%	1230	25.60%	1119	-111
AEP	Available Economic Capacity	SH_P	58.40%	0.00%	3592	55.50%	3260	-332
AEP	Available Economic Capacity	SH_OP	34.00%	0.00%	2149	26.10%	1755	-394
ALLIANT_E	Available Economic Capacity	S_35	39.40%	0.00%	1969	39.70%	1981	12
ALLIANT_E	Available Economic Capacity	S_SP	79.50%	0.00%	6395	79.70%	6433	38
ALLIANT_E	Available Economic Capacity	S_P	70.50%	0.00%	5205	70.30%	5190	-15
ALLIANT_E	Available Economic Capacity	S_OP	0.00%	0.00%	7083	0.00%	7083	0
ALLIANT_E	Available Economic Capacity	W_SP	12.40%	0.00%	1025	12.60%	1027	2
ALLIANT_E	Available Economic Capacity	W_P	38.40%	0.00%	2043	38.90%	2074	31
ALLIANT_E	Available Economic Capacity	W_OP	0.00%	0.00%	8511	0.00%	8511	0
ALLIANT_E	Available Economic Capacity	SH_SP	74.00%	0.00%	5634	74.10%	5640	7
ALLIANT_E	Available Economic Capacity	SH_P	68.10%	0.00%	4840	64.80%	4409	-431
ALLIANT_E	Available Economic Capacity	SH_OP	0.00%	0.00%	7070	0.00%	7070	0
AMEREN	Available Economic Capacity	S_35	6.30%	2.10%	371	9.00%	397	27
AMEREN	Available Economic Capacity	S_SP	7.20%	1.20%	349	9.00%	372	23
AMEREN	Available Economic Capacity	S_P	4.90%	0.00%	627	5.90%	595	-31
AMEREN	Available Economic Capacity	S_OP	9.40%	0.00%	1132	10.90%	1048	-85
AMEREN	Available Economic Capacity	W_SP	5.80%	0.00%	539	6.50%	520	-19
AMEREN	Available Economic Capacity	W_P	5.60%	0.00%	611	6.10%	580	-31
AMEREN	Available Economic Capacity	W_OP	14.60%	0.00%	1399	11.60%	1229	-169
AMEREN	Available Economic Capacity	SH_SP	14.40%	0.90%	501	15.10%	507	6
AMEREN	Available Economic Capacity	SH_P	6.70%	0.20%	567	7.50%	540	-27
AMEREN	Available Economic Capacity	SH_OP	0.00%	0.00%	2002	0.00%	1608	-393
CIN	Available Economic Capacity	S_35	35.30%	0.00%	1580	33.20%	1460	-119
CIN	Available Economic Capacity	S_SP	90.00%	0.00%	8117	85.00%	7260	-857
CIN	Available Economic Capacity	S_P	69.90%	0.00%	5028	67.40%	4694	-334
CIN	Available Economic Capacity	S_OP	70.80%	0.00%	5168	68.10%	4811	-357
CIN	Available Economic Capacity	W_SP	38.00%	0.00%	1843	35.10%	1658	-185
CIN	Available Economic Capacity	W_P	60.30%	0.00%	4025	57.00%	3672	-353
CIN	Available Economic Capacity	W_OP	48.30%	0.00%	2720	46.60%	2571	-149
CIN	Available Economic Capacity	SH_SP	0.00%	0.00%	1917	0.00%	1478	-439
CIN	Available Economic Capacity	SH_P	64.90%	0.00%	4390	61.10%	3929	-461
CIN	Available Economic Capacity	SH_OP	48.90%	0.00%	2930	43.30%	2483	-446
COMED	Available Economic Capacity	S_35	22.20%	0.00%	1692	22.40%	1692	0
COMED	Available Economic Capacity	S_SP	43.20%	0.00%	2728	42.20%	2647	-81
COMED	Available Economic Capacity	S_P	64.30%	0.00%	4415	62.40%	4187	-228
COMED	Available Economic Capacity	S_OP	60.90%	0.00%	4025	57.20%	3616	-408
COMED	Available Economic Capacity	W_SP	13.10%	0.00%	695	12.60%	684	-11
COMED	Available Economic Capacity	W_P	46.70%	0.00%	2509	45.30%	2386	-123
COMED	Available Economic Capacity	W_OP	41.00%	0.00%	2248	38.80%	2093	-155
COMED	Available Economic Capacity	SH_SP	34.60%	0.00%	1423	33.00%	1324	-99
COMED	Available Economic Capacity	SH_P	14.50%	0.00%	799	14.00%	787	-12

Sensitivity: No Transmission Costs **Exhibit No. AC-514**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Available Economic Capacity	SH_OP	45.70%	0.00%	2479	43.00%	2256	-224
CSW_SPP	Available Economic Capacity	S_35	6.10%	4.60%	604	9.40%	595	-9
CSW_SPP	Available Economic Capacity	S_SP	13.50%	8.80%	762	17.40%	757	-5
CSW_SPP	Available Economic Capacity	S_P	6.30%	16.80%	853	13.00%	801	-52
CSW_SPP	Available Economic Capacity	S_OP	5.30%	0.00%	738	2.70%	811	72
CSW_SPP	Available Economic Capacity	W_SP	2.60%	24.00%	1003	23.90%	1002	-2
CSW_SPP	Available Economic Capacity	W_P	5.70%	0.00%	1077	5.20%	986	-91
CSW_SPP	Available Economic Capacity	W_OP	5.30%	0.00%	563	4.90%	519	-44
CSW_SPP	Available Economic Capacity	SH_SP	11.30%	10.50%	614	17.90%	674	60
CSW_SPP	Available Economic Capacity	SH_P	11.00%	9.10%	599	15.50%	614	14
CSW_SPP	Available Economic Capacity	SH_OP	9.70%	0.80%	712	8.50%	642	-70
ENT	Available Economic Capacity	S_35	9.50%	0.10%	1674	9.50%	1665	-9
ENT	Available Economic Capacity	S_SP	37.20%	0.00%	1698	37.40%	1641	-57
ENT	Available Economic Capacity	S_P	15.20%	0.00%	950	15.20%	873	-78
ENT	Available Economic Capacity	S_OP	7.70%	0.00%	650	7.80%	615	-35
ENT	Available Economic Capacity	W_SP	2.10%	5.40%	2920	6.90%	2935	15
ENT	Available Economic Capacity	W_P	3.70%	0.00%	609	3.80%	536	-73
ENT	Available Economic Capacity	W_OP	2.00%	0.00%	544	2.10%	476	-68
ENT	Available Economic Capacity	SH_SP	14.90%	0.50%	759	14.90%	721	-37
ENT	Available Economic Capacity	SH_P	5.10%	0.30%	785	5.30%	715	-69
ENT	Available Economic Capacity	SH_OP	3.30%	0.20%	632	3.50%	561	-71
IP	Available Economic Capacity	S_35	11.30%	0.00%	560	10.90%	551	-9
IP	Available Economic Capacity	S_SP	19.70%	0.00%	884	19.40%	874	-10
IP	Available Economic Capacity	S_P	11.20%	0.00%	593	10.90%	584	-9
IP	Available Economic Capacity	S_OP	14.30%	0.00%	924	14.70%	929	5
IP	Available Economic Capacity	W_SP	13.10%	0.00%	652	12.70%	640	-12
IP	Available Economic Capacity	W_P	5.20%	0.00%	732	5.10%	729	-3
IP	Available Economic Capacity	W_OP	18.40%	0.00%	949	19.00%	960	11
IP	Available Economic Capacity	SH_SP	17.20%	0.00%	761	16.70%	742	-19
IP	Available Economic Capacity	SH_P	23.20%	0.00%	996	23.50%	990	-6
IP	Available Economic Capacity	SH_OP	51.90%	0.00%	3020	51.50%	2981	-39
KCPL	Available Economic Capacity	S_35	8.40%	0.00%	828	8.70%	802	-26
KCPL	Available Economic Capacity	S_SP	5.90%	0.00%	727	6.10%	707	-20
KCPL	Available Economic Capacity	S_P	3.80%	0.00%	959	4.10%	807	-152
KCPL	Available Economic Capacity	S_OP	7.60%	0.00%	1420	7.70%	1169	-251
KCPL	Available Economic Capacity	W_SP	8.30%	3.80%	585	8.60%	566	-19
KCPL	Available Economic Capacity	W_P	6.80%	0.00%	521	7.10%	498	-23
KCPL	Available Economic Capacity	W_OP	0.00%	0.00%	2624	0.00%	2063	-562
KCPL	Available Economic Capacity	SH_SP	7.00%	0.00%	709	7.10%	658	-50
KCPL	Available Economic Capacity	SH_P	5.90%	0.00%	645	6.00%	586	-59
KCPL	Available Economic Capacity	SH_OP	0.00%	0.00%	3071	0.00%	2277	-794
LGE	Available Economic Capacity	S_35	39.70%	0.00%	1963	38.30%	1871	-92
LGE	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	S_P	0.00%	0.00%	5673	0.00%	5673	0
LGE	Available Economic Capacity	S_OP	0.00%	0.00%	4508	0.00%	4508	0
LGE	Available Economic Capacity	W_SP	0.00%	0.00%	3266	0.00%	3266	0
LGE	Available Economic Capacity	W_P	0.00%	0.00%	3175	0.00%	3175	0
LGE	Available Economic Capacity	W_OP	0.00%	0.00%	3025	0.00%	3025	0
LGE	Available Economic Capacity	SH_SP	0.00%	0.00%	6019	0.00%	6019	0
LGE	Available Economic Capacity	SH_P	0.00%	0.00%	3818	0.00%	3818	0
LGE	Available Economic Capacity	SH_OP	0.00%	0.00%	3908	0.00%	3908	0
MPS	Available Economic Capacity	S_35	11.00%	0.00%	924	10.60%	874	-50
MPS	Available Economic Capacity	S_SP	45.20%	0.00%	2630	44.00%	2446	-184
MPS	Available Economic Capacity	S_P	16.30%	0.00%	1310	16.40%	1181	-129
MPS	Available Economic Capacity	S_OP	14.20%	0.00%	1369	14.20%	1233	-136
MPS	Available Economic Capacity	W_SP	40.30%	0.00%	2283	30.30%	1634	-648
MPS	Available Economic Capacity	W_P	29.70%	0.00%	1668	27.40%	1467	-201
MPS	Available Economic Capacity	W_OP	26.70%	0.00%	1686	24.40%	1472	-213

Sensitivity: No Transmission Costs **Exhibit No. AC-514**

Market	Analysis	Period	BASE AEP Mkt Share	CSW Mkt Share	HHI Pre-Merger	MERGER Merged Mkt Share	HHI Post-Merger	HHI Change
MPS	Available Economic Capacity	SH_SP	70.90%	0.00%	5155	61.20%	3936	-1218
MPS	Available Economic Capacity	SH_P	0.00%	0.00%	1800	0.00%	1389	-411
MPS	Available Economic Capacity	SH_OP	0.00%	0.00%	2212	0.00%	2198	-14
NIPS	Available Economic Capacity	S_35	33.70%	0.00%	1468	32.50%	1397	-71
NIPS	Available Economic Capacity	S_SP	0.00%	0.00%	7771	0.00%	3056	-4715
NIPS	Available Economic Capacity	S_P	0.00%	0.00%	3104	0.00%	2682	-421
NIPS	Available Economic Capacity	S_OP	54.10%	0.00%	3454	49.50%	3063	-391
NIPS	Available Economic Capacity	W_SP	0.00%	0.00%	2710	0.00%	2465	-245
NIPS	Available Economic Capacity	W_P	11.40%	0.00%	1625	0.00%	1835	210
NIPS	Available Economic Capacity	W_OP	41.20%	0.00%	2355	36.30%	2073	-282
NIPS	Available Economic Capacity	SH_SP	27.30%	0.00%	1982	0.00%	2054	72
NIPS	Available Economic Capacity	SH_P	64.50%	0.00%	4347	61.40%	3976	-372
NIPS	Available Economic Capacity	SH_OP	46.10%	0.00%	2727	41.10%	2392	-334
OKGE	Available Economic Capacity	S_35	3.20%	2.00%	1072	5.60%	1036	-36
OKGE	Available Economic Capacity	S_SP	9.60%	0.00%	1710	10.10%	1495	-215
OKGE	Available Economic Capacity	S_P	5.60%	0.00%	3015	4.70%	2822	-193
OKGE	Available Economic Capacity	S_OP	20.70%	0.00%	1453	18.20%	1243	-210
OKGE	Available Economic Capacity	W_SP	2.30%	5.50%	1672	7.00%	1666	-6
OKGE	Available Economic Capacity	W_P	3.20%	0.00%	1826	3.70%	1754	-72
OKGE	Available Economic Capacity	W_OP	16.10%	0.00%	1354	16.80%	1177	-177
OKGE	Available Economic Capacity	SH_SP	4.50%	1.20%	827	6.20%	803	-24
OKGE	Available Economic Capacity	SH_P	4.50%	0.20%	1515	5.30%	1440	-75
OKGE	Available Economic Capacity	SH_OP	15.30%	0.00%	1875	6.00%	1639	-236
STJO	Available Economic Capacity	S_35	8.50%	0.00%	791	8.80%	794	2
STJO	Available Economic Capacity	S_SP	6.30%	0.00%	659	7.00%	597	-62
STJO	Available Economic Capacity	S_P	7.80%	0.00%	1369	7.70%	1229	-140
STJO	Available Economic Capacity	S_OP	10.80%	0.00%	1446	10.80%	1390	-57
STJO	Available Economic Capacity	W_SP	9.70%	0.00%	780	9.90%	755	-26
STJO	Available Economic Capacity	W_P	7.90%	0.00%	897	8.00%	856	-41
STJO	Available Economic Capacity	W_OP	0.00%	0.00%	1664	0.00%	1465	-199
STJO	Available Economic Capacity	SH_SP	9.70%	0.00%	707	9.50%	666	-41
STJO	Available Economic Capacity	SH_P	7.90%	0.00%	754	7.80%	722	-32
STJO	Available Economic Capacity	SH_OP	0.00%	0.00%	2603	0.00%	1994	-609
SWEPA	Available Economic Capacity	S_35	3.70%	1.30%	870	5.00%	806	-64
SWEPA	Available Economic Capacity	S_SP	9.60%	0.00%	1802	8.60%	1565	-237
SWEPA	Available Economic Capacity	S_P	2.70%	0.00%	3396	3.00%	1559	-1837
SWEPA	Available Economic Capacity	S_OP	2.40%	0.00%	2047	2.60%	1227	-820
SWEPA	Available Economic Capacity	W_SP	4.70%	7.30%	770	11.00%	810	40
SWEPA	Available Economic Capacity	W_P	7.00%	0.00%	1164	6.80%	1057	-106
SWEPA	Available Economic Capacity	W_OP	8.60%	0.00%	1187	8.30%	984	-203
SWEPA	Available Economic Capacity	SH_SP	17.80%	0.40%	924	17.40%	846	-78
SWEPA	Available Economic Capacity	SH_P	13.10%	0.00%	1015	12.80%	824	-192
SWEPA	Available Economic Capacity	SH_OP	14.00%	0.00%	923	13.60%	908	-16
TVA	Available Economic Capacity	S_35	31.20%	0.00%	1419	30.20%	1370	-49
TVA	Available Economic Capacity	S_SP	35.40%	0.00%	1602	34.60%	1554	-48
TVA	Available Economic Capacity	S_P	72.60%	0.00%	5361	67.80%	4703	-658
TVA	Available Economic Capacity	S_OP	46.80%	0.00%	3207	32.90%	2176	-1031
TVA	Available Economic Capacity	W_SP	56.60%	0.00%	3402	53.50%	3068	-334
TVA	Available Economic Capacity	W_P	0.00%	0.00%	4101	0.00%	4101	0
TVA	Available Economic Capacity	W_OP	0.00%	0.00%	4289	0.00%	4289	0
TVA	Available Economic Capacity	SH_SP	33.30%	0.00%	1366	31.10%	1228	-138
TVA	Available Economic Capacity	SH_P	0.00%	0.00%	4101	0.00%	2485	-1616
TVA	Available Economic Capacity	SH_OP	0.00%	0.00%	4571	0.00%	4571	0
WR	Available Economic Capacity	S_35	5.90%	0.00%	1301	5.80%	1311	11
WR	Available Economic Capacity	S_SP	26.50%	0.00%	1377	26.10%	1351	-26
WR	Available Economic Capacity	S_P	62.90%	0.00%	4189	49.00%	2752	-1436
WR	Available Economic Capacity	S_OP	2.20%	0.00%	2610	1.30%	1868	-742
WR	Available Economic Capacity	W_SP	46.60%	0.00%	2656	42.70%	2295	-360

Sensitivity: No Transmission Costs

Exhibit No. AC-514

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
WR	Available Economic Capacity	W_P	33.20%	0.00%	1678	32.30%	1595	-83
WR	Available Economic Capacity	W_OP	17.10%	0.00%	1588	16.70%	1556	-32
WR	Available Economic Capacity	SH_SP	22.50%	0.00%	1393	21.70%	1337	-56
WR	Available Economic Capacity	SH_P	44.80%	0.00%	2470	39.70%	2011	-459
WR	Available Economic Capacity	SH_OP	0.00%	0.00%	2166	0.00%	1666	-500

Sensitivity: TTCs

Exhibit No. AC-515

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Economic Capacity	S_35	0.50%	1.40%	895	1.90%	896	1
AECI	Economic Capacity	S_SP	0.70%	1.70%	972	2.30%	975	3
AECI	Economic Capacity	S_P	0.30%	3.70%	844	4.00%	842	-2
AECI	Economic Capacity	S_OP	1.10%	4.60%	863	5.70%	867	4
AECI	Economic Capacity	W_SP	1.00%	3.70%	1129	4.40%	1132	3
AECI	Economic Capacity	W_P	1.10%	0.00%	1286	1.20%	1286	0
AECI	Economic Capacity	W_OP	2.40%	0.00%	1321	2.60%	1315	-6
AECI	Economic Capacity	SH_SP	1.10%	5.80%	649	6.90%	656	8
AECI	Economic Capacity	SH_P	1.30%	4.70%	666	6.00%	671	5
AECI	Economic Capacity	SH_OP	1.90%	5.00%	710	7.00%	722	12
AEP	Economic Capacity	S_35	36.50%	0.00%	1554	36.20%	1537	-17
AEP	Economic Capacity	S_SP	44.40%	0.00%	2218	44.10%	2196	-22
AEP	Economic Capacity	S_P	49.60%	0.00%	2716	49.30%	2689	-27
AEP	Economic Capacity	S_OP	41.00%	0.00%	2121	41.00%	2121	0
AEP	Economic Capacity	W_SP	51.10%	0.00%	2850	50.80%	2823	-26
AEP	Economic Capacity	W_P	52.40%	0.00%	3007	52.10%	2979	-28
AEP	Economic Capacity	W_OP	49.40%	0.00%	2768	49.10%	2736	-33
AEP	Economic Capacity	SH_SP	40.00%	0.00%	1849	39.70%	1830	-19
AEP	Economic Capacity	SH_P	44.60%	0.00%	2249	44.30%	2226	-23
AEP	Economic Capacity	SH_OP	39.50%	0.00%	1945	39.10%	1920	-25
ALLIANT_E	Economic Capacity	S_35	1.10%	0.00%	2845	1.20%	2844	-1
ALLIANT_E	Economic Capacity	S_SP	1.50%	0.00%	2551	1.60%	2549	-2
ALLIANT_E	Economic Capacity	S_P	1.60%	0.00%	2599	1.60%	2600	1
ALLIANT_E	Economic Capacity	S_OP	0.30%	0.00%	1958	0.30%	1920	-38
ALLIANT_E	Economic Capacity	W_SP	1.60%	0.00%	1701	1.70%	1699	-2
ALLIANT_E	Economic Capacity	W_P	0.90%	0.00%	1744	0.90%	1745	1
ALLIANT_E	Economic Capacity	W_OP	0.20%	0.00%	1144	0.20%	1145	1
ALLIANT_E	Economic Capacity	SH_SP	0.90%	0.00%	1544	0.90%	1541	-3
ALLIANT_E	Economic Capacity	SH_P	1.20%	0.00%	1455	1.30%	1451	-4
ALLIANT_E	Economic Capacity	SH_OP	0.30%	0.00%	1285	0.30%	1289	5
AMEREN	Economic Capacity	S_35	1.80%	3.10%	2462	5.50%	2473	11
AMEREN	Economic Capacity	S_SP	1.70%	3.00%	2401	5.40%	2416	16
AMEREN	Economic Capacity	S_P	1.90%	1.80%	2474	3.10%	2477	3
AMEREN	Economic Capacity	S_OP	0.20%	0.00%	2763	0.20%	2715	-48
AMEREN	Economic Capacity	W_SP	2.10%	1.40%	2365	4.10%	2318	-47
AMEREN	Economic Capacity	W_P	0.60%	0.00%	2553	0.60%	2533	-20
AMEREN	Economic Capacity	W_OP	0.30%	0.00%	2225	0.30%	2227	2
AMEREN	Economic Capacity	SH_SP	2.90%	4.40%	1809	7.60%	1839	30
AMEREN	Economic Capacity	SH_P	3.20%	3.30%	1856	5.70%	1865	10
AMEREN	Economic Capacity	SH_OP	0.20%	0.00%	1713	0.30%	1712	-1
CIN	Economic Capacity	S_35	12.50%	0.10%	1986	12.50%	1986	1
CIN	Economic Capacity	S_SP	3.50%	0.00%	2580	3.50%	2580	0
CIN	Economic Capacity	S_P	0.90%	0.00%	1743	0.90%	1743	0
CIN	Economic Capacity	S_OP	11.80%	0.00%	1392	11.80%	1392	0
CIN	Economic Capacity	W_SP	8.50%	0.00%	2641	8.50%	2641	0
CIN	Economic Capacity	W_P	1.10%	0.00%	1701	1.10%	1701	0
CIN	Economic Capacity	W_OP	12.80%	0.00%	1709	12.90%	1709	0
CIN	Economic Capacity	SH_SP	0.90%	0.00%	2013	0.90%	2013	0
CIN	Economic Capacity	SH_P	0.90%	0.00%	1955	0.90%	1955	0
CIN	Economic Capacity	SH_OP	10.80%	0.00%	1393	10.80%	1392	0

Sensitivity: TTCs

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Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Economic Capacity	S_35	0.40%	0.00%	6448	0.40%	6448	0
COMED	Economic Capacity	S_SP	0.40%	0.00%	6374	0.40%	6373	-1
COMED	Economic Capacity	S_P	0.50%	0.00%	5843	0.50%	5842	-1
COMED	Economic Capacity	S_OP	0.20%	0.00%	5106	0.20%	5107	1
COMED	Economic Capacity	W_SP	8.00%	0.20%	3897	8.20%	3900	3
COMED	Economic Capacity	W_P	1.80%	0.00%	4191	1.80%	4188	-3
COMED	Economic Capacity	W_OP	3.20%	0.00%	3144	3.20%	3146	2
COMED	Economic Capacity	SH_SP	7.90%	0.30%	3170	8.30%	3182	12
COMED	Economic Capacity	SH_P	7.00%	0.00%	3487	6.90%	3485	-2
COMED	Economic Capacity	SH_OP	2.40%	0.00%	2517	2.40%	2514	-3
CSW_SPP	Economic Capacity	S_35	0.30%	58.60%	3530	57.80%	3443	-87
CSW_SPP	Economic Capacity	S_SP	0.40%	57.00%	3344	56.30%	3265	-78
CSW_SPP	Economic Capacity	S_P	0.50%	42.80%	2104	42.20%	2061	-43
CSW_SPP	Economic Capacity	S_OP	0.70%	38.60%	1864	38.10%	1829	-35
CSW_SPP	Economic Capacity	W_SP	0.40%	51.50%	2812	51.10%	2761	-51
CSW_SPP	Economic Capacity	W_P	0.80%	34.80%	1485	34.00%	1425	-61
CSW_SPP	Economic Capacity	W_OP	0.80%	33.60%	1366	33.40%	1347	-19
CSW_SPP	Economic Capacity	SH_SP	0.50%	46.30%	2315	45.80%	2278	-38
CSW_SPP	Economic Capacity	SH_P	0.90%	32.40%	1268	32.50%	1270	2
CSW_SPP	Economic Capacity	SH_OP	1.10%	29.10%	1130	29.60%	1153	23
ENT	Economic Capacity	S_35	0.20%	0.50%	5184	0.70%	5184	0
ENT	Economic Capacity	S_SP	0.60%	1.30%	2498	1.80%	2500	2
ENT	Economic Capacity	S_P	0.20%	1.00%	2559	1.10%	2559	0
ENT	Economic Capacity	S_OP	0.80%	0.50%	2728	1.20%	2728	1
ENT	Economic Capacity	W_SP	0.20%	3.40%	5192	3.40%	5201	9
ENT	Economic Capacity	W_P	0.40%	1.90%	2676	1.40%	2710	34
ENT	Economic Capacity	W_OP	0.70%	2.30%	2708	2.30%	2732	23
ENT	Economic Capacity	SH_SP	0.30%	3.80%	3747	4.10%	3748	1
ENT	Economic Capacity	SH_P	0.50%	4.60%	1592	5.00%	1593	1
ENT	Economic Capacity	SH_OP	1.10%	7.40%	1689	8.50%	1717	28
IP	Economic Capacity	S_35	3.70%	0.50%	1920	4.20%	1923	3
IP	Economic Capacity	S_SP	3.80%	0.40%	2034	4.20%	2037	3
IP	Economic Capacity	S_P	5.40%	0.40%	1875	6.00%	1879	4
IP	Economic Capacity	S_OP	1.30%	0.10%	2211	1.50%	2208	-3
IP	Economic Capacity	W_SP	5.90%	0.30%	1925	6.30%	1929	5
IP	Economic Capacity	W_P	3.60%	0.00%	2119	3.60%	2125	5
IP	Economic Capacity	W_OP	5.10%	0.00%	2014	5.10%	2012	-2
IP	Economic Capacity	SH_SP	4.80%	1.10%	1537	6.00%	1551	14
IP	Economic Capacity	SH_P	3.10%	0.00%	1627	2.80%	1635	9
IP	Economic Capacity	SH_OP	3.60%	0.00%	1182	3.10%	1196	14

Sensitivity: TTCs

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Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
KCPL	Economic Capacity	S_35	0.50%	1.10%	2070	1.60%	2071	1
KCPL	Economic Capacity	S_SP	0.40%	1.00%	2403	1.40%	2404	1
KCPL	Economic Capacity	S_P	0.40%	2.20%	2070	2.50%	2070	1
KCPL	Economic Capacity	S_OP	0.50%	0.00%	2329	0.50%	2330	0
KCPL	Economic Capacity	W_SP	1.00%	2.20%	1472	3.20%	1473	1
KCPL	Economic Capacity	W_P	1.20%	2.50%	1633	3.70%	1636	3
KCPL	Economic Capacity	W_OP	1.00%	0.00%	1508	1.00%	1504	-4
KCPL	Economic Capacity	SH_SP	0.90%	3.60%	1330	4.50%	1336	6
KCPL	Economic Capacity	SH_P	1.20%	3.10%	1247	4.40%	1253	5
KCPL	Economic Capacity	SH_OP	2.90%	0.00%	920	2.80%	915	-5
LGE	Economic Capacity	S_35	7.60%	0.10%	2412	7.60%	2412	0
LGE	Economic Capacity	S_SP	2.40%	0.00%	1049	2.40%	1049	0
LGE	Economic Capacity	S_P	2.40%	0.00%	1138	2.40%	1138	0
LGE	Economic Capacity	S_OP	0.80%	0.00%	1365	0.80%	1365	0
LGE	Economic Capacity	W_SP	1.20%	0.00%	1757	1.20%	1757	0
LGE	Economic Capacity	W_P	1.30%	0.00%	1946	1.30%	1946	0
LGE	Economic Capacity	W_OP	10.70%	0.00%	1086	10.70%	1086	0
LGE	Economic Capacity	SH_SP	1.10%	0.00%	1507	1.10%	1507	0
LGE	Economic Capacity	SH_P	1.10%	0.00%	1500	1.10%	1500	0
LGE	Economic Capacity	SH_OP	0.80%	0.00%	1240	0.80%	1240	0
MPS	Economic Capacity	S_35	0.80%	0.00%	3548	1.00%	3658	110
MPS	Economic Capacity	S_SP	0.80%	0.00%	2905	0.90%	2900	-6
MPS	Economic Capacity	S_P	0.90%	0.00%	2602	1.00%	2600	-2
MPS	Economic Capacity	S_OP	1.20%	0.00%	2162	1.30%	2173	11
MPS	Economic Capacity	W_SP	0.40%	0.00%	931	0.40%	925	-6
MPS	Economic Capacity	W_P	0.30%	0.00%	928	0.40%	922	-7
MPS	Economic Capacity	W_OP	3.10%	0.00%	939	3.30%	925	-13
MPS	Economic Capacity	SH_SP	2.10%	0.00%	1368	2.20%	1364	-4
MPS	Economic Capacity	SH_P	0.50%	0.00%	1034	0.50%	1021	-13
MPS	Economic Capacity	SH_OP	1.80%	0.00%	1171	1.80%	1148	-23
NIPS	Economic Capacity	S_35	6.40%	0.10%	2461	6.50%	2462	1
NIPS	Economic Capacity	S_SP	0.50%	0.00%	1673	0.50%	1673	0
NIPS	Economic Capacity	S_P	0.50%	0.00%	1505	0.50%	1505	0
NIPS	Economic Capacity	S_OP	0.90%	0.00%	1372	0.90%	1372	0
NIPS	Economic Capacity	W_SP	0.80%	0.00%	1328	0.80%	1328	0
NIPS	Economic Capacity	W_P	0.80%	0.00%	1328	0.80%	1328	0
NIPS	Economic Capacity	W_OP	0.80%	0.00%	1215	0.80%	1215	0
NIPS	Economic Capacity	SH_SP	6.30%	0.00%	1247	6.30%	1247	0
NIPS	Economic Capacity	SH_P	6.30%	0.00%	1260	6.30%	1260	0
NIPS	Economic Capacity	SH_OP	0.70%	0.00%	1135	0.70%	1135	0
OKGE	Economic Capacity	S_35	0.10%	2.50%	5409	2.60%	5409	0
OKGE	Economic Capacity	S_SP	0.20%	2.40%	5504	2.50%	5505	0
OKGE	Economic Capacity	S_P	0.30%	7.00%	3068	7.20%	3069	1
OKGE	Economic Capacity	S_OP	0.80%	6.70%	3566	6.90%	3562	-4
OKGE	Economic Capacity	W_SP	0.20%	7.60%	3804	7.60%	3804	0
OKGE	Economic Capacity	W_P	0.40%	9.70%	1967	9.90%	1966	-1
OKGE	Economic Capacity	W_OP	0.80%	0.00%	2270	0.90%	2275	5
OKGE	Economic Capacity	SH_SP	0.20%	6.60%	3574	6.80%	3575	1
OKGE	Economic Capacity	SH_P	0.40%	7.70%	1668	8.10%	1667	0
OKGE	Economic Capacity	SH_OP	0.80%	0.00%	2060	0.80%	2070	10

Sensitivity: TTCs

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Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
STJO	Economic Capacity	S_35	1.00%	1.50%	717	2.60%	719	2
STJO	Economic Capacity	S_SP	0.90%	1.40%	758	2.40%	760	2
STJO	Economic Capacity	S_P	1.00%	2.70%	743	3.80%	747	4
STJO	Economic Capacity	S_OP	1.20%	0.00%	919	1.20%	916	-3
STJO	Economic Capacity	W_SP	2.00%	2.70%	888	5.20%	892	4
STJO	Economic Capacity	W_P	2.30%	2.90%	754	5.20%	760	6
STJO	Economic Capacity	W_OP	1.10%	0.00%	925	1.10%	916	-9
STJO	Economic Capacity	SH_SP	1.50%	4.00%	621	5.50%	629	8
STJO	Economic Capacity	SH_P	1.70%	3.10%	611	4.90%	619	8
STJO	Economic Capacity	SH_OP	3.30%	0.00%	905	3.20%	898	-7
SWEPA	Economic Capacity	S_35	0.20%	6.40%	1388	6.60%	1389	1
SWEPA	Economic Capacity	S_SP	0.30%	5.40%	1166	5.70%	1172	6
SWEPA	Economic Capacity	S_P	0.30%	5.00%	1427	5.10%	1411	-16
SWEPA	Economic Capacity	S_OP	0.40%	6.00%	1285	6.20%	1280	-5
SWEPA	Economic Capacity	W_SP	1.00%	16.80%	779	17.50%	796	18
SWEPA	Economic Capacity	W_P	1.50%	7.40%	895	8.50%	903	8
SWEPA	Economic Capacity	W_OP	0.80%	12.10%	762	12.20%	738	-24
SWEPA	Economic Capacity	SH_SP	1.60%	0.00%	1155	1.70%	1167	12
SWEPA	Economic Capacity	SH_P	2.10%	0.00%	967	2.20%	980	13
SWEPA	Economic Capacity	SH_OP	0.80%	0.00%	957	0.90%	957	0
TVA	Economic Capacity	S_35	12.60%	0.00%	838	12.60%	838	0
TVA	Economic Capacity	S_SP	12.60%	0.00%	799	12.60%	799	0
TVA	Economic Capacity	S_P	10.90%	0.00%	976	10.90%	976	0
TVA	Economic Capacity	S_OP	4.60%	0.00%	1208	4.60%	1208	0
TVA	Economic Capacity	W_SP	4.00%	0.00%	675	4.00%	675	0
TVA	Economic Capacity	W_P	0.70%	0.00%	1077	0.70%	1077	0
TVA	Economic Capacity	W_OP	5.60%	0.00%	1155	5.60%	1155	0
TVA	Economic Capacity	SH_SP	11.90%	1.10%	612	12.80%	634	22
TVA	Economic Capacity	SH_P	1.30%	0.00%	871	1.30%	871	0
TVA	Economic Capacity	SH_OP	4.90%	0.00%	943	4.90%	943	0
WR	Economic Capacity	S_35	0.20%	0.60%	4015	0.90%	4040	24
WR	Economic Capacity	S_SP	0.30%	1.50%	2935	1.80%	2936	0
WR	Economic Capacity	S_P	0.10%	0.00%	3135	0.10%	3129	-6
WR	Economic Capacity	S_OP	0.90%	0.00%	1775	0.90%	1775	0
WR	Economic Capacity	W_SP	0.10%	0.00%	2514	0.10%	2513	-1
WR	Economic Capacity	W_P	0.20%	0.00%	2676	0.20%	2675	-1
WR	Economic Capacity	W_OP	0.50%	0.00%	2463	0.50%	2461	-2
WR	Economic Capacity	SH_SP	1.00%	4.70%	1896	5.80%	1900	4
WR	Economic Capacity	SH_P	0.10%	0.00%	1857	0.10%	1855	-2
WR	Economic Capacity	SH_OP	0.60%	0.00%	1591	0.60%	1591	0

Sensitivity: TTCs

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Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Available Economic Capacity	S_35	13.30%	0.00%	708	13.90%	714	6
AECI	Available Economic Capacity	S_SP	0.00%	0.00%	784	0.00%	693	-92
AECI	Available Economic Capacity	S_P	0.00%	0.00%	1639	0.00%	1404	-235
AECI	Available Economic Capacity	S_OP	0.00%	0.00%	1311	0.00%	1184	-127
AECI	Available Economic Capacity	W_SP	6.50%	0.20%	757	6.70%	731	-26
AECI	Available Economic Capacity	W_P	0.00%	0.00%	973	0.00%	905	-68
AECI	Available Economic Capacity	W_OP	0.70%	0.00%	1189	0.00%	1153	-36
AECI	Available Economic Capacity	SH_SP	25.30%	0.30%	1025	24.50%	964	-61
AECI	Available Economic Capacity	SH_P	0.00%	0.00%	991	0.00%	914	-76
AECI	Available Economic Capacity	SH_OP	9.00%	0.00%	942	9.40%	884	-59
AEP	Available Economic Capacity	S_35	35.50%	0.00%	1647	33.50%	1528	-119
AEP	Available Economic Capacity	S_SP	98.50%	0.00%	9697	98.30%	9670	-27
AEP	Available Economic Capacity	S_P	99.80%	0.00%	9959	99.80%	9957	-2
AEP	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
AEP	Available Economic Capacity	W_SP	99.70%	0.00%	9943	99.70%	9939	-5
AEP	Available Economic Capacity	W_P	99.80%	0.00%	9959	99.80%	9956	-2
AEP	Available Economic Capacity	W_OP	99.80%	0.00%	9970	99.80%	9965	-5
AEP	Available Economic Capacity	SH_SP	85.50%	0.00%	7392	84.00%	7160	-232
AEP	Available Economic Capacity	SH_P	99.00%	0.00%	9803	98.90%	9790	-13
AEP	Available Economic Capacity	SH_OP	99.70%	0.00%	9935	99.60%	9912	-22
ALLIANT_E	Available Economic Capacity	S_35	0.00%	0.00%	1299	0.00%	1277	-22
ALLIANT_E	Available Economic Capacity	S_SP	0.00%	0.00%	1749	0.00%	1737	-12
ALLIANT_E	Available Economic Capacity	S_P	0.00%	0.00%	1619	0.00%	1619	0
ALLIANT_E	Available Economic Capacity	S_OP	0.00%	0.00%	7092	0.00%	7092	0
ALLIANT_E	Available Economic Capacity	W_SP	6.80%	0.00%	948	6.40%	943	-5
ALLIANT_E	Available Economic Capacity	W_P	0.00%	0.00%	1615	0.00%	1552	-63
ALLIANT_E	Available Economic Capacity	W_OP	0.00%	0.00%	4799	0.00%	4799	0
ALLIANT_E	Available Economic Capacity	SH_SP	0.00%	0.00%	1628	0.00%	1422	-206
ALLIANT_E	Available Economic Capacity	SH_P	0.00%	0.00%	2010	0.00%	1785	-225
ALLIANT_E	Available Economic Capacity	SH_OP	0.00%	0.00%	8205	0.00%	8205	0
AMEREN	Available Economic Capacity	S_35	19.30%	0.00%	1134	20.70%	1138	5
AMEREN	Available Economic Capacity	S_SP	4.70%	0.60%	392	6.00%	393	1
AMEREN	Available Economic Capacity	S_P	1.00%	0.00%	1016	1.50%	996	-20
AMEREN	Available Economic Capacity	S_OP	0.00%	0.00%	2553	0.00%	2271	-282
AMEREN	Available Economic Capacity	W_SP	2.50%	0.00%	876	2.50%	862	-14
AMEREN	Available Economic Capacity	W_P	6.10%	0.00%	1293	6.00%	1257	-36
AMEREN	Available Economic Capacity	W_OP	0.00%	0.00%	2600	0.00%	2600	0
AMEREN	Available Economic Capacity	SH_SP	10.80%	0.40%	566	12.90%	590	24
AMEREN	Available Economic Capacity	SH_P	8.90%	0.00%	1301	8.40%	1215	-86
AMEREN	Available Economic Capacity	SH_OP	0.00%	0.00%	4776	0.00%	4776	0
CIN	Available Economic Capacity	S_35	48.10%	0.00%	2582	44.70%	2303	-279
CIN	Available Economic Capacity	S_SP	0.00%	0.00%	3882	0.00%	3882	0
CIN	Available Economic Capacity	S_P	0.00%	0.00%	3260	0.00%	3260	0
CIN	Available Economic Capacity	S_OP	0.00%	0.00%	5151	0.00%	5151	0
CIN	Available Economic Capacity	W_SP	0.00%	0.00%	2277	0.00%	2252	-25
CIN	Available Economic Capacity	W_P	0.00%	0.00%	3094	0.00%	3094	0
CIN	Available Economic Capacity	W_OP	0.00%	0.00%	2990	0.00%	2889	-101
CIN	Available Economic Capacity	SH_SP	0.00%	0.00%	3973	0.00%	2216	-1757
CIN	Available Economic Capacity	SH_P	0.00%	0.00%	3266	0.00%	3266	0
CIN	Available Economic Capacity	SH_OP	0.00%	0.00%	4468	0.00%	2822	-1645

Sensitivity: TTCs

Exhibit No. AC-515

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Available Economic Capacity	S_35	18.70%	0.00%	1989	18.30%	1972	-16
COMED	Available Economic Capacity	S_SP	13.20%	0.00%	2039	12.70%	2024	-15
COMED	Available Economic Capacity	S_P	0.00%	0.00%	2308	0.00%	2120	-188
COMED	Available Economic Capacity	S_OP	0.00%	0.00%	5396	0.00%	5396	0
COMED	Available Economic Capacity	W_SP	34.70%	0.00%	1880	34.70%	1872	-8
COMED	Available Economic Capacity	W_P	0.00%	0.00%	2084	0.00%	2084	0
COMED	Available Economic Capacity	W_OP	0.00%	0.00%	2733	0.00%	2733	0
COMED	Available Economic Capacity	SH_SP	39.60%	0.00%	1872	37.80%	1739	-133
COMED	Available Economic Capacity	SH_P	0.00%	0.00%	1793	0.00%	1756	-37
COMED	Available Economic Capacity	SH_OP	0.00%	0.00%	2081	0.00%	1819	-262
CSW_SPP	Available Economic Capacity	S_35	9.90%	3.10%	582	12.00%	574	-8
CSW_SPP	Available Economic Capacity	S_SP	17.90%	6.70%	1002	20.20%	996	-6
CSW_SPP	Available Economic Capacity	S_P	0.00%	17.10%	909	6.80%	681	-227
CSW_SPP	Available Economic Capacity	S_OP	6.70%	0.00%	913	5.60%	788	-125
CSW_SPP	Available Economic Capacity	W_SP	3.20%	22.40%	935	22.60%	956	21
CSW_SPP	Available Economic Capacity	W_P	0.00%	0.00%	1006	0.00%	905	-101
CSW_SPP	Available Economic Capacity	W_OP	0.00%	0.00%	1040	0.00%	915	-125
CSW_SPP	Available Economic Capacity	SH_SP	20.40%	10.30%	925	24.50%	1009	84
CSW_SPP	Available Economic Capacity	SH_P	0.00%	8.60%	902	3.50%	764	-138
CSW_SPP	Available Economic Capacity	SH_OP	0.00%	0.00%	1145	0.00%	1004	-141
ENT	Available Economic Capacity	S_35	9.50%	0.00%	1761	9.50%	1741	-20
ENT	Available Economic Capacity	S_SP	0.00%	0.00%	2453	0.00%	1770	-683
ENT	Available Economic Capacity	S_P	0.00%	0.00%	2304	0.00%	1653	-651
ENT	Available Economic Capacity	S_OP	0.00%	0.00%	5983	0.00%	5269	-714
ENT	Available Economic Capacity	W_SP	3.50%	0.10%	3684	3.60%	3622	-62
ENT	Available Economic Capacity	W_P	0.00%	0.00%	988	0.00%	939	-49
ENT	Available Economic Capacity	W_OP	0.00%	0.00%	1092	0.00%	954	-138
ENT	Available Economic Capacity	SH_SP	31.30%	0.60%	1338	29.90%	1238	-100
ENT	Available Economic Capacity	SH_P	0.00%	0.00%	1549	0.00%	1343	-207
ENT	Available Economic Capacity	SH_OP	0.00%	0.00%	1526	0.00%	1371	-155
IP	Available Economic Capacity	S_35	19.20%	0.00%	886	19.90%	905	19
IP	Available Economic Capacity	S_SP	33.00%	0.00%	1446	33.90%	1477	31
IP	Available Economic Capacity	S_P	21.70%	0.00%	1230	22.20%	1217	-13
IP	Available Economic Capacity	S_OP	16.80%	0.00%	1782	16.60%	1755	-27
IP	Available Economic Capacity	W_SP	32.70%	0.00%	1582	32.50%	1577	-5
IP	Available Economic Capacity	W_P	0.00%	0.00%	1718	0.00%	1700	-18
IP	Available Economic Capacity	W_OP	16.10%	0.00%	1792	11.70%	1806	14
IP	Available Economic Capacity	SH_SP	28.30%	0.00%	1249	28.20%	1244	-5
IP	Available Economic Capacity	SH_P	0.00%	0.00%	1983	0.00%	1920	-63
IP	Available Economic Capacity	SH_OP	0.00%	0.00%	2484	0.00%	2418	-66

Sensitivity: TTCs **Exhibit No. AC-515**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
KCPL	Available Economic Capacity	S_35	10.20%	0.00%	951	10.80%	927	-25
KCPL	Available Economic Capacity	S_SP	4.90%	0.00%	793	5.30%	789	-4
KCPL	Available Economic Capacity	S_P	0.00%	0.00%	2398	0.00%	1528	-870
KCPL	Available Economic Capacity	S_OP	0.00%	0.00%	2336	0.00%	1751	-586
KCPL	Available Economic Capacity	W_SP	10.70%	0.00%	833	10.90%	775	-58
KCPL	Available Economic Capacity	W_P	0.00%	0.00%	905	0.00%	895	-10
KCPL	Available Economic Capacity	W_OP	0.00%	0.00%	4913	0.00%	4913	0
KCPL	Available Economic Capacity	SH_SP	16.30%	0.00%	988	16.20%	892	-95
KCPL	Available Economic Capacity	SH_P	0.00%	0.00%	2083	0.00%	1837	-245
KCPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5891	0.00%	5891	0
LGE	Available Economic Capacity	S_35	51.30%	0.00%	2917	48.80%	2692	-225
LGE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_OP	0.00%	0.00%	8415	0.00%	8415	0
LGE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
MPS	Available Economic Capacity	S_35	5.10%	0.00%	1317	4.10%	1187	-130
MPS	Available Economic Capacity	S_SP	0.00%	0.00%	3016	0.00%	2364	-653
MPS	Available Economic Capacity	S_P	0.00%	0.00%	2379	0.00%	2379	0
MPS	Available Economic Capacity	S_OP	0.00%	0.00%	3165	0.00%	2896	-269
MPS	Available Economic Capacity	W_SP	0.00%	0.00%	5089	0.00%	5089	0
MPS	Available Economic Capacity	W_P	0.00%	0.00%	4038	0.00%	4038	0
MPS	Available Economic Capacity	W_OP	0.00%	0.00%	2821	0.00%	2821	0
MPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3168	0.00%	1986	-1182
MPS	Available Economic Capacity	SH_P	0.00%	0.00%	8455	0.00%	8455	0
MPS	Available Economic Capacity	SH_OP	0.00%	0.00%	6140	0.00%	6140	0
NIPS	Available Economic Capacity	S_35	39.90%	0.00%	1978	39.20%	1927	-52
NIPS	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_OP	0.00%	0.00%	9715	0.00%	9715	0
NIPS	Available Economic Capacity	SH_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	SH_P	0.00%	0.00%	5985	0.00%	5985	0
NIPS	Available Economic Capacity	SH_OP	0.00%	0.00%	9677	0.00%	9677	0
OKGE	Available Economic Capacity	S_35	3.80%	0.00%	1236	4.30%	1151	-86
OKGE	Available Economic Capacity	S_SP	0.00%	0.00%	2989	0.00%	2347	-642
OKGE	Available Economic Capacity	S_P	0.00%	0.00%	3213	0.00%	1964	-1249
OKGE	Available Economic Capacity	S_OP	0.00%	0.00%	7022	0.00%	3280	-3743
OKGE	Available Economic Capacity	W_SP	0.00%	0.00%	1756	0.00%	1722	-34
OKGE	Available Economic Capacity	W_P	0.00%	0.00%	1843	0.00%	1407	-436
OKGE	Available Economic Capacity	W_OP	0.00%	0.00%	4771	0.00%	2729	-2042
OKGE	Available Economic Capacity	SH_SP	5.00%	0.20%	937	5.60%	885	-52
OKGE	Available Economic Capacity	SH_P	0.00%	0.00%	2122	0.00%	2136	14
OKGE	Available Economic Capacity	SH_OP	0.00%	0.00%	5476	0.00%	2460	-3016

Sensitivity: TTCs

Exhibit No. AC-515

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
STJO	Available Economic Capacity	S_35	9.90%	0.00%	1332	10.30%	1299	-33
STJO	Available Economic Capacity	S_SP	5.30%	0.00%	784	5.60%	791	7
STJO	Available Economic Capacity	S_P	0.00%	0.00%	1250	0.00%	1213	-37
STJO	Available Economic Capacity	S_OP	0.00%	0.00%	2021	0.00%	1573	-448
STJO	Available Economic Capacity	W_SP	0.00%	0.00%	1035	0.00%	971	-64
STJO	Available Economic Capacity	W_P	0.00%	0.00%	1212	0.00%	1159	-54
STJO	Available Economic Capacity	W_OP	0.00%	0.00%	4757	0.00%	4757	0
STJO	Available Economic Capacity	SH_SP	15.60%	0.00%	1048	15.50%	1008	-40
STJO	Available Economic Capacity	SH_P	0.00%	0.00%	1146	0.00%	1100	-46
STJO	Available Economic Capacity	SH_OP	0.00%	0.00%	5161	0.00%	5161	0
SWEPA	Available Economic Capacity	S_35	2.90%	0.00%	947	2.80%	871	-76
SWEPA	Available Economic Capacity	S_SP	6.70%	0.00%	2515	5.80%	1045	-1470
SWEPA	Available Economic Capacity	S_P	0.00%	0.00%	2832	0.00%	1809	-1023
SWEPA	Available Economic Capacity	S_OP	0.00%	0.00%	3203	0.00%	2144	-1059
SWEPA	Available Economic Capacity	W_SP	0.00%	0.20%	1348	0.10%	1148	-200
SWEPA	Available Economic Capacity	W_P	0.00%	0.00%	1590	0.00%	1340	-249
SWEPA	Available Economic Capacity	W_OP	0.00%	0.00%	1518	0.00%	1258	-260
SWEPA	Available Economic Capacity	SH_SP	0.30%	0.70%	955	1.10%	842	-114
SWEPA	Available Economic Capacity	SH_P	0.00%	0.00%	1780	0.00%	1517	-263
SWEPA	Available Economic Capacity	SH_OP	0.00%	0.00%	1431	0.00%	1246	-185
TVA	Available Economic Capacity	S_35	36.00%	0.00%	1718	35.20%	1657	-61
TVA	Available Economic Capacity	S_SP	44.90%	0.00%	2364	43.90%	2262	-102
TVA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_SP	49.00%	0.00%	2602	45.60%	2289	-313
TVA	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
WR	Available Economic Capacity	S_35	6.90%	0.00%	1209	7.10%	1207	-2
WR	Available Economic Capacity	S_SP	0.00%	0.00%	3003	0.00%	2090	-913
WR	Available Economic Capacity	S_P	0.00%	0.00%	4154	0.00%	2295	-1859
WR	Available Economic Capacity	S_OP	0.00%	0.00%	7480	0.00%	7480	0
WR	Available Economic Capacity	W_SP	0.00%	0.00%	1876	0.00%	1876	0
WR	Available Economic Capacity	W_P	0.00%	0.00%	3501	0.00%	3501	0
WR	Available Economic Capacity	W_OP	0.00%	0.00%	3305	0.00%	3305	0
WR	Available Economic Capacity	SH_SP	0.00%	0.00%	1701	0.00%	1406	-295
WR	Available Economic Capacity	SH_P	0.00%	0.00%	2466	0.00%	1741	-725
WR	Available Economic Capacity	SH_OP	0.00%	0.00%	4701	0.00%	3181	-1520

Simultaneous Transfer Limits

Destination Market		Exporting Market			
Node	Area	Node	Area	Limiting Factor	Source
AMEREN	SMAIN	AEP	ECAR EAST	Albion 345/138 kV Tr.	MAIN Summer Report 1998
IP	SMAIN	AEP	ECAR EAST	Albion 345/138 kV Tr.	MAIN Summer Report 1998
SIPC	SMAIN	BREC	ECAR WEST	Albion 345/138 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	CIN	ECAR WEST	Albion 345/138 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	COMED	NI	Albion 345/138 kV Tr.	MAIN Summer Report 1998
CILCO	SMAIN	COMED	NI	Albion 345/138 kV Tr.	MAIN Summer Report 1998
IP	SMAIN	COMED	NI	Albion 345/138 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	NIPS	ECAR WEST	Albion 345/138 kV Tr.	MAIN Summer Report 1998
SWPS	WC SPP	CSW_SPP	WC SPP	ALTUSJT4138-	SPP OASIS Calculations
SWPS	WC SPP	WEPL	N SPP	ALTUSJT4138-	SPP OASIS Calculations
EDE	N SPP	AECI	SERCW	BATEVL5161-CUSHMN51611	SPP OASIS Calculations
SPRM	N SPP	AECI	SERCW	BATEVL5161-CUSHMN51611	SPP OASIS Calculations
ENT	SERCW	CELE	SOLA	BEACRK4138-BVRCRK31151	SPP OASIS Calculations
ENT	SERCW	LAFA	SOLA	BEACRK4138-BVRCRK31151	SPP OASIS Calculations
PJM	MAAC	APS	ECAR EAST	Bedington-Doubs 500 kV	ECAR Summer Report 1999
PJM	MAAC	FENER	ECAR EAST	Bedington-Doubs 500 kV	ECAR Summer Report 1999
VP	VACAR	AEP	ECAR EAST	Bedington-Doubs 500 kV	ECAR Summer Report 1999
VP	VACAR	APS	ECAR EAST	Bedington-Doubs 500 kV	ECAR Summer Report 1999
AECI	SERCW	AMEREN	SMAIN	Bedington-Doubs 500kV	ECAR Summer Report 1999
ENT	SERCW	AMEREN	SMAIN	Bedington-Doubs 500kV	ECAR Summer Report 1999
TVA	TVA	AMEREN	SMAIN	Bland-Franks 345 kV	MAIN Summer Report 1998
TVA	TVA	EEI	SMAIN	Bland-Franks 345 kV	MAIN Summer Report 1998
TVA	TVA	IP	SMAIN	Bland-Franks 345 kV	MAIN Summer Report 1998
EDE	N SPP	CSW_SPP	WC SPP	BRKLNE5161-SPRGFLD51611	SPP OASIS Calculations
EDE	N SPP	ENT	SERCW	BRKLNE5161-SPRGFLD51611	SPP OASIS Calculations
EDE	N SPP	GRRD	WC SPP	BRKLNE5161-SPRGFLD51611	SPP OASIS Calculations
EDE	N SPP	KCPL	N SPP	BRKLNE5161-SPRGFLD51611	SPP OASIS Calculations
EDE	N SPP	WR	N SPP	BRKLNE5161-SPRGFLD51611	SPP OASIS Calculations
AEP	ECAR EAST	AMEREN	SMAIN	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
AEP	ECAR EAST	COMED	NI	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
AEP	ECAR EAST	IP	SMAIN	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
AEP	ECAR EAST	TVA	TVA	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
CIN	ECAR WEST	AMEREN	SMAIN	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
NIPS	ECAR WEST	AMEREN	SMAIN	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
LGE	ECAR WEST	EEI	SMAIN	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
BREC	ECAR WEST	SIPC	SMAIN	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
BREC	ECAR WEST	TVA	TVA	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
EKPC	ECAR WEST	TVA	TVA	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
LGE	ECAR WEST	TVA	TVA	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
AMEREN	SMAIN	AECI	SERCW	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
AMEREN	SMAIN	ENT	SERC	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
AMEREN	SMAIN	TVA	TVA	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
EEI	SMAIN	TVA	TVA	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
IP	SMAIN	TVA	TVA	Bull Run-Volunteer 500 kV	MAIN Winter Report 1998
EDE	N SPP	SWEPA	WC SPP	BULLSH*5161-FLIPN51611	SPP OASIS Calculations
SPRM	N SPP	SWEPA	WC SPP	BULLSH*5161-FLIPN51611	SPP OASIS Calculations
GRRD	WC SPP	SWEPA	WC SPP	BULLSH*5161-FLIPN51611	SPP OASIS Calculations
WEFA	WC SPP	SWEPA	WC SPP	BULLSH*5161-FLIPN51611	SPP OASIS Calculations
DPC	MINN	ALLIANT_E	WUMS	Cassel-Wien 115 kV	MAIN Summer Report 1998
NSP	MINN	ALLIANT_E	WUMS	Cassel-Wien 115 kV	MAIN Summer Report 1998
NSP	MINN	WEP	WUMS	Cassel-Wien 115 kV	MAIN Summer Report 1998
NSP	MINN	WPS	WUMS	Cassel-Wien 115 kV	MAIN Summer Report 1998
CSW_SPP	WC SPP	GRRD	WC SPP	CATSAGR5161-CATOOSA41382	SPP OASIS Calculations
OKGE	WC SPP	GRRD	WC SPP	CATSAGR5161-CATOOSA41382	SPP OASIS Calculations
WEFA	WC SPP	GRRD	WC SPP	CATSAGR5161-CATOOSA41382	SPP OASIS Calculations
SEC	N SPP	WEPL	N SPP	CLIFTON3115-GRNLEAF31151	SPP OASIS Calculations
WR	N SPP	WEPL	N SPP	CLIFTON3115-GRNLEAF31151	SPP OASIS Calculations
AMEREN	SMAIN	CSW_SPP	WC SPP	Clinton-Windsor 161 kV	MAIN Winter Report 1998

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
AMEREN	SMAIN	KCPL	N SPP	Clinton-Windsor 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	MPS	N SPP	Clinton-Windsor 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	STJO	MO	Clinton-Windsor 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	SWEPA	WC SPP	Clinton-Windsor 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	WR	N SPP	Clinton-Windsor 161 kV	MAIN Winter Report 1998
WEFA	WC SPP	OKGE	WC SPP	CORNVIL4138-CORNTP41381	SPP OASIS Calculations
WEFA	WC SPP	SWEPA	WC SPP	CORNVIL4138-CORNTP41381	SPP OASIS Calculations
ENT	SERCW	CAJN	SERCW	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
ENT	SERCW	CELE	SOLA	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	CIMO	N SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	CSW_SPP	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
ENT	SERCW	CSW_SPP	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	EDE	N SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
ENT	SERCW	EDE	N SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	GRRD	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	KCPL	N SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
ENT	SERCW	LAFA	SOLA	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
ENT	SERCW	LEPA	SOLA	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	LES	NEBR	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	MPS	N SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
ENT	SERCW	OKGE	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	SPRM	N SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	STJO	MO	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	SWEPA	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
ENT	SERCW	SWEPA	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AECI	SERCW	WR	N SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	CSW_SPP	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	SWEPA	WC SPP	Dardanelle-Russellville 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	ALLIANT_W	IOWA	Denmark-Viele 161 kV	MAIN Winter Report 1998

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
AMEREN	SMAIN	MIDAM	IOWA	Denmark-Viele 161 kV	MAIN Winter Report 1998
IP	SMAIN	MIDAM	IOWA	Denmark-Viele 161 kV	MAIN Winter Report 1998
WEP	WUMS	NSP	MINN	Eau Claire Arpin 345 kV Flow Limit	MAIN Summer Report 1998
WPS	WUMS	NSP	MINN	Eau Claire Arpin 345 kV Flow Limit	MAIN Summer Report 1998
STJO	MO	MIDAM	IOWA	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
STJO	MO	NPPD	NEBR	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
STJO	MO	OPPD	NEBR	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
KCPL	N SPP	MIDAM	IOWA	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
SEC	N SPP	NPPD	NEBR	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
WR	N SPP	OPPD	NEBR	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
LES	NEBR	MIDAM	IOWA	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
LES	NEBR	NPPD	NEBR	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
LES	NEBR	OPPD	NEBR	Fairport-Lathrop 161 kV	MAIN Summer Report 1998
CSW_SPP	WC SPP	SWEPA	WC SPP	FLIPN5161-SUMMIT51611	SPP OASIS Calculations
GRRD	WC SPP	SWEPA	WC SPP	FLIPN5161-SUMMIT51611	SPP OASIS Calculations
OKGE	WC SPP	SWEPA	WC SPP	FLIPN5161-SUMMIT51611	SPP OASIS Calculations
AEP	ECAR EAST	AMEREN	SMAIN	Foster Sugar Creek 345 kV	MAIN Summer Report 1998
AEP	ECAR EAST	COMED	NI	Foster Sugar Creek 345 kV	MAIN Summer Report 1998
AEP	ECAR EAST	IP	SMAIN	Foster Sugar Creek 345 kV	MAIN Summer Report 1998
KCPL	N SPP	AMEREN	SMAIN	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
MPS	N SPP	AMEREN	SMAIN	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	CSW_SPP	WC SPP	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	ENT	SERCW	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	SWEPA	WC SPP	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	TVA	TVA	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
EEI	SMAIN	TVA	TVA	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
IP	SMAIN	TVA	TVA	Ft. Smith 500/161 kV Tr.	MAIN Summer Report 1998
GRRD	WC SPP	AECI	SERCW	FTSMI5161-COLNY51611	SPP OASIS Calculations
GRRD	WC SPP	CSW_SPP	WC SPP	FTSMI5161-COLNY51611	SPP OASIS Calculations

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
WR	N SPP	AECI	SERCW	FTSMI8500-FTSMI51611	SPP OASIS Calculations
WR	N SPP	AMEREN	SMAIN	FTSMI8500-FTSMI51611	SPP OASIS Calculations
CSW_SPP	WC SPP	ENT	SERCW	FTSMI8500-FTSMI51611	SPP OASIS Calculations
GRRD	WC SPP	WEFA	WC SPP	FTSMI8500-FTSMI51611	SPP OASIS Calculations
OKGE	WC SPP	ENT	SERCW	FTSMI8500-FTSMI51611	SPP OASIS Calculations
OKGE	WC SPP	SWEPA	WC SPP	FTSMI8500-FTSMI51611	SPP OASIS Calculations
SWEPA	WC SPP	AECI	SERCW	FTSMI8500-FTSMI51611	SPP OASIS Calculations
SWEPA	WC SPP	AMEREN	SMAIN	FTSMI8500-FTSMI51611	SPP OASIS Calculations
BREC	ECAR WEST	TVA	TVA	Gallatin Hatsville 161 kV	MAIN Summer Report 1998
EKPC	ECAR WEST	TVA	TVA	Gallatin Hatsville 161 kV	MAIN Summer Report 1998
LGE	ECAR WEST	TVA	TVA	Gallatin Hatsville 161 kV	MAIN Summer Report 1998
TVA	TVA	AEP	ECAR EAST	Green River-River Queen 161 kV	MAIN Summer Report 1998
TVA	TVA	BREC	ECAR WEST	Green River-River Queen 161 kV	MAIN Summer Report 1998
TVA	TVA	EKPC	ECAR WEST	Green River-River Queen 161 kV	MAIN Summer Report 1998
TVA	TVA	LGE	ECAR WEST	Green River-River Queen 161 kV	MAIN Summer Report 1998
KCPL	N SPP	MPS	WC SPP	GRNWD5161-PHILL51611	SPP OASIS Calculations
WR	N SPP	MPS	WC SPP	GRNWD5161-PHILL51611	SPP OASIS Calculations
CSW_SPP	WC SPP	ENT	SERCW	GYPSY6230-MADISON62301	SPP OASIS Calculations
OKGE	WC SPP	ENT	SERCW	GYPSY6230-MADISON62301	SPP OASIS Calculations
SWEPA	WC SPP	ENT	SERCW	GYPSY6230-MADISON62301	SPP OASIS Calculations
EDE	N SPP	AECI	SERCW	HAYTI5161-BLYINT51611	SPP OASIS Calculations
KCPL	N SPP	AECI	SERCW	HAYTI5161-BLYINT51611	SPP OASIS Calculations
SPRM	N SPP	AECI	SERCW	HAYTI5161-BLYINT51611	SPP OASIS Calculations
WR	N SPP	AECI	SERCW	HAYTI5161-BLYINT51611	SPP OASIS Calculations
CSW_SPP	WC SPP	AECI	SERCW	HAYTI5161-BLYINT51611	SPP OASIS Calculations
GRRD	WC SPP	AECI	SERCW	HAYTI5161-BLYINT51611	SPP OASIS Calculations
MPS	WC SPP	AECI	SERCW	HAYTI5161-BLYINT51611	SPP OASIS Calculations
TVA	TVA	AMEREN	SMAIN	Hayti-Blytheville 161 kV	MAIN Winter Report 1998
TVA	TVA	EEI	SMAIN	Hayti-Blytheville 161 kV	MAIN Winter Report 1998

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
TVA	TVA	IP	SMAIN	Hayti-Blytheville 161 kV	MAIN Winter Report 1998
EDE	N SPP	WR	N SPP	HECGT3115-CIRCLE31151	SPP OASIS Calculations
KCPL	N SPP	WR	N SPP	HECGT3115-CIRCLE31151	SPP OASIS Calculations
MIDW	N SPP	WR	N SPP	HECGT3115-CIRCLE31151	SPP OASIS Calculations
MIDW	N SPP	SEC	N SPP	HOLCOMB3115-PLYMELL31151	SPP OASIS Calculations
WEPL	N SPP	SEC	N SPP	HOLCOMB3115-PLYMELL31151	SPP OASIS Calculations
ALLIANT_W	IOWA	AMEREN	SMAIN	La Cygne-Stillwell 345 kV	MAIN Summer Report 1998
ALLIANT_W	IOWA	COMED	NI	La Cygne-Stillwell 345 kV	MAIN Summer Report 1998
DPC	MINN	ALLIANT_E	WUMS	La Cygne-Stillwell 345 kV	MAIN Summer Report 1998
NSP	MINN	ALLIANT_E	WUMS	La Cygne-Stillwell 345 kV	MAIN Summer Report 1998
MIDAM	IOWA	AMEREN	SMAIN	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
MIDAM	IOWA	COMED	NI	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
MIDAM	IOWA	IP	SMAIN	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
MIDAM	IOWA	KCPL	N SPP	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
MIDAM	IOWA	LES	NEBR	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
MIDAM	IOWA	STJO	MO	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
NPPD	NEBR	LES	NEBR	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
OPPD	NEBR	LES	NEBR	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
NPPD	NEBR	SEC	N SPP	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
NPPD	NEBR	STJO	MO	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
OPPD	NEBR	STJO	MO	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
OPPD	NEBR	WR	N SPP	LaCygne-Stilwell 345 kV	MAIN Summer Report 1998
AMEREN	SMAIN	WR	N SPP	Lawrence Hil' 230/115 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	KCPL	N SPP	Lawrence Hill 230/115 kV Tr.	MAIN Winter Report 1998
AMEREN	SMAIN	MPS	N SPP	Lawrence Hill 230/115 kV Tr.	MAIN Winter Report 1998
ALLIANT_W	IOWA	AMEREN	SMAIN	Lockport-Lisle 345 kV Red	MAIN Summer Report 1998
MIDAM	IOWA	AMEREN	SMAIN	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
MIDAM	IOWA	IP	SMAIN	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
MIDAM	IOWA	KCPL	N SPP	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
MIDAM	IOWA	STJO	MO	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
COMED	NI	AEP	ECAR EAST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
COMED	NI	AMEREN	SMAIN	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
COMED	NI	CILCO	SMAIN	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
COMED	NI	IP	SMAIN	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
COMED	NI	NIPS	ECAR WEST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	AEP	ECAR EAST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
IP	SMAIN	AEP	ECAR EAST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
SIPC	SMAIN	BREC	ECAR WEST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	CIN	ECAR WEST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	CSW_SPP	WC SPP	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	KCPL	N SPP	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
EEI	SMAIN	LGE	ECAR WEST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	MPS	N SPP	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	NIPS	ECAR WEST	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	STJO	MO	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	SWEPA	WC SPP	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
AMEREN	SMAIN	WR	N SPP	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
ALLIANT_E	WUMS	AMEREN	SMAIN	Lockport-Lisle 345 kV Red	MAIN Summer Report 1998
ALLIANT_E	WUMS	COMED	NI	Lockport-Lisle 345 kV Red	MAIN Summer Report 1998
WEP	WUMS	COMED	NI	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
ALLIANT_E	WUMS	DPC	MINN	Lockport-Lisle 345 kV Red	MAIN Summer Report 1998
ALLIANT_E	WUMS	NSP	MINN	Lockport-Lisle 345 kV Red	MAIN Summer Report 1998
WEP	WUMS	NSP	MINN	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
WPS	WUMS	NSP	MINN	Lockport-Lisle 345 Kv Red	MAIN Summer Report 1998
SWEPA	WC SPP	AECI	SERCW	MAYFL3115-LKCON31151	SPP OASIS Calculations
SWEPA	WC SPP	AMEREN	SMAIN	MAYFL3115-LKCON31151	SPP OASIS Calculations
SWEPA	WC SPP	CSW_SPP	WC SPP	MAYFL3115-LKCON31151	SPP OASIS Calculations
SWEPA	WC SPP	ENT	SERCW	MAYFL3115-LKCON31151	SPP OASIS Calculations

Simultaneous Transfer Limits

Destination Market		Exporting Market			
Node	Area	Node	Area	Limiting Factor	Source
WR	N SPP	MIDW	N SPP	MED-LDG3115-MED-LDG41381	SPP OASIS Calculations
WR	N SPP	WEPL	N SPP	MED-LDG3115-MED-LDG41381	SPP OASIS Calculations
KCPL	N SPP	AMEREN	SMAIN	MER1&4138-MRSLTAP11381	SPP OASIS Calculations
WR	N SPP	AMEREN	SMAIN	MER1&4138-MRSLTAP11381	SPP OASIS Calculations
CSW_SPP	WC SPP	AMEREN	SMAIN	MER1&4138-MRSLTAP11381	SPP OASIS Calculations
SWEPA	WC SPP	AMEREN	SMAIN	MER1&4138-MRSLTAP11381	SPP OASIS Calculations
COMED	NI	AEP	ECAR EAST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
COMED	NI	NIPS	ECAR WEST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
AMEREN	SMAIN	AEP	ECAR EAST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
IP	SMAIN	AEP	ECAR EAST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
SIPC	SMAIN	BREC	ECAR WEST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
AMEREN	SMAIN	CIN	ECAR WEST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
EEI	SMAIN	LGE	ECAR WEST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
AMEREN	SMAIN	NIPS	ECAR WEST	Mitchell-Chicago Avenue 138 kV	MAIN Winter Report 1998
SWPS	WC SPP	CSW_SPP	WC SPP	MORWODS4138-ELKCITY41381	SPP OASIS Calculations
SWPS	WC SPP	WEPL	N SPP	MORWODS4138-ELKCITY41381	SPP OASIS Calculations
SWPS	WC SPP	CSW_SPP	WC SPP	N.E.S.-4138-RICECK41381	SPP OASIS Calculations
WEFA	WC SPP	CSW_SPP	WC SPP	N.E.S.-4138-RICECK41381	SPP OASIS Calculations
WR	N SPP	CSW_SPP	WC SPP	N.E.S.-7345-NEOSHO73451	SPP OASIS Calculations
WR	N SPP	OKGE	WC SPP	N.E.S.-7345-NEOSHO73451	SPP OASIS Calculations
KACY	N SPP	KCPL	N SPP	NEASTN5161-GRAND51611	SPP OASIS Calculations
WR	N SPP	KCPL	N SPP	NEASTN5161-GRAND51611	SPP OASIS Calculations
TVA	TVA	AEP	ECAR EAST	New Hardinsburg 161/138 kV Tr	MAIN Winter Report 1998
TVA	TVA	BREC	ECAR WEST	New Hardinsburg 161/138 kV Tr	MAIN Winter Report 1998
TVA	TVA	EKPC	ECAR WEST	New Hardinsburg 161/138 kV Tr	MAIN Winter Report 1998
TVA	TVA	LGE	ECAR WEST	New Hardinsburg 161/138 kV Tr	MAIN Winter Report 1998
ALLIANT_E	WUMS	AMEREN	SMAIN	Oak Creek 230/138 kV Tr.	MAIN Winter Report 1998
ALLIANT_E	WUMS	COMED	NI	Oak Creek 230/138 kV Tr.	MAIN Winter Report 1998
KCPL	N SPP	AMEREN	SMAIN	OSAGE138-ELDON1611	SPP OASIS Calculations

Simultaneous Transfer Limits

Destination Market		Exporting Market			
Node	Area	Node	Area	Limiting Factor	Source
WR	N SPP	AMEREN	SMAIN	OSAGE138-ELDON1611	SPP OASIS Calculations
CSW_SPP	WC SPP	AMEREN	SMAIN	OSAGE138-LKSIDE11381	SPP OASIS Calculations
SWEPA	WC SPP	AMEREN	SMAIN	OSAGE138-LKSIDE11381	SPP OASIS Calculations
CSW_SPP	WC SPP	AMEREN	SMAIN	RIVMIN2138-DELBRG11381	SPP OASIS Calculations
MPS	WC SPP	AMEREN	SMAIN	RIVMIN2138-DELBRG11381	SPP OASIS Calculations
KCPL	N SPP	AMEREN	SMAIN	Russellville Dardanelle 161 kV	MAIN Winter Report 1998
MPS	N SPP	AMEREN	SMAIN	Russellville Dardanelle 161 kV	MAIN Winter Report 1998
WR	N SPP	AMEREN	SMAIN	Russellville Dardanelle 161 kV	MAIN Winter Report 1998
KCPL	N SPP	AMEREN	SMAIN	Russellville-Dardanelle 161 kV	MAIN Summer Report 1998
WR	N SPP	AMEREN	SMAIN	Russellville-Dardanelle 161 kV	MAIN Summer Report 1998
CIMO	N SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
EDE	N SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
KCPL	N SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
MPS	N SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
SPRM	N SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
WR	N SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
EDE	N SPP	ENT	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	TVA	TVA	Russellville-Dardanelle 161 kV	MAIN Summer Report 1998
EEI	SMAIN	TVA	TVA	Russellville-Dardanelle 161 kV	MAIN Summer Report 1998
IP	SMAIN	TVA	TVA	Russellville-Dardanelle 161 kV	MAIN Summer Report 1998
CELE	SOLA	ENT	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
LAFA	SOLA	ENT	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
LEPA	SOLA	ENT	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
CSW_SPP	WC SPP	AMEREN	SMAIN	Russellville Dardanelle 161 kV	MAIN Winter Report 1998
SWEPA	WC SPP	AMEREN	SMAIN	Russellville Dardanelle 161 kV	MAIN Winter Report 1998
CSW_SPP	WC SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
GRRD	WC SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
SWEPA	WC SPP	AECI	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
CSW_SPP	WC SPP	ENT	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
OKGE	WC SPP	ENT	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
SWEPA	WC SPP	ENT	SERCW	Russellville-Dardanelle 161 kV	MAIN Winter Report 1998
GRRD	WC SPP	SWEPA	WC SPP	SALINA5161-KERRGR51611	SPP OASIS Calculations
GRRD	WC SPP	WEFA	WC SPP	SALINA5161-KERRGR51611	SPP OASIS Calculations
GRRD	WC SPP	CSW_SPP	WC SPP	SALINA5161-KERRGR51612	SPP OASIS Calculations
GRRD	WC SPP	OKGE	WC SPP	SALINA5161-KERRGR51612	SPP OASIS Calculations
WR	N SPP	CSW_SPP	WC SPP	SCOFVLE4138-DEARING41381	SPP OASIS Calculations
WR	N SPP	OKGE	WC SPP	SCOFVLE4138-DEARING41381	SPP OASIS Calculations
STJO	MO	MIDAM	IOWA	Scott City Sctab 115 kV	MAIN Winter Report 1998
STJO	MO	NPPD	NEBR	Scott City Sctab 115 kV	MAIN Winter Report 1998
STJO	MO	OPPD	NEBR	Scott City Sctab 115 kV	MAIN Winter Report 1998
KCPL	N SPP	MIDAM	IOWA	Scott City Sctab 115 kV	MAIN Winter Report 1998
SEC	N SPP	NPPD	NEBR	Scott City Sctab 115 kV	MAIN Winter Report 1998
WR	N SPP	OPPD	NEBR	Scott City Sctab 115 kV	MAIN Winter Report 1998
LAFA	SOLA	CELE	SOLA	SCOTT4138-BONIN41381	SPP OASIS Calculations
LAFA	SOLA	ENT	SERCW	SCOTT4138-BONIN41381	SPP OASIS Calculations
MPS	WC SPP	AECI	SERCW	SIBLEY5161-DUNCAN51611	SPP OASIS Calculations
MPS	WC SPP	KCPL	N SPP	SIBLEY5161-DUNCAN51611	SPP OASIS Calculations
MPS	WC SPP	WR	N SPP	SIBLEY5161-DUNCAN51611	SPP OASIS Calculations
MIDAM	IOWA	KCPL	N SPP	St. Joe Midway 161 kV	MAIN Winter Report 1998
MIDAM	IOWA	LES	NEBR	St. Joe Midway 161 kV	MAIN Winter Report 1998
MIDAM	IOWA	STJO	MO	St. Joe Midway 161 kV	MAIN Winter Report 1998
NPPD	NEBR	LES	NEBR	St. Joe Midway 161 kV	MAIN Winter Report 1998
OPPD	NEBR	LES	NEBR	St. Joe Midway 161 kV	MAIN Winter Report 1998
NPPD	NEBR	SEC	N SPP	St. Joe Midway 161 kV	MAIN Winter Report 1998
NPPD	NEBR	STJO	MO	St. Joe Midway 161 kV	MAIN Winter Report 1998
OPPD	NEBR	STJO	MO	St. Joe Midway 161 kV	MAIN Winter Report 1998
OPPD	NEBR	WR	N SPP	St. Joe Midway 161 kV	MAIN Winter Report 1998
AMEREN	SMAIN	AEP	ECAR EAST	Stallings 345/138 kV Tr.	MAIN Summer Report 1998

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
AMEREN	SMAIN	CIN	ECAR WEST	Stallings 345/138 kV Tr.	MAIN Summer Report 1998
AMEREN	SMAIN	COMED	NI	Stallings 345/138 kV Tr.	MAIN Summer Report 1998
NIPS	ECAR WEST	COMED	NI	State Line-Wolf Lake 138 kV	MAIN Winter Report 1998
BREC	ECAR WEST	SIPC	SMAIN	State Line-Wolf Lake 138 kV	MAIN Winter Report 1998
EDE	N SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
KCPL	N SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
SPRM	N SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
WR	N SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
CSW_SPP	WC SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
GRRD	WC SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
MPS	WC SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
SWEPA	WC SPP	AECI	SERCW	STFRAN5161-GRNFRT51611	SPP OASIS Calculations
AECI	SERCW	CSW_SPP	WC SPP	T.P.S.-4138-36LEWIS41381	SPP OASIS Calculations
ENT	SERCW	CSW_SPP	WC SPP	T.P.S.-4138-36LEWIS41381	SPP OASIS Calculations
GRRD	WC SPP	OKGE	WC SPP	T.P.S.-4138-36LEWIS41381	SPP OASIS Calculations
OKGE	WC SPP	CSW_SPP	WC SPP	T.P.S.-4138-36LEWIS41381	SPP OASIS Calculations
SWEPA	WC SPP	CSW_SPP	WC SPP	T.P.S.-4138-36LEWIS41381	SPP OASIS Calculations
WR	N SPP	CSW_SPP	WC SPP	TECHILL3115-TEC31151	SPP OASIS Calculations
WR	N SPP	OKGE	WC SPP	TECHILL3115-TEC31151	SPP OASIS Calculations
PJM	MAAC	APS	ECAR EAST	Voltage Limit Bedington-Doubs 500kV	VEM Winter Report 1997
PJM	MAAC	FENER	ECAR EAST	Voltage Limit Bedington-Doubs 500kV	VEM Winter Report 1997
CAPO	VACAR	AEP	ECAR EAST	Voltage Limit Bedington-Doubs 500kV	VEM Winter Report 1997
DUKE	VACAR	AEP	ECAR EAST	Voltage Limit Bedington-Doubs 500kV	VEM Winter Report 1997
SWPS	WC SPP	CSW_SPP	WC SPP	WELEETK4138-WELEETK41381	SPP OASIS Calculations
WEFA	WC SPP	CSW_SPP	WC SPP	WELEETK4138-WELEETK41381	SPP OASIS Calculations
CELE	SOLA	CSW_SPP	WC SPP	WILBT4138-LIVON41381	SPP OASIS Calculations
CELE	SOLA	ENT	SERCW	WILBT4138-LIVON41381	SPP OASIS Calculations
LAFA	SOLA	ENT	SERCW	WILBT4138-LIVON41381	SPP OASIS Calculations
SEC	N SPP	MIDW	N SPP	WJCCTYE3115-WJCCTY31151	SPP OASIS Calculations

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
WR	N SPP	EDE	N SPP	WJCCTYE3115-WJCCTY31151	SPP OASIS Calculations
WR	N SPP	KACY	N SPP	WJCCTYE3115-WJCCTY31151	SPP OASIS Calculations
WR	N SPP	MPS	WC SPP	WJCCTYE3115-WJCCTY31151	SPP OASIS Calculations
WR	N SPP	OKGE	WC SPP	WJCCTYE3115-WJCCTY31151	SPP OASIS Calculations
STEC	ERCOT	TMPA	ERCOT	Big Brown to Jewett 345 kV	Ercot ISO WWW Page - 1998 Winter
DGG	ERCOT	TMPA	ERCOT	Big Brown to Jewett 345 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	TMPA	ERCOT	Big Brown to Jewett 345 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	TMPA	ERCOT	Big Brown to Jewett 345 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	TMPA	ERCOT	Big Brown to Jewett 345 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	WTU	ERCOT	Bowie to HardySW 138 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	WTU	ERCOT	Bowie to HardySW 138 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	WTU	ERCOT	Bowie to HardySW 138 kV	Ercot ISO WWW Page - 1998 Winter
TNMP	ERCOT	WTU	ERCOT	Bowie to HardySW 138 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	WTU	ERCOT	Bowie to HardySW 138 kV	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	CPS	ERCOT	Braunig to Elmendrf 138 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	CPS	ERCOT	Braunig to Elmendrf 138 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	STEC	ERCOT	Braunig to Elmendrf 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	BRYN	ERCOT	Dansby C to Dansby 69 138/69 kV Auto	Ercot ISO WWW Page - 1998 Winter
DGG	ERCOT	BRYN	ERCOT	Dansby C to Dansby 69 138/69 kV Auto	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	BRYN	ERCOT	Dansby C to Dansby 69 138/69 kV Auto	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	CPS	ERCOT	Fratt to kirby 138 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	CPS	ERCOT	Fratt to kirby 138 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	HLP	ERCOT	Holman to Lytton 345 kV	Ercot ISO WWW Page - 1998 Winter
COA	ERCOT	HLP	ERCOT	Holman to Lytton 345 kV	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	HLP	ERCOT	Holman to Lytton 345 kV	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	BEC	ERCOT	Dansby C to Dansby 69 138/69 kV Auto	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	DGG	ERCOT	Dansby C to Dansby 69 138/69 kV Auto	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	TMPA	ERCOT	Dansby C to Dansby 69 138/69 kV Auto	Ercot ISO WWW Page - 1998 Winter
TNMP	ERCOT	HLP	ERCOT	Dow345 5 to Dow138 8 345/138 kV Auto	Ercot ISO WWW Page - 1998 Winter

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
TNMP	ERCOT	TU	ERCOT	Dow345 5 to Dow138 8 345/138 kV Auto	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	BEC	ERCOT	Hilltop to N. Weatherford 138 kV	Ercot ISO WWW Page - 1998 Winter
DGG	ERCOT	BEC	ERCOT	Hilltop to N. Weatherford 138 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	BEC	ERCOT	Hilltop to N. Weatherford 138 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	BEC	ERCOT	Hilltop to N. Weatherford 138 kV	Ercot ISO WWW Page - 1998 Winter
TNMP	ERCOT	BEC	ERCOT	Hilltop to N. Weatherford 138 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	BEC	ERCOT	Hilltop to N. Weatherford 138 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	BEC	ERCOT	Hilltop to N. Weatherford 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	CPS	ERCOT	Hondo to Hondo Creek 138 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	CPS	ERCOT	Hondo to Hondo Creek 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	DGG	ERCOT	Hood to Decordova 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	LCRA	ERCOT	Hood to Decordova 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	WTU	ERCOT	Hood to Decordova 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	TMPA	ERCOT	Jewett 345/138 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	TMPA	ERCOT	Jewett 345/138 kV	Ercot ISO WWW Page - 1998 Winter
DGG	ERCOT	TMPA	ERCOT	Jewett 345/138 kV	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	LCRA	ERCOT	Killeen Fort Hood Tap To Killeen Clear Creek 138 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	HLP	ERCOT	Killeen Fort Hood Tap To Killeen Clear Creek 138 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	TU	ERCOT	Killeen Fort Hood Tap To Killeen Clear Creek 138 kV	Ercot ISO WWW Page - 1998 Winter
COA	ERCOT	HLP	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	HLP	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	STEC	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	TMPA	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
DGG	ERCOT	TMPA	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	TMPA	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	TMPA	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	TMPA	ERCOT	Jewett S to Lake Creek 345 kV	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	CBEN	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	CBEN	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
LCRA	ERCOT	CBEN	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	CBEN	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	CBEN	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	CBEN	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	CPS	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	HLP	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	LCRA	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	TMPA	ERCOT	L-463 to Victoria 138 kV	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	CPS	ERCOT	Leon to Pleasenton 138 kV	Ercot ISO WWW Page - 1998 Winter
STEC	ERCOT	CPS	ERCOT	Leon to Pleasenton 138 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	CPS	ERCOT	Leon to Pleasenton 138 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	LCRA	ERCOT	Leon to Putnam tap 138 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	TU	ERCOT	Leon to Putnam tap 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	WTU	ERCOT	Leon to Putnam tap 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	DGG	ERCOT	Olinger to Ben Davis 138 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	DGG	ERCOT	Olinger to Ben Davis 138 kV	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	CBEN	ERCOT	Rayburn to Vitoria 138 kV	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	CBEN	ERCOT	Rayburn to Vitoria 138 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	CBEN	ERCOT	Rayburn to Vitoria 138 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	CBEN	ERCOT	Rayburn to Vitoria 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	TNMP	ERCOT	Wcolmain to Sclpcogn 138 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	TNMP	ERCOT	Wcolmain to Sclpcogn 138 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	TNMP	ERCOT	Wcolmain to Sclpcogn 138 kV	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	DGG	ERCOT	Watson CP to Jewett 138 kV	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	TMPA	ERCOT	Watson CP to Jewett 138 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	TU	ERCOT	Watson CP to Jewett 138 kV	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	BEC	ERCOT	Watson CP to Jewett 138 kV - S	Ercot ISO WWW Page - 1998 Winter
BRYN	ERCOT	DGG	ERCOT	Watson CP to Jewett 138 kV - S	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	DGG	ERCOT	Watson CP to Jewett 138 kV - S	Ercot ISO WWW Page - 1998 Winter

Simultaneous Transfer Limits

Destination Market		Exporting Market			
Node	Area	Node	Area	Limiting Factor	Source
BRYN	ERCOT	TMPA	ERCOT	Watson CP to Jewett 138 kV - S	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	TU	ERCOT	Watson CP to Jewett 138 kV - S	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	TU	ERCOT	Watson CP to Jewett 138 kV - S	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	CPS	ERCOT	WAP to South Texas 345 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	STEC	ERCOT	WAP to South Texas 345 kV	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	CBEN	ERCOT	WAP to South Texas 345 kV	Ercot ISO WWW Page - 1998 Winter
HLP	ERCOT	STEC	ERCOT	WAP to South Texas 345 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	LCRA	ERCOT	Tricorn to Trinidad2 345 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	LCRA	ERCOT	Tricorn to Trinidad2 345 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	LCRA	ERCOT	Tricorn to Trinidad2 345 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	HLP	ERCOT	STP to Lon Hill 345 kV - S	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	LCRA	ERCOT	STP to Lon Hill 345 kV - S	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	CBEN	ERCOT	Stockdale to Kennedy Switch 138 kV	Ercot ISO WWW Page - 1998 Winter
LCRA	ERCOT	CBEN	ERCOT	Stockdale to Kennedy Switch 138 kV	Ercot ISO WWW Page - 1998 Winter
WTU	ERCOT	CBEN	ERCOT	Stockdale to Kennedy Switch 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	LCRA	ERCOT	Stephenville tap to Stephenville 138 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	LCRA	ERCOT	Stephenville tap to Stephenville 138 kV	Ercot ISO WWW Page - 1998 Winter
CBEN	ERCOT	STEC	ERCOT	Stephenville tap to Stephenville 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	TU	ERCOT	Stephenville tap to Stephenville 138 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	HLP	ERCOT	Robertson to Milano M 138 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	STEC	ERCOT	Robertson to Milano M 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	BRYN	ERCOT	Robertson to Watson CP 138 kV	Ercot ISO WWW Page - 1998 Winter
DGG	ERCOT	BRYN	ERCOT	Robertson to Watson CP 138 kV	Ercot ISO WWW Page - 1998 Winter
TMPA	ERCOT	BRYN	ERCOT	Robertson to Watson CP 138 kV	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	LCRA	ERCOT	Skyline to Marion 345 kV	Ercot ISO WWW Page - 1998 Winter
CPS	ERCOT	STEC	ERCOT	Skyline to Marion 345 kV	Ercot ISO WWW Page - 1998 Winter
TU	ERCOT	LCRA	ERCOT	Sandow Rogers 138 kV	Ercot ISO WWW Page - 1998 Winter
BEC	ERCOT	LCRA	ERCOT	Sandow Rogers 138 kV	Ercot ISO WWW Page - 1998 Winter
MIDAM	IOWA	NSP	MINN	Drayton-Prairie 230 kV	MAPP 1998 Summer Operational Study

Simultaneous Transfer Limits

Destination Market		Exporting Market		Limiting Factor	Source
Node	Area	Node	Area		
MIDAM	IOWA	STJO	MO	Drayton-Prairie 230 kV	MAPP 1998 Summer Operational Study
MIDAM	IOWA	LES	NEBR	Drayton-Prairie 230 kV	MAPP 1998 Summer Operational Study
ALLIANT_W	IOWA	AMEREN	SMAIN	Drayton-Prairie 230 kV - 2	MAPP 1998 Summer Operational Study
MIDAM	IOWA	IP	SMAIN	Drayton-Prairie 230 kV - 2	MAPP 1998 Summer Operational Study
NPPD	NEBR	STJO	MO	Drayton-Prairie 230 kV	MAPP 1998 Summer Operational Study
NPPD	NEBR	SEC	N SPP	Drayton-Prairie 230 kV	MAPP 1998 Summer Operational Study
NPPD	NEBR	OPPD	NEBR	Drayton-Prairie 230 kV	MAPP 1998 Summer Operational Study
AMEREN	SMAIN	MIDAM	IOWA	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
AMEREN	SMAIN	STJO	MO	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
AMEREN	SMAIN	KCPL	N SPP	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
AMEREN	SMAIN	MPS	N SPP	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
AMEREN	SMAIN	WR	N SPP	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
AMEREN	SMAIN	SWEPA	WC SPP	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
NPPD	NEBR	STJO	MO	Watertown-Granite Fls 230 kV	MAPP 1998 Summer Operational Study
OPPD	NEBR	STJO	MO	Watertown-Granite Fls 230 kV	MAPP 1998 Summer Operational Study
NPPD	NEBR	SEC	N SPP	Watertown-Granite Fls 230 kV	MAPP 1998 Summer Operational Study
OPPD	NEBR	WR	N SPP	Watertown-Granite Fls 230 kV	MAPP 1998 Summer Operational Study
MIDAM	IOWA	STJO	MO	Watertown-Granite Fls 230 kV	MAPP 1998 Summer Operational Study
MIDAM	IOWA	LES	NEBR	Watertown-Granite Fls 230 kV	MAPP 1998 Summer Operational Study
ALLIANT_E	WUMS	DPC	MINN	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
ALLIANT_E	WUMS	NSP	MINN	Eau Claire Arpin 345 kV	MAPP 1998 Summer Operational Study
LES	NEBR	NPPD	NEBR	Gentleman-Sweetwater 345 kV #1	MAPP 1998 Summer Operational Study
LES	NEBR	OPPD	NEBR	Gentleman-Sweetwater 345 kV #1	MAPP 1998 Summer Operational Study
NPPD	NEBR	BEPC	DAK	Granite Fls-Minn Vly T 230 kV	MAPP 1998 Summer Operational Study
NPPD	NEBR	WAPA	DAK	Granite Fls-Minn Vly T 230 kV	MAPP 1998 Summer Operational Study

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CSW_SPP	Economic Capacity	S_35	0.20%	63.40%	4114	62.70%	4026	-88
CSW_SPP	Economic Capacity	S_SP	0.30%	62.00%	3937	61.20%	3842	-94
CSW_SPP	Economic Capacity	S_P	0.30%	53.40%	3057	51.30%	2832	-224
CSW_SPP	Economic Capacity	S_OP	0.40%	49.00%	2645	46.80%	2428	-217
CSW_SPP	Economic Capacity	W_SP	0.40%	56.50%	3306	55.30%	3179	-128
CSW_SPP	Economic Capacity	W_P	0.70%	37.60%	1649	36.60%	1578	-72
CSW_SPP	Economic Capacity	W_OP	0.90%	37.80%	1658	37.10%	1612	-46
CSW_SPP	Economic Capacity	SH_SP	0.50%	50.60%	2714	49.00%	2560	-155
CSW_SPP	Economic Capacity	SH_P	0.90%	36.50%	1561	35.60%	1503	-58
CSW_SPP	Economic Capacity	SH_OP	1.50%	32.00%	1313	31.90%	1303	-11
CBEN	Economic Capacity	S_35	0.00%	66.80%	4691	64.10%	4339	-352
CBEN	Economic Capacity	S_SP	0.00%	64.00%	4371	62.00%	4134	-237
CBEN	Economic Capacity	S_P	0.00%	61.30%	4117	59.30%	3872	-245
CBEN	Economic Capacity	S_OP	0.00%	54.80%	3435	50.80%	3022	-413
CBEN	Economic Capacity	W_SP	0.00%	72.00%	5336	69.20%	4939	-397
CBEN	Economic Capacity	W_P	0.00%	69.10%	5005	64.80%	4454	-551
CBEN	Economic Capacity	W_OP	0.00%	68.40%	4927	64.10%	4371	-556
CBEN	Economic Capacity	SH_SP	0.00%	55.50%	3415	52.50%	3101	-313
CBEN	Economic Capacity	SH_P	0.00%	54.00%	3332	50.70%	2999	-333
CBEN	Economic Capacity	SH_OP	0.00%	44.10%	2534	40.10%	2217	-317
VALLEY	Economic Capacity	S_35	0.00%	78.00%	6177	64.60%	4437	-1739
VALLEY	Economic Capacity	S_SP	0.00%	77.80%	6138	63.50%	4321	-1816
VALLEY	Economic Capacity	S_P	0.00%	79.20%	6339	64.50%	4447	-1892
VALLEY	Economic Capacity	S_OP	0.00%	75.80%	5864	60.50%	4014	-1850
VALLEY	Economic Capacity	W_SP	0.00%	75.50%	5868	62.70%	4255	-1613
VALLEY	Economic Capacity	W_P	0.00%	79.50%	6398	64.20%	4433	-1965
VALLEY	Economic Capacity	W_OP	0.00%	79.90%	6459	64.60%	4482	-1977
VALLEY	Economic Capacity	SH_SP	0.00%	70.00%	5057	56.20%	3505	-1552
VALLEY	Economic Capacity	SH_P	0.00%	70.20%	5078	55.20%	3427	-1651
VALLEY	Economic Capacity	SH_OP	0.00%	69.80%	5039	54.30%	3356	-1683
WTU	Economic Capacity	S_35	0.00%	41.20%	2374	40.90%	2352	-23
WTU	Economic Capacity	S_SP	0.00%	33.00%	1995	32.50%	1971	-24
WTU	Economic Capacity	S_P	0.00%	31.40%	2431	30.90%	2405	-26
WTU	Economic Capacity	S_OP	0.00%	19.10%	2259	21.00%	2222	-37
WTU	Economic Capacity	W_SP	0.00%	49.00%	4019	48.90%	4014	-5
WTU	Economic Capacity	W_P	0.00%	38.70%	3768	38.50%	3765	-3
WTU	Economic Capacity	W_OP	0.00%	38.80%	3782	38.70%	3778	-4
WTU	Economic Capacity	SH_SP	0.00%	33.90%	2227	33.50%	2197	-29
WTU	Economic Capacity	SH_P	0.00%	27.40%	2077	26.80%	2050	-26
WTU	Economic Capacity	SH_OP	0.00%	23.00%	2055	22.40%	2029	-25

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
BRYN	Economic Capacity	S_OP	0.00%	15.20%	1438	15.00%	1411	-27
BRYN	Economic Capacity	W_SP	0.00%	0.60%	2118	0.60%	2118	0
BRYN	Economic Capacity	W_P	0.00%	1.20%	2437	1.20%	2443	6
BRYN	Economic Capacity	W_OP	0.00%	0.60%	2491	0.60%	2492	2
BRYN	Economic Capacity	SH_SP	0.00%	14.50%	1279	14.10%	1269	-10
BRYN	Economic Capacity	SH_P	0.00%	15.60%	1547	14.80%	1503	-44
BRYN	Economic Capacity	SH_OP	0.00%	20.00%	1643	18.40%	1574	-69
CAPO	Economic Capacity	S_35	2.10%	0.00%	6821	2.30%	6750	-71
CAPO	Economic Capacity	S_SP	2.20%	0.00%	6797	2.30%	6726	-71
CAPO	Economic Capacity	S_P	0.60%	0.00%	6750	0.60%	6692	-58
CAPO	Economic Capacity	S_OP	1.70%	0.00%	3900	1.80%	3801	-99
CAPO	Economic Capacity	W_SP	5.80%	0.00%	4220	5.40%	4246	25
CAPO	Economic Capacity	W_P	4.00%	0.00%	2397	3.90%	2414	17
CAPO	Economic Capacity	W_OP	3.80%	0.00%	2143	3.70%	2164	21
CAPO	Economic Capacity	SH_SP	3.80%	0.00%	4561	4.10%	4487	-74
CAPO	Economic Capacity	SH_P	1.30%	0.00%	4474	1.40%	4409	-65
CAPO	Economic Capacity	SH_OP	0.60%	0.00%	2265	0.60%	2236	-29
CELE	Economic Capacity	S_35	0.00%	5.10%	6627	5.10%	6626	0
CELE	Economic Capacity	S_SP	0.20%	10.10%	4390	10.20%	4391	0
CELE	Economic Capacity	S_P	0.10%	0.60%	8017	0.80%	8017	0
CELE	Economic Capacity	S_OP	0.30%	0.70%	7949	0.90%	7948	0
CELE	Economic Capacity	W_SP	0.20%	7.30%	4716	7.00%	4763	47
CELE	Economic Capacity	W_P	0.90%	10.60%	2229	10.70%	2267	38
CELE	Economic Capacity	W_OP	0.80%	12.50%	2210	12.50%	2249	39
CELE	Economic Capacity	SH_SP	0.80%	1.90%	4442	1.30%	4480	38
CELE	Economic Capacity	SH_P	2.10%	3.70%	2342	4.10%	2386	44
CELE	Economic Capacity	SH_OP	2.10%	5.40%	2346	5.90%	2392	46
CIMO	Economic Capacity	S_35	0.50%	0.90%	1349	1.50%	1303	-47
CIMO	Economic Capacity	S_SP	0.60%	1.00%	1121	1.90%	1099	-22
CIMO	Economic Capacity	S_P	0.10%	0.00%	1312	0.10%	1301	-11
CIMO	Economic Capacity	S_OP	1.00%	0.00%	1339	1.30%	1314	-25
CIMO	Economic Capacity	W_SP	0.50%	0.00%	862	0.50%	868	6
CIMO	Economic Capacity	W_P	0.40%	0.00%	1101	0.40%	1078	-23
CIMO	Economic Capacity	W_OP	3.30%	0.00%	876	4.60%	871	-4
CIMO	Economic Capacity	SH_SP	0.20%	0.00%	1223	0.20%	1199	-23
CIMO	Economic Capacity	SH_P	0.40%	0.00%	990	0.40%	994	3
CIMO	Economic Capacity	SH_OP	2.50%	0.00%	979	3.50%	967	-11
CIN	Economic Capacity	S_35	14.10%	0.10%	2104	13.90%	2127	23
CIN	Economic Capacity	S_SP	7.90%	0.00%	2913	7.70%	2898	-15
CIN	Economic Capacity	S_P	3.80%	0.00%	1830	3.80%	1817	-14
CIN	Economic Capacity	S_OP	14.00%	0.00%	1552	14.00%	1556	3
CIN	Economic Capacity	W_SP	7.20%	0.00%	2696	6.50%	2614	-81
CIN	Economic Capacity	W_P	1.10%	0.00%	1700	1.10%	1668	-33
CIN	Economic Capacity	W_OP	13.10%	0.00%	1737	11.20%	1697	-39
CIN	Economic Capacity	SH_SP	2.90%	0.00%	2085	2.80%	2098	13
CIN	Economic Capacity	SH_P	2.70%	0.00%	2035	2.70%	2048	14
CIN	Economic Capacity	SH_OP	11.10%	0.00%	1415	11.20%	1429	13
COA	Economic Capacity	S_35	0.00%	3.30%	3464	3.20%	3464	0
COA	Economic Capacity	S_SP	0.00%	5.20%	1981	5.30%	1975	-7
COA	Economic Capacity	S_P	0.00%	5.50%	1975	5.60%	1969	-7
COA	Economic Capacity	S_OP	0.00%	5.40%	1977	5.60%	1970	-7
COA	Economic Capacity	W_SP	0.00%	3.20%	4718	3.20%	4718	0
COA	Economic Capacity	W_P	0.00%	6.30%	2954	7.60%	2940	-14
COA	Economic Capacity	W_OP	0.00%	6.50%	2955	7.90%	2942	-14
COA	Economic Capacity	SH_SP	0.00%	5.60%	3172	5.50%	3171	-1
COA	Economic Capacity	SH_P	0.00%	8.00%	1986	8.10%	1974	-12
COA	Economic Capacity	SH_OP	0.00%	9.50%	2075	9.70%	2055	-21
COMED	Economic Capacity	S_35	0.60%	0.00%	5681	0.60%	5553	-128
COMED	Economic Capacity	S_SP	0.40%	0.00%	5597	0.40%	5468	-128
COMED	Economic Capacity	S_P	0.40%	0.00%	5023	0.40%	4890	-133
COMED	Economic Capacity	S_OP	0.20%	0.00%	4156	0.20%	4040	-116
COMED	Economic Capacity	W_SP	9.20%	0.40%	3775	8.20%	3337	-439
COMED	Economic Capacity	W_P	1.90%	0.00%	4046	1.70%	3483	-563

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Economic Capacity	W_OP	3.70%	0.00%	3027	3.10%	2622	-405
COMED	Economic Capacity	SH_SP	9.80%	0.40%	2933	9.90%	2932	-1
COMED	Economic Capacity	SH_P	9.10%	0.00%	3144	8.80%	3129	-15
COMED	Economic Capacity	SH_OP	2.80%	0.00%	2342	2.70%	2332	-10
CP	Economic Capacity	S_35	8.50%	0.00%	2976	8.30%	2991	15
CP	Economic Capacity	S_SP	8.30%	0.00%	3038	8.10%	3054	16
CP	Economic Capacity	S_P	6.20%	0.00%	2637	6.10%	2654	17
CP	Economic Capacity	S_OP	12.00%	0.00%	2982	11.70%	3000	18
CP	Economic Capacity	W_SP	12.10%	0.00%	2295	11.40%	2271	-25
CP	Economic Capacity	W_P	14.40%	0.00%	2323	13.40%	2283	-39
CP	Economic Capacity	W_OP	16.00%	0.00%	2238	15.00%	2207	-32
CP	Economic Capacity	SH_SP	12.20%	0.00%	2164	12.10%	2155	-9
CP	Economic Capacity	SH_P	15.00%	0.00%	2217	14.90%	2206	-11
CP	Economic Capacity	SH_OP	10.10%	0.00%	2310	10.00%	2305	-6
CPS	Economic Capacity	S_35	0.00%	4.80%	5445	4.80%	5445	0
CPS	Economic Capacity	S_SP	0.00%	7.80%	3462	7.80%	3462	0
CPS	Economic Capacity	S_P	0.00%	6.70%	3455	6.70%	3456	1
CPS	Economic Capacity	S_OP	0.00%	6.70%	3468	6.70%	3469	1
CPS	Economic Capacity	W_SP	0.00%	0.00%	5303	0.00%	5303	1
CPS	Economic Capacity	W_P	0.00%	0.10%	2959	0.10%	2961	2
CPS	Economic Capacity	W_OP	0.00%	0.10%	2934	0.10%	2936	2
CPS	Economic Capacity	SH_SP	0.00%	9.90%	3323	9.40%	3314	-10
CPS	Economic Capacity	SH_P	0.00%	12.40%	2113	11.10%	2077	-37
CPS	Economic Capacity	SH_OP	0.00%	14.80%	1812	14.00%	1810	-2
DECO	Economic Capacity	S_35	5.60%	0.00%	4058	5.50%	4063	5
DECO	Economic Capacity	S_SP	5.20%	0.00%	4158	5.10%	4163	5
DECO	Economic Capacity	S_P	0.60%	0.00%	3861	0.60%	3867	5
DECO	Economic Capacity	S_OP	0.30%	0.00%	3917	0.30%	3929	11
DECO	Economic Capacity	W_SP	7.60%	0.00%	3732	7.10%	3719	-12
DECO	Economic Capacity	W_P	6.80%	0.00%	3632	6.20%	3619	-13
DECO	Economic Capacity	W_OP	7.40%	0.00%	3431	6.70%	3453	23
DECO	Economic Capacity	SH_SP	11.80%	0.00%	3364	11.70%	3364	0
DECO	Economic Capacity	SH_P	4.00%	0.00%	3481	4.00%	3490	8
DECO	Economic Capacity	SH_OP	0.30%	0.00%	3749	0.30%	3747	-2
DGG	Economic Capacity	S_35	0.00%	6.00%	2399	6.00%	2399	-1
DGG	Economic Capacity	S_SP	0.00%	12.10%	1258	12.10%	1242	-16
DGG	Economic Capacity	S_P	0.00%	13.80%	1411	13.70%	1387	-24
DGG	Economic Capacity	S_OP	0.00%	14.40%	1440	14.20%	1415	-26
DGG	Economic Capacity	W_SP	0.00%	3.60%	3785	3.60%	3785	0
DGG	Economic Capacity	W_P	0.00%	5.10%	3120	5.70%	3055	-65
DGG	Economic Capacity	W_OP	0.00%	5.50%	3124	6.10%	3059	-65
DGG	Economic Capacity	SH_SP	0.00%	12.40%	1509	12.00%	1501	-8
DGG	Economic Capacity	SH_P	0.00%	15.10%	1565	14.30%	1523	-42
DGG	Economic Capacity	SH_OP	0.00%	19.50%	1668	17.90%	1602	-66
DLCO	Economic Capacity	S_35	11.50%	0.00%	1968	11.40%	1972	4
DLCO	Economic Capacity	S_SP	11.60%	0.00%	1999	11.40%	2002	3
DLCO	Economic Capacity	S_P	15.00%	0.00%	2142	14.80%	2140	-2
DLCO	Economic Capacity	S_OP	18.20%	0.00%	2067	18.00%	2065	-3
DLCO	Economic Capacity	W_SP	9.10%	0.00%	2317	8.50%	2292	-25
DLCO	Economic Capacity	W_P	8.50%	0.00%	2275	8.00%	2247	-28
DLCO	Economic Capacity	W_OP	9.20%	0.00%	2162	8.60%	2134	-28
DLCO	Economic Capacity	SH_SP	12.60%	0.00%	1638	12.40%	1637	-1
DLCO	Economic Capacity	SH_P	14.50%	0.00%	1883	14.50%	1885	2
DLCO	Economic Capacity	SH_OP	14.60%	0.00%	1794	14.50%	1791	-4
DPL	Economic Capacity	S_35	16.20%	0.00%	1635	15.90%	1627	-8
DPL	Economic Capacity	S_SP	7.60%	0.00%	1636	7.50%	1636	0
DPL	Economic Capacity	S_P	5.70%	0.00%	1677	5.30%	1694	17
DPL	Economic Capacity	S_OP	9.80%	0.00%	1577	9.70%	1584	7
DPL	Economic Capacity	W_SP	1.80%	0.00%	1818	3.70%	1671	-147
DPL	Economic Capacity	W_P	2.10%	0.00%	1877	2.10%	1692	-185
DPL	Economic Capacity	W_OP	12.80%	0.00%	1575	10.90%	1429	-146
DPL	Economic Capacity	SH_SP	4.60%	0.00%	1479	4.80%	1452	-27
DPL	Economic Capacity	SH_P	1.70%	0.00%	1749	1.70%	1748	0

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
DPL	Economic Capacity	SH_OP	9.20%	0.00%	1501	9.20%	1507	7
DUKE	Economic Capacity	S_35	3.50%	0.00%	4438	3.50%	4437	-1
DUKE	Economic Capacity	S_SP	0.50%	0.00%	4612	0.50%	4612	-1
DUKE	Economic Capacity	S_P	2.10%	0.00%	3548	2.20%	3549	1
DUKE	Economic Capacity	S_OP	2.90%	0.00%	2599	2.90%	2599	0
DUKE	Economic Capacity	W_SP	1.70%	0.00%	4402	1.60%	4403	1
DUKE	Economic Capacity	W_P	1.40%	0.00%	3451	1.20%	3454	3
DUKE	Economic Capacity	W_OP	2.10%	0.00%	3157	2.10%	3146	-11
DUKE	Economic Capacity	SH_SP	0.60%	0.00%	4108	0.60%	4108	0
DUKE	Economic Capacity	SH_P	0.90%	0.00%	3078	0.90%	3080	2
DUKE	Economic Capacity	SH_OP	1.90%	0.00%	2071	2.00%	2069	-2
EDE	Economic Capacity	S_35	0.40%	4.00%	1653	4.40%	1742	89
EDE	Economic Capacity	S_SP	0.30%	3.90%	1713	4.30%	1803	90
EDE	Economic Capacity	S_P	0.80%	0.90%	4496	1.60%	3500	-997
EDE	Economic Capacity	S_OP	2.20%	2.00%	2848	3.80%	2115	-732
EDE	Economic Capacity	W_SP	0.50%	12.50%	1111	12.70%	1131	20
EDE	Economic Capacity	W_P	0.70%	10.30%	651	10.70%	655	4
EDE	Economic Capacity	W_OP	0.90%	11.90%	596	12.20%	584	-12
EDE	Economic Capacity	SH_SP	0.90%	2.00%	2144	2.40%	2098	-46
EDE	Economic Capacity	SH_P	1.40%	2.50%	1421	3.60%	1384	-37
EDE	Economic Capacity	SH_OP	2.00%	0.00%	1129	3.00%	1089	-40
EKPC	Economic Capacity	S_35	6.40%	0.10%	2419	6.60%	2356	-64
EKPC	Economic Capacity	S_SP	9.90%	0.00%	2188	10.10%	2134	-55
EKPC	Economic Capacity	S_P	3.90%	0.00%	1768	3.90%	1723	-45
EKPC	Economic Capacity	S_OP	1.80%	0.00%	1516	1.80%	1476	-40
EKPC	Economic Capacity	W_SP	9.90%	0.00%	2317	9.10%	2315	-2
EKPC	Economic Capacity	W_P	3.70%	0.00%	2413	3.70%	2443	30
EKPC	Economic Capacity	W_OP	9.30%	0.00%	1841	7.00%	1864	23
EKPC	Economic Capacity	SH_SP	7.30%	0.30%	1868	7.20%	1893	25
EKPC	Economic Capacity	SH_P	3.20%	0.00%	1757	3.20%	1786	29
EKPC	Economic Capacity	SH_OP	1.60%	0.00%	1315	1.60%	1330	16
ENT	Economic Capacity	S_35	0.20%	0.20%	5427	0.40%	5483	55
ENT	Economic Capacity	S_SP	0.60%	0.20%	2728	0.80%	2781	53
ENT	Economic Capacity	S_P	0.20%	0.90%	2768	0.90%	2790	22
ENT	Economic Capacity	S_OP	0.80%	0.70%	2991	1.30%	3015	24
ENT	Economic Capacity	W_SP	0.20%	3.50%	5220	3.40%	5270	50
ENT	Economic Capacity	W_P	0.40%	2.00%	2699	1.40%	2773	75
ENT	Economic Capacity	W_OP	0.70%	2.70%	2719	2.10%	2799	80
ENT	Economic Capacity	SH_SP	0.30%	3.90%	3749	4.20%	3695	-55
ENT	Economic Capacity	SH_P	0.60%	4.80%	1620	5.20%	1593	-27
ENT	Economic Capacity	SH_OP	1.10%	5.90%	1676	6.80%	1661	-15
FENER	Economic Capacity	S_35	8.20%	0.00%	3359	8.00%	3372	14
FENER	Economic Capacity	S_SP	8.80%	0.00%	3341	8.60%	3353	13
FENER	Economic Capacity	S_P	6.70%	0.00%	3420	6.40%	3419	0
FENER	Economic Capacity	S_OP	8.20%	0.00%	3082	8.00%	3088	7
FENER	Economic Capacity	W_SP	4.70%	0.00%	4363	4.20%	4300	-63
FENER	Economic Capacity	W_P	3.10%	0.00%	4538	3.00%	4480	-57
FENER	Economic Capacity	W_OP	3.30%	0.00%	4493	2.80%	4432	-61
FENER	Economic Capacity	SH_SP	11.90%	0.00%	2390	11.70%	2389	-1
FENER	Economic Capacity	SH_P	11.70%	0.00%	2631	11.40%	2631	0
FENER	Economic Capacity	SH_OP	8.90%	0.00%	2736	8.90%	2728	-8
GRRD	Economic Capacity	S_35	0.10%	0.20%	3297	0.00%	4477	1181
GRRD	Economic Capacity	S_SP	0.10%	0.30%	3053	0.00%	4211	1158
GRRD	Economic Capacity	S_P	0.00%	12.10%	2938	10.80%	2984	46
GRRD	Economic Capacity	S_OP	0.20%	1.00%	2789	3.40%	2878	89
GRRD	Economic Capacity	W_SP	0.30%	16.20%	1152	15.00%	1149	-4
GRRD	Economic Capacity	W_P	0.40%	11.90%	1280	10.90%	1296	16
GRRD	Economic Capacity	W_OP	1.00%	0.00%	1772	1.50%	1784	11
GRRD	Economic Capacity	SH_SP	0.40%	12.00%	1607	12.40%	1549	-58
GRRD	Economic Capacity	SH_P	0.50%	7.50%	1351	8.10%	1305	-45
GRRD	Economic Capacity	SH_OP	1.10%	0.00%	1854	3.20%	1778	-76
HEC	Economic Capacity	S_35	7.20%	0.10%	1679	7.10%	1685	6

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
HEC	Economic Capacity	S_SP	7.20%	0.10%	1679	7.10%	1685	6
HEC	Economic Capacity	S_P	3.10%	0.00%	2225	3.10%	2230	5
HEC	Economic Capacity	S_OP	20.00%	0.00%	1294	20.20%	1303	10
HEC	Economic Capacity	W_SP	10.40%	0.10%	1821	9.90%	1792	-30
HEC	Economic Capacity	W_P	3.70%	0.00%	2367	3.40%	2317	-50
HEC	Economic Capacity	W_OP	20.60%	0.00%	1875	19.90%	1844	-31
HEC	Economic Capacity	SH_SP	17.80%	0.10%	1673	17.70%	1668	-5
HEC	Economic Capacity	SH_P	3.50%	0.00%	2285	3.40%	2288	3
HEC	Economic Capacity	SH_OP	20.70%	0.00%	1200	20.90%	1220	20
HLP	Economic Capacity	S_35	0.00%	2.70%	5011	2.60%	5011	0
HLP	Economic Capacity	S_SP	0.00%	7.10%	2748	7.30%	2734	-14
HLP	Economic Capacity	S_P	0.00%	6.10%	2573	6.40%	2558	-15
HLP	Economic Capacity	S_OP	0.00%	6.10%	2586	6.40%	2570	-16
HLP	Economic Capacity	W_SP	0.00%	3.50%	4642	3.30%	4641	-1
HLP	Economic Capacity	W_P	0.00%	5.90%	2630	5.90%	2622	-8
HLP	Economic Capacity	W_OP	0.00%	6.00%	2671	6.20%	2682	10
HLP	Economic Capacity	SH_SP	0.00%	4.90%	4431	4.70%	4430	-2
HLP	Economic Capacity	SH_P	0.00%	10.00%	2516	10.60%	2494	-22
HLP	Economic Capacity	SH_OP	0.00%	10.20%	2605	11.10%	2584	-22
IP	Economic Capacity	S_35	4.70%	0.50%	1929	4.80%	1941	12
IP	Economic Capacity	S_SP	4.80%	0.40%	2014	4.80%	1999	-16
IP	Economic Capacity	S_P	4.80%	0.50%	1906	7.00%	1845	-61
IP	Economic Capacity	S_OP	6.40%	0.50%	2030	7.10%	1984	-45
IP	Economic Capacity	W_SP	6.20%	0.60%	1905	6.10%	1782	-123
IP	Economic Capacity	W_P	3.20%	0.00%	2082	3.10%	1913	-169
IP	Economic Capacity	W_OP	5.60%	0.00%	1973	5.40%	1780	-193
IP	Economic Capacity	SH_SP	5.20%	0.70%	1549	5.20%	1608	59
IP	Economic Capacity	SH_P	1.10%	0.00%	1697	1.70%	1708	11
IP	Economic Capacity	SH_OP	6.10%	0.00%	1108	4.40%	1117	10
IPL	Economic Capacity	S_35	16.30%	0.10%	1834	16.10%	1823	-11
IPL	Economic Capacity	S_SP	6.40%	0.00%	1848	6.40%	1843	-5
IPL	Economic Capacity	S_P	2.70%	0.00%	2175	2.70%	2173	-2
IPL	Economic Capacity	S_OP	1.10%	0.00%	2624	1.10%	2584	-40
IPL	Economic Capacity	W_SP	1.10%	0.00%	1941	1.00%	1747	-194
IPL	Economic Capacity	W_P	3.10%	0.00%	1778	2.80%	1606	-172
IPL	Economic Capacity	W_OP	1.10%	0.00%	2598	1.10%	2610	12
IPL	Economic Capacity	SH_SP	12.30%	0.00%	1505	12.00%	1522	18
IPL	Economic Capacity	SH_P	1.40%	0.00%	1425	1.40%	1442	17
IPL	Economic Capacity	SH_OP	1.00%	0.00%	1752	1.00%	1755	4
KACY	Economic Capacity	S_35	0.10%	0.30%	5983	0.30%	6982	999
KACY	Economic Capacity	S_SP	0.10%	0.30%	5971	0.30%	6975	1004
KACY	Economic Capacity	S_P	0.00%	0.00%	4425	0.00%	5207	783
KACY	Economic Capacity	S_OP	0.60%	0.00%	3567	0.70%	4383	816
KACY	Economic Capacity	W_SP	0.20%	0.00%	2210	0.20%	2121	-89
KACY	Economic Capacity	W_P	0.50%	0.00%	1662	0.50%	1611	-52
KACY	Economic Capacity	W_OP	0.20%	0.00%	1333	0.20%	1314	-19
KACY	Economic Capacity	SH_SP	0.30%	2.30%	2681	3.10%	2469	-212
KACY	Economic Capacity	SH_P	0.10%	0.00%	2837	0.90%	2521	-316
KACY	Economic Capacity	SH_OP	1.40%	0.00%	1699	2.10%	1615	-84
KCPL	Economic Capacity	S_35	0.60%	0.40%	2626	1.10%	2636	9
KCPL	Economic Capacity	S_SP	0.50%	0.40%	3051	0.90%	3057	6
KCPL	Economic Capacity	S_P	0.50%	1.30%	2409	1.80%	2425	16
KCPL	Economic Capacity	S_OP	0.50%	0.00%	2570	0.50%	2597	27
KCPL	Economic Capacity	W_SP	1.10%	3.00%	1670	4.50%	1748	78
KCPL	Economic Capacity	W_P	1.40%	3.60%	1889	5.20%	1890	1
KCPL	Economic Capacity	W_OP	1.00%	0.00%	1604	1.00%	1574	-30
KCPL	Economic Capacity	SH_SP	1.00%	1.90%	1461	3.10%	1519	58
KCPL	Economic Capacity	SH_P	1.30%	1.70%	1371	3.20%	1428	57
KCPL	Economic Capacity	SH_OP	2.30%	0.00%	1059	2.40%	1026	-34
LAFA	Economic Capacity	S_35	0.00%	0.40%	8668	0.40%	8668	0
LAFA	Economic Capacity	S_SP	0.00%	1.90%	7159	1.90%	7159	-1
LAFA	Economic Capacity	S_P	0.00%	0.20%	5960	0.20%	5960	0
LAFA	Economic Capacity	S_OP	0.00%	0.20%	5957	0.10%	5957	0

Sensitivity: Loop Flow Impact

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Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
LAFA	Economic Capacity	W_SP	0.40%	1.50%	4656	1.80%	4655	-1
LAFA	Economic Capacity	W_P	0.80%	3.00%	2514	3.70%	2515	1
LAFA	Economic Capacity	W_OP	1.10%	3.80%	2457	4.60%	2462	5
LAFA	Economic Capacity	SH_SP	1.00%	1.80%	3914	2.90%	3676	-239
LAFA	Economic Capacity	SH_P	1.10%	3.10%	2221	4.30%	2067	-153
LAFA	Economic Capacity	SH_OP	2.30%	3.30%	2227	5.70%	2082	-145
LCRA	Economic Capacity	S_35	0.00%	8.30%	1558	8.10%	1555	-3
LCRA	Economic Capacity	S_SP	0.00%	7.20%	1909	7.20%	1903	-6
LCRA	Economic Capacity	S_P	0.00%	7.10%	1926	7.60%	1912	-13
LCRA	Economic Capacity	S_OP	0.00%	7.20%	2238	7.60%	2219	-19
LCRA	Economic Capacity	W_SP	0.00%	4.90%	2366	4.90%	2366	0
LCRA	Economic Capacity	W_P	0.00%	3.50%	2174	4.00%	2145	-29
LCRA	Economic Capacity	W_OP	0.00%	3.50%	2170	4.00%	2141	-28
LCRA	Economic Capacity	SH_SP	0.00%	6.90%	2182	6.40%	2158	-24
LCRA	Economic Capacity	SH_P	0.00%	6.50%	2198	6.00%	2174	-24
LCRA	Economic Capacity	SH_OP	0.00%	6.40%	2438	6.70%	2423	-16
LGE	Economic Capacity	S_35	7.90%	0.10%	2987	7.80%	3004	16
LGE	Economic Capacity	S_SP	2.50%	0.00%	1379	2.50%	1375	-4
LGE	Economic Capacity	S_P	2.60%	0.00%	1702	2.70%	1694	-9
LGE	Economic Capacity	S_OP	5.20%	0.00%	1380	5.30%	1371	-9
LGE	Economic Capacity	W_SP	1.20%	0.00%	1761	1.20%	1757	-4
LGE	Economic Capacity	W_P	1.30%	0.00%	1802	1.30%	1762	-40
LGE	Economic Capacity	W_OP	13.20%	0.00%	1097	16.70%	1120	23
LGE	Economic Capacity	SH_SP	1.20%	0.00%	1739	1.20%	1789	50
LGE	Economic Capacity	SH_P	1.20%	0.00%	1747	1.20%	1798	51
LGE	Economic Capacity	SH_OP	2.10%	0.00%	1322	3.10%	1312	-10
MPS	Economic Capacity	S_35	0.70%	0.00%	4591	0.80%	4717	126
MPS	Economic Capacity	S_SP	0.70%	0.00%	3805	0.70%	3805	0
MPS	Economic Capacity	S_P	0.80%	0.00%	2573	0.90%	2584	11
MPS	Economic Capacity	S_OP	1.10%	0.00%	2023	1.10%	2025	2
MPS	Economic Capacity	W_SP	0.40%	0.00%	1017	0.40%	1011	-6
MPS	Economic Capacity	W_P	0.30%	0.00%	839	0.30%	850	10
MPS	Economic Capacity	W_OP	2.90%	0.00%	840	2.90%	838	-3
MPS	Economic Capacity	SH_SP	1.70%	0.00%	1384	1.80%	1480	96
MPS	Economic Capacity	SH_P	0.40%	0.00%	984	0.50%	983	-1
MPS	Economic Capacity	SH_OP	2.00%	0.00%	1123	2.30%	1034	-89
NIPS	Economic Capacity	S_35	13.50%	0.10%	1981	13.40%	1949	-32
NIPS	Economic Capacity	S_SP	0.90%	0.00%	1441	0.90%	1448	7
NIPS	Economic Capacity	S_P	0.90%	0.00%	1342	0.90%	1354	12
NIPS	Economic Capacity	S_OP	0.80%	0.00%	1174	0.80%	1185	10
NIPS	Economic Capacity	W_SP	1.00%	0.00%	1259	1.00%	1170	-89
NIPS	Economic Capacity	W_P	1.00%	0.00%	1259	1.00%	1170	-89
NIPS	Economic Capacity	W_OP	0.70%	0.00%	1212	2.40%	1026	-186
NIPS	Economic Capacity	SH_SP	7.50%	0.00%	1183	7.70%	1197	13
NIPS	Economic Capacity	SH_P	7.50%	0.00%	1196	7.70%	1210	14
NIPS	Economic Capacity	SH_OP	4.60%	0.00%	1071	4.70%	1087	16
NSP	Economic Capacity	S_35	0.40%	0.10%	2412	0.50%	2411	0
NSP	Economic Capacity	S_SP	0.00%	0.00%	2129	0.00%	2129	0
NSP	Economic Capacity	S_P	0.00%	0.00%	1873	0.00%	1871	-2
NSP	Economic Capacity	S_OP	0.90%	0.00%	2391	0.90%	2381	-9
NSP	Economic Capacity	W_SP	0.50%	0.00%	2926	0.50%	2929	4
NSP	Economic Capacity	W_P	0.00%	0.00%	1529	0.00%	1529	0
NSP	Economic Capacity	W_OP	1.00%	0.00%	1903	1.00%	1905	1
NSP	Economic Capacity	SH_SP	0.00%	0.00%	1889	0.00%	1889	0
NSP	Economic Capacity	SH_P	0.00%	0.00%	1878	0.00%	1878	0
NSP	Economic Capacity	SH_OP	0.50%	0.00%	2405	0.50%	2405	0
OKGE	Economic Capacity	S_35	0.10%	2.50%	5724	0.40%	6561	837
OKGE	Economic Capacity	S_SP	0.20%	2.30%	5826	0.60%	6657	831
OKGE	Economic Capacity	S_P	0.30%	20.60%	2458	17.10%	2665	207
OKGE	Economic Capacity	S_OP	0.80%	14.30%	2435	11.60%	2766	331
OKGE	Economic Capacity	W_SP	0.20%	6.10%	4085	4.80%	4617	532
OKGE	Economic Capacity	W_P	0.50%	11.60%	2126	9.50%	2491	365
OKGE	Economic Capacity	W_OP	0.90%	0.00%	2393	1.00%	2821	429

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
OKGE	Economic Capacity	SH_SP	0.20%	6.10%	3795	5.00%	4238	444
OKGE	Economic Capacity	SH_P	0.50%	7.30%	1809	6.30%	2102	293
OKGE	Economic Capacity	SH_OP	0.80%	3.30%	2117	2.80%	2435	318
SCEG	Economic Capacity	S_35	1.30%	0.00%	2814	1.40%	2811	-3
SCEG	Economic Capacity	S_SP	2.20%	0.00%	2730	2.20%	2728	-2
SCEG	Economic Capacity	S_P	2.10%	0.00%	2698	2.20%	2695	-3
SCEG	Economic Capacity	S_OP	1.90%	0.00%	2697	1.90%	2694	-3
SCEG	Economic Capacity	W_SP	2.40%	0.00%	2660	2.30%	2661	1
SCEG	Economic Capacity	W_P	1.90%	0.00%	2694	1.80%	2695	1
SCEG	Economic Capacity	W_OP	1.80%	0.00%	2638	1.70%	2639	1
SCEG	Economic Capacity	SH_SP	2.00%	0.00%	2490	2.10%	2488	-2
SCEG	Economic Capacity	SH_P	2.10%	0.00%	2489	2.10%	2488	-2
SCEG	Economic Capacity	SH_OP	1.70%	0.00%	2506	1.80%	2502	-4
SIGE	Economic Capacity	S_35	5.80%	0.00%	2463	5.70%	2475	11
SIGE	Economic Capacity	S_SP	5.90%	0.00%	2465	5.80%	2476	11
SIGE	Economic Capacity	S_P	2.40%	0.00%	3399	2.40%	3397	-2
SIGE	Economic Capacity	S_OP	1.50%	0.00%	2272	1.50%	2282	10
SIGE	Economic Capacity	W_SP	6.30%	0.00%	2335	5.80%	2332	-3
SIGE	Economic Capacity	W_P	2.30%	0.00%	2847	2.20%	2869	22
SIGE	Economic Capacity	W_OP	1.70%	0.00%	2199	1.70%	2210	11
SIGE	Economic Capacity	SH_SP	4.60%	0.00%	2313	4.60%	2326	13
SIGE	Economic Capacity	SH_P	1.50%	0.00%	2734	1.50%	2739	6
SIGE	Economic Capacity	SH_OP	1.60%	0.00%	2096	1.60%	2104	8
SOCO	Economic Capacity	S_35	0.50%	0.00%	6169	0.50%	6169	0
SOCO	Economic Capacity	S_SP	0.70%	0.00%	6234	0.60%	6234	0
SOCO	Economic Capacity	S_P	0.20%	0.00%	6355	0.20%	6356	1
SOCO	Economic Capacity	S_OP	0.90%	0.00%	6118	0.80%	6116	-3
SOCO	Economic Capacity	W_SP	0.40%	0.00%	6430	0.40%	6431	1
SOCO	Economic Capacity	W_P	0.40%	0.00%	6339	0.40%	6333	-6
SOCO	Economic Capacity	W_OP	1.20%	0.00%	6366	1.10%	6365	0
SOCO	Economic Capacity	SH_SP	0.30%	0.00%	5817	0.20%	5810	-7
SOCO	Economic Capacity	SH_P	0.70%	0.00%	5785	0.70%	5779	-6
SOCO	Economic Capacity	SH_OP	1.10%	0.00%	5759	1.10%	5747	-12
SPRM	Economic Capacity	S_35	0.10%	1.90%	5150	1.20%	5629	480
SPRM	Economic Capacity	S_SP	0.00%	0.70%	3817	0.60%	4274	457
SPRM	Economic Capacity	S_P	0.10%	0.00%	3934	0.10%	4373	439
SPRM	Economic Capacity	S_OP	0.50%	0.00%	3523	0.80%	3976	453
SPRM	Economic Capacity	W_SP	0.50%	0.00%	2186	0.40%	2363	177
SPRM	Economic Capacity	W_P	0.50%	0.00%	2186	0.40%	2363	177
SPRM	Economic Capacity	W_OP	1.40%	0.00%	1740	2.70%	1794	54
SPRM	Economic Capacity	SH_SP	0.10%	1.20%	2886	1.50%	2833	-52
SPRM	Economic Capacity	SH_P	0.30%	0.00%	2541	0.30%	2475	-66
SPRM	Economic Capacity	SH_OP	1.80%	0.00%	2066	2.70%	1973	-93
STEC	Economic Capacity	S_35	0.00%	0.00%	4613	0.00%	4613	0
STEC	Economic Capacity	S_SP	0.00%	0.00%	4508	0.00%	4508	0
STEC	Economic Capacity	S_P	0.00%	0.30%	6001	0.30%	6001	0
STEC	Economic Capacity	S_OP	0.00%	15.80%	2472	15.80%	2472	0
STEC	Economic Capacity	W_SP	0.00%	3.60%	2100	3.60%	2101	0
STEC	Economic Capacity	W_P	0.00%	0.00%	4723	0.00%	4723	0
STEC	Economic Capacity	W_OP	0.00%	0.00%	4594	0.00%	4594	0
STEC	Economic Capacity	SH_SP	0.00%	15.60%	1581	14.90%	1558	-22
STEC	Economic Capacity	SH_P	0.00%	9.50%	4755	10.90%	4597	-159
STEC	Economic Capacity	SH_OP	0.00%	8.30%	4908	9.30%	4828	-80
STJO	Economic Capacity	S_35	1.30%	0.90%	1133	2.10%	1130	-3
STJO	Economic Capacity	S_SP	1.10%	0.90%	1172	1.90%	1170	-2
STJO	Economic Capacity	S_P	1.40%	3.00%	1136	4.70%	1141	5
STJO	Economic Capacity	S_OP	1.30%	0.00%	996	1.30%	1003	8
STJO	Economic Capacity	W_SP	2.20%	2.70%	725	5.20%	711	-14
STJO	Economic Capacity	W_P	2.30%	2.10%	762	4.30%	751	-11
STJO	Economic Capacity	W_OP	1.20%	0.00%	828	1.20%	816	-12
STJO	Economic Capacity	SH_SP	1.40%	3.60%	542	5.10%	542	0
STJO	Economic Capacity	SH_P	1.50%	2.20%	668	3.80%	648	-20
STJO	Economic Capacity	SH_OP	3.70%	0.00%	880	3.40%	868	-12

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
SWEPA	Economic Capacity	S_35	0.50%	5.10%	1423	3.70%	1435	11
SWEPA	Economic Capacity	S_SP	0.50%	5.50%	1278	3.20%	1314	36
SWEPA	Economic Capacity	S_P	0.60%	0.00%	1510	0.70%	1446	-64
SWEPA	Economic Capacity	S_OP	0.80%	15.90%	959	13.20%	940	-19
SWEPA	Economic Capacity	W_SP	0.90%	11.00%	709	11.10%	725	17
SWEPA	Economic Capacity	W_P	1.30%	6.80%	749	7.20%	761	12
SWEPA	Economic Capacity	W_OP	2.50%	7.80%	579	9.40%	589	10
SWEPA	Economic Capacity	SH_SP	1.70%	0.00%	1084	1.80%	1120	36
SWEPA	Economic Capacity	SH_P	2.40%	0.00%	940	2.50%	926	-14
SWEPA	Economic Capacity	SH_OP	1.00%	0.00%	735	1.10%	756	22
SWPS	Economic Capacity	S_35	0.00%	3.00%	7903	1.50%	8290	387
SWPS	Economic Capacity	S_SP	0.00%	3.40%	6736	1.80%	7237	501
SWPS	Economic Capacity	S_P	0.00%	2.00%	7089	0.30%	7580	490
SWPS	Economic Capacity	S_OP	0.10%	1.70%	8409	0.40%	9071	662
SWPS	Economic Capacity	W_SP	0.00%	2.40%	7952	1.10%	8348	395
SWPS	Economic Capacity	W_P	0.00%	2.60%	6631	1.20%	7169	538
SWPS	Economic Capacity	W_OP	0.10%	2.30%	7953	1.10%	8626	673
SWPS	Economic Capacity	SH_SP	0.00%	1.40%	8122	0.50%	8268	147
SWPS	Economic Capacity	SH_P	0.00%	0.50%	7154	0.50%	7397	243
SWPS	Economic Capacity	SH_OP	0.00%	0.00%	8496	0.60%	8755	259
TMPA	Economic Capacity	S_35	0.00%	8.50%	1628	8.50%	1628	0
TMPA	Economic Capacity	S_SP	0.00%	5.40%	1728	6.50%	1707	-22
TMPA	Economic Capacity	S_P	0.00%	9.60%	1627	10.10%	1623	-4
TMPA	Economic Capacity	S_OP	0.00%	6.40%	1658	7.40%	1633	-25
TMPA	Economic Capacity	W_SP	0.00%	3.80%	1455	3.80%	1455	0
TMPA	Economic Capacity	W_P	0.00%	3.30%	2104	3.60%	2078	-26
TMPA	Economic Capacity	W_OP	0.00%	3.60%	2098	3.80%	2072	-26
TMPA	Economic Capacity	SH_SP	0.00%	4.00%	1859	3.90%	1858	-1
TMPA	Economic Capacity	SH_P	0.00%	3.70%	1914	3.60%	1901	-13
TMPA	Economic Capacity	SH_OP	0.00%	3.90%	2057	4.10%	2044	-13
TNMP	Economic Capacity	S_35	0.00%	1.40%	2017	1.40%	2017	0
TNMP	Economic Capacity	S_SP	0.00%	1.40%	1702	1.40%	1704	2
TNMP	Economic Capacity	S_P	0.00%	2.30%	1630	2.10%	1637	6
TNMP	Economic Capacity	S_OP	0.00%	2.60%	1781	2.50%	1800	19
TNMP	Economic Capacity	W_SP	0.00%	0.80%	2558	0.80%	2559	0
TNMP	Economic Capacity	W_P	0.00%	2.50%	2320	2.50%	2321	1
TNMP	Economic Capacity	W_OP	0.00%	2.20%	2320	2.30%	2321	1
TNMP	Economic Capacity	SH_SP	0.00%	3.10%	2057	3.10%	2058	1
TNMP	Economic Capacity	SH_P	0.00%	2.60%	1916	2.50%	1921	6
TNMP	Economic Capacity	SH_OP	0.00%	2.90%	1942	2.80%	1948	6
TU	Economic Capacity	S_35	0.00%	2.80%	7591	2.80%	7591	0
TU	Economic Capacity	S_SP	0.00%	6.70%	5358	6.80%	5327	-31
TU	Economic Capacity	S_P	0.00%	8.30%	5039	8.30%	5010	-29
TU	Economic Capacity	S_OP	0.00%	8.50%	5079	8.50%	5072	-8
TU	Economic Capacity	W_SP	0.00%	3.50%	8687	3.40%	8686	0
TU	Economic Capacity	W_P	0.00%	6.40%	7324	7.30%	7185	-140
TU	Economic Capacity	W_OP	0.00%	6.40%	7325	7.30%	7185	-140
TU	Economic Capacity	SH_SP	0.00%	7.50%	5462	7.30%	5458	-3
TU	Economic Capacity	SH_P	0.00%	9.60%	3414	9.40%	3394	-20
TU	Economic Capacity	SH_OP	0.00%	10.20%	3772	10.10%	3711	-61
TVA	Economic Capacity	S_35	13.30%	0.00%	829	13.20%	827	-3
TVA	Economic Capacity	S_SP	13.30%	0.00%	801	13.20%	799	-2
TVA	Economic Capacity	S_P	9.00%	0.00%	841	8.70%	838	-4
TVA	Economic Capacity	S_OP	10.30%	0.00%	963	9.90%	950	-12
TVA	Economic Capacity	W_SP	4.50%	0.00%	672	3.80%	642	-30
TVA	Economic Capacity	W_P	1.00%	0.00%	718	0.90%	722	4
TVA	Economic Capacity	W_OP	6.80%	0.00%	813	5.90%	799	-14
TVA	Economic Capacity	SH_SP	13.00%	1.20%	688	13.40%	709	21
TVA	Economic Capacity	SH_P	0.60%	0.00%	862	0.60%	872	9
TVA	Economic Capacity	SH_OP	10.00%	0.00%	894	9.60%	895	1
VP	Economic Capacity	S_35	2.90%	0.00%	6769	2.80%	6768	-1
VP	Economic Capacity	S_SP	3.50%	0.00%	6453	3.40%	6461	8

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
VP	Economic Capacity	S_P	5.40%	0.00%	5844	5.30%	5859	15
VP	Economic Capacity	S_OP	5.90%	0.00%	5767	5.80%	5782	15
VP	Economic Capacity	W_SP	1.10%	0.00%	7048	1.10%	7048	0
VP	Economic Capacity	W_P	1.10%	0.00%	7050	1.10%	7102	52
VP	Economic Capacity	W_OP	1.90%	0.00%	6921	1.50%	6984	63
VP	Economic Capacity	SH_SP	0.80%	0.00%	6914	0.80%	6914	0
VP	Economic Capacity	SH_P	1.70%	0.00%	6498	1.80%	6498	0
VP	Economic Capacity	SH_OP	3.10%	0.00%	5853	3.00%	5892	39
WEFA	Economic Capacity	S_35	0.10%	6.90%	3071	6.90%	3701	629
WEFA	Economic Capacity	S_SP	0.10%	5.00%	2071	4.80%	2413	342
WEFA	Economic Capacity	S_P	0.00%	17.90%	1769	15.20%	1714	-54
WEFA	Economic Capacity	S_OP	0.20%	20.40%	1841	18.10%	1792	-48
WEFA	Economic Capacity	W_SP	0.50%	0.00%	2518	0.00%	2671	152
WEFA	Economic Capacity	W_P	0.00%	0.00%	1968	0.00%	2025	57
WEFA	Economic Capacity	W_OP	1.50%	0.00%	1930	2.20%	1866	-64
WEFA	Economic Capacity	SH_SP	0.30%	8.60%	1621	6.70%	1595	-26
WEFA	Economic Capacity	SH_P	0.10%	0.00%	1731	0.10%	1748	16
WEFA	Economic Capacity	SH_OP	0.60%	0.50%	1693	1.00%	1660	-33
WEP	Economic Capacity	S_35	0.80%	0.00%	5051	1.00%	5084	33
WEP	Economic Capacity	S_SP	1.10%	0.00%	4678	1.30%	4714	36
WEP	Economic Capacity	S_P	1.40%	0.00%	5182	1.40%	5200	18
WEP	Economic Capacity	S_OP	1.70%	0.00%	2089	1.60%	1991	-99
WEP	Economic Capacity	W_SP	1.00%	0.10%	3988	1.10%	3992	4
WEP	Economic Capacity	W_P	1.60%	0.00%	3737	1.60%	3735	-2
WEP	Economic Capacity	W_OP	0.80%	0.00%	2818	0.80%	2815	-3
WEP	Economic Capacity	SH_SP	1.00%	0.00%	2044	1.00%	2046	3
WEP	Economic Capacity	SH_P	1.00%	0.00%	2119	1.00%	2119	0
WEP	Economic Capacity	SH_OP	1.00%	0.00%	1497	1.00%	1502	5
WEPL	Economic Capacity	S_35	0.00%	0.50%	5520	0.40%	5240	-280
WEPL	Economic Capacity	S_SP	0.00%	0.00%	4889	0.00%	4403	-486
WEPL	Economic Capacity	S_P	0.10%	0.00%	2937	0.10%	2790	-147
WEPL	Economic Capacity	S_OP	0.00%	0.00%	1599	0.10%	1518	-81
WEPL	Economic Capacity	W_SP	0.00%	0.00%	3563	0.00%	3481	-81
WEPL	Economic Capacity	W_P	0.00%	0.00%	3696	0.00%	3593	-103
WEPL	Economic Capacity	W_OP	0.20%	0.00%	3600	0.40%	3419	-182
WEPL	Economic Capacity	SH_SP	0.00%	0.20%	3478	0.30%	3407	-71
WEPL	Economic Capacity	SH_P	0.00%	0.00%	3686	0.00%	3504	-182
WEPL	Economic Capacity	SH_OP	0.30%	0.00%	1725	0.50%	1600	-125
WR	Economic Capacity	S_35	0.30%	0.70%	4684	0.80%	4672	-13
WR	Economic Capacity	S_SP	0.20%	0.80%	3505	1.60%	3469	-35
WR	Economic Capacity	S_P	0.10%	0.80%	3882	0.90%	3845	-37
WR	Economic Capacity	S_OP	1.00%	0.00%	2068	1.00%	1967	-101
WR	Economic Capacity	W_SP	0.10%	0.90%	2554	0.10%	2533	-21
WR	Economic Capacity	W_P	0.10%	0.00%	2826	0.10%	2750	-76
WR	Economic Capacity	W_OP	0.60%	0.00%	2890	0.60%	2803	-87
WR	Economic Capacity	SH_SP	0.50%	1.60%	2380	2.40%	2298	-82
WR	Economic Capacity	SH_P	0.10%	0.00%	2256	0.10%	2185	-72
WR	Economic Capacity	SH_OP	0.60%	0.00%	1829	0.60%	1791	-38

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CSW_SPP	Available Economic Capacity	S_35	8.50%	6.90%	656	14.10%	700	44
CSW_SPP	Available Economic Capacity	S_SP	22.40%	13.50%	1101	28.10%	1208	108
CSW_SPP	Available Economic Capacity	S_P	0.00%	18.30%	1002	5.60%	1025	23
CSW_SPP	Available Economic Capacity	S_OP	7.10%	0.00%	866	6.90%	764	-102
CSW_SPP	Available Economic Capacity	W_SP	3.10%	26.30%	1095	26.20%	1080	-14
CSW_SPP	Available Economic Capacity	W_P	0.00%	0.00%	959	0.00%	823	-137
CSW_SPP	Available Economic Capacity	W_OP	0.00%	0.00%	969	0.00%	811	-158
CSW_SPP	Available Economic Capacity	SH_SP	6.10%	11.50%	711	13.00%	659	-52
CSW_SPP	Available Economic Capacity	SH_P	0.00%	12.60%	591	4.80%	470	-121
CSW_SPP	Available Economic Capacity	SH_OP	0.00%	0.00%	1270	0.00%	1088	-182
CBEN	Available Economic Capacity	S_35	0.00%	54.70%	3787	46.50%	3028	-759
CBEN	Available Economic Capacity	S_SP	0.00%	66.80%	4961	54.30%	3588	-1374
CBEN	Available Economic Capacity	S_P	0.00%	68.70%	5231	54.00%	3408	-1823
CBEN	Available Economic Capacity	S_OP	0.00%	55.90%	3718	35.30%	2110	-1607
CBEN	Available Economic Capacity	W_SP	0.00%	46.10%	3081	41.30%	2682	-399
CBEN	Available Economic Capacity	W_P	0.00%	67.90%	4790	58.00%	3618	-1173
CBEN	Available Economic Capacity	W_OP	0.00%	63.50%	4303	55.10%	3363	-940
CBEN	Available Economic Capacity	SH_SP	0.00%	61.40%	4155	47.00%	2713	-1442
CBEN	Available Economic Capacity	SH_P	0.00%	51.40%	2971	42.60%	2209	-761
CBEN	Available Economic Capacity	SH_OP	0.00%	45.20%	2650	29.20%	1618	-1032
VALLEY	Available Economic Capacity	S_35	0.00%	64.30%	4642	44.90%	2900	-1743
VALLEY	Available Economic Capacity	S_SP	0.00%	69.70%	5360	50.20%	3403	-1957
VALLEY	Available Economic Capacity	S_P	0.00%	57.10%	3898	37.70%	2437	-1461
VALLEY	Available Economic Capacity	S_OP	0.00%	59.50%	4020	40.00%	2460	-1559
VALLEY	Available Economic Capacity	W_SP	0.00%	56.40%	3673	38.20%	2288	-1385
VALLEY	Available Economic Capacity	W_P	0.00%	62.40%	4289	43.00%	2622	-1667
VALLEY	Available Economic Capacity	W_OP	0.00%	64.10%	4473	44.70%	2738	-1735
VALLEY	Available Economic Capacity	SH_SP	0.00%	61.20%	3997	41.90%	2359	-1637
VALLEY	Available Economic Capacity	SH_P	0.00%	48.60%	3068	29.50%	1944	-1123
VALLEY	Available Economic Capacity	SH_OP	0.00%	51.60%	3306	32.40%	2062	-1244
WTU	Available Economic Capacity	S_35	0.00%	31.90%	2618	30.10%	2500	-117
WTU	Available Economic Capacity	S_SP	0.00%	45.50%	3314	25.90%	1860	-1454
WTU	Available Economic Capacity	S_P	0.00%	31.10%	5058	21.10%	2648	-2410
WTU	Available Economic Capacity	S_OP	0.00%	39.40%	2724	20.30%	1600	-1124
WTU	Available Economic Capacity	W_SP	0.00%	29.40%	4788	28.80%	4783	-5
WTU	Available Economic Capacity	W_P	0.00%	12.70%	4990	12.40%	5003	13
WTU	Available Economic Capacity	W_OP	0.00%	16.20%	5133	15.90%	5150	18
WTU	Available Economic Capacity	SH_SP	0.00%	46.80%	2989	37.10%	2066	-923
WTU	Available Economic Capacity	SH_P	0.00%	23.40%	1214	20.00%	1054	-160
WTU	Available Economic Capacity	SH_OP	0.00%	28.40%	2245	22.80%	1951	-294

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
AECI	Available Economic Capacity	S_35	11.20%	0.00%	1544	11.10%	1424	-120
AECI	Available Economic Capacity	S_SP	0.00%	0.00%	950	0.00%	847	-102
AECI	Available Economic Capacity	S_P	0.00%	0.00%	1575	0.00%	1369	-206
AECI	Available Economic Capacity	S_OP	0.00%	0.00%	1485	0.00%	1322	-163
AECI	Available Economic Capacity	W_SP	7.60%	0.00%	804	8.40%	758	-46
AECI	Available Economic Capacity	W_P	0.00%	0.00%	986	0.00%	921	-65
AECI	Available Economic Capacity	W_OP	1.10%	0.00%	1088	1.30%	1029	-59
AECI	Available Economic Capacity	SH_SP	19.30%	0.80%	903	19.20%	868	-35
AECI	Available Economic Capacity	SH_P	0.00%	0.00%	1044	0.00%	971	-73
AECI	Available Economic Capacity	SH_OP	9.10%	0.00%	971	9.70%	921	-50
AEP	Available Economic Capacity	S_35	35.50%	0.00%	1653	33.40%	1526	-128
AEP	Available Economic Capacity	S_SP	98.50%	0.00%	9697	98.30%	9670	-27
AEP	Available Economic Capacity	S_P	99.80%	0.00%	9959	99.80%	9957	-2
AEP	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
AEP	Available Economic Capacity	W_SP	99.70%	0.00%	9943	99.70%	9939	-5
AEP	Available Economic Capacity	W_P	99.80%	0.00%	9959	99.80%	9956	-2
AEP	Available Economic Capacity	W_OP	99.80%	0.00%	9970	99.80%	9965	-5
AEP	Available Economic Capacity	SH_SP	85.50%	0.00%	7392	84.00%	7160	-232
AEP	Available Economic Capacity	SH_P	99.00%	0.00%	9803	98.90%	9790	-13
AEP	Available Economic Capacity	SH_OP	99.70%	0.00%	9935	99.60%	9912	-22
ALLIANT_E	Available Economic Capacity	S_35	8.30%	0.00%	912	0.00%	856	-56
ALLIANT_E	Available Economic Capacity	S_SP	0.00%	0.00%	1839	0.00%	1455	-384
ALLIANT_E	Available Economic Capacity	S_P	0.00%	0.00%	1619	0.00%	1619	0
ALLIANT_E	Available Economic Capacity	S_OP	0.00%	0.00%	7083	0.00%	7083	0
ALLIANT_E	Available Economic Capacity	W_SP	7.60%	0.00%	1035	4.80%	1037	2
ALLIANT_E	Available Economic Capacity	W_P	0.00%	0.00%	1756	0.00%	1663	-94
ALLIANT_E	Available Economic Capacity	W_OP	0.00%	0.00%	8511	0.00%	8511	0
ALLIANT_E	Available Economic Capacity	SH_SP	0.00%	0.00%	1993	0.00%	1749	-244
ALLIANT_E	Available Economic Capacity	SH_P	0.00%	0.00%	2283	0.00%	1984	-299
ALLIANT_E	Available Economic Capacity	SH_OP	0.00%	0.00%	7132	0.00%	7132	0
AMEREN	Available Economic Capacity	S_35	24.10%	0.00%	1231	24.90%	1229	-2
AMEREN	Available Economic Capacity	S_SP	6.50%	1.10%	399	8.00%	407	8
AMEREN	Available Economic Capacity	S_P	3.40%	0.00%	1093	1.50%	1074	-20
AMEREN	Available Economic Capacity	S_OP	0.00%	0.00%	2683	0.00%	2406	-277
AMEREN	Available Economic Capacity	W_SP	3.10%	0.00%	938	3.10%	938	0
AMEREN	Available Economic Capacity	W_P	6.30%	0.00%	1254	6.10%	1192	-62
AMEREN	Available Economic Capacity	W_OP	0.00%	0.00%	2600	0.00%	2600	0
AMEREN	Available Economic Capacity	SH_SP	11.30%	0.40%	574	14.30%	616	42
AMEREN	Available Economic Capacity	SH_P	8.70%	0.00%	1225	8.10%	1125	-100
AMEREN	Available Economic Capacity	SH_OP	0.00%	0.00%	4776	0.00%	4776	0
APS	Available Economic Capacity	S_35	53.20%	0.00%	3660	48.40%	3249	-411
APS	Available Economic Capacity	S_SP	98.80%	0.00%	9764	98.70%	9744	-20
APS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
APS	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
APS	Available Economic Capacity	W_SP	83.80%	0.00%	7155	82.50%	6967	-137
APS	Available Economic Capacity	W_P	0.00%	0.00%	7739	0.00%	7739	0
APS	Available Economic Capacity	W_OP	71.40%	0.00%	5919	69.50%	5758	-161
APS	Available Economic Capacity	SH_SP	22.00%	0.00%	2233	20.00%	2223	-10
APS	Available Economic Capacity	SH_P	47.80%	0.00%	3253	40.40%	2891	-362
APS	Available Economic Capacity	SH_OP	76.90%	0.00%	6448	76.70%	6431	-17
BEC	Available Economic Capacity	S_35	0.00%	34.30%	2500	29.20%	2203	-297
BEC	Available Economic Capacity	S_SP	0.00%	78.00%	6563	24.80%	2305	-4258
BEC	Available Economic Capacity	S_P	0.00%	78.00%	6563	22.60%	2132	-4430
BEC	Available Economic Capacity	S_OP	0.00%	27.70%	3728	2.60%	2321	-1407
BEC	Available Economic Capacity	W_SP	0.00%	27.80%	3112	27.30%	3095	-17
BEC	Available Economic Capacity	W_P	0.00%	45.70%	3142	8.60%	1780	-1361
BEC	Available Economic Capacity	W_OP	0.00%	10.20%	2300	5.80%	1805	-494
BEC	Available Economic Capacity	SH_SP	0.00%	51.60%	3522	35.00%	2010	-1512
BEC	Available Economic Capacity	SH_P	0.00%	48.00%	3540	22.90%	1702	-1838
BEC	Available Economic Capacity	SH_OP	0.00%	32.00%	2707	13.10%	1704	-1003
BRYN	Available Economic Capacity	S_35	0.00%	46.10%	3196	42.50%	2889	-308
BRYN	Available Economic Capacity	S_SP	0.00%	79.20%	6700	34.70%	2388	-4312
BRYN	Available Economic Capacity	S_P	0.00%	79.20%	6700	33.40%	2312	-4388
BRYN	Available Economic Capacity	S_OP	0.00%	36.80%	2907	15.10%	1697	-1210

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
BRYN	Available Economic Capacity	W_SP	0.00%	21.80%	1977	20.00%	1963	-14
BRYN	Available Economic Capacity	W_P	0.00%	0.00%	3366	0.00%	3415	50
BRYN	Available Economic Capacity	W_OP	0.00%	0.00%	7228	0.00%	4149	-3079
BRYN	Available Economic Capacity	SH_SP	0.00%	53.30%	3658	36.60%	2185	-1473
BRYN	Available Economic Capacity	SH_P	0.00%	49.20%	3686	23.20%	1827	-1859
BRYN	Available Economic Capacity	SH_OP	0.00%	31.60%	2348	13.00%	1534	-814
CAPO	Available Economic Capacity	S_35	88.20%	0.00%	7797	87.10%	7617	-180
CAPO	Available Economic Capacity	S_SP	87.50%	0.00%	7689	86.10%	7459	-229
CAPO	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
CAPO	Available Economic Capacity	SH_SP	84.40%	0.00%	7177	79.90%	6450	-727
CAPO	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
CAPO	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
CELE	Available Economic Capacity	S_35	2.20%	4.30%	1619	6.70%	1616	-3
CELE	Available Economic Capacity	S_SP	0.00%	0.00%	2741	0.00%	1894	-846
CELE	Available Economic Capacity	S_P	0.00%	0.00%	2015	0.00%	1789	-226
CELE	Available Economic Capacity	S_OP	0.00%	0.00%	3493	0.00%	3172	-321
CELE	Available Economic Capacity	W_SP	1.70%	7.60%	1804	8.00%	1878	74
CELE	Available Economic Capacity	W_P	0.00%	0.00%	1518	0.00%	1253	-264
CELE	Available Economic Capacity	W_OP	15.10%	0.00%	1091	11.70%	914	-177
CELE	Available Economic Capacity	SH_SP	9.10%	0.30%	1211	7.20%	1069	-142
CELE	Available Economic Capacity	SH_P	0.00%	0.00%	4545	0.00%	4312	-233
CELE	Available Economic Capacity	SH_OP	24.00%	0.00%	1871	22.20%	1674	-198
CIMO	Available Economic Capacity	S_35	7.10%	0.00%	944	8.40%	950	6
CIMO	Available Economic Capacity	S_SP	0.00%	0.00%	5255	0.00%	4083	-1172
CIMO	Available Economic Capacity	S_P	0.00%	0.00%	9519	0.00%	9388	-131
CIMO	Available Economic Capacity	S_OP	0.00%	0.00%	6784	0.00%	7076	292
CIMO	Available Economic Capacity	W_SP	0.00%	0.00%	9205	0.00%	9253	48
CIMO	Available Economic Capacity	W_P	0.00%	0.00%	4759	0.00%	4842	84
CIMO	Available Economic Capacity	W_OP	0.00%	0.00%	4993	0.00%	4988	-5
CIMO	Available Economic Capacity	SH_SP	0.00%	0.00%	4774	0.00%	4774	0
CIMO	Available Economic Capacity	SH_P	0.00%	0.00%	6240	0.00%	6284	44
CIMO	Available Economic Capacity	SH_OP	0.00%	0.00%	5700	0.00%	5849	148
CIN	Available Economic Capacity	S_35	50.60%	0.00%	2809	46.40%	2430	-379
CIN	Available Economic Capacity	S_SP	0.00%	0.00%	3882	0.00%	3882	0
CIN	Available Economic Capacity	S_P	0.00%	0.00%	3260	0.00%	3260	0
CIN	Available Economic Capacity	S_OP	0.00%	0.00%	5151	0.00%	5151	0
CIN	Available Economic Capacity	W_SP	0.00%	0.00%	2356	0.00%	1953	-403
CIN	Available Economic Capacity	W_P	0.00%	0.00%	3254	0.00%	2731	-523
CIN	Available Economic Capacity	W_OP	0.00%	0.00%	3180	0.00%	2300	-880
CIN	Available Economic Capacity	SH_SP	0.00%	0.00%	3973	0.00%	2216	-1757
CIN	Available Economic Capacity	SH_P	0.00%	0.00%	3266	0.00%	3267	1
CIN	Available Economic Capacity	SH_OP	0.00%	0.00%	4306	0.00%	2750	-1556
COA	Available Economic Capacity	S_35	0.00%	34.90%	3355	31.70%	3149	-206
COA	Available Economic Capacity	S_SP	0.00%	77.40%	6501	34.00%	3551	-2950
COA	Available Economic Capacity	S_P	0.00%	77.40%	6501	34.00%	3551	-2950
COA	Available Economic Capacity	S_OP	0.00%	76.00%	6352	30.80%	3581	-2771
COA	Available Economic Capacity	W_SP	0.00%	15.80%	2405	15.70%	2405	0
COA	Available Economic Capacity	W_P	0.00%	0.00%	5068	0.00%	5068	0
COA	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
COA	Available Economic Capacity	SH_SP	0.00%	81.20%	6942	45.50%	3704	-3238
COA	Available Economic Capacity	SH_P	0.00%	72.60%	5661	40.70%	3077	-2584
COA	Available Economic Capacity	SH_OP	0.00%	0.00%	5010	0.00%	3654	-1356
COMED	Available Economic Capacity	S_35	30.30%	0.00%	2064	29.50%	1980	-85
COMED	Available Economic Capacity	S_SP	29.00%	0.00%	2050	28.80%	2031	-19
COMED	Available Economic Capacity	S_P	0.00%	0.00%	2308	0.00%	2124	-184
COMED	Available Economic Capacity	S_OP	0.00%	0.00%	5397	0.00%	5397	0
COMED	Available Economic Capacity	W_SP	38.30%	0.00%	2123	33.30%	1678	-445
COMED	Available Economic Capacity	W_P	0.00%	0.00%	2058	0.00%	1872	-186
COMED	Available Economic Capacity	W_OP	0.00%	0.00%	2742	0.00%	2633	-109
COMED	Available Economic Capacity	SH_SP	41.30%	0.00%	2010	39.00%	1826	-184

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
COMED	Available Economic Capacity	SH_P	0.00%	0.00%	1744	0.00%	1700	-43
COMED	Available Economic Capacity	SH_OP	0.00%	0.00%	2081	0.00%	1836	-246
CP	Available Economic Capacity	S_35	55.80%	0.00%	3380	53.80%	3188	-192
CP	Available Economic Capacity	S_SP	58.30%	0.00%	3613	56.50%	3425	-188
CP	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
CP	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
CP	Available Economic Capacity	W_SP	27.80%	0.00%	1415	25.20%	1330	-85
CP	Available Economic Capacity	W_P	77.70%	0.00%	6301	77.70%	6288	-13
CP	Available Economic Capacity	W_OP	87.70%	0.00%	7767	87.80%	7777	10
CP	Available Economic Capacity	SH_SP	79.10%	0.00%	6412	77.30%	6148	-263
CP	Available Economic Capacity	SH_P	96.00%	0.00%	9238	95.80%	9195	-44
CP	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
CPS	Available Economic Capacity	S_35	0.00%	39.10%	3436	33.50%	3069	-367
CPS	Available Economic Capacity	S_SP	0.00%	78.00%	6563	34.20%	3572	-2991
CPS	Available Economic Capacity	S_P	0.00%	78.00%	6563	34.20%	3572	-2991
CPS	Available Economic Capacity	S_OP	0.00%	78.00%	6563	34.20%	3572	-2991
CPS	Available Economic Capacity	W_SP	0.00%	50.00%	5000	20.00%	2000	-3000
CPS	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
CPS	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
CPS	Available Economic Capacity	SH_SP	0.00%	74.20%	5844	45.30%	3230	-2614
CPS	Available Economic Capacity	SH_P	0.00%	73.10%	5729	41.00%	3104	-2625
CPS	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	5417	-4583
DECO	Available Economic Capacity	S_35	97.40%	0.00%	9492	97.20%	9450	-42
DECO	Available Economic Capacity	S_SP	64.40%	0.00%	4519	62.70%	4338	-181
DECO	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
DECO	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
DECO	Available Economic Capacity	W_SP	63.40%	0.00%	4673	61.90%	4540	-133
DECO	Available Economic Capacity	W_P	0.00%	0.00%	4019	0.00%	4020	1
DECO	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
DECO	Available Economic Capacity	SH_SP	32.00%	0.00%	3643	0.00%	5663	2020
DECO	Available Economic Capacity	SH_P	0.00%	0.00%	6219	0.00%	6219	0
DECO	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
DGG	Available Economic Capacity	S_35	0.00%	45.80%	3198	42.10%	2886	-312
DGG	Available Economic Capacity	S_SP	0.00%	78.00%	6563	29.20%	2255	-4308
DGG	Available Economic Capacity	S_P	0.00%	78.00%	6563	29.40%	2209	-4354
DGG	Available Economic Capacity	S_OP	0.00%	34.40%	2832	10.40%	1751	-1080
DGG	Available Economic Capacity	W_SP	0.00%	28.80%	1169	25.20%	946	-223
DGG	Available Economic Capacity	W_P	0.00%	25.00%	2500	14.30%	1429	-1071
DGG	Available Economic Capacity	W_OP	0.00%	20.00%	1200	15.40%	888	-312
DGG	Available Economic Capacity	SH_SP	0.00%	53.20%	3652	36.50%	2182	-1471
DGG	Available Economic Capacity	SH_P	0.00%	48.70%	3630	23.50%	1759	-1871
DGG	Available Economic Capacity	SH_OP	0.00%	33.20%	2722	13.60%	1758	-964
DLCO	Available Economic Capacity	S_35	90.80%	0.00%	8273	89.80%	8088	-184
DLCO	Available Economic Capacity	S_SP	100.00%	0.00%	10000	100.00%	10000	0
DLCO	Available Economic Capacity	S_P	43.90%	0.00%	3148	43.90%	3144	-4
DLCO	Available Economic Capacity	S_OP	66.80%	0.00%	5565	66.70%	5560	-5
DLCO	Available Economic Capacity	W_SP	71.40%	0.00%	5515	71.30%	5510	-5
DLCO	Available Economic Capacity	W_P	67.80%	0.00%	5631	62.20%	5296	-335
DLCO	Available Economic Capacity	W_OP	64.50%	0.00%	5419	64.40%	5416	-3
DLCO	Available Economic Capacity	SH_SP	56.60%	0.00%	4042	53.90%	3835	-207
DLCO	Available Economic Capacity	SH_P	83.70%	0.00%	7275	83.70%	7270	-5
DLCO	Available Economic Capacity	SH_OP	69.90%	0.00%	5793	69.90%	5789	-4
DPL	Available Economic Capacity	S_35	64.20%	0.00%	4282	62.10%	4042	-240
DPL	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
DPL	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
DPL	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
DPL	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
DPL	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
DUKE	Available Economic Capacity	S_35	78.30%	0.00%	6271	76.10%	5966	-305

Sensitivity: Loop Flow Impact

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
DUKE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
DUKE	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
EDE	Available Economic Capacity	S_35	10.60%	0.00%	714	12.20%	767	53
EDE	Available Economic Capacity	S_SP	6.50%	1.90%	785	9.70%	755	-30
EDE	Available Economic Capacity	S_P	0.00%	0.00%	3441	0.00%	2031	-1411
EDE	Available Economic Capacity	S_OP	0.00%	0.00%	9842	0.00%	4551	-5291
EDE	Available Economic Capacity	W_SP	2.50%	10.20%	691	12.10%	709	18
EDE	Available Economic Capacity	W_P	0.00%	0.00%	1656	0.00%	1555	-100
EDE	Available Economic Capacity	W_OP	0.00%	0.00%	1293	0.00%	1157	-135
EDE	Available Economic Capacity	SH_SP	0.00%	0.00%	2661	0.00%	2328	-333
EDE	Available Economic Capacity	SH_P	0.00%	0.00%	2266	0.00%	2031	-235
EDE	Available Economic Capacity	SH_OP	0.00%	0.00%	2965	0.00%	2457	-509
EKPC	Available Economic Capacity	S_35	51.40%	0.00%	2959	49.90%	2815	-144
EKPC	Available Economic Capacity	S_SP	87.80%	0.00%	7754	88.60%	7900	147
EKPC	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
EKPC	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
EKPC	Available Economic Capacity	W_SP	32.30%	0.00%	2278	32.30%	2136	-142
EKPC	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
EKPC	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
EKPC	Available Economic Capacity	SH_SP	26.70%	0.00%	1852	24.50%	1814	-38
EKPC	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
EKPC	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
ENT	Available Economic Capacity	S_35	13.50%	0.00%	2045	11.60%	2006	-39
ENT	Available Economic Capacity	S_SP	0.00%	0.00%	3586	0.00%	2543	-1043
ENT	Available Economic Capacity	S_P	0.00%	0.00%	2351	0.00%	1728	-623
ENT	Available Economic Capacity	S_OP	0.00%	0.00%	7306	0.00%	5941	-1365
ENT	Available Economic Capacity	W_SP	3.80%	0.00%	3892	3.00%	3925	33
ENT	Available Economic Capacity	W_P	0.00%	0.00%	1013	0.00%	962	-51
ENT	Available Economic Capacity	W_OP	0.00%	0.00%	993	0.00%	842	-151
ENT	Available Economic Capacity	SH_SP	33.80%	0.60%	1495	33.00%	1418	-77
ENT	Available Economic Capacity	SH_P	0.00%	0.00%	1566	0.00%	1418	-148
ENT	Available Economic Capacity	SH_OP	0.00%	0.00%	1258	0.00%	1096	-162
FENER	Available Economic Capacity	S_35	70.60%	0.00%	5121	68.20%	4811	-311
FENER	Available Economic Capacity	S_SP	97.10%	0.00%	9426	96.90%	9395	-31
FENER	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
FENER	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
FENER	Available Economic Capacity	W_SP	0.00%	0.00%	3549	0.00%	3549	0
FENER	Available Economic Capacity	W_P	0.00%	0.00%	8113	0.00%	8113	0
FENER	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
FENER	Available Economic Capacity	SH_SP	28.10%	0.00%	1478	25.70%	1393	-85
FENER	Available Economic Capacity	SH_P	46.30%	0.00%	2922	39.00%	2521	-401
FENER	Available Economic Capacity	SH_OP	62.00%	0.00%	5287	60.30%	5214	-73
GRRD	Available Economic Capacity	S_35	2.20%	0.00%	1137	1.00%	1158	21
GRRD	Available Economic Capacity	S_SP	0.00%	0.00%	2372	0.00%	5011	2639
GRRD	Available Economic Capacity	S_P	0.00%	0.00%	7713	0.00%	3834	-3879
GRRD	Available Economic Capacity	S_OP	0.00%	0.00%	8560	0.00%	4744	-3816
GRRD	Available Economic Capacity	W_SP	0.00%	0.00%	1351	0.00%	1943	592
GRRD	Available Economic Capacity	W_P	0.00%	0.00%	2517	0.00%	1931	-586
GRRD	Available Economic Capacity	W_OP	0.00%	0.00%	3866	0.00%	2243	-1623
GRRD	Available Economic Capacity	SH_SP	4.10%	0.20%	893	6.00%	900	7
GRRD	Available Economic Capacity	SH_P	0.00%	0.00%	3705	0.00%	3516	-188
GRRD	Available Economic Capacity	SH_OP	0.00%	0.00%	5331	0.00%	2983	-2348
HEC	Available Economic Capacity	S_35	67.60%	0.00%	4887	66.30%	4741	-146
HEC	Available Economic Capacity	S_SP	68.70%	0.00%	4988	67.40%	4836	-152
HEC	Available Economic Capacity	S_P	0.00%	0.00%	5045	0.00%	5045	0
HEC	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
HEC	Available Economic Capacity	W_SP	37.00%	0.00%	1985	34.70%	1829	-156

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
HEC	Available Economic Capacity	W_P	0.00%	0.00%	2752	0.00%	2284	-469
HEC	Available Economic Capacity	W_OP	0.00%	0.00%	9002	0.00%	9002	0
HEC	Available Economic Capacity	SH_SP	14.90%	0.00%	1511	7.20%	1612	102
HEC	Available Economic Capacity	SH_P	0.00%	0.00%	2296	0.00%	2372	76
HEC	Available Economic Capacity	SH_OP	0.00%	0.00%	7852	0.00%	7852	0
HLP	Available Economic Capacity	S_35	0.00%	31.70%	2264	23.90%	1887	-377
HLP	Available Economic Capacity	S_SP	0.00%	77.40%	6499	24.70%	2250	-4250
HLP	Available Economic Capacity	S_P	0.00%	77.40%	6499	22.50%	2127	-4373
HLP	Available Economic Capacity	S_OP	0.00%	36.40%	2659	14.90%	1592	-1066
HLP	Available Economic Capacity	W_SP	0.00%	8.50%	2516	8.10%	2498	-18
HLP	Available Economic Capacity	W_P	0.00%	54.10%	3400	24.00%	1436	-1964
HLP	Available Economic Capacity	W_OP	0.00%	0.00%	3136	0.00%	1936	-1200
HLP	Available Economic Capacity	SH_SP	0.00%	43.30%	3131	24.40%	1825	-1306
HLP	Available Economic Capacity	SH_P	0.00%	40.80%	3620	23.00%	1975	-1645
HLP	Available Economic Capacity	SH_OP	0.00%	32.10%	2451	13.10%	1597	-854
IP	Available Economic Capacity	S_35	23.70%	0.00%	1002	22.90%	953	-49
IP	Available Economic Capacity	S_SP	40.70%	0.00%	1948	38.80%	1807	-141
IP	Available Economic Capacity	S_P	28.80%	0.00%	1448	28.00%	1347	-101
IP	Available Economic Capacity	S_OP	22.90%	0.00%	1770	23.10%	1605	-165
IP	Available Economic Capacity	W_SP	34.00%	0.00%	1637	32.60%	1537	-100
IP	Available Economic Capacity	W_P	0.00%	0.00%	1674	0.00%	1540	-134
IP	Available Economic Capacity	W_OP	15.60%	0.00%	1724	11.40%	1515	-209
IP	Available Economic Capacity	SH_SP	27.40%	0.00%	1205	28.90%	1264	59
IP	Available Economic Capacity	SH_P	0.00%	0.00%	2051	0.00%	1865	-186
IP	Available Economic Capacity	SH_OP	0.00%	0.00%	2426	0.00%	2249	-176
IPL	Available Economic Capacity	S_35	62.70%	0.00%	4104	61.00%	3914	-190
IPL	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	S_OP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
IPL	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0
KACY	Available Economic Capacity	S_35	3.30%	0.00%	1448	4.80%	1346	-101
KACY	Available Economic Capacity	S_SP	0.00%	0.00%	1907	0.00%	1961	54
KACY	Available Economic Capacity	S_P	0.00%	0.00%	6711	0.00%	6822	111
KACY	Available Economic Capacity	S_OP	0.00%	0.00%	8194	0.00%	8040	-154
KACY	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
KACY	Available Economic Capacity	W_P	0.00%	0.00%	6651	0.00%	6651	0
KACY	Available Economic Capacity	W_OP	0.00%	0.00%	5629	0.00%	5630	1
KACY	Available Economic Capacity	SH_SP	0.00%	0.00%	2736	0.00%	2467	-269
KACY	Available Economic Capacity	SH_P	0.00%	0.00%	4225	0.00%	3663	-562
KACY	Available Economic Capacity	SH_OP	0.00%	0.00%	4859	0.00%	4923	64
KCPL	Available Economic Capacity	S_35	13.80%	0.00%	1133	13.00%	1105	-27
KCPL	Available Economic Capacity	S_SP	6.60%	0.00%	771	6.20%	787	16
KCPL	Available Economic Capacity	S_P	0.00%	0.00%	1588	6.10%	1053	-535
KCPL	Available Economic Capacity	S_OP	0.00%	0.00%	1792	0.00%	1577	-215
KCPL	Available Economic Capacity	W_SP	10.50%	0.00%	722	3.00%	839	117
KCPL	Available Economic Capacity	W_P	0.00%	0.00%	932	0.00%	1255	323
KCPL	Available Economic Capacity	W_OP	0.00%	0.00%	5213	0.00%	5151	-62
KCPL	Available Economic Capacity	SH_SP	8.70%	0.00%	884	9.40%	810	-73
KCPL	Available Economic Capacity	SH_P	0.00%	0.00%	2366	0.00%	1801	-565
KCPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5725	0.00%	6005	279
LAFA	Available Economic Capacity	S_35	0.00%	0.00%	6843	0.00%	6826	-18
LAFA	Available Economic Capacity	S_SP	0.00%	0.00%	8702	0.00%	3943	-4759
LAFA	Available Economic Capacity	S_P	0.00%	0.00%	3333	0.00%	5000	1666
LAFA	Available Economic Capacity	S_OP	0.00%	0.00%	9999	0.00%	3460	-6539
LAFA	Available Economic Capacity	W_SP	2.20%	5.20%	3016	5.20%	3041	25
LAFA	Available Economic Capacity	W_P	0.00%	0.00%	2882	0.00%	2530	-352
LAFA	Available Economic Capacity	W_OP	0.70%	0.00%	2100	0.60%	1773	-326
LAFA	Available Economic Capacity	SH_SP	23.30%	0.00%	1478	23.30%	1351	-128
LAFA	Available Economic Capacity	SH_P	0.00%	0.00%	3266	0.00%	2824	-442

Sensitivity: Loop Flow Impact **Exhibit No. AC-517**

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
LAFA	Available Economic Capacity	SH_OP	0.80%	0.00%	1966	1.50%	1735	-231
LCRA	Available Economic Capacity	S_35	0.00%	35.20%	2665	31.50%	2431	-234
LCRA	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	3945	-6055
LCRA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	5000	-5000
LCRA	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	5000	-5000
LCRA	Available Economic Capacity	W_SP	0.00%	5.10%	2399	5.00%	2396	-3
LCRA	Available Economic Capacity	W_P	0.00%	0.00%	5056	0.00%	2563	-2492
LCRA	Available Economic Capacity	W_OP	0.00%	0.00%	5642	0.00%	2926	-2715
LCRA	Available Economic Capacity	SH_SP	0.00%	81.60%	6997	34.00%	2384	-4613
LCRA	Available Economic Capacity	SH_P	0.00%	66.50%	5008	19.20%	1879	-3129
LCRA	Available Economic Capacity	SH_OP	0.00%	0.00%	6074	0.00%	3309	-2766
LGE	Available Economic Capacity	S_35	54.00%	0.00%	3187	51.50%	2948	-239
LGE	Available Economic Capacity	S_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	W_OP	0.00%	0.00%	8415	0.00%	8415	0
LGE	Available Economic Capacity	SH_SP	0.00%	0.00%	0	0.00%	0	0
LGE	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
LGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
MPS	Available Economic Capacity	S_35	13.80%	0.00%	1054	12.60%	993	-61
MPS	Available Economic Capacity	S_SP	0.00%	0.00%	2221	0.00%	2083	-138
MPS	Available Economic Capacity	S_P	0.00%	0.00%	2484	0.00%	2484	0
MPS	Available Economic Capacity	S_OP	0.00%	0.00%	3438	0.00%	2591	-847
MPS	Available Economic Capacity	W_SP	0.00%	0.00%	4129	0.00%	4244	115
MPS	Available Economic Capacity	W_P	0.00%	0.00%	4071	0.00%	4127	57
MPS	Available Economic Capacity	W_OP	0.00%	0.00%	2856	0.00%	2916	60
MPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3168	0.00%	1986	-1182
MPS	Available Economic Capacity	SH_P	0.00%	0.00%	8266	0.00%	8214	-52
MPS	Available Economic Capacity	SH_OP	0.00%	0.00%	6140	0.00%	6140	0
NIPS	Available Economic Capacity	S_35	28.40%	0.00%	1337	27.70%	1304	-33
NIPS	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	W_OP	0.00%	0.00%	9560	0.00%	9735	175
NIPS	Available Economic Capacity	SH_SP	0.00%	0.00%	10000	0.00%	10000	0
NIPS	Available Economic Capacity	SH_P	0.00%	0.00%	5985	0.00%	5985	0
NIPS	Available Economic Capacity	SH_OP	0.00%	0.00%	9677	0.00%	9677	0
NSP	Available Economic Capacity	S_35	9.90%	0.00%	970	10.90%	1030	60
NSP	Available Economic Capacity	S_SP	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	S_P	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	S_OP	0.00%	0.00%	7094	0.00%	7094	0
NSP	Available Economic Capacity	W_SP	0.00%	0.00%	3275	0.00%	3275	0
NSP	Available Economic Capacity	W_P	0.00%	0.00%	4849	0.00%	4849	0
NSP	Available Economic Capacity	W_OP	0.00%	0.00%	8518	0.00%	8518	0
NSP	Available Economic Capacity	SH_SP	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	SH_P	0.00%	0.00%	7387	0.00%	7387	0
NSP	Available Economic Capacity	SH_OP	0.00%	0.00%	8207	0.00%	8207	0
OKGE	Available Economic Capacity	S_35	4.60%	0.00%	1182	4.80%	1312	130
OKGE	Available Economic Capacity	S_SP	0.00%	0.00%	3464	0.00%	3184	-280
OKGE	Available Economic Capacity	S_P	0.00%	0.00%	3213	0.00%	2020	-1193
OKGE	Available Economic Capacity	S_OP	0.00%	0.00%	7022	0.00%	3189	-3833
OKGE	Available Economic Capacity	W_SP	0.00%	0.00%	1831	0.00%	2034	203
OKGE	Available Economic Capacity	W_P	0.00%	0.00%	1736	0.00%	1325	-411
OKGE	Available Economic Capacity	W_OP	0.00%	0.00%	4550	0.00%	2611	-1939
OKGE	Available Economic Capacity	SH_SP	5.90%	0.20%	776	6.90%	765	-11
OKGE	Available Economic Capacity	SH_P	0.00%	0.00%	2271	0.00%	1762	-509
OKGE	Available Economic Capacity	SH_OP	0.00%	0.00%	5869	0.00%	2559	-3310
SCEG	Available Economic Capacity	S_35	94.10%	0.00%	8865	92.90%	8652	-213
SCEG	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	5000	-5000

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
SCEG	Available Economic Capacity	S_P	99.90%	0.00%	9986	99.90%	9987	1
SCEG	Available Economic Capacity	S_OP	42.20%	0.00%	3714	42.20%	3709	-4
SCEG	Available Economic Capacity	W_SP	67.20%	0.00%	4822	67.20%	4821	-1
SCEG	Available Economic Capacity	W_P	18.50%	0.00%	1795	17.60%	1800	5
SCEG	Available Economic Capacity	W_OP	7.40%	0.00%	1805	6.90%	1807	3
SCEG	Available Economic Capacity	SH_SP	65.10%	0.00%	4555	64.00%	4448	-107
SCEG	Available Economic Capacity	SH_P	44.30%	0.00%	2509	43.90%	2468	-41
SCEG	Available Economic Capacity	SH_OP	10.20%	0.00%	1522	10.00%	1506	-16
SIGE	Available Economic Capacity	S_35	79.70%	0.00%	6412	78.90%	6290	-122
SIGE	Available Economic Capacity	S_SP	86.20%	0.00%	7454	86.00%	7416	-38
SIGE	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	W_SP	28.50%	0.00%	1961	26.80%	1887	-74
SIGE	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	SH_SP	0.00%	0.00%	2002	0.00%	2024	23
SIGE	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
SIGE	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
SOCO	Available Economic Capacity	S_35	76.80%	0.00%	5964	76.50%	5906	-58
SOCO	Available Economic Capacity	S_SP	0.00%	0.00%	4302	0.00%	3120	-1182
SOCO	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	3548	-6452
SOCO	Available Economic Capacity	S_OP	81.40%	0.00%	6756	81.20%	6725	-31
SOCO	Available Economic Capacity	W_SP	0.00%	0.00%	5000	0.00%	5000	0
SOCO	Available Economic Capacity	W_P	0.00%	0.00%	3166	0.00%	3141	-26
SOCO	Available Economic Capacity	W_OP	34.40%	0.00%	3683	32.40%	3675	-8
SOCO	Available Economic Capacity	SH_SP	0.00%	0.00%	10000	0.00%	3480	-6520
SOCO	Available Economic Capacity	SH_P	0.00%	0.00%	4085	0.00%	3924	-161
SOCO	Available Economic Capacity	SH_OP	85.40%	0.00%	7347	84.50%	7199	-148
SPRM	Available Economic Capacity	S_35	3.00%	0.00%	2500	4.70%	2779	279
SPRM	Available Economic Capacity	S_SP	0.00%	0.00%	5000	0.00%	2549	-2451
SPRM	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
SPRM	Available Economic Capacity	S_OP	0.00%	0.00%	6993	0.00%	5812	-1181
SPRM	Available Economic Capacity	W_SP	0.00%	0.00%	8188	0.00%	8188	0
SPRM	Available Economic Capacity	W_P	0.00%	0.00%	4718	0.00%	4718	0
SPRM	Available Economic Capacity	W_OP	0.00%	0.00%	3645	0.00%	3639	-5
SPRM	Available Economic Capacity	SH_SP	0.00%	0.00%	5743	0.00%	4407	-1337
SPRM	Available Economic Capacity	SH_P	0.00%	0.00%	3868	0.00%	3868	0
SPRM	Available Economic Capacity	SH_OP	0.00%	0.00%	9913	0.00%	9910	-2
STEC	Available Economic Capacity	S_35	0.00%	54.10%	4054	36.50%	2771	-1282
STEC	Available Economic Capacity	S_SP	0.00%	80.30%	6662	56.00%	3941	-2722
STEC	Available Economic Capacity	S_P	0.00%	65.00%	5449	0.00%	5456	7
STEC	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	5000	-5000
STEC	Available Economic Capacity	W_SP	0.00%	6.00%	3473	5.50%	3504	31
STEC	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
STEC	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
STEC	Available Economic Capacity	SH_SP	0.00%	77.70%	6249	53.80%	3678	-2571
STEC	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
STEC	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
STJO	Available Economic Capacity	S_35	11.30%	0.00%	1391	10.30%	1362	-28
STJO	Available Economic Capacity	S_SP	6.30%	0.00%	817	5.80%	819	2
STJO	Available Economic Capacity	S_P	0.00%	0.00%	1177	0.00%	1143	-34
STJO	Available Economic Capacity	S_OP	0.00%	0.00%	2288	0.00%	1760	-527
STJO	Available Economic Capacity	W_SP	0.00%	0.00%	984	0.00%	924	-59
STJO	Available Economic Capacity	W_P	0.00%	0.00%	1392	0.00%	1307	-85
STJO	Available Economic Capacity	W_OP	0.00%	0.00%	4757	0.00%	4757	0
STJO	Available Economic Capacity	SH_SP	9.60%	0.00%	826	9.80%	786	-41
STJO	Available Economic Capacity	SH_P	0.00%	0.00%	1058	0.00%	966	-92
STJO	Available Economic Capacity	SH_OP	0.00%	0.00%	5099	0.00%	5099	0
SWEPA	Available Economic Capacity	S_35	4.90%	0.30%	907	4.60%	950	44
SWEPA	Available Economic Capacity	S_SP	17.10%	0.00%	2396	26.20%	1374	-1023
SWEPA	Available Economic Capacity	S_P	0.00%	0.00%	3332	0.00%	3131	-200
SWEPA	Available Economic Capacity	S_OP	0.00%	0.00%	2701	0.00%	1860	-840
SWEPA	Available Economic Capacity	W_SP	0.00%	0.00%	1142	0.00%	926	-217
SWEPA	Available Economic Capacity	W_P	0.00%	0.00%	1923	0.00%	1569	-353

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
SWEPA	Available Economic Capacity	W_OP	0.00%	0.00%	1540	0.00%	1298	-241
SWEPA	Available Economic Capacity	SH_SP	0.00%	0.50%	911	4.20%	726	-184
SWEPA	Available Economic Capacity	SH_P	0.00%	0.00%	2069	0.00%	1964	-104
SWEPA	Available Economic Capacity	SH_OP	0.00%	0.00%	1484	0.00%	1411	-73
SWPS	Available Economic Capacity	S_35	0.80%	0.00%	3998	0.00%	4957	959
SWPS	Available Economic Capacity	S_SP	0.00%	0.00%	6116	0.00%	4933	-1183
SWPS	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	7629	-2371
SWPS	Available Economic Capacity	S_OP	0.00%	0.00%	7503	0.00%	2838	-4665
SWPS	Available Economic Capacity	W_SP	0.20%	2.50%	5860	1.10%	6618	758
SWPS	Available Economic Capacity	W_P	0.00%	0.00%	2802	0.00%	3733	931
SWPS	Available Economic Capacity	W_OP	0.00%	0.00%	4074	0.00%	4220	146
SWPS	Available Economic Capacity	SH_SP	0.00%	0.00%	3993	0.00%	4699	706
SWPS	Available Economic Capacity	SH_P	0.00%	0.00%	4123	0.00%	6503	2380
SWPS	Available Economic Capacity	SH_OP	0.00%	0.00%	5050	0.00%	3984	-1066
TMPA	Available Economic Capacity	S_35	0.00%	20.20%	2485	18.60%	2394	-91
TMPA	Available Economic Capacity	S_SP	0.00%	78.00%	6563	24.80%	2305	-4258
TMPA	Available Economic Capacity	S_P	0.00%	78.00%	6563	22.60%	2132	-4430
TMPA	Available Economic Capacity	S_OP	0.00%	27.70%	3728	2.60%	2368	-1360
TMPA	Available Economic Capacity	W_SP	0.00%	14.20%	2480	13.70%	2480	0
TMPA	Available Economic Capacity	W_P	0.00%	0.00%	3365	0.00%	2037	-1328
TMPA	Available Economic Capacity	W_OP	0.00%	0.00%	2704	0.00%	2464	-240
TMPA	Available Economic Capacity	SH_SP	0.00%	51.60%	3522	35.00%	2031	-1490
TMPA	Available Economic Capacity	SH_P	0.00%	48.00%	3540	23.10%	1721	-1819
TMPA	Available Economic Capacity	SH_OP	0.00%	32.30%	2735	13.20%	1931	-804
TNMP	Available Economic Capacity	S_35	0.00%	43.60%	3959	41.40%	3777	-182
TNMP	Available Economic Capacity	S_SP	0.00%	78.00%	6563	24.80%	2258	-4304
TNMP	Available Economic Capacity	S_P	0.00%	78.00%	6563	22.80%	2143	-4420
TNMP	Available Economic Capacity	S_OP	0.00%	34.30%	2745	3.20%	2030	-714
TNMP	Available Economic Capacity	W_SP	0.00%	11.20%	3331	11.00%	3311	-20
TNMP	Available Economic Capacity	W_P	0.00%	0.00%	3056	0.00%	2096	-960
TNMP	Available Economic Capacity	W_OP	0.00%	0.00%	2006	0.00%	1815	-192
TNMP	Available Economic Capacity	SH_SP	0.00%	55.60%	3800	34.10%	2146	-1654
TNMP	Available Economic Capacity	SH_P	0.00%	48.90%	3433	27.60%	1936	-1498
TNMP	Available Economic Capacity	SH_OP	0.00%	38.20%	2207	15.60%	1416	-791
TU	Available Economic Capacity	S_35	0.40%	36.20%	2717	33.20%	2524	-193
TU	Available Economic Capacity	S_SP	0.00%	59.90%	4147	24.60%	2063	-2083
TU	Available Economic Capacity	S_P	0.00%	43.70%	3030	16.60%	1531	-1499
TU	Available Economic Capacity	S_OP	3.00%	27.30%	1558	4.90%	1301	-257
TU	Available Economic Capacity	W_SP	0.10%	8.30%	6106	8.20%	6105	-1
TU	Available Economic Capacity	W_P	0.00%	0.00%	1542	0.00%	1339	-203
TU	Available Economic Capacity	W_OP	1.70%	0.00%	946	2.90%	900	-46
TU	Available Economic Capacity	SH_SP	3.00%	46.20%	2487	32.70%	1689	-797
TU	Available Economic Capacity	SH_P	0.00%	40.30%	2435	22.70%	1540	-895
TU	Available Economic Capacity	SH_OP	0.90%	31.70%	1651	14.50%	1155	-496
TVA	Available Economic Capacity	S_35	38.80%	0.00%	1870	36.60%	1709	-161
TVA	Available Economic Capacity	S_SP	47.90%	0.00%	2632	46.60%	2497	-135
TVA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	S_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	W_OP	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_SP	49.70%	0.00%	2666	46.30%	2343	-323
TVA	Available Economic Capacity	SH_P	0.00%	0.00%	10000	0.00%	10000	0
TVA	Available Economic Capacity	SH_OP	0.00%	0.00%	10000	0.00%	10000	0
VP	Available Economic Capacity	S_35	67.00%	0.00%	4948	65.70%	4764	-184
VP	Available Economic Capacity	S_SP	100.00%	0.00%	10000	100.00%	10000	0
VP	Available Economic Capacity	S_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	S_OP	100.00%	0.00%	10000	100.00%	10000	0
VP	Available Economic Capacity	W_SP	100.00%	0.00%	10000	100.00%	10000	0
VP	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	W_OP	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	SH_SP	80.40%	0.00%	6853	78.40%	6610	-244
VP	Available Economic Capacity	SH_P	0.00%	0.00%	0	0.00%	0	0
VP	Available Economic Capacity	SH_OP	0.00%	0.00%	0	0.00%	0	0

Sensitivity: Loop Flow Impact

Exhibit No. AC-517

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
WEFA	Available Economic Capacity	S_35	2.50%	0.00%	2057	1.70%	2413	356
WEFA	Available Economic Capacity	S_SP	0.00%	0.00%	10000	0.00%	5000	-5000
WEFA	Available Economic Capacity	S_P	0.00%	0.00%	10000	0.00%	5000	-5000
WEFA	Available Economic Capacity	S_OP	0.00%	0.00%	3595	0.00%	2399	-1196
WEFA	Available Economic Capacity	W_SP	0.00%	0.00%	10000	0.00%	5000	-5000
WEFA	Available Economic Capacity	W_P	0.00%	0.00%	0	0.00%	0	0
WEFA	Available Economic Capacity	W_OP	0.00%	0.00%	5089	0.00%	3493	-1597
WEFA	Available Economic Capacity	SH_SP	0.00%	0.00%	2554	0.00%	1927	-627
WEFA	Available Economic Capacity	SH_P	0.00%	0.00%	5673	0.00%	3025	-2648
WEFA	Available Economic Capacity	SH_OP	0.00%	0.00%	3675	0.00%	2767	-908
WEP	Available Economic Capacity	S_35	8.50%	0.00%	1584	7.80%	1347	-237
WEP	Available Economic Capacity	S_SP	12.70%	0.00%	1200	12.00%	1020	-181
WEP	Available Economic Capacity	S_P	0.00%	0.00%	1171	0.00%	1340	169
WEP	Available Economic Capacity	S_OP	0.00%	0.00%	4199	0.00%	4199	0
WEP	Available Economic Capacity	W_SP	9.00%	0.00%	1274	5.60%	1286	12
WEP	Available Economic Capacity	W_P	0.00%	0.00%	1631	0.00%	1681	50
WEP	Available Economic Capacity	W_OP	0.00%	0.00%	2901	0.00%	2906	5
WEP	Available Economic Capacity	SH_SP	6.70%	0.00%	1149	5.00%	1177	23
WEP	Available Economic Capacity	SH_P	0.00%	0.00%	1142	0.00%	1148	6
WEP	Available Economic Capacity	SH_OP	0.00%	0.00%	4256	0.00%	4256	0
WEPL	Available Economic Capacity	S_35	0.60%	0.00%	3495	1.10%	3206	-289
WEPL	Available Economic Capacity	S_SP	0.00%	0.00%	3847	0.00%	2008	-1839
WEPL	Available Economic Capacity	S_P	0.00%	0.00%	4606	0.00%	4606	0
WEPL	Available Economic Capacity	S_OP	0.00%	0.00%	7604	0.00%	7764	160
WEPL	Available Economic Capacity	W_SP	0.00%	0.00%	4480	0.00%	4535	55
WEPL	Available Economic Capacity	W_P	0.00%	0.00%	3466	0.00%	3467	1
WEPL	Available Economic Capacity	W_OP	0.00%	0.00%	3655	0.00%	3627	-28
WEPL	Available Economic Capacity	SH_SP	0.00%	0.00%	2997	0.00%	2674	-323
WEPL	Available Economic Capacity	SH_P	0.00%	0.00%	3680	0.00%	3013	-667
WEPL	Available Economic Capacity	SH_OP	0.00%	0.00%	5186	0.00%	5266	80
WR	Available Economic Capacity	S_35	8.10%	0.00%	1289	7.60%	1315	26
WR	Available Economic Capacity	S_SP	0.00%	0.00%	3003	0.00%	2058	-944
WR	Available Economic Capacity	S_P	0.00%	0.00%	4154	0.00%	2288	-1866
WR	Available Economic Capacity	S_OP	0.00%	0.00%	7480	0.00%	7480	0
WR	Available Economic Capacity	W_SP	0.00%	0.00%	1876	0.00%	1458	-418
WR	Available Economic Capacity	W_P	0.00%	0.00%	3205	0.00%	2299	-906
WR	Available Economic Capacity	W_OP	0.00%	0.00%	3305	0.00%	2590	-716
WR	Available Economic Capacity	SH_SP	0.00%	0.00%	1787	0.00%	1460	-327
WR	Available Economic Capacity	SH_P	0.00%	0.00%	2466	0.00%	1740	-726
WR	Available Economic Capacity	SH_OP	0.00%	0.00%	5121	0.00%	3250	-1871

Exhibit No. AC-518

Electric Generating Facilities Served by the LIG Pipeline

Plant	Owner	Capacity (MW) [1]	Capacity Factor (%) [2]	Pipeline Connections [3]	Type of Delivery Service [4]	LIG (%) [5]
D.G. Hunter	ALEX	157	1.16	LIG Only	Interruptible	100%
Coughlin	CELE	334	7.19	Columbia Gulf	Interruptible	42%
Rodemacher	CELE	440	18.76	Trunkline	Interruptible	44%
Teche	CELE	407	32.17	Columbia Gulf, ANR, Texas Gas	Interruptible	51%
Doc Bonin	LAFA	328	12.23	Columbia Gulf, Texas Gas	Firm	100%
Natchitoches	LAFA	54		LIG Only	Firm	100%
Morgan City	LEPA	62		Texas Gas	Firm	100%
Houma	LEPA	62	12.62	Koch, AGP	Interruptible	
Plaquemine (Dow)	LEPA	41		Texas Eastern, LRC		

Sources:

[1] SPP OE411 - 1997.
[2] Electric World 1998 106th Edition, except for Rodemacher (FERC Form 1 Report dated 4/30/97.)
[3] Louisiana IntraState Pipeline
[4] Louisiana IntraState Pipeline
[5] Louisiana IntraState Pipeline

LIG Pipeline Analysis

Exhibit No. AC-519

Market	Analysis	Period	AEP Mkt Share	BASE CSW Mkt Share	HHI Pre-Merger	Merged Mkt Share	MERGER HHI Post-Merger	HHI Change
CELE	Economic Capacity	S_35	5.10%	7.00%	6629	12.00%	6698	69
CELE	Economic Capacity	S_SP	10.10%	0.20%	4390	10.10%	4389	-1
CELE	Economic Capacity	S_P	0.60%	0.10%	8017	0.80%	8017	0
CELE	Economic Capacity	W_SP	7.30%	5.00%	4718	12.30%	4789	71
CELE	Economic Capacity	W_P	10.60%	0.90%	2229	11.20%	2242	13
CELE	Economic Capacity	SH_SP	1.90%	0.80%	4442	2.90%	4446	4
CELE	Economic Capacity	SH_P	3.70%	2.10%	2342	6.30%	2361	19
CSW_SPP	Economic Capacity	S_35	63.40%	0.20%	4114	62.60%	4009	-105
CSW_SPP	Economic Capacity	S_SP	62.00%	0.30%	3937	61.10%	3832	-105
CSW_SPP	Economic Capacity	S_P	53.40%	0.30%	3057	52.60%	2970	-87
CSW_SPP	Economic Capacity	W_SP	56.50%	0.40%	3306	56.00%	3247	-60
CSW_SPP	Economic Capacity	W_P	37.60%	0.70%	1649	37.20%	1620	-29
CSW_SPP	Economic Capacity	SH_SP	50.60%	0.50%	2714	50.20%	2671	-44
CSW_SPP	Economic Capacity	SH_P	36.50%	0.90%	1561	36.70%	1575	14
ENT	Economic Capacity	S_35	0.20%	0.20%.	5427	0.40%	5427	0
ENT	Economic Capacity	S_SP	0.20%	0.60%	2728	0.80%	2729	0
ENT	Economic Capacity	S_P	0.90%	0.20%	2768	1.00%	2770	3
ENT	Economic Capacity	W_SP	3.50%	0.20%	5220	3.40%	5233	14
ENT	Economic Capacity	W_P	2.00%	0.40%	2699	1.40%	2741	43
ENT	Economic Capacity	SH_SP	3.90%	0.30%	3749	4.20%	3751	1
ENT	Economic Capacity	SH_P	4.80%	0.60%	1620	5.30%	1621	1
LAFA	Economic Capacity	S_35	0.40%	7.40%	7471	7.80%	7477	6
LAFA	Economic Capacity	S_SP	1.90%	0.00%	7159	1.90%	7159	-1
LAFA	Economic Capacity	S_P	0.20%	0.00%	5960	0.20%	5960	0
LAFA	Economic Capacity	W_SP	1.50%	4.70%	4140	6.10%	4154	14
LAFA	Economic Capacity	W_P	3.00%	0.80%	2514	3.80%	2518	4
LAFA	Economic Capacity	SH_SP	1.80%	1.00%	3914	2.80%	3918	3
LAFA	Economic Capacity	SH_P	3.10%	1.10%	2221	4.20%	2226	5

Summary of Projected Merchant Plant Capacity

	New Capacity						Uncommitted Capacity					
	1998	1999	2000	2001	2002	Total	1998	1999	2000	2001	2002	Total
ECAR	-	-	-	1,860	-	1,860	-	-	-	910	-	910
ERCOT	220	1,238	6,400	1,030	500	9,388	130	1,018	5,955	450	500	8,053
MAIN	117	934	1,885	600	-	3,536	15	934	1,585	600	-	3,134
MAPP	-	100	255	-	-	355	-	19	76	-	-	95
SERC	-	1,470	1,934	1,100	-	4,504	-	1,360	1,719	1,100	-	4,179
SPP	-	530	530	825	-	1,885	-	340	530	825	-	1,695
TOTAL	337	4,272	11,004	5,415	500	21,528	145	3,671	9,865	3,885	500	18,066

Merchant Plants Scheduled to be On-line by the Year 2002

ECAR, ERCOT, MAIN, MAPP, SERC and SPP

Project Name	City, State	Operator	Cogen Host / Electricity Purchaser	Capacity (MW) Total Project	Capacity (MW) Un-Comm	Fuel Type	Unit Type	Installation Date		Project Status	Source Code
ECAR											
RE Burger Repowering	Shadyside, OH	National Pwr Part & OES Ventures	- / -	280	280	REF CL	ST	2001	6	P	1
Rouge Cogen	Dearborn, MI	Dearborn Industrial Generation	Ford & Rouge Steel / Same	550	150	NG	CC	2001	6	I	7
Wyandotte	Wyandotte, MI	Nordic Electric	- / -	480	480	NG	CC	2001	9	P	15
Amoco's Whiting Refinery	Whiting, IN	Primary Energy, Inc.	Amoco Refinery / Same[c]	550	0	NG	COGEN	2001	3	P	12
ERCOT											
Phillips Cogen	Pasadena, TX	Calpine Corp.	Phillips Houston Chem / Same	220	130	NG	COGEN	1998	6		1
Frontera	Hidalgo County, TX	CSW Energy	- / -	500	500	NG	CC	1999	6	U	1 , 13
Mustang Station[a]	Denver City, TX	Quixx Corp.	- / -	488	488	NG	GT	1999	6	T	1, 8
West Texas Wind Farm (Phase I)	West Texas	American National Power	- / -	250	30	Wind	WT	1999	6	P	3
Edinburg (Phase I)	Edinburg, TX	American National Power	- / -	500	500	NG	CC	2000	6	P	1
Gregory	Gregory, TX	LG&E Power Services	Reynolds Metal / Same	550	345	NG	COGEN	2000	6	U	14
Grimes County[b]	Grimes County, TX	Tenaska	- / -	800	800	NG	CC	2000	6	P	1
Guadalupe County Merchant Plant	Marion, TX	Panda Energy	- / -	750	750	NG	CC	2000	6	P	5
Ingleside	Ingleside, TX	Occidental Energy Ventures	- / Occidental's OxyChem	440	200	NG	CC	2000	1	U	1
Paris	Paris, TX	Panda Energy	- / -	1,000	1,000	NG	CC	2000	6	P	1
Phillips Cogen Expansion	Pasadena, TX	Calpine Corp.	Phillips Houston Chem / Same	510	510	NG	CC	2000	6	P	4
TXI Railport	Midlothian, TX	American National Power	- / -	1,100	1,100	NG	CC	2000	6	T	3
Ultramar Diamond Shamrock	Three Rivers, TX	US Gen	Ultramar Refinery / -	750	750	NG	COGEN	2000	6	P	1
Corpus Christi	Corpus Christi, TX	LG&E Power Development	Renolds Metal / Same[c]	330	0	NG	COGEN	2001	6	P	1
Edinburg	Edinburg, TX	Calpine Corp.	- / Magic Valley Elec. Coop.	700	450	NG	CC	2001	6	P	1
Edinburg (Phase II)	Edinburg, TX	American National Power	- / -	500	500	NG	CC	2002	6	P	1
MAIN											
Millenium Petrochemical	Morris, IL	NRG Energy	Millenium Petrochemical / Same	117	15	NG	COGEN	1998	late		1
Elwood	Elwood, IL	Dominion and Peoples Energy	- / -	300	300	NG	GT	1999	6	U	19 , 25
Wood River	Roxana, IL	Houston Industries Power Gen.	- / -	634	634	NG	CC	1999	6	U	1
Polsky Peaking Facility	Dane/Rock Cty, WI	Polsky Energy	- / Alliant	525	375	NG	GT	2000	6	P	25
Neenah	Neenah, WI	Southern Energy	- / -	300	300	NG	GT	2000	6	P	25
Island Lake	Island Lake, IL	KN Energy	- / -	510	510	NG	CC	2000	6	P	20 , 25
Southeast Wisc. Merchant Plant	SE Wisconsin	Polsky Energy & Alliant	- / Alliant-WP&L	550	400	NG	GT	2000	6	P	6
Proposed Merchant Facility	IL	CalEnergy and MidAmerican	- / -	600	600	NG	CC	2001	6	P	18 , 25

Merchant Plants Scheduled to be On-line by the Year 2002

ECAR, ERCOT, MAIN, MAPP, SERC and SPP

Project Name	City, State	Operator	Cogen Host / Electricity Purchaser	Capacity (MW) Total Project	Capacity (MW) Un-Comm	Fuel Type	Unit Type	Installation Date		Project Status	Source Code
MAPP											
Buena Vista	Buena Vista, IA	Enron Wind / FPL Energy	- / MidAmerican and IES	100	19	Wind	WT	1999	1	V	1
DePere (Phase II)	DePere, WI	Polsky Energy	International Paper	255	76	NG	CC	2000	6	U	1
SERC											
Dalton	Dalton, GA	World Energy Systems	- / TVA	85	15	NG	GT	1999	6	U	1
Enron Caladonia	Caladonia, MS	Enron Capital & Trade Resources	- / -	475	475	NG	GT	1999	6	V	1
Enron Fulton	Fulton, MS	Enron Capital & Trade Resources	- / -	260	260	NG	GT	1999	6	V	1
Enron New Albany	New Albany, MS	Enron Capital & Trade Resources	- / -	390	390	NG	GT	1999	6	V	1
CP&L Monroe, GA	Monroe, GA	Carolina Power & Light	- / -	160	160	NG	GT	1999	6	P	22 , 25
Sabine Cogen	Orange, TX	Air Liquide America and HIPG	Bayer Corp / Same	100	60	NG	Cogen	1999	11	T	24, 25
Batesville	Batesville, MS	Cogentrix and LS Power	- / -	800	800	NG	CC	2000	6	U	16 , 25
Cataula	Columbus, GA	Sonat-Calpine	- / Georgia Power	680	465	NG	CC	2000	6	U	1 , 2
Enron Brownsville	Brownsville, TN	Enron Capital & Trade Resources	- / -	454	454	NG	GT	2000	6	U	9
CP&L Merchant Peaker	NC	Carolina Power & Light	- / -	1,100	1,100	NG	GT	2001	6	P	21 , 25
SPP											
Air Liquide America	Geismer, LA	Air Liquide America	- / BASF Corp.	80	15	NG	GT	1999	9	U	1
St. Francis (Phase I)	Glennonville, MO	Duke Energy	- / Associated Electric Coop.	250	125	NG	CC	1999	6	U	17 , 25
Sterlington	Sterlington, LA	Koch Power Louisiana	- / -	200	200	NG	GT	1999	5	P	10
Mid-American Industrial Park	Chouteau, OK	AEC and KAMO Power	- / -	530	530	NG	CC	2000	7	T	23 , 25
Jenks	Jenks, OK	Cogentrix Energy, Inc.	- / -	825	825	NG	GT	2001	6	P	11

Merchant Plants Scheduled to be On-line by the Year 2002

ECAR, ERCOT, MAIN, MAPP, SERC and SPP

Project Name	City, State	Operator	Cogen Host / Electricity Purchaser	Capacity (MW) Total Project	Un-Comm	Fuel Type	Unit Type	Installation Date	Project Status	Source Code

NERC Project Status Codes:

I	Intent to purchase from IPP; no PPA; no construction
P	Planned for installation; no utility authorization; no construction
T	Regulatory approval complete; no construction
U	Under construction; < 50% complete
V	Under construction; > 50% complete

Sources:
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[4] *The Energy Daily*, October 30, 1998, page 2.
[5] *The Global Power Report.*
[6] *The Electricity Daily*, July 24, 1998, page 1.
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[8] New Century Energies Press Release, May 15, 1998. Printed on web page.
[9] Enron's Web Site, "Power Plants - Under Construction."
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[20] KN Energy RFP, "Northeast Illinois Power Project -- 510 MW." (http://www.knenergy.com/nipp.html)
[21] CP&L General News Release, "CP&L Will No Longer Pursue Rowan County Site for Electric Plant." Dec. 22, 1998.
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[24] Houston Industries Power Generation, Inc. News Release, "Houston Industries and Air Liquide America Partner on Bayer Corp. Generation Plant." July 31, 1998.
[25] McGuire, Woods, Battle & Boothe, LLP, "Merchant Power Scoreboard." (http://www.mwbb.com/services/energy-mp.htm)

Notes:
[a] Mustang Station primarily will serve Golden Spread Electric Coop.; it is unclear how much is uncommitted.
[b] Tenaska's Grimes County Plant will be situated electrically such that it can sell power in ERCOT or SERC via the Eastern Interconnect.
[c] Since data on the amount of electricity available for market is not available, none of the plant's capacity is assumed to be uncommitted.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF :

JOINT APPLICATION OF KENTUCKY POWER COMPANY,)
AMERICAN ELECTRIC POWER COMPANY, INC.)
AND CENTRAL AND SOUTH WEST CORPORATION) CASE NO. 99-
REGARDING A PROPOSED MERGER)

DIRECT TESTIMONY

OF

THOMAS E. MITCHELL

APRIL 1999

TESTIMONY INDEX

SUBJECT PAGE

EXHIBITS

EXHIBIT TEM-1	List Of Witness' Previous Regulatory Testimony
EXHIBIT TEM-2	Unaudited Pro Forma Financial Data

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DIRECT TESTIMONY

OF

THOMAS E. MITCHELL

APRIL 1999

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, ADDRESS AND PLACE OF EMPLOYMENT.

A. My name is Thomas E. Mitchell. My business address is 1 Riverside Plaza, Columbus, Ohio 43215-2373. I am the Director of the Accounting Policy and Research Staff of the American Electric Power Service Corporation (AEPSC). In my present position, I am the senior accounting technician in American Electric Power Company, Inc.'s (AEP) recently consolidated Accounting Department.

Q. BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science Degree in Accounting from Virginia Polytechnic Institute and State University (VPI&SU) in 1977. I also hold a Master of Business Administration Degree from VPI&SU and a Bachelor of Arts Degree in Government from the University of Notre Dame. I have been a Certified Public Accountant since 1978. I was first employed by Appalachian Power Company (APCO), an AEP electric operating affiliate, in 1979 and, except for employment with Norfolk Southern Corporation as an assistant accounting manager (1984-1985), have held various technical and administrative positions with APCO's Accounting Department until March 31, 1998 when I was promoted to my present position. Prior to assuming my present position as the AEP System's senior accounting technician, my responsibilities included managing APCO's Accounting Department and the development of accounting data for APCO's various regulatory filings in Virginia, West Virginia and the Federal Energy Regulatory Commission. In 1982, I attended the American Electric Power Management Development Program at The Ohio State University.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have previously testified before the Virginia State Corporation Commission, the Public Service Commission of West Virginia and the Federal Energy Regulatory Commission (FERC). I have also provided testimony in connection with the proposed merger in Arkansas, Louisiana, Oklahoma and Texas. A list of these proceedings is attached to this testimony as EXHIBIT TEM-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

1) Briefly describe the proposed combination of AEP and Central and South West Corporation (CSW);

2) Describe the method of accounting for the proposed combination and testify as to its compliance with generally accepted accounting principles, as well as FERC requirements;

3) Describe and provide pro forma (as if merged) financial data for the combined entity;

4) Review the federal income tax implications of the merger;

5) Discuss the accounting implications of the Applicants' proposed regulatory plan; and

6) Suggest language to include in a Commission Final Order that would support deferral and amortization of the costs of the merger.

III. SUMMARY OF TESTIMONY

Q. COULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Yes. Based on the facts and circumstances of the proposed merger of AEP and CSW, the new combined entity will account for the merger as a pooling of interests. My testimony explains the pooling of interests accounting method and provides pro forma pooled historical financial data as if the merger had been completed. The combination should qualify as a tax free transaction for federal income tax purposes. My testimony also explains the accounting for the Applicants' proposal to defer and amortize, over a five-year period on a straight-line basis, the Kentucky retail jurisdictional share of the merger costs and proposes ordering language to satisfy the requirements of generally accepted accounting principles (GAAP) to defer these costs.

Q. PLEASE IDENTIFY AND DESCRIBE EACH OF THE EXHIBITS THAT YOU ARE SPONSORING.

A. I am sponsoring the following Exhibits to my testimony:

- EXHIBIT TEM-1 consists of a list of prior testimony.
- EXHIBIT TEM-2 consists of 13 pages from the Applicants' Joint Proxy Statement filed with the Securities and Exchange Commission (SEC) that contain the unaudited pro forma combined condensed financial statements as if the merger had already occurred.

IV. PROPOSED MERGER TRANSACTION

Q. PLEASE DESCRIBE THE MERGER TRANSACTION CONTEMPLATED BY AEP AND CSW.

A. The merger agreement dated December 21, 1997 by and between AEP and CSW (Merger Agreement) provides for AEP to acquire the common stock of CSW. Each share of CSW common stock will be exchanged for 0.6 of a share of AEP common stock. The combination proposed by AEP and CSW is fully described in the Merger Agreement, a copy of which is attached to the Application. A portion of the Applicants' Joint Proxy Statement containing pro forma historical financial information is included as EXHIBIT TEM-2 to my testimony. The Joint Proxy Statement has been filed with the SEC and mailed to the shareholders of AEP and CSW.

V. METHOD OF ACCOUNTING FOR THE COMBINATION

Q. WHAT IS THE AUTHORITATIVE ACCOUNTING PRONOUNCEMENT REGARDING COMBINATIONS OF BUSINESS ENTITIES?

A. Accounting Principles Board (APB) Opinion No. 16, Business Combinations, is the authoritative accounting pronouncement regarding combinations of business entities. APB Opinion No. 16 contains GAAP for business combinations in general and is not limited to combinations of regulated entities.

Q. WHAT ACCOUNTING METHODS DOES APB OPINION NO. 16 PROVIDE TO ACCOUNT FOR CORPORATE MERGERS?

A. APB No. 16 provides for two methods of accounting for business combinations. Those two methodologies are the "purchase method" and the "pooling of interests" method. These two methods are mutually exclusive. A merger may be either one or the other, but not a combination of both. The structure of the proposed combination, as well as the facts and circumstances surrounding the business transaction, will determine which of the two accounting methods must be used.

Q. PLEASE DESCRIBE THE PURCHASE METHOD OF ACCOUNTING.

A. In general, the purchase methodology accounts for a business combination as the acquisition of one company by another. It requires that the assets of the combined entity reflect the economic purchase price of the acquired entity. As a result, if the purchase price for a non-regulated entity exceeds the book value of the entity, the assets would be written up to fair value and goodwill would be recorded for any remaining difference. However, a regulated entity would record an "acquisition adjustment" for the entire excess of the purchase price over the original cost.

Q. CAN YOU PROVIDE A BRIEF EXAMPLE OF THE PURCHASE TYPE OF BUSINESS COMBINATION?

A. Yes. If we assume that a company having a single asset with a book value of $100 and a market value of $150 is acquired for $175, the books and balance sheet of the combined entity would show that the book value of the asset was "written up" or increased $50 to $150 and that $25 in goodwill was added as an additional asset. If the company is a regulated utility, the book value of the asset remains at $100 and a $75 acquisition adjustment would be recorded.

Q. WHEN IS IT APPROPRIATE UNDER APB OPINION NO. 16 TO USE THE PURCHASE METHOD OF ACCOUNTING FOR A MERGER?

A. The purchase method of accounting is appropriate if the structure of, and facts and circumstances surrounding, the merger do not require a pooling of interests methodology.

Q. PLEASE DESCRIBE THE POOLING OF INTERESTS METHOD OF ACCOUNTING.

A. The pooling of interests method of accounting for a merger treats the business combination as a uniting of ownership interests of two (or more) companies via an exchange of voting securities. This results in a mutual sharing of substantially all of the rights and risks of ownership of the combined company. With pooling accounting, there is a continuity of the combined shareholder interests; it is intended to present two or more common stockholder interests as a single interest in a combined entity. The exchange ratio of voting common stock determines the previously separate ownership groups' respective interests in the combined corporation. In a pooling transaction, the respective groups of stockholders neither withdraw a portion of their investment nor invest additional assets in the combined entity. In a pooling, the shareholders of each merging entity maintain their relative equity interest in the merged entity.

In accounting for a pooling of interests combination, the assets, liabilities and equity accounts, including retained earnings, of each company are simply combined on a single balance sheet as though the two companies had always been commonly owned. Operating results of both companies are also combined for all periods shown prior to the closing date of the business combination.

Q. WHAT MAKES THE ACCOUNTING FOR THE POOLING OF INTERESTS METHOD DIFFERENT FROM THE ACCOUNTING FOR THE PURCHASE METHOD OF ACCOUNTING?

A. Under the pooling of interests methodology, the carrying value of the assets does not change. There is no goodwill or acquisition adjustment booked on the combined entities' financial statements. Using the previous example, the combined entities' books and balance sheet would simply show an asset whose book value is $100. There would be no reflection in the merged financial statements of the $50 excess of asset market value over historic book value or cost nor of the additional intangible asset with a value of $25 for the excess of the purchase price over the asset's market values. The value paid for the stock exchanged in excess of the book value of the net assets acquired is not reflected on the combined balance sheet in a pooling of interests.

Q. WHEN IS IT APPROPRIATE UNDER APB NO. 16 TO USE THE POOLING OF INTERESTS METHOD OF ACCOUNTING FOR MERGERS?

A. A business combination that meets all 12 conditions contained in paragraphs 45 to 48 of APB Opinion No. 16 must be accounted for by use of the pooling of interests method. All other business combinations must be accounted for using the purchase methodology.

Q. WHAT METHOD IS APPROPRIATE UNDER APB OPINION NO. 16 TO ACCOUNT FOR THE PROPOSED MERGER BETWEEN AEP AND CSW?

A. The proposed business combination of AEP and CSW meets all 12 conditions specified in APB Opinion No. 16 for use of the pooling of interests methodology. Therefore, the combination must be accounted for using the pooling of interests method of accounting.

Q. PLEASE BRIEFLY DESCRIBE EACH OF THE TWELVE APB OPINION NO. 16 CRITERIA WHICH MUST BE MET TO USE THE POOLING OF INTERESTS METHOD OF ACCOUNTING.

A. The twelve conditions to use the pooling of interests method are contained in paragraphs 45-48 of Opinion APB No. 16 and can be briefly summarized as follows:

Combining Companies

1) Each of the combining companies is autonomous and has not been a subsidiary of another company within two years before the plan of combination is initiated. The combining companies must not have been over 50% owned by another company for two years prior to initiating the plan to combine.

2) Each of the combining companies is independent of the other combining companies. Neither company may hold more than 10% of the outstanding voting common stock of the other company.

The proposed AEP/CSW merger meets each of the two criteria concerning the combining companies. Neither company has been over 50% owned by another company within two years of initiating the plan to combine and neither company holds 10% of the outstanding voting common stock of the other company.

Manner of Combining Interests

3) The combination is effected in a single transaction or is completed in accordance with a specific plan within one year after the plan is initiated unless governmental approvals or litigation delay the combination beyond a year.

4) The common stock issued has identical rights to the existing common stock of the issuer (AEP) and substantially all (90% or more) of the surrender's (CSW) stock is surrendered.

5) The equity interest of the voting common stock of the combining companies did not change in the last two years or will not change as a result of the combination.

6) Neither company has acquired shares of its common stock within two years of the combination unless a valid business reason not related to the combination can be demonstrated.

7) The ratio of the interest of an individual common shareholder to those of other common shareholders does not change as a result of the exchange of stock to effect the combination.

8) The combination does not deprive common shareholders of their voting rights nor does it restrict such rights.

9) There are no pending stock transactions or other consideration after the combination occurs, i.e., no provisions of the combination relating to either the issuance of securities or other consideration can be dependent on events subsequent to the consummation of the combination.

The proposed transaction between AEP and CSW meets the above criteria regarding the manner of combining interests. The proposed combination is contemplated to occur in a single transaction. The delay beyond a year is due to the process of obtaining required governmental approvals. Additionally, substantially all (90% or more) of CSW's stock is being surrendered and the AEP common stock issued has identical rights to the existing AEP stock. Further, the equity interests of the voting stock have not changed in the two years prior to the combination and neither company has acquired shares of its common stock within two years of the combination. Additionally, the combination will not affect shareholder rights and there are no pending stock transactions or other consideration to be paid after the combination occurs (i.e., there are no provisions relating to either the issuance of securities or other consideration that are dependent on events subsequent to the date of the consummation of the combination).

Absence of Planned Transactions

10) There can be no planned reacquisitions of all or part of the common stock issued to effect the combination.

11) There can be no financial transaction that benefits former shareholders and negates the value of the stock issued to those former shareholders, such as a loan guaranty secured by the stock issued in the combination.

The proposed combination complies with the above two criteria regarding the absence of planned transactions. No transactions are contemplated upon the consummation of the merger.

12) There is no plan to dispose of a significant part of the assets of the combining companies within two years of consummation of the combination other than to eliminate duplicate facilities or excess capacity.

The testimony of Mr. Richard E. Munczinski discusses a combination of certain mitigation measures now proposed by the Applicants at the Federal Energy Regulatory Commission (FERC), including the proposed divestiture under certain conditions of CSW's ownership interest in portions of two generating plants.

The mitigation plan proposed by the Applicants provides that the Applicants would not divest assets if the sale of those assets jeopardized the ability to qualify for a "pooling of interests". Accounting Principles Board Opinion No. 16 provides that a combination will qualify for a pooling of interests if, among other requirements, there is no plan to dispose of assets of the combining companies within two years of consummation of the combination. Delaying the initiation of divestiture for at least two years after the combination occurs ensures that the sale of those assets will not jeopardize the ability to qualify for pooling of interests.

Q. PLEASE SUMMARIZE YOUR OPINION CONCERNING ACCOUNTING FOR APPLICANTS' PROPOSED COMBINATION.

A. In summary, the proposed combination of AEP and CSW meets all of the above twelve criteria and, therefore, must be accounted for as a pooling of interests. As a result, there will be no acquisition adjustment in this case.

Q. IS THE PROPOSED MERGER CONDITIONAL UPON THE APPLICANTS' PROPOSED ACCOUNTING TREATMENT?

A. Yes. Additionally, the receipt by AEP of a letter from Deloitte & Touche LLP and by CSW from Arthur Andersen LLP, their respective independent accountants, stating that the transaction will qualify as a pooling of interests, is a condition of the proposed merger.

VI. PROPOSED MERGER PRO FORMA FINANCIAL DATA

Q. CAN YOU PROVIDE PRO FORMA FINANCIAL DATA RELATED TO THE COMBINATION?

A. Yes. Pro forma pooled historical financial data included in the Joint Proxy Statement is included in EXHIBIT TEM-2. This historical financial data was derived from the Income Statements of AEP and CSW for each of the calendar years in the three-year period ended December 31, 1997 and from the December 31, 1997 Balance Sheets of AEP and CSW. It should be noted that, pursuant to the terms of the Merger Agreement, the number of AEP shares outstanding in this Exhibit reflects the issuance of additional shares of AEP common stock to former CSW common shareowners in the ratio of 0.6 of a share of AEP common stock for one share of CSW common stock.

Q. WHY WAS THIS PRO FORMA FINANCIAL DATA PREPARED?

A. The SEC requires that merger parties prepare pro forma pooled historical financial data reflecting the effect of a proposed business combination on the historical financial statements of the parties to the proposed business combination.

Q. PLEASE DESCRIBE THE PRO FORMA FINANCIAL DATA CONTAINED IN THE ATTACHED EXHIBITS.

A. The pro forma financial data combines the historical balance sheets and statements of income of AEP and CSW after giving effect to the combination under the pooling of interests method of accounting as if the combination had occurred on December 31, 1997, for balance sheet data, and January 1, 1995, for three years of income statement data. The pro forma adjustments are described in the notes to the pro forma financial data in EXHIBIT TEM-2, Pages 12 of 13 and 13 of 13. The statements reflect combined revenues of $11.4 billion for the 12 months ended December 31, 1997 and a combined total common shareholders' equity of $8.2 billion as of December 31, 1997.

Q. ARE THE EXPECTED SYNERGY SAVINGS REFLECTED IN THE PRO FORMA FINANCIAL DATA IN EXHIBIT TEM-2?

A. No. As stated in the notes to the pro forma combined balance sheet and statements of income, no pro forma adjustments have been made to reflect the effects of the synergy savings from the merger of AEP and CSW.

Q. WHY ARE THE SAVINGS NOT REFLECTED IN THE STATEMENTS?

A. Under a pooling of interests methodology, pursuant to SEC Regulation S-X, only the historical financial statements of combining entities are combined. Synergy merger savings have not been realized and so are not reflected in past historic periods. Instead, they will be reflected in future accounting periods.

Q. DO THE FINANCIAL STATEMENTS IN EXHIBIT TEM-2 REFLECT THE COSTS OF THE MERGER?

A. Only to a limited extent. The $50 million adjustment to Retained Earnings (and corresponding credit to current liabilities) reflected on page 9 of 13 of EXHIBIT TEM-2, represents a portion of the merger's estimated costs, which the SEC staff requested to be shown as an expense, upon consummation of the transaction. This presentation is in accordance with the SEC Staff's interpretation of its Regulation S-X. If Applicants' proposed regulatory treatment is approved, this charge will occur on a straight-line basis over a 5-year period rather than in a single charge in the year the merger is consummated.

Q. PLEASE EXPLAIN THE $85 MILLION DECREASE TO PAID-IN-CAPITAL AND THE CORRESPONDING $85 MILLION INCREASE TO COMMON STOCK FOR THE COMBINED ENTITY REFLECTED ON PAGE 9 OF 13 IN YOUR EXHIBIT TEM-2.

A. This adjustment reflects the fact that one share of CSW stock will be exchanged for 0.6 of a share of AEP stock and adjusts for the difference in par value between AEP's and CSW's common stock ($6.50 and $3.50, respectively) for the additional shares of AEP stock that will be issued as a result of the merger as illustrated below:

Description	Amount
Number of CSW shares outstanding	212,235,320
Merger exchange rate	X .6
Additional shares of AEP stock issues	127,341,192
Par value per AEP share	$6.50
	827,717,748
CSW common stock par value ($3.50 per share)	(743,000,000)
Increase to Common Stock and reduction to Paid-In-Capital	$84,717,748[1]

Because the transaction is to be accounted for as a pooling of interests, the book values of the combined assets and liabilities are not adjusted to reflect their current market value. They will remain the same on the combined entity's balance sheet. The combined balance sheet will not reflect either goodwill or an acquisition adjustment since the economic purchase price is not reflected on the combined entity's accounting books and balance sheet under a pooling of interests methodology.

Q. DOES RECORDING THE COMBINATION OF AEP AND CSW USING THE POOLING OF INTERESTS METHOD COMPLY WITH THE FERC UNIFORM SYSTEM OF ACCOUNTS (US OF A)?

A. Yes. The accounting proposed by the Applicants is consistent with the FERC US of A and with prior accounting treatment of pooling of interests filed with and approved by FERC.

Q. HAVE THE GENERAL ACCOUNTING POLICIES AND PROCEDURES FOR THE COMBINED ENTITY BEEN ESTABLISHED?

A. No. There have been no determinations made regarding the specific accounting policies and practices of the combined entity. However, a review of the Applicants' respective accounting policies and practices indicate that they are similar and no significant changes in accounting policies and practices that would have a material impact on revenues, jurisdictional cost of service or rate base are anticipated.

VII. FEDERAL INCOME TAX IMPLICATIONS OF THE MERGER

Q. WILL THERE BE ANY FEDERAL INCOME TAX EXPENSE OR PAYMENT REQUIRED BY THE COMPANIES AS A RESULT OF THE COMBINATION OF AEP AND CSW?

A. No. According to opinions obtained from AEP's and CSW's federal income tax counsels, the combination should qualify as a tax-free corporate reorganization for federal income tax purposes in accordance with Section 368 of the Internal Revenue Code (IRC). As a result, no tax gain or loss will be recognized by AEP or CSW in connection with the merger. With the exception of cash received by CSW shareholders for fractional shares of CSW stock, no AEP or CSW shareholder will recognize taxable income or loss on the transaction.

Q. DOES AEP OR CSW HAVE ANY NET OPERATING LOSS, INVESTMENT TAX CREDIT, OR ALTERNATIVE MINIMUM TAX CREDIT CARRYFORWARDS THAT MAY BE ADVERSELY AFFECTED AS A RESULT OF THE MERGER?

A. No. AEP and CSW had no net operating loss, investment tax credit, or alternative minimum tax credit carryforwards at December 31, 1997.

Q. WILL THE COMBINED ENTITY FILE A SINGLE CONSOLIDATED FEDERAL INCOME TAX RETURN AFTER THEIR CONSOLIDATION?

A. Yes. The IRC provides that a group of affiliated companies may file a single, consolidated federal income tax return. AEP and CSW each file a consolidated federal income tax return currently. The combined company will also file a consolidated tax return after the merger is consummated.

Q. WILL THE COMBINATION OF AEP AND CSW AFFECT ANY INDIVIDUAL AFFILIATED COMPANY'S FEDERAL INCOME TAX ALLOCATION?

A. No. AEP and CSW both follow an intercompany tax allocation methodology that is approved by the SEC. These methodologies are primarily based on a "stand alone" allocation method where each company is allocated tax expense or benefit as if that company had filed its own federal income tax return. A new combined intercompany tax allocation methodology will be submitted to the SEC for approval and will continue the "stand alone" allocation methodology approved by the SEC and currently used by both AEP and CSW.

VIII. ACCOUNTING IMPACT OF PROPOSED REGULATORY TREATMENT

Q. HAVE THE APPLICANTS PROPOSED A SPECIFIC REGULATORY TREATMENT FOR MERGER COSTS?

A. Yes. As explained in Mr. Richard E. Munczinski's testimony, the Applicants have proposed that the Commission approve the sharing of the Kentucky retail jurisdictional share of merger savings net of merger costs and approve the deferral of the Kentucky retail jurisdictional share of merger costs, including change in control payments, and allow their amortization for recovery over a five-year period on a straight-line basis.

Q. IF APPROVED BY THE COMMISSION, WHAT ARE THE ACCOUNTING IMPLICATIONS OF THIS PROPOSAL?

A. Merger costs related to a regulated business, or portion of a business, may be capitalized and deferred beyond the merger's consummation if it is probable that the respective regulatory commissions will permit recovery of these costs through the regulatory process. Financial Accounting Standards Board Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), requires that costs which are being recovered in cost-based rates over time be deferred and amortized over the period approved for recovery by the regulator. If the Applicants' regulatory proposal, as detailed in Mr. Munczinski's testimony, is approved by the Commission, Kentucky Power Company will defer its Kentucky retail jurisdictional share of these merger costs and amortize them over a five-year period on a straight-line basis in accordance with SFAS No. 71.

Q. ARE YOU REQUESTING SPECIFIC LANGUAGE BE INCLUDED IN THE COMMISSION'S ORDER IN THIS PROCEEDING IN ORDER TO COMPLY WITH THE REQUIREMENTS OF SFAS NO. 71?

A. Yes. The Applicants respectfully request that the following language be included in the Commission's order:

AEP and CSW will incur transaction, regulatory processing, and transition costs to merge and combine the two companies. The Commission orders that the Kentucky retail jurisdictional share of the estimated merger costs be deferred and amortized for recovery over five years. The amortization should begin with the date of the combination and continue for five years on a straight-line basis.

Q. HOW WILL OTHER ASPECTS OF THE PROPOSED REGULATORY PLAN BE ACCOUNTED FOR?

A. The proposed regulatory plan, as presented by Mr. Munczinski, provides for a Net Merger Savings Credit for the customer portion of non-fuel net merger savings resulting from the merger. Merger savings will be reflected in future accounting periods as they are realized and customer billings and revenues will be appropriately reduced by the Net Merger Savings Credit.

Q. PLEASE SUMMARIZE THE ACCOUNTING WHICH THE APPLICANTS PROPOSE FOR SHARING THE KENTUCKY RETAIL JURISDICTIONAL SHARE OF NET MERGER SAVINGS DUE KENTUCKY RATEPAYERS.

A. Applicants are proposing to share the Kentucky retail jurisdictional share of the net merger savings through the application of a Net Merger Savings Credit. The Net Merger Savings Credit is based on an estimate of the annual fixed net merger savings that are expected to occur over future periods and should, therefore, reasonably approximate the annual actual savings. As such, the annual Net Merger Savings Credit should be automatically offset with a reasonable matching of merger-related costs and savings without any special accounting. Therefore, it is not necessary to practice deferred accounting for the merger savings. However, since merger costs are substantially expected to be incurred up-front but will be recovered over a longer period, we are proposing to defer merger costs up to the estimate and amortize them over a five-year period.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COUNTY OF BOYD

COMMONWEALTH OF KENTUCKY CASE NO. 99-

Affidavit

Thomas E. Mitchell, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Thomas E. Mitchell

Subscribed and sworn to before me by Thomas E. Mitchell this 5TH day of April 1999.

Mary M. Soltesz

Notary Public

MARY M. SOLTESZ
NOTARY PUBLIC, STATE OF OHIO
MY COMMISSION EXPIRES JULY 12, 1999

My Commission Expires 7-12-99

THOMAS E. MITCHELL
PREVIOUS TESTIMONY

Related to the following Appalachian Power Company Applications for Increase in Electric Rates with respect to accounting schedules and certain ratemaking adjustments to reflect the going-level revenue, expenses, and rate base amounts used in determining the requested revenue increase:

VIRGINIA STATE CORPORATION COMMISSION

- Case No. PUE960301
- Case No. PUE940063
- Case No. PUE920081
- Case No. PUE900026

PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

- Case No. 96-0458-E-GI
- Case No. 91-026-E-42T
- Case No. 83-697-E-42T

FEDERAL ENERGY REGULATORY COMMISSION

- Docket Nos. ER92-324-000 and ER92-323-000
- Docket Nos. ER90-132-000, ER90-133-000, and EL89-53-000

THOMAS E. MITCHELL
PREVIOUS TESTIMONY

Related to the following Joint Application of American Electric Power Company, Inc. and Central and Southwest Corporation regarding a proposed merger:

ARKANSAS PUBLIC SERVICE COMMISSION

- Case No. 98-172-U

LOUISIANA PUBLIC SERVICE COMMISSION

- Case No. U-23327

CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

- Case No. PUD 980000444

PUBLIC UTILITY COMMISSION OF TEXAS

- Case No. 19265

UNAUDITED PRO FORMA COMBINED CONDENSED FINANCIAL STATEMENTS

The following unaudited pro forma combined condensed financial statements reflect the historical condensed balance sheets and condensed statements of income of AEP and CSW, including their respective subsidiaries, after giving effect to the Merger as a pooling of interests. The unaudited pro forma combined condensed balance sheet gives effect to the Merger as though it occurred on the balance sheet date, December 31, 1997.

The unaudited pro forma combined condensed statements of income for the years ended December 31, 1997, 1996 and 1995 give effect to the Merger as if it occurred on January 1, 1995. The statements are based on accounting for the business combination as a pooling of interests and are based on the assumptions in the notes to unaudited pro forma combined condensed financial statements. Certain CSW historical income statement and balance sheet items were reclassified to conform with the presentation expected to be used by AEP after the Merger is completed.

The unaudited pro forma combined condensed financial statements are not necessarily indicative of the results of operations that might have occurred had the Merger actually taken place on January 1, 1995 or the actual financial position that might have resulted had the Merger been consummated on December 31, 1997 or of the future results of operations or financial position of AEP. The unaudited pro forma combined condensed financial statements have been prepared from, and should be read in conjunction with the historical financial statements and related notes thereto of AEP and CSW, incorporated by reference herein. See "WHERE YOU CAN FIND MORE INFORMATION."

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF INCOME
Year Ended December 31, 1997
(in millions—except per share amounts)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
OPERATING REVENUES:				
U.S. Electric	$6,161	$3,321		$ 9,482
United Kingdom	—	1,870		1,870
TOTAL OPERATING REVENUES	6,161	5,191		11,352
OPERATING EXPENSES:				
Fuel	1,627	1,177		2,804
Purchased Power	416	89		505
United Kingdom Cost of Sales	—	1,291		1,291
Other Operation	1,228	948		2,176
Maintenance	483	152		635
Depreciation and Amortization	591	491		1,082
Taxes Other Than Federal Income Taxes	491	240		731
Federal Income Taxes	341	106		447
TOTAL OPERATING EXPENSES	5,177	4,494		9,671
OPERATING INCOME	984	697		1,681
NONOPERATING INCOME	60	70		130
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	1,044	767		1,811
INTEREST CHARGES	406	436		842
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	18	12		30
GAIN ON REACQUIRED PREFERRED STOCK OF SUBSIDIARIES	—	10		10
INCOME BEFORE EXTRAORDINARY ITEM	620	329		949
EXTRAORDINARY LOSS—U.K. WINDFALL TAX	(109)	(176)		(285)
NET INCOME	$ 511	$ 153		$ 664
Average Number of Shares Outstanding	189.0	212.1	(84.8)	316.3
EARNINGS PER SHARE (basic and diluted):				
Before Extraordinary Item	$ 3.28	$ 1.55		$ 3.00
Extraordinary Loss	(0.58)	(0.83)		(0.90)
EARNINGS PER SHARE	$ 2.70	$ 0.72		$ 2.10

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF INCOME
Year Ended December 31, 1996
(in millions—except per share amounts)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
OPERATING REVENUES:				
U.S. Electric	$5,849	$3,248		$9,097
United Kingdom	—	1,848		1,848
TOTAL OPERATING REVENUES	5,849	5,096		10,945
OPERATING EXPENSES:				
Fuel	1,601	1,151		2,752
Purchased Power	86	77		163
United Kingdom Cost of Sales	—	1,331		1,331
Other Operation	1,210	780		1,990
Maintenance	503	150		653
Depreciation and Amortization	601	459		1,060
Taxes Other Than Federal Income Taxes	498	255		753
Federal Income Taxes	342	152		494
TOTAL OPERATING EXPENSES	4,841	4,355		9,196
OPERATING INCOME	1,008	741		1,749
NONOPERATING INCOME (LOSS)	2	(7)		(5)
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	1,010	734		1,744
INTEREST CHARGES	381	419		800
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	42	18		60
INCOME FROM CONTINUING OPERATIONS	587	297		884
DISCONTINUED OPERATIONS	—	132		132
NET INCOME	$ 587	$ 429		$1,016
Average Number of Shares Outstanding	187.3	207.5	(83.0)	311.8
EARNINGS PER SHARE (basic and diluted):				
Continuing Operations	$ 3.14	$ 1.43		$ 2.84
Discontinued Operations	—	0.64		0.42
EARNINGS PER SHARE	$ 3.14	$ 2.07		$ 3.26

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF INCOME
Year Ended December 31, 1995
(in millions—except per share amounts)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
OPERATING REVENUES:				
U.S. Electric	$5,670	$2,883		$8,553
United Kingdom	—	208		208
TOTAL OPERATING REVENUES	5,670	3,091		8,761
OPERATING EXPENSES:				
Fuel	1,537	1,004		2,541
Purchased Power	88	41		129
United Kingdom Cost of Sales	—	158		158
Other Operation	1,184	551		1,735
Maintenance	542	155		697
Depreciation and Amortization	593	352		945
Taxes Other Than Federal Income Taxes	489	178		667
Federal Income Taxes	272	67		339
TOTAL OPERATING EXPENSES	4,705	2,506		7,211
OPERATING INCOME	965	585		1,550
NONOPERATING INCOME	20	135		155
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	985	720		1,705
INTEREST CHARGES	400	324		724
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	55	19		74
INCOME FROM CONTINUING OPERATIONS	530	377		907
DISCONTINUED OPERATIONS	—	25		25
NET INCOME	$ 530	$ 402		$ 932
Average Number of Shares Outstanding	185.8	191.7	(76.7)	300.8
EARNINGS PER SHARE (basic and diluted):				
Continuing Operations	$ 2.85	$ 1.97		$ 3.02
Discontinued Operations	—	0.13		0.08
EARNINGS PER SHARE	$ 2.85	$ 2.10		$ 3.10

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED STATEMENT OF INCOME

Year Ended December 31, 1997

(in millions—except per share amounts)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
OPERATING REVENUES:			
U.S. Electric	$3,321		$3,321
United Kingdom	1,870		1,870
Other Diversified	77	$ (77)(A)	—
TOTAL OPERATING REVENUES	5,268	(77)	5,191
OPERATING EXPENSES:			
U.S. Electric Fuel	1,177		1,177
U.S. Electric Purchased Power	89		89
United Kingdom Cost of Sales	1,291		1,291
Other Operation	981	(33)(A)	948
Maintenance	152		152
Depreciation and Amortization	497	(6)(A)	491
Taxes Other Than Federal Income Taxes	195	45 (B)	240
Federal Income Taxes	151	(45)(A,B)	106
TOTAL OPERATING EXPENSES	4,533	(39)	4,494
OPERATING INCOME	735	(38)	697
NONOPERATING INCOME	32	38 (A)	70
INCOME BEFORE INTEREST CHARGES	767	—	767
INTEREST CHARGES:			
Interest on Long-term Debt	333		333
Distributions on Trust Preferred Securities	17		17
Interest on Short-term Debt and Other	86		86
TOTAL INTEREST CHARGES	436		436
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	12		12
GAIN ON REACQUIRED PREFERRED STOCK OF SUBSIDIARIES	(10)		(10)
INCOME BEFORE EXTRAORDINARY ITEM	329		329
EXTRAORDINARY LOSS—U.K. WINDFALL TAX	(176)		(176)
NET INCOME FOR COMMON STOCK	$ 153	$ —	$ 153
Average Number of Shares Outstanding	212.1		212.1
EARNINGS PER SHARE (basic and diluted):			
Before Extraordinary Item	$ 1.55		$ 1.55
Extraordinary Loss	(0.83)		(0.83)
EARNINGS PER SHARE	$ 0.72		$ 0.72

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED STATEMENT OF INCOME
Year Ended December 31, 1996
(in millions—except per share amounts)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
OPERATING REVENUES:			
U.S. Electric	$3,248		$3,248
United Kingdom	1,848		1,848
Other Diversified	59	$ (59)(A)	—
TOTAL OPERATING REVENUES	5,155	(59)	5,096
OPERATING EXPENSES:			
U.S. Electric Fuel	1,151		1,151
U.S. Electric Purchased Power	77		77
United Kingdom Cost of Sales	1,331		1,331
Other Operation	785	(5)(A)	780
Maintenance	150		150
Depreciation and Amortization	464	(5)(A)	459
Taxes Other Than Federal Income Taxes	178	77 (A,B)	255
Federal Income Taxes	224	(72)(A,B)	152
TOTAL OPERATING EXPENSES	4,360	(5)	4,355
OPERATING INCOME	795	(54)	741
NONOPERATING INCOME (LOSS)	(61)	54 (A)	(7)
INCOME BEFORE INTEREST CHARGES	734	—	734
INTEREST CHARGES:			
Interest on Long-term Debt	325		325
Interest on Short-term Debt and Other	94		94
TOTAL INTEREST CHARGES	419		419
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	18		18
INCOME FROM CONTINUING OPERATIONS	297		297
DISCONTINUED OPERATIONS	132		132
NET INCOME FOR COMMON STOCK	$ 429	$ —	$ 429
Average Number of Shares Outstanding	207.5		207.5
EARNINGS PER SHARE (basic and diluted):			
Continuing Operations	$ 1.43		$ 1.43
Discontinued Operations	0.64		0.64
EARNINGS PER SHARE	$ 2.07		$ 2.07

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED STATEMENT OF INCOME
Year Ended December 31, 1995
(in millions—except per share amounts)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
OPERATING REVENUES:			
U.S. Electric	$2,883		$2,883
United Kingdom	208		208
Other Diversified	52	$ (52)(A)	—
TOTAL OPERATING REVENUES	3,143	(52)	3,091
OPERATING EXPENSES:			
U.S. Electric Fuel	1,004		1,004
U.S. Electric Purchased Power	41		41
United Kingdom Cost of Sales	158		158
Other Operation	557	(6)(A)	551
Maintenance	155		155
Depreciation and Amortization	353	(1)(A)	352
Taxes Other Than Federal Income Taxes	162	16 (A,B)	178
Federal Income Taxes	92	(25)(A,B)	67
TOTAL OPERATING EXPENSES	2,522	(16)	2,506
OPERATING INCOME	621	(36)	585
NONOPERATING INCOME	99	36 (A)	135
INCOME BEFORE INTEREST CHARGES	720	—	720
INTEREST CHARGES:			
Interest on Long-term Debt	223		223
Interest on Short-term Debt and Other	101		101
TOTAL INTEREST CHARGES	324		324
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	19		19
INCOME FROM CONTINUING OPERATIONS	377		377
DISCONTINUED OPERATIONS	25		25
NET INCOME FOR COMMON STOCK	$ 402	$ —	$ 402
Average Number of Shares Outstanding	191.7		191.7
EARNINGS PER SHARE (basic and diluted):			
Continuing Operations	$ 1.97		$ 1.97
Discontinued Operations	0.13		0.13
EARNINGS PER SHARE	$ 2.10		$ 2.10

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

UNAUDITED PRO FORMA COMBINED CONDENSED BALANCE SHEET
December 31, 1997
(in millions)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
ASSETS				
ELECTRIC UTILITY PLANT:				
Production	$ 9,493	$ 5,824		$15,317
Transmission	3,502	1,558		5,060
Distribution	4,654	4,453		9,107
General (including mining assets and nuclear fuel)	1,605	1,577		3,182
Construction Work in Progress	343	184		527
Total Electric Utility Plant	19,597	13,596		33,193
Accumulated Depreciation and Amortization	7,964	5,217		13,181
NET ELECTRIC UTILITY PLANT	11,633	8,379		20,012
OTHER PROPERTY AND INVESTMENTS	1,359	800		2,159
CURRENT ASSETS:				
Cash and Cash Equivalents	91	75		166
Accounts Receivable (net)	668	840		1,508
Fuel	225	65		290
Materials and Supplies	264	172		436
Accrued Utility Revenues	189	76		265
Prepayments and Other	81	78		159
TOTAL CURRENT ASSETS	1,518	1,306		2,824
REGULATORY ASSETS	1,817	1,440		3,257
GOODWILL	—	1,428		1,428
DEFERRED CHARGES	288	98		386
TOTAL	$16,615	$13,451		$30,066

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

UNAUDITED PRO FORMA COMBINED CONDENSED BALANCE SHEET

December 31, 1997

(in millions)

	AEP (As Reported)	CSW (As Reclassified)	Pro Forma Adjustments	Pro Forma Combined
CAPITALIZATION AND LIABILITIES				
CAPITALIZATION:				
Common Stock	$ 1,293	$ 743	$ 85	$ 2,121
Paid-in Capital	1,779	1,039	(85)	2,733
Retained Earnings	1,605	1,774	(50)	3,329
Total Common Shareholders' Equity	4,677	3,556	(50)	8,183
Cumulative Preferred Stocks of Subsidiaries:				
Not Subject to Mandatory Redemption	47	176		223
Subject to Mandatory Redemption	128	26		154
Certain Subsidiary-obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts	—	335		335
Long-term Debt	5,129	3,898		9,027
TOTAL CAPITALIZATION	9,981	7,991	(50)	17,922
OTHER NONCURRENT LIABILITIES	1,246	27		1,273
CURRENT LIABILITIES:				
Preferred Stock and Long-term Debt Due Within One Year	295	32		327
Short-term Debt	555	1,413		1,968
Accounts Payable	353	558		911
Taxes Accrued	381	171		552
Interest Accrued	76	87		163
Obligations Under Capital Leases	101	2		103
Other	323	236	50	609
TOTAL CURRENT LIABILITIES	2,084	2,499	50	4,633
DEFERRED INCOME TAXES	2,561	2,432		4,993
DEFERRED INVESTMENT TAX CREDITS	376	278		654
DEFERRED GAIN ON SALE AND LEASEBACK—ROCKPORT PLANT UNIT 2	231	—		231
DEFERRED CREDITS	136	224		360
TOTAL	$16,615	$13,451		$30,066

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED BALANCE SHEET

December 31, 1997

(in millions)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
ASSETS			
FIXED ASSETS:			
Electric			
Production	$ 5,824		$ 5,824
Transmission	1,558		1,558
Distribution	4,453		4,453
General	1,381	$ 196 (C)	1,577
Construction Work in Progress	184		184
Nuclear Fuel	196	(196)(C)	—
Total Electric	13,596	—	13,596
Other Diversified	250	(250)(D)	—
Total Fixed Assets	13,846	(250)	13,596
Accumulated Depreciation and Amortization	5,218	(1)(D)	5,217
NET FIXED ASSETS	8,628	(249)	8,379
OTHER PROPERTY AND INVESTMENTS	—	800 (D,E,F)	800
CURRENT ASSETS:			
Cash and Cash Equivalents	75		75
Accounts Receivable	916	(76)(G)	840
Fuel	65		65
Materials and Supplies	172		172
Accrued Utility Revenues	—	76 (G)	76
Under-Recovered Fuel Costs	84	(84)(H)	—
Prepayments and Other	78		78
TOTAL CURRENT ASSETS	1,390	(84)	1,306
DEFERRED CHARGES AND OTHER ASSETS:			
Deferred Plant Costs	503	(503)(H)	—
Mirror CWIP Asset	285	(285)(H)	—
Other Non-Utility Investments	448	(448)(E)	—
Securities Available for Sale	103	(103)(F)	—
Income Tax Related Regulatory Assets, Net	329	(329)(H)	—
Goodwill	1,428		1,428
Regulatory Assets	—	1,440 (H)	1,440
Other Deferred Charges	337	(239)(H)	98
TOTAL DEFERRED CHARGES AND OTHER ASSETS	3,433	(467)	2,966
TOTAL	$13,451	$ —	$13,451

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

CENTRAL AND SOUTH WEST CORPORATION

UNAUDITED RECLASSIFYING CONDENSED CONSOLIDATED BALANCE SHEET

December 31, 1997

(in millions)

	CSW (As Reported)	CSW (Reclassifying Entries)	CSW (As Reclassified)
CAPITALIZATION AND LIABILITIES			
CAPITALIZATION:			
Common Stock	$ 743		$ 743
Paid-in Capital	1,039		1,039
Retained Earnings	1,746	$ 28 (I)	1,774
Foreign Currency Translation Adjustment and Other	28	(28)(I)	—
Total Common Shareholders' Equity	3,556	—	3,556
Cumulative Preferred Stocks of Subsidiaries:			
Not Subject to Mandatory Redemption	176		176
Subject to Mandatory Redemption	26		26
Certain Subsidiary-obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts	335		335
Long-term Debt	3,898		3,898
TOTAL CAPITALIZATION	7,991	—	7,991
OTHER NONCURRENT LIABILITIES	—	27 (J,K)	27
CURRENT LIABILITIES:			
Preferred Stock and Long-term Debt Due Within One Year	32		32
Short-term Debt	721	692 (L)	1,413
Short-term Debt—CSW Credit, Inc.	636	(636)(L)	—
Loan Notes	56	(56)(L)	—
Accounts Payable	558		558
Taxes Accrued	171		171
Interest Accrued	87		87
Obligations Under Capital Leases	—	2 (J)	2
Other	238	(2)(J)	236
TOTAL CURRENT LIABILITIES	2,499	—	2,499
DEFERRED INCOME TAXES	2,432		2,432
DEFERRED INVESTMENT TAX CREDITS	278		278
DEFERRED CREDITS	251	(27)(J,K)	224
TOTAL	$13,451	$ —	$13,451

See "Notes to Unaudited Pro Forma Combined Condensed Financial Statements".

Notes to Unaudited Pro Forma Combined Condensed Financial Statements

1. There were no material intercompany transactions between AEP, including its subsidiaries, and CSW, including its subsidiaries, during the periods presented.

2. The unaudited pro forma combined condensed financial statements reflect the conversion of each outstanding CSW Share into 0.60 of an AEP Share, as provided in the Merger Agreement. The unaudited pro forma combined condensed financial statements are presented as if the companies were combined during all periods included therein. The combined authorized shares reflect the number of shares which would be authorized assuming the Share Issuance proposed herein had been approved on December 31, 1997.

3. The principal accounting policies for both companies' regulated operations are to follow the methods used by their respective regulatory commissions in establishing rates. The consummation of the Merger is not expected to result in any changes in the way regulators treat allowable costs for rate-making purposes. The effects of accounting policy differences are immaterial and have not been adjusted in the pro forma combined condensed financial statements.

4. The pro forma average number of outstanding AEP Shares was calculated by multiplying the average number of outstanding CSW Shares during the year by the exchange ratio of 0.60 of an AEP Share and adding the result to the average number of outstanding AEP Shares during the year.

5. The pro forma adjustment to common stock and paid-in capital represents the effects of recording the Merger of AEP and CSW as of the consummation date using the pooling of interests method of accounting whereby the common stock and paid-in capital amounts are adjusted to reflect the difference in par value ($6.50 per AEP Share compared with $3.50 per CSW Share) and the exchange ratio of 0.60 of an AEP Share for each CSW Share.

6. In connection with the Merger, the companies expect to incur charges estimated at approximately $50 million for transaction costs. Such costs include investment banking (financial advisors), legal, accounting, filing, printing and other related fees and costs to consummate the Merger. The combined company intends to seek recovery of the transaction costs through the regulatory process. The pro forma combined condensed financial statements do not reflect any of the costs savings estimated to result from the merger or any cost to achieve the merger. As noted in the "Reasons for the Merger" section, a sharing of the cost savings, net of the costs to achieve the Merger, is expected to be the outcome of the various regulatory proceedings. See "Reasons for the Merger" for further discussion regarding estimated synergies and cost savings (page 42).

7. The CSW unaudited reclassifying condensed financial statements reflect the reclassifying entries necessary to adjust CSW's condensed balance sheet and condensed statement of income presentation to be consistent with the presentation expected to be used by AEP after the Merger is completed. The following describes such reclassifying entries:

   Statements of Income Reclassifying Entries

   (A) To reclassify other diversified income and expenses to nonoperating income.

   (B) To reclassify state and United Kingdom income taxes.

   Balance Sheets Reclassifying Entries

   (C) To reclassify nuclear fuel.

(D) To reclassify non-utility plant and related accumulated depreciation.

(E) To reclassify other non-utility investments.

(F) To reclassify securities available for sale.

(G) To reclassify accrued utility revenues.

(H) To reclassify regulatory assets.

(I) To reclassify foreign currency translation and other.

(J) To reclassify obligations under capital leases.

(K) To reclassify operating reserves.

(L) To reclassify short-term debt.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF :

JOINT APPLICATION OF KENTUCKY POWER COMPANY,	)
AMERICAN ELECTRIC POWER COMPANY, INC.	)
AND CENTRAL AND SOUTH WEST CORPORATION	)CASE NO. 99-
REGARDING A PROPOSED MERGER	)

DIRECT TESTIMONY

OF

TIMOTHY C. MOSHER

APRIL 1999

TESTIMONY INDEX

EXHIBITS

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF :

JOINT APPLICATION OF KENTUCKY POWER COMPANY,	)
AMERICAN ELECTRIC POWER COMPANY, INC.	)
AND CENTRAL AND SOUTH WEST CORPORATION	)CASE NO. 99-
REGARDING A PROPOSED MERGER	)

DIRECT TESTIMONY

OF

TIMOTHY C. MOSHER

APRIL 1999

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Timothy C. Mosher. My business address is 1701 Central Ave., Ashland, Kentucky 41101.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Kentucky Power Company dba American Electric Power Company, Inc. (AEP) as Kentucky State President.

II. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Detroit in 1969 and a Masters of Business Administration Degree from the University of Akron in 1974. I am a Registered Professional Engineer in the State of Ohio (Registration # E-38467).

I began my career with AEP in January 1970 with Ohio Power Company (OPCo) as a Power Sales Engineer in the Canton Division. In 1974, I transferred to the General Office in Canton as an Administrative Assistant - Industrial in the Marketing Department. My responsibilities there included management of several electric thermal storage projects, as well as, studies regarding industrial customer usage patterns.

In 1977, I transferred to the Steubenville Division of OPCo as Industrial Marketing Manager. Responsibilities there include supervising power sales engineers, as well as, handling the largest of our industrial customers.

In 1978, I transferred to Kenton, Ohio as the Area Manager. Kenton was one of the offices of the Lima Division of OPCo. My responsibilities there included managing the 32 employee workforce that provided all aspects of customer service to nearly 15,000 customers.

In 1981, I transferred to the Canton General Office of OPCo as Administrative Assistant - Governmental Affairs. My responsibilities focused on representing OPCo to the Ohio General Assembly. I worked closely with the management team of OPCo as legislation was considered to study its possible effects on our operations. I also worked very closely with our Division and Area Managers on developing relationships with the members of the General Assembly. Additionally, I worked closely with utility associations and other coalitions to develop strategic plans for addressing pending legislation or to have legislation developed for possible consideration.

In 1987, I transferred to the Canton Division of OPCo as the Marketing Manager. There I was responsible for developing the strategic marketing plan for the industrial, commercial and residential sectors. I worked on defining marketing goals and developing the course of action to reach those goals.

In 1989, I transferred to the Zanesville Division of OPCo as the Division Manager. My responsibilities included marketing, engineering, line distribution and customer service for approximately 75,000 customers. In 1993 the Zanesville Division and the Newark Division were consolidated into the Central Region of the combined Ohio Power/Columbus Southern Power Company. The managerial duties remained the same, but the customer base grew to 175,000.

I assumed my current position in January 1996. My present responsibilities include governmental affairs contacts with both the Governor's office and the state legislature, environmental affairs, regulatory policy development, key customer contact, and community and economic development. Additionally, I work very closely with AEP's corporate communications personnel and the region operating personnel to assure quality customer service throughout our twenty county service territory in Kentucky. We presently serve 170,000 customers.

Q. HAVE YOU APPEARED AS A WITNESS BEFORE ANY REGULATORY COMMISSIONS?

A. No.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am presenting general information concerning an overview of Kentucky Power Company's operation in the Commonwealth, its commitment to adequacy and reliability of its retail service, safety, community and economic development and communications and accountability.

IV. KENTUCKY POWER OVERVIEW

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF KPCO.

A. All of KPCO's common stock is owned by AEP, a public utility holding company. KPCO serves approximately 170,000 customers located in twenty counties in Eastern Kentucky. The Company serves a population of approximately 385,000 in Kentucky with approximately 680 employees. Our service territory covers nearly 3,800 square miles.

Q. DOES KPCO OWN ANY GENERATING ASSETS IN KENTUCKY?

A. KPCO wholly owns the Big Sandy Power Plant in Louisa, Ky. The plant has a total generating capacity of 1060 MW from two units, one 800 MW and the other 260 MW. The plant burns 3 million tons of Eastern Kentucky coal annually.

Q. HOW HAS KPCO ORGANIZED ITS OPERATIONS TO PROVIDE SAFE AND RELIABLE SERVICE TO ITS CUSTOMERS?

A. All of the day-to-day contacts of customers with KPCO are with the Energy Delivery and Customer Relations business group. This group handles the customer from the initial request for service forward. All service connections, meter reading, billing, customer inquiry, disconnections and other customer service functions are handled by this group.

The cornerstone of these operations is the region office and the district offices that report to it. The district offices in Kentucky are located in Pikeville and Ashland. They are responsible to the region office for the actual day-to-day operation and maintenance of the network. They perform the tree trimming, ordinary maintenance and service restoration functions. The district offices have field responsibility for customer-related activities including meter reading; connections and disconnections; collection; co-ordinating the installation of new, expanded or replacement electrical facilities; and providing information about the efficient and economical use of energy in customers' homes and businesses.

Customer requests for service and inquiries regarding billing are handled by the call center in Ashland, one of four such centralized call centers on AEP's System. All of AEP's call centers provide 24 hour/seven day-a-week service. Ashland's call center received 635,000 calls last year and had a 96% call completion rate.

Q. IS KPCO WILLING TO MAKE ANY COMMITMENTS CONCERNING ADEQUACY AND RELIABILITY OF RETAIL SERVICE AS A RESULT OF THE MERGER?

A. KPCO will strive to improve the overall quality and reliability of its electric service at levels no less than it has achieved in the past decade.

In order to permit the Commission to monitor our performance, KPCO will provide service reliability reports annually indicating its calendar year Kentucky *Customer Average Interruption Duration Index (CAIDI)* and Kentucky *System*

Average Interruption Frequency Index (SAIFI). The determination and reporting of the indices shall include all storms.

KPCO will also provide annual call center performance measure results for those centers which handle Kentucky customer calls. These will include the call center *Average Speed of Answer (ASA), Abandonment Rate, and Call Blockage*. In his testimony, Mr. Mark A. Bailey will define the specifics of the reliability and call center performance measures and explain the performance targets for the company.

V. SAFETY

Q. WHAT KINDS OF TRAINING REGARDING SAFETY DOES KPCO PROVIDE ITS EMPLOYEES?

A. Two generalized training programs are "Safety Management 2000" for managers and "Behavior-Based Safety Management" for employees. Both of these programs are designed to make safety a part of day-to-day activity within KPCO. In addition to these general programs, KPCO instructs employees on the safety aspects of their specific jobs. Exhibit TCM-1 contains more details regarding AEP's employee safety training programs.

Q. DR. DRAPER TESTIFIES THAT AEP HAS AN ACTIVE PUBLIC SAFETY PROGRAM. CAN YOU PROVIDE MORE DETAILS REGARDING THAT PROGRAM?

A. Yes. As an example of that program, AEP provides public safety messages designed to provide electrical awareness information to the general public. They are seasonal and reflect safety precautions based upon incidents that have occurred in the past. Other details regarding our public education program can be found in EXHIBIT TCM-2.

Q. WILL THESE SAFETY PROGRAMS CHANGE FOR KPCO AFTER THE MERGER?

A. CSW already has similar programs. After the merger closes, the separate efforts of the two companies will be carefully evaluated and the best practices of each will be chosen for the combined company. Given AEP's and KPCO's emphasis on safety, AEP will be ready, willing and able to provide safe service to KPCO's customers.

VI. ECONOMIC/COMMUNITY DEVELOPMENT

Q. DOES AEP CONSIDER ECONOMIC DEVELOPMENT PART OF ITS PROGRAM FOR SERVICE QUALITY?

A. Yes. Economic Development is an enhanced service to our customers, as economic growth in the communities we serve benefits both our customers and employees. Economic growth is one of the factors included within the incentive plans for Consumer Services and Transmission and Distribution management employees that Mr. Bailey refers to in his testimony.

Q. WHAT KINDS OF SERVICES DOES AEP PROVIDE FOR ECONOMIC DEVELOPMENT?

A. AEP provides assistance to employers in locating potential sites and supplies extensive information regarding available buildings, communities, existing industries, financing, taxes, state and local regulations, utilities, transportation, training and inspection tours.

As part of its economic development program, AEP offers an interactive multi-state database, "ProCure" which provides information relating to available industrial buildings and sites via the Internet. Community profiles containing additional information can also be accessed by existing and potential customers, community officials, and others, via links on the company's home page relating to economic development. AEP's "Going Global" program has assisted 141 customers (2 in Kentucky) to explore international markets.

Q. HOW DOES AEP MEASURE THE SUCCESS OF ITS COMMUNITY DEVELOPMENT PROGRAMS?

A. AEP's programs are goal and performance tracking oriented. AEP instituted a first-of-its-kind quantified measurement tool and produces an annual report relating the program's net revenue contribution to AEP. We also annually survey our local economic development allies to insure that we are delivering programs in which they are interested. AEP's efforts in conjunction with those of others involved in the economic development process were successful in bringing 2,382 jobs in 1998, 572 jobs in 1997 and 1833 jobs in 1996 to areas within KPCO's service territory.

Q. WILL THESE ECONOMIC DEVELOPMENT PROGRAMS CHANGE AFTER THE MERGER?

A. AEP will meld its economic development program with CSW's. This unified program will incorporate the best aspects of both companies' programs, will attract new jobs to the states served by the combined system and enhance the competitive position of AEP's customers.

VII. COMMUNICATIONS AND ACCOUNTABILITY

Q. WILL AEP CONTINUE ITS PRACTICE OF REGULARLY COMMUNICATING WITH REGULATORS REGARDING QUALITY OF SERVICE ISSUES?

A. AEP has made it a practice to visit the public service commissions and staff twice a year in each of the states in which we do business. AEP participants generally include the Executive Vice President of Energy Delivery and Customer Relations, the State President, the Senior Vice President of Energy Pricing and Regulatory Affairs, the Senior Vice President of Distribution, and the Vice President of Consumer Services (all of whom report to the Executive Vice President ED&CR). During these visits we update the Commission attendees on our activities since the last visit and regularly discuss service quality initiatives we are undertaking.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony demonstrates:

- AEP will continue to provide safe, reliable and adequate service to KPCO's customers,

- AEP commits that following the proposed Merger it will maintain or when necessary improve the level of customer service to Kentucky customers,
- The district operations of KPCO will continue to have the authority and ability to provide quality service within Kentucky,
- KPCO will continue its safety programs for its customers or employees,
- AEP will meld its economic/community development programs with CSW and will incorporate the best aspects of both companies' programs to attract new jobs to Kentucky.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COUNTY OF BOYD

COMMONWEALTH OF KENTUCKY CASE NO. 99-

Affidavit

Timothy C. Mosher, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Timothy C. Mosher

Timothy C. Mosher

Subscribed and sworn to before me by Timothy C. Mosher this 7th day of April 1999.

Jane E. Taylor

Notary Public

My Commission Expires March 18, 2000

AEP SAFETY TRAINING PROGRAM

Below are summaries of several key AEP employee safety programs which have been undertaken over the past few years along with a listing of other safety training provided to employees.

Safety Management 2000

Safety Management 2000 is a training program geared toward managers and supervisors which has been on-going for the past three years. Approximately 2000 managers and supervisors (Kentucky approximately 40) have participated in the two-day sessions. Safety Management 2000 strives to incorporate measurement systems for supervisory performance, include middle managers in safety activities, instill credibility to our safety performance, develop a culture that supports safety, encourage employee participation in the safety decision-making process and promote positive reinforcement for accident prevention activities.

Highlights of the training include:

Justifying resources for accident prevention
Safety commitment
Accident causation
Safety motivation
Performance measurement
Process improvement
Total quality management principles
Leading change

Behavior-Based Safety Management

Behavior-Based Safety training is AEP's introductory Safety management course for employees. The sessions stress accident prevention and employee participation. Elements include: accident causation, accident investigation, behavioral analysis, safety sampling, trend analysis and motivation.

Behavior-Based Safety training has been on-going for the past four years. AEP has trained approximately 900 (Kentucky approximately 20) employees in Behavior-Based principles. The concepts of behavioral analysis are process driven. Employees and supervisors come together to identify the organizational barriers which prevent accident prevention excellence. Employees are encouraged to study the systems and processes which lead to at-risk behavior, accidents and property damage. Through proper analysis, evaluation and feedback, accident causation factors can be eliminated. (Additionally, all Kentucky employees completed the Start Safety Program. This is a motivational approach to enhance a person's safety attitude).

Ergonomics

Ergonomics is the study of people and their work. While ergonomics could technically be classified as an engineering discipline, it is also a philosophy. Its value is in allowing individuals to look at things from a different perspective, to break convention, to escape from the way it has always been done, to improve performance by fundamentally understanding the role of the workplace.

A basic understanding of ergonomic principles allows employees to contribute to the identification of occupational risk factors that might be present in their jobs. The use of ergonomic risk identification, more commonly known as Task Analysis, along with problem solving techniques, allows employees to initiate ergonomic interventions which reduce job exposure and increase efficiency, quality and satisfaction.

No quality ergonomic effort is complete without an effective training component. AEP's goal is to raise ergonomic awareness across the system and convey the company's commitment to reduce occupational risk factors.

Since the introduction of Ergonomics in 1998, AEP currently has 18 active ergonomic teams (Kentucky has three) in place with more scheduled to come on line in 1999.

Root Cause Analysis

Root Cause Analysis was introduced in 1998 which is a process that goes beyond ordinary accident investigations. This program trains investigators in techniques to perform in-depth investigations of human performance factors that lead to accidents. The process includes six modules which are procedures, training, communications, organizational factors, human engineering and supervision.

It is our intention to have a committee trained in this process for every region and plant within AEP.

Additional AEP Safety and Health Training Programs:

Cardio Pulmonary Resuscitation
First Aid
Arsenic

Asbestos
Lead
Respiratory Protection
Mercury
Clearance Tagging Power Plant Energy Control
Switching and Tagging T&D Energy Control
Confined Spaces
Crane Safety
Excavation Safety
Fire Response/Brigade
Incipient Fire
Traffic Control Safety
Hazard Communication/Chemical Control
Hearing Conservation
Heat Stress
Welding, Cutting and Brazing Safety
Mechanical Power Press Safety
Multi-piece Rim Wheel Safety
Personal Protective Equipment
Safety Glasses
Footwear
Insulated Protective Equipment
Hard Hat
Hazardous Materials and Emergency Response
Compressed Gas Cylinder Safety
Powered Industrial Truck Operations
Process Safety Management for Hazardous Substances
Radiation Safety
Commercial Drivers Licenses
Chain Saw Safety
Defensive Driving
Department of Transportation Hazardous Materials
Lockout - Tagout
Emergency Action Planning
PCB Cleanup
Electric Vehicle Safety
Bucket Truck Rescue
Tower Rescue
Power Generation, Transmission and Distribution Safety
Fall Protection
Scaffold Safety
New Leader Safety

40 kV Gloving
Job Briefing
Chlorine Handling
Fire Resistant Clothing
Station Entry Qualification

AEP SAFETY PUBLIC EDUCATION PROGRAM

Background

On January 1, 1997, AEP implemented a Corporate Public Safety Program and established the position of Manager of Public Safety to coordinate this effort throughout the system. Prior to initiation of this system-wide approach, public safety primarily resided with the operating companies.

There are four specific groups of people who have been the primary focus of attention - the general public, commercial contractors, first responders (i.e., firefighters, EMT's, law enforcement officers), and AEP contractors.

Contacts were made with the Occupational Safety and Health Administration (OSHA) in the seven states in which we operate and also with several contractor groups and professional agencies. These affiliations were established for two main reasons. First, to demonstrate our commitment to public safety and to develop partnering arrangements with the different agencies. Second, to identify concerns and issues that are prevalent within their operations.

The following summarizes activities and programs that were developed to heighten public safety awareness with respect to the potential hazards of electricity.

General Public

Public safety messages designed to provide electrical safety awareness information to the general public are being used at the system call centers. They are seasonal and reflect safety precautions based upon incidents that have occurred in the past. (Example: AEP cares about your safety. Keep all ladders, antennas, booms, and poles clear of power lines by at least 10 feet in every direction.)

Since implementation of the public safety messages for the general public, several callers have expressed appreciation for AEP's interest in providing electrical safety tips (Example: During abnormal flooding conditions in southern Ohio, callers said they appreciated the reminder to keep power cords out of wet areas.)

An in-house video was developed for the purpose of educating and involving all employees in the process of hazard awareness and reporting. A toll-free telephone number was standardized for the entire system for reporting conditions that may exist that pose the potential for imminent personal injury or significant property damage. Over 500 calls were received during 1998. A form was also standardized for employees to report situations of a less serious nature. Utilizing this process enables the employee to receive feedback once the situation has been corrected. This program is now included as part of New Employee Orientation.

A more in-depth training program was designed for our meter readers who cover the most territory. Unsatisfactory conditions are reported through their electronic hand-held meter reading device by using special codes designed for this purpose.

An electrical safety brochure for the homeowner was developed to provide safety information to the general public specifically for home projects. These brochures are being widely distributed throughout the system to lumber yards, building permit locations and other local establishments. They are also available through the call centers for customers who request information regarding electrical safety

Posters and small cards that convey electrical safety with respect to antenna installation/removal were created and are currently being distributed across the system to various establishments that sell and install TV and CB type equipment. This information has also been made available over the internet.

The manager of public safety works closely with corporate communications to provide input into external communication efforts. These include designing television commercials, selecting electrical safety publications and videos that are made available to schools and safety information that is provided to the customer in the form of a bill insert. In 1998, two new AEP safety commercials were produced and are currently being used throughout the system.

Commercial Contractors

AEP has established contacts with crane, trucking and various construction companies for the purpose of developing information that could be used to better educate contractors about the potential hazards that exist while working around energized lines and facilities. As a result, two safety brochures were published and are being furnished in significant quantity to various construction companies, contractor associations and state OSHA'S.

Live line demonstrations were also conducted at several contractor expositions, including the Ohio Contractor Exposition in Columbus, Ohio and a Builders' Exposition in Ft. Wayne, Indiana. The demonstration vividly illustrates the speed and nature of electricity, the hidden power of electricity, how electricity travels down wet or contaminated wood and rope, the dangers associated with improperly maintained personal protective rubber gloves and the similarities with underground and overhead wires used in the utility industry. Over 1200 contractors witnessed the demonstration during 1998.

A booklet entitled "Preventing Electrical Hazards" has been developed and will be used to further educate contractors and industry about electrical safety. ABD opportunities are expected.

Electrical Safety For First Responders

This presentation had previously been given exclusively to firefighters, mainly in the Columbus area, by the Region personnel. Now the program is coordinated by the Manager of Public Safety and is primarily presented by the Distribution Safety Coordinators throughout the system.

The program has been expanded to provide additional knowledge to first responders, such as firefighters, emergency medical technicians, and law enforcement officers. The enhanced training reflects hazards associated with downed power lines, the dangers of pulling meters and the proper method of removing an energized line by using a polypropylene rope.

In 1998 over 3000 first responders attended the program. An electrical safety booklet, specifically for first responders, was also designed for the program and is distributed to participants at the conclusion of the program.

An in-house video of a live electrical safety presentation was produced and is made available to first responders. This video can be used to reduce the number of live presentations currently being made.

AEP Contractors

An internally developed training program that places heightened emphasis on AEP contractor safety has been given to over 1500 AEP employees (Kentucky approximately 30) throughout the system.

The one-half day program covers our expectations regarding the safety of contractors who work for AEP. The program covers the General Terms and Conditions contract language, a process for evaluating safety programs of potential bidders, observation techniques and a guide for reading OSHA standards.

Public Education Program Recognition

AEP was recognized by the Central Ohio Builders' Exchange Association for its partnering efforts to develop program to eliminate electrical injuries to contractors. This was done through publications which were distributed to over (2400) members of the association.

Through various outreach efforts, an electrical training program covering 1910.269 was presented to compliance officers for IOSHA (Indiana Occupational Safety and Health Administration). In addition, met with the other OSHA agencies throughout the system offering a similar training program.

Facilitators were presented a certificate of appreciation for presenting the electrical safety program to approximately 120 Stark County deputy sheriffs in Canton, Ohio.

A database that tracks public safety incidents was developed and instantaneously disseminates information regarding accidents that have occurred within the system. Over 200 management employees have immediate access to the information as it is reported.

For the second straight year, after implementing the Corporate Public Safety Program, there were 33% fewer claims reported in comparison with the previous five year average.

COMMONWEALTH OF KENTUCKY

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MARK A. BAILEY

APRIL 1999

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REGARDING A PROPOSED MERGER)

DIRECT TESTIMONY

OF

MARK A. BAILEY

APRIL 1999

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark A. Bailey. My business address is 700 Morrison Road, Gahanna, Ohio 43230.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director - Energy Delivery & Customer Relations (ED&CR).

II. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering from Ohio Northern University in 1974 and a Masters of Science Degree in Management from the Massachusetts Institute of Technology in 1988. I am a Registered Professional Engineer in the State of Ohio (Registration # E-43633).

I began my career with American Electric Power Company, Inc. (AEP) in 1974 with Ohio Power Company (OPCo) as an Electrical Engineer in the Portsmouth Division. In early 1975, I transferred to AEP's Power Generation organization where I worked for a number of years in various engineering and supervisory assignments at several OPCo fossil generating stations.

In 1983, I became Administrative Assistant to the President of OPCo with responsibility for coordinating administrative matters involving OPCo's generating stations and the General Office. I also performed special studies for the president in non-power plant areas such as operating division performance measurement. In 1985, I was named OPCo's Tiffin Division Manager where I had line, engineering, marketing and customer service responsibilities for the division's roughly 55,000 customers. In 1988, I was promoted to Executive Assistant and worked under the direction of AEPSC's Executive Vice President - Operations. In that capacity I performed various special studies involving AEP's operating companies and also assisted in the design of the company's Management Incentive Compensation Plan.

In 1989, I was elected Vice President - Operations for Indiana Michigan Power Company (I&M) with responsibility for the company's operating Divisions, Transmission and Distribution, General Services, System Operations and Purchasing and Stores functions. I also had administrative responsibilities for the company's fossil and nuclear generating stations.

In 1994, I was named Vice President - Administration for I&M with responsibility for the company's Accounting, Rates, Marketing, Customer Services and Purchasing and Stores functions as well as administrative responsibility for the company's generating plants.

Following AEP's reorganization in 1996, I became Director - Regions with the AEPSC, responsible for the system's six southern distribution regions as well as the system's Transmission and Distribution (T&D) Material Distribution function.

I assumed my present position in January, 1998 and am responsible for day to day internal administration and management of the ED&CR business group and direct responsibility for the system's T&D Material Distribution function. In my capacity, I am responsible for establishing operational metrics and targets for the various business units and departments within the ED&CR business group as well as special studies for the Executive Vice President - Energy Delivery & Customer Relations.

Q. HAVE YOU APPEARED AS A WITNESS BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have appeared before the Arkansas Public Service Commission concerning the business combination of AEP and CSW in Docket No. 98-172-U.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am addressing customer service quality issues. I will also discuss the common view AEP and KPCO share with Central and South West Corporation (CSW) in maintaining, monitoring and, where necessary, improving our quality of service following the merger and describe AEP's current service quality goals and objectives.

IV. SAFE, RELIABLE AND ADEQUATE SERVICE

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

A. I testify that Applicants are ready, willing and able to continue providing safe, reliable and adequate service. I also address AEP's commitment to maintain or where necessary improve the quality of service to Kentucky customers.

In order to address those factors it is necessary to define what is meant by "service," discuss the goals the Company has set for each component of service, specify the organization and support necessary to achieve those goals, and evaluate how well AEP meets those goals.

Q. HOW DOES AEP DEFINE SERVICE QUALITY?

A. Customer service is about treating people right. It means keeping the power on, answering the phone quickly, solving, not just handling, problems, and keeping the customer satisfied.

Q. IS SERVICE QUALITY A GOAL FOR AEP?

A. Yes. One of AEP's corporate goals is to attract and retain customers by identifying and meeting their needs better than anyone else. AEP intends to meet this goal by: 1) achieving the top quartile of customer satisfaction results in the industry; 2) producing reliability results above industry standards; 3) achieving safety results that will place the company in the top ten percent of Edison Electric Institute Utilities; and 4) achieving a cost profile that will place the company in the top third of the industry. AEP has set a target date of December 31, 2000 to meet these objectives.

Q. HOW DOES AEP MEASURE SERVICE QUALITY?

A. AEP measures its service quality on the basis of safety, reliability, and customer satisfaction.

Q. HOW DOES AEP MEASURE SAFETY?

A. Safety performance is measured by three indices: the Occupational Safety and Health Administration Recordable Case Incidence Rate, the Severity Rate (i.e., Lost and Restricted Workdays) and the Vehicle Accident Frequency Rate. The details concerning these measures are contained in EXHIBIT MAB-1. This exhibit also contains information concerning KPCO's performance in the measured areas for the years 1996 - 1998.

Q. HOW DOES AEP MEASURE RELIABILITY?

A. AEP captures the frequency of outages and the duration of outages and compares them to the annual targets. The details of this calculation are contained within EXHIBIT MAB-2. This exhibit also contains information concerning KPCO's performance in the measured areas for the years 1996 - 1998.

Q. HOW DOES AEP MEASURE CUSTOMER SATISFACTION?

A. AEP surveys the company's various customer classes. Those surveys provide our customers a direct way to give opinions on reliability, power quality, outage restoration and other specific aspects of AEP's operations.

Q. HOW ARE EMPLOYEES MADE AWARE OF THE GOALS OF SAFETY, RELIABILITY AND CUSTOMER SATISFACTION?

A. Our goals in these areas are regularly communicated to employees through meetings and bulletin board postings. To further emphasize their importance, all full-time ED&CR employees are eligible to participate in incentive plans. These plans reward employees based on the accomplishment of certain specified goals. For example, the employees of the Energy Delivery Business group who participate in the Companywide Incentive Plan have 55-65% of their awards based on safety, reliability and customer satisfaction. The awards are weighted so that 60% of the award is based on the performance of the employee's region or department and 40% on the performance of the overall business unit. This encourages employees to help other regions and departments provide high quality service.

Management employees participate in a similar plan, the Management Incentive Compensation Plan. While a substantial portion (30-35%) of the Energy Delivery Business group's incentive is based on safety, reliability and customer satisfaction, they also have corporate goals such as budget, inventory, economic development and business development factors included within their plan. These factors are effective incentives for managers to provide customers with affordable, reliable and safe electricity.

Q. ARE THERE OTHER MEASURES USED BY AEP TO ENCOURAGE EMPLOYEES TO PROVIDE HIGH QUALITY SERVICE?

A. Yes. Customer calls to AEP are handled by the Customer Services division. That division measures *average speed of answer, the abandonment rate and call blockage* for calls into the call centers. The details of these measures are included within EXHIBIT MAB-3. This exhibit also contains information concerning how each of the AEP Call Centers performed in the measured areas in 1998. The employees and managers are provided incentives to improve performance in the measured areas.

Q. HOW WELL HAS KPCO DONE IN THESE SERVICE QUALITY MEASURES?

A. As stated earlier, AEP's goal for 1999 is to be in the top quartile of customer satisfaction results in the industry. In 1998 we ranked among the best performing utilities in *American Customer Satisfaction Index* (fourth of nineteen utilities) as well as in our own proprietary customer satisfaction surveys.

KPCO had a target *outage frequency* of 1.549 outages per customer per year for 1998, and achieved 1.519. In *outage duration*, KPCO had a goal of 3.170 hours per outage and achieved an outage duration of 5.960 hours. This includes outages caused by major storms. If the effects of the three major storms which occurred during 1998 are eliminated, the *outage frequency* would be 1.210 and the *outage duration* would be 3.370 hours. There were no major storms for 1996 and 1997 in KPCO's service territory.

The Ashland call center had an *average speed of answer* target of 30 seconds for 1998 and achieved 41.7 seconds. The center's *abandonment rate* target was 5 percent and it achieved 4.4%. The center's *call blockage rate* target was 2 percent and it achieved 0.4%. The AEP call centers are still in the process of development, and I anticipate that the actual statistic for *average speed of answer* will improve in 1999.

V. CUSTOMER SERVICE AND BUDGET RESOURCES

Q. ARE THERE CLEAR LINES OF RESPONSIBILITY AND AUTHORITY AT AEP CONCERNING CUSTOMER SERVICE?

A. Yes. Local management has clear authority and adequate resources to do the job required. The management at the region and district levels have primary responsibility for all aspects of customer service. As shown on the organizational chart I prepared (EXHIBIT MAB-4), all of the customer service functions within AEP report to Mr. William J. Lhota, Executive Vice President of Energy Delivery and Customer Relations.

Q. WHAT IS THE LEVEL OF REGION RESPONSIBILITY DURING OUTAGES?

A. During outages, region and district management have full discretion to bring in whatever resources are required in order to restore service as quickly and safely as possible. This discretion includes the use of overtime as required involving all region internal and contract personnel. The region directors can call on AEP resources outside their region to assist in restoring the outage. The director's authority even extends to the ability to rent helicopters, and other equipment to assist in the restoration effort.

Q. HOW IS THE BUDGET FOR EACH REGION ESTABLISHED?

A. Each year, AEP starts with the goals, performance measures and targets I discussed earlier in my testimony. Each region is asked to develop an annual business plan which includes specific actions they plan to take to achieve the targets. Once the business plans are developed, each region develops an annual budget to support its plan. The region plans are rolled together on a system-wide basis, and submitted to senior management. The Energy Delivery and Customer Relations budget group may recommend adjustments to the region budgets in order to achieve corporate objectives. If adjustments are necessary, senior management works with the budget group and the region to make the necessary changes. Once agreement is reached, the overall budget is submitted to Mr. Lhota for final approval.

Q. DO THE AEP REGION DIRECTORS HAVE SUFFICIENT AUTHORITY AND RESOURCES TO PROVIDE QUALITY SERVICE?

A. Yes. AEP relies on the input of the region directors in setting budgets. Each budget gives the region directors the capabilities to meet the goals and targets set for the corporation. Since employees and managers are rewarded for superior performance, everyone in the business unit has an incentive to make sure that the employees who are on the front line have all the resources and authority necessary to provide high quality service.

VI. EFFECT OF THE MERGER ON CUSTOMER SERVICE

Q. WHAT CHANGES DO YOU ANTICIPATE AS A RESULT OF THE MERGER IN THE CUSTOMER SERVICE AREA?

A. AEP commits that quality of service for KPCO customers will be maintained or where necessary improved as a result of this merger. Both AEP and CSW have similar definitions of service quality. Where there are differences in the quality of service measures and targets used by the two companies, I anticipate that we will develop a unified set of measures and goals based on the unique terrain, climate and other operating conditions of each operating company.

Q. WILL THE BUDGET PROCESS CHANGE IN THE COMBINED COMPANY?

A. It is too early to know exactly how the budget allocation process will occur for the combined companies. However, the resource planning process of both companies is substantially similar, and should result in similar outcomes.

Q. WILL AEP'S INCENTIVE PLANS CHANGE AS A RESULT OF THE MERGER?

A. Those decisions have not been made. As the combined companies develop a unified system of goals and targets, I anticipate that the service quality results will be used in the incentive plans. Just as AEP and CSW now currently provide incentives to employees to provide quality service, so also will the combined companies provide similar incentives.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony demonstrates:

- AEP will continue to provide safe, reliable and adequate service to KPCO's customers,
- AEP commits that following the proposed Merger it will maintain or when necessary improve the quality of services to Kentucky customers,
- The local operations within KPCO will continue to have the authority and ability to provide quality service within Kentucky.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COUNTY OF BOYD

COMMONWEALTH OF KENTUCKY CASE NO.

Affidavit

Mark A. Bailey, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Mark A. Bailey

Mark A. Bailey

Subscribed and sworn to before me by Mark A. Bailey this 5th day of April 1999.

James L. Reeves

Notary Public

JAMES L. REEVES
ATTORNEY AT LAW
NOTARY PUBLIC - STATE OF OHIO
MY COMMISSION HAS NO EXPIRATION DATE

My Commision Expires ____________

AEP SAFETY MEASURES

AEP uses 3 principal measures to monitor employee safety performance. These are:

1) OSHA Recordable Case Incident Rate which is defined as the number of OSHA recordable cases per 200, 000 hours worked. It is calculated using the equation:

$$\frac{\text{(number of recordable accidents)} \times 200{,}000}{\text{hours worked}}$$

2) Severity Rate which is defined as the number of lost and restricted work days per 200,000 hours worked. It is calculated using the equation:

$$\frac{\text{(number of lost workdays + number of restricted workdays)} \times 200{,}000}{\text{number of hours worked}}$$

3) Vehicle Accident Frequency Rate which is defined as the number of reportable vehicle accidents per million miles driven. It is calculated using the equation:

$$\frac{\text{(number of reportable vehicle accidents)} \times 1{,}000{,}000}{\text{miles driven}}$$

KyPCo Employee Safety Performance

Measure	Year	Performance
Recordable Incident Rate	1996	10.86
	1997	9.73
	1998	8.87
Severity Rate	1996	69
	1997	99
	1998	180
Vehicle Accident Frequency Rate	1996	6.18
	1997	10.12
	1998	5.54

AEP RELIABILITY MEASURES

AEP uses 3 primary measures to monitor its service reliability. These are:

1) System Average Interruption Frequency Index (SAIFI) which is defined as the number of customers interrupted divided by the number of customers served. It is calculated using the equation:

$$\text{SAIFI} = \frac{\text{number of customers interrupted}}{\text{number of customers served}}$$

2. Customer Average Interruption Duration Index (CAIDI) which is defined as the number of customer hours of interruption divided by the number of customers interrupted. It is calculated using the equation:

$$\text{CAIDI} = \frac{\text{number of customer hours of interruption}}{\text{number of customers interrupted}}$$

3) Customer Service Reliability Index (CSRI) which is an average of the interruption frequency divided by the interruption frequency target and the interruption duration divided by the duration target and converted to a percentage. It is calculated using the equation:

$$\text{CSRI} = \left[\left[\left[\frac{\text{(interruption frequency)}}{\text{(interruption frequency target)}}\right] + \left[\frac{\text{(interruption duration)}}{\text{(interruption duration target)}}\right]\right] /2 \right] \times 100$$

KyPCo Reliability Performance

Measure	Year	Performance	Target
SAIFI	1996	1.530	1.478
	1997	1.342	1.498
	1998	1.519*	1.549
CAIDI	1996	3.104	5.986
(hours)	1997	3.040	5.657
	1998	5.960*	3.170
CSRI	1996	77.69	100.0
(percent)	1997	71.66	98.0
	1998	143.04*	100.0

* Includes major storms.

EXHIBIT MAB-3

AEP CALL CENTER MEASURES

The AEP Call Centers use 3 primary measures to monitor their performance. These are:

1) Average Speed of Answer (ASA) is defined as the average time that elapses in seconds between the instant when a call is answered and the time it is connected to a Call Center representative (CSR) or an interactive voice recorder (IVR). It is calculated using the equation:

$$\underset{\text{(seconds)}}{\text{Average Speed of Answer}} = \frac{\text{time for all calls between call answer and CSR/IVR connection}}{\text{total number of calls made to the Call Center}}$$

2) Abandonment Rate is the percentage of callers who hang up before being connected to a Call Center representative (CSR) or an interactive voice recorder (IVR). It is calculated using the equation:

$$\underset{\text{(percent)}}{\text{Abandonment Rate}} = \frac{\{\text{total number of callers who hang up}\}}{\{\text{total number of calls made to the Call Center}\}} \times 100$$

3) Call Blockage is the percentage of non-outage call attempts which do not get connected to a Call Center (busy signal, etc.). It is calculated using the equation:

$$\underset{\text{(percent)}}{\text{Call Blockage}} = \frac{\{\text{total number of non-outage calls that do not get connected}\}}{\{\text{total number of non-outage calls made to the Call Center}\}} \times 100$$

AEP Call Center Performance

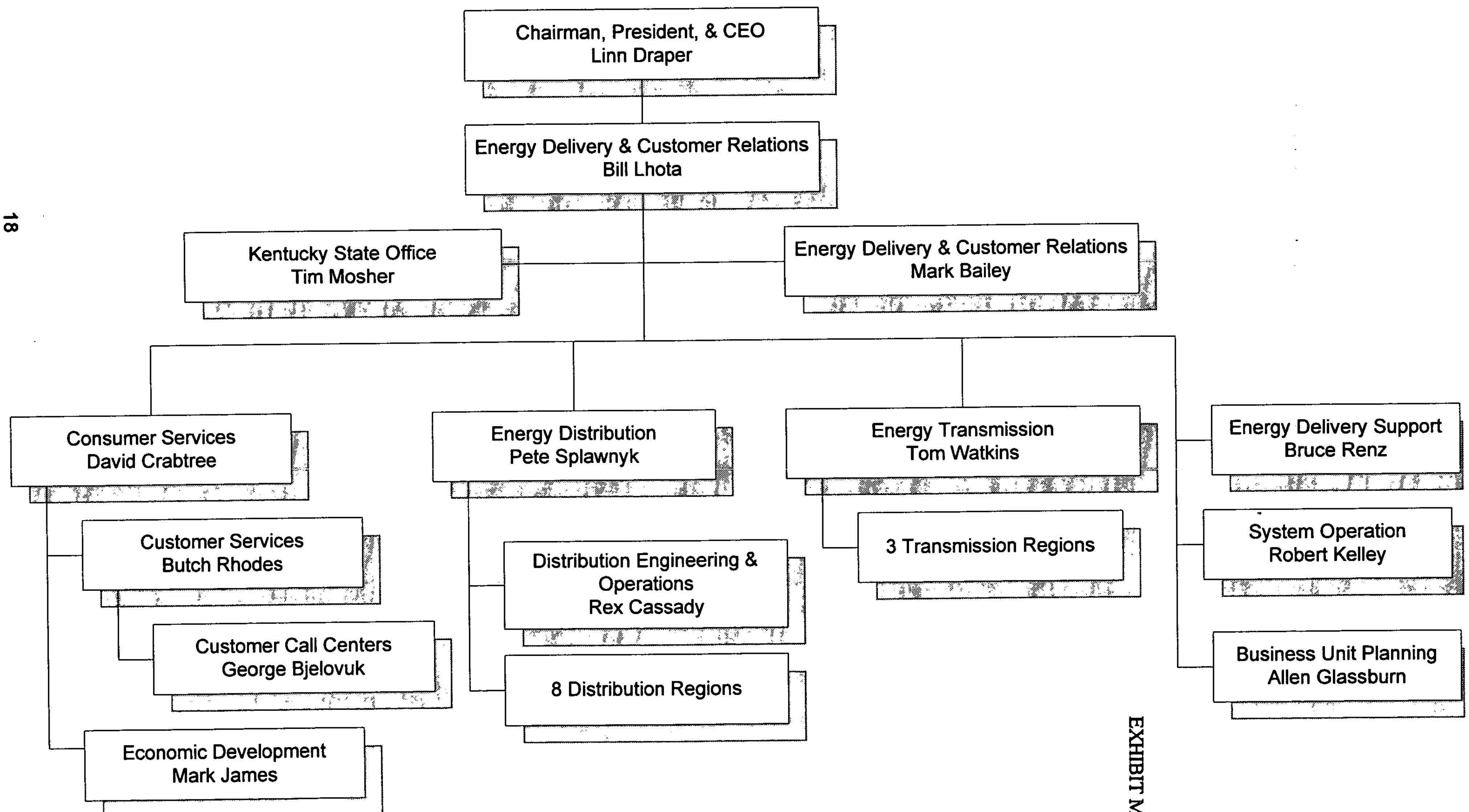
Measure	Center	Year	Performance	Target
Average Speed of Answer (seconds)	Groveport	1998	52	45
	Ft. Wayne	1998	69	60
	Ashland	1998	42	30
	Hurricane	1998	44	45
Abandonment Rate (percent)	Groveport	1998	5.4	7.0
	Ft. Wayne	1998	4.5	7.0
	Ashland	1998	4.4	5.0
	Hurricane	1998	5.3	7.0
Call Blockage (percent)	Groveport	1998	7.2	2.0
	Ft. Wayne	1998	0.5	2.0
	Ashland	1998	0.4	2.0
	Hurricane	1998	0.3	2.0

EXHIBIT MAB-4

AMERICAN ELECTRIC POWER

Selected Energy Delivery & Customer Relations Groups

January 1, 1999



CASE NUMBER:

99-149

File No. 30-150

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C.

FORM U5S
ANNUAL REPORT

For the year ended December 31, 2001

Filed Pursuant to the Public Utility Holding Company Act of 1935
by

AMERICAN ELECTRIC POWER COMPANY, INC.
1 Riverside Plaza, Columbus, Ohio 43215

AMERICAN ELECTRIC POWER COMPANY, INC.

FORM U5S – ANNUAL REPORT
For the Year Ended December 31, 2001

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Item 1. System Companies and Investment Therein As Of December 31, 2001.				
Name of Company	Number of Common Shares Owned	Voting Power	Issuer Book Value (in OOO's)	Owner's Book Value (in 000'S)
00. American Electric Power Company, Inc. [Note A]				
01. American Electric Power Service Corporation [Note B]	13,500	100%	(8,573)	(8,573)
01. AEP C&I Company, LLC [Note W]	Uncertified	100%	(3,267)	(3,267)
02. AEP Ohio Commercial & Industrial Retail Company, LLC [Note W]	Uncertified	100%	(6)	(6)
02. AEP Texas Commercial & Industrial Retail GP, LLC [Note W]	Uncertified	100%	(158)	(158)
03. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]	Partnership	1%	(1)	(1)
02. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]	Partnership	100%	(238)	(238)
02. AEP Gas Power GP, LLC [Note G]	Uncertified	100%	(3,089)	(3,089)
03. AEP Gas Power Systems, LLC [Note G]	100	75%	(133)	(100)
01. AEP Coal, Inc. [Note L]	-	100%	635	635
01. AEP Communications, Inc. [Note C]	100	100%	(53,093)	(53,093)
02. AEP Communications, LLC [Note C]	Uncertified	100%	(56,954)	(56,954)
03. American Fiber Touch, LLC [Note C]	Uncertified	50%	15,149	12,267
03. AEP Fiber Venture, LLC [Note C]	Uncertified	100%	30,470	30,470
04. AFN Communications, LLC [Note C]	5,008	48%	32,235	26,152
01. AEP Energy Services, Inc. [Note D]	200	100%	78,472	78,472
01. AEP Generating Company [Note J]	1,000	100%	38,195	38,195
01. AEP Indian Mesa LP, LLC [Note X]	Uncertified	100%	-	-
02. Indian Mesa Power Partners I LP [Note X]	Partnership	99%	-	-
02. Indian Mesa Power Partners II LP [Note X]	Partnership	99%	-	-
02. AEP Indian Mesa GP, LLC [Note X]	Uncertified	100%	-	-
03. Indian Mesa Power Partners I LP [Note X]	Partnership	1%	-	-
03. Indian Mesa Power Partners II LP [Note X]	Partnership	1%	-	-
01. AEP Investments, Inc. [Note F]	100	100%	19,359	19,359
02. AEP EmTech, LLC [Note DD]	Uncertified	100%	(1,028)	(1,028)
03. Altra Energy Technologies, Inc. [Note DD]	N/A	5%	5,300	5,300
03. Amperion, Inc. [Note DD]	N/A	38%	3,743	3,743
02. Pantellos Corporation [Note DD]	28,883	5%	2,492	2,492
01. Mutual Energy L.L.C. [Note W]	Uncertified	100%	(8,082)	(8,082)
02. Mutual Energy Service Company, L.L.C. [Note W]	Uncertified	100%	(7,555)	(7,555)
02. AEP Ohio Retail Energy, LLC [Note W]	Uncertified	100%	(521)	(521)
01. AEP Power Marketing, Inc. [Note N]	100	100%	-	-
01. AEP T&D Services, LLC [Note BB]	Uncertified	100%	(77)	(77)
01. AEP Pro Serv, Inc. [Note I]	110	100%	(800)	(800)
02. Power-span Corp [Note DD]	N/A	10%	5,000	5,000
02. PHPK Technologies, Inc. [Note DD]	N/A	40%	1,237	1,237
01. AEP Retail Energy LLC [Note W]	Uncertified	100%	(224)	(224)
01. AEP Texas POLR, LLC [Note W]	Uncertified	100%	(2)	(2)
02. AEP Texas POLR GP, LLC [Note W]	Uncertified	100%	-	-
03. POLR Power, L.P. [Note W]	Partnership	1%	-	-
02. POLR Power, L.P. [Note W]	Partnership	100%	-	-
01. AEP Resources, Inc. [Note H]	100	100%	155,095	155,095
02. AEP Delaware Investment Company [Note H]	100	100%	29,303	29,303
03. AEP Holdings I CV [Note H]	10	15%	56,341	56,341
04. AEPR Global Investments B.V. [Note H]	N/A	85%	178,033	178,033
05. Energia de Mexicali, S de RL de CV [Note H]	Uncertified	0%	-	-
05. AEPR Global Holland Holding B.V. [Note H]	Uncertified	100%	178,017	178,017
04. AEP Holdings II CV [Note H]	Partnership	85%	185,161	157,588
05. AEP Energy Services Limited [Note H]	Uncertified	100%	33,147	34,766
06. AEP Energy Services (Austria) GmbH [Note H]	Uncertified	100%	13	13
06. AEP Energy Services (Switzerland) GmbH [Note H]	Uncertified	100%	10	10
06. AEP Energy Services GmbH [Note H]	Uncertified	100%	23	23
05. AEPR Global Ventures B.V. [Note H]	Uncertified	100%	(621)	(621)
06. Energia de Mexicali, S de RL de CV [Note H]	Uncertified	100%	(243)	(243)
06. AEP Energy Services (Norway) AS [Note H]	Uncertified	100%	-	-
06. Operaciones Azteca VIII, S. de R.L. de C.V. [Note H]	Uncertified	50%	2	2
06. Servicios Azteca VIII, S. de R.L. de C.V. [Note H]	Uncertified	50%	(222)	(222)
05. Intergen Denmark, Aps [Note H]	Partnership	50%	23,474	23,474
06. Intergen Denmark Finance Aps [Note H]	Partnership	100%	N/A	N/A
06. Intergen Mexico, B.V. [Note H]	Partnership	100%	N/A	N/A
07. Intergen Aztec Energy VIII B.V. [Note H]	Partnership	100%	N/A	N/A
08. Intergen Aztec Energy VI B.V. [Note H]	Partnership	100%	N/A	N/A
08. Energia Azteca VIII S. de R.L. de C.V. [Note H]	Partnership	100%	N/A	N/A
05. AEP Energy Services UK Generation Limited [Note H]	Uncertified	100%	52,678	52,678
05. Compresion Bajio S de R.L. de C.V. [Note H]	Uncertified	50%	2,655	2,655
02. AEP Delaware Investment Company II [Note H]	1,000	100%	85,119	85,119
03. AEP Holdings II CV [Note H]	Uncertified	15%	32,676	27,810

Item 1. System Companies and Investment Therein As Of December 31, 2001.				
Name of Company	Number of Common Shares Owned	Voting Power	Issuer Book Value (in OOO's)	Owner's Book Value (in 000'S)
04. AEP Energy Services Limited [Note H]	Uncertified	100%	6,135	6,135
05. AEP Energy Services (Austria) GmbH [Note H]	Uncertified	100%	2	2
05. AEP Energy Services (Switzerland) GmbH [Note H]	Uncertified	100%	2	2
05. AEP Energy Services GmbH [Note H]	Uncertified	100%	4	4
04. AEPR Global Ventures B.V. [Note H]	Uncertified	100%	(110)	(110)
05. Energia de Mexicali, S de RL de CV [Note H]	Uncertified	100%	(1)	1
05. AEP Energy Services (Norway) AS [Note H]	Uncertified	100%	-	-
05. Operaciones Azteca VIII, S. de R.L. de C.V. [Note H]	Uncertified	50%	2	2
05. Servicios Azteca VIII, S. de R.L. de C.V. [Note H]	Uncertified	50%	(222)	(222)
04. Intergen Denmark, Aps [Note H]	Partnership	50%	23,499	23,499
05. Intergen Denmark Finance Aps [Note H]	Partnership	50%	N/A	N/A
05. Intergen Mexico, B.V. [Note H]	Partnership	100%	N/A	N/A
06. Intergen Aztec Energy VIII B.V. [Note H]	Partnership	100%	N/A	N/A
07. Intergen Aztec Energy VI B.V. [Note H]	Partnership	100%	N/A	N/A
07. Energia Azteca VIII S. de R.L. de C.V. [Note H]	Partnership	100%	N/A	N/A
04. AEP Energy Services UK Generation Limited [Note H]	Uncertified	100%	9,296	9,296
04. Compresion Bajio S de R.L. de C.V. [Note H]	Uncertified	50%	2,655	2,655
02. AEP Delaware Investment Company III [Note H]	Uncertified	100%	985,730	985,730
03. AEP Holdings I CV [Note H]	Partnership	85%	319,264	319,264
04. AEPR Global Investments BV [Note H]	Uncertified	15%	31,418	31,418
05. Energia de Mexicali, S de RL de CV [Note H]	Uncertified	0%	-	-
05. AEPR Global Holland Holding BV [Note H]	Uncertified	100%	31,415	31,415
04. AEP Holdings II CV [Note H]	Partnership	15%	27,810	27,810
05. AEP Energy Services Limited [Note H]	Uncertified	100%	6,135	6,135
06. AEP Energy Services (Austria) GmbH [Note H]	Uncertified	100%	2	2
06. AEP Energy Services (Switzerland) GmbH [Note H]	Uncertified	100%	2	2
06. AEP Energy Services GmbH [Note H]	Uncertified	100%	10	10
05. AEPR Global Ventures B.V. [Note H]	Uncertified	100%	(234)	(234)
06. Energia de Mexicali, S de RL de CV [Note H]	Uncertified	100%	(286)	(286)
06. AEP Energy Services (Norway) AS [Note H]	Uncertified	100%	-	-
06. Operaciones Azteca VIII, S. de R.L. de C.V. [Note H]	Uncertified	50%	2	2
06. Servicios Azteca VIII, S. de R.L. de C.V. [Note H]	Uncertified	50%	(222)	(222)
05. Intergen Denmark, Aps [Note H]	Partnership	50%	23,474	23,474
06. Intergen Denmark Finance Aps [Note H]	Partnership	100%	N/A	N/A
06. Intergen Mexico, B.V. [Note H]	Partnership	100%	N/A	N/A
07. Intergen Aztec Energy VIII B.V. [Note H]	Partnership	100%	N/A	N/A
08. Intergen Aztec Energy VI B.V. [Note H]	Partnership	100%	N/A	N/A
08. Energia Azteca VIII S. de R.L. de C.V. [Note H]	Partnership	100%	N/A	N/A
05. AEP Energy Services UK Generation Limited [Note H]	Uncertified	100%	9,296	9,296
05. Compresion Bajio S de R.L. de C.V. [Note H]	Uncertified	50%	2,655	2,655
03. AEPR Global Investments BV [Note H]	Uncertified	15%	31,418	31,418
04. AEPR Global Holland Holding BV [Note H]	Uncertified	100%	31,415	31,415
02. AEP Memco LLC [Note Y]	Uncertified	100%	41,925	41,925
03. AEP Elmwood LLC [Note Y]	Uncertified	100%	4,463	4,463
04. Conlease, Inc. [Note Y]	Uncertified	100%	-	-
04. International Marine Terminals [Note Y]	Uncertified	33-	-	-
02. AEP Resources Australia Holdings Pty Ltd [Note H]	1	100%	140,560	143,849
03. AEP Resources CitiPower I Pty Ltd [Note H]	1	100%	N/A	N/A
04. Australia's Energy Partnership [Note H]	Partnership	99%	1,104,060	1,104,060
05. Marregon (No. 2) Pty Ltd [Note H]	179,190,000	100%	-	-
06. CitiPower Pty [Note H]	5	100%	8,112	8,112
07. CitiPower Trust [Note H]	Uncertified	100%	1,128,656	1,128,656
06. Marregon Pty Ltd [Note H]	1	100%	-	-
04. AEP Resources CitiPower II Pty Ltd [Note H]	1	100%	1,953	1,953
05. Australia's Energy Partnership [Note H]	Uncertified	1%	11,152	11,152
06. Marregon (No. 2) Pty Ltd [Note H]	1,810,000	100%	-	-
07. CitiPower Pty [Note H]	-	100%	82	82
08. CitiPower Trust [Note H]	Uncertified	100%	11,401	11,401
07. Marregon Pty Ltd [Note H]	-	100%	-	-
02. AEP Resources Australia Pty., Ltd. [Note H]	3,753,752	100%	15,042	17,958
03. Pacific Hydro Limited [Note H]	23,478,300	20%	17,809	17,809
02. AEP Resources Limited [Note H]	1	100%	755	755
02. AEP Energy Services Gas Holding Company [Note CC]	10	100%	67,777	67,777
03. AEP Energy Services Gas Holding Company II, LLC [Note CC]	Uncertified	100%	622,626	622,626
04. Caddis Partners, LLC [Note CC]	Uncertified	100%	2,211	2,211
04. AEP Energy Services Ventures III, Inc. [Note CC]	10	100%	158,297	158,297
04. HPL Holdings Inc. [Note CC]	100	100%	852,953	852,953

Item 1. System Companies and Investment Therein As Of December 31, 2001.				
Name of Company	Number of Common Shares Owned	Voting Power	Issuer Book Value (in OOO's)	Owner's Book Value (in 000'S)
05. AEP Gas Marketing, LP [Note CC]	Uncertified	100%	7,185	7,185
05. HPL GP, LLC [Note CC]	5	100%	611	611
06. HPL Resources Company LP [Note CC]	Uncertified	1%	-	-
06. AEP Gas Marketing, LP [Note CC]	Uncertified	1%	34	34
06. Houston Pipe Line Company LP [Note CC]	Uncertified	1%	585	585
07. Mid-Texas Pipeline Company [Note CC]	Uncertified	50%	34,635	34,635
05. HPL Resources Company LP [Note CC]	Uncertified	100%	(1)	(1)
05. Houston Pipe Line Company LP [Note CC]	995	100%	845,141	845,141
06. Mid-Texas Pipeline Company [Note CC]	N/A	50%	(1)	(1)
04. AEP Energy Services Investments, Inc. [Note CC]	100	100%	116,672	116,672
05. LIG Pipeline Company [Note CC]	100	100%	116,627	116,627
06. LIG, Inc. [Note CC]	100	100%	11,645	11,645
07. Louisiana Intrastate Gas Company, L.L.C. [Note CC]	100	10%	10,501	10,501
08. LIG Chemical Company [Note CC]	100	100%	(12,693)	(12,693)
09. LIG Liquids Company, L.L.C. [Note CC]	10	10%	1,240	1,240
08. LIG Liquids Company, L.L.C. [Note CC]	90	90%	11,158	11,158
08. Tuscaloosa Pipeline Company [Note CC]	100	100%	703	703
06. Louisiana Intrastate Gas Company, L.L.C. [[Note CC]	900	90%	94,509	94,509
07. LIG Chemical Company [Note CC]	900	100%	(12,693)	(12,693)
08. LIG Liquids Company, L.L.C. [Note CC]	90	10%	1,378	1,378
07. LIG Liquids Company, L.L.C. [Note CC]	810	90%	12,398	12,398
07. Tuscaloosa Pipeline Company [Note CC]	900	100%	705	705
04. AEP Energy Services Ventures, Inc. [Note CC]	100	100%	15,012	15,012
05. AEP Acquisition, LLC [Note CC]	Uncertified	50%	9,125	9,125
06. Jefferson Island Storage & Hub L.L.C. [Note CC]	50	100%	102,637	102,637
04. AEP Energy Services Ventures II, Inc. [Note CC]	10	100%	15,014	15,014
05. AEP Acquisition, LLC [Note CC]	Uncertified	50%	9,125	9,125
06. Jefferson Island Storage & Hub L.L.C. [Note CC]	50	100%	102,637	102,637
02. AEP Resources International, Limited [Note H]	2	100%	41,885	41,88
03. NGLE Pushan Power, LDC [Note H]	99	99%	41,498	41,49
04. Nanyang General Light Electric Co., Ltd. [Note H]	Uncertified	70%	31,894	31,89
03. AEP Resources Project Management Company, Ltd. [Note H]	Uncertified	100%	412	40
04. NGLE Pushan Power, LDC [Note H]	99	1%	419	41
05. Nanyang General Light Electric Co., Ltd. [Note H]	Uncertified	70%	13,669	13,66
02. AEP Resource Services, LLC [Note H]	Uncertified	100%	1,433	1,43
02. Ventures Lease Co., LLC [Note Q]	Uncertified	100%	-	-
01. Appalachian Power Company [Note J]	13,499,500	99%	112,671	112,67
02. Cedar Coal Co. [Note K]	2,000	100%	4,954	4,95
02. Central Appalachian Coal Company [Note K]	3,000	100%	760	76
02. Central Coal Company [Note K]	3,000	50%	604	60
02. Southern Appalachian Coal Company [Note K]	6,950	100%	9,786	9,78
02. West Virginia Power Company [Note N]	100	100%	267	25
01. Columbus Southern Power Company [Note J]	16,410,426	100%	791,498	791,41
02. Colomet, Inc. [Note T]	1,500	100%	2,277	2,27
02. Conesville Coal Preparation Company [Note M]	100	100%	1,600	1,10
02. Simco Inc. [Note N]	90,000	100%	363	36
02. Ohio Valley Electric Corporation [Note E]	4,300	4%	430	43
03. Indiana-Kentucky Electric Corporation [Note E]	17,000	100%	3,400	3,40
01. Franklin Real Estate Company [Note T]	100	100%	30	3
02. Indiana Franklin Realty, Inc. [Note T]	10	100%	1	
01. Indiana Michigan Power Company [Note J]	1,400,000	100%	860,570	860,51
02. Blackhawk Coal Company [Note K]	39,521	100%	50,661	50,66
02. Price River Coal Company [Note K]	1,091	100%	27	2
01. Kentucky Power Company [Note J]	1,009,000	100%	256,130	256,13
01. Kingsport Power Company [Note J]	410,000	100%	23,782	23,78
01. Ohio Power Company [Note J]	27,952,473	99%	1,184,785	1,184,78
02. Cardinal Operating Company [Note E]	250	50%	-	-
02. Central Coal Company [Note K]	1,500	50%	604	60
01. Ohio Valley Electric Corporation [Note E]	39,900	40%	3,990	3,99
02. Indiana-Kentucky Electric Corporation [Note E]	17,000	100%	3,400	3,40
01. Wheeling Power Company [Note J]	150,000	100%	27,838	27,83
01. Central and South West Corporation [Note O]	100	100%	4,132,276	4,133,87
02. Central Power and Light Company [Note J]	6,755,535	100%	1,400,086	1,400,08
03. CPL Transition Funding LLC (DE) [Note AA]	Uncertified	100%	-	-
02. Public Service Company of Oklahoma [Note J]	9,013,000	100%	480,225	480,22
03. Ash Creek Mining Company [Note K]	383,904	100%	3	
02. Southwestern Electric Power Company [Note J]	7,536,640	100%	689,574	689,57

Item 1. System Companies and Investment Therein As Of December 31, 2001.				
Name of Company	Number of Common Shares Owned	Voting Power	Issuer Book Value (in OOO's)	Owner's Book Value (in 000'S)
03. The Arklahoma Corporation [Note P]	238	44%	367	175
03. Southwest Arkansas Utilities Corporation [Note N]	100	N/A	10	10
03. Dolet Hills Lignite Company, LLC [Note L]	Uncertified	100%	25,910	25,910
02. West Texas Utilities Company [Note J]	5,488,560	100%	245,420	245,420
02. CSW Leasing, Inc. [Note Q]	800	80%	27,468	21,974
02. AEP Credit, Inc. [Note R]	246	100%	65,578	65,578
02. C3 Communications, Inc. [Note C]	1,000	100%	(89,664)	(89,664)
04. CSWC TeleChoice Management, Inc. [Note C]	100	100%	1	1
04. CSWC TeleChoice, Inc. [Note C]	100	100%	1	1
03. INFINITEC [Note C]	1,000	100%	162,924	162,924
02. CSW Energy Inc. [Note S]	1,000	100%	162,974	162,974
03. AEP Wind GP, LLC [Note X]	Uncertified	100%	1	1
04. Trent Wind Farm, LP [Note X]	Partnership	1%	1	1
03. AEP Wind LP, LLC [Note X]	Uncertified	100%	145	145
04. Trent Wind Farm, LP [Note X]	Partnership	99%	94	94
03. CSW Development-I, Inc. [Note S]	1,000	100%	51,815	51,815
04. Polk Power GP II, Inc. [Note S]	500	50%	145	145
05. Polk Power GP, Inc. [Note S]	1,000	100%	181	181
06. Polk Power Partners, LP [Note S]	Partnership	1%	588	588
04. CSW Mulberry II, Inc. [[Note S]	1,000	100%	26,644	26,644
05. CSW Mulberry, Inc. [Note S]	1,000	100%	28,502	28,502
04. Polk Power Partners, LP [Note S]	Partnership	46%	26,910	26,910
04. Noah I Power GP, Inc. [Note S]	1,000	100%	(1)	(1)
05. Noah I Power Partners, LP [Note S]	Partnership	1%	167	167
04. Noah I Power Partners, LP [Note S]	Partnership	95%	15,774	15,774
05. Brush Cogeneration Partners [Note S]	Partnership	50%	17,017	17,017
04. Orange Cogeneration GP II, Inc. [Note S]	500	50%	9	9
05. Orange Cogeneration G.P., Inc. [Note S]	1,000	100%	16	16
06. Orange Cogeneration Limited Partnership [Note S]	Partnership	1%	(61)	(61)
07. Orange Cogen Funding Corp. [Note S]	1,000	100%	1	1
04. CSW Orange II, Inc. [Note S]	1,000	100%	2,923	2,923
05. CSW Orange, Inc. [Note S]	1,000	100%	5,284	5,284
06. Orange Cogeneration Limited Partnership [Note S]	Partnership	50%	(3,028)	(3,028)
07. Orange Cogen Funding Corp. [Note S]	1,000	100%	N/A	N/A
03. CSW Development-II, Inc. [Note S]	1,000	100%	(3,999)	(3,999)
03. CSW Ft. Lupton, Inc. [Note S]	1,000	100%	97,640	97,640
04. Thermo Cogeneration Partnership, L.P. [Note S]	Partnership	50%	13,752	13,752
03. Newgulf Power Venture, Inc. [Note S]	1,000	100%	11,522	11,522
03. CSW Sweeny GP I, Inc. [Note S]	1,000	100%	232	232
04. CSW Sweeny GP II, Inc. [Note S]	1,000	100%	831	831
05. Sweeney Cogeneration Limited Partnership [Note S]	Partnership	1%	654	654
03. CSW Sweeny LP I, Inc. [Note S]	1,000	50%	8,925	8,925
04. CSW Sweeny LP II, Inc. [Note S]	1,000	100%	41,711	41,711
05. Sweeney Cogeneration Limited Partnership [Note S]	Partnership	49%	32,030	32,030
03. CSW Services International, Inc. [Note I]	1,000	100%	1,529	1,529
03. Diversified Energy Contractors Company, LLC [Note I]	1,000	100%	17,595	17,595
04. DECCO II LLC [Note I]	1,000	100%	-	-
05. Diversified Energy Contractors, LP [Note I]	Partnership	99%	(21)	(21)
04. Diversified Energy Contractors, LP [Note I]	Partnership	99%	(2,052)	(2,052)
04. Industry and Energy Associates, L.L.C. [Note I]	1,000	100%	1,485	1,485
03. CSW Eastex GP I, Inc. [Note S]	1,000	100%	424	424
04. CSW Eastex GP II, Inc. [Note S]	1,000	100%	427	427
05. Eastex Cogeneration Limited Partnership [Note S]	Partnership	1%	423	423
03. CSW Eastex LP I, Inc. [Note S]	1,000	100%	20,266	20,266
04. CSW Eastex LP II, Inc. [Note S]	1,000	100%	20,687	20,687
05. Eastex Cogeneration Limited Partnership [Note S]	Partnership	49%	20,721	20,721
02. CSW International, Inc. [Note H]	1,000	100%	963,364	963,364
03 CSWI Netherlands, Inc. [Note H]	N/A	100%	N/A	N/A
03. CSW International Two, Inc. [Note H]	1,000	100%	610,218	610,218
04. CSW UK Holdings [Note H]	427,275,004	100%	636,079	636,079
05. CSWI Europe Limited [Note H]	1,000	100%	28,787	28,787
06. South Coast Power Limited [Note H]	1	50%	-	-
06. Shoreham Operations Company Limited [Note H]	2	50%	-	-
05. CSW UK Finance Company [Note H]	427,275,002	90%	693,699	693,699
06. CSW Investments [Note H]	699,825,002	90%	1,100,550	1,100,550
07. SEEBOARD Group plc [Note H]	969,169	100%	1,340,850	1,340,850
08. SEEBOARD (Generation) Limited [Note H]	1,000	100%	18,031	18,031

Item 1. System Companies and Investment Therein As Of December 31, 2001.				
Name of Company	Number of Common Shares Owned	Voting Power	Issuer Book Value (in OOO's)	Owner's Book Value (in 000'S)
09. Medway Power Limited [Note H]	3,750	38%	61,354	61,354
08. SEEBOARD Natural Gas Limited [Note H]	2	100%	(1,961)	(1,961)
09. SEEBOARD Energy Gas Limited [Note H]	Uncertified	100%	-	-
08. SEEBOARD plc [Note H]	250,493,703	100%	394,051	394,051
09. Longfield Insurance Company Limited [Note H]	500,000	100%	1,234	1,234
09. Seeb Limited [Note H]	10,000	100%	23	23
09. SEEBOARD Employment Services Limited [Note H]	2	100%	970	970
09. SEEBOARD Insurance Company Limited [Note H]	1,000,000	100%	10,861	10,861
09. SEEBOARD International Limited [Note H]	500,000	100%	1,028	1,028
09. SEEBOARD Share Scheme Trustees Limited [Note L]	2	N/A	-	-
09. SEEBOARD Trading Limited [Note H]	10,000,002	100%	36,471	36,471
09. SEEPOWER Limited [Note H]	10,000	100%	2,898	2,898
10. SEEBOARD Metering Limited [Note H]	10,000	100%	(180)	(180)
10. Power Asset Development Company Limited [Note H]	50	50%	1,002	1,002
10. SEEBOARD Powerlink Limited [Note H]	800,000	80%	20,478	20,478
09. Southern Gas Limited [Note H]	500,000	100%	(11,109)	(11,109)
09. SEEBOARD Power Networks plc [Note N]	50,000	100%	306,193	306,193
09. SEEBOARD Energy Limited [Note N]	50,000	100%	75,348	75,348
09. SEEBOARD Energy Gas Limited [Note N]	6,000,000	100%	(6,463)	(6,463)
03. CSW International Three, Inc. [Note H]	1,000	100%	145	145
05. CSW Investments [Note H]	100	10%	145	145
03. CSW International, Inc. (a Cayman Island Company) [Note H]	1,000	100%	166,595	166,595
04. CSW Vale L.L.C. [Note H]	Partnership	99%	179,445	179,445
05. Caiua-Servicos de Electricidade S/A [Note H]	8,724,909	20%	-	-
05. Empresa de Electricidade Vale de Paranapanema S.A. [Note H]	21,498,445	21%	-	-
06. Caiua-Servicos de Electricidade S/A [Note H]	N/A	61%	N/A	N/A
04. CSW Power do Brazil, Ltda [Note H]	Uncertified	0%	-	-
03. CSW Vale L.L.C. [Note H]	Partnership	1%	1,813	1,813
04. CSW Power do Brazil, Ltda [Note H]	Uncertified	100%	-	-
04. Caiua-Servicos de Electricidade S/A [Note H]	N/A	20%	N/A	N/A
04. Empresa de Electricidade Vale de Paranapanema S.A. [Note H]	N/A	44%	N/A	N/A
05. Caiua-Servicos de Electricidade S/A [Note H]	N/A	20%	N/A	N/A
03. Chile Energy Holdings, L.L.C. [Note H]	N/A	90%	N/A	N/A
03. Latin American Energy Holdings, Inc. [Note H]	N/A	100%	N/A	N/A
04. Chile Energy Holdings, L.L.C. [Note H]	N/A	10%	N/A	N/A
03. CSW International Energy Development Ltd. [Note H]	Uncertified	100%	-	-
04. Tenaska CSW International Ltd. [Note H]	1,000	50%	-	-
02. EnerShop Inc. [Note I]	N/A	100%	(17,959)	(17,959)
03. Envirotherm, Inc. [Note I]	N/A	100%	N/A	N/A
02. CSW Energy Services, Inc. [Note I]	N/A	100%	(47,163)	(47,163)
03. Nuvest, L.L.C. [Note U]	N/A	93%	(18,398)	(18,398)
04. National Temporary Services, Inc. [Note U]	N/A	100%	N/A	N/A
05. Octagon, Inc. [Note U]	N/A	100%	N/A	N/A
04. Numanco, L.L.C. [Note U]	N/A	100%	N/A	N/A
05. NuSun, Inc. [Note U]	N/A	100%	N/A	N/A
06. Sun Technical Services, Inc. [Note U]	N/A	100%	N/A	N/A
06. Calibration and Testing Corporation [Note U]	N/A	100%	N/A	N/A
05. ESG Technical Services, L.L.C. [Note U]	N/A	100%	N/A	N/A
05. National Environmental Services Technology, L.L.C. [Note U]	N/A	100%	N/A	N/A
05. ESG Indonesia, L.L.C. [Note U]	N/A	100%	N/A	N/A
05. ESG, L.L.C. [Note U]	N/A	50%	N/A	N/A
05. Numanco Services, LLC	N/A	100%	N/A	N/A
02. REP Holdco, Inc. [Note W]	3,000	100%	(1,125)	(1,125)
03. Mutual Energy CPL L.P. [Note W]	Uncertified	100%	(1,494)	(1,494)
03. Mutual Energy WTU L.P. [Note W]	Uncertified	100%	(398)	(398)
03. Mutual Energy SWEPCO L.P. [Note W]	Uncertified	100%	(4)	(4)
03. REP General Partner LLC [Note W]	Uncertified	100%	5	5
04. Mutual Energy CPL L.P. [Note W]	Uncertified	1%	(1,494)	(7)
04. Mutual Energy WTU L.P. [Note W]	Uncertified	1%	(398)	(2)
04. Mutual Energy SWEPCO L.P. [Note W]	Uncertified	1%	(4)	(4)
Notes:				
A. Public utility holding company.				
B. Management, professional and technical services.				
C. Telecommunications.				
D. Broker and market energy commodities.				

Item 1. System Companies and Investment Therein As Of December 31, 2001.				
	Number of Common Shares Owned	Voting Power	Issuer Book Value (in OOO's)	Owner's Book Value (in 000'S)
Name of Company				
E. Generation.				
F. Investor in companies developing energy-related ideas, products and technologies.				
G. Distributed generation products.				
H. International energy-related investments, trading and other projects.				
I. Non-regulated energy-related services and products.				
J. Domestic electric utility.				
K. Coal mining (inactive).				
L. Coal mining (active).				
M. Coal preparation.				
N. Inactive.				
O. Subsidiary public utility holding company.				
P. Electric transmission.				
Q. Leasing.				
R. Accounts receivable factoring.				
S. Independent power.				
T. Real estate.				
U. Staff augmentation to power plants.				
V. Retail energy sales.				
W. Marketing of natural gas, electricity or energy-related products.				
X. Wind Power Generation.				
Y. Barging Services				
AA. Finance Subsidiary				
BB. Energy services including operations, supply chain, transmission and distribution				
CC. Gas pipeline and processing				
DD. Domestic energy-related investments, trading and other projects				
N/A. Information not available				

ITEM 2. ACQUISITIONS OR SALES OF UTILITY ASSETS

Name of Company	Consideration	Brief Description of Transaction	Location	Exemption
Columbus Southern Power	1,284,000	OSU Transformers and Facilities	CSP's OSU 138 KV Substation	Rule 44

ITEM 3. ISSUE, SALE, PLEDGE, GUARANTEE OR ASSUMPTION OF SYSTEM SECURITIES

Name of Issuer and Description of Issues (1)	Date and Form of Transactions (2)	Consideration (3) (in thousands)	Authorization or Exemption (4)
Appalachian Power Company:			
Floating Rate Notes, Series A, Due 2003	08/20/2001 - Public Offering	124,588	Rule 52
Indiana Michigan Power Company:			
6.125% Notes, Due December 15, 2006	12/12/2001 - Public Offering	297,656	Rule 52
Kingsport Power Company:			
6.73% Notes, Due February 15, 2004	2/16/2001 - Private Sale to Bank	20,000	Rule 52

GUARANTEE:

At December 31, 2001, American Electric Power Company, Inc. had outstanding parental guaranties of approximately $2.5 billion.

Note: We have not reported transactions previously reported on form U-6B2.

ITEM 4. ACQUISITION, REDEMPTION OR RETIREMENT OF SYSTEM SECURITIES

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
American Electric Power Service Corp:				
Mortgage Notes 9.60% Series Due 2008	AEPSC	2,000	EXT	Rule 42
Appalachian Power Company:				
First Mortgage Bonds 6.38% Series Due 2001	APCo	100,000	EXT	Rule 42
Senior Unsecured Note Payable - Variable Due 2001	APCo	75,000	EXT	Rule 42
Central Power and Light Company:				
First Mortgage Bonds 6.875% Series Due 2003	CPL	800	EXT	Rule 42
Note Payable Variable Due 2001	CPL	200,000	EXT	Rule 42
Trust Preferred Securities 8.00% Due 2037	CPL	12,250	EXT	Rule 42

ITEM 4. (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
Columbus Southern Power Company:				
Cumulative Preferred Stock				
$100 Par Value				
7.00% Series	CSPCo	5,000	EXT	Rule 42
Senior Unsecured Note Payable				
6.85% Due 2005	CSPCo	11,730	EXT	Rule 42
Junior Debentures				
8.375% Due 2025	CSPCo	2,189	EXT	Rule 42
First Mortgage Bonds				
6.10% Series Due 2003	CSPCo	14,880	EXT	Rule 42
6.55% Series Due 2004	CSPCo	23,432	EXT	Rule 42
6.60% Series Due 2003	CSPCo	14,994	EXT	Rule 42
6.75% Series Due 2004	CSPCo	23,944	EXT	Rule 42
6.80% Series Due 2003	CSPCo	31,975	EXT	Rule 42
7.15% Series Due 2002	CSPCo	13,616	EXT	Rule 42
7.25% Series Due 2002	CSPCo	42,821	EXT	Rule 42
7.45% Series Due 2024	CSPCo	31,550	EXT	Rule 42
7.60% Series Due 2024	CSPCo	30,851	EXT	Rule 42
7.90% Series Due 2023	CSPCo	10,425	EXT	Rule 42
8.40% Series Due 2022	CSPCo	15,557	EXT	Rule 42
8.70% Series Due 2022	CSPCo	34,667	EXT	Rule 42
8.40% Series Due 2022	CSPCo	12,102	EXT	Rule 42
CSW Energy:				
Senior Unsecured Note Payable				
6.875% Due 2001	CSWE	200,000	EXT	Rule 42

ITEM 4. (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
Indiana Michigan Power Company:				
First Mortgage Bonds				
7.35% Series Due 2023	I&M	5,051	EXT	Rule 42
7.63% Series Due 2001	I&M	40,000	EXT	Rule 42
Kentucky Power Company:				
First Mortgage Bonds				
8.90% Series Due 2001	KPCo	40,000	EXT	Rule 42
8.95% Series Due 2001	KPCo	20,000	EXT	Rule 42
Kingsport Power Company:				
Notes Payable				
6.75% Due 2001	KGPCo	10,000	EXT	Rule 42
Ohio Power Company:				
First Mortgage Bonds				
6.00% Series Due 2003	OPCo	12,359	EXT	Rule 42
6.15% Series Due 2023	OPCo	29,760	EXT	Rule 42
8.80% Series Due 2022	OPCo	47,146	EXT	Rule 42
6.75% Series Due 2003	OPCo	9,027	EXT	Rule 42
6.55% Series Due 2003	OPCo	4,817	EXT	Rule 42
7.75% Series Due 2023	OPCo	35,876	EXT	Rule 42
7.375% Series Due 2023	OPCo	20,934	EXT	Rule 42
7.10% Series Due 2023	OPCo	8,304	EXT	Rule 42
7.30% Series Due 2024	OPCo	12,129	EXT	Rule 42
Senior Unsecured Notes Payable Variable - Due 2001	OPCo	75,000	EXT	Rule 42
Public Service Company of Oklahoma:				
First Mortgage Bonds				
5.91% Series Due 2001	PSO	6,000	EXT	Rule 42
6.02% Series Due 2001	PSO	14,000	EXT	Rule 42

ITEM 4. (CONTINUED)

Name of Issuer and Title of Issue (1)	Name of Company Acquiring, Redeeming or Retiring Securities (2)	Consideration (3) (in thousands)	Extinguished (EXT) or Held (H) for Further Disposition (4)	Authorization or Exemption (5)
SEEBOARD:				
Yankeebonds: 7.98% Due 2001	SEE	186,817	EXT	Rule 42
Southern Ohio Coal Company:				
Notes Payable 6.20% Due 2001	SOCCo	30,000	EXT	Rule 42
Finance Obligation 6.98% Due 2001	SOCCo	12,506	EXT	Rule 42
Wheeling Power Company:				
Notes Payable 6.75% Due 2001	WPCo	10,000	EXT	Rule 42
7.5625% Due 2001	WPCo	11,000	EXT	Rule 42

Note: We have not reported transactions previously reported on form U-6B2.

ITEM 5. INVESTMENTS IN SECURITIES OF NONSYSTEM COMPANIES AS OF DECEMBER 31, 2001.

1. Aggregate amount of investments in persons operating in the retail service area of AEP or of its subsidiaries.

Name of Company (1)	Aggregate Amount of Investments in Persons (Entities), Operating in Retail Service Area of Owner (2) (in thousands)	Number of Persons (Entities) (3)	Description of Persons (Entities) (4)
APCo	$ 731	9	Industrial Development Corporations
AEPINV	1,237	1	Economic Development Company
AEPINV	100	1	Economic Development Company
WPCo	13	1	Industrial Development Corporation

2. Securities owned not included in 1 above.

Name of Company (1)	Name of Issuer (2)	Nature of Issuer's Business (3)	Description of Securities (4)	Number of Shares (5)	Percent of Voting Power (6)	Owner's Book Value (7) (in thousands)
AEPINV	Intersource Technologies, Inc.	Research & Technology Development	Common Stock Preferred Stock	800,000 95,000	9.9	-
AEPINV	EnviroTech Investment Fund I	Research & Technology Development	Limited Partner	*	9.8	2,492
AEPINV	Altra Energy Technologies, Inc.	Internet-based Energy Trading	Convertible Preferred Stock Redeemable Preferred	952,381 300,000	**	5,000 300
AEPPRO	Powerspan Corp.	Research & Technology Development	Convertible Preferred Stock	5,369,851	9.8	5,000
AEPES	IntercontinentalExchange LLC	Trading platform for Electric Utilities	Limited Liability Company	***	5.3	6,541
AEP	Integrated Communications System, Inc.	Development of Demand Side Management	Common Stock	80,000	8.4	-
AEPINV	Pantellos Corporation	Internet-based Supply Chain	Common Stock	538,935	5.0	5,289

ITEM 5. (CONTINUED)
2. Securities owned not included in ITEM 1 (Continued).

Name of Company (1)	Name of Issuer (2)	Nature of Issuer's Business (3)	Description of Securities (4)	Number of Shares (5)	Percent of Voting Power (6)	Owner's Book Value (7) (in thousands)
AEPINV	Active Power, Inc.	Research & Technology Development	Common Stock	118,843	0.3	2,906
SEEBOARD plc	Electricity Pension Trustee Limited	Trustee Company	Common Stock	20,000	4.9	29,860
SEEBOARD plc	ESN Holdings Limited	Trustee Company	Common Stock	104	4.9	155
SEEBOARD plc	ESN Holdings Limited	Trustee Company	Preference shares	50,000	N/A	74,650
PSO	AEMT, Inc	Manufacturer and sells residential surge protectors and power quality devices for industrial customers	Preferred Stock Series 1,			
			Class A Non-voting	250,000	N/A	322
			Class B Non-voting	781,250	N/A	1,506
PSO	The RIKA Companies	Engaged in the development and commercialization of computer automation technology for the electric power industry	Membership Units	217	4.0	1,918
	RIKA Management Company, LLC					
	Universal Power Products Company, LLC					
	Automated Substation Development Co, LLC					
	RC Training, LLC					

* Limited Partnership Interests
** Less than 3%
*** One-third Membership Interest

ITEM 6. OFFICERS AND DIRECTORS
PART I as of December 31, 2001

The following are the abbreviations to be used for principal business address and positions.

Principal Business Address	Code
1 Riverside Plaza Columbus, OH 43215	(a)
40 Franklin Road Roanoke, VA 24022	(b)
700 Morrison Road Gahanna, OH 43230	(c)
One Summit Square Fort Wayne, IN 46801	(d)
555 Office Center Place Gahanna, OH 43230	(e)
Dayuan Zhuan Village Pushan Town, Nanyang City People's Republic of China	(f)
Walker House P.O. Box 908GT George Town, Grand Cayman Cayman Islands	(g)
400 W. 15th Street Austin, TX 78701	(h)
1105 North Market Street Wilmington, DE 19801	(i)
600 Bourke Street Melbourne, Victoria 3000 Australia	(j)
29/30 St. James's Street, London SW1A 1HB, Great Britain	(k)
P.O. Box B Brilliant, OH 43913	(l)
301 Cleveland Ave., SW Canton, OH 44702	(m)
225 South 15th Street Philadelphia, PA 19102	(n)
222 Bayou Road Belle Chasse, LA 70037	(o)
P.O. Box 127, Convent, LA 70723	(p)
Herengracht 548 1017 CG Amsterdam The Netherlands	(q)
Suite 400, Deseret Building Salt Lake City, UT 84111	(r)
1701 Central Avenue Ashland, KY 41101	(s)
301 Virginia Street East Charleston, WV 25301	(t)
P.O. Box 75 Wheeling, WV 26003	(u)
16090 Swingley Ridge Rd.#600 Chesterfield, MO 63017	(v)
P.O. Box 468 Piketon, Ohio 45661	(w)
2600 Via Fortuna, Ste 500 Austin, TX 78746	(x)
P.O. Box 309, S. Church St. George Town, Grand Cayman Cayman Islands	(y)
Hoffsveien 1D 0275 Oslo, Norway	(z)
474 Flinders Street Melbourne, Victoria 3000 Australia	(aa)
1201 Louisiana St., Suite 1200 Houston, TX 77002	(bb)
Av Dr. Churcrizaldan, 920-8E 13 Andares, Market Place Tower 04583-404-Sao Paulo-SP-Brazil	(cc)
Level 15, 624 Bourke Street Melbourne, Victoria 3000 Australia	(dd)
Bahnstrasse 16, 40212 Dusseldorf, Germany	(ee)
50 Berkeley Street, 6th Fl. Mayfair, London W1J8AP GB	(ff)
Dr Karl Lueger-Ring 12 1010 Wien, Austria	(gg)
Alpenstrasse 12 CH-6304 Zug, Switzerland	(hh)
130 N. Main Street Butte, MT 59701	(ii)
212 E. 6th Street Tulsa, OK 74119	(jj)
539 N. Carancahua Street Corpus Christi, TX 78401	(kk)
1616 Woodall Rodgers Fwy Dallas, TX 75202	(ll)
Forest Gate, Brighton Road Crawley, West Sussex RH11 9BH Great Britain	(mm)
Torre Chapultepec Piso 13 Ruben Dario, No.281, Bosques de Chapultepec 11580 Mexico, D.F.	(pp)
Williams Tower 2, W. 2nd Street Tulsa, OK 74121	(qq)
428 Travis Street Shreveport, LA 71156	(rr)
301 Cypress Street Abilene, TX 79601	(ss)

Position	Code
Director	D
Chairman of the Board	CB
Vice Chairman of the Board	VCB
President	P
Chief Executive Officer	CEO
Chief Operating Officer	COO
Executive Vice President	EVP
Senior Vice President	SVP
Vice President	VP
Controller	C
Deputy Controller	DC
Secretary	S
Treasurer	T
Acting General Counsel	AGC
Chief Financial Officer	CFO
Chief Accounting Officer	CAO
Chief Information Officer	CIO
Chief Risk Officer	CRO
Managing Director	MD
Board of Managers	B
Delegate Manager	DM
General Manager	GM
General Counsel	GC
Assistant Controller	AC
Assistant Secretary	AS
Assistant Treasurer	AT
Assistant General Counsel	AstGC

The officer's or director's principal business address is the same as indicated in the Company heading unless another address is provided with the individual's name.

American Electric Power Company, Inc.

Name and Principal Address(a)	Position
E. R. Brooks 3919 Crescent Drive Granbury, TX 76049	D
Donald M. Carlton 8501 Mo-Pac Blvd. Austin, TX 78720	D
John P. DesBarres P.O. Box 189 Park City, UT 84060	D
E. Linn Draper, Jr.	D,CB,P,CEO
Robert W. Fri 6001 Overlea Road Bethesda, MD 20816	D
William R. Howell 6501 Legacy Drive Plano, TX 75024	D
Lester A Hudson, Jr. P.O. Box 8583 Greenville, SC 29604	D
Leonard J. Kujawa 225 Peachtree St.,NE Atlanta, GA 30303	D
James L. Powell 301 W. Beauregard San Angelo, TX 76903	D
Richard L. Sandor 111 W. Jackson Blvd., 14th FL. Chicago, IL 60604	D
Thomas V. Shockley, III	D,VCB
Donald G. Smith P.O. Box 13948 Roanoke, VA 24038	D
Linda Gillespie Stuntz 1275 Pennsylvania Ave.,NW Washington, DC 20004	D
Kathryn D. Sullivan 795 Old Oak Trace Columbus, OH 43235	D
Henry W. Fayne	VP
Susan Tomasky	VP,S,CFO
Armando A. Pena	T
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
William L. Scott	AC
Thomas G. Berkemeyer	AS
Jeffrey D. Cross	AS
Geoffrey S. Chatas	AT
Wendy G. Hargus (11)	AT

AEP Acquisition, L.L.C.

Name and Principal Address(a)	Position
Thomas V. Shockley,III	CB
Eric J. van der Walde	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Leonard V. Assante	C
Timothy A. King	S

AEP Coal, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Charles A. Ebetino,Jr.(e)	D,P
Armando A. Pena	D,VP,T
Susan Tomasky	D,VP
Timothy A. King	S

AEP Communications, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Frederick J. Boyle	VP
Holly Keller Koeppel	VP
Peter R. Thomas	VP
Jeffrey J. Tolnar	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

AEP Communications, LLC

Name and Principal Address(a)	Position
Holly Keller Koeppel	B,VP
Armando A. Pena	B,T
Susan Tomasky	B,P
Jeffrey D. Cross	S

AEP Credit, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO,P
Henry W. Fayne	D,VP
L. T. McDowell (11)	D
Armando A. Pena	D,T
Thomas V. Shockley, III	D
Susan Tomasky	D,VP
Joseph H. Vipperman	D
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP C&I Company, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,VP,T
Thomas V. Shockley,III	B,CB,P
Geoffrey S. Chatas	VP
Timothy A. King	S

AEP Delaware Investment Company

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,P,T
Mark A. Pyle (a)	D
Joseph M. Buonaiuto (a)	C

AEP Delaware Investment Company II

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,P,T
Mark A. Pyle (a)	D
Joseph M. Buonaiuto(a)	C

AEP Delaware Investment Company III

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,P,T
Mark A. Pyle (a)	D
Joseph M. Buonaiuto(a)	C

AEP Elmwood LLC

Name and Principal Address(o)	Position
Steven A. Appelt (a)	B,VP
Dwayne L. Hart (a)	B,VP
Armando A. Pena (a)	B,T
Douglas K. Penrod (a)	B,VP
Eric J. van der Walde(a)	B,P
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

AEP EmTech, LLC

Name and Principal Address(a)	Position
Henry W. Fayne	B
Thomas V. Shockley,III	B
Susan Tomasky	B
John D. Harper	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Thomas L. Jones	VP
Holly Keller Koeppel	VP
John H. Provanzana	VP
Timothy A. King	S
Armando A. Pena	T

AEP Energy Services Gas Holding Company

Name and Principal Address(i)	Position
E. Linn Draper, Jr.(a)	D,CB,CEO
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,P
Susan Tomasky (a)	D
Eric J. van der Walde (a)	D,VP
Geoffrey S. Chatas (a)	VP
Jeffrey D. Cross (a)	VP
Dwayne L. Hart (a)	VP
Joseph M. Buonaiuto (a)	C
Thomas S. Ashford (a)	S

AEP Energy Services Gas Holding Company II

Name and Principal Address(a)	Position
None	

AEP Energy Services GmbH

Name and Principal Address(ee)	Position
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD,T
Thomas V. Shockley,III(a)	MD

AEP Energy Services Investments, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Joseph M. Buonaiuto (a)	C

AEP Energy Services Limited

Name and Principal Address(ff)	Position
Geoffrey S. Chatas (a)	D
Jeffrey D. Cross (a)	D
John Whitehead	D
Henry D. Jones	MD
Armando A. Pena (a)	T
Linda M. Pszon	S

AEP Energy Servies Norway AS

Name and Prinipal Address(z)	Position
Thor Lien	D

AEP Energy Services Trading Limited

Name and Principal Address(ff)	Position
Henry D. Jones	D
John Whitehead	D
Linda M. Pszon	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Energy Services UK Generation Limited

Name and Principal Address(ff)	Position
Geoffrey S. Chatas (a)	D
Jeffrey D. Cross (a)	D
Henry D. Jones	D
Armando A. Pena (a)	D,T
John Whitehead	D
Linda M. Pszon	S

AEP Energy Services (Austria) GmbH

Name and Principal Address(gg)	Position
Paul D. Addis (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD,T

AEP Energy Services (Switzerland) GmbH

Name and Principal Address(hh)	Position
Paul D. Addis (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD,T

AEP Energy Services Ventures, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Joseph M. Buonaiuto (a)	C

AEP Energy Services Ventures II, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Joseph M. Buonaiuto (a)	C

AEP Energy Services Ventures III, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Joseph M. Buonaiuto (a)	C

AEP Energy Services, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,P
Susan Tomasky	D,VP
Eric J. van der Walde	D,EVP
Steven A. Appelt	EVP
Dwayne L. Hart	SVP
Henry D. Jones (ff)	SVP
Andrew W. Patterson	SVP
William C. Reed, II	SVP
George Rooney	SVP
David A. Banks	VP
Thomas A. Barry	VP
Robert W. DeLarm	VP
David B. Dunn	VP
Paul S. Mason	VP
Kevin McGowan	VP
Lylwyn T. Michals (bb)	VP
Glenn Riepl	VP
Donald M. Norman	VP
P. M. O'Brien	VP
Douglas K. Penrod	VP
Brent A. Price	VP
Richard R. Snowdon	VP
Brian X. Tierney	VP
Gregory E. Wolfe Koin Cntr, 222 SW Columbia St. Suite 1550, Portland, OR 97201	VP
Charles E. Zebula	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

AEP Fiber Venture, LLC

Name and Principal Address(a)	Position
Holly Keller Koeppel	B,VP
Armando A. Pena	B,VP,T
Susan Tomasky	B,P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Timothy A. King	S

AEP Funding Limited

Name and Principal Address(g)	Position
Jeffrey D. Cross (a)	D,S
Armando A. Pena (a)	D,T

AEP Gas Marketing LP

Name and Principal Address(bb)	Position
Thomas V. Shockley,III(a)	P
Steven A. Appelt (a)	VP
Geoffrey S. Chatas (a)	VP
Jeffrey D. Cross (a)	VP
Edward D. Gottlob	VP
Dwayne L. Hart (a)	VP
Armando A. Pena (a)	VP,T
Eric J. van der Walde (a)	VP
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

AEP Gas Power GP, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,T
Thomas V. Shockley,III	B,CB,P
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Gas Power Systems, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B
Charles C. Cooper 430 Telser Road Lake Zurich, IL 60047-1588	B
Daniel O. Dickinson 430 Telser Road Lake Zurich, IL 60047-1588	B
Mark W. Marano	B,P,CEO
John F. Norris, Jr.	B
Armando A. Pena	T
Timothy A. King	S

AEP Generating Company

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Armando A. Pena	D,VP,T
Robert P. Powers	D
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Joseph H. Vipperman	D,VP
John F. Norris, Jr.	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

AEP Indian Mesa GP, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Dwayne L. Hart	B,VP
Armando A. Pena	B,VP,T
Thomas V. Shockley,III	B,CB,P
Geoffrey S. Chatas	VP
Timothy A. King	S

AEP Indian Mesa LP, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Dwayne L. Hart	B,VP
Armando A. Pena	B,VP,T
Thomas V. Shockley,III	B,CB,P
Geoffrey S. Chatas	VP
Timothy A. King	S

AEP Investments, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Frederick J. Boyle	VP
Holly Keller Koeppel	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

AEP Kentucky Coal, L.L.C.

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Charles A. Ebetino,Jr. (e)	B,P
Armando A. Pena	B,VP,T
Susan Tomasky	VP
Timothy A. King	S

AEP MEMCo LLC

Name and Principal Address(v)	Position
Steven A. Appelt (a)	B,VP
Dwayne L. Hart (a)	B,VP
Armando A. Pena (a)	B,T
Douglas K. Penrod (a)	B,VP
Eric J. van der Walde(a)	B,P
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

AEP Ohio Coal, L.L.C.

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Charles A. Ebetino, Jr.	B,P
Armando A. Pena	B,VP,T
Susan Tomasky	VP
Timothy A. King	S

AEP Ohio Commercial & Industrial Retail Company, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,VP,T
Thomas V. Shockley,III	B,CB,P
Geoffrey S. Chatas	VP
Timothy A. King	S

AEP Ohio Retail Energy, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP,S
Armando A. Pena	B,T
Thomas V. Shockley,III	B,CB,P

AEP Power Marketing, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Susan Tomasky	D,VP
Thomas V. Shockley,III	P
Joseph M. Buonaiuto	C,CAO
Thomas S. Ashford	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Pro Serv, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
John F. Norris, Jr.	D
Armando A. Pena	D,VP,T
Robert P. Powers	D,VP
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
John R. Jones	P
V. A. Lepore	SVP
L. E. Dillahunty (11)	VP
Mark A. Gray	VP
James A. Howard	VP
Dennis A. Lantzy	VP
John A. Mazzone	VP
J. K. McWilliams	VP
Martin L. Mearhoff	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

AEP Resource Services, LLC

Name and Principal Address(a)	Position
Frederick J. Boyle	B,VP
Armando A. Pena	P,T
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Timothy A. King	S

AEP Resources, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	SVP
Frederick J. Boyle	VP
Henry D. Jones (ff)	VP
Holly Keller Koeppel	VP
James H. Sweeney 155 West Nationwide Blvd. Columbus, OH 43215	VP
Christopher Wilson (k)	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

AEP Resources Australia Holdings Pty Ltd

Name and Principal Address(j)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Frederick J. Boyle (a)	D
Holly Keller Koeppel (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Jeffrey D. Cross (a)	S
Simon Lucas (dd)	S

AEP Resources Australia Pty., Ltd.

Name and Principal Address(j)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Jeffrey D. Cross (a)	D,S
Armando A. Pena (a)	D
Timothy A. King (a)	S

AEP Resources do Brasil Ltda.

Name and Principal Address(cc)	Position
Hercules Celescuekci	DM

AEP Resources CitiPower I Pty Ltd

Name and Principal Address(j)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Frederick J. Boyle (a)	D
Holly Keller Koeppel (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Jeffrey D. Cross (a)	S
Simon Lucas (dd)	S

AEP Resources CitiPower II Pty Ltd

Name and Principal Address(j)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Frederick J. Boyle (a)	D
Holly Keller Koeppel (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Jeffrey D. Cross (a)	S
Simon Lucas (dd)	S

AEP Resources International, Limited

Name and Principal Address(g)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T,CFO
David Mustine (c)	SVP
Jeffrey D. Cross (a)	VP,GC
John R. Jones (a)	VP
Dennis A. Lantzy (a)	VP
Leonard V. Assante(a)	C,CAO

AEP Resources Limited

Name and Principal Address(k)	Position
Jeffrey D. Cross (a)	D,S
Armando A. Pena (a)	D,T
Christopher Wilson	MD

AEP Resources Project Management Company, Ltd.

Name and Principal Address(g)	Position
Jeffrey D. Cross (a)	D
Armando A. Pena (a)	D,T
Walkers SPV Limited	S

AEP Retail Energy, LLC

Name and Principal Address(a)	Position
Henry W. Fayne	B,VP
Susan Tomasky	B,S
Armando A. Pena	T

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

AEP Texas Commercial & Industrial Retail GP, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,T
Thomas V. Shockley,III	B,CB,P
Timothy A. King	S

AEP Texas Commercial & Industrial Retail Limited Partnership

Name and Principal Address(h)	Position
Thomas V. Shockley,III(a)	P
Steven A. Appelt (a)	VP
Geoffrey S. Chatas (a)	VP
Jeffrey D. Cross (a)	VP
Andrew W. Patterson (a)	VP
Armando A. Pena (a)	VP,T
George Rooney (a)	VP
Timothy A. King (a)	S

AEP Texas POLR, LLC

Name and Principal Address(a)	Position
Steven A. Appelt	B,VP
Jeffrey D. Cross	B,VP
Armando A. Pena	B,T
Thomas V. Shockley,III	B,CB,P
Timothy A. King	S

AEP Texas POLR GP, LLC

Name and Principal Address(h)	Position
Steven A. Appelt (a)	B,VP
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,T
Thomas V. Shockley,III(a)	B,CB,P
Timothy A. King (a)	S

AEP T&D Services, LLC

Name and Principal Address(a)	Position
Jeffrey D. Cross	B,VP
Glenn M. Files (c)	B,VP
David Mustine (c)	B,VP
Armando A. Pena	B,T
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	B,VP
Timothy A. King	S

AEP West Virginia Coal, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Charles A. Ebetino,Jr.(e)	D,P
Armando A. Pena	D,VP,T
Susan Tomasky	D,VP
Timothy A. King	S

AEP Wind GP, LLC

Name and Principal Address(a)	Position
Thomas V. Shockley,III	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Dwayne L. Hart	VP
Armando A. Pena	VP,T
Timothy A. King	S

AEP Wind LP, LLC

Name and Principal Address(a)	Position
Thomas V. Shockley,III	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Dwayne L. Hart	VP
Armando A. Pena	VP,T
Timothy A. King	S

AEPR Global Holland Holding B.V.

Name and Principal Address(g)	Position
AEP Resources, Inc. (a)	MD
Geoffrey S. Chatas (a)	MD
Jeffrey D. Cross (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD
John Whitehead (ff)	MD
John David Young (ff)	MD

AEPR Global Investments B.V.

Name and Principal Address(g)	Position
Geoffrey S. Chatas (a)	MD
Jeffrey D. Cross (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD
John Whitehead (ff)	MD
Christopher Wilson (k)	MD

AEPR Global Ventures B.V.

Name and Principal Address(g)	Position
Geoffrey S. Chatas (a)	MD
Jeffrey D. Cross (a)	MD
Henry D. Jones (ff)	MD
Armando A. Pena (a)	MD
John Whitehead (ff)	MD
Christopher Wilson (k)	MD

American Electric Power Service Corporation

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,P,CEO
Henry W. Fayne	D,EVP
Robert P. Powers	D,EVP
Thomas V. Shockley, III	D,VCB,COO
Susan Tomasky	D,EVP,GC,AS
Joseph H. Vipperman	D,EVP
Melinda S. Ackerman	SVP
Nicholas J. Ashooh	SVP
J. C. Baker	SVP
A. Christopher Bakken,III One Cook Place Bridgman, MI 49106	SVP
Joseph M. Buonaiuto	SVP,C,CAO
Jeffrey D. Cross	SVP,AGC,AS
Thomas M. Hagan	SVP
Dale E. Heydlauff	SVP
Michael F. Moore	SVP,CIO
R. E. Munczinski	SVP
John F. Norris, Jr.	SVP
Armando A. Pena	SVP,T
Leonard V. Assante	VP,DC
Edward J. Brady	VP
Bruce H. Braine	VP

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

(Continued)
American Electric Power Service Corporation

Name and Principal Address(a)	Position
Robert T. Burns (ll)	VP
Geoffrey S. Chatas	VP,AS
W. N. D'Onofrio	VP
Diane M. Fitzgerald 1367 Silverbrook Lane St.Joseph, MI 49085	VP
Joseph Hamrock (c)	VP
Jane A. Harf 88 East Broad Street, Ste 800 Columbus, OH 43215	VP
Wendy G. Hargus (ll)	VP,AT
John D. Harper	VP
Timothy G. Harshbarger	VP
Thomas S. Jobes	VP
Anthony P. Kavanagh 801 Pennsylvania Ave. Washington, DC 20004	VP
Michael D. Martin	VP
Martin L. Mearhoff	VP
Mark W. Menezes 801 Pennsylvania Ave. Washington, DC 20004	VP
D. Michael Miller	VP
Richard A. Mueller	VP
Charles R. Patton 400 West 15th Street Ste 1500 Austin, TX 78701	VP
Gary M. Prescott	VP
H. E. Rhodes (c)	VP
Daniel J. Rogier	VP
William L. Scott	VP
O. J. Sever	VP
William L. Sigmon, Jr.	VP
Scott N. Smith	VP,CRO
Stuart Solomon	VP
Mark A. Welch	VP
Mark G. Zardus	VP
Waldo Zerger 221 North Front Street Columbus, OH 43215	VP
Thomas S. Ashford	S
Thomas G. Berkemeyer	AS,AstGC

American Fiber Touch, LLC

Name and Principal Address(ii)	Position
Perry J. Cole	B
Holly Keller Koeppel (a)	B
Michael J. Meldahl	B

Appalachian Power Company

Name and Principal Address(b)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
R. D. Carson, Jr. 1051 East Cary Street, 7th Fl. Richmond, VA 23219	VP
Mark E. Dempsey (t)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr.(a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford(a)	S

Ash Creek Mining Company

Name and Principal Address(jj)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford(a)	S

Australia's Energy Partnership

Name and Principal Address(j)	Position
Armando A. Pena (a)	T

Blackhawk Coal Company

Name and Principal Address(r)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford(a)	S

C3 Communications, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,P
Frederick J. Boyle	VP
Holly Keller Koeppel	VP
Peter R. Thomas	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

C3 Networks & Communications Limited Partnership

Name and Principal Address(x)	Position
Susan Tomasky (a)	P
Geoffrey S. Chatas (a)	VP
Jeffrey D. Cross (a)	VP
Holly Keller Koeppel (a)	VP
Armando A. Pena (a)	VP,T
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

C3 Networks GP, L.L.C.

Name and Principal Address(x)	Position
Jeffrey D. Cross (a)	B,VP
Holly Keller Koeppel (a)	B,VP
Armando A. Pena (a)	B,VP,T
Susan Tomasky (a)	B,P
Geoffrey S. Chatas (a)	VP
Timothy A. King (a)	S

C3 Networks Limited Partnership

Name and Principal Address(x)	Position
Susan Tomasky (a)	P
Geoffrey S. Chatas (a)	VP
Jeffrey D. Cross (a)	VP
Holly Keller Koeppel (a)	VP
Armando A. Pena (a)	VP,T
Timothy A. King (a)	S

Cardinal Operating Company

Name and Principal Address(l)	Position
Anthony J. Ahern 6677 Busch Blvd. Columbus, OH 43226	D
J. C. Baker (a)	D
Richard K. Byrne 6677 Busch Blvd. Columbus, OH 43226	D,VP
E. Linn Draper, Jr. (a)	D,P
Henry W. Fayne (a)	D,VP
John R. Jones (a)	D,VP
Ralph E. Luffler P.O. Box 250 Lancaster, OH 43130-0250	D,VP
Steven K. Nelson P.O. Box 280 Coshocton, OH 43812	D,VP
John F. Norris, Jr. (a)	D,VP
Michael L. Sims 3888 Stillwell Beckett Rd. Oxford, OH 45056	D
Joseph M. Buonaiuto (a)	C
Armando A. Pena (a)	T
Thomas S. Ashford (a)	S

Cedar Coal Co.

Name and Principal Address(b)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford(a)	S

Central and South West Corporation

Name and Principal Address(ll)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO,P
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,T
Robert P. Powers (a)	D
Thomas V. Shockley,III(a)	D,VCB,COO
Susan Tomasky (a)	D
Joseph H. Vipperman (a)	D
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Central Appalachian Coal Company

Name and Principal Address(b)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Central Coal Company

Name and Principal Address(b)	Position
E. Linn Draper, Jr.(a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Central Power and Light Company

Name and Principal Address(kk)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
Julio C. Reyes (h)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Chile Energy Holdings, L.L.C.

Name and Principal Address(y)	Position
Jeffrey D. Cross (a)	D,VP
Dwayne L. Hart (a)	D,P
Armando A. Pena (a)	D,VP
Susan Tomasky (a)	D
Geoffrey S. Chatas (a)	VP
Sandra S. Bennett (a)	C
Wendy G. Hargus (ll)	T
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CitiPower Pty

Name and Principal Address(dd)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Frederick J. Boyle (a)	D
Michael Codd, AC	D
Jeffrey D. Cross (a)	D,S
Brian Healey	D
Holly Keller Koeppel (a)	D
John Marshall	D
Armando A. Pena (a)	D,T
Simon Lucas	S

CitiPower Trust
Principal Address (j)

NONE

Colomet, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,P,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,VP
Susan Tomasky	D,VP
Joseph H. Vipperman	D,VP
Glenn M. Files (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

Columbus Southern Power Company

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,P
Armando A. Pena	D,VP,T
Robert P. Powers	D,VP
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Joseph H. Vipperman	D,VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
Floyd W. Nickerson 88 East Broad Street, Ste 800 Columbus, OH 43215	VP
John F. Norris, Jr.	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

Conesville Coal Preparation Company

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley,III	D,VP
Susan Tomasky	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

Conlease, Inc.

Name and Principal Address (p)	
Steven A. Appelt (a)	D
Dwayne L. Hart (a)	D,VP
Armando A. Pena (a)	D,VP,T
Douglas K. Penrod (a)	D,VP
Eric J. van der Walde(a)	D,P
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

CSW Development-3, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Development-II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Development-I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Eastex GP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Eastex GP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW Eastex LP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Eastex LP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Energy Services, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel	D,P
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D
Joseph M. Buonaiuto	C,CAO
Thomas S. Ashford	S

CSW Energy, Inc.

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,P
Susan Tomasky	D,VP
Dwayne L. Hart	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

CSW Frontera GP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Frontera GP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Frontera LP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Frontera LP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Ft. Lupton, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW International Three, Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Joseph M. Buonaiuto	C

CSW International Two, Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Joseph M. Buonaiuto	C

CSW International (U.K.), Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Joseph M. Buonaiuto	C

CSW International, Inc.(a Delaware Corp.)

Name and Principal Address(a)	Position
E. Linn Draper, Jr.	D,CB,CEO
Henry W. Fayne	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley, III	D,P
Susan Tomasky	D,VP
Dwayne L. Hart	VP
Joseph M. Buonaiuto	C,CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW International, Inc. (a Cayman Corp.)

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Susan Tomasky	D
Geoffrey S. Chatas	VP
Sandra S. Bennett	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Investments

Name and Principal Address (mm)	Position
H. Cadoux-Hudson	D
E. Linn Draper, Jr. (a)	D
T. J. Ellis	D
M. J. Pavia	D
Armando A. Pena (a)	D
Thomas V. Shockley, III (a)	D
Susan Tomasky (a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW Leasing, Inc.

Name and Principal Address (a)	Position
E. Linn Draper, Jr.	D, CB
Henry W. Fayne	D, P
Thomas V. Shockley, III	D, VP
Susan Tomasky	D, VP
Nikita Zdanow 1211 Ave. Of the Americas New York, NY 10036	D
Kenneth Brown (11)	SVP
Jeffrey Knittle (11)	SVP
Jean Stein (11)	SVP
Joseph H. Vipperman	VP
Joseph M. Buonaiuto	C, CAO
Leonard V. Assante	DC
Thomas S. Ashford	S
Armando A. Pena	T

CSW Mulberry II, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Mulberry, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Nevada, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Northwest GP, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Northwest LP, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Orange II, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Orange, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

CSW Power Marketing, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSW Services International, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Sandra S. Bennett	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

CSW Sweeny GP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

CSW Sweeny GP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

CSW Sweeny LP II, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

CSW Sweeny LP I, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

CSW UK Finance Company

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
E. Linn Draper,Jr.(a)	D
T. J. Ellis	D,CB
M. J. Pavia	D,CFO
Armando A. Pena (a)	D,T
Thomas V. Shockley,III(a)	D
Susan Tomasky (a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW UK Holdings

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
E. Linn Draper,Jr.(a)	D
T. J. Ellis	D,CB
M. J. Pavia	D,CFO
Armando A. Pena (a)	D,T
Thomas V. Shockley,III(a)	D
Susan Tomasky (a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW UK Investments Limited

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
E. Linn Draper, Jr.(a)	D
T. J. Ellis	D
M. J. Pavia	D
Armando A. Pena (a)	D
Thomas V. Shockley,III(a)	D
Susan Tomasky (a)	D
J. Weight	D
Christopher Wilson (k)	D
Jeffrey D. Cross (a)	S

CSW Vale L.L.C.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Susan Tomasky	D
Geoffrey S. Chatas	VP
Sandra S. Bennett	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

CSWC Southwest Holdings, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley,III	D
Susan Tomasky	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Joseph M. Buonaiuto	C
Timothy A. King	S

CSWC TeleChoice Management, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley,III	D
Susan Tomasky	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Joseph M. Buonaiuto	C
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

CSWC TeleChoice, Inc.

Name and Principal Address(a)	Position
Holly Keller Koeppel	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley,III	D
Susan Tomasky	P
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Joseph M. Buonaiuto	C
Timothy A. King	S

CSWI Europe Limited

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
Heny D. Jones (ff)	D
Timothy A. King (a)	S

CSWI Netherlands, Inc.

Name and Principal Address(a)	Position
Geoffrey S. Chatas	D,VP
Jeffrey D. Cross	D,VP
Timothy A. King	D,S
Armando A. Pena	D,P,T
Mark A. Pyle	D
Joseph M. Buonaiuto	C

DECCO II, LLC

Name and Principal Address(a)	Position
John R. Jones	CEO
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Joseph M. Buonaiuto	C
Timothy A. King	S

Diversified Energy Contractors Company, LLC

Name and Principal Address(a)	Position
John R. Jones	CEO
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
James A. Howard	VP
John A. Mazzone	VP
Armando A. Pena	VP,T
Joseph M. Buonaiuto	C
Timothy A. King	S

Dolet Hills Lignite Company, LLC

Name and Principal Address(rr)	Position
Jeffrey D. Cross (a)	B,VP
E. Linn Draper, Jr. (a)	B,CB,CEO
Armando A. Pena (a)	B,VP,T
Thomas V. Shockley,III(a)	B
Charles A. Ebetino,Jr.(e)	P,COO
Thomas S. Ashford (a)	S

Energia de Mexicali, S de R.L.de C.V.

Name and Principal Address(pp)	Position
Jeffrey D. Cross (a)	B
Armando A. Pena (a)	B
James H. Sweeney 155 West Nationwide Blvd. Columbus, OH 43215	B

EnerShop Inc.

Name and Principal Address(a)	Position
Steven A. Appelt	D,VP
Jeffrey D. Cross	D,VP
Armando A. Pena	D,VP,T
Thomas V. Shockley,III	D,CB,P
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S

Envirotherm, Inc.

Name and Principal Address(ll)	Position
Steven A. Appelt (a)	D,VP
Jeffrey D. Cross (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,CB,P
Geoffrey S. Chatas (a)	VP
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Franklin Real Estate Company

Name and Principal Address(n)	Position
E. Linn Draper, Jr. (a)	D,CEO,P
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Houston Pipe Line Company LP

Name and Principal Address(bb)	Position
Thomas V. Shockley,III(a)	P
Steven A. Appelt (a)	VP
Geoffrey S. Chatas (a)	VP
Jeffrey D. Cross (a)	VP
Edward D. Gottlob	VP
Dwayne L. Hart (a)	VP
Armando A. Pena (a)	VP,T
Eric J. van der Walde (a)	VP
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

HPL GP, LLC

Name and Principal Address(a)	Position
Geoffrey S. Chatas	B,VP
Jeffrey D. Cross	B,VP
Dwayne L. Hart	B,VP
Armando A. Pena	B,VP,T
Eric J. van der Walde	B
Thomas V. Shockley,III	P
Steven A. Appelt	VP
Joseph M. Buonaiuto	C
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

HPL Holdings, Inc.

Name and Principal Address(i)	Position
Sean Breiner	D
Geoffrey S. Chatas (a)	D,VP
Jeffrey D. Cross (a)	D,VP
David W. Dupert	D
Timothy A. King (a)	D,S
Armando A. Pena (a)	D,VP,T
Mark A. Pyle (a)	D
Thomas V. Shockley,III(a)	P
Dwayne L. Hart (a)	VP
Joseph M. Buonaiuto (a)	C

HPL Resources Company LP

Name and Principal Address(bb)	Position
Thomas V. Shockley,III(a)	P
Steven A. Appelt (a)	VP
Geoffrey S. Chatas (a)	VP
Jeffrey D. Cross (a)	VP
Edward D. Gottlob	VP
Dwayne L. Hart (a)	VP
Armando A. Pena (a)	VP,T
Eric J. van der Walde (a)	VP
Joseph M. Buonaiuto (a)	C
Timothy A. King (a)	S

Indiana-Kentucky Electric Corporation

Name and Principal Address(w)	Position
E. Linn Draper, Jr. (a)	D,P
Arthur R. Garfield 76 South Main Street Akron, OH 44308	D
Andrew E. Goebel 20 NW Fourth Street Evansville, IN 47741	D
Ronald G. Jochum 20 NW Fourth Street Evansville, IN 47741	D
Michael P. Morrell 10435 Downsville Pike Hagerstown, MD 21740	D
John R. Sampson 101 W. Ohio Street, Ste 1320 Indianapolis, IN 46204	D
David L. Hart (a)	VP
David E. Jones	VP
Armando A. Pena (a)	VP
John D. Brodt	S,T

Indiana Franklin Realty, Inc.

Name and Principal Address(d)	Position
E. Linn Draper, Jr. (a)	D,CEO,P
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Indiana Michigan Power Company

Name and Principal Address(d)	Position
Karl G. Boyd	D
E. Linn Draper, Jr. (a)	D,CB,CEO
John E. Ehler 3514 Landin Rd. New Haven, IN 46774	D
Henry W. Fayne (a)	D,P
David L. Lahrman	D
Marc E. Lewis	D
Susanne M. Moorman	D
Robert P. Powers (a)	D,VP
John R. Sampson 101 W. Ohio Street, Ste 1320 Indianapolis, IN 46204	D,VP
Thomas V. Shockley,III(a)	D,VP
D. B. Synowiec 2791 N. U.S. Highway 231 Rockport, IN 47635	D
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
A. Christopher Bakken III One Cook Place Bridgman, MI 49106	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
Armando A. Pena (a)	VP,T
Michael W. Rencheck 500 Circle Drive Buchanan, MI 49107	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Industry and Energy Associates,L.L.C.

Name and Principal Address(a)	Position
John R. Jones	CEO
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Armando A. Pena	VP,T
Kenneth B. Rogers 9 Donald B. Dean Drive South Portland, ME 04106	VP
Leonard V. Assante	C
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Jefferson Island Storage & Hub L.L.C.

Name and Principal Address (bb)	Position
Jeffrey D. Cross (a)	B,VP
Dwayne L. Hart (a)	B
Armando A. Pena (a)	B,VP,T
Thomas V. Shockley,III (a)	B,CB
Eric J. van der Walde (a)	B,P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

Kentucky Power Company

Name and Principal Address (s)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III (a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
T. C. Mosher 101 Enterprise Drive Frankfort, KY 40601	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Kingsport Power Company

Name and Principal Address (b)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III (a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
R. D. Carson, Jr. 1051 East Cary Street, 7th Fl. Richmond, VA 23219	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Latin American Energy Holdings, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

LIG Chemical Company

Name and Principal Address (bb)	Position
Jeffrey D. Cross (a)	D,VP
Dwayne L. Hart (a)	D
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III (a)	D,CB
Eric J. van der Walde (a)	D,P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

LIG Liquids Company, L.L.C.

Name and Principal Address (bb)	Position
Jeffrey D. Cross (a)	B,VP
Dwayne L. Hart (a)	B
Armando A. Pena (a)	B,VP,T
Thomas V. Shockley,III (a)	B,CB
Eric J. van der Walde (a)	B,P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

LIG Pipeline Company

Name and Principal Address (bb)	Position
Jeffrey D. Cross (a)	D,VP
Dwayne L. Hart (a)	D
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III (a)	D,CB
Eric J. van der Walde (a)	D,P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

LIG, Inc.

Name and Principal Address (bb)	Position
Jeffrey D. Cross (a)	D,VP
Dwayne L. Hart (a)	D
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III (a)	D,CB
Eric J. van der Walde (a)	D,P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Louisiana Intrastate Gas Company, L.L.C.

Name and Principal Address(bb)	Position
Jeffrey D. Cross (a)	B,VP
Dwayne L. Hart (a)	B
Armando A. Pena (a)	B,VP,T
Thomas V. Shockley,III(a)	B,CB
Eric J. van der Walde(a)	B,P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

Marregon Pty Limited

Name and Principal Address(j)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Frederick J. Boyle (a)	D
Jeffrey D. Cross (a)	D,S
Holly Keller Koeppel (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Simon Lucas (dd)	S

Marregon (No. 2) Pty Limited

Name and Principal Address(j)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Frederick J. Boyle (a)	D
Jeffrey D. Cross (a)	D,S
Holly Keller Koeppel (a)	D
John Marshall (dd)	D
Armando A. Pena (a)	D,T
Simon Lucas (dd)	S

Mulberry Holdings, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

Mutual Energy L.L.C.

Name and Principal Address(a)	Position
Thomas V. Shockley,III	CB,P
Steven A. Appelt	VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Timothy A. King	S
Armando A. Pena	T

Mutual Energy Service Company, LLC

Name and Principal Address(a)	Position
Thomas V. Shockley,III	CB,P
Steven A. Appelt	VP
Geoffrey S. Chatas	VP
Jeffrey D. Cross	VP
Timothy A. King	S
Armando A. Pena	T

Nanyang General Light Electric Co., Ltd.

Name and Principal Address(f)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Donald M. Clements,Jr.(a)	D,CB
Jeffrey D. Cross (a)	D,S
Bernard Hu 2648 Durfee Ave., #B El Monte, CA 91732	D
Dennis A. Lantzy (a)	D
Armando A. Pena (a)	D
Lu Ming Tao	D
Xu Xinglong	D,VCB
Hao Zhengshan	D

Newgulf Power Venture, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

NGLE Pushan Power, LDC

Name and Principal Address(g)	Position
Jeffrey D. Cross (a)	D
Armando A. Pena (a)	D,VP,T
Walkers SPV Limited	S

Noah I Power GP, Inc.

Name and Principal Address(a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Geoffrey S. Chatas	VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (ll)	T

Ohio Power Company

Name and Principal Address(m)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
Floyd W. Nickerson 88 East Broad Street, Ste 800 Columbus, OH 43215	VP
John F. Norris, Jr.(a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Ohio Valley Electric Corporation

Name and Principal Address (w)	Position
David C. Benson 4350 Northern Pike Monroeville, PA 15146	D
H. Peter Burg 76 South Main Street Akron, OH 44308	D
E. Linn Draper, Jr. (a)	D,P
Henry W. Fayne (a)	D
Arthur R. Garfield 76 South Main Street Akron, OH 44308	D
Andrew E. Goebel 20 NW Fourth Street Evansville, IN 47741	D
Michael P. Morrell 10435 Downsville Pike Hagerstown, MD 21740	D
Alan J. Noia 10435 Downsville Pike Hagerstown, MD 21740	D
Guy L. Pipitone 76 South Main Street Akron, OH 44308	D
John C. Procario 139 East Fourth Street Cincinnati, OH 45202	D
H. Ted Santo 1065 Woodman Drive Dayton, OH 45432	D
Thomas V. Shockley, III (a)	D
A. Roger Smith 220 West Main Street Louisville, KY 40202	D
Paul W. Thompson 220 West Main Street Louisville, KY 40202	D
David L. Hart (a)	VP
David E. Jones	VP
Armando A. Pena (a)	VP
John D. Brodt	S,T

Operaciones Azteca VIII, S. de R.L. de C.V.

Name and Principal Address (pp)	Position
Frederick J. Boyle (a)	D
Philip Cantner Two Alhambra Plaza, Suite 1100 Coral Gables, FL 33134	D
James H. Sweeney 155 West Nationwide Blvd. Columbus, OH 43215	D
J. Christopher Terajewicz One Bowdoin Square Boston, MA 02114	D
Robert H. Warburton One Bowdoin Square Boston, MA 02114	D
Jorge Young Two Alhambra Plaza, Ste 1100 Coral Gables, FL 33134	D
Carlos de Maria y Campos Segura Torre Optima Av. Paseo de las Palmas #405, 3rd Fl., Lomas de Chapultepec 11000 Mexico, D.F.	S

Orange Cogen Funding Corp.

Name and Principal Address (a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,P
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
Timothy A. King	S

Orange Cogeneration GP II, Inc.

Name and Principal Address (a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,CEO
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,P
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
David L. Siddall 1001 Louisiana Street Houston, TX 77002	S

Orange Cogeneration GP, Inc.

Name and Principal Address (a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,CEO
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,P
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
David L. Siddall 1001 Louisiana Street Houston, TX 77002	S

Orange Holdings, Inc.

Name and Principal Address (a)	Position
Jeffrey D. Cross	D,VP
Dwayne L. Hart	D,P
Armando A. Pena	D,VP
Joseph M. Buonaiuto	C
Timothy A. King	S
Wendy G. Hargus (11)	T

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Pacific Hydro Limited

Name and Principal Address(aa)	Position
Donald E. Boyd Level 31, Aurora Plc.,88 Phillip St. Sydney/NSW 2000 Australia	D
Kingsley G. Culley	D,CB
Peter L. Downie	D
Michael C. Fitzpatrick	D
Jeffrey Harding	D
John L. C. McInnes	D
Philip van der Riet	D
Peter F. Westaway	D
Matthew G. C. Williams	D
Anthony G. Evans	S

Polk Power GP II, Inc.

Name and Principal Address(a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,P
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,CEO
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
Timothy A. King	S

Polk Power GP, Inc.

Name and Principal Address(a)	Position
Joseph H. Emberger	D
Dwayne L. Hart	D,P
Larry Kellerman 1001 Louisiana Street Houston, TX 77002	D,CEO
John O'Rourke 1001 Louisiana Street Houston, TX 77002	D
A. Wade Smith	GM
Timothy A. King	S

POLR Power, L.P.

Name and Principal Address(h)	Position
Thomas V. Shockley,III(a)	P
Steven A. Appelt (a)	VP
Jeffrey D. Cross (a)	VP
Timothy A. King (a)	S
Armando A. Pena (a)	T

Price River Coal Company, Inc.

Name and Principal Address(d)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Charles A. Ebetino,Jr.(e)	P,COO
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Public Service Company of Oklahoma

Name and Principal Address(jj)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
T. D. Churchwell 1601 N.W. Expressway,Ste 1400 Oklahoma City, OK 73118	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

REP General Partner L.L.C.

Name and Principal Address(h)	Position
Steven A. Appelt (a)	B,VP
Jeffrey D. Cross (a)	B,VP
Armando A. Pena (a)	B,VP,T
Thomas V. Shockley,III(a)	B,P
Timothy A. King (a)	S

REP Holdco Inc.

Name and Principal Address(gg)	Position
Steven A. Appelt (a)	D,VP
Jeffrey D. Cross (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,CB,P
Timothy A. King (a)	S

SEEBOARD Group plc

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
E. Linn Draper,Jr.(a)	D
T. J. Ellis	D
M. J. Pavia	D
Armando A. Pena (a)	D
Thomas V. Shockley,III(a)	D
J. Weight	D
Christopher Wilson (k)	D

SEEBOARD plc

Name and Principal Address(mm)	Position
H. Cadoux-Hudson	D
T. J. Ellis	D
M. J. Pavia	D
J. Weight	D
M. A. Nagle	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

Servicios Azteca VIII, S.de R.L. de C.V.

Name and Principal Address (pp)	Position
Frederick J. Boyle (a)	D
Philip Cantner Two Alhambra Plaza, Ste 1100 Coral Gables, FL 33134	D
John H. Foster Two Alhambra Plaza, Ste 1100 Coral Gables, FL 33134	D, CB
Carlos Riva One Bowdoin Square Boston, MA 02114	D
James H. Sweeney 155 West Nationwide Blvd. Columbus, OH 43215	D
Enrique Tabora Two Alhambra Plaza, Ste 1100 Coral Gables, FL 33134	D
Carlos de Maria y Campos Segura Torre Optima Av. Paseo de las Palmas #405 3rd Fl., Lomas de Chapultepec 11000 Mexico	S

Shoreham Operations Company Limited

Name and Principal Address (mm)	Position
Joseph H. Emberger (a)	D
E. S. Golland	D
Jeffrey D. Lafleur (ff)	D
C. D. MacKendrick	S

Simco Inc.

Name and Principal Address (a)	Position
E. Linn Draper, Jr.	D, CB, CEO
Henry W. Fayne	D, VP
Armando A. Pena	D, VP, T
Thomas V. Shockley, III	D, VP
Susan Tomasky	D, VP
Charles A. Ebetino, Jr. (e)	P, COO
Joseph M. Buonaiuto	C, CAO
Leonard V. Assante	DC
Thomas S. Ashford	S

Snowcap Coal Company, Inc.

Name and Principal Address (a)	Position
David M. Cohen	D, VP
Charles A. Ebetino, Jr. (e)	D, P
Scott H. Finch	D, T
Michael. R. Rankin	D, S
John W. Seidensticker	D, VP

South Coast Power Limited

Name and Principal Address (mm)	Position
E. S. Golland	D
Henry D. Jones (ff)	D
B. J. McNaught	D

Southern Appalachian Coal Company

Name and Principal Address (b)	Position
E. Linn Draper, Jr. (a)	D, CB, CEO
Henry W. Fayne (a)	D, VP
Armando A. Pena (a)	D, VP, T
Thomas V. Shockley, III (a)	D, VP
Susan Tomasky (a)	D, VP
Charles A. Ebetino, Jr. (e)	P, COO
Joseph M. Buonaiuto (a)	C, CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Southwestern Electric Power Company

Name and Principal Address (rr)	Position
E. Linn Draper, Jr. (a)	D, CB, CEO
Henry W. Fayne (a)	D, P
Armando A. Pena (a)	D, VP, T
Robert P. Powers (a)	D, VP
Thomas V. Shockley, III (a)	D, VP
Susan Tomasky (a)	D, VP
Joseph H. Vipperman (a)	D, VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
Michael H. Madison	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
Julio C. Reyes (h)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Joseph M. Buonaiuto (a)	C, CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Southwestern Electric Wholesale Company

Name and Principal Address (a)	Position
Jeffrey D. Cross	D, VP
Dwayne L. Hart	D, P
Armando A. Pena	D, VP
Geoffrey S. Chatas	VP
Leonard V. Assante	C
Timothy A. King	S

Tuscaloosa Pipeline Company

Name and Principal Address (bb)	Position
Jeffrey D. Cross (a)	D, VP
Dwayne L. Hart (a)	D
Armando A. Pena (a)	D, VP, T
Thomas V. Shockley, III (a)	D, CB
Eric J. van der Walde (a)	D, P
Geoffrey S. Chatas (a)	VP
Leonard V. Assante (a)	C
Timothy A. King (a)	S

Ventures Lease Co., LLC

Name and Principal Address (a)	Position
Jeffrey D. Cross	B, VP
Armando A. Pena	B, P, T
Geoffrey S. Chatas	VP
Timothy A. King	S

ITEM 6. OFFICERS AND DIRECTORS
PART I (Continued)

West Texas Utilities Company

Name and Principal Address(ss)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr. (a)	VP
Julio C. Reyes (h)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, Ohio 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

West Virginia Power Company

Name and Principal Address(t)	Position
E. Linn Draper, Jr. (a)	D,CEO
Henry W. Fayne (a)	D,VP
Armando A. Pena (a)	D,VP,T
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
John F. Norris, Jr. (a)	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

Wheeling Power Company

Name and Principal Address(u)	Position
E. Linn Draper, Jr. (a)	D,CB,CEO
Henry W. Fayne (a)	D,P
Armando A. Pena (a)	D,VP,T
Robert P. Powers (a)	D,VP
Thomas V. Shockley,III(a)	D,VP
Susan Tomasky (a)	D,VP
Joseph H. Vipperman (a)	D,VP
Mark E. Dempsey (t)	VP
Glenn M. Files (c)	VP
Michelle S. Kalnas (c)	VP
David Mustine (c)	VP
John F. Norris, Jr.(a)	VP
M. P. Ryan (c)	VP
Richard P. Verret 825 Tech Center Drive Gahanna, OH 43230	VP
Joseph M. Buonaiuto (a)	C,CAO
Leonard V. Assante (a)	DC
Thomas S. Ashford (a)	S

ITEM 6. (CONTINUED)

Part II. Each officer and director with a financial connection within the provisions of Section 17(c) of the Act are as follows:

Name of Officer or Director (1)	Name and Location of Financial Institution (2)	Position Held in Financial Institution (3)	Applicable Exemption Rule (4)
David W. Dupert	Provident Bank of Maryland Investment Co. Baltimore, MD	Director	70(d)
	State Bank of Long Island Financial Services Corp. Long Island, N.Y.	Director	70(d)
	State Bank of Long Island Portfolio Management Corp. Long Island, N.Y.	Director	70(d)
	Central Pennsylvania Investment Company Parent Co: Omega Financial Corp. State College, PA	Director	70(d)
	Minatola National Bank Vineland, NJ	Director	70(d)
	Lincoln Investment Company Vineland, NJ	Director	70(d)
William R. Howell	Bankers Trust New York, N.Y.	Director	70(b)
L.A. Hudson, Jr.	American National Bankshares, Inc. Danville, Virginia	Director	70(a)
	American National Bank & Trust Co. Danville, Virginia	Director	70(a)
W.J. Lhota	Huntington Bancshares, Inc. Columbus, Ohio	Director	70(c)
James L. Powell	First National Bank of Mertzon Mertzon, Texas	Advisory Director	70(a)
M.P. Ryan	Firstar Columbus, Ohio	Advisory Director	70(f)
Richard L. Sandor	Bear, Stearns Financial Products, Inc. Chicago, Illinois	Director	70(b)
	Bear, Stearns Trading Risk Management Inc. Chicago, Illinois	Director	70(b)
Lu Ming Tao	City Commerical Bank of Nanyang Nanyang City Province, China	Vice Chairman	70(c)
A. E. Goebel	Old National Bank Evansville, IN	Director	70(c)

ITEM 6. (continued)

Part III. The disclosures made in the System companies' most recent proxy statement and annual report on Form 10-K with respect to items (a) through (f) follow:

(a) COMPENSATION OF DIRECTORS AND EXECUTIVE OFFICERS

Executive Compensation

THE FOLLOWING TABLE shows for 2001, 2000 and 1999 the compensation earned by the chief executive officer, the four other most highly compensated executive officers (as defined by regulations of the Securities and Exchange Commission) of AEP at December 31, 2001 and Mr. Lhota who resigned as an executive officer on December 12, 2001.

Summary Compensation Table

		Annual Compensation		Long-Term Compensation		
				Awards	Payouts	
Name	Year	Salary ($)	Bonus ($)(1)	Securities Underlying Options (#)	LTIP Payouts($)(1)	All Other Compensation ($)(2)
E. Linn Draper, Jr.	2001	910,000	682,090	-0-	311,253	122,395
	2000	850,000	485,775	700,000	-0-	106,699
	1999	820,000	208,280	-0-	-0-	103,218
Thomas V. Shockley, III (3)	2001	590,000	353,788	-0-	79,781	100,678
	2000	304,417	140,500	250,000	824,399	9,170,069
Henry W. Fayne	2001	420,000	305,861	-0-	83,697	75,576
	2000	365,000	152,972	200,000	-0-	47,074
	1999	315,000	56,007	-0-	-0-	34,885
Susan Tomasky (4)	2001	410,000	300,365	-0-	54,455	73,483
	2000	355,000	148,780	200,000	-0-	47,946
William J. Lhota (5)	2001	435,000	239,250	-0-	106,271	2,165,742
	2000	415,000	173,927	200,000	-0-	62,394
	1999	400,000	71,120	-0-	-0-	55,690
Joseph H. Vipperman	2001	370,000	203,378	-0-	87,692	82,209
	2000	350,000	146,685	200,000	-0-	70,112
	1999	330,000	58,674	-0-	-0-	63,006

Notes to Summary Compensation Table

(1) Amounts in the *Bonus* column reflect awards under the Senior Officer Annual Incentive Compensation Plan (SOIP), except for Mr. Shockley as disclosed in footnote 3, and, in the case of Mr. Fayne and Ms. Tomasky, lump sum payments of $75,000 each in 2001 in lieu of immediate salary increases in connection with their promotions during the year. Payments pursuant to the SOIP are made in the first quarter of the succeeding fiscal year for performance in the year indicated.

Amounts in the *Long-Term Compensation — Payouts* column reflect performance share unit targets earned under the AEP 2000 Long-Term Incentive Plan for three-year performance periods, except for Mr. Shockley as disclosed in footnote 3. See below under *Long-Term Incentive Plans — Awards in 2001* for additional information.

(2) Amounts in the *All Other Compensation* column, except for the additional compensation to Messrs. Shockley and Lhota as disclosed in footnotes (3) and (5), respectively, include (i) AEP's matching contributions under the AEP Retirement Savings Plan and the AEP Supplemental Savings Plan, a non-qualified plan designed to supplement the AEP Savings Plan, (ii) subsidiary companies director fees, (iii) vehicle allowance, and (iv) split-dollar insurance. Split-dollar insurance represents the present value of the interest projected to accrue for the employee's benefit on the current year's insurance premium paid by AEP. Cumulative net life insurance premiums paid are recovered by AEP at the later of retirement or 15 years. Detail of the 2001 amounts in the *All Other Compensation* column is shown below.

Item	Dr. Draper	Mr. Shockley	Mr. Fayne	Ms. Tomasky	Mr. Lhota	Mr. Vipperman
Savings Plan Matching Contributions	$ 5,119	$ 7,650	$ 5,775	$ 5,825	$ 7,650	$ 6,950
Supplemental Savings Plan Matching Contributions	35,831	18,876	20,009	19,320	19,752	16,301
Subsidiaries Directors Fees	16,550	14,650	16,300	16,300	13,450	10,450
Vehicle Allowance	14,400	12,000	12,000	12,000	12,000	12,000
Split-Dollar Insurance	50,495	47,502	21,492	20,038	24,055	36,508

(3) Mr. Shockley joined AEP from Central and South West Corporation and became an executive officer when the merger with CSW was consummated on June 15, 2000. The *Salary* column for Mr. Shockley shows the amount earned for his AEP service after the date of the merger. The amounts in the *Bonus* and *LTIP Payouts* columns for 2000 represent his prorated payment under the CSW Annual Incentive Plan and the value of Common Stock awarded under the CSW 1992 Long-Term Incentive Plan, respectively. He also received a payment of $9,154,924 under his change in control agreement with CSW that is included in the *All Other Compensation* column.

(4) No 1999 compensation information is reported for Ms. Tomasky because she was not an executive officer in this year.

(5) Mr. Lhota resigned from his executive positions with AEP on December 12, 2001, and left active employment on December 31, 2001. He is receiving severance of $2,022,750, equal to three times base salary and annual incentive at target, with $1,152,750 paid upon his termination of active employment and the remainder as a continuation of his annual salary of $435,000 through December 2003. As a result, Mr. Lhota retains his eligibility for the upcoming two-year period under AEP's savings and retirement plans. Mr. Lhota also received a lump sum payment of accrued vacation pay of $66,085.

Compensation of Directors

Annual Retainers and Meeting Fees. Directors who are officers of AEP or employees of any of its subsidiaries do not receive any compensation, other than their regular salaries and the accident insurance coverage described below, for attending meetings of AEP's Board of Directors. The other members of the Board receive an annual retainer of $35,000 for their services, an additional annual retainer of $5,000 for each Committee that they chair, a fee of $1,200 for each meeting of the Board and of any Committee that they attend (except a meeting of the Executive Committee held on the same day as a Board meeting), and a fee of $1,200 per day for any inspection trip or conference.

Deferred Compensation and Stock Plan. The Deferred Compensation and Stock Plan for Non-Employee Directors permits non-employee directors to choose to receive up to 100 percent of their annual Board retainer in shares of AEP Common Stock and/or units that are equivalent in value to shares of Common Stock ("Stock Units"), deferring receipt by the non-employee director until termination of service or for a period that results in payment commencing not later than five years thereafter. AEP Common Stock is distributed and/or Stock Units are credited to directors, as the case may be, when the retainer is payable, and are based on the closing price of the Common Stock on the payment date. Amounts equivalent to cash dividends on the Stock Units accrue as additional Stock Units. Payment of Stock Units to a director from deferrals of the retainer and dividend credits is made in cash or AEP Common Stock, or a combination of both, as elected by the director.

Stock Unit Accumulation Plan. The Stock Unit Accumulation Plan for Non-Employee Directors annually awards 1,200 Stock Units to each non-employee director as of the first day of the month in which the non-employee director becomes a member of the Board. Amounts equivalent to cash dividends on the Stock Units accrue as additional Stock Units. Stock Units are paid to the director in cash upon termination of service unless the director has elected to defer payment for a period that results in payment commencing not later than five years thereafter.

Insurance. AEP maintains a group 24-hour accident insurance policy to provide a $1,000,000 accidental death benefit for each director. The current policy, effective September 1, 2001 through September 1, 2004, has a premium of $31,050. In addition, AEP pays each director (excluding officers of AEP or employees of any of its subsidiaries) an amount to provide for the federal and state income taxes incurred in connection with the maintenance of this coverage ($630 for 2001).

Central and South West Corporation Programs. Mr. Powell, as a former CSW director, is enrolled in a medical and dental program formerly offered by CSW to its non-employee directors. AEP is continuing this program, pursuant to the terms of the merger with CSW, for those CSW directors who had previously elected to participate. Mr. Powell pays a portion of the cost of his coverage. Upon Mr. Powell's termination of service with the Board, he will be eligible to receive retiree medical and dental benefits coverage.

(b) OWNERSHIP OF SECURITIES

THE FOLLOWING TABLE sets forth the beneficial ownership of AEP Common Stock and stock-based units as of January 1, 2002 for all directors as of the date of this proxy statement, all nominees to the Board of Directors, each of the persons named in the Summary Compensation Table and all directors and executive officers as a group. Unless otherwise noted, each person had sole voting and investment power over the number of shares of Common Stock and stock-based units of AEP set forth across from his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares	Note Reference	Stock Units(a)	Options Exercisable Within 60 Days	Total
E. R. Brooks	64,150	(b)	1,607	65,105	130,862
D. M. Carlton	6,431		1,607	—	8,038
J. P. DesBarres	5,000	(c)	2,733	—	7,733
E. L. Draper, Jr.	4,941	(b)(c)	119,218	233,333	357,492
H. W. Fayne	6,019	(b)(d)	13,735	66,666	86,420
R. W. Fri	2,000		3,458	—	5,458
W. R. Howell	1,692		2,174	—	3,866
L. A. Hudson, Jr.	1,853	(e)	5,571	—	7,424
L. J. Kujawa	1,328	(e)	5,892	—	7,220
W. J. Lhota	20,141	(b)(c)	17,117	66,666	103,924
J. L. Powell	4,020		1,891	—	5,911
R. L. Sandor	1,092		1,891	—	2,983
T. V. Shockley, III	44,372	(b)(d)(e)	—	94,450	138,822
D. G. Smith	2,500		3,896	—	6,396
L. G. Stuntz	1,500	(c)	5,938	—	7,438
K. D. Sullivan	—		4,991	—	4,991
S. Tomasky	656	(b)	4,329	66,666	71,651
J. H. Vipperman	11,377	(b)(c)	7,201	66,666	85,244
All directors, nominees and executive officers as a group (19 persons)	264,739	(d)(f)	204,458	680,385	1,149,582

Notes on Stock Ownership

(a) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.

(b) Includes the following numbers of share equivalents held in the AEP Retirement Savings Plan and, for Messrs. Brooks and Shockley, the CSW Retirement Savings Plan: Mr. Brooks, 44,145; Dr. Draper, 4,280; Mr. Fayne, 5,412; Mr. Lhota, 17,961; Mr. Shockley, 6,579; Ms. Tomasky, 656; Mr. Vipperman, 10,498; and all directors and executive officers, 89,967.

(c) Includes the following numbers of shares held in joint tenancy with a family member: Mr. DesBarres, 5,000; Dr. Draper, 661; Mr. Lhota, 2,180; Ms. Stuntz, 300; and Mr. Vipperman, 80.

(d) Does not include, for Messrs. Fayne and Shockley, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Fayne and Shockley share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares.

(e) Includes the following numbers of shares held by family members over which beneficial ownership is disclaimed: Dr. Hudson, 750; Mr. Kujawa, 28; and Mr. Shockley, 496.

(f) Represents less than 1% of the total number of shares outstanding.

(c) CONTRACTS AND TRANSACTIONS WITH SYSTEM COMPANIES

None

(d) INDEBTEDNESS TO SYSTEM COMPANIES

None

(e) PARTICIPATION IN BONUS AND PROFIT SHARING ARRANGEMENTS AND OTHER BENEFITS

Long-Term Incentive Plans - Awards In 2001

Each of the awards set forth below establishes performance share unit targets, which represent units equivalent to shares of Common Stock, pursuant to the Company's 2000 Long-Term Incentive Plan. Since it is not possible to predict future dividends and the price of AEP Common Stock, credits of performance share units in amounts equal to the dividends that would have been paid if the performance share unit targets were established in the form of shares of Common Stock are not included in the table.

The ability to earn performance share unit targets is tied to achieving specified levels of total shareholder return ("TSR") relative to the S&P Electric Utility Index. The Human Resources Committee may, at its discretion, reduce the number of performance share unit targets otherwise earned. In accordance with the performance goals established for the periods set forth below, the threshold, target and maximum awards are equal to 20%, 100% and 200%, respectively, of the performance share unit targets. No payment will be made for performance below the threshold.

Payments of earned awards are deferred in the form of phantom stock units (equivalent to shares of

AEP Common Stock) until the officer has met the equivalent stock ownership target discussed in the Human Resources Committee Report. Once officers meet and maintain their respective targets, they may elect either to continue to defer or to receive further earned awards in cash and/or Common Stock.

Name	Number of Performance Share Units	Performance Period Until Maturation or Payout	Estimated Future Payouts of Performance Share Units Under Non-Stock Price-Based Plan Threshold (#)	Target (#)	Maximum (#)
E. L. Draper, Jr.	14,919	2001-2003	2,984	14,919	29,838
T.V. Shockley, III	7,738	2001-2003	1,548	7,738	15,476
H. W. Fayne	5,049	2001-2003	1,010	5,049	10,098
S. Tomasky	4,929	2001-2003	986	4,929	9,858
W. J. Lhota	5,230	2001-2003	1,046	5,230	10,460
J.H.Vipperman	4,448	2001-2003	890	4,448	8,896

Retirement Benefits

The American Electric Power System Retirement Plan provides pensions for all employees of AEP System companies (except for employees covered by certain collective bargaining agreements or by the Central and South West Corporation Cash Balance Retirement Plan or certain other employees), including the executive officers of AEP. The Retirement Plan is a noncontributory defined benefit plan.

The Retirement Plan was amended effective January 1, 2001. The amendment provided that the final average pay benefit accrual formula will terminate on December 31, 2010 and, effective January 1, 2001, a cash balance accrual formula was added to the Retirement Plan. Employees participating in the Retirement Plan on December 31, 2000 accrue retirement benefits under both formulas and employees hired after December 31, 2000 accrue retirement benefits solely under the cash balance formula. Employees accruing benefits under both formulas may choose either the final average pay formula or the cash balance formula for their accrued benefit at the time employment is terminated. The accrued benefit earned by an employee under the final average pay formula as of December 31, 2010, the date the final average pay formula will be discontinued, is the minimum benefit an employee can receive from the Retirement Plan after that time.

The following table shows the approximate annual annuities that would be payable to employees in certain higher salary classifications under the final average pay formula, assuming retirement at December 31, 2001 after various periods of service and with benefits commencing at age 65.

Pension Plan Table

Highest Average Annual Earnings	Years of Accredited Service					
	15	20	25	30	35	40
$ 400,000	$93,210	$124,280	$155,350	$186,420	$ 217,490	$ 244,090
500,000	117,210	156,280	195,350	234,420	273,490	306,740
600,000	141,210	188,280	235,350	282,420	329,490	369,390
700,000	165,210	220,280	275,350	330,420	385,490	432,040
1,000,000	237,210	316,280	395,350	474,420	553,490	619,990
1,200,000	285,210	380,280	475,350	570,420	665,490	745,290
2,000,000	447,210	636,280	795,350	954,420	1,113,490	1,246,490

The amounts shown in the table are the straight life annuities payable under the Retirement Plan final average pay formula without reduction for the joint and survivor annuity. Retirement benefits listed in the table are not subject to any deduction for Social Security or other offset amounts. The retirement annuity is reduced 3% per year in the case of a termination of employment and commencement of benefits between ages 55 and 62. If an employee terminates employment and commences benefits at or after age 62, there is no reduction in the retirement annuity.

Compensation upon which retirement benefits under the final average pay formula are based, for the executive officers named in the Summary Compensation Table above consists of the average of the 36 consecutive months of the officer's highest aggregate salary and Senior Officer Annual Incentive Compensation Plan awards, shown in the *Salary and Bonus* columns, respectively, of the Summary Compensation Table, out of the officer's most recent 10 years of service.

Under the cash balance formula each employee has an account to which dollar amount credits are allocated annually based on a percentage of the employee's compensation. Compensation for the cash balance formula includes annual salary and annual incentive compensation plan awards up to a maximum total compensation of $1,000,000. The applicable percentage is determined by age and years of service with AEP as of December 31 of each year (or as of the employee's termination date, if earlier). The following table shows the percentage used to determine dollar amount credits at the age and years of service indicated:

Sum of Age Plus Years of Service	Applicable Percentage
<30	3.0%
30-39	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

To transition from the final average pay formula to the cash balance formula, the employee's account under the cash balance formula was credited with an opening balance using a number of factors.

The estimated annual annuities at age 65 under the cash balance formula payable to the executive officers named in the Summary Compensation Table (except for Mr. Shockley who participates in the Central and South West Corporation retirement plan discussed below) are:

Name	Annual Benefit
E. L. Draper, Jr.	$685,000
H. W. Fayne	254,000
S. Tomasky	280,000
W. J. Lhota	343,000
J.H. Vipperman	305,000

These amounts are based on the following assumptions:

- Salary amounts shown in the *Salary* column for calendar year 2001 are used with no subsequent adjustments in future years plus annual incentive awards at the 2001 target level.
- Conversion of the lump-sum cash balance to a single life annuity at age 65, based on an interest rate of 5.12% and the 1983 Group Annuity Mortality Table.

AEP maintains a supplemental retirement plan which provides for the payment of:

- Retirement benefits that are not payable due to limitations imposed by Federal tax law on benefits paid by qualified plans.
- Supplemental retirement benefits provided by individual agreements with certain AEP employees.

The supplemental retirement plan provides for supplemental benefits under both the final average pay and cash balance formulas. Retirement Plan benefits shown above include all supplemental retirement benefits.

Dr. Draper and Ms. Tomasky have individual agreements with AEP which provide them with supplemental retirement benefits that credit them with years of service in addition to their years of service with AEP as follows: Dr. Draper, 24 years; and Ms. Tomasky, 20 years. The agreements each provide that these supplemental retirement benefits are reduced by pension entitlements from plans sponsored by prior employers.

As of December 31, 2001, for the executive officers named in the Summary Compensation Table (except for Mr. Shockley as discussed in the following two paragraphs), the number of years of service applicable for retirement benefit calculation purposes under either the final average pay formula or the cash balance formula were as follows: Dr. Draper, 33 years; Mr. Fayne, 26 years; Ms. Tomasky, 23 years; Mr. Lhota, 36 years; and Mr. Vipperman, 39 years. The years of service for Dr. Draper and Ms. Tomasky include years of service provided by their respective agreements with AEP described in the preceding paragraph.

Under the terms of the merger agreement between AEP and Central and South West Corporation, the CSW Cash Balance Retirement Plan continues as a separate plan through at least July 1, 2002, for those AEP System employees who were participants in the CSW Cash Balance Plan as of December 31, 2000. Employees of CSW who had attained age 50 and completed 10 years of service with a CSW company as of July 1, 1997, accrue retirement benefits under the CSW Cash Balance Plan under both the final average pay and cash balance formulas. Employees accruing benefits under both formulas may choose the benefit accrued under either formula at the time employment is terminated.

As an employee of CSW before the merger, Mr. Shockley participates in the CSW Cash Balance Plan. Under the CSW Plan, at age 65 the estimated annual annuities payable to Mr. Shockley under the final average pay and cash balance formulas are $201,000 and $216,000, respectively. Mr. Shockley's estimated annual annuity under (i) the final average pay formula is computed as of January 1, 2002 and (ii) the cash balance formula is based on the same assumptions described above for the AEP cash balance formula. Mr. Shockley has an agreement with CSW entered into prior to the merger under which he is entitled to supplemental retirement benefits that credit him with (i) 30 years of service if he remains employed with AEP until age 60 or thereafter and (ii) up to four years of additional service if he retires prior to age 60.

Four AEP System employees (including Messrs. Fayne, Lhota and Vipperman) whose pensions may be adversely affected by amendments to the Retirement Plan made as a result of the Tax Reform Act of 1986 are eligible for certain supplemental retirement benefits. Such payments, if any, will be equal to any reduction occurring because of such amendments. Assuming retirement in 2002 of the executive officers named in the Summary Compensation Table, only Mr. Vipperman would be affected and his annual supplemental benefit would be $4,000.

AEP made available a voluntary deferred-compensation program in 1982 and 1986, which permitted certain members of AEP System management to defer receipt of a portion of their salaries. Under this program, a participant was able to defer up to 10% annually over a four-year period of his or her salary, and receive supplemental retirement or survivor benefit payments over a 15-year period. The amount of supplemental retirement payments received is dependent upon the amount deferred, age at the time the deferral election was made, and number of years until the participant retires. The following table sets forth, for the executive officers named in the Summary Compensation Table, the amounts of annual deferrals and, assuming retirement at age 65, annual supplemental retirement payments under the 1982 and 1986 programs.

	1982 Program	
Name	Annual Amount Deferred (4-Year Period)	Annual Amount of Supplemental Retirement Payment (15-Year Period)
J. H. Vipperman......................	$ 11,000	$ 90,750

	1986 Program	
Name	Annual Amount Deferred (4-Year Period)	Annual Amount of Supplemental Retirement Payment (15-Year Period)
H. W. Fayne............................	$ 9,000	$ 95,400
J. H. Vipperman......................	10,000	67,500

Severance Plan

In connection with the merger with Central and South West Corporation, AEP's Board of Directors adopted a severance plan on February 24, 1999, effective March 1, 1999, that includes Messrs. Fayne and Vipperman and Ms. Tomasky. The severance plan provides for payments and other benefits if, at any time before June 15, 2002 (the second anniversary of the merger consummation date), the officer's employment is terminated (i) by AEP without "cause" or (ii) by the officer because of a detrimental change in responsibilities or a reduction in salary or benefits. Under the severance plan, the officer will receive:

- A lump sum payment equal to three times the officer's annual base salary plus target annual incentive under the Senior Officer Annual Incentive Compensation Plan.
- Maintenance for a period of three additional years of all medical and dental insurance benefits substantially similar to those benefits to which the officer was entitled immediately prior to termination, reduced to the extent comparable benefits are otherwise received.
- Outplacement services not to exceed a cost of $30,000 or use of an office and secretarial services for up to one year.

AEP's obligation for the payments and benefits under the severance plan is subject to the waiver by the officer of any other severance benefits that may be provided by AEP. In addition, the officer agrees to refrain from the disclosure of confidential information relating to AEP.

Change-In-Control Agreements

AEP has change-in-control agreements with Dr. Draper, Messrs. Shockley, Fayne and

Vipperman and Ms. Tomasky. If there is a "change-in-control" of AEP and the employee's employment is terminated by AEP or by the employee for reasons substantially similar to those in the severance plan, these agreements provide for substantially the same payments and benefits as the severance plan with the following additions:

- Three years of service credited for purposes of determining non-qualified retirement benefits, with such credited service proportionately reduced to zero if termination occurs between ages 62 and 65.
- Payment, if required, to make the employee whole for any excise tax imposed by Section 4999 of the Internal Revenue Code.

"Change-in-control" means:

- The acquisition by any person of the beneficial ownership of securities representing 25% or more of AEP's voting stock.
- A change in the composition of a majority of the Board of Directors under certain circumstances within any two-year period.
- Approval by the shareholders of the liquidation of AEP, disposition of all or substantially all of the assets of AEP or, under certain circumstances, a merger of AEP with another corporation.

(f) RIGHTS TO INDEMNITY

THE DIRECTORS and officers of AEP and its subsidiaries are insured, subject to certain exclusions, against losses resulting from any claim or claims made against them while acting in their capacities as directors and officers. The American Electric Power System companies are also insured, subject to certain exclusions and deductibles, to the extent that they have indemnified their directors and officers for any such losses. Such insurance, effective January 1, 2002 through December 31, 2002, is provided by: Associated Electric & Gas Insurance Services, Energy Insurance Mutual, Clarendon National Insurance Company, Great American Insurance Company, Zurich American Insurance Company, Zurich Specialties London (UK) Ltd., National Union Fire Insurance Company of Pittsburgh, PA, Liberty Mutual Insurance Company, Federal Insurance Company, Starr Excess International, Royal Insurance Company of America, Gulf Insurance Company, Starr Excess Casualty Insurance Limited, Oil Casualty Insurance Limited, XL Insurance, Ltd., XL Specialty Insurance Company, SR International Business Insurance Company Ltd., and Lumbermens Mutual Casualty Company. The total cost of this insurance is $2,690,766.

Fiduciary liability insurance provides coverage for AEP System companies, their directors and officers, and any employee deemed to be a fiduciary or trustee, for breach of fiduciary responsibility, obligation, or duties as imposed under the Employee Retirement Income Security Act of 1974. This coverage, provided by Associated Electric & Gas Insurance Services, The Federal Insurance Company, and Zurich American Insurance Company, was renewed, effective July 1, 2000 through June 30, 2003, for a cost of $355,350.

ITEM 7. CONTRIBUTIONS AND PUBLIC RELATIONS

Expenditures, disbursements or payments during the year, in money, goods or services directly or indirectly to or for the account of:

(1) Any political party, candidate for public office or holder of such office, or any committee or agent thereof.
- NONE

(2) Any citizens group or public relations counsel.

Calendar Year 2001

Name of Company and Name or Number of Recipients or Beneficiaries	Purpose	Accounts Charged, if any, Per Books of Disbursing Company	Amounts (in thousands)

NONE

ITEM 8. SERVICE, SALES AND CONSTRUCTION CONTRACTS

Part I. Contracts for services, including engineering or construction services, or goods supplied or sold between System companies are as follows:

Calendar Year 2001

Nature of Transactions (1)	Company Performing Service (2)	Company Receiving Service (3)	Compensation (4) (in thousands)	Date of Contract (5)	In Effect On Dec. 31st (Yes or No) (6)
Communication Services	CECom	CPL	$ 197	1/01/99	Yes
Project and Administrative Suc.	APCo	CECom	(9)	3/01/01	Yes
Machine Shop Services	APCo	System Operating Companies	11,084	1/01/79	Yes
Racine Hydro Service	APCo	OPCo	32	6/01/78	Yes
Simulator Training Services	APCo	System Operating Companies	1,123	12/12/87	Yes
Communications Services	AEPCLLC	APCo	2,925	3/04/98	Yes
Communications Services	AEPCLLC	KPCo	160	11/18/97	Yes
Communications Services	AEPCLLC	I&M	1,800	10/24/98	Yes
Communications Services	AEPCLLC	WPCo	5		
Communications Services	AEPCLLC	OPCo	2,201	2/12/98	Yes
Communications Services	AEPCLLC	CSPCo	1,123	2/12/98	Yes
Project & Administrative Svc.	KGPCo	AEPCLLC	172	6/01/99	Yes
Project & Administrative Svc.	APCo	AEPCLLC	2,664	3/04/98	Yes
Project & Administrative Svc.	KPCo	AEPCLLC	139	11/18/97	Yes
Project & Administrative Svc.	I&M	AEPCLLC	517	10/24/98	Yes
Project & Administration Svc.	OPCo	AEPCLLC	196	2/12/98	Yes
Project & Administrative Svc.	WPCo	AEPCLLC	57	10/24/98	Yes
Project & Administrative Svc.	CSPCo	AEPCLLC	(3)	02/12/98	Yes
Barging Transportation	I&M	System Operating Companies	30,226	5/01/86	Yes
A/R Factoring	AEP CREDIT	APCo	5,218	6/16/00	Yes
A/R Factoring	AEP CREDIT	CPL	14,573	6/16/00	Yes
A/R Factoring	AEP CREDIT	CSPCo	15,201	6/16/00	Yes
A/R Factoring	AEP CREDIT	I&M	8,458	6/16/00	Yes
A/R Factoring	AEP CREDIT	KGPCo	645	6/16/00	Yes
A/R Factoring	AEP CREDIT	KPCo	2,651	6/16/00	Yes
A/R Factoring	AEP CREDIT	OPCo	12,844	6/16/00	Yes
A/R Factoring	AEP CREDIT	PSO	9,573	6/16/00	Yes
A/R Factoring	AEP CREDIT	SWEPCo	7,366	6/16/00	Yes
A/R Factoring	AEP CREDIT	WTU	3,753	6/16/00	Yes
Coal Mine Shutdown Costs	BHCCo	I&M	(79)	1/01/82	No
Coal Mine Shutdown Costs	CeCCo	APCo	4,184	12/01/76	No
Coal Mine Shutdown Costs	CACCo	APCo	260	9/14/83	No
Coal	CCPC	CSPCo	10,821	11/05/84	Yes
Coal	COCCo	OPCo	11,428	4/01/83	No

ITEM 8. (CONTINUED)

Coal Mine Shutdown Costs	SACCo	APCo	(135)	3/01/78	No
Coal	SOCCo	OPCo	142,213	2/01/74	No
Coal Mine Shutdown Costs	SOCCo	OPCo	534	10/01/72	No
Coal	WCCo	OPCo	5,168	1/01/83	No
Operating Services	AEPRGHC	AEPES	22,661	5/17/99	No
Coal Conveyance	STMCo Inc.	CCPC	196	5/01/91	YES
Technical and Administrative Svc.	AEPSC	OVEC	4,174	12/7/56	YES
Technical and Administrative Svc.	AEPSC	IKEC	6,630	12/7/56	YES
Maintenance Services	APCO	OVEC	375	1/01/79	YES
Maintenance Services	APCO	IKEC	25	1/01/79	YES

Transactions between AEP System companies pursuant to the Affiliated Transactions Agreement dated December 31, 1996 are reported in Exhibit F of this U5S.

Part II. Contracts to purchase services or goods between any System company and (1) any affiliate company (other than a System company) or (2) any other company in which any officer or director of the System company, receiving service under the contract, is a partner or owns 5 percent or more of any class of equity securities. - NONE.

Part III. Employment of any other person, by any System company, for the performance on a continuing basis, of management, supervisory or financial advisory services. - NONE.

ITEM 9. WHOLESALE GENERATORS AND FOREIGN UTILITY COMPANIES

Part I.

The following table shows the required information for investment in wholesale generation and foreign utility companies as of December 31, 2001:

(a) Company name, business address, facilities and interest held;
(b) Capital invested, recourse debt, guarantees and transfer of assets between affiliates;
(c) Debt to equity ratio and earnings;
(d) Contracts for service, sales or construction with affiliates.

Foreign Utility Companies:

(a) SEEBOARD plc
Forest Gate, Brighton Road
Crawley, West Sussex RH11 9BH
United Kingdom
Distributes and supplies electricity to approximately 2 million customers in the United Kingdom.
AEP owns 100%.
(b) Capital invested - $829 million. Recourse debt - NONE. Guarantees - NONE.
Asset transfers - NONE.
(c) Debt to equity ratio - 0.9 to 1; Earnings $89 million.
(d) NONE

(a) AEPR Global Holland Holding B.V
Herengracht 548
1017 CG Amsterdam, The Netherlands
(b) Capital Invested - $880 million. Recourse debt - NONE. Guarantees - NONE.
Asset Transfers - NONE.
(c) Debt to equity ratio - 2.3:1; Earnings - NONE.
(d) NONE

(a) AEP Energy Services UK Generation Limited
50 Berkeley Street
Mayfair London W1J89AP, Great Britain
(b) Capital invested - $124 million. Recourse debt - NONE. Guarantees - NONE.
Asset transfers - NONE.
(c) Debt to equity ratios - 1.2:1; Earnings - NONE.
(d) NONE

ITEM 9. (Continued)

Part I. (Continued)

(a) Nanyang General Light Electric Co., Ltd.
Dayuan Zhuan Village
Pushan Town, Nanyang City
People's Republic of China
Owns and operates a two unit electric generating plant in China.
AEP owns 70%.

(b) Capital invested $91 million. Recourse debt - NONE.
Guarantees - NONE.
Asset transfers - NONE.

(c) Debt to equity ratio - 1.6 to 1.
Earnings - $6 million.

(d) Nanyang has contracts with AEP ProServe Company for consulting and administrative service which resulted in a fee of $600,000.

(a) Empresa de Eletricidade Vale Paranapanema S.A. ("Vale")
Avenida Paulista, No. 2439, 5th floor
Sao Paulo, Sao Paulo
Brazil
Owns a majority interest in five electric operating companies in Brazil.
AEP owns a 44% share of Vale and a 20% share of a Vale subsidiary.

(b) Capital invested $215 million.
Recourse debt - NONE.
Convertible debt - NONE.
Guarantees - NONE.
Asset transfers - NONE.

(c) Debt to equity ratio 0.2 to 1. Earnings $4.2 million.

(d) NONE

ITEM 9. (Continued)

Part I. (Continued)

(a) Pacific Hydro Limited
Level 8
474 Flinders Street
Melbourne, Victoria
3000 Australia
Develops and owns hydroelectric facilities in the Asia Pacific region.
AEP owns 20%.
(b) Capital invested - $17 million.
Recourse Debt - NONE.
Guarantees - NONE.
Assets transferred - NONE.
(c) Noncurrent liabilities to equity ratio - 0.3 to 1.
Earnings - $3.4 million.
(d) NONE

(a) CitiPower Pty.
600 Bourke Street
Melbourne Victoria
3000 Australia
CitiPower distributes and sells electricity to approximately 260,000 customers over 3,990 miles of distribution lines.
AEP owns 100%.
(b) Capital invested - $341 million.
Recourse debt - NONE.
Guarantees - NONE.
Asset transfers - NONE.
(c) Debt to equity ratio - 5.5 to 1.
Earnings - $(6) million.
(d) NONE.

(a) AEP Energy Services Limited
29/30 St. James's Street
London SW1A 1HB
Great Britain
AEP owns 100%.
(b) Capital invested - $70 million.
Recourse debt - NONE.
Guarantees - NONE.
(c) Earnings - $(0.4) million.
(d) Not Available.

ITEM 9. (Continued)

Part I. (Continued)

(a) InterGen Denmark, Aps
Torre Chapultepec,
Piso 13,
Ruben Dario 281, Col.
Bosques de
Chapultepec, Mexico, D.F. 11520.
Construction and operation of a 600 megawatt natural gas-fired, combined cycle plant. AEP owns 50%.

(b) Capital invested - $6 million. Recourse debt - NONE. Guarantees - NONE.
Asset transfers - NONE.

(c) Earnings - ($2.2 million).

(d) NONE

Exempt Wholesale Generators:

(a) Newgulf Power Venture, Inc.
1 Riverside Plaza
Columbus, Ohio
Operation of 85 megawatt plant in Texas.

(b) Capital invested - $17 million. Recourse debt - NONE. Guarantees - NONE.
Asset transfers - NONE

(c) Debt to equity ratio - 0.2:1

(d) NONE

(a) AEP Indian Mesa LP, LLC
1 Riverside Plaza
Columbus, Ohio
Operation of Windfarm in Texas.

(b) Capital invested - $175 million. Recourse debt - none. Guarantees - none.
Asset transfer - none.

(c) Debt to equity ratios is 0.9:1

(d) None

(a) South Coast Power Limited
Shoreham, East Sussex
United Kingdom

(b) Capital invested - $23 million. Recourse debt - none. Guarantees - none.
Asset transfers - none.

(c) Debt to equity ratio - 0.3:1

(d) None

ITEM 9. (Continued)

Part I. (Continued)

(a) Trent Windfarm L.P.
1 Riverside Plaza
Columbus, Ohio
Operation of Windfarm in Texas.
(b) Capital invested - $138 million. Recourse debt - none. Guarantees - none. Asset transfer - none.
(c) Debt to equity ratios is 1:1
(d) None

(a) South Coast Power Limited
Shoreham, East Sussex
United Kingdom
(b) Capital invested - $23 million. Recourse debt - none. Guarantees - none. Asset transfers - none.
(c) Debt to equity ratio - 0.3:1
(d) None

Part II.

See Exhibit's G and H

Part III.

American Electric Power Company, Inc.'s aggregate investment in foreign utility companies is $3.1 billion and in exempt wholesale generators is $331 million which is 43.6% of its investment in domestic public utility subsidiary companies.

ITEM 10. FINANCIAL STATEMENTS AND EXHIBITS

FINANCIAL STATEMENTS	Section and Page No.
Consent of Independent Public Accountants	A-1
Consolidating Statements of Income	B-1 to B-19
Consolidating Balance Sheets	B-20 to B-55
Consolidating Statements of Cash Flows	B-56 to B-72
Consolidating Statements of Retained Earnings	B-73 to B-83
Note to Consolidating Financial Statements	C
Financial Statements of Subsidiaries Not Consolidated:	
OVEC	D-1 to D-4

EXHIBITS	
Exhibit A	E
Exhibit B & C	**
Exhibit D	**
Exhibit E	**
Exhibit F	**
Exhibit G	**
Exhibit H	***

** These Exhibits are included only the in copy filed with the Securities and Exchange Commission.
*** Filed confidentially pursuant to Rule 104(b) of the PUHCA.

SIGNATURE

The undersigned system company has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, pursuant to the requirements of the Public Utility Holding Company Act of 1935.

AMERICAN ELECTRIC POWER COMPANY, INC.

By /s/ Armando A. Pena

Armando A. Pena
Treasurer

April 29, 2002

KPSC Case No. 99-149
Item No. 1
Attachment 2B

2002 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

AEP Texas Central Company

AEP Texas North Company

Appalachian Power Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

Audited Financial Statements and
Management's Discussion and Analysis

AEP AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in this American Electric Power Company, Inc. Annual Report on Form U5S to the Securities and Exchange Commission, filed pursuant to the Public Utility Holding Company Act of 1935, for the year ended December 31, 2001, of our reports dated February 22, 2002, included in or incorporated by reference in the combined Annual Report on Form 10-K to the Securities and Exchange Commission of American Electric Power Company, Inc. and its subsidiaries and of certain of its subsidiaries for the year ended December 31, 2001.

Deloitte & Touche LLP
Columbus, Ohio

April 29, 2002

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
OPERATING REVENUES				
GROSS OPERATING REVENUES	61,257,102,193.28	3,665,636,777.08	2,410.99	6,999,430,256.98
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	61,257,102,193.28	3,665,636,777.08	2,410.99	6,999,430,256.98
OPERATING EXPENSES				
OPERATIONS				
FUEL	3,239,703,889.04	(3,237,592.06)	0.00	351,556,909.70
PURCHASED POWER	49,512,942,755.69	4,766,999,034.71	0.00	5,600,860,791.90
OTHER OPERATION	3,218,047,532.22	(1,055,343,129.06)	53,566,465.76	263,798,176.57
MAINTENANCE	748,121,756.29	(90,297,770.20)	8,427.01	132,373,029.51
TOTAL OPER/MAINT EXPENSES	56,718,815,933.24	3,618,120,543.39	53,574,892.77	6,348,588,907.68
DEPRECIATION AND AMORTIZATION	1,383,576,451.53	(13,630,033.18)	0.00	180,393,075.52
TAXES OTHER THAN INCOME TAXES	667,874,931.00	(42,908,723.71)	0.00	99,877,582.63
STATE, LOCAL & FOREIGN INCOME TAXES	100,074,459.41	(10,769,575.84)	0.00	14,576,854.00
FEDERAL INCOME TAXES	502,325,019.88	(5,116,367.00)	(14,735,573.84)	81,007,632.00
TOTAL OPERATING EXPENSES	59,372,666,795.06	3,545,695,843.66	38,839,318.93	6,724,444,051.83
NET OPERATING INCOME	1,884,435,398.22	119,940,933.42	(38,836,907.94)	274,986,205.15
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	306,536,434.10	(8,743,294,924.62)	1,198,195,281.67	2,320,648,945.69
OTHER INCOME DEDUCTIONS	(207,284,817.38)	7,402,573,621.33	0.00	(2,312,466,074.05)
TAXES APPL TO OTHER INC &DED	14,549,774.58	(11,272.00)	(43,427.93)	(1,314,868.02)
NET OTHR INCOME AND DEDUCTIONS	113,801,391.30	(1,340,732,575.29)	1,198,151,853.74	6,868,003.62
INCOME BEFORE INTEREST CHARGES	1,998,236,789.52	(1,220,791,641.87)	1,159,314,945.80	281,854,208.77
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	732,945,466.28	(37,533,721.81)	44,253,995.02	109,486,292.09
INT SHORT TERM DEBT - AFFIL	14,992.26	(152,767,725.04)	12,233,078.35	9,753,735.87
INT SHORT TERM DEBT - NON-AFFL	147,738,093.35	0.00	131,831,039.29	967,890.89
AMORT OF DEBT DISC, PREM & EXP	5,705,290.94	0.00	165,224.03	1,413,379.76
AMORT LOSS ON REACQUIRED DEBT	5,368,293.40	0.00	0.00	1,255,820.67
AMORT GAIN ON REACQUIRED DEBT	(151,833.94)	0.00	0.00	(131,037.86)
OTHER INTEREST EXPENSE	121,802,837.84	0.00	3,342.05	1,746,427.57
TOTAL INTEREST CHARGES	1,013,423,140.13	(190,301,446.85)	188,486,678.74	124,492,508.99
AFUDC BORROWED FUNDS - CR	(41,279,302.66)	0.00	0.00	(4,456,576.27)
NET INTEREST CHARGES	972,143,837.47	(190,301,446.85)	188,486,678.74	120,035,932.72
MINORITY INTEREST IN FINANCE SUBSIDIARY	(13,130,000.00)	(13,130,000.00)	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	18,070,000.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	(50,431,431.10)	18,520,000.00	0.00	0.00
NET INCOME BEFORE PREF DIV	980,601,520.95	(1,025,100,195.02)	970,828,267.06	161,818,276.05
PREF STK DIVIDEND REQUIREMENT	9,773,227.84	0.00	0.00	2,011,289.60
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	970,828,293.11	(1,025,100,195.02)	970,828,267.06	159,806,986.45

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO
OPERATING REVENUES				
GROSS OPERATING REVENUES	4,299,862,800.94	4,803,625,061.84	1,659,394,832.66	78,832,307.24
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	4,299,862,800.94	4,803,625,061.84	1,659,394,832.66	78,832,307.24
OPERATING EXPENSES				
OPERATIONS				
FUEL	175,152,898.89	250,098,259.60	70,635,346.49	0.00
PURCHASED POWER	3,250,855,384.12	3,531,491,589.12	1,409,759,940.77	54,776,630.05
OTHER OPERATION	221,341,579.70	451,194,446.39	59,175,222.20	8,106,304.51
MAINTENANCE	62,453,854.17	127,263,317.62	22,444,313.55	2,200,226.71
TOTAL OPER/MAINT EXPENSES	3,709,803,716.88	4,360,047,612.73	1,562,014,823.01	65,083,161.27
DEPRECIATION AND AMORTIZATION	127,363,676.46	164,230,378.31	32,490,516.35	3,262,028.06
TAXES OTHER THAN INCOME TAXES	111,481,193.87	65,517,805:54	7,853,227.05	3,014,235.88
STATE, LOCAL & FOREIGN INCOME TAXES	8,755,303.00	9,360,349.00	488,988.00	232,748.00
FEDERAL INCOME TAXES	90,281,837.00	44,763,711.00	8,869,552.00	2,090,440.00
TOTAL OPERATING EXPENSES	4,047,685,727.21	4,643,919,856.58	1,611,717,106.41	73,682,613.21
NET OPERATING INCOME	252,177,073.73	159,705,205.26	47,677,726.25	5,149,694.03
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	1,334,302,602.56	1,474,572,575.21	569,602,074.35	(10,873.47)
OTHER INCOME DEDUCTIONS	(1,322,356,764.08)	(1,456,932,107.73)	(567,667,265.25)	(97,375.29)
TAXES APPL TO OTHER INC &DED	(4,207,319.20)	(7,910,564.32)	(687,149.58)	112,750.00
NET OTHR INCOME AND DEDUCTIONS	7,738,519.28	9,729,903.16	1,247,659.52	4,501.24
INCOME BEFORE INTEREST CHARGES	259,915,593.01	169,435,108.42	48,925,385.77	5,154,195.27
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	61,940,947.43	78,243,676.69	24,478,440.70	1,263,131.86
INT SHORT TERM DEBT - AFFIL	4,958,361.33	13,087,648.48	2,328,397.81	402,954.65
INT SHORT TERM DEBT - NON-AFFL	(44,015.09)	23.38	203.38	23.38
AMORT OF DEBT DISC, PREM & EXP	608,354.48	1,010,810.42	566,613.61	30,555.58
AMORT LOSS ON REACQUIRED DEBT	1,273,545.08	1,444,883.47	45,726.42	222.75
AMORT GAIN ON REACQUIRED DEBT	0.00	(998.62)	0.00	0.00
OTHER INTEREST EXPENSE	1,872,621.32	1,474,442.40	446,868.95	42,319.94
TOTAL INTEREST CHARGES	70,609,814.55	95,260,486.22	27,866,250.87	1,739,208.16
AFUDC BORROWED FUNDS - CR	(2,594,823.79)	(1,613,328.42)	(505,405.86)	8,737.85
NET INTEREST CHARGES	68,014,990.76	93,647,157.80	27,360,845.01	1,747,946.01
MINORITY INTEREST IN FINANCE SUBSIDIARY	0.00	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	(30,024,282.58)	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	161,876,319.67	75,787,950.62	21,564,540.76	3,406,249.26
PREF STK DIVIDEND REQUIREMENT	1,094,662.81	4,621,138.02	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	160,781,656.86	71,166,812.60	21,564,540.76	3,406,249.26

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	WPCO	AEGCO	AEPSC
OPERATING REVENUES				
GROSS OPERATING REVENUES	6,262,401,987.00	83,410,464.45	227,548,459.00	1,105,133,959.41
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	6,262,401,987.00	83,410,464.45	227,548,459.00	1,105,133,959.41
OPERATING EXPENSES				
OPERATIONS				
FUEL	686,568,258.02	0.00	102,828,366.38	3,237,592.06
PURCHASED POWER	4,287,708,669.18	55,275,027.62	0.00	1,273,282.85
OTHER OPERATION	403,404,431.98	7,559,713.04	79,307,905.95	922,722,025.67
MAINTENANCE	142,877,773.43	3,125,553.38	8,852,599.35	90,297,770.20
TOTAL OPER/MAINT EXPENSES	5,520,559,132.61	65,960,294.04	190,988,871.68	1,017,530,670.78
DEPRECIATION AND AMORTIZATION	239,981,498.54	3,699,113.66	22,422,581.56	13,598,144.26
TAXES OTHER THAN INCOME TAXES	159,778,072.58	5,079,211.44	4,257,553.47	42,908,723.71
STATE, LOCAL & FOREIGN INCOME TAXES	21,703,276.00	508,957.00	1,615,107.00	10,769,575.84
FEDERAL INCOME TAXES	79,669,878.00	2,436,818.00	1,286,849.00	2,599,215.09
TOTAL OPERATING EXPENSES	6,021,691,857.73	77,684,394.14	220,570,962.71	1,087,406,329.68
NET OPERATING INCOME	240,710,129.27	5,726,070.31	6,977,496.29	17,727,629.73
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	1,880,294,276.52	92,893.71	29,967.54	(464,553.17)
OTHER INCOME DEDUCTIONS	(1,863,471,770.37)	(251,340.87)	(42,999.26)	(11,510,179.86)
TAXES APPL TO OTHER INC &DED	1,863,766.57	154,018.37	3,496,439.97	0.00
NET OTHR INCOME AND DEDUCTIONS	18,686,272.72	(4,428.79)	3,483,408.25	(11,974,733.03)
INCOME BEFORE INTEREST CHARGES	259,396,401.99	5,721,641.52	10,460,904.54	5,752,896.70
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	81,857,616.08	1,360,995.42	1,577,750.87	4,978,625.00
INT SHORT TERM DEBT - AFFIL	14,630,373.27	246,638.02	753,737.94	3,655,597.11
INT SHORT TERM DEBT - NON-AFFL	(2,390.81)	26,263.79	0.00	(59,864.69)
AMORT OF DEBT DISC, PREM & EXP	1,031,799.06	30,555.58	(25,020.54)	5,213.64
AMORT LOSS ON REACQUIRED DEBT	603,694.69	467.88	322,107.36	421,825.08
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	3,170,992.66	15,671.53	13.00	442,249.42
TOTAL INTEREST CHARGES	101,292,084.95	1,680,592.22	2,628,588.63	9,443,645.56
AFUDC BORROWED FUNDS - CR	(7,689,199.76)	(26,952.36)	(42,350.21)	(3,690,748.86)
NET INTEREST CHARGES	93,602,885.19	1,653,639.86	2,586,238.42	5,752,896.70
MINORITY INTEREST IN FINANCE SUBSIDIARY	0.00	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	(18,348,148.52)	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	147,445,368.28	4,068,001.66	7,874,666.12	(0.00)
PREF STK DIVIDEND REQUIREMENT	1,258,738.20	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	146,186,630.08	4,068,001.66	7,874,666.12	(0.00)

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CCCO	FRECO	IFRI	AEPPM	AEPES
OPERATING REVENUES					
GROSS OPERATING REVENUES	0.00	0.00	0.00	0.00	12,822,768,396.50
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	0.00	0.00	0.00	0.00	12,822,768,396.50
OPERATING EXPENSES					
OPERATIONS					
FUEL	0.00	0.00	0.00	0.00	0.00
PURCHASED POWER	0.00	0.00	0.00	0.00	12,534,272,762.65
OTHER OPERATION	0.00	0.00	0.00	240.34	143,485,870.60
MAINTENANCE	0.00	0.00	0.00	0.00	406,292.31
TOTAL OPER/MAINT EXPENSES	0.00	0.00	0.00	240.34	12,678,164,925.56
DEPRECIATION AND AMORTIZATION	0.00	0.00	0.00	0.00	3,208,330.92
TAXES OTHER THAN INCOME TAXES	0.00	0.00	0.00	0.00	453,760.69
STATE, LOCAL & FOREIGN INCOME TAXES	0.00	0.00	0.00	0.00	1,249,764.00
FEDERAL INCOME TAXES	0.00	0.00	0.00	0.00	0.00
TOTAL OPERATING EXPENSES	0.00	0.00	0.00	240.34	12,683,076,781.17
NET OPERATING INCOME	0.00	0.00	0.00	(240.34)	139,691,615.33
OTHER INCOME AND DEDUCTIONS					
OTHER INCOME	307,878.83	0.00	0.00	0.00	2,669,210.98
OTHER INCOME DEDUCTIONS	(282,708.22)	0.00	0.00	0.00	(31,407.32)
TAXES APPL TO OTHER INC &DED	(25,170.61)	0.00	0.00	19.00	(53,768,063.68)
NET OTHR INCOME AND DEDUCTIONS	0.00	0.00	0.00	19.00	(51,130,260.02)
INCOME BEFORE INTEREST CHARGES	0.00	0.00	0.00	(221.34)	88,561,355.31
INTEREST CHARGES					
INTEREST ON LONG-TERM DEBT	0.00	0.00	0.00	0.00	500,046.93
INT SHORT TERM DEBT - AFFIL	0.00	0.00	0.00	0.00	3,397,922.93
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	0.00	0.00	11,750.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	0.00	0.00	0.00	0.00	2,426,740.33
TOTAL INTEREST CHARGES	0.00	0.00	0.00	0.00	6,336,460.19
AFUDC BORROWED FUNDS - CR	0.00	0.00	0.00	0.00	0.00
NET INTEREST CHARGES	0.00	0.00	0.00	0.00	6,336,460.19
MINORITY INTEREST IN FINANCE SUBSIDIARY	0.00	0.00	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	0.00	0.00	0.00	(221.34)	82,224,895.12
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	0.00	0.00	0.00	(221.34)	82,224,895.12

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPINV CONSOLIDATED	AEPR CONSOLIDATED	AEPPRO	AEPC CONSOLIDATED
OPERATING REVENUES				
GROSS OPERATING REVENUES	0.00	8,177,387,380.26	177,003,939.43	13,837,226.07
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	0.00	8,177,387,380.26	177,003,939.43	13,837,226.07
OPERATING EXPENSES				
OPERATIONS				
FUEL	0.00	14,583,141.05	0.00	0.00
PURCHASED POWER	0.00	7,846,369,452.22	0.00	0.00
OTHER OPERATION	1,836,957.77	191,425,669.02	178,094,628.66	19,385,990.68
MAINTENANCE	0.00	29,886,358.46	0.00	833,966.55
TOTAL OPER/MAINT EXPENSES	1,836,957.77	8,082,264,620.75	178,094,628.66	20,219,957.23
DEPRECIATION AND AMORTIZATION	0.00	69,088,990.23	12,622.56	3,055,678.25
TAXES OTHER THAN INCOME TAXES	0.00	1,518,065.48	27.61	4,981.50
STATE, LOCAL & FOREIGN INCOME TAXES	0.00	6,218,148.53	0.00	0.00
FEDERAL INCOME TAXES	0.00	1,717,434.00	0.00	1.00
TOTAL OPERATING EXPENSES	1,836,957.77	8,160,807,258.99	178,107,278.83	23,280,617.98
NET OPERATING INCOME	(1,836,957.77)	16,580,121.27	(1,103,339.40)	(9,443,391.91)
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	2,700,158.89	5,844,270.22	2,270,974.94	(7,244,962.18)
OTHER INCOME DEDUCTIONS	(228,307.56)	(3,138,491.63)	(491.00)	(29,738,610.25)
TAXES APPL TO OTHER INC &DED	(234,937.00)	26,436,960.91	(605,540.19)	22,423,678.29
NET OTHR INCOME AND DEDUCTIONS	2,236,914.33	29,142,739.50	1,664,943.75	(14,559,894.14)
INCOME BEFORE INTEREST CHARGES	399,956.56	45,722,860.77	561,604.35	(24,003,286.05)
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	0.00	73,471,424.20	0.00	8,730,672.53
INT SHORT TERM DEBT - AFFIL	92,580.59	28,828,859.46	266,419.88	4,264,543.36
INT SHORT TERM DEBT - NON-AFFL	0.00	4,327,213.57	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	586,614.44	0.00	30,839.04
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	1,253.00	1,397,243.85	2,595.31	73,749.64
TOTAL INTEREST CHARGES	93,833.59	108,611,355.52	269,015.19	13,099,804.57
AFUDC BORROWED FUNDS - CR	0.00	(46,712.69)	0.00	(2,266,650.80)
NET INTEREST CHARGES	93,833.59	108,564,642.83	269,015.19	10,833,153.77
MINORITY INTEREST IN FINANCE SUBSIDIARY	0.00	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	306,122.97	(62,841,782.06)	292,589.16	(34,836,439.82)
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	306,122.97	(62,841,782.06)	292,589.16	(34,836,439.82)

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSW CONSOLIDATED	AEPRELLC	AEP C&I CONSOLIDATED	AEP T&D SVC
OPERATING REVENUES				
GROSS OPERATING REVENUES	10,849,400,234.72	610,507.43	0.00	740,429.90
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	10,849,400,234.72	610,507.43	0.00	740,429.90
OPERATING EXPENSES				
OPERATIONS				
FUEL	1,588,280,708.91	0.00	0.00	0.00
PURCHASED POWER	6,172,103,114.03	452,438.09	0.00	0.00
OTHER OPERATION	1,228,441,654.50	304,154.71	1,972,682.68	844,175.33
MAINTENANCE	215,386,424.73	1,163.55	0.00	6,177.65
TOTAL OPER/MAINT EXPENSES	9,204,211,902.17	757,756.35	1,972,682.68	850,352.98
DEPRECIATION AND AMORTIZATION	531,759,544.26	0.00	20,371.89	0.00
TAXES OTHER THAN INCOME TAXES	209,039,084.43	0.00	356.92	(228.09)
STATE, LOCAL & FOREIGN INCOME TAXES	35,270,293.88	0.00	0.00	0.00
FEDERAL INCOME TAXES	207,111,911.63	0.00	1.00	0.00
TOTAL OPERATING EXPENSES	10,187,392,736.37	757,756.35	1,993,412.49	850,124.89
NET OPERATING INCOME	662,007,498.35	(147,248.92)	(1,993,412.49)	(109,694.99)
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	265,683,800.94	16,411.77	320,156.19	0.00
OTHER INCOME DEDUCTIONS	(38,990,874.97)	(25,000.00)	(2,626,671.00)	0.00
TAXES APPL TO OTHER INC &DED	22,753,316.97	55,972.74	1,757,087.87	36,484.03
NET OTHR INCOME AND DEDUCTIONS	249,446,242.94	47,384.51	(549,426.94)	36,484.03
INCOME BEFORE INTEREST CHARGES	911,453,741.29	(99,864.41)	(2,542,839.43)	(73,210.96)
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	278,335,573.27	0.00	0.00	0.00
INT SHORT TERM DEBT - AFFIL	52,585,562.64	11,615.84	724,256.22	3,604.37
INT SHORT TERM DEBT - NON-AFFL	10,670,132.30	0.00	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	250,351.84	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	(19,797.46)	0.00	0.00	0.00
OTHER INTEREST EXPENSE	108,686,306.87	0.00	0.00	0.00
TOTAL INTEREST CHARGES	450,508,129.46	11,615.84	724,256.22	3,604.37
AFUDC BORROWED FUNDS - CR	(18,355,291.49)	0.00	0.00	0.00
NET INTEREST CHARGES	432,152,837.97	11,615.84	724,256.22	3,604.37
MINORITY INTEREST IN FINANCE SUBSIDIARY	0.00	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	18,070,000.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	(20,579,000.00)	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	476,791,903.32	(111,480.25)	(3,267,095.65)	(76,815.33)
PREF STK DIVIDEND REQUIREMENT	787,399.21	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	476,004,504.11	(111,480.25)	(3,267,095.65)	(76,815.33)

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPTEXASGP	AEPCOAL	MESA LP CONSOLIDATED	MUTUALENER CONSOLIDATED
OPERATING REVENUES				
GROSS OPERATING REVENUES	0.00	29,029,566.48	0.00	1,045,194.90
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	0.00	29,029,566.48	0.00	1,045,194.90
OPERATING EXPENSES				
OPERATIONS				
FUEL	0.00	0.00	0.00	0.00
PURCHASED POWER	0.00	0.00	0.00	744,638.38
OTHER OPERATION	2,853.40	24,788,689.95	0.00	12,630,821.87
MAINTENANCE	0.00	0.00	0.00	2,278.31
TOTAL OPER/MAINT EXPENSES	2,853.40	24,788,689.95	0.00	13,377,738.56
DEPRECIATION AND AMORTIZATION	0.00	2,619,933.88	0.00	0.00
TAXES OTHER THAN INCOME TAXES	0.00	0.00	0.00	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	0.00	94,671.00	0.00	0.00
FEDERAL INCOME TAXES	0.00	341,681.00	0.00	0.00
TOTAL OPERATING EXPENSES	2,853.40	27,844,975.83	0.00	13,377,738.56
NET OPERATING INCOME	(2,853.40)	1,184,590.65	0.00	(12,332,543.66)
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	0.00	0.00	0.00	267.53
OTHER INCOME DEDUCTIONS	0.00	0.00	0.00	0.00
TAXES APPL TO OTHER INC &DED	998.00	0.00	0.00	4,266,594.39
NET OTHR INCOME AND DEDUCTIONS	998.00	0.00	0.00	4,266,861.92
INCOME BEFORE INTEREST CHARGES	(1,855.40)	1,184,590.65	0.00	(8,065,681.74)
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	0.00	0.00	0.00	0.00
INT SHORT TERM DEBT - AFFIL	0.00	540,218.69	0.00	16,610.49
INT SHORT TERM DEBT - NON-AFFL	0.00	9,823.96	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	0.00	0.00	0.00	0.00
TOTAL INTEREST CHARGES	0.00	550,042.65	0.00	16,610.49
AFUDC BORROWED FUNDS - CR	0.00	0.00	0.00	0.00
NET INTEREST CHARGES	0.00	550,042.65	0.00	16,610.49
MINORITY INTEREST IN FINANCE SUBSIDIARY	0.00	0.00	0.00	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	(1,855.40)	634,548.00	0.00	(8,082,292.23)
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	(1,855.40)	634,548.00	0.00	(8,082,292.23)

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSW CONSOLIDATED	CSW ELIMINATIONS	CSW	CPL CONSOLIDATED
OPERATING REVENUES				
GROSS OPERATING REVENUES	10,849,400,234.72	(79,617,351.10)	0.00	3,321,727,335.49
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	10,849,400,234.72	(79,617,351.10)	0.00	3,321,727,335.49
OPERATING EXPENSES				
OPERATIONS				
FUEL	1,588,280,708.91	0.00	0.00	492,057,324.77
PURCHASED POWER	6,172,103,114.03	0.00	0.00	1,769,346,355.63
OTHER OPERATION	1,228,441,654.50	(30,070,815.63)	11,230,855.39	321,227,344.98
MAINTENANCE	215,386,424.73	0.00	0.00	71,212,159.38
TOTAL OPER/MAINT EXPENSES	9,204,211,902.17	(30,070,815.63)	11,230,855.39	2,653,843,184.76
DEPRECIATION AND AMORTIZATION	531,759,544.26	0.00	326,496.00	168,341,221.92
TAXES OTHER THAN INCOME TAXES	209,039,084.43	0.00	0.00	90,915,830.73
STATE, LOCAL & FOREIGN INCOME TAXES	35,270,293.88	0.00	0.00	14,848,886.31
FEDERAL INCOME TAXES	207,111,911.63	0.00	(6,148,671.00)	98,047,529.00
TOTAL OPERATING EXPENSES	10,187,392,736.37	(30,070,815.63)	5,408,680.39	3,025,996,652.72
NET OPERATING INCOME	662,007,498.35	(5,546,535.47)	(5,408,680.39)	295,730,682.77
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	265,683,800.94	(505,631,483.11)	500,020,855.60	4,925,690.31
OTHER INCOME DEDUCTIONS	(38,990,874.97)	0.00	498,989.26	0.00
TAXES APPL TO OTHER INC &DED	22,753,316.97	0.00	100.00	398,255.00
NET OTHR INCOME AND DEDUCTIONS	249,446,242.94	(505,631,483.11)	500,519,944.86	5,323,945.31
INCOME BEFORE INTEREST CHARGES	911,453,741.29	(511,178,018.58)	495,111,264.47	301,054,628.08
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	278,335,573.27	0.00	0.00	86,980,425.34
INT SHORT TERM DEBT - AFFIL	52,585,562.64	(12,401,562.22)	12,870,873.25	11,414,223.39
INT SHORT TERM DEBT - NON-AFFL	10,670,132.30	0.00	0.00	3,145,546.91
AMORT OF DEBT DISC, PREM & EXP	250,351.84	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	(19,797.46)	0.00	0.00	(48.34)
OTHER INTEREST EXPENSE	108,686,306.87	0.00	68,926.00	21,671,171.65
TOTAL INTEREST CHARGES	450,508,129.46	(12,401,562.22)	12,939,799.25	123,211,318.95
AFUDC BORROWED FUNDS - CR	(18,355,291.49)	0.00	0.00	(6,942,889.50)
NET INTEREST CHARGES	432,152,837.97	(12,401,562.22)	12,939,799.25	116,268,429.45
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	18,070,000.00	18,070,000.00	0.00	0.00
NET EXTRAORDINARY ITEMS	(20,579,000.00)	(18,070,000.00)	0.00	(2,509,000.00)
NET INCOME BEFORE PREF DIV	476,791,903.32	(498,776,456.36)	482,171,465.22	182,277,198.63
PREF STK DIVIDEND REQUIREMENT	787,399.21	0.00	0.00	241,551.21
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	476,004,504.11	(498,776,456.36)	482,171,465.22	182,035,647.42

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	PSO CONSOLIDATED	SWEPCO CONSOLIDATED	WTU	SEEBOARD
OPERATING REVENUES				
GROSS OPERATING REVENUES	2,201,248,847.72	2,574,448,380.82	1,064,270,633.22	1,451,232,846.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	2,201,248,847.72	2,574,448,380.82	1,064,270,633.22	1,451,232,846.00
OPERATING EXPENSES				
OPERATIONS				
FUEL	461,470,046.27	457,613,167.41	177,140,170.46	0.00
PURCHASED POWER	1,309,945,601.62	1,504,626,984.66	634,847,996.12	953,336,176.00
OTHER OPERATION	139,926,684.99	173,830,874.25	111,262,718.41	241,499,849.00
MAINTENANCE	46,188,542.97	74,677,091.54	22,342,992.96	0.00
TOTAL OPER/MAINT EXPENSES	1,957,530,875.85	2,210,748,117.86	945,593,877.95	1,194,836,025.00
DEPRECIATION AND AMORTIZATION	80,244,800.89	119,543,430.19	50,705,347.81	95,742,899.00
TAXES OTHER THAN INCOME TAXES	31,972,751.62	55,834,341.57	28,318,822.76	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	7,915,010.00	8,339,890.00	1,973,328.00	0.00
FEDERAL INCOME TAXES	26,597,820.00	33,775,849.00	4,289,115.00	7,432,024.00
TOTAL OPERATING EXPENSES	2,104,261,258.36	2,428,241,628.62	1,030,880,491.52	1,298,010,948.00
NET OPERATING INCOME	96,987,589.36	146,206,752.20	33,390,141.70	153,221,898.00
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	371,701.12	1,283,478.92	1,504,542.60	26,367,807.00
OTHER INCOME DEDUCTIONS	0.00	0.00	0.00	0.00
TAXES APPL TO OTHER INC &DED	(351,790.00)	(542,675.00)	690,957.00	(8,317,145.00)
NET OTHR INCOME AND DEDUCTIONS	19,911.12	740,803.92	2,195,499.60	18,050,662.00
INCOME BEFORE INTEREST CHARGES	97,007,500.48	146,947,556.12	35,585,641.30	171,272,560.00
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	29,304,932.18	41,400,800.62	16,842,349.80	83,111,756.00
INT SHORT TERM DEBT - AFFIL	6,281,396.28	3,369,802.68	3,103,779.72	42,168.00
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	187,716.36	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	(19,749.12)	0.00
OTHER INTEREST EXPENSE	9,044,275.19	14,973,315.47	4,478,804.14	0.00
TOTAL INTEREST CHARGES	44,818,320.01	59,743,918.77	24,405,184.54	83,153,924.00
AFUDC BORROWED FUNDS - CR	(5,569,680.63)	(2,162,948.63)	(1,130,151.85)	0.00
NET INTEREST CHARGES	39,248,639.38	57,580,970.14	23,275,032.69	83,153,924.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	57,758,861.10	89,366,585.98	12,310,608.61	88,118,636.00
PREF STK DIVIDEND REQUIREMENT	212,636.56	229,054.64	104,156.80	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	57,546,224.54	89,137,531.34	12,206,451.81	88,118,636.00

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSWI CONSOLIDATED	CSWE CONSOLIDATED	ENERSHOP	CSWL
OPERATING REVENUES				
GROSS OPERATING REVENUES	29,379,415.00	101,167,502.00	127,870.38	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	29,379,415.00	101,167,502.00	127,870.38	0.00
OPERATING EXPENSES				
OPERATIONS				
FUEL	0.00	0.00	0.00	0.00
PURCHASED POWER	0.00	0.00	0.00	0.00
OTHER OPERATION	3,315,128.00	63,589,387.00	1,040,900.34	166,249.07
MAINTENANCE	0.00	0.00	0.00	0.00
TOTAL OPER/MAINT EXPENSES	3,315,128.00	63,589,387.00	1,040,900.34	166,249.07
DEPRECIATION AND AMORTIZATION	235,169.00	5,438,894.00	242,409.24	0.00
TAXES OTHER THAN INCOME TAXES	13,712.00	1,611,520.00	716.14	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	0.00	601,858.00	0.00	0.00
FEDERAL INCOME TAXES	183,755.00	34,494,434.00	0.00	(5,776,031.37)
TOTAL OPERATING EXPENSES	3,747,764.00	105,736,093.00	1,284,025.72	(5,609,782.30)
NET OPERATING INCOME	25,631,651.00	(4,568,591.00)	(1,156,155.34)	5,609,782.30
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	30,178,734.00	95,445,985.00	(569,905.06)	2,291,013.02
OTHER INCOME DEDUCTIONS	0.00	0.00	(119,782.38)	(14,066,613.00)
TAXES APPL TO OTHER INC &DED	(491,402.00)	0.00	986,731.59	(39,257.00)
NET OTHR INCOME AND DEDUCTIONS	29,687,332.00	95,445,985.00	297,044.15	(11,814,856.98)
INCOME BEFORE INTEREST CHARGES	55,318,983.00	90,877,394.00	(859,111.19)	(6,205,074.68)
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	0.00	11,111,976.00	575,000.00	0.00
INT SHORT TERM DEBT - AFFIL	7,604,775.00	11,884,332.00	528,475.63	0.00
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	10,865.56	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	3,700.65	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	0.00	3,049,903.00	0.00	0.00
TOTAL INTEREST CHARGES	7,604,775.00	26,046,211.00	1,118,041.84	0.00
AFUDC BORROWED FUNDS - CR	0.00	0.00	0.00	0.00
NET INTEREST CHARGES	7,604,775.00	26,046,211.00	1,118,041.84	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	47,714,208.00	64,831,183.00	(1,977,153.03)	(6,205,074.68)
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	47,714,208.00	64,831,183.00	(1,977,153.03)	(6,205,074.68)

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	C3 COMM CONSOLIDATED	CSWESI CONSOLIDATED	CSWPWRM	AEP CREDIT	REPHLD CONSOLIDATED
OPERATING REVENUES					
GROSS OPERATING REVENUES	12,694,719.77	0.00	0.00	172,720,035.42	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	12,694,719.77	0.00	0.00	172,720,035.42	0.00
OPERATING EXPENSES					
OPERATIONS					
FUEL	0.00	0.00	0.00	0.00	0.00
PURCHASED POWER	0.00	0.00	0.00	0.00	0.00
OTHER OPERATION	27,652,748.13	94,378,761.31	0.00	67,210,658.70	2,180,310.56
MAINTENANCE	965,637.88	0.00	0.00	0.00	0.00
TOTAL OPER/MAINT EXPENSES	28,618,386.01	94,378,761.31	0.00	67,210,658.70	2,180,310.56
DEPRECIATION AND AMORTIZATION	9,515,483.89	1,423,392.32	0.00	0.00	0.00
TAXES OTHER THAN INCOME TAXES	238,882.89	1,365.28	0.00	131,141.44	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	0.00	0.00	0.00	1,591,321.57	0.00
FEDERAL INCOME TAXES	0.00	0.00	0.00	14,216,088.00	0.00
TOTAL OPERATING EXPENSES	38,372,752.79	95,803,518.91	0.00	83,149,209.71	2,180,310.56
NET OPERATING INCOME	(25,678,033.02)	(95,803,518.91)	0.00	89,570,825.71	(2,180,310.56)
OTHER INCOME AND DEDUCTIONS					
OTHER INCOME	(1,560,651.48)	67,051,547.63	0.00	4,338.83	146.56
OTHER INCOME DEDUCTIONS	(25,299,344.00)	(124.85)	0.00	0.00	(4,000.00)
TAXES APPL TO OTHER INC &DED	18,303,175.20	11,359,949.23	0.00	0.00	756,417.95
NET OTHR INCOME AND DEDUCTIONS	(8,556,820.28)	78,411,372.01	0.00	4,338.83	752,564.51
INCOME BEFORE INTEREST CHARGES	(34,234,853.30)	(17,392,146.90)	0.00	89,575,164.54	(1,427,746.05)
INTEREST CHARGES					
INTEREST ON LONG-TERM DEBT	6,708,333.33	2,300,000.00	0.00	0.00	0.00
INT SHORT TERM DEBT - AFFIL	4,483,242.83	1,378,897.26	0.00	2,025,158.82	0.00
INT SHORT TERM DEBT - NON-AFFL	0.00	2,568,922.08	0.00	4,944,797.75	0.00
AMORT OF DEBT DISC, PREM & EXP	44,134.08	14,800.75	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	5,831.42	(5,529.44)	0.00	55,399,609.44	0.00
TOTAL INTEREST CHARGES	11,241,541.66	6,257,090.65	0.00	62,369,566.01	0.00
AFUDC BORROWED FUNDS - CR	(2,549,620.88)	0.00	0.00	0.00	0.00
NET INTEREST CHARGES	8,691,920.78	6,257,090.65	0.00	62,369,566.01	0.00
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	0.00	0.00	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	(42,926,774.08)	(23,649,237.55)	0.00	27,205,598.53	(1,427,746.05)
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00	0.00	0.00
Gain (Loss) on Reacq. Preferred Stock	0.00	0.00	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	(42,926,774.08)	(23,649,237.55)	0.00	27,205,598.53	(1,427,746.05)

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APPALACHIAN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	APCO CONSOLIDATED	APCO ELIMINATIONS	APCO	CACCO
OPERATING REVENUES				
GROSS OPERATING REVENUES	6,999,430,256.98	(3,697,129.56)	7,003,127,386.54	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	6,999,430,256.98	(3,697,129.56)	7,003,127,386.54	0.00
OPERATING EXPENSES				
OPERATIONS				
FUEL	351,556,909.70	0.00	351,556,909.70	0.00
PURCHASED POWER	5,600,860,791.90	0.00	5,600,860,791.90	0.00
OTHER OPERATION	263,798,176.57	(3,701,396.56)	267,499,573.13	0.00
MAINTENANCE	132,373,029.51	0.00	132,373,029.51	0.00
TOTAL OPER/MAINT EXPENSES	6,348,588,907.68	(3,701,396.56)	6,352,290,304.24	0.00
DEPRECIATION AND AMORTIZATION	180,393,075.52	0.00	180,393,075.52	0.00
TAXES OTHER THAN INCOME TAXES	99,877,582.63	0.00	99,877,582.63	0.00
STATE, LOCAL, AND FOREIGN INCOME TAXES	14,576,854.00	0.00	14,576,854.00	0.00
FEDERAL INCOME TAXES	81,007,632.00	0.00	81,007,632.00	0.00
TOTAL OPERATING EXPENSES	6,724,444,051.83	(3,701,396.56)	6,728,145,448.39	0.00
NET OPERATING INCOME	274,986,205.15	4,267.00	274,981,938.15	0.00
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	2,320,648,945.69	(160,332,151.98)	2,474,936,542.35	371,023.10
OTHER INCOME DEDUCTIONS	(2,312,466,074.05)	159,695,896.35	(2,467,463,389.72)	(346,585.10)
TAXES APPL TO OTHER INC &DED	(1,314,868.02)	0.00	(600,276.24)	(416.00)
NET OTHR INCOME AND DEDUCTIONS	6,868,003.62	(636,255.63)	6,872,876.39	24,022.00
INCOME BEFORE INTEREST CHARGES	281,854,208.77	(631,988.63)	281,854,814.54	24,022.00
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	109,486,292.09	0.00	109,486,292.09	0.00
INT SHORT TERM DEBT - AFFIL	9,753,735.87	(605.77)	9,754,341.64	0.00
INT SHORT TERM DEBT - NON-AFFL	967,890.89	0.00	967,890.89	0.00
AMORT OF DEBT DISC, PREM & EXP	1,413,379.76	0.00	1,413,379.76	0.00
AMORT LOSS ON REACQUIRED DEBT	1,255,820.67	0.00	1,255,820.67	0.00
AMORT GAIN ON REACQUIRED DEBT	(131,037.86)	0.00	(131,037.86)	0.00
OTHER INTEREST EXPENSE	1,746,427.57	0.00	1,746,427.57	0.00
TOTAL INTEREST CHARGES	124,492,508.99	(605.77)	124,493,114.76	0.00
AFUDC BORROWED FUNDS - CR	(4,456,576.27)	0.00	(4,456,576.27)	0.00
NET INTEREST CHARGES	120,035,932.72	(605.77)	120,036,538.49	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	161,818,276.05	(631,382.86)	161,818,276.05	24,022.00
PREF STK DIVIDEND REQUIREMENT	2,011,289.60	0.00	2,011,289.60	0.00
NET INCOME - EARN FOR CMMN STK	159,806,986.45	(631,382.86)	159,806,986.45	24,022.00

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APPALACHIAN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CECCO	SACCO	WVPCO
OPERATING REVENUES			
GROSS OPERATING REVENUES	0.00	0.00	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	0.00	0.00	0.00
OPERATING EXPENSES			
OPERATIONS			
FUEL	0.00	0.00	0.00
PURCHASED POWER	0.00	0.00	0.00
OTHER OPERATION	0.00	0.00	0.00
MAINTENANCE	0.00	0.00	0.00
TOTAL OPER/MAINT EXPENSES	0.00	0.00	0.00
DEPRECIATION AND AMORTIZATION	0.00	0.00	0.00
TAXES OTHER THAN INCOME TAXES	0.00	0.00	0.00
STATE, LOCAL, AND FOREIGN INCOME TAXES	0.00	0.00	0.00
FEDERAL INCOME TAXES	0.00	0.00	0.00
TOTAL OPERATING EXPENSES	0.00	0.00	0.00
NET OPERATING INCOME	0.00	0.00	0.00
OTHER INCOME AND DEDUCTIONS			
OTHER INCOME	4,654,705.07	1,006,142.30	12,684.85
OTHER INCOME DEDUCTIONS	(4,346,245.07)	(5,691.30)	(59.21)
TAXES APPL TO OTHER INC &DED	(208,153.00)	(500,250.00)	(5,772.78)
NET OTHR INCOME AND DEDUCTIONS	100,307.00	500,201.00	6,852.86
INCOME BEFORE INTEREST CHARGES	100,307.00	500,201.00	6,852.86
INTEREST CHARGES			
INTEREST ON LONG-TERM DEBT	0.00	0.00	0.00
INT SHORT TERM DEBT - AFFIL	0.00	0.00	0.00
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00
OTHER INTEREST EXPENSE	0.00	0.00	0.00
TOTAL INTEREST CHARGES	0.00	0.00	0.00
AFUDC BORROWED FUNDS - CR	0.00	0.00	0.00
NET INTEREST CHARGES	0.00	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	100,307.00	500,201.00	6,852.86
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	100,307.00	500,201.00	6,852.86

<PAGE>
COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	CSPCO ELIMINATIONS	CSPCO
OPERATING REVENUES			
GROSS OPERATING REVENUES	4,299,862,800.94	(12,655,728.33)	4,301,501,263.27
PROVISION FOR RATE REFUND	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	4,299,862,800.94	(12,655,728.33)	4,301,501,263.27
OPERATING EXPENSES			
OPERATIONS			
FUEL	175,152,898.89	(177,434.12)	175,329,559.11
PURCHASED POWER	3,250,855,384.12	0.00	3,250,855,384.12
OTHER OPERATION	221,341,579.70	(9,739,633.36)	223,060,546.97
MAINTENANCE	62,453,854.17	(1,502,801.00)	62,453,959.73
TOTAL OPER/MAINT EXPENSES	3,709,803,716.88	(11,419,868.48)	3,711,699,449.93
DEPRECIATION AND AMORTIZATION	127,363,676.46	(1,061,772.00)	127,363,676.46
TAXES OTHER THAN INCOME TAXES	111,481,193.87	(243,940.88)	111,481,193.87
STATE, LOCAL, AND FOREIGN INCOME TAXES	8,755,303.00	0.00	8,755,303.00
FEDERAL INCOME TAXES	90,281,837.00	0.00	90,161,653.00
TOTAL OPERATING EXPENSES	4,047,685,727.21	(12,725,581.36)	4,049,461,276.26
NET OPERATING INCOME	252,177,073.73	69,853.03	252,039,987.01
OTHER INCOME AND DEDUCTIONS			
OTHER INCOME	1,334,302,602.56	(90,140,799.43)	1,424,322,390.94
OTHER INCOME DEDUCTIONS	(1,322,356,764.08)	89,905,557.00	(1,412,355,360.95)
TAXES APPL TO OTHER INC &DED	(4,207,319.20)	0.00	(4,125,659.39)
NET OTHR INCOME AND DEDUCTIONS	7,738,519.28	(235,242.43)	7,841,370.60
INCOME BEFORE INTEREST CHARGES	259,915,593.01	(165,389.40)	259,881,357.61
INTEREST CHARGES			
INTEREST ON LONG-TERM DEBT	61,940,947.43	0.00	61,906,103.43
INT SHORT TERM DEBT - AFFIL	4,958,361.33	(605.79)	4,958,967.12
INT SHORT TERM DEBT - NON-AFFL	(44,015.09)	0.00	(44,015.09)
AMORT OF DEBT DISC, PREM & EXP	608,354.48	0.00	608,354.48
AMORT LOSS ON REACQUIRED DEBT	1,273,545.08	0.00	1,273,545.08
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00
OTHER INTEREST EXPENSE	1,872,621.32	0.00	1,872,621.32
TOTAL INTEREST CHARGES	70,609,814.55	(605.79)	70,575,576.34
AFUDC BORROWED FUNDS - CR	(2,594,823.79)	0.00	(2,594,819.98)
NET INTEREST CHARGES	68,014,990.76	(605.79)	67,980,756.36
NET EXTRAORDINARY ITEMS	(30,024,282.58)	0.00	(30,024,282.58)
NET INCOME BEFORE PREF DIV	161,876,319.67	(164,783.61)	161,876,318.67
PREF STK DIVIDEND REQUIREMENT	1,094,662.81	0.00	1,094,662.81
NET INCOME - EARN FOR CMMN STK	160,781,656.86	(164,783.61)	160,781,655.86

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COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	COLM	CCPC	SIMCO
OPERATING REVENUES			
GROSS OPERATING REVENUES	0.00	10,821,666.00	195,600.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	0.00	10,821,666.00	195,600.00
OPERATING EXPENSES			
OPERATIONS			
FUEL	0.00	0.00	773.90
PURCHASED POWER	0.00	0.00	0.00
OTHER OPERATION	0.00	8,029,569.00	(8,902.91)
MAINTENANCE	0.00	1,502,801.00	(105.56)
TOTAL OPER/MAINT EXPENSES	0.00	9,532,370.00	(8,234.57)
DEPRECIATION AND AMORTIZATION	0.00	992,676.00	69,096.00
TAXES OTHER THAN INCOME TAXES	0.00	240,849.00	3,091.88
STATE, LOCAL, AND FOREIGN INCOME TAXES	0.00	0.00	0.00
FEDERAL INCOME TAXES	0.00	79,258.00	40,926.00
TOTAL OPERATING EXPENSES	0.00	10,845,153.00	104,879.31
NET OPERATING INCOME	0.00	(23,487.00)	90,720.69
OTHER INCOME AND DEDUCTIONS			
OTHER INCOME	73,335.65	35,280.00	12,395.40
OTHER INCOME DEDUCTIONS	0.00	93,051.00	(11.13)
TAXES APPL TO OTHER INC &DED	(69,888.81)	0.00	(11,771.00)
NET OTHR INCOME AND DEDUCTIONS	3,446.84	128,331.00	613.27
INCOME BEFORE INTEREST CHARGES	3,446.84	104,844.00	91,333.96
INTEREST CHARGES			
INTEREST ON LONG-TERM DEBT	0.00	34,844.00	0.00
INT SHORT TERM DEBT - AFFIL	0.00	0.00	0.00
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00
OTHER INTEREST EXPENSE	0.00	0.00	0.00
TOTAL INTEREST CHARGES	0.00	34,844.00	0.00
AFUDC BORROWED FUNDS - CR	0.00	0.00	(3.81)
NET INTEREST CHARGES	0.00	34,844.00	(3.81)
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	3,446.84	70,000.00	91,337.77
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	3,446.84	70,000.00	91,337.77

<PAGE>
INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	I&M CONSOLIDATED	I&M ELIMINATIONS	I&M	BHCCO	PRCCO
OPERATING REVENUES					
GROSS OPERATING REVENUES	4,803,625,061.84	(1,833,044.18)	4,805,458,106.02	0.00	0.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	4,803,625,061.84	(1,833,044.18)	4,805,458,106.02	0.00	0.00
OPERATING EXPENSES					
OPERATIONS					
FUEL	250,098,259.60	0.00	250,098,259.60	0.00	0.00
PURCHASED POWER	3,531,491,589.12	0.00	3,531,491,589.12	0.00	0.00
OTHER OPERATION	451,194,446.39	(1,833,044.18)	453,027,490.57	0.00	0.00
MAINTENANCE	127,263,317.62	0.00	127,263,317.62	0.00	0.00
TOTAL OPER/MAINT EXPENSES	4,360,047,612.73	(1,833,044.18)	4,361,880,656.91	0.00	0.00
DEPRECIATION AND AMORTIZATION	164,230,378.31	0.00	164,230,378.31	0.00	0.00
TAXES OTHER THAN INCOME TAXES	65,517,805.54	0.00	65,517,805.54	0.00	0.00
STATE, LOCAL & FOREIGN INCOME TAXES	9,360,349.00	0.00	9,360,349.00	0.00	0.00
FEDERAL INCOME TAXES	44,763,711.00	0.00	44,763,711.00	0.00	0.00
TOTAL OPERATING EXPENSES	4,643,919,856.58	(1,833,044.18)	4,645,752,900.76	0.00	0.00
NET OPERATING INCOME	159,705,205.26	0.00	159,705,205.26	0.00	0.00
OTHER INCOME AND DEDUCTIONS					
OTHER INCOME	1,474,572,575.21	(917,313.57)	1,473,363,143.36	2,126,745.42	0.00
OTHER INCOME DEDUCTIONS	(1,456,932,107.73)	(79,038.43)	(1,456,335,148.88)	(517,920.42)	0.00
TAXES APPL TO OTHER INC &DED	(7,910,564.32)	0.00	(7,298,091.32)	(612,473.00)	0.00
NET OTHR INCOME AND DEDUCTIONS	9,729,903.16	(996,352.00)	9,729,903.16	996,352.00	0.00
INCOME BEFORE INTEREST CHARGES	169,435,108.42	(996,352.00)	169,435,108.42	996,352.00	0.00
INTEREST CHARGES					
INTEREST ON LONG-TERM DEBT	78,243,676.69	0.00	78,243,676.69	0.00	0.00
INT SHORT TERM DEBT - AFFIL	13,087,648.48	0.00	13,087,648.48	0.00	0.00
INT SHORT TERM DEBT - NON-AFFL	23.38	0.00	23.38	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	1,010,810.42	0.00	1,010,810.42	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	1,444,883.47	0.00	1,444,883.47	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	(998.62)	0.00	(998.62)	0.00	0.00
OTHER INTEREST EXPENSE	1,474,442.40	0.00	1,474,442.40	0.00	0.00
TOTAL INTEREST CHARGES	95,260,486.22	0.00	95,260,486.22	0.00	0.00
AFUDC BORROWED FUNDS - CR	(1,613,328.42)	0.00	(1,613,328.42)	0.00	0.00
NET INTEREST CHARGES	93,647,157.80	0.00	93,647,157.80	0.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	75,787,950.62	(996,352.00)	75,787,950.62	996,352.00	0.00
PREF STK DIVIDEND REQUIREMENT	4,621,138.02	0.00	4,621,138.02	0.00	0.00
NET INCOME - EARN FOR CMMN STK	71,166,812.60	(996,352.00)	71,166,812.60	996,352.00	0.00

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OHIO POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	OPCO ELIMINATIONS	OPCO
OPERATING REVENUES			
GROSS OPERATING REVENUES	6,262,401,987.00	(165,705,855.96)	6,269,297,984.96
PROVISION FOR RATE REFUND	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	6,262,401,987.00	(165,705,855.96)	6,269,297,984.96
OPERATING EXPENSES			
OPERATIONS			
FUEL	686,568,258.02	(2,275,619.04)	688,843,877.06
PURCHASED POWER	4,287,708,669.18	0.00	4,287,708,669.18
OTHER OPERATION	403,404,431.98	(125,755,213.51)	407,040,788.49
MAINTENANCE	142,877,773.43	(18,953,059.00)	142,877,773.43
TOTAL OPER/MAINT EXPENSES	5,520,559,132.61	(146,983,891.55)	5,526,471,108.16
DEPRECIATION AND AMORTIZATION	239,981,498.54	(12,141,971.00)	239,981,498.54
TAXES OTHER THAN INCOME TAXES	159,778,072.58	(7,752,267.00)	159,778,072.58
STATE, LOCAL, AND FOREIGN INCOME TAXES	21,703,276.00	0.00	19,403,276.00
FEDERAL INCOME TAXES	79,669,878.00	0.00	76,395,276.00
TOTAL OPERATING EXPENSES	6,021,691,857.73	(166,878,129.55)	6,022,029,231.28
NET OPERATING INCOME	240,710,129.27	1,172,273.59	247,268,753.68
OTHER INCOME AND DEDUCTIONS			
OTHER INCOME	1,880,294,276.52	(134,282,278.74)	2,004,020,106.26
OTHER INCOME DEDUCTIONS	(1,863,471,770.37)	125,975,508.39	(1,987,489,533.76)
TAXES APPL TO OTHER INC &DED	1,863,766.57	0.00	(4,590,427.43)
NET OTHR INCOME AND DEDUCTIONS	18,686,272.72	(8,306,770.35)	11,940,145.07
INCOME BEFORE INTEREST CHARGES	259,396,401.99	(7,134,496.76)	259,208,898.75
INTEREST CHARGES			
INTEREST ON LONG-TERM DEBT	81,857,616.08	0.00	81,669,527.08
INT SHORT TERM DEBT - AFFIL	14,630,373.27	(605.76)	14,630,979.03
INT SHORT TERM DEBT - NON-AFFL	(2,390.81)	0.00	(2,390.81)
AMORT OF DEBT DISC, PREM & EXP	1,031,799.06	0.00	1,031,799.06
AMORT LOSS ON REACQUIRED DEBT	603,694.69	0.00	603,694.69
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00
OTHER INTEREST EXPENSE	3,170,992.66	0.00	3,170,972.66
TOTAL INTEREST CHARGES	101,292,084.95	(605.76)	101,104,581.71
AFUDC BORROWED FUNDS - CR	(7,689,199.76)	0.00	(7,689,199.76)
NET INTEREST CHARGES	93,602,885.19	(605.76)	93,415,381.95
NET EXTRAORDINARY ITEMS	(18,348,148.52)	0.00	(18,348,148.52)
NET INCOME BEFORE PREF DIV	147,445,368.28	(7,133,891.00)	147,445,368.28
PREF STK DIVIDEND REQUIREMENT	1,258,738.20	0.00	1,258,738.20
NET INCOME - EARN FOR CMMN STK	146,186,630.08	(7,133,891.00)	146,186,630.08

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OHIO POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	COCCO	SOCCO	WCCO
OPERATING REVENUES			
GROSS OPERATING REVENUES	11,428,178.00	142,213,264.00	5,168,416.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	11,428,178.00	142,213,264.00	5,168,416.00
OPERATING EXPENSES			
OPERATIONS			
FUEL	0.00	0.00	0.00
PURCHASED POWER	0.00	0.00	0.00
OTHER OPERATION	10,783,171.00	106,569,080.00	4,766,606.00
MAINTENANCE	2,049,165.00	14,722,534.00	2,181,360.00
TOTAL OPER/MAINT EXPENSES	12,832,336.00	121,291,614.00	6,947,966.00
DEPRECIATION AND AMORTIZATION	0.00	11,843,052.00	298,919.00
TAXES OTHER THAN INCOME TAXES	959,527.00	5,918,133.00	874,607.00
STATE, LOCAL, AND FOREIGN INCOME TAXES	0.00	(1,200,000.00)	3,500,000.00
FEDERAL INCOME TAXES	7,041,865.00	2,383,465.00	(6,150,728.00)
TOTAL OPERATING EXPENSES	20,833,728.00	140,236,264.00	5,470,764.00
NET OPERATING INCOME	(9,405,550.00)	1,977,000.00	(302,348.00)
OTHER INCOME AND DEDUCTIONS			
OTHER INCOME	2,729,753.00	6,605,791.00	1,220,905.00
OTHER INCOME DEDUCTIONS	(568,299.00)	(1,229,818.00)	(159,628.00)
TAXES APPL TO OTHER INC &DED	0.00	(245,806.00)	6,700,000.00
NET OTHR INCOME AND DEDUCTIONS	2,161,454.00	5,130,167.00	7,761,277.00
INCOME BEFORE INTEREST CHARGES	(7,244,096.00)	7,107,167.00	7,458,929.00
INTEREST CHARGES			
INTEREST ON LONG-TERM DEBT	0.00	188,089.00	0.00
INT SHORT TERM DEBT - AFFIL	0.00	0.00	0.00
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00
OTHER INTEREST EXPENSE	20.00	0.00	0.00
TOTAL INTEREST CHARGES	20.00	188,089.00	0.00
AFUDC BORROWED FUNDS - CR	0.00	0.00	0.00
NET INTEREST CHARGES	20.00	188,089.00	0.00
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	(7,244,116.00)	6,919,078.00	7,458,929.00
PREF STK DIVIDEND REQUIREMENT	0.00	0.00	0.00
NET INCOME - EARN FOR CMMN STK	(7,244,116.00)	6,919,078.00	7,458,929.00

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SOUTHWESTERN ELECTRIC POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF INCOME
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	SWEPCO CONSOLIDATED	SWEPCO ELIMINATIONS	SWEPCO	DOLETHILLS
OPERATING REVENUES				
GROSS OPERATING REVENUES	2,574,448,380.82	(14,993,549.00)	2,552,176,061.82	37,265,868.00
PROVISION FOR RATE REFUND	0.00	0.00	0.00	0.00
TOTAL OPERATING REVENUES, NET	2,574,448,380.82	(14,993,549.00)	2,552,176,061.82	37,265,868.00
OPERATING EXPENSES				
OPERATIONS				
FUEL	457,613,167.41	(1,726,493.48)	459,339,660.89	0.00
PURCHASED POWER	1,504,626,984.66	0.00	1,504,626,984.66	0.00
OTHER OPERATION	173,830,874.25	(10,585,022.11)	157,953,344.81	26,462,551.55
MAINTENANCE	74,677,091.54	0.00	74,677,091.54	0.00
TOTAL OPER/MAINT EXPENSES	2,210,748,117.86	(12,311,515.59)	2,196,597,081.90	26,462,551.55
DEPRECIATION AND AMORTIZATION	119,543,430.19	(2,270,794.35)	116,137,238.83	5,676,985.71
TAXES OTHER THAN INCOME TAXES	55,834,341.57	(411,239.06)	55,217,483.69	1,028,096.94
STATE, LOCAL, AND FOREIGN INCOME TAXES	8,339,890.00	0.00	8,263,807.00	76,083.00
FEDERAL INCOME TAXES	33,775,849.00	0.00	32,896,880.00	878,969.00
TOTAL OPERATING EXPENSES	2,428,241,628.62	(14,993,549.00)	2,409,112,491.42	34,122,686.20
NET OPERATING INCOME	146,206,752.20	(0.00)	143,063,570.40	3,143,181.80
OTHER INCOME AND DEDUCTIONS				
OTHER INCOME	1,283,478.92	(2,200,467.23)	3,453,328.71	30,617.44
OTHER INCOME DEDUCTIONS	0.00	0.00	0.00	0.00
TAXES APPL TO OTHER INC &DED	(542,675.00)	0.00	(542,675.00)	0.00
NET OTHR INCOME AND DEDUCTIONS	740,803.92	(2,200,467.23)	2,910,653.71	30,617.44
INCOME BEFORE INTEREST CHARGES	146,947,556.12	(2,200,467.23)	145,974,224.11	3,173,799.24
INTEREST CHARGES				
INTEREST ON LONG-TERM DEBT	41,400,800.62	(568,088.23)	41,400,800.62	568,088.23
INT SHORT TERM DEBT - AFFIL	3,369,802.68	0.00	2,396,470.67	973,332.01
INT SHORT TERM DEBT - NON-AFFL	0.00	0.00	0.00	0.00
AMORT OF DEBT DISC, PREM & EXP	0.00	0.00	0.00	0.00
AMORT LOSS ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
AMORT GAIN ON REACQUIRED DEBT	0.00	0.00	0.00	0.00
OTHER INTEREST EXPENSE	14,973,315.47	0.00	14,973,315.47	0.00
TOTAL INTEREST CHARGES	59,743,918.77	(568,088.23)	58,770,586.76	1,541,420.24
AFUDC BORROWED FUNDS - CR	(2,162,948.63)	0.00	(2,162,948.63)	0.00
NET INTEREST CHARGES	57,580,970.14	(568,088.23)	56,607,638.13	1,541,420.24
NET EXTRAORDINARY ITEMS	0.00	0.00	0.00	0.00
NET INCOME BEFORE PREF DIV	89,366,585.98	(1,632,379.00)	89,366,585.98	1,632,379.00
PREF STK DIVIDEND REQUIREMENT	229,054.64	0.00	229,054.64	0.00
NET INCOME - EARN FOR CMMN STK	89,137,531.34	(1,632,379.00)	89,137,531.34	1,632,379.00

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	17,621,780,867.37	31,888.92	0.00	2,093,531,758.74
TRANSMISSION	6,221,371,672.78	0.00	0.00	1,222,225,955.09
DISTRIBUTION	11,309,726,911.68	0.00	0.00	1,887,020,721.58
GENERAL	4,130,242,810.41	0.00	0.00	257,956,883.89
CONSTRUCTION WORK IN PROGRESS	1,101,936,302.80	0.00	0.00	203,921,729.88
TOTAL ELECTRIC UTILITY PLANT	40,385,058,565.04	31,888.92	0.00	5,664,657,049.18
LESS ACCUM PRV-DEPR,DEPL,AMORT	(16,024,763,571.88)	0.00	0.00	(2,296,480,679.00)
NET ELECTRIC UTILITY PLANT	24,360,294,993.16	31,888.92	0.00	3,368,176,370.18
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	182,902,203.23	0.00	0.00	21,632,660.03
INVEST IN SUBSIDIARY & ASSOC	713,746,715.25	(8,624,618,358.62)	8,664,552,681.62	603,868.00
TOTAL OTHER INVESTMENTS	4,615,559,014.20	(984,632,728.65)	900,312,196.63	347,748,533.76
TOTAL OTHER SPECIAL FUNDS	932,708,473.72	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	6,444,916,406.40	(9,609,251,087.27)	9,564,864,878.25	369,985,061.79
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	332,238,148.98	0.00	79,265,221.18	13,662,995.31
ADVANCES TO AFFILIATES	5,719.30	(3,057,881,942.92)	2,785,941,201.59	11,409,952.97
ACCOUNTS RECEIVABLE-CUSTOMERS	587,804,543.76	244,622,199.19	0.00	113,370,816.88
ACCOUNTS RECEIVABLE - MISC	1,350,751,458.35	(9,445,392.51)	9,145,244.66	11,847,324.07
A/P FOR UNCOLLECTIBLE ACCOUNTS	(70,315,493.29)	0.00	0.00	(1,876,921.82)
ACCOUNTS RECEIVABLE- ASSOC COS	13,715,582.84	(2,260,507,040.11)	338,688,647.69	63,367,887.52
FUEL	605,007,811.90	0.00	0.00	56,698,667.95
MATERIALS & SUPPLIES	461,151,309.61	(13,328,830.74)	0.00	59,849,039.02
ACCRUED UTILITY REVENUES	376,731,759.05	150,874,990.93	0.00	30,907,372.74
PREPAYMENTS	156,318,770.03	(473,959.55)	13,440,885.74	3,774,724.24
ENERGY TRADING CONTRACTS	8,573,145,666.04	(63,832,617.00)	0.00	566,283,611.93
OTHER CURRENT ASSETS	177,642,569.78	0.00	0.00	12,244,072.55
TOTAL CURRENT ASSETS	12,564,197,846.35	(5,009,972,592.71)	3,226,481,200.86	941,539,543.36
REGULATORY ASSETS				
REGULATORY ASSETS	3,622,148,123.07	0.00	0.00	495,319,627.64
FAS109 DFIT RECLASS (A/C 254)	(460,418,390.61)	4,970,498.00	(6,990,653.00)	(36,497,329.00)
NET REGULATORY ASSETS	3,161,729,732.46	4,970,498.00	(6,990,653.00)	458,822,298.64
DEFERRED CHARGES				
CLEARING ACCOUNTS	(102,593,254.22)	(3,048,922.08)	64,802.74	244,389.02
UNAMORTIZED DEBT EXPENSE	45,261,032.67	0.00	7,544,620.21	3,407,553.66
OTHER DEFERRED DEBITS	808,161,033.58	(87,125,154.56)	17,387,067.91	38,612,619.93
TOTAL DEFERRED CHARGES	750,828,812.03	(90,174,076.64)	24,996,490.86	42,264,562.61
TOTAL ASSETS	47,281,967,790.40	(14,704,395,369.70)	12,809,351,916.97	5,180,787,836.58

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	2,153,027,480.50	(738,722,214.43)	2,153,027,480.50	260,457,768.00
PREMIUM ON CAPITAL STOCK	1,962,345,528.27	(263,733,919.06)	1,962,345,528.27	762,826.38
PAID-IN CAPITAL	817,060,323.60	(4,490,707,024.22)	820,358,003.60	714,683,741.99
RETAINED EARNINGS	3,296,122,080.50	(3,129,150,987.34)	3,296,122,054.43	150,796,650.14
COMMON SHAREHOLDERS' EQUITY	8,228,555,412.87	(8,622,314,145.05)	8,231,853,066.80	1,126,700,986.51
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	94,655,000.00	0.00	0.00	10,860,000.00
PS NOT SUBJ MANDATORY REDEMP	61,610,401.74	0.00	0.00	17,790,500.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	321,250,000.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	9,752,800,981.81	(901,100,000.00)	1,268,773,381.34	1,476,551,890.41
TOTAL CAPITALIZATION	18,458,871,796.42	(9,523,414,145.05)	9,500,626,448.14	2,631,903,376.92
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	219,225,305.17	(25,917,690.24)	0.00	33,928,399.29
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	1,114,992,529.11	0.00	0.00	50,175,477.93
TOTAL OTH NONCURRENT LIAB'S	1,334,217,834.28	(25,917,690.24)	0.00	84,103,877.22
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	2,300,477,416.28	(200,000,000.00)	0.00	80,006,878.49
SHORT-TERM DEBT	3,155,211,453.25	0.00	3,038,412,935.71	0.00
A/P - GENERAL	2,245,421,627.93	0.00	392,709.59	131,387,416.77
A/P- ASSOC. COS.	17,556,408.12	(1,773,101,945.93)	1,866,087.78	84,517,934.33
ADVANCES FROM AFFILIATES	0.00	(3,021,489,796.83)	246,902,450.18	303,226,866.67
CUSTOMER DEPOSITS	264,063,785.17	0.00	0.00	13,177,233.40
TAXES ACCRUED	651,880,568.66	(725,340.00)	(503,373.00)	55,583,447.85
INTEREST ACCRUED	152,786,688.27	(13,608,185.34)	9,503,694.05	21,769,907.45
DIVIDENDS DECLARED	10,292,301.38	0.00	0.00	360,635.63
OBLIG UNDER CAP LEASES- CURR	74,511,876.51	0.00	0.00	12,356,725.75
ENERGY TRADING CONTRACTS	8,312,006,681.92	(64,265,123.00)	0.00	549,703,474.79
OTHR CURR & ACCRUED LIAB	916,133,167.50	(46,481.30)	17,090,832.32	62,580,858.74
TOTAL CURRENT LIABILITIES	18,100,341,974.99	(5,073,236,872.40)	3,313,665,336.63	1,314,671,379.87
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	6,070,656,196.66	(5,016,594.00)	(1,771,726.00)	865,908,592.00
DFIT & DSIT RECLASS (A/C 190)	(1,247,411,345.95)	6,778,234.00	(3,258,265.00)	(162,333,905.00)
NET DEFERRED INCOME TAXES	4,823,244,850.71	1,761,640.00	(5,029,991.00)	703,574,687.00
DEF INVESTMENT TAX CREDITS	490,715,608.44	(9,230,754.00)	0.00	38,328,187.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	393,627,158.79	0.00	0.00	137,040,715.58
UNAMORT GAIN REACQUIRED DEBT	149,011.60	0.00	0.00	111,920.01
TOTAL REGULATORY LIABILITIES	393,776,170.39	0.00	0.00	137,152,635.59
DEFERRED CREDITS	3,680,799,555.17	(74,357,548.01)	90,123.20	271,053,692.98
TOTAL DEF CREDITS & REG LIAB'S	9,388,536,184.71	(81,826,662.01)	(4,939,867.80)	1,150,109,202.57
TOTAL CAPITAL & LIABILITIES	47,281,967,790.40	(14,704,395,369.70)	12,809,351,916.97	5,180,787,836.58

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	1,574,506,041.22	2,758,160,077.14	271,070,588.33	0.00
TRANSMISSION	401,404,522.72	957,336,718.30	374,115,983.35	14,930,598.87
DISTRIBUTION	1,159,105,019.48	900,920,965.86	402,537,075.58	77,560,972.60
GENERAL	146,732,305.14	233,004,797.39	65,058,968.58	5,063,820.92
CONSTRUCTION WORK IN PROGRESS	72,571,605.04	74,298,932.82	15,632,677.57	746,709.86
TOTAL ELECTRIC UTILITY PLANT	3,354,319,493.60	4,923,721,491.51	1,128,415,293.41	98,302,102.25
LESS ACCUM PRV-DEPR,DEPL,AMORT	(1,377,031,924.03)	(2,436,972,552.67)	(384,104,202.34)	(35,175,081.38)
NET ELECTRIC UTILITY PLANT	1,977,287,569.57	2,486,748,938.84	744,311,091.07	63,127,020.87
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	29,291,848.32	77,294,414.72	5,522,227.31	21,034.53
INVEST IN SUBSIDIARY & ASSOC	430,000.00	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	204,562,051.16	266,227,227.07	78,942,083.32	258,355.00
TOTAL OTHER SPECIAL FUNDS	0.00	834,108,675.61	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	234,283,899.48	1,177,630,317.40	84,464,310.63	279,389.53
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	12,357,347.14	16,804,249.36	1,946,366.70	472,052.59
ADVANCES TO AFFILIATES	1,272,513.37	46,309,293.04	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	41,769,951.78	60,863,606.27	20,035,539.39	605,704.06
ACCOUNTS RECEIVABLE - MISC	16,968,297.34	25,398,062.33	3,332,892.62	270,647.71
A/P FOR UNCOLLECTIBLE ACCOUNTS	(745,119.51)	(740,902.53)	(263,620.18)	(2,937.00)
ACCOUNTS RECEIVABLE- ASSOC COS	63,469,678.54	31,907,757.55	16,012,469.52	1,866,876.54
FUEL	20,018,628.14	28,988,624.81	12,059,829.82	0.00
MATERIALS & SUPPLIES	38,984,591.25	91,440,326.76	15,765,586.27	194,890.03
ACCRUED UTILITY REVENUES	7,086,677.45	2,071,505.45	5,394,660.43	0.00
PREPAYMENTS	1,410,869.98	4,480,242.29	601,612.21	1,129,364.50
ENERGY TRADING CONTRACTS	347,197,900.62	399,195,694.12	139,605,220.99	0.00
OTHER CURRENT ASSETS	27,323,653.96	2,016,708.00	713,301.84	735,359.99
TOTAL CURRENT ASSETS	577,114,990.06	708,735,167.45	215,203,859.61	5,271,958.42
REGULATORY ASSETS				
REGULATORY ASSETS	277,935,220.88	498,607,390.04	108,236,585.50	4,913,971.42
FAS109 DFIT RECLASS (A/C 254)	(15,668,035.00)	(89,680,290.00)	(10,543,941.00)	(443,015.00)
NET REGULATORY ASSETS	262,267,185.88	408,927,100.04	97,692,644.50	4,470,956.42
DEFERRED CHARGES				
CLEARING ACCOUNTS	61,430.13	282,926.05	130,945.52	1,707.93
UNAMORTIZED DEBT EXPENSE	2,023,601.68	4,229,507.30	289,007.25	69,444.42
OTHER DEFERRED DEBITS	54,102,078.35	30,454,412.45	11,151,619.05	196,641.58
TOTAL DEFERRED CHARGES	56,187,110.16	34,966,845.80	11,571,571.82	267,793.93
TOTAL ASSETS	3,107,140,755.15	4,817,008,369.53	1,153,243,477.63	73,417,119.17

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	41,026,065.00	56,583,866.43	50,450,000.00	4,100,000.00
PREMIUM ON CAPITAL STOCK	257,892,417.78	4,319,844.45	0.00	0.00
PAID-IN CAPITAL	316,476,557.07	725,060,923.27	156,846,734.00	13,800,000.00
RETAINED EARNINGS	176,102,772.91	74,605,269.60	48,833,324.41	5,881,581.13
COMMON SHAREHOLDERS' EQUITY	791,497,812.76	860,569,903.75	256,130,058.41	23,781,581.13
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	10,000,000.00	64,945,000.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	8,735,700.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	571,347,775.29	1,312,082,023.77	251,092,947.04	20,000,000.00
TOTAL CAPITALIZATION	1,372,845,588.05	2,246,332,627.52	507,223,005.45	43,781,581.13
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	27,052,195.42	51,092,776.15	6,742,318.80	827,186.47
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	9,662,329.98	636,176,049.20	5,187,110.06	1,068,929.83
TOTAL OTH NONCURRENT LIAB'S	36,714,525.40	687,268,825.35	11,929,428.86	1,896,116.30
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	220,500,000.00	340,000,000.00	95,000,000.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	62,393,378.49	90,816,742.25	24,049,858.03	220,851.67
A/P- ASSOC. COS.	83,697,206.85	43,955,995.19	22,556,730.74	6,745,279.68
ADVANCES FROM AFFILIATES	182,656,601.44	0.00	66,199,838.61	5,915,448.90
CUSTOMER DEPOSITS	5,883,721.03	9,269,682.96	4,460,837.80	833,503.15
TAXES ACCRUED	116,363,845.67	69,760,947.77	10,304,695.37	1,425,651.70
INTEREST ACCRUED	10,906,842.80	20,691,492.22	5,268,754.11	794,979.04
DIVIDENDS DECLARED	175,000.00	1,121,706.65	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	7,835,242.22	10,839,953.41	2,840,582.22	305,441.52
ENERGY TRADING CONTRACTS	334,957,549.76	383,713,700.51	144,363,593.92	0.00
OTHR CURR & ACCRUED LIAB	20,706,143.01	62,043,990.93	9,456,363.12	1,148,369.27
TOTAL CURRENT LIABILITIES	1,046,075,531.27	1,032,214,211.89	384,501,253.92	17,389,524.93
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	518,488,718.00	732,755,493.00	199,230,845.00	11,973,908.00
DFIT & DSIT RECLASS (A/C 190)	(74,767,049.00)	(332,224,617.00)	(30,926,475.00)	(2,510,849.00)
NET DEFERRED INCOME TAXES	443,721,669.00	400,530,876.00	168,304,370.00	9,463,059.00
DEF INVESTMENT TAX CREDITS	37,176,416.00	105,448,564.00	10,404,620.00	714,608.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	30,975.81	52,441,653.02	6,551,333.72	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	37,091.59	0.00	0.00
TOTAL REGULATORY LIABILITIES	30,975.81	52,478,744.61	6,551,333.72	0.00
DEFERRED CREDITS	170,576,049.62	292,734,520.16	64,329,465.68	172,229.81
TOTAL DEF CREDITS & REG LIAB'S	651,505,110.43	851,192,704.77	249,589,789.40	10,349,896.81
TOTAL CAPITAL & LIABILITIES	3,107,140,755.15	4,817,008,369.53	1,153,243,477.63	73,417,119.17

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	WPCO	AEGCO	AEPSC
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	3,007,865,531.86	0.00	638,296,963.88	0.00
TRANSMISSION	891,282,831.60	23,675,265.12	0.00	432.17
DISTRIBUTION	1,081,121,781.57	73,053,615.84	0.00	0.00
GENERAL	245,232,016.42	6,347,666.69	3,011,641.67	359,888,698.78
CONSTRUCTION WORK IN PROGRESS	165,073,508.50	1,158,430.10	6,945,554.19	128,566,364.58
TOTAL ELECTRIC UTILITY PLANT	5,390,575,669.95	104,234,977.75	648,254,159.74	488,455,495.53
LESS ACCUM PRV-DEPR,DEPL,AMORT	(2,452,570,932.97)	(44,108,164.81)	(337,151,277.94)	(185,527,881.91)
NET ELECTRIC UTILITY PLANT	2,938,004,736.98	60,126,812.94	311,102,881.80	302,927,613.62
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	32,122,175.14	1,957,971.36	119,589.14	0.00
INVEST IN SUBSIDIARY & ASSOC	686,552.00	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	293,228,062.38	57,991.52	0.00	101,412,743.78
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	326,036,789.52	2,015,962.88	119,589.14	101,412,743.78
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	8,847,678.14	302,626.60	983,219.93	2,714,972.91
ADVANCES TO AFFILIATES	0.00	0.00	0.00	22,381,766.37
ACCOUNTS RECEIVABLE-CUSTOMERS	84,694,284.42	5,167,796.37	0.00	236,632.86
ACCOUNTS RECEIVABLE - MISC	20,409,148.76	62,330.69	147,442.16	13,040,038.99
A/P FOR UNCOLLECTIBLE ACCOUNTS	(1,379,086.90)	(64,128.48)	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	148,563,112.67	744,062.12	22,343,784.04	194,051,703.48
FUEL	84,723,564.97	0.00	15,243,126.91	149.99
MATERIALS & SUPPLIES	88,768,076.70	97,493.98	4,479,874.06	0.00
ACCRUED UTILITY REVENUES	0.00	2,115,659.00	0.00	0.00
PREPAYMENTS	3,598,099.40	168,654.09	243,857.37	3,562,373.77
ENERGY TRADING CONTRACTS	472,245,684.18	0.00	0.00	0.00
OTHER CURRENT ASSETS	17,267,199.00	1,416,648.20	0.00	38,500,295.47
TOTAL CURRENT ASSETS	927,737,761.34	10,011,142.57	43,441,304.47	274,487,933.84
REGULATORY ASSETS				
REGULATORY ASSETS	669,837,808.90	22,261,475.76	25,548,067.84	3,474,241.19
FAS109 DFIT RECLASS (A/C 254)	(25,212,606.61)	(342,114.00)	(43,065,407.00)	(12,953,498.00)
NET REGULATORY ASSETS	644,625,202.29	21,919,361.76	(17,517,339.16)	(9,479,256.81)
DEFERRED CHARGES				
CLEARING ACCOUNTS	73,997.75	6,726.09	(586.88)	717,913.88
UNAMORTIZED DEBT EXPENSE	3,771,249.38	69,444.42	483,535.39	1,197,282.81
OTHER DEFERRED DEBITS	75,817,061.68	1,603,755.35	987,273.42	1,272,777.90
TOTAL DEFERRED CHARGES	79,662,308.81	1,679,925.86	1,470,221.93	3,187,974.59
TOTAL ASSETS	4,916,066,798.94	95,753,206.01	338,616,658.18	672,537,009.02

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	WPCO	AEGCO	AEPSC
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	321,201,454.00	2,428,460.00	1,000,000.00	1,350,000.00
PREMIUM ON CAPITAL STOCK	729,130.45	0.00	0.00	0.00
PAID-IN CAPITAL	461,556,623.78	15,595,573.00	23,434,000.00	(9,922,903.00)
RETAINED EARNINGS	401,297,351.38	9,813,599.40	13,761,108.71	0.00
COMMON SHAREHOLDERS' EQUITY	1,184,784,559.61	27,837,632.40	38,195,108.71	(8,572,903.00)
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	8,850,000.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	16,647,700.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	1,203,841,523.53	20,000,000.00	44,793,340.08	55,100,000.00
TOTAL CAPITALIZATION	2,414,123,783.14	47,837,632.40	82,988,448.79	46,527,097.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	64,260,714.08	2,568,152.45	75,591.97	32,211,982.06
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	66,125,597.98	3,001,620.04	0.00	103,424,818.46
TOTAL OTH NONCURRENT LIAB'S	130,386,312.06	5,569,772.49	75,591.97	135,636,800.52
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00	2,000,000.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	134,418,106.91	288,221.78	7,582,222.59	41,710,150.73
A/P- ASSOC. COS.	176,519,600.54	8,786,706.68	1,654,464.90	85,995,040.62
ADVANCES FROM AFFILIATES	300,212,874.81	5,569,610.80	32,049,050.59	0.00
CUSTOMER DEPOSITS	5,452,031.21	289,669.66	0.00	0.00
TAXES ACCRUED	126,770,255.04	2,516,954.89	4,776,817.29	22,485,306.09
INTEREST ACCRUED	17,679,214.45	589,446.25	938,597.13	2,841,566.60
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	16,405,200.08	675,796.32	235,890.60	22,326,394.38
ENERGY TRADING CONTRACTS	456,046,702.21	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	87,070,016.97	1,151,485.51	7,268,679.32	401,966,690.30
TOTAL CURRENT LIABILITIES	1,320,574,002.22	19,867,891.89	54,505,722.42	579,325,148.72
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	933,827,065.51	22,302,564.00	103,831,372.00	86,687,496.96
DFIT & DSIT RECLASS (A/C 190)	(135,938,491.00)	(5,708,805.00)	(75,855,920.00)	(185,585,833.00)
NET DEFERRED INCOME TAXES	797,888,574.51	16,593,759.00	27,975,452.00	(98,898,336.04)
DEF INVESTMENT TAX CREDITS	21,925,356.00	413,208.00	56,304,117.00	851,086.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	1,236,941.00	5,399,379.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	1,236,941.00	5,399,379.00	0.00	0.00
DEFERRED CREDITS	229,931,830.01	71,563.23	116,767,326.00	9,095,212.82
TOTAL DEF CREDITS & REG LIAB'S	1,050,982,701.52	22,477,909.23	201,046,895.00	(88,952,037.22)
TOTAL CAPITAL & LIABILITIES	4,916,066,798.94	95,753,206.01	338,616,658.18	672,537,009.02

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CCCO	FRECO	IFRI	AEPPM
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	0.00	0.00	0.00	0.00
TRANSMISSION	0.00	0.00	0.00	0.00
DISTRIBUTION	0.00	0.00	0.00	0.00
GENERAL	0.00	0.00	0.00	0.00
CONSTRUCTION WORK IN PROGRESS	0.00	0.00	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	0.00	0.00	0.00	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	0.00	0.00	0.00	0.00
NET ELECTRIC UTILITY PLANT	0.00	0.00	0.00	0.00
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	700,846.00	0.00	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	0.00	1,000.00	0.00	0.00
TOTAL OTHER INVESTMENTS	0.00	11.00	11.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	700,846.00	1,011.00	11.00	0.00
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	20,945.60	662,204.68	120,138.87	0.00
ADVANCES TO AFFILIATES	293,082.06	304,257.35	19,455.39	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	3,967.22	412.42	0.00	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	6,244.95	(112,974.62)	111,005.10	100.00
FUEL	0.00	0.00	0.00	0.00
MATERIALS & SUPPLIES	0.00	0.00	0.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00	0.00
PREPAYMENTS	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00
OTHER CURRENT ASSETS	3,979.00	0.00	0.00	0.00
TOTAL CURRENT ASSETS	328,218.83	853,899.83	250,599.36	100.00
REGULATORY ASSETS				
REGULATORY ASSETS	0.00	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	(66,000.00)	0.00	0.00	0.00
NET REGULATORY ASSETS	(66,000.00)	0.00	0.00	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	0.00	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	0.00	6,734.40	410.92	0.00
TOTAL DEFERRED CHARGES	0.00	6,734.40	410.92	0.00
TOTAL ASSETS	963,064.83	861,645.23	251,021.28	100.00

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CCCO	FRECO	IFRI	AEPPM
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	3,000.00	10,000.00	1,000.00	100.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	1,204,736.00	0.00	0.00	0.00
RETAINED EARNINGS	0.00	19,968.85	0.00	(373.34)
COMMON SHAREHOLDERS' EQUITY	1,207,736.00	29,968.85	1,000.00	(273.34)
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	0.00	0.00	0.00	0.00
TOTAL CAPITALIZATION	1,207,736.00	29,968.85	1,000.00	(273.34)
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	295,160.00	0.00	0.00	0.00
TOTAL OTH NONCURRENT LIAB'S	295,160.00	0.00	0.00	0.00
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	0.00	0.00	0.00	0.00
A/P- ASSOC. COS.	2,620.47	101,352.89	108,108.55	575.34
ADVANCES FROM AFFILIATES	0.00	0.00	0.00	0.00
CUSTOMER DEPOSITS	0.00	0.00	0.00	0.00
TAXES ACCRUED	(13,380.42)	(28.35)	0.00	(119.00)
INTEREST ACCRUED	0.00	0.00	91.74	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	6,920.78	728,654.20	141,806.99	0.00
TOTAL CURRENT LIABILITIES	(3,839.17)	829,978.74	250,007.28	456.34
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	23,830.00	0.00	0.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(559,822.00)	0.00	0.00	(83.00)
NET DEFERRED INCOME TAXES	(535,992.00)	0.00	0.00	(83.00)
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00
DEFERRED CREDITS	0.00	1,697.64	14.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	(535,992.00)	1,697.64	14.00	(83.00)
TOTAL CAPITAL & LIABILITIES	963,064.83	861,645.23	251,021.28	100.00

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPES	AEPINV CONSOLIDATED	AEPR CONSOLIDATED	AEPPRO
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	0.00	0.00	1,201,321,698.03	0.00
TRANSMISSION	0.00	0.00	456,862,837.34	0.00
DISTRIBUTION	0.00	0.00	352,392,017.24	0.00
GENERAL	2,444,961.80	0.00	446,308,352.46	157,280.93
CONSTRUCTION WORK IN PROGRESS	13,131,096.06	302,734.00	20,995,579.04	0.00
TOTAL ELECTRIC UTILITY PLANT	15,576,057.86	302,734.00	2,477,880,484.11	157,280.93
LESS ACCUM PRV-DEPR,DEPL,AMORT	(2,185,238.05)	0.00	(105,037,036.25)	(54,510.60)
NET ELECTRIC UTILITY PLANT	13,390,819.81	302,734.00	2,372,843,447.86	102,770.33
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	0.00	0.00	2,364,000.00	0.00
INVEST IN SUBSIDIARY & ASSOC	- 6,540,881.36	1,237,286.64	112,756,369.74	0.00
TOTAL OTHER INVESTMENTS	956,419,696.61	16,086,706.49	1,057,929,425.29	5,000,000.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	962,960,577.97	17,323,993.13	1,173,049,795.03	5,000,000.00
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	910,000.49	0.00	60,969,675.88	332,360.59
ADVANCES TO AFFILIATES	65,950,065.72	0.00	6,383,022.91	57,968,341.71
ACCOUNTS RECEIVABLE-CUSTOMERS	331.96	0.00	48,232,446.85	0.00
ACCOUNTS RECEIVABLE - MISC	805,090,658.53	0.00	176,684,283.41	8,123,709.96
A/P FOR UNCOLLECTIBLE ACCOUNTS	(207.34)	0.00	(45,046,023.69)	(959,027.23)
ACCOUNTS RECEIVABLE- ASSOC COS	585,887,034.50	224,956.17	368,706,407.44	7,595,725.77
FUEL	113,647,392.22	0.00	147,293,838.97	0.00
MATERIALS & SUPPLIES	0.00	0.00	7,108,794.24	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	102,096,893.05	0.00
PREPAYMENTS	(791,913.46)	8,359.00	78,144,014.12	263,937.95
ENERGY TRADING CONTRACTS	5,865,337,604.20	0.00	222,522,378.52	0.00
OTHER CURRENT ASSETS	64,826,770.98	0.00	9,529,019.17	0.00
TOTAL CURRENT ASSETS	7,500,857,737.80	233,315.17	1,182,624,750.87	73,325,048.75
REGULATORY ASSETS				
REGULATORY ASSETS	0.00	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	(2,823,106.26)	0.00	19,897,152.68	398,137.21
UNAMORTIZED DEBT EXPENSE	0.00	0.00	18,114,738.18	0.00
OTHER DEFERRED DEBITS	2,425,813.36	0.00	77,982,202.41	101,333,001.39
TOTAL DEFERRED CHARGES	(397,292.90)	0.00	115,994,093.27	101,731,138.60
TOTAL ASSETS	8,476,811,842.68	17,860,042.30	4,844,512,087.03	180,158,957.68

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPES	AEPINV CONSOLIDATED	AEPR CONSOLIDATED	AEPPRO
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	200.00	100.00	100.00	110,000.00
PREMIUM ON CAPITAL STOCK	0.00	9,900.00	9,900.00	0.00
PAID-IN CAPITAL	36,685,774.77	29,222,509.98	246,438,157.08	3,890,000.00
RETAINED EARNINGS	41,786,520.57	(9,873,548.06)	(95,579,409.53)	(4,799,653.66)
COMMON SHAREHOLDERS' EQUITY	78,472,495.34	19,358,961.92	150,868,747.55	(799,653.66)
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	0.00	0.00	1,236,188,752.29	0.00
TOTAL CAPITALIZATION	78,472,495.34	19,358,961.92	1,387,057,499.84	(799,653.66)
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	86,380.23	0.00	358,905.01	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	1,548,677.58	0.00	66,159,810.44	73,928.67
TOTAL OTH NONCURRENT LIAB'S	1,635,057.81	0.00	66,518,715.45	73,928.67
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	889,252,509.79	0.00
SHORT-TERM DEBT	0.00	0.00	40,500.00	0.00
A/P - GENERAL	875,098,740.59	0.00	244,404,134.67	4,907,764.87
A/P- ASSOC. COS.	687,213,450.04	495,083.42	345,613,465.90	18,069,133.56
ADVANCES FROM AFFILIATES	0.00	3,877,433.69	504,048,958.76	0.00
CUSTOMER DEPOSITS	80,174,925.00	0.00	205,221.22	0.00
TAXES ACCRUED	16,018,187.49	(281,807.00)	48,251,841.93	245,689.18
INTEREST ACCRUED	0.01	11,138.41	10,126,349.82	0.00
DIVIDENDS DECLARED	0.00	0.00	8,458,238.57	0.00
OBLIG UNDER CAP LEASES- CURR	398,211.76	0.00	189,868.20	0.00
ENERGY TRADING CONTRACTS	5,662,034,055.02	0.00	200,577,626.17	0.00
OTHR CURR & ACCRUED LIAB	15,130,904.01	1,679.86	71,380,202.36	4,833,424.67
TOTAL CURRENT LIABILITIES	7,336,068,473.92	4,103,528.38	2,322,548,917.39	28,056,012.28
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	145,958,783.00	(631,294.00)	153,120,145.62	9,874.00
DFIT & DSIT RECLASS (A/C 190)	(104,796,159.00)	(4,971,154.00)	(103,967,493.33)	(1,476,008.00)
NET DEFERRED INCOME TAXES	41,162,624.00	(5,602,448.00)	49,152,652.29	(1,466,134.00)
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00
DEFERRED CREDITS	1,019,473,191.61	0.00	1,019,234,302.06	154,294,804.39
TOTAL DEF CREDITS & REG LIAB'S	1,060,635,815.61	(5,602,448.00)	1,068,386,954.35	152,828,670.39
TOTAL CAPITAL & LIABILITIES	8,476,811,842.68	17,860,042.30	4,844,512,087.03	180,158,957.68

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPC CONSOLIDATED	CSW CONSOLIDATED	AEPRELLC	AEP C&I CONSOLIDATED
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	0.00	6,076,996,319.25	0.00	0.00
TRANSMISSION	0.00	1,879,536,528.22	0.00	0.00
DISTRIBUTION	0.00	5,376,014,741.93	0.00	0.00
GENERAL	77,463,894.44	2,002,462,646.30	0.00	130,500.00
CONSTRUCTION WORK IN PROGRESS	21,732,372.71	373,561,314.81	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	99,196,267.15	15,708,571,550.51	0.00	130,500.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	(6,235,351.91)	(6,359,488,432.25)	0.00	(20,371.89)
NET ELECTRIC UTILITY PLANT	92,960,915.24	9,349,083,118.26	0.00	110,128.11
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	0.00	11,875,436.68	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	76,558,621.72	460,232,323.47	0.00	14,765,489.32
TOTAL OTHER INVESTMENTS	2,725,642.00	1,371,807,676.84	0.00	(2,526,671.00)
TOTAL OTHER SPECIAL FUNDS	0.00	98,599,798.11	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	79,284,263.72	1,942,515,235.10	0.00	12,238,818.32
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	95,691.15	122,760,697.28	85.88	45,200.00
ADVANCES TO AFFILIATES	53,315,077.20	6,242,085.20	0.00	97,547.34
ACCOUNTS RECEIVABLE-CUSTOMERS	(29.71)	(31,794,736.56)	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	5,795,458.52	236,447,003.17	129,139.91	215.81
A/P FOR UNCOLLECTIBLE ACCOUNTS	(1,348,523.13)	(17,888,995.48)	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	2,079,828.04	428,273,589.53	1,171.58	116,199.53
FUEL	0.00	120,768,370.54	0.00	0.00
MATERIALS & SUPPLIES	1,224,446.97	164,047,790.58	0.00	2,519,230.49
ACCRUED UTILITY REVENUES	0.00	76,184,000.00	0.00	0.00
PREPAYMENTS	85,764.52	46,445,007.95	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	624,590,188.48	0.00	0.00
OTHER CURRENT ASSETS	431,917.06	1,707,683.00	0.00	0.00
TOTAL CURRENT ASSETS	61,679,630.62	1,777,782,683.69	130,397.37	2,778,393.17
REGULATORY ASSETS				
REGULATORY ASSETS	0.00	1,516,013,733.90	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	(223,926,000.00)	0.00	0.00
NET REGULATORY ASSETS	0.00	1,292,087,733.90	0.00	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	(58,040.94)	(118,762,823.63)	(0.01)	33.70
UNAMORTIZED DEBT EXPENSE	1,288,623.19	2,772,424.78	0.00	0.00
OTHER DEFERRED DEBITS	10,304,842.82	462,792,617.65	(0.13)	0.03
TOTAL DEFERRED CHARGES	11,535,425.07	346,802,218.80	(0.14)	33.73
TOTAL ASSETS	245,460,234.65	14,708,270,989.75	130,397.23	15,127,373.33

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPC CONSOLIDATED	CSW CONSOLIDATED	AEPRELLC	AEP C&I CONSOLIDATED
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	100.00	1.00	0.00	0.00
PREMIUM ON CAPITAL STOCK	9,900.00	0.00	0.00	0.00
PAID-IN CAPITAL	28,290,000.00	1,724,146,916.28	0.00	0.00
RETAINED EARNINGS	(75,226,305.13)	2,402,749,873.50	(224,206.86)	(3,267,095.65)
COMMON SHAREHOLDERS' EQUITY	(46,926,305.13)	4,126,896,790.78	(224,206.86)	(3,267,095.65)
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	18,436,501.74	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	321,250,000.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	125,196,000.03	3,050,933,348.03	0.00	0.00
TOTAL CAPITALIZATION	78,269,694.90	7,517,516,640.55	(224,206.86)	(3,267,095.65)
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	25,938,393.48	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	372,310.87	145,919,685.60	0.00	0.00
TOTAL OTH NONCURRENT LIAB'S	26,310,704.35	145,919,685.60	0.00	0.00
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	873,718,028.00	0.00	0.00
SHORT-TERM DEBT	50,000,000.00	63,676,839.00	0.00	0.00
A/P - GENERAL	1,241,502.58	620,931,734.78	38,802.45	895.06
A/P- ASSOC. COS.	3,214,142.74	119,112,227.37	8,507.52	232,419.82
ADVANCES FROM AFFILIATES	51,982,441.31	1,136,240,443.99	466,140.48	18,175,801.78
CUSTOMER DEPOSITS	0.00	144,316,959.74	0.00	0.00
TAXES ACCRUED	5,315,350.18	182,710,243.06	(121,440.00)	(216,935.00)
INTEREST ACCRUED	160,117.34	64,759,214.28	610.70	54,294.59
DIVIDENDS DECLARED	0.00	176,720.53	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	126,558.19	(23,988.14)	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	644,875,102.54	0.00	0.00
OTHR CURR & ACCRUED LIAB	2,674,879.53	130,146,977.87	(9,681.06)	181,202.82
TOTAL CURRENT LIABILITIES	114,714,991.87	3,980,640,503.02	382,940.09	18,427,679.07
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	3,734,956.00	2,289,232,167.57	0.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(11,637,528.00)	(17,641,242.62)	(28,336.00)	0.00
NET DEFERRED INCOME TAXES	(7,902,572.00)	2,271,590,924.95	(28,336.00)	0.00
DEF INVESTMENT TAX CREDITS	0.00	228,380,200.44	0.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	190,926,160.66	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	190,926,160.66	0.00	0.00
DEFERRED CREDITS	34,067,415.53	373,296,874.53	0.00	(33,210.09)
TOTAL DEF CREDITS & REG LIAB'S	26,164,843.53	3,064,194,160.58	(28,336.00)	(33,210.09)
TOTAL CAPITAL & LIABILITIES	245,460,234.65	14,708,270,989.75	130,397.23	15,127,373.33

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEP T&D SVC	AEPTEXASGP	AEPCOAL	MESA LP CONSOLIDATED	MUTUALENER CONSOLIDATED
ASSETS:					
ELECTRIC UTILITY PLANT					
PRODUCTION	0.00	0.00	0.00	0.00	0.00
TRANSMISSION	0.00	0.00	0.00	0.00	0.00
DISTRIBUTION	0.00	0.00	0.00	0.00	0.00
GENERAL	0.00	0.00	103,978,375.00	175,000,000.00	0.00
CONSTRUCTION WORK IN PROGRESS	0.00	0.00	0.00	0.00	3,297,693.64
TOTAL ELECTRIC UTILITY PLANT	0.00	0.00	103,978,375.00	175,000,000.00	3,297,693.64
LESS ACCUM PRV-DEPR,DEPL,AMORT	0.00	0.00	(2,619,933.88)	0.00	0.00
NET ELECTRIC UTILITY PLANT	0.00	0.00	101,358,441.12	175,000,000.00	3,297,693.64
OTHER PROPERTY AND INVESTMENT					
NET NONUTILITY PROPERTY	0.00	0.00	0.00	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	0.00	0.00	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	0.00	0.00	0.00	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	0.00	0.00	0.00	0.00	0.00
CURRENT AND ACCRUED ASSETS					
CASH AND CASH EQUIVALENTS	0.00	0.00	8,964,418.70	0.00	0.00
ADVANCES TO AFFILIATES	0.00	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	0.00	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	303,938.93	0.00	26,037,554.07	0.00	959,079.58
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	1,337.02	1,000.00	203,921.76	0.00	111,096.51
FUEL	0.00	0.00	5,158,343.56	0.00	407,274.02
MATERIALS & SUPPLIES	0.00	0.00	0.00	0.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00	0.00	0.00
PREPAYMENTS	0.00	0.00	226,875.91	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00	0.00
OTHER CURRENT ASSETS	0.00	0.00	925,961.56	0.00	0.00
TOTAL CURRENT ASSETS	305,275.95	1,000.00	41,517,075.56	0.00	1,477,450.11
REGULATORY ASSETS					
REGULATORY ASSETS	0.00	0.00	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00	0.00	0.00
DEFERRED CHARGES					
CLEARING ACCOUNTS	220,062.88	0.00	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	0.00	0.00	2,163,986.97	0.00	6,691,270.70
TOTAL DEFERRED CHARGES	220,062.88	0.00	2,163,986.97	0.00	6,691,270.70
TOTAL ASSETS	525,338.83	1,000.00	145,039,503.65	175,000,000.00	11,466,414.45

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEP T&D SVC	AEPTEXASGP	AEPCOAL	MESA LP CONSOLIDATED	MUTUALENER CONSOLIDATED
CAPITALIZATION AND LIABILITIES:					
CAPITALIZATION					
COMMON STOCK					
COMMON STOCK	0.00	0.00	0.00	0.00	0.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	0.00	0.00	0.00	0.00	0.00
RETAINED EARNINGS	(76,815.33)	(1,855.40)	634,548.00	0.00	(8,082,292.23)
COMMON SHAREHOLDERS' EQUITY	(76,815.33)	(1,855.40)	634,548.00	0.00	(8,082,292.23)
CUMULATIVE PREFERRED STOCK					
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES					
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)					
LONG-TERM DEBT LESS AMT DUE 1 YR	0.00	0.00	0.00	18,000,000.00	0.00
TOTAL CAPITALIZATION	(76,815.33)	(1,855.40)	634,548.00	18,000,000.00	(8,082,292.23)
OTHER NONCURRENT LIABILITIES					
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	0.00	0.00	25,801,022.47	0.00	0.00
TOTAL OTH NONCURRENT LIAB'S	0.00	0.00	25,801,022.47	0.00	0.00
CURRENT LIABILITIES					
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	3,081,178.54	0.00	0.00
A/P - GENERAL	2,265.39	0.00	5,536,128.73	0.00	0.00
A/P- ASSOC. COS.	66,278.85	2,953.40	93,802,013.96	0.00	6,320,972.91
ADVANCES FROM AFFILIATES	217,583.96	0.00	0.00	147,854,987.18	15,893,263.68
CUSTOMER DEPOSITS	0.00	0.00	0.00	0.00	0.00
TAXES ACCRUED	134,470.14	(98.00)	4,617,234.78	(10,990,000.00)	(2,547,849.00)
INTEREST ACCRUED	1,021.76	0.00	291,366.78	0.00	6,174.08
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	182,079.06	0.00	11,276,010.39	9,145,012.82	(123,854.99)
TOTAL CURRENT LIABILITIES	603,699.16	2,855.40	118,603,933.18	146,010,000.00	19,548,706.68
DEF CREDITS & REGULATORY LIAB					
DEFERRED INCOME TAXES	0.00	0.00	0.00	10,990,000.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(1,545.00)	0.00	0.00	0.00	0.00
NET DEFERRED INCOME TAXES	(1,545.00)	0.00	0.00	10,990,000.00	0.00
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES					
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00	0.00
DEFERRED CREDITS	0.00	0.00	0.00	0.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	(1,545.00)	0.00	0.00	10,990,000.00	0.00
TOTAL CAPITAL & LIABILITIES	525,338.83	1,000.00	145,039,503.65	175,000,000.00	11,466,414.45

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSW CONSOLIDATED	CSW ELIMINATIONS	CSW	CPL
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	6,076,996,319.25	0.00	0.00	3,169,421,304.82
TRANSMISSION	1,879,536,528.22	0.00	0.00	663,654,688.62
DISTRIBUTION	5,376,014,741.93	0.00	0.00	1,279,037,886.33
GENERAL	2,002,462,646.30	0.00	0.00	488,518,471.13
CONSTRUCTION WORK IN PROGRESS	373,561,314.81	0.00	0.00	169,074,812.08
TOTAL ELECTRIC UTILITY PLANT	15,708,571,550.51	0.00	0.00	5,769,707,162.98
LESS ACCUM PRV-DEPR,DEPL,AMORT	(6,359,488,432.25)	0.00	0.00	(2,347,427,657.04)
NET ELECTRIC UTILITY PLANT	9,349,083,118.26	0.00	0.00	3,422,279,505.94
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	11,875,436.68	0.00	0.00	2,315,319.36
INVEST IN SUBSIDIARY & ASSOC	460,232,323.47	(4,884,204,026.58)	4,168,172,506.58	2,000.00
TOTAL OTHER INVESTMENTS	1,371,807,676.84	(2,250,884.14)	29,598,106.34	72,855,936.70
TOTAL OTHER SPECIAL FUNDS	98,599,798.11	0.00	0.00	98,599,798.11
TOTAL OTHER PROP AND INVSTMNTS	1,942,515,235.10	(4,886,454,910.72)	4,197,770,612.92	173,773,054.17
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	122,760,697.28	0.00	0.00	10,909,717.25
ADVANCES TO AFFILIATES	6,242,085.20	0.00	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	(31,794,736.56)	200,778,442.14	0.00	38,272,766.42
ACCOUNTS RECEIVABLE - MISC	236,447,003.17	0.00	948,483.90	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	(17,888,995.48)	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	428,273,589.53	(476,148,263.21)	24,208,250.92	6,249,279.98
FUEL	120,768,370.54	0.00	0.00	38,689,642.74
MATERIALS & SUPPLIES	164,047,790.58	0.00	0.00	55,474,693.61
ACCRUED UTILITY REVENUES	76,184,000.00	0.00	0.00	46,869,000.00
PREPAYMENTS	46,445,007.95	0.00	(581,786.91)	2,443,368.14
ENERGY TRADING CONTRACTS	624,590,188.48	0.00	0.00	212,979,008.00
OTHER CURRENT ASSETS	1,707,683.00	0.00	0.00	298,685.00
TOTAL CURRENT ASSETS	1,777,782,683.69	(275,369,821.07)	24,574,947.91	412,186,161.14
REGULATORY ASSETS				
REGULATORY ASSETS	1,516,013,733.90	0.00	0.00	1,286,157,904.42
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	1,516,013,733.90	0.00	0.00	1,286,157,904.42
DEFERRED CHARGES				
CLEARING ACCOUNTS	(118,762,823.63)	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	2,772,424.78	0.00	0.00	0.00
OTHER DEFERRED DEBITS	462,792,617.65	39,600,098.77	2,423,718.88	67,115,131.98
TOTAL DEFERRED CHARGES	346,802,218.80	39,600,098.77	2,423,718.88	67,115,131.98
TOTAL ASSETS	14,932,196,989.75	(5,122,224,633.02)	4,224,769,279.71	5,361,511,757.65

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSW CONSOLIDATED	CSW ELIMINATIONS	CSW	CPL
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	1.00	(599,001,995.00)	1.00	168,888,375.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	1,724,146,916.28	(2,614,204,669.60)	1,724,146,916.28	405,000,000.00
RETAINED EARNINGS	2,402,749,873.50	(1,670,619,279.69)	2,408,129,435.40	826,197,470.29
COMMON SHAREHOLDERS' EQUITY	4,126,896,790.78	(4,883,825,944.29)	4,132,276,352.68	1,400,085,845.29
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	18,436,501.74	0.00	0.00	5,966,568.87
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	321,250,000.00	0.00	0.00	136,250,000.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	3,050,933,348.03	0.00	0.00	988,767,526.20
TOTAL CAPITALIZATION	7,517,516,640.55	(4,883,825,944.29)	4,132,276,352.68	2,531,069,940.36
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	145,919,685.60	0.00	0.00	108,076,627.53
TOTAL OTH NONCURRENT LIAB'S	145,919,685.60	0.00	0.00	108,076,627.53
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	873,718,028.00	0.00	0.00	265,000,000.00
SHORT-TERM DEBT	63,676,839.00	0.00	0.00	0.00
A/P - GENERAL	620,931,734.78	0.00	492,900.70	65,306,606.20
A/P- ASSOC. COS.	119,112,227.37	(231,979,053.80)	15,101,675.25	96,169,891.14
ADVANCES FROM AFFILIATES	1,136,240,443.99	203,815.52	49,128,320.82	354,277,094.99
CUSTOMER DEPOSITS	144,316,959.74	0.00	0.00	26,744,329.36
TAXES ACCRUED	182,710,243.06	0.00	(18,679,551.10)	83,511,967.99
INTEREST ACCRUED	64,759,214.28	2,595,414.04	1,541,442.68	18,524,064.09
DIVIDENDS DECLARED	176,720.53	(9,391,579.37)	0.00	40,258.55
OBLIG UNDER CAP LEASES- CURR	(23,988.14)	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	644,875,102.54	0.00	0.00	219,485,339.79
OTHR CURR & ACCRUED LIAB	130,146,977.87	0.00	5,923,375.96	19,463,969.30
TOTAL CURRENT LIABILITIES	3,980,640,503.02	(238,571,403.61)	53,508,164.31	1,148,523,521.41
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	2,289,232,167.57	0.00	2,387,812.91	1,163,795,027.97
DFIT & DSIT RECLASS (A/C 190)	(17,641,242.62)	0.00	0.00	0.00
NET DEFERRED INCOME TAXES	2,271,590,924.95	0.00	2,387,812.91	1,163,795,027.97
DEF INVESTMENT TAX CREDITS	228,380,200.44	0.00	0.00	122,892,590.02
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	414,852,160.66	0.00	0.00	220,671,247.35
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	414,852,160.66	0.00	0.00	220,671,247.35
DEFERRED CREDITS	373,296,874.53	172,714.88	36,596,949.81	66,482,803.01
TOTAL DEF CREDITS & REG LIAB'S	3,288,120,160.58	172,714.88	38,984,762.72	1,573,841,668.35
TOTAL CAPITAL & LIABILITIES	14,932,196,989.75	(5,122,224,633.02)	4,224,769,279.71	5,361,511,757.65

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	PSO CONSOLIDATED	SWEPCO CONSOLIDATED	WTU	SEEBOARD
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	1,034,711,260.90	1,429,355,515.44	443,508,238.09	0.00
TRANSMISSION	427,110,067.06	538,748,605.56	250,023,166.98	0.00
DISTRIBUTION	972,805,625.33	1,042,522,709.60	431,969,376.67	1,649,679,144.00
GENERAL	203,571,735.74	376,015,615.68	112,796,684.20	343,691,521.00
CONSTRUCTION WORK IN PROGRESS	56,899,811.29	74,121,735.91	22,574,904.40	0.00
TOTAL ELECTRIC UTILITY PLANT	2,695,098,500.32	3,460,764,182.19	1,260,872,370.34	1,993,370,665.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	(1,184,442,455.53)	(1,550,618,108.66)	(546,162,575.55)	(710,229,164.00)
NET ELECTRIC UTILITY PLANT	1,510,656,044.79	1,910,146,073.53	714,709,794.79	1,283,141,501.00
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	4,473,604.61	4,232,711.01	853,801.70	0.00
INVEST IN SUBSIDIARY & ASSOC	3,746,186.51	196,435.96	2,000.00	43,755,908.00
TOTAL OTHER INVESTMENTS	55,778,510.81	64,987,377.93	21,659,162.38	1,128,999,212.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	63,998,301.93	69,416,524.90	22,514,964.08	1,172,755,120.00
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	5,794,623.97	5,415,250.74	2,453,471.52	88,975,003.00
ADVANCES TO AFFILIATES	0.00	6,242,085.20	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	31,100,285.97	44,499,122.56	18,524,360.58	195,306,879.00
ACCOUNTS RECEIVABLE - MISC	0.00	(2,261,960.12)	0.00	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	10,905,192.83	14,331,366.11	8,656,082.74	74,461,420.00
FUEL	21,559,102.22	52,212,350.83	8,307,274.75	0.00
MATERIALS & SUPPLIES	36,784,585.98	32,527,148.17	11,190,050.74	18,205,006.00
ACCRUED UTILITY REVENUES	9,120,000.00	11,466,000.00	8,729,000.00	0.00
PREPAYMENTS	2,121,660.32	18,416,393.71	866,427.73	21,417,734.00
ENERGY TRADING CONTRACTS	162,199,825.92	186,159,106.01	63,252,248.55	0.00
OTHER CURRENT ASSETS	246,969.00	298,779.00	99,278.00	0.00
TOTAL CURRENT ASSETS	279,832,246.21	369,305,642.21	122,078,194.61	398,366,042.00
REGULATORY ASSETS				
REGULATORY ASSETS	56,416,524.28	111,181,673.25	62,257,631.95	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	56,416,524.28	111,181,673.25	62,257,631.95	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	0.00	(118,868,099.71)	0.00	0.00
UNAMORTIZED DEBT EXPENSE	195,380.25	0.00	0.00	0.00
OTHER DEFERRED DEBITS	37,331,593.97	223,576,041.87	26,395,829.41	51,721,250.00
TOTAL DEFERRED CHARGES	37,526,974.22	104,707,942.16	26,395,829.41	51,721,250.00
TOTAL ASSETS	1,948,430,091.43	2,564,757,856.05	947,956,414.84	2,905,983,913.00

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	PSO CONSOLIDATED	SWEPCO CONSOLIDATED	WTU	SEEBOARD
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	157,230,000.00	135,659,520.00	137,214,000.00	1,000.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	180,000,000.00	245,000,000.00	2,236,000.00	747,442,558.00
RETAINED EARNINGS	142,994,538.42	308,914,741.35	105,970,218.12	340,612,956.00
COMMON SHAREHOLDERS' EQUITY	480,224,538.42	689,574,261.35	245,420,218.12	1,088,056,514.00
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	5,283,381.64	4,704,420.64	2,482,130.59	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	75,000,000.00	110,000,000.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	345,128,836.38	494,688,142.61	220,966,636.23	700,661,051.00
TOTAL CAPITALIZATION	905,636,756.44	1,298,966,824.60	468,868,984.94	1,788,717,565.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	7,183,476.55	26,452,577.65	4,119,240.87	0.00
TOTAL OTH NONCURRENT LIAB'S	7,183,476.55	26,452,577.65	4,119,240.87	0.00
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	106,000,000.00	150,595,000.00	35,000,000.00	315,822,879.00
SHORT-TERM DEBT	0.00	0.00	0.00	14,264,264.00
A/P - GENERAL	72,758,902.12	71,810,201.55	33,781,939.19	259,799,656.00
A/P- ASSOC. COS.	49,976,602.31	48,934,644.14	20,117,319.65	1,251,533.00
ADVANCES FROM AFFILIATES	123,086,617.80	123,609,420.67	50,448,227.65	19,035,097.00
CUSTOMER DEPOSITS	21,041,497.44	19,879,984.82	4,190,888.00	72,445,965.00
TAXES ACCRUED	18,150,367.38	36,522,250.73	17,357,685.16	39,035,620.00
INTEREST ACCRUED	7,298,258.19	13,630,530.33	1,244,255.65	16,534,163.00
DIVIDENDS DECLARED	53,159.18	57,263.62	26,039.18	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	167,657,809.96	192,317,631.94	65,414,320.85	0.00
OTHR CURR & ACCRUED LIAB	12,242,867.58	39,672,794.50	11,974,769.41	33,739,768.00
TOTAL CURRENT LIABILITIES	578,266,081.96	697,029,722.30	239,555,444.74	771,928,945.00
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	296,876,549.00	369,781,227.00	145,049,158.00	269,165,239.00
DFIT & DSIT RECLASS (A/C 190)	0.00	0.00	0.00	(872,760.00)
NET DEFERRED INCOME TAXES	296,876,549.00	369,781,227.00	145,049,158.00	268,292,479.00
DEF INVESTMENT TAX CREDITS	33,992,236.19	48,714,448.00	22,780,926.23	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	78,600,130.68	67,261,807.76	48,318,974.87	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	78,600,130.68	67,261,807.76	48,318,974.87	0.00
DEFERRED CREDITS	47,874,860.61	56,551,248.74	19,263,685.19	77,044,924.00
TOTAL DEF CREDITS & REG LIAB'S	457,343,776.48	542,308,731.50	235,412,744.29	345,337,403.00
TOTAL CAPITAL & LIABILITIES	1,948,430,091.43	2,564,757,856.05	947,956,414.84	2,905,983,913.00

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSWI CONSOLIDATED	CSWE CONSOLIDATED	ENERSHOP	CSWL
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	0.00	0.00	0.00	0.00
TRANSMISSION	0.00	0.00	0.00	0.00
DISTRIBUTION	0.00	0.00	0.00	0.00
GENERAL	4,083,763.00	380,479,019.00	676,130.36	3,750,000.37
CONSTRUCTION WORK IN PROGRESS	0.00	0.00	5,109.99	0.00
TOTAL ELECTRIC UTILITY PLANT	4,083,763.00	380,479,019.00	681,240.35	3,750,000.37
LESS ACCUM PRV-DEPR,DEPL,AMORT	(1,518,852.00)	(4,527,717.00)	(493,354.14)	0.00
NET ELECTRIC UTILITY PLANT	2,564,911.00	375,951,302.00	187,886.21	3,750,000.37
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	0.00	0.00	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	983,152,584.00	145,408,729.00	0.00	0.00
TOTAL OTHER INVESTMENTS	0.00	0.00	60,666.83	(165,417.15)
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	983,152,584.00	145,408,729.00	60,666.83	(165,417.15)
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	859,431.00	2,354,218.00	0.00	7,213,081.00
ADVANCES TO AFFILIATES	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	0.00	0.00	(576.46)	0.00
ACCOUNTS RECEIVABLE - MISC	3,674,316.00	85,811,006.00	622,229.39	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	20,368,289.00	449,073.00	185.25	0.00
FUEL	0.00	0.00	0.00	0.00
MATERIALS & SUPPLIES	0.00	0.00	0.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00	0.00
PREPAYMENTS	(293,361.00)	1,081,749.00	13,582.02	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00
OTHER CURRENT ASSETS	0.00	0.00	302,372.00	0.00
TOTAL CURRENT ASSETS	24,608,675.00	89,696,046.00	937,792.20	7,213,081.00
REGULATORY ASSETS				
REGULATORY ASSETS	0.00	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	0.00	0.00	4,897.93	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	160,743.56	0.00
OTHER DEFERRED DEBITS	26,652.00	7,450,396.00	382,042.56	0.00
TOTAL DEFERRED CHARGES	26,652.00	7,450,396.00	547,684.05	0.00
TOTAL ASSETS	1,010,352,822.00	618,506,473.00	1,734,029.29	10,797,664.22

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSWI CONSOLIDATED	CSWE CONSOLIDATED	ENERSHOP	CSWL
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	1,000.00	1,000.00	100.00	1,000.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	828,087,992.00	105,834,017.00	900.00	34,726,215.47
RETAINED EARNINGS	21,190,977.00	115,605,613.00	(17,959,989.37)	(33,863,641.04)
COMMON SHAREHOLDERS' EQUITY	849,279,969.00	221,440,630.00	(17,958,989.37)	863,574.43
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	0.00	50,078,400.00	15,029,628.75	0.00
TOTAL CAPITALIZATION	849,279,969.00	271,519,030.00	(2,929,360.62)	863,574.43
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	0.00	0.00	36,792.00	0.00
TOTAL OTH NONCURRENT LIAB'S	0.00	0.00	36,792.00	0.00
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	368,385.00	17,700,699.00	304,506.84	0.00
A/P- ASSOC. COS.	102,517,489.00	8,703,672.00	123,856.45	12,201.96
ADVANCES FROM AFFILIATES	72,592,702.00	245,926,907.00	4,271,430.84	0.00
CUSTOMER DEPOSITS	0.00	0.00	0.00	0.00
TAXES ACCRUED	(18,494,180.00)	16,151,434.00	(175,909.93)	7,205,614.90
INTEREST ACCRUED	60,623.00	699,770.00	29,247.87	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	(20,669.00)	4,620,443.00	23,142.34	0.00
TOTAL CURRENT LIABILITIES	157,024,350.00	293,802,925.00	4,576,274.41	7,217,816.86
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	0.00	39,685,500.00	888,893.50	7,639,587.93
DFIT & DSIT RECLASS (A/C 190)	(3,212,033.00)	(1,241,301.00)	(838,570.00)	(4,923,315.00)
NET DEFERRED INCOME TAXES	(3,212,033.00)	38,444,199.00	50,323.50	2,716,272.93
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00
DEFERRED CREDITS	7,260,536.00	14,740,319.00	0.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	4,048,503.00	53,184,518.00	50,323.50	2,716,272.93
TOTAL CAPITAL & LIABILITIES	1,010,352,822.00	618,506,473.00	1,734,029.29	10,797,664.22

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	C3 COMM CONSOLIDATED	CSWESI CONSOLIDATED	CSWPWRMKT	AEP CREDIT	REPHLD CONSOLIDATED
ASSETS:					
ELECTRIC UTILITY PLANT					
PRODUCTION	0.00	0.00	0.00	0.00	0.00
TRANSMISSION	0.00	0.00	0.00	0.00	0.00
DISTRIBUTION	0.00	0.00	0.00	0.00	0.00
GENERAL	74,518,162.40	14,361,543.42	0.00	0.00	0.00
CONSTRUCTION WORK IN PROGRESS	50,884,941.14	0.00	0.00	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	125,403,103.54	14,361,543.42	0.00	0.00	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	(14,062,684.13)	(5,864.20)	0.00	0.00	0.00
NET ELECTRIC UTILITY PLANT	111,340,419.41	14,355,679.22	0.00	0.00	0.00
OTHER PROPERTY AND INVESTMENT					
NET NONUTILITY PROPERTY	0.00	0.00	0.00	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	0.00	0.00	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	0.00	285,005.14	0.00	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	0.00	285,005.14	0.00	0.00	0.00
CURRENT AND ACCRUED ASSETS					
CASH AND CASH EQUIVALENTS	133,512.80	(1,044,612.00)	0.00	0.00	(303,000.00)
ADVANCES TO AFFILIATES	0.00	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	13,162.08	0.00	0.00	(560,289,178.85)	0.00
ACCOUNTS RECEIVABLE - MISC	888,968.45	22,621,146.56	0.00	124,142,666.43	146.56
A/P FOR UNCOLLECTIBLE ACCOUNTS	(162,158.34)	(148,881.90)	0.00	(17,577,955.24)	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	932,171.14	23,289,233.95	0.00	720,130,578.29	440,729.53
FUEL	0.00	0.00	0.00	0.00	0.00
MATERIALS & SUPPLIES	5,791,767.63	4,074,538.45	0.00	0.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00	0.00	0.00
PREPAYMENTS	183,250.27	113,490.67	0.00	662,500.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00	0.00
OTHER CURRENT ASSETS	461,600.00	0.00	0.00	0.00	0.00
TOTAL CURRENT ASSETS	8,242,274.03	48,904,915.73	0.00	267,068,610.63	137,876.09
REGULATORY ASSETS					
REGULATORY ASSETS	0.00	0.00	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00	0.00	0.00
DEFERRED CHARGES					
CLEARING ACCOUNTS	(22,752.12)	123,130.27	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	1,797,761.86	618,539.11	0.00	0.00	0.00
OTHER DEFERRED DEBITS	(9,557,466.92)	16,337,278.13	0.00	0.00	(9,949.00)
TOTAL DEFERRED CHARGES	(7,782,457.18)	17,078,947.51	0.00	0.00	(9,949.00)
TOTAL ASSETS	111,800,236.26	80,624,547.60	0.00	267,068,610.63	127,927.09

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CENTRAL AND SOUTH WEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	C3 COMM CONSOLIDATED	CSWESI CONSOLIDATED	CSWPWRMKT	AEP CREDIT	REPHLD CONSOLIDATED
CAPITALIZATION AND LIABILITIES:					
CAPITALIZATION					
COMMON STOCK					
COMMON STOCK	1,000.00	1,000.00	0.00	1,000.00	3,000.0
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00	0.0
PAID-IN CAPITAL	0.00	0.00	0.00	65,576,987.13	300,000.0
RETAINED EARNINGS	(95,831,707.98)	(47,163,711.95)	0.00	0.00	(1,427,746.0
COMMON SHAREHOLDERS' EQUITY	(95,830,707.98)	(47,162,711.95)	0.00	65,577,987.13	(1,124,746.0
CUMULATIVE PREFERRED STOCK					
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00	0.0
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00	0.00	0.0
TRUST PREFERRED SECURITIES					
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00	0.
LT DEBT (LESS AMT DUE IN 1 YR)					
LONG-TERM DEBT LESS AMT DUE 1 YR	175,269,048.86	60,344,078.00	0.00	0.00	0.
TOTAL CAPITALIZATION	79,438,340.88	13,181,366.05	0.00	65,577,987.13	(1,124,746.
OTHER NONCURRENT LIABILITIES					
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00	0.
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00	0.
ACCUMULATED PROVISIONS - MISC	45,000.00	5,971.00	0.00	0.00	0.
TOTAL OTH NONCURRENT LIAB'S	45,000.00	5,971.00	0.00	0.00	0.
CURRENT LIABILITIES					
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00	0.0
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	1,300,149.00	0.00	0.00	0.0
SHORT-TERM DEBT	0.00	49,412,575.00	0.00	0.00	0.0
A/P - GENERAL	3,395,157.45	4,283,352.18	0.00	90,929,428.55	0.0
A/P- ASSOC. COS.	2,710,891.79	587,811.95	0.00	2,426,233.39	2,457,459.1
ADVANCES FROM AFFILIATES	13,665,415.65	16,333,629.08	0.00	63,661,764.97	0.0
CUSTOMER DEPOSITS	14,295.12	0.00	0.00	0.00	0.0
TAXES ACCRUED	1,758,649.47	(4,478,667.42)	0.00	5,440,747.88	(595,786.0
INTEREST ACCRUED	65,415.56	55,312.72	0.00	2,480,717.15	0.0
DIVIDENDS DECLARED	0.00	0.00	0.00	9,391,579.37	0.0
OBLIG UNDER CAP LEASES- CURR	(23,988.14)	0.00	0.00	0.00	0.0
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00	0.0
OTHR CURR & ACCRUED LIAB	2,759,109.89	356,406.89	0.00	0.00	(609,000.0
TOTAL CURRENT LIABILITIES	24,344,946.79	67,850,569.40	0.00	174,330,471.31	1,252,673.1
DEF CREDITS & REGULATORY LIAB					
DEFERRED INCOME TAXES	1,158,373.88	546,025.38	0.00	(7,741,227.00)	0.0
DFIT & DSIT RECLASS (A/C 190)	0.00	(6,553,263.62)	0.00	0.00	0.0
NET DEFERRED INCOME TAXES	1,158,373.88	(6,007,238.24)	0.00	(7,741,227.00)	0.0
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES					
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00	0.00
DEFERRED CREDITS	6,813,574.71	5,593,879.39	0.00	34,901,379.19	0.00
TOTAL DEF CREDITS & REG LIAB'S	7,971,948.59	(413,358.85)	0.00	27,160,152.19	0.00
TOTAL CAPITAL & LIABILITIES	111,800,236.26	80,624,547.60	0.00	267,068,610.63	127,927.09

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APPALACHIAN POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	APCO CONSOLIDATED	APCO ELIMINATIONS	APCO	CACCO
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	2,093,531,758.74	0.00	2,093,531,758.74	0.00
TRANSMISSION	1,222,225,955.09	0.00	1,222,225,955.09	0.00
DISTRIBUTION	1,887,020,721.58	0.00	1,887,020,721.58	0.00
GENERAL	257,956,883.89	0.00	257,956,883.89	0.00
CONSTRUCTION WORK IN PROGRESS	203,921,729.88	0.00	203,921,729.88	0.00
TOTAL ELECTRIC UTILITY PLANT	5,664,657,049.18	0.00	5,664,657,049.18	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	(2,296,480,679.00)	0.00	(2,296,480,679.00)	0.00
NET ELECTRIC UTILITY PLANT	3,368,176,370.18	0.00	3,368,176,370.18	0.00
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	21,632,660.03	0.00	21,054,695.03	0.00
INVEST IN SUBSIDIARY & ASSOC	603,868.00	(15,757,234.57)	16,361,102.57	0.00
TOTAL OTHER INVESTMENTS	347,748,533.76	0.00	340,046,891.76	292,672.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	369,985,061.79	(15,757,234.57)	377,462,689.36	292,672.00
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	13,662,995.63	0.00	16,268,787.47	645.65
ADVANCES TO AFFILIATES	11,409,952.97	0.00	0.00	1,812,634.50
ACCOUNTS RECEIVABLE-CUSTOMERS	113,370,816.88	0.00	113,370,816.88	0.00
ACCOUNTS RECEIVABLE - MISC	11,847,324.07	0.00	8,233,993.74	120,591.23
A/P FOR UNCOLLECTIBLE ACCOUNTS	(1,876,921.82)	0.00	(1,879,876.77)	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	63,367,887.52	(8,372,052.79)	69,695,892.79	361,514.97
FUEL	56,698,667.95	0.00	56,698,667.95	0.00
MATERIALS & SUPPLIES	59,849,039.02	(105.71)	59,849,144.73	0.00
ACCRUED UTILITY REVENUES	30,907,372.74	0.00	30,907,372.74	0.00
PREPAYMENTS	3,774,724.24	0.00	3,774,664.24	0.00
ENERGY TRADING CONTRACTS	566,283,611.93	0.00	566,283,611.93	0.00
OTHER CURRENT ASSETS	12,244,072.23	0.00	8,091,360.55	0.00
TOTAL CURRENT ASSETS	941,539,543.36	(8,372,158.50)	931,294,436.25	2,295,386.35
REGULATORY ASSETS				
REGULATORY ASSETS	495,319,627.64	0.00	494,707,687.64	0.00
FAS109 DFIT RECLASS (A/C 254)	(36,497,329.00)	0.00	(35,252,866.00)	(210,000.00)
NET REGULATORY ASSETS	458,822,298.64	0.00	459,454,821.64	(210,000.00)
DEFERRED CHARGES				
CLEARING ACCOUNTS	244,389.02	0.00	244,389.02	0.00
UNAMORTIZED DEBT EXPENSE	3,407,553.66	0.00	3,407,553.66	0.00
OTHER DEFERRED DEBITS	38,612,619.93	234,734.04	38,270,486.35	0.00
TOTAL DEFERRED CHARGES	42,264,562.61	234,734.04	41,922,429.03	0.00
TOTAL ASSETS	5,180,787,836.58	(23,894,659.03)	5,178,310,746.46	2,378,058.35

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APPALACHIAN POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	APCO CONSOLIDATED	APCO ELIMINATIONS	APCO	CACCO
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	260,457,768.00	(210,050.00)	260,457,768.00	3,000.00
PREMIUM ON CAPITAL STOCK	762,826.38	(8,900,000.01)	762,826.38	0.00
PAID-IN CAPITAL	714,683,741.99	(5,513,293.00)	714,683,741.99	449,990.00
RETAINED EARNINGS	150,796,650.14	(1,143,890.59)	150,796,650.14	307,103.00
COMMON SHAREHOLDERS' EQUITY	1,126,700,986.51	(15,767,233.60)	1,126,700,986.51	760,093.00
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	10,860,000.00	0.00	10,860,000.00	0.00
PS NOT SUBJ MANDATORY REDEMP	17,790,500.00	0.00	17,790,500.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	1,476,551,890.41	0.00	1,476,551,890.41	0.00
TOTAL CAPITALIZATION	2,631,903,376.92	(15,767,233.60)	2,631,903,376.92	760,093.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	33,928,399.29	0.00	33,928,399.29	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	50,175,477.93	0.00	35,960,169.11	2,336,634.00
TOTAL OTH NONCURRENT LIAB'S	84,103,877.22	0.00	69,888,568.40	2,336,634.00
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	80,006,878.49	0.00	80,006,878.49	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	131,387,416.77	0.00	131,180,159.18	909.00
A/P- ASSOC. COS.	84,517,934.33	(8,127,425.43)	91,303,546.97	235,657.35
ADVANCES FROM AFFILIATES	303,226,866.67	0.00	303,226,866.67	0.00
CUSTOMER DEPOSITS	13,177,233.40	0.00	13,177,233.40	0.00
TAXES ACCRUED	55,583,447.85	0.00	55,439,348.09	(11,973.00)
INTEREST ACCRUED	21,769,907.45	0.00	21,769,907.45	0.00
DIVIDENDS DECLARED	360,635.63	0.00	360,635.63	0.00
OBLIG UNDER CAP LEASES- CURR	12,356,725.75	0.00	12,356,725.75	0.00
ENERGY TRADING CONTRACTS	549,703,474.79	0.00	549,703,474.79	0.00
OTHR CURR & ACCRUED LIAB	62,580,858.74	0.00	62,410,695.15	113,400.00
TOTAL CURRENT LIABILITIES	1,314,671,379.87	(8,127,425.43)	1,320,935,471.57	337,993.35
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	865,908,592.00	0.00	864,586,854.00	73,500.00
DFIT & DSIT RECLASS (A/C 190)	(162,333,905.00)	0.00	(155,073,040.00)	(1,130,162.00)
NET DEFERRED INCOME TAXES	703,574,687.00	0.00	709,513,814.00	(1,056,662.00)
DEF INVESTMENT TAX CREDITS	38,328,187.00	0.00	38,328,187.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	137,040,715.58	0.00	137,040,715.58	0.00
UNAMORT GAIN REACQUIRED DEBT	111,920.01	0.00	111,920.01	0.00
TOTAL REGULATORY LIABILITIES	137,152,635.59	0.00	137,152,635.59	0.00
DEFERRED CREDITS	271,053,692.98	0.00	270,588,692.98	0.00
TOTAL DEF CREDITS & REG LIAB'S	1,150,109,202.57	0.00	1,155,583,329.57	(1,056,662.00)
TOTAL CAPITAL & LIABILITIES	5,180,787,836.58	(23,894,659.03)	5,178,310,746.46	2,378,058.35

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APPALACHIAN POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CECCO	SACCO	WVPCO
ASSETS:			
ELECTRIC UTILITY PLANT			
PRODUCTION	0.00	0.00	0.00
TRANSMISSION	0.00	0.00	0.00
DISTRIBUTION	0.00	0.00	0.00
GENERAL	0.00	0.00	0.00
CONSTRUCTION WORK IN PROGRESS	0.00	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	0.00	0.00	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	0.00	0.00	0.00
NET ELECTRIC UTILITY PLANT	0.00	0.00	0.00
OTHER PROPERTY AND INVESTMENT			
NET NONUTILITY PROPERTY	0.00	568,338.00	9,627.00
INVEST IN SUBSIDIARY & ASSOC	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	3,704,481.00	3,704,489.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	3,704,481.00	4,272,827.00	9,627.00
CURRENT AND ACCRUED ASSETS			
CASH AND CASH EQUIVALENTS	110,194.49	113,641.05	1,617.65
ADVANCES TO AFFILIATES	5,143,863.49	4,199,446.80	254,008.18
ACCOUNTS RECEIVABLE-CUSTOMERS	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	1,494,734.56	1,997,250.17	754.37
A/P FOR UNCOLLECTIBLE ACCOUNTS	2,954.95	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	1,645,872.76	35,618.45	1,041.34
FUEL	0.00	0.00	0.00
MATERIALS & SUPPLIES	0.00	0.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00
PREPAYMENTS	0.00	0.00	60.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00
OTHER CURRENT ASSETS	1,320,821.00	0.00	0.00
TOTAL CURRENT ASSETS	9,718,441.25	6,345,956.47	257,481.54
REGULATORY ASSETS			
REGULATORY ASSETS	157,816.00	454,124.00	0.00
FAS109 DFIT RECLASS (A/C 254)	(810,000.00)	(224,463.00)	0.00
NET REGULATORY ASSETS	(652,184.00)	229,661.00	0.00
DEFERRED CHARGES			
CLEARING ACCOUNTS	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00
OTHER DEFERRED DEBITS	106,661.19	0.00	738.35
TOTAL DEFERRED CHARGES	106,661.19	0.00	738.35
TOTAL ASSETS	12,877,399.44	10,848,444.47	267,846.89

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APPALACHIAN POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CECCO	SACCO	WVPCO
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK			
COMMON STOCK	200,000.00	6,950.00	100.00
PREMIUM ON CAPITAL STOCK	0.00	8,900,000.01	0.00
PAID-IN CAPITAL	4,868,403.00	0.00	194,900.00
RETAINED EARNINGS	(114,808.32)	879,293.00	72,302.91
COMMON SHAREHOLDERS' EQUITY	4,953,594.68	9,786,243.01	267,302.91
CUMULATIVE PREFERRED STOCK			
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00
TRUST PREFERRED SECURITIES			
TRUST PREFERRED SECURITIES	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)			
LONG-TERM DEBT LESS AMT DUE 1 YR	0.00	0.00	0.00
TOTAL CAPITALIZATION	4,953,594.68	9,786,243.01	267,302.91
OTHER NONCURRENT LIABILITIES			
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	11,878,674.82	0.00	0.00
TOTAL OTH NONCURRENT LIAB'S	11,878,674.82	0.00	0.00
CURRENT LIABILITIES			
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00
A/P - GENERAL	206,348.59	0.00	0.00
A/P- ASSOC. COS.	15,182.00	1,088,492.46	2,480.98
ADVANCES FROM AFFILIATES	0.00	0.00	0.00
CUSTOMER DEPOSITS	0.00	0.00	0.00
TAXES ACCRUED	111,483.76	46,526.00	(1,937.00)
INTEREST ACCRUED	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	56,763.59	0.00	0.00
TOTAL CURRENT LIABILITIES	389,777.94	1,135,018.46	543.98
DEF CREDITS & REGULATORY LIAB			
DEFERRED INCOME TAXES	847,121.00	401,117.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(5,191,769.00)	(938,934.00)	0.00
NET DEFERRED INCOME TAXES	(4,344,648.00)	(537,817.00)	0.00
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00
REGULATORY LIABILITIES			
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00
DEFERRED CREDITS	0.00	465,000.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	(4,344,648.00)	(72,817.00)	0.00
TOTAL CAPITAL & LIABILITIES	12,877,399.44	10,848,444.47	267,846.89

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COLUMBUS SOUTHERN POWER, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	CSPCO ELIMINATIONS	CSPCO
ASSETS:			
ELECTRIC UTILITY PLANT			
PRODUCTION	1,574,506,041.22	0.00	1,574,506,041.22
TRANSMISSION	401,404,522.72	0.00	401,404,522.72
DISTRIBUTION	1,159,105,019.48	0.00	1,159,105,019.48
GENERAL	146,732,305.14	0.00	142,673,555.21
CONSTRUCTION WORK IN PROGRESS	72,571,605.04	0.00	72,235,160.74
TOTAL ELECTRIC UTILITY PLANT	3,354,319,493.60	0.00	3,349,924,299.37
LESS ACCUM PRV-DEPR,DEPL,AMORT	(1,377,031,924.03)	0.00	(1,373,698,107.10)
NET ELECTRIC UTILITY PLANT	1,977,287,569.57	0.00	1,976,226,192.27
OTHER PROPERTY AND INVESTMENT			
NET NONUTILITY PROPERTY	29,291,848.32	0.00	24,684,315.69
INVEST IN SUBSIDIARY & ASSOC	430,000.00	(7,062,377.71)	7,492,377.71
TOTAL OTHER INVESTMENTS	204,562,051.16	0.00	204,434,457.76
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	234,283,899.48	(7,062,377.71)	236,611,151.16
CURRENT AND ACCRUED ASSETS			
CASH AND CASH EQUIVALENTS	12,357,347.14	(1,736,168.00)	14,049,273.73
ADVANCES TO AFFILIATES	1,272,513.37	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	41,769,951.78	0.00	41,769,951.78
ACCOUNTS RECEIVABLE - MISC	16,968,297.34	0.00	16,903,440.34
A/P FOR UNCOLLECTIBLE ACCOUNTS	(745,119.51)	0.00	(745,119.51)
ACCOUNTS RECEIVABLE- ASSOC COS	63,469,678.54	(1,417,582.44)	63,481,209.18
FUEL	20,018,628.14	0.00	20,018,628.14
MATERIALS & SUPPLIES	38,984,591.25	0.00	37,621,296.25
ACCRUED UTILITY REVENUES	7,086,677.45	0.00	7,086,677.45
ENERGY TRADING CONTRACTS	347,197,900.62	0.00	347,197,900.62
PREPAYMENTS	1,410,869.98	0.00	1,410,733.98
OTHER CURRENT ASSETS	27,323,653.96	1,736,168.00	25,582,205.96
TOTAL CURRENT ASSETS	577,114,990.06	(1,417,582.44)	574,376,197.92
REGULATORY ASSETS			
REGULATORY ASSETS	277,935,220.88	0.00	277,871,498.88
FAS109 DFIT RECLASS (A/C 254)	(15,668,035.00)	0.00	(15,668,035.00)
NET REGULATORY ASSETS	262,267,185.88	0.00	262,203,463.88
DEFERRED CHARGES			
CLEARING ACCOUNTS	61,430.13	0.00	45,130.14
UNAMORTIZED DEBT EXPENSE	2,023,601.68	0.00	2,023,601.68
OTHER DEFERRED DEBITS	54,102,078.35	(96,420.70)	54,041,216.73
TOTAL DEFERRED CHARGES	56,187,110.16	(96,420.70)	56,109,948.55
TOTAL ASSETS	3,107,140,755.15	(8,576,380.85)	3,105,526,953.78

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COLUMBUS SOUTHERN POWER, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	CSPCO ELIMINATIONS	CSPCO
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK			
COMMON STOCK	41,026,065.00	(1,609,000.00)	41,026,065.00
PREMIUM ON CAPITAL STOCK	257,892,417.78	(30,000.00)	257,892,417.78
PAID-IN CAPITAL	316,476,557.07	(668,589.30)	316,476,557.07
RETAINED EARNINGS	176,102,772.91	(1,932,486.75)	176,102,771.91
COMMON SHAREHOLDERS' EQUITY	791,497,812.76	(4,240,076.05)	791,497,811.76
CUMULATIVE PREFERRED STOCK			
PS SUBJECT TO MANDATORY REDEMP	10,000,000.00	0.00	10,000,000.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00
TRUST PREFERRED SECURITIES			
TRUST PREFERRED SECURITIES	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)			
LONG-TERM DEBT LESS AMT DUE 1 YR	571,347,775.29	(2,822,302.00)	571,347,775.29
TOTAL CAPITALIZATION	1,372,845,588.05	(7,062,378.05)	1,372,845,587.05
OTHER NONCURRENT LIABILITIES			
OBLIGATIONS UNDER CAP LEASE	27,052,195.42	0.00	27,014,438.81
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	9,662,329.98	0.00	7,403,438.77
TOTAL OTH NONCURRENT LIAB'S	36,714,525.40	0.00	34,417,877.58
CURRENT LIABILITIES			
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	220,500,000.00	0.00	220,500,000.00
SHORT-TERM DEBT	0.00	0.00	0.00
A/P - GENERAL	62,393,378.49	0.00	62,200,073.04
A/P- ASSOC. COS.	83,697,206.85	(1,514,002.80)	84,842,355.46
ADVANCES FROM AFFILIATES	182,656,601.44	0.00	182,656,601.44
CUSTOMER DEPOSITS	5,883,721.03	0.00	5,883,721.03
TAXES ACCRUED	116,363,845.67	0.00	116,227,722.55
INTEREST ACCRUED	10,906,842.80	0.00	10,869,842.80
DIVIDENDS DECLARED	175,000.00	0.00	175,000.00
OBLIG UNDER CAP LEASES- CURR	7,835,242.22	0.00	7,620,924.72
ENERGY TRADING CONTRACTS	334,957,549.76	0.00	334,957,549.76
OTHR CURR & ACCRUED LIAB	20,706,143.01	0.00	19,910,607.92
TOTAL CURRENT LIABILITIES	1,046,075,531.27	(1,514,002.80)	1,045,844,398.72
DEF CREDITS & REGULATORY LIAB			
DEFERRED INCOME TAXES	518,488,718.00	0.00	518,418,886.00
DFIT & DSIT RECLASS (A/C 190)	(74,767,049.00)	0.00	(73,520,594.00)
NET DEFERRED INCOME TAXES	443,721,669.00	0.00	444,898,292.00
DEF INVESTMENT TAX CREDITS	37,176,416.00	0.00	37,158,430.00
REGULATORY LIABILITIES			
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	30,975.81	0.00	30,975.81
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	30,975.81	0.00	30,975.81
DEFERRED CREDITS	170,576,049.62	0.00	170,331,392.62
TOTAL DEF CREDITS & REG LIAB'S	651,505,110.43	0.00	652,419,090.43
TOTAL CAPITAL & LIABILITIES	3,107,140,755.15	(8,576,380.85)	3,105,526,953.78

<PAGE>
COLUMBUS SOUTHERN POWER, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	COLM	CCPC	SIMCO
ASSETS:			
ELECTRIC UTILITY PLANT			
PRODUCTION	0.00	0.00	0.00
TRANSMISSION	0.00	0.00	0.00
DISTRIBUTION	0.00	0.00	0.00
GENERAL	0.00	2,237,373.75	1,821,376.18
CONSTRUCTION WORK IN PROGRESS	336,444.30	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	336,444.30	2,237,373.75	1,821,376.18
LESS ACCUM PRV-DEPR,DEPL,AMORT	0.00	(1,825,911.64)	(1,507,905.29)
NET ELECTRIC UTILITY PLANT	336,444.30	411,462.11	313,470.89
OTHER PROPERTY AND INVESTMENT			
NET NONUTILITY PROPERTY	4,607,532.63	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	0.00	127,593.40	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	4,607,532.63	127,593.40	0.00
CURRENT AND ACCRUED ASSETS			
CASH AND CASH EQUIVALENTS	28,889.43	15,351.98	0.00
ADVANCES TO AFFILIATES	70,548.63	957,165.03	244,799.71
ACCOUNTS RECEIVABLE-CUSTOMERS	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	36,057.12	20,167.91	8,631.97
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	5,132.74	1,400,898.80	20.26
FUEL	0.00	0.00	0.00
MATERIALS & SUPPLIES	0.00	1,363,295.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00
PREPAYMENTS	0.00	136.00	0.00
OTHER CURRENT ASSETS	0.00	5,280.00	0.00
TOTAL CURRENT ASSETS	140,627.92	3,762,294.72	253,451.94
REGULATORY ASSETS			
REGULATORY ASSETS	0.00	63,722.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	63,722.00	0.00
DEFERRED CHARGES			
CLEARING ACCOUNTS	0.00	0.00	16,299.99
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00
OTHER DEFERRED DEBITS	122,382.16	34,900.16	0.00
TOTAL DEFERRED CHARGES	122,382.16	34,900.16	16,299.99
TOTAL ASSETS	5,206,987.01	4,399,972.39	583,222.82

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COLUMBUS SOUTHERN POWER, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	COLM	CCPC	SIMCO
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK			
COMMON STOCK	1,500,000.00	100,000.00	9,000.00
PREMIUM ON CAPITAL STOCK	30,000.00	0.00	0.00
PAID-IN CAPITAL	0.00	400,000.00	268,589.30
RETAINED EARNINGS	747,181.54	1,099,983.00	85,323.21
COMMON SHAREHOLDERS' EQUITY	2,277,181.54	1,599,983.00	362,912.51
CUMULATIVE PREFERRED STOCK			
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00
TRUST PREFERRED SECURITIES			
TRUST PREFERRED SECURITIES	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)			
LONG-TERM DEBT LESS AMT DUE 1 YR	2,822,302.00	0.00	0.00
TOTAL CAPITALIZATION	5,099,483.54	1,599,983.00	362,912.51
OTHER NONCURRENT LIABILITIES			
OBLIGATIONS UNDER CAP LEASE	0.00	37,756.61	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	0.00	2,258,891.21	0.00
TOTAL OTH NONCURRENT LIAB'S	0.00	2,296,647.82	0.00
CURRENT LIABILITIES			
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00
A/P - GENERAL	0.00	193,305.45	0.00
A/P- ASSOC. COS.	16,647.29	351,912.50	294.40
ADVANCES FROM AFFILIATES	0.00	0.00	0.00
CUSTOMER DEPOSITS	0.00	0.00	0.00
TAXES ACCRUED	(3,545.00)	125,906.12	13,762.00
INTEREST ACCRUED	0.00	37,000.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	214,317.50	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	(255.82)	795,663.00	127.91
TOTAL CURRENT LIABILITIES	12,846.47	1,718,104.57	14,184.31
DEF CREDITS & REGULATORY LIAB			
DEFERRED INCOME TAXES	0.00	(27,118.00)	96,950.00
DFIT & DSIT RECLASS (A/C 190)	0.00	(1,187,645.00)	(58,810.00)
NET DEFERRED INCOME TAXES	0.00	(1,214,763.00)	38,140.00
DEF INVESTMENT TAX CREDITS	0.00	0.00	17,986.00
REGULATORY LIABILITIES			
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00
DEFERRED CREDITS	94,657.00	0.00	150,000.00
TOTAL DEF CREDITS & REG LIAB'S	94,657.00	(1,214,763.00)	206,126.00
TOTAL CAPITAL & LIABILITIES	5,206,987.01	4,399,972.39	583,222.82

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INDIANA MICHIGAN POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	I&M CONSOLIDATED	I&M ELIMINATIONS	I&M	BHCCO	PRCCO
ASSETS:					
ELECTRIC UTILITY PLANT					
PRODUCTION	2,758,160,077.14	0.00	2,758,160,077.14	0.00	0.00
TRANSMISSION	957,336,718.30	0.00	957,336,718.30	0.00	0.00
DISTRIBUTION	900,920,965.86	0.00	900,920,965.86	0.00	0.00
GENERAL	233,004,797.39	0.00	233,004,797.39	0.00	0.00
CONSTRUCTION WORK IN PROGRESS	74,298,932.82	0.00	74,298,932.82	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	4,923,721,491.51	0.00	4,923,721,491.51	0.00	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	(2,436,972,552.67)	0.00	(2,436,972,552.67)	0.00	0.00
NET ELECTRIC UTILITY PLANT	2,486,748,938.84	0.00	2,486,748,938.84	0.00	0.00
OTHER PROPERTY AND INVESTMENT					
NET NONUTILITY PROPERTY	77,294,414.72	0.00	45,565,958.72	31,728,456.00	0.00
INVEST IN SUBSIDIARY & ASSOC	0.00	(50,688,097.83)	50,688,097.83	0.00	0.00
TOTAL OTHER INVESTMENTS	266,227,227.07	0.00	257,913,022.07	8,314,205.00	0.00
TOTAL OTHER SPECIAL FUNDS	834,108,675.61	0.00	834,108,675.61	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	1,177,630,317.40	(50,688,097.83)	1,188,275,754.23	40,042,661.00	0.00
CURRENT AND ACCRUED ASSETS					
CASH AND CASH EQUIVALENTS	16,804,249.76	0.00	16,753,363.20	50,886.56	0.00
ADVANCES TO AFFILIATES	46,309,293.04	0.00	38,425,774.17	7,883,518.87	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	60,863,606.27	0.00	60,863,606.27	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	25,398,062.33	0.00	22,282,926.24	3,115,136.09	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	(740,902.53)	0.00	(740,902.53)	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	31,907,757.55	(141,445.82)	31,991,820.06	30,108.31	27,275.00
FUEL	28,988,624.81	0.00	28,988,624.81	0.00	0.00
MATERIALS & SUPPLIES	91,440,326.76	0.00	91,440,326.76	0.00	0.00
ACCRUED UTILITY REVENUES	2,071,505.45	0.00	2,071,505.45	0.00	0.00
ENERGY TRADING CONTRACTS	399,195,694.12	0.00	399,195,694.12	0.00	0.00
PREPAYMENTS	4,480,242.29	0.00	4,480,242.29	0.00	0.00
OTHER CURRENT ASSETS	2,016,707.60	0.00	1,878,519.60	138,188.00	0.00
TOTAL CURRENT ASSETS	708,735,167.45	(141,445.82)	697,631,500.44	11,217,837.83	27,275.00
REGULATORY ASSETS					
REGULATORY ASSETS	498,607,390.04	0.00	496,528,359.04	2,079,031.00	0.00
FAS109 DFIT RECLASS (A/C 254)	(89,680,290.00)	0.00	(89,701,226.00)	20,936.00	0.00
NET REGULATORY ASSETS	408,927,100.04	0.00	406,827,133.04	2,099,967.00	0.00
DEFERRED CHARGES					
CLEARING ACCOUNTS	282,926.05	0.00	282,926.05	0.00	0.00
UNAMORTIZED DEBT EXPENSE	4,229,507.30	0.00	4,229,507.30	0.00	0.00
OTHER DEFERRED DEBITS	30,454,412.45	478.25	30,453,934.20	0.00	0.00
TOTAL DEFERRED CHARGES	34,966,845.80	478.25	34,966,367.55	0.00	0.00
TOTAL ASSETS	4,817,008,369.53	(50,829,065.40)	4,814,449,694.10	53,360,465.83	27,275.00

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INDIANA MICHIGAN POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	I&M CONSOLIDATED	I&M ELIMINATIONS	I&M	BHCCO	PRCCO
CAPITALIZATION AND LIABILITIES:					
CAPITALIZATION					
COMMON STOCK					
COMMON STOCK	56,583,866.43	(39,548,275.00)	56,583,866.43	39,521,000.00	27,275.00
PREMIUM ON CAPITAL STOCK	4,319,844.45	0.00	4,319,844.45	0.00	0.00
PAID-IN CAPITAL	725,060,923.27	(1,303,000.00)	725,060,923.27	1,303,000.00	0.00
RETAINED EARNINGS	74,605,269.60	(9,836,822.83)	74,605,269.60	9,836,822.83	0.00
COMMON SHAREHOLDERS' EQUITY	860,569,903.75	(50,688,097.83)	860,569,903.75	50,660,822.83	27,275.00
CUMULATIVE PREFERRED STOCK					
PS SUBJECT TO MANDATORY REDEMP	64,945,000.00	0.00	64,945,000.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	8,735,700.00	0.00	8,735,700.00	0.00	0.00
TRUST PREFERRED SECURITIES					
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)					
LONG-TERM DEBT LESS AMT DUE 1 YR	1,312,082,023.77	0.00	1,312,082,023.77	0.00	0.00
TOTAL CAPITALIZATION	2,246,332,627.52	(50,688,097.83)	2,246,332,627.52	50,660,822.83	27,275.00
OTHER NONCURRENT LIABILITIES					
OBLIGATIONS UNDER CAP LEASE	51,092,776.15	0.00	51,092,776.15	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	636,176,049.20	0.00	635,525,549.20	650,500.00	0.00
TOTAL OTH NONCURRENT LIAB'S	687,268,825.35	0.00	686,618,325.35	650,500.00	0.00
CURRENT LIABILITIES					
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	340,000,000.00	0.00	340,000,000.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00	0.00
A/P - GENERAL	90,816,742.25	0.00	90,816,742.25	0.00	0.00
A/P- ASSOC. COS.	43,955,995.19	(113,692.57)	43,883,029.22	186,658.54	0.00
ADVANCES FROM AFFILIATES	0.00	0.00	0.00	0.00	0.00
CUSTOMER DEPOSITS	9,269,682.96	0.00	9,269,682.96	0.00	0.00
TAXES ACCRUED	69,760,947.77	0.00	70,610,011.77	(849,064.00)	0.00
INTEREST ACCRUED	20,691,492.22	0.00	20,691,492.22	0.00	0.00
DIVIDENDS DECLARED	1,121,706.65	0.00	1,121,706.65	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	10,839,953.41	0.00	10,839,953.41	0.00	0.00
ENERGY TRADING CONTRACTS	383,713,700.51	0.00	383,713,700.51	0.00	0.00
OTHR CURR & ACCRUED LIAB	62,043,990.93	0.00	62,005,569.47	38,421.46	0.00
TOTAL CURRENT LIABILITIES	1,032,214,211.89	(113,692.57)	1,032,951,888.46	(623,984.00)	0.00
DEF CREDITS & REGULATORY LIAB					
DEFERRED INCOME TAXES	732,755,493.00	0.00	728,930,948.00	3,824,545.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(332,224,617.00)	0.00	(326,457,386.00)	(5,767,231.00)	0.00
NET DEFERRED INCOME TAXES	400,530,876.00	0.00	402,473,562.00	(1,942,686.00)	0.00
DEF INVESTMENT TAX CREDITS	105,448,564.00	0.00	105,448,564.00	0.00	0.00
REGULATORY LIABILITIES					
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	52,441,653.02	0.00	52,441,653.02	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	37,091.59	0.00	37,091.59	0.00	0.00
TOTAL REGULATORY LIABILITIES	52,478,744.61	0.00	52,478,744.61	0.00	0.00
DEFERRED CREDITS	292,734,520.16	(27,275.00)	288,145,982.16	4,615,813.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	851,192,704.77	(27,275.00)	848,546,852.77	2,673,127.00	0.00
TOTAL CAPITAL & LIABILITIES	4,817,008,369.53	(50,829,065.40)	4,814,449,694.10	53,360,465.83	27,275.00

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OHIO POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	OPCO ELIMINATIONS	OPCO	COCCO	SOCCO	WCCO
ASSETS:						
ELECTRIC UTILITY PLANT						
PRODUCTION	3,007,865,531.86	0.00	3,007,865,531.86	0.00	0.00	0.00
TRANSMISSION	891,282,831.60	0.00	891,282,831.60	0.00	0.00	0.00
DISTRIBUTION	1,081,121,781.57	0.00	1,081,121,781.57	0.00	0.00	0.00
GENERAL	245,232,016.42	0.00	245,232,016.42	0.00	0.00	0.00
CONSTRUCTION WORK IN PROGRESS	165,073,508.50	0.00	165,073,508.50	0.00	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	5,390,575,669.95	0.00	5,390,575,669.95	0.00	0.00	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	(2,452,570,932.97)	0.00	(2,452,570,932.97)	0.00	0.00	0.00
NET ELECTRIC UTILITY PLANT	2,938,004,736.98	0.00	2,938,004,736.98	0.00	0.00	0.00
OTHER PROPERTY AND INVESTMENT						
NET NONUTILITY PROPERTY	32,122,175.14	0.00	32,122,175.14	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	293,228,062.38	3,327.00	293,224,735.38	0.00	0.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	326,036,789.52	3,077.00	326,033,712.52	0.00	0.00	0.00
CURRENT AND ACCRUED ASSETS						
CASH AND CASH EQUIVALENTS	8,847,678.37	(2,862,076.77)	11,709,755.14	0.00	0.00	0.00
ADVANCES TO AFFILIATES	0.00	0.00	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	84,694,284.42	0.00	84,694,284.42	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	20,409,148.76	0.00	20,409,148.76	0.00	0.00	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	(1,379,086.90)	0.00	(1,379,086.90)	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	148,563,112.67	(17,284.09)	148,580,396.76	0.00	0.00	0.00
FUEL	84,723,564.97	0.00	84,723,564.97	0.00	0.00	0.00
MATERIALS & SUPPLIES	88,768,076.70	(54.43)	88,768,131.13	0.00	0.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	472,245,684.18	0.00	472,245,684.18	0.00	0.00	0.00
PREPAYMENTS	3,598,099.40	0.00	3,598,099.40	0.00	0.00	0.00
OTHER CURRENT ASSETS	17,267,198.77	2,862,076.77	14,405,122.00	0.00	0.00	0.00
TOTAL CURRENT ASSETS	927,737,761.34	(17,338.52)	927,755,099.86	0.00	0.00	0.00
REGULATORY ASSETS						
REGULATORY ASSETS	669,837,808.90	0.00	669,837,808.90	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	(25,212,606.61)	0.00	(25,212,606.61)	0.00	0.00	0.00
NET REGULATORY ASSETS	644,625,202.29	0.00	644,625,202.29	0.00	0.00	0.00
DEFERRED CHARGES						
CLEARING ACCOUNTS	73,997.75	0.00	73,997.75	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	3,771,249.38	0.00	3,771,249.38	0.00	0.00	0.00
OTHER DEFERRED DEBITS	75,817,061.68	(146,176.62)	75,963,238.30	0.00	0.00	0.00
TOTAL DEFERRED CHARGES	79,662,308.81	(146,176.62)	79,808,485.43	0.00	0.00	0.00
TOTAL ASSETS	4,916,066,798.94	(160,438.14)	4,916,227,237.08	0.00	0.00	0.00

<PAGE>
OHIO POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	OPCO ELIMINATIONS	OPCO	COCCO	SOCCO	WCCO
CAPITALIZATION AND LIABILITIES:						
CAPITALIZATION						
COMMON STOCK						
COMMON STOCK	321,201,454.00	0.00	321,201,454.00	0.00	0.00	0.00
PREMIUM ON CAPITAL STOCK	729,130.45	0.00	729,130.45	0.00	0.00	0.00
PAID-IN CAPITAL	461,556,623.78	0.00	461,556,623.78	0.00	0.00	0.00
RETAINED EARNINGS	401,297,351.38	(0.00)	401,297,351.38	0.00	0.00	0.00
COMMON SHAREHOLDERS' EQUITY	1,184,784,559.61	(0.00)	1,184,784,559.61	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK						
PS SUBJECT TO MANDATORY REDEMP	8,850,000.00	0.00	8,850,000.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	16,647,700.00	0.00	16,647,700.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES						
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)						
LONG-TERM DEBT LESS AMT DUE 1 YR	1,203,841,523.53	0.00	1,203,841,523.53	0.00	0.00	0.00
TOTAL CAPITALIZATION	2,414,123,783.14	(0.00)	2,414,123,783.14	0.00	0.00	0.00
OTHER NONCURRENT LIABILITIES						
OBLIGATIONS UNDER CAP LEASE	64,260,714.08	0.00	64,260,714.08	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	66,125,597.98	0.00	66,125,597.98	0.00	0.00	0.00
TOTAL OTH NONCURRENT LIAB'S	130,386,312.06	0.00	130,386,312.06	0.00	0.00	0.00
CURRENT LIABILITIES						
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00	0.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00	0.00	0.00
A/P - GENERAL	134,418,106.91	0.00	134,418,106.91	0.00	0.00	0.00
A/P- ASSOC. COS.	176,519,600.54	(160,438.14)	176,680,038.68	0.00	0.00	0.00
ADVANCES FROM AFFILIATES	300,212,874.81	0.00	300,212,874.81	0.00	0.00	0.00
CUSTOMER DEPOSITS	5,452,031.21	0.00	5,452,031.21	0.00	0.00	0.00
TAXES ACCRUED	126,770,255.04	0.00	126,770,255.04	0.00	0.00	0.00
INTEREST ACCRUED	17,679,214.45	0.00	17,679,214.45	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	16,405,200.08	0.00	16,405,200.08	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	456,046,702.21	0.00	456,046,702.21	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	87,070,016.97	0.00	87,070,016.97	0.00	0.00	0.00
TOTAL CURRENT LIABILITIES	1,320,574,002.22	(160,438.14)	1,320,734,440.36	0.00	0.00	0.00
DEF CREDITS & REGULATORY LIAB						
DEFERRED INCOME TAXES	933,827,065.51	0.00	933,827,065.51	0.00	0.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(135,938,491.00)	0.00	(135,938,491.00)	0.00	0.00	0.00
NET DEFERRED INCOME TAXES	797,888,574.51	0.00	797,888,574.51	0.00	0.00	0.00
DEF INVESTMENT TAX CREDITS	21,925,356.00	0.00	21,925,356.00	0.00	0.00	0.00
REGULATORY LIABILITIES						
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	1,236,941.00	0.00	1,236,941.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	1,236,941.00	0.00	1,236,941.00	0.00	0.00	0.00
DEFERRED CREDITS	229,931,830.01	0.00	229,931,830.01	0.00	0.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	1,050,982,701.52	0.00	1,050,982,701.52	0.00	0.00	0.00
TOTAL CAPITAL & LIABILITIES	4,916,066,798.94	(160,438.14)	4,916,227,237.08	0.00	0.00	0.00

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SOUTHWESTERN ELECTRIC POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	SWEPCO CONSOLIDATED	SWEPCO ELIMINATIONS	SWEPCO	DOLETHILLS
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	1,429,355,515.44	0.00	1,429,355,515.44	0.00
TRANSMISSION	538,748,605.56	0.00	538,748,605.56	0.00
DISTRIBUTION	1,042,522,709.60	0.00	1,042,522,709.60	0.00
GENERAL	376,015,615.68	0.00	328,964,425.25	47,051,190.43
CONSTRUCTION WORK IN PROGRESS	74,121,735.91	0.00	74,121,735.91	0.00
TOTAL ELECTRIC UTILITY PLANT	3,460,764,182.19	0.00	3,413,712,991.76	47,051,190.43
LESS ACCUM PRV-DEPR,DEPL,AMORT	(1,550,618,108.66)	0.00	(1,547,021,429.65)	(3,596,679.01)
NET ELECTRIC UTILITY PLANT	1,910,146,073.53	0.00	1,866,691,562.11	43,454,511.42
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	4,232,711.01	0.00	4,232,711.01	0.00
INVEST IN SUBSIDIARY & ASSOC	196,435.96	(25,912,039.69)	26,108,475.65	0.00
TOTAL OTHER INVESTMENTS	64,987,377.93	0.00	64,987,377.93	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	69,416,524.90	(25,912,039.69)	95,328,564.59	0.00
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	5,415,250.74	0.00	5,414,730.74	500.00
ADVANCES TO AFFILIATES	6,242,085.20	(60,505,917.77)	60,505,917.77	6,242,085.20
ACCOUNTS RECEIVABLE-CUSTOMERS	44,499,122.56	0.00	44,499,122.56	0.00
ACCOUNTS RECEIVABLE - MISC	(2,261,960.12)	(568,088.23)	(1,903,015.77)	209,143.88
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	14,331,366.11	(4,748,635.00)	14,331,366.11	4,748,635.00
FUEL	52,212,350.83	0.00	46,822,768.99	5,389,581.84
MATERIALS & SUPPLIES	32,527,148.17	0.00	29,100,148.17	3,427,000.00
ACCRUED UTILITY REVENUES	11,466,000.00	0.00	11,466,000.00	0.00
PREPAYMENTS	18,416,393.71	0.00	18,363,795.84	52,597.87
ENERGY TRADING CONTRACTS	186,159,106.01	0.00	186,159,106.01	0.00
OTHER CURRENT ASSETS	298,779.00	0.00	298,799.00	0.00
TOTAL CURRENT ASSETS	369,305,642.21	(65,822,641.00)	415,058,739.42	20,069,543.79
REGULATORY ASSETS				
REGULATORY ASSETS	111,181,673.25	0.00	111,181,673.25	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	111,181,673.25	0.00	111,181,673.25	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	(118,868,099.71)	0.00	(118,868,099.71)	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	223,576,041.87	2,268,427.32	163,934,735.64	57,372,878.91
TOTAL DEFERRED CHARGES	104,707,942.16	2,268,427.32	45,066,635.93	57,372,878.91
TOTAL ASSETS	2,564,757,856.05	(89,466,253.37)	2,533,327,175.30	120,896,934.12

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SOUTHWESTERN ELECTRIC POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEET
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	SWEPCO CONSOLIDATED	SWEPCO ELIMINATIONS	SWEPCO	DOLETHILLS
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	135,659,520.00	0.00	135,659,520.00	0.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	245,000,000.00	(25,210,448.69)	245,000,000.00	25,210,448.69
RETAINED EARNINGS	308,914,741.35	(699,591.00)	308,914,741.35	699,591.00
COMMON SHAREHOLDERS' EQUITY	689,574,261.35	(25,910,039.69)	689,574,261.35	25,910,039.69
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	4,704,420.64	0.00	4,704,420.64	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	110,000,000.00	0.00	110,000,000.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 YR	494,688,142.61	0.00	494,688,142.61	0.00
TOTAL CAPITALIZATION	1,298,966,824.60	(25,910,039.69)	1,298,966,824.60	25,910,039.69
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	26,452,577.65	0.00	5,020,319.90	21,432,257.75
TOTAL OTH NONCURRENT LIAB'S	26,452,577.65	0.00	5,020,319.90	21,432,257.75
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	150,595,000.00	0.00	150,595,000.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	71,810,201.55	0.00	69,380,114.40	2,430,087.15
A/P- ASSOC. COS.	48,934,644.14	(2,482,207.68)	51,136,627.92	280,223.90
ADVANCES FROM AFFILIATES	123,609,420.67	(60,505,917.77)	123,609,420.67	60,505,917.77
CUSTOMER DEPOSITS	19,879,984.82	0.00	19,879,984.82	0.00
TAXES ACCRUED	36,522,250.73	0.00	35,505,273.36	1,016,977.37
INTEREST ACCRUED	13,630,530.33	(568,088.23)	13,630,530.33	568,088.23
DIVIDENDS DECLARED	57,263.62	0.00	57,263.62	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	192,317,631.94	0.00	192,317,631.94	0.00
OTHR CURR & ACCRUED LIAB	39,672,794.50	0.00	30,919,452.24	8,753,342.26
TOTAL CURRENT LIABILITIES	697,029,722.30	(63,556,213.68)	687,031,299.30	73,554,636.68
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	369,781,227.00	0.00	369,781,227.00	0.00
DFIT & DSIT RECLASS (A/C 190)	0.00	0.00	0.00	0.00
NET DEFERRED INCOME TAXES	369,781,227.00	0.00	369,781,227.00	0.00
DEF INVESTMENT TAX CREDITS	48,714,448.00	0.00	48,714,448.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	67,261,807.76	0.00	67,261,807.76	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	67,261,807.76	0.00	67,261,807.76	0.00
DEFERRED CREDITS	56,551,248.74	0.00	56,551,248.74	0.00
TOTAL DEF CREDITS & REG LIAB'S	542,308,731.50	0.00	542,308,731.50	0.00
TOTAL CAPITAL & LIABILITIES	2,564,757,856.05	(89,466,253.37)	2,533,327,175.30	120,896,934.12

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	AEP CONS.	ELIM & ADJ	COMBINED	AEP Inc.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	970,828,282	(1,034,086,030)	2,004,914,312	970,828,267
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	1,412,574,581		1,412,574,581	
Prov for Def Income Taxes (net)	163,035,298	0	163,035,298	(932,866)
Def Invest Tax Credits (net)	(28,517,791)	9,477,258	(37,995,049)	
AFUDC - Equity	(2,030,411)		(2,030,411)	
Equity/Undist. Subs. Earnings	764,730	620,300,569	(619,535,839)	(620,300,569)
Mark to market Energy Trading	(257,000,000)	(45,939,000)	(211,061,000)	
Decrease (Increase) in:				
Accounts Receivable (net)	1,763,621,302	1,078,070,606	685,550,696	(330,022,117)
Fuel, Materials & Supplies	(82,456,071)	12,775,019	(95,231,090)	33,575
Accrued Utility Revenues	25,800,083	(15,557,924)	41,358,007	
Incr (Decr) in Accounts Payable	(460,569,592)	(487,178,428)	26,608,836	(7,460,565)
Other Oper. Items Assets (Sch 1)	(190,966,959)	(525,564,408)	334,597,449	
Other Oper. Items Liab. (Sch 1)	(363,716,005)	245,751,704	(609,467,709)	(286,501,269)
NET CASH PROVIDED (USED) OPERATING	2,951,367,447	(141,950,634)	3,093,318,081	(274,355,544)
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(1,698,750,508)	8,660,487	(1,707,410,995)	
Other Gross Additions	(135,278,336)		(135,278,336)	
Total Gross Additions	(1,834,028,844)	8,660,487	(1,842,689,331)	0
AFUDC - Equity	2,030,411		2,030,411	
Cash Used Plant & Prop. Adds	(1,831,998,433)	8,660,487	(1,840,658,920)	0
Invest in Subs - Equity & Debt	30,333,487	1,119,869,010	(1,089,535,523)	(902,399,010)
Purchase of Houston Pipe Line	(726,567,366)		(726,567,366)	
Purchase of U. K. Generation	(943,197,338)		(943,197,338)	
Purchase of MEMCO	(265,966,785)		(265,966,785)	
Purchase of Quaker Coal Co.	(101,000,000)		(101,000,000)	
Purchase of Indian Mesa	(175,000,000)		(175,000,000)	
Proceeds - Sale of Yorkshire	383,332,905		383,332,905	
Proceeds - Sale of Frontera	264,731,214		264,731,214	
Proceeds - Sales of Property	45,600,761	(3,618,587)	49,219,348	
Proceeds - Sale & Leaseback Trans	23,420		23,420	
Other Investing Activities	(111,910,303)		(111,910,303)	
NET CASH PROVIDED (USED) INVESTING	(3,431,618,438)	1,124,910,910	(4,556,529,348)	(902,399,010)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	(17,470,000)	17,470,000	
Common Stock	10,698,105		10,698,105	10,395,105
Preferred Stock	0		0	
Minority Interest	746,423,012		746,423,012	
Long-term Debt	2,930,796,085		2,930,796,085	1,244,607,382
Long-term Debt - Affiliated Cos.	0	(1,217,652,590)	1,217,652,590	
Change in Money Pool	0	(394,044,433)	394,044,433	198,781,531
Short-term Debt (net)	(596,960,366)		(596,960,366)	525,321,710
Total Issuances	3,090,956,836	(1,629,167,023)	4,720,123,859	1,979,105,728
Cash Paid To Retire:				
Preferred Stock	(5,000,000)		(5,000,000)	
Long-term Debt	(1,834,547,516)		(1,834,547,516)	
Long-term Debt - Affiliated Cos.	0	117,652,590	(117,652,590)	
Total Retirements	(1,839,547,516)	117,652,590	(1,957,200,106)	0
Dividends Paid on Common Stock	(773,168,114)	395,322,374	(1,168,490,488)	(773,168,114)
Preferred Dividends on Minority Interests	(4,671,613)	0	(4,671,613)	
Dividends Paid on Preferred Stock	0	8,150,608	(8,150,608)	
NET CASH PROVIDED (USED) FINANCING	473,569,593	(1,108,041,451)	1,581,611,044	1,205,937,614
EFFECT OF EXCHANGE RATE CHANGES	(3,667,236)		(3,667,236)	
NET INCREASE (DECREASE) IN CASH	(10,348,634)	(125,081,175)	114,732,541	29,183,060
CASH AT BEGINNING OF PERIOD	342,586,777		342,586,777	50,082,161
CASH AT END OF PERIOD	332,238,143	(125,081,175)	457,319,318	79,265,221
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	972,450,135	(190,301,447)	1,162,751,582	179,530,781
Income Taxes (State & Federal)	569,427,003		569,427,003	(25,554,193)
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	8,017,600	(5,229,613)	13,247,213	0
NonUtility Assets - Capital Leases	9,341,887		9,341,887	0
Total Capital Leases	17,359,487	(5,229,613)	22,589,100	0

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	AEPSC	APCo CONSOL.	OPCo CONSOL.	I&M CONSOL.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income		161,818,276	147,445,368	75,787,951
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	13,598,144	180,505,480	252,123,403	166,360,007
Prov for Def Income Taxes (net)	(63,060,973)	42,498,113	215,832,825	(29,204,810)
Def Invest Tax Credits (net)	(50,808)	(4,764,823)	(3,288,192)	(8,324,685)
AFUDC - Equity		5,338	(29,564)	45,778
Equity/Undist. Subs. Earnings		0	0	
Mark to market Energy Trading		(68,254,000)	(59,833,000)	(19,502,000)
Decrease (Increase) in:				
Accounts Receivable (net)	55,345,219	134,098,915	51,638,892	64,842,213
Fuel, Materials & Supplies		(19,956,663)	4,852,315	(19,425,760)
Accrued Utility Revenues		35,591,132	263,690	(2,071,505)
Incr (Decr) in Accounts Payable	7,384,842	(45,073,190)	9,886,755	(60,185,499)
Other Oper. Items Assets (Sch 1)		(64,626,669)	84,091,540	15,962,866
Other Oper. Items Liab. (Sch 1)	178,711,807	33,578,572	(616,228,265)	51,923,158
NET CASH PROVIDED (USED) OPERATING	191,928,231	385,420,481	86,755,767	236,207,714
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	0	(305,603,150)	(343,796,191)	(90,796,082)
Other Gross Additions	(106,207,963)	(437,755)	(804,446)	(210,350)
Total Gross Additions	(106,207,963)	(306,040,905)	(344,600,637)	(91,006,432)
AFUDC - Equity		(5,338)	29,564	(45,778)
Cash Used Plant & Prop. Adds	(106,207,963)	(306,046,243)	(344,571,073)	(91,052,210)
Invest in Subs - Equity & Debt			171,928	
Purchase of Houston Pipe Line				
Purchase of U. K. Generation				
Purchase of MEMCO				
Purchase of Quaker Coal Co.				
Purchase of Indian Mesa				
Proceeds - Sale of Yorkshire				
Proceeds - Sale of Frontera				
Proceeds - Sales of Property		1,181,969	16,583,079	1,074,349
Proceeds - Sale & Leaseback Trans			23,420	0
Other Investing Activities			(32,115,000)	(92,615,925)
NET CASH PROVIDED (USED) INVESTING	(106,207,963)	(304,864,274)	(359,907,646)	(182,593,786)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent		0		
Common Stock				
Preferred Stock		0		
Minority Interest				
Long-term Debt		124,587,500	0	297,655,636
Long-term Debt - Affiliated Cos.			300,000,000	
Change in Money Pool	(83,780,011)	300,204,241	392,699,157	(299,891,219)
Short-term Debt (net)		(191,495,000)	0	0
Total Issuances	(83,780,011)	233,296,741	692,699,157	(2,235,583)
Cash Paid To Retire:				
Preferred Stock		0		
Long-term Debt	(2,000,000)	(175,000,000)	(297,858,040)	(44,922,491)
Long-term Debt - Affiliated Cos.		0	0	0
Total Retirements	(2,000,000)	(175,000,000)	(297,858,040)	(44,922,491)
Dividends Paid on Common Stock		(129,594,120)	(142,975,781)	0
Preferred Dividends on Minority Interests				
Dividends Paid on Preferred Stock		(1,442,543)	(1,258,738)	(4,486,827)
NET CASH PROVIDED (USED) FINANCING	(85,780,011)	(72,739,922)	250,606,598	(51,644,901)
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	(59,743)	7,816,285	(22,545,281)	1,969,027
CASH AT BEGINNING OF PERIOD	2,774,716	5,846,710	31,392,958	14,835,222
CASH AT END OF PERIOD	2,714,973	13,662,995	8,847,677	16,804,249
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	5,590,733	117,283,027	94,746,680	92,139,687
Income Taxes (State & Federal)	87,963,600	56,981,200	(22,416,867)	100,469,900
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	2,510,162	2,284,894	1,022,906
NonUtility Assets - Capital Leases	9,246,719	0	95,168	0
Total Capital Leases	9,246,719	2,510,162	2,380,062	1,022,906

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	CSPCo CONSOL.	KEPCo	KGPCo	WPCo
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	161,876,319	21,564,541	3,406,249	4,068,002
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	128,500,123	32,490,516	3,262,028	3,699,114
Prov for Def Income Taxes (net)	24,107,869	6,293,296	529,999	79,504
Def Invest Tax Credits (net)	(4,058,087)	(1,252,008)	(83,172)	(38,397)
AFUDC - Equity	297,939	832	660	0
Equity/Undist. Subs. Earnings				
Mark to market Energy Trading	(44,680,000)	(1,454,000)		
Decrease (Increase) in:				
Accounts Receivable (net)	19,985,865	23,693,453	5,389,355	2,219,450
Fuel, Materials & Supplies	(7,780,073)	(7,656,906)	7,824	(1,372)
Accrued Utility Revenues	2,551,640	1,105,393	4,265,878	215,565
Incr (Decr) in Accounts Payable	(16,248,484)	(22,942,929)	(1,614,233)	(3,018,434)
Other Oper. Items Assets (Sch 1)	1,735,369	(7,792,389)		
Other Oper. Items Liab. (Sch 1)	(32,844,669)	(10,703,357)	(194,688)	(922,780)
NET CASH PROVIDED (USED) OPERATING	233,443,811	33,346,442	14,969,900	6,300,652
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(122,476,192)	(37,107,882)	(4,054,404)	(3,389,575)
Other Gross Additions	(9,757,500)	(97,279)		
Total Gross Additions	(132,233,692)	(37,205,161)	(4,054,404)	(3,389,575)
AFUDC - Equity	(297,939)	(832)	(660)	0
Cash Used Plant & Prop. Adds	(132,531,631)	(37,205,993)	(4,055,064)	(3,389,575)
Invest in Subs - Equity & Debt				
Purchase of Houston Pipe Line				
Purchase of U. K. Generation				
Purchase of MEMCO				
Purchase of Quaker Coal Co.				
Purchase of Indian Mesa				
Proceeds - Sale of Yorkshire				
Proceeds - Sale of Frontera				
Proceeds - Sales of Property	10,840,454	215,760		0
Proceeds - Sale & Leaseback Trans	0			0
Other Investing Activities				
NET CASH PROVIDED (USED) INVESTING	(121,691,177)	(36,990,233)	(4,055,064)	(3,389,575)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent				
Common Stock				
Preferred Stock	0			
Minority Interest				
Long-term Debt		0	20,000,000	20,000,000
Long-term Debt - Affiliated Cos.	200,000,000	75,000,000		
Change in Money Pool	92,652,315	18,564,431	(18,128,252)	5,569,611
Short-term Debt (net)	0	0	0	(5,025,000)
Total Issuances	292,652,315	93,564,431	1,871,748	20,544,611
Cash Paid To Retire:				
Preferred Stock	(5,000,000)			
Long-term Debt	(314,733,231)	(60,000,000)	(10,000,000)	(21,000,000)
Long-term Debt - Affiliated Cos.	0			
Total Retirements	(319,733,231)	(60,000,000)	(10,000,000)	(21,000,000)
Dividends Paid on Common Stock	(82,952,078)	(30,244,396)	(2,743,999)	(2,976,000)
Preferred Dividends on Minority Interests				
Dividends Paid on Preferred Stock	(962,500)			
NET CASH PROVIDED (USED) FINANCING	(110,995,494)	3,320,035	(10,872,251)	(3,431,389)
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	757,140	(323,756)	42,585	(520,312)
CASH AT BEGINNING OF PERIOD	11,600,207	2,270,123	429,468	822,940
CASH AT END OF PERIOD	12,357,347	1,946,367	472,053	302,628
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	68,595,700	27,090,057	1,499,319	1,548,218
Income Taxes (State & Federal)	80,484,500	7,548,500	1,875,327	1,810,200
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	1,019,036	817,140	15,381	151,325
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	1,019,036	817,140	15,381	151,325

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	AEP PRO SERV	AEGCo	CCCo	COpCo
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	292,589	7,874,666		0
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	12,623	22,422,582		
Prov for Def Income Taxes (net)	(1,203,810)	(6,224,093)	(8,538)	0
Def Invest Tax Credits (net)		(3,413,473)		
AFUDC - Equity		(21,720)		
Equity/Undist. Subs. Earnings				
Mark to market Energy Trading				
Decrease (Increase) in:				
Accounts Receivable (net)	(7,074,859)	1,224,319	55,815	0
Fuel, Materials & Supplies	1,820	(4,738,850)		
Accrued Utility Revenues				
Incr (Decr) in Accounts Payable	14,571,225	(4,595,622)	(25,550)	0
Other Oper. Items Assets (Sch 1)				
Other Oper. Items Liab. (Sch 1)	18,016,427	(7,578,536)	(25,916)	0
NET CASH PROVIDED (USED) OPERATING	24,616,015	4,949,273	(4,189)	0
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant		(6,770,357)		
Other Gross Additions		(119,589)		
Total Gross Additions	0	(6,889,946)	0	0
AFUDC - Equity		21,720		
Cash Used Plant & Prop. Adds	0	(6,868,226)	0	0
Invest in Subs - Equity & Debt				
Purchase of Houston Pipe Line				
Purchase of U. K. Generation				
Purchase of MEMCO				
Purchase of Quaker Coal Co.				
Purchase of Indian Mesa				
Proceeds - Sale of Yorkshire				
Proceeds - Sale of Frontera				
Proceeds - Sales of Property				
Proceeds - Sale & Leaseback Trans				
Other Investing Activities				
NET CASH PROVIDED (USED) INVESTING	0	(6,868,226)	0	0
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0			
Common Stock				
Preferred Stock				
Minority Interest				
Long-term Debt				
Long-term Debt - Affiliated Cos.				
Change in Money Pool	(57,968,342)	3,981,430	18,632	
Short-term Debt (net)		0		
Total Issuances	(57,968,342)	3,981,430	18,632	0
Cash Paid To Retire:				
Preferred Stock				
Long-term Debt				
Long-term Debt - Affiliated Cos.				
Total Retirements	0	0	0	0
Dividends Paid on Common Stock		(3,836,000)		
Preferred Dividends on Minority Interests				
Dividends Paid on Preferred Stock				
NET CASH PROVIDED (USED) FINANCING	(57,968,342)	145,430	18,632	0
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	(33,352,327)	(1,773,523)	14,443	0
CASH AT BEGINNING OF PERIOD	33,684,687	2,756,743	6,503	0
CASH AT END OF PERIOD	332,360	983,220	20,946	0
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	269,015	1,508,655	0	0
Income Taxes (State & Federal)	181,813	8,597,100	11,800	0
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	0	0	0

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	AEPINV CONSOL.	FRECo	IFRI	AEPR CONSOL.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	306,123	0	0	(62,841,782)
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization				69,088,990
Prov for Def Income Taxes (net)	(674,201)			6,520,602
Def Invest Tax Credits (net)				
AFUDC - Equity				
Equity/Undist. Subs. Earnings	(151,672)			(5,594,430)
Mark to market Energy Trading				
Decrease (Increase) in:				
Accounts Receivable (net)	(225,347)	361,899	(51,015)	(414,337,243)
Fuel, Materials & Supplies	1,338			84,486,147
Accrued Utility Revenues				(563,786)
Incr (Decr) in Accounts Payable	342,728	94,877	103,624	414,967,554
Other Oper. Items Assets (Sch 1)				
Other Oper. Items Liab. (Sch 1)	(443,190)	690,505	130,889	(77,355,147)
NET CASH PROVIDED (USED) OPERATING	(844,221)	1,147,281	183,498	14,370,905
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant				(43,515,883)
Other Gross Additions	(302,734)			(4,375,900)
Total Gross Additions	(302,734)	0	0	(47,891,783)
AFUDC - Equity				
Cash Used Plant & Prop. Adds	(302,734)	0	0	(47,891,783)
Invest in Subs - Equity & Debt				0
Purchase of Houston Pipe Line				(726,567,366)
Purchase of U. K. Generation				(943,197,338)
Purchase of MEMCO				(265,966,785)
Purchase of Quaker Coal Co.				
Purchase of Indian Mesa				
Proceeds - Sale of Yorkshire				383,332,905
Proceeds - Sale of Frontera				
Proceeds - Sales of Property				
Proceeds - Sale & Leaseback Trans				
Other Investing Activities	(2,716,650)	0		(7,279,500)
NET CASH PROVIDED (USED) INVESTING	(3,019,384)	0	0	(1,607,569,867)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	0		
Common Stock				
Preferred Stock				
Minority Interest				751,970,936
Long-term Debt				944,483,472
Long-term Debt - Affiliated Cos.				168,412,925
Change in Money Pool	3,863,605	(555,778)	(95,045)	(155,665,138)
Short-term Debt (net)				40,500
Total Issuances	3,863,605	(555,778)	(95,045)	1,709,242,695
Cash Paid To Retire:				
Preferred Stock				
Long-term Debt				(25,524,814)
Long-term Debt - Affiliated Cos.				(67,652,590)
Total Retirements	0	0	0	(93,177,404)
Dividends Paid on Common Stock				
Preferred Dividends on Minority Interests				(4,671,613)
Dividends Paid on Preferred Stock				
NET CASH PROVIDED (USED) FINANCING	3,863,605	(555,778)	(95,045)	1,611,393,678
EFFECT OF EXCHANGE RATE CHANGES				(1,234,575)
NET INCREASE (DECREASE) IN CASH	0	591,503	88,453	16,960,141
CASH AT BEGINNING OF PERIOD	0	70,701	31,686	44,009,531
CASH AT END OF PERIOD	0	662,204	120,139	60,969,672
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	82,695	0	0	105,315,401
Income Taxes (State & Federal)	1,243,000	0	0	(66,285,545)
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	0	0	196,756
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	0	0	196,756

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	AEPC CONSOL.	AEPPM	AEPES	CSW CONSOL.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	(34,836,444)	(221)	82,224,895	476,004,505
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	3,055,678		3,208,331	528,980,585
Prov for Def Income Taxes (net)	(7,814,264)	0	90,361,006	(125,086,722)
Def Invest Tax Credits (net)				(12,721,404)
AFUDC - Equity				(2,329,674)
Equity/Undist. Subs. Earnings	21,076,468			(14,565,636)
Mark to market Energy Trading				(17,338,000)
Decrease (Increase) in:				
Accounts Receivable (net)	13,078,293	0	(101,080,132)	1,194,270,837
Fuel, Materials & Supplies	(1,224,460)		(89,827,727)	(25,917,450)
Accrued Utility Revenues	0			0
Incr (Decr) in Accounts Payable	(3,145,839)	340	334,937,312	(697,359,139)
Other Oper. Items Assets (Sch 1)				305,226,732
Other Oper. Items Liab. (Sch 1)	21,427,520	(119)	(138,791,147)	105,112,615
NET CASH PROVIDED (USED) OPERATING	11,616,952	0	181,032,538	1,714,277,249
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(2,854,927)		(10,849,829)	(733,218,148)
Other Gross Additions				(12,834,320)
Total Gross Additions	(2,854,927)	0	(10,849,829)	(746,052,468)
AFUDC - Equity				2,329,674
Cash Used Plant & Prop. Adds	(2,854,927)	0	(10,849,829)	(743,722,794)
Invest in Subs - Equity & Debt			(3,333,333)	(183,975,108)
Purchase of Houston Pipe Line				
Purchase of U. K. Generation				
Purchase of MEMCO				
Purchase of Quaker Coal Co.				
Purchase of Indian Mesa				
Proceeds - Sale of Yorkshire				
Proceeds - Sale of Frontera				264,731,214
Proceeds - Sales of Property				19,323,737
Proceeds - Sale & Leaseback Trans				
Other Investing Activities	(54,951,043)			95,930,998
NET CASH PROVIDED (USED) INVESTING	(57,805,970)	0	(14,183,162)	(547,711,953)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0		17,470,000	0
Common Stock				303,000
Preferred Stock				
Minority Interest	(5,514,715)			
Long-term Debt				261,462,095
Long-term Debt - Affiliated Cos.	123,876,538			350,363,127
Change in Money Pool	(122,082,211)		(188,799,732)	122,315,568
Short-term Debt (net)	50,000,000			(978,883,755)
Total Issuances	46,279,612	0	(171,329,732)	(244,439,965)
Cash Paid To Retire:				
Preferred Stock				0
Long-term Debt				(883,508,940)
Long-term Debt - Affiliated Cos.				(50,000,000)
Total Retirements	0	0	0	(933,508,940)
Dividends Paid on Common Stock				
Preferred Dividends on Minority Interests				
Dividends Paid on Preferred Stock				
NET CASH PROVIDED (USED) FINANCING	46,279,612	0	(171,329,732)	(1,177,948,905)
EFFECT OF EXCHANGE RATE CHANGES				(2,432,661)
NET INCREASE (DECREASE) IN CASH	90,594	0	(4,480,356)	(13,816,270)
CASH AT BEGINNING OF PERIOD	5,096	0	5,390,357	136,576,968
CASH AT END OF PERIOD	95,690	0	910,001	122,760,698
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	10,642,197	0	6,336,460	449,620,296
Income Taxes (State & Federal)	(25,552,100)	50	12,061,400	353,509,318
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	5,229,613	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	5,229,613	0	0	0

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	AEPRELLC (AEP Retail)	AEPC&I CONSOL.	AEPT&DSVC	AEPTEXASGP (AEP Texas)
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	(111,480)	(3,267,098)	(76,815)	(1,855)
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization		2,647,043		
Prov for Def Income Taxes (net)	32,361			0
Def Invest Tax Credits (net)				
AFUDC - Equity				
Equity/Undist. Subs. Earnings				
Mark to market Energy Trading				
Decrease (Increase) in:				
Accounts Receivable (net)	(128,772)	(116,416)	(305,276)	(1,000)
Fuel, Materials & Supplies		(2,519,230)		
Accrued Utility Revenues				
Incr (Decr) in Accounts Payable	25,135	233,315	68,544	2,953
Other Oper. Items Assets (Sch 1)				
Other Oper. Items Liab. (Sch 1)	(132,709)	18,528	95,963	(98)
NET CASH PROVIDED (USED) OPERATING	(315,465)	(3,003,858)	(217,584)	0
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant				
Other Gross Additions		(130,500)		
Total Gross Additions	0	(130,500)	0	0
AFUDC - Equity				
Cash Used Plant & Prop. Adds	0	(130,500)	0	0
Invest in Subs - Equity & Debt				
Purchase of Houston Pipe Line				
Purchase of U. K. Generation				
Purchase of MEMCO				
Purchase of Quaker Coal Co.				
Purchase of Indian Mesa				
Proceeds - Sale of Yorkshire				
Proceeds - Sale of Frontera				
Proceeds - Sales of Property				
Proceeds - Sale & Leaseback Trans				
Other Investing Activities	0	(14,865,489)		
NET CASH PROVIDED (USED) INVESTING	0	(14,995,989)	0	0
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0		0	
Common Stock				
Preferred Stock				
Minority Interest		(33,209)		
Long-term Debt				
Long-term Debt - Affiliated Cos.				
Change in Money Pool	315,551	18,078,255	217,584	
Short-term Debt (net)				
Total Issuances	315,551	18,045,046	217,584	0
Cash Paid To Retire:				
Preferred Stock				
Long-term Debt				
Long-term Debt - Affiliated Cos.				
Total Retirements	0	0	0	0
Dividends Paid on Common Stock				
Preferred Dividends on Minority Interests				
Dividends Paid on Preferred Stock				
NET CASH PROVIDED (USED) FINANCING	315,551	18,045,046	217,584	0
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	86	45,199	0	0
CASH AT BEGINNING OF PERIOD	0	0	0	0
CASH AT END OF PERIOD	86	45,199	0	0
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	11,005	669,961	2,583	0
Income Taxes (State & Federal)	29,000	(1,553,000)	(174,000)	(1,000)
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	0	0	0

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American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	MUTUALENER CONSOL.	AEP COAL	AEP TEXAS POLR CONS.	AEP INDIAN MESA CONS.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	(8,082,292)	634,548	0	0
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization		2,619,934		
Prov for Def Income Taxes (net)	0	0		10,990,000
Def Invest Tax Credits (net)				
AFUDC - Equity				
Equity/Undist. Subs. Earnings				
Mark to market Energy Trading				
Decrease (Increase) in:				
Accounts Receivable (net)	(1,070,176)	(26,241,476)	0	0
Fuel, Materials & Supplies	(407,274)	(5,158,344)		
Accrued Utility Revenues				
Incr (Decr) in Accounts Payable	6,320,973	99,338,143	0	0
Other Oper. Items Assets (Sch 1)				
Other Oper. Items Liab. (Sch 1)	(9,356,801)	38,668,810	0	(1,844,987)
NET CASH PROVIDED (USED) OPERATING	(12,595,570)	109,861,615	0	9,145,013
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant		(2,978,375)		
Other Gross Additions				
Total Gross Additions	0	(2,978,375)	0	0
AFUDC - Equity				
Cash Used Plant & Prop. Adds	0	(2,978,375)	0	0
Invest in Subs - Equity & Debt				
Purchase of Houston Pipe Line				
Purchase of U. K. Generation				
Purchase of MEMCO				
Purchase of Quaker Coal Co.		(101,000,000)		
Purchase of Indian Mesa				(175,000,000)
Proceeds - Sale of Yorkshire				
Proceeds - Sale of Frontera				
Proceeds - Sales of Property				
Proceeds - Sale & Leaseback Trans				
Other Investing Activities	(3,297,694)	0	0	
NET CASH PROVIDED (USED) INVESTING	(3,297,694)	(103,978,375)	0	(175,000,000)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent		0	0	
Common Stock				
Preferred Stock				
Minority Interest				
Long-term Debt				18,000,000
Long-term Debt - Affiliated Cos.				
Change in Money Pool	15,893,263			147,854,987
Short-term Debt (net)		3,081,179		
Total Issuances	15,893,263	3,081,179	0	165,854,987
Cash Paid To Retire:				
Preferred Stock				
Long-term Debt				
Long-term Debt - Affiliated Cos.				
Total Retirements	0	0	0	0
Dividends Paid on Common Stock				
Preferred Dividends on Minority Interests				
Dividends Paid on Preferred Stock				
NET CASH PROVIDED (USED) FINANCING	15,893,263	3,081,179	0	165,854,987
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	(1)	8,964,419	0	0
CASH AT BEGINNING OF PERIOD	0	0	0	0
CASH AT END OF PERIOD	(1)	8,964,419	0	0
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	10,436	258,676	0	0
Income Taxes (State & Federal)	(1,803,000)	0	0	0
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	0	0	0

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Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	CSW CONS.	ELIM & ADJ	COMBINED	CSW CORP.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	476,004,505	(499,563,857)	975,568,362	482,171,465
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	528,980,585	0	528,980,585	326,496
Prov for Def Income Taxes (net)	(125,086,722)	0	(125,086,722)	2,307,388
Def Invest Tax Credits (net)	(12,721,404)	0	(12,721,404)	0
AFUDC - Equity	(2,329,674)	0	(2,329,674)	0
Equity/Undist. Subs. Earnings	(14,565,636)	152,308,367	(166,874,003)	(123,788,357)
Decrease (Increase) in:	0	0	0	0
Accounts Rec. Affiliated West	0	(160,068,205)	160,068,205	(17,576,627)
Accounts Rec. Affiliated East	(183,861,237)	0	(183,861,237)	0
Accounts Rec. - Factored West	0	8,679,586	(8,679,586)	0
Accounts Rec. - Factored East	(4,261,577)	0	(4,261,577)	(8,917,644)
Accounts Rec. - Nonaffiliated	1,382,393,651	0	1,382,393,651	1,130,285
Dividends Receivable	0	0	0	0
Fuel, Materials & Supplies	(25,917,450)	0	(25,917,450)	0
Accrued Utility Revenues	0	0	0	0
Accounts Payable - Affiliated West	(0)	10,157,326	(10,157,326)	15,704
Accounts Payable - Affiliated East	(571,756,847)	0	(571,756,847)	(340,653,379)
Accounts Payable - Nonaffiliated	(125,602,292)	0	(125,602,292)	(4,039,714)
Interest Payable - Affiliated West	0	(92,678)	92,678	0
Interest Payable - Affiliated East	(1,544,726)	0	(1,544,726)	0
Mark to market Energy Trading	(17,338,000)	(17,338,000)	0	0
Other Oper. Items Assets (Sch 1)	305,226,732	305,226,732	0	0
Other Oper. Items Liab. (Sch 1)	106,657,341	(170,742,752)	277,400,093	9,834,224
NET CASH PROVIDED (USED) OPERATING	1,714,277,249	(371,433,481)	2,085,710,730	809,842
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(733,218,148)	0	(733,218,148)	0
Other Gross Additions	(12,834,320)	0	(12,834,320)	0
Total Gross Additions	(746,052,468)	0	(746,052,468)	0
AFUDC - Equity	2,329,674	0	2,329,674	0
Cash Used Plant & Prop. Adds	(743,722,794)	0	(743,722,794)	0
Invest in Subs - Equity & Debt	(183,975,108)	0	(183,975,108)	0
Proceeds - Sales of Property	19,323,737	0	19,323,737	0
Proceeds - Sale of Frontera	264,731,214	0	264,731,214	0
Proceeds - Sale & Leaseback Trans	0	0	0	0
Other Investing Activities	95,930,998	811,042	95,119,956	(811,042)
NET CASH PROVIDED (USED) INVESTING	(547,711,953)	811,042	(548,522,995)	(811,042)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	19,222,754	(19,222,754)	0
Common Stock	303,000	0	303,000	0
Preferred Stock	0	0	0	0
Minority Interest	0	0	0	0
Long-term Debt	261,462,095	0	261,462,095	0
Long-Term Debt - Affiliated Cos.	350,363,127	0	350,363,127	0
Money Pool Payable - East	105,981,939	0	105,981,939	0
Money Pool Payable - West	16,333,629	0	16,333,629	0
Short-term Debt (net)	(978,883,755)	0	(978,883,755)	0
Total Issuances	(244,439,965)	19,222,754	(263,662,719)	0
Cash Paid To Retire:				
Preferred Stock	0	0	0	0
Long-term Debt	(883,508,940)	0	(883,508,940)	0
Long-term Debt - Affiliated Cos.	(50,000,000)	0	(50,000,000)	0
Total Retirements	(933,508,940)	0	(933,508,940)	0
Dividends Paid on Common Stock	0	347,709,105	(347,709,105)	0
Dividends Paid on Preferred Stock	0	787,400	(787,400)	0
NET CASH PROVIDED (USED) FINANCING	(1,177,948,905)	367,719,259	(1,545,668,164)	0
EFFECT OF EXCHANGE RATE CHANGES	(2,432,661)	0	(2,432,661)	0
NET INCREASE (DECREASE) IN CASH	(13,816,270)	(2,903,180)	(10,913,090)	(1,200)
CASH AT BEGINNING OF PERIOD	136,576,968	2,903,180	133,673,788	1,200
CASH AT END OF PERIOD	122,760,698	0	122,760,698	(0)
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	449,620,296	0	449,620,296	0
Income Taxes (State & Federal)	353,509,318	0	353,509,318	0
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	0	0	0

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Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	CPLCo CONSOL.	PSOCo CONSOL.	SWEPCo CONSOL.	WTUCo
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	182,277,199	57,758,861	89,366,586	12,310,609
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	168,341,222	80,244,801	121,814,226	50,705,348
Prov for Def Income Taxes (net)	(72,567,527)	(17,751,024)	(31,396,485)	(11,891,049)
Def Invest Tax Credits (net)	(5,206,908)	(1,790,796)	(4,452,888)	(1,270,812)
AFUDC - Equity	(860,657)	(900,909)	(571,968)	3,860
Equity/Undist. Subs. Earnings	0	0	0	0
Decrease (Increase) in:	0	0	0	0
Accounts Rec. Affiliated West	27,089,484	0	(8,910,888)	(99,869)
Accounts Rec. Affiliated East	(2,067,016)	(7,452,525)	(243,598)	25,667,101
Accounts Rec. - Factored West	0	0	(8,679,586)	0
Accounts Rec. - Factored East	8,657,742	0	0	(4,001,675)
Accounts Rec. - Nonaffiliated	19,181,848	28,856,779	7,841,779	21,406,043
Dividends Receivable	0	0	0	0
Fuel, Materials & Supplies	(18,215,024)	(587,848)	(15,806,843)	3,186,438
Accrued Utility Revenues	0	0	0	0
Accounts Payable - Affiliated West	9,778,536	0	(976,422)	(18,615,190)
Accounts Payable - Affiliated East	11,843,579	(23,699,507)	1,878,802	(12,208,309)
Accounts Payable - Nonaffiliated	(76,933,098)	(31,619,600)	(35,392,810)	(29,908,162)
Interest Payable - Affiliated West	0	0	0	0
Interest Payable - Affiliated East	(1,493,885)	(1,037,440)	0	(215,112)
Mark to market Energy Trading	(12,048,000)	0	(3,472,000)	(1,818,000)
Other Oper. Items Assets (Sch 1)	200,396,956	40,042,128	28,353,924	36,433,724
Other Oper. Items Liab. (Sch 1)	31,745,616	27,796,354	30,259,223	2,674,996
NET CASH PROVIDED (USED) OPERATING	469,920,067	149,859,274	169,611,052	72,359,941
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(194,592,630)	(125,420,705)	(112,296,858)	(39,658,470)
Other Gross Additions	(354,057)	(359,111)	(411,540)	(126,968)
Total Gross Additions	(194,946,687)	(125,779,816)	(112,708,398)	(39,785,438)
AFUDC - Equity	860,657	900,909	571,968	(3,860)
Cash Used Plant & Prop. Adds	(194,086,030)	(124,878,907)	(112,136,430)	(39,789,298)
Invest in Subs - Equity & Debt	0	0	(85,716,367)	0
Proceeds - Sales of Property	0	0	0	0
Proceeds - Sale of Frontera	0	0	0	0
Proceeds - Sale & Leaseback Trans	0	0	0	0
Other Investing Activities	0	0	0	0
NET CASH PROVIDED (USED) INVESTING	(194,086,030)	(124,878,907)	(197,852,797)	(39,789,298)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	0	0	0
Common Stock	0	0	0	0
Preferred Stock	0	0	0	0
Minority Interest	0	0	0	0
Long-term Debt	260,161,946	0	0	0
Long-Term Debt - Affiliated Cos.	0	0	0	0
Money Pool Payable - East	84,565,438	41,966,246	106,786,869	(8,129,932)
Money Pool Payable - West	0	0	0	0
Short-term Debt (net)	0	0	0	0
Total Issuances	344,727,384	41,966,246	106,786,869	(8,129,932)
Cash Paid To Retire:				
Preferred Stock	0	0	0	0
Long-term Debt	(475,606,000)	(20,000,000)	(595,000)	0
Long-term Debt - Affiliated Cos.	0	0	0	0
Total Retirements	(475,606,000)	(20,000,000)	(595,000)	0
Dividends Paid on Common Stock	(148,057,007)	(52,240,069)	(74,212,088)	(28,823,941)
Dividends Paid on Preferred Stock	(241,551)	(212,637)	(229,055)	(104,157)
NET CASH PROVIDED (USED) FINANCING	(279,177,174)	(30,486,460)	31,750,726	(37,058,030)
EFFECT OF EXCHANGE RATE CHANGES	0	0	0	0
NET INCREASE (DECREASE) IN CASH	(3,343,137)	(5,506,093)	3,508,981	(4,487,387)
CASH AT BEGINNING OF PERIOD	14,252,854	11,300,717	1,906,269	6,940,859
CASH AT END OF PERIOD	10,909,717	5,794,624	5,415,250	2,453,472
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	109,834,983	38,250,023	51,125,534	19,279,398
Income Taxes (State & Federal)	161,529,377	38,652,982	49,176,363	21,997,000
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	0	0	0

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Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	SEEBOARD	CSW COMM	LEASING	CREDIT
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	88,118,636	(42,926,774)	(6,205,075)	27,205,599
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	90,693,144	9,515,484	0	0
Prov for Def Income Taxes (net)	1,305,629	(3,612,690)	0	(1,341,160)
Def Invest Tax Credits (net)	0	0	0	0
AFUDC - Equity	0	0	0	0
Equity/Undist. Subs. Earnings	(10,967,403)	0	0	0
Decrease (Increase) in:	0	0	0	0
Accounts Rec. Affiliated West	0	0	0	0
Accounts Rec. Affiliated East	0	800,826	(1,037,181)	(177,339,925)
Accounts Rec. - Factored West	0	0	0	0
Accounts Rec. - Factored East	0	0	0	0
Accounts Rec. - Nonaffiliated	3,290,058	(2,886,571)	234,780	1,228,629,115
Dividends Receivable	0	0	0	0
Fuel, Materials & Supplies	(5,382,151)	3,374,435	0	0
Accrued Utility Revenues	0	0	0	0
Accounts Payable - Affiliated West	0	0	(268,024)	(34,936)
Accounts Payable - Affiliated East	(1,503,528)	(8,627,569)	0	2,234,256
Accounts Payable - Nonaffiliated	10,752,149	(1,605,741)	(23,782)	90,929,429
Interest Payable - Affiliated West	0	0	0	0
Interest Payable - Affiliated East	92,678	31,811	0	2,480,717
Mark to market Energy Trading	0	0	0	0
Other Oper. Items Assets (Sch 1)	0	0	0	0
Other Oper. Items Liab. (Sch 1)	(62,943,094)	2,106,662	16,053,532	13,769,821
NET CASH PROVIDED (USED) OPERATING	113,456,118	(43,830,127)	8,754,250	1,186,532,916
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(119,726,802)	10,955,044	0	0
Other Gross Additions	0	(11,819,068)	0	0
Total Gross Additions	(119,726,802)	(864,024)	0	0
AFUDC - Equity	0	0	0	0
Cash Used Plant & Prop. Adds	(119,726,802)	(864,024)	0	0
Invest in Subs - Equity & Debt	609,497	0	0	0
Proceeds - Sales of Property	1,469,987	0	17,853,750	0
Proceeds - Sale of Frontera	0	0	0	0
Proceeds - Sale & Leaseback Trans	0	0	0	0
Other Investing Activities	6,227,855	0	0	0
NET CASH PROVIDED (USED) INVESTING	(111,419,463)	(864,024)	17,853,750	0
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	0	9,600,315	(28,823,069)
Common Stock	0	0	0	0
Preferred Stock	0	0	0	0
Minority Interest	0	0	0	0
Long-term Debt	0	0	0	0
Long-Term Debt - Affiliated Cos.	0	175,269,049	0	0
Money Pool Payable - East	23,349,653	(130,443,385)	0	63,661,765
Money Pool Payable - West	0	0	0	0
Short-term Debt (net)	192,651,670	0	0	(1,220,948,000)
Total Issuances	216,001,323	44,825,664	9,600,315	(1,186,109,304)
Cash Paid To Retire:				
Preferred Stock	0	0	0	0
Long-term Debt	(187,307,940)	0	0	0
Long-term Debt - Affiliated Cos.	0	0	0	0
Total Retirements	(187,307,940)	0	0	0
Dividends Paid on Common Stock	(14,376,000)	0	(30,000,000)	0
Dividends Paid on Preferred Stock	0	0	0	0
NET CASH PROVIDED (USED) FINANCING	14,317,383	44,825,664	(20,399,685)	(1,186,109,304)
EFFECT OF EXCHANGE RATE CHANGES	(1,321,652)	0	0	0
NET INCREASE (DECREASE) IN CASH	15,032,386	131,513	6,208,315	423,612
CASH AT BEGINNING OF PERIOD	73,942,617	2,000	1,004,767	(423,612)
CASH AT END OF PERIOD	88,975,003	133,513	7,213,082	0
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	125,729,346	6,542,116	0	62,369,566
Income Taxes (State & Federal)	17,095,536	0	0	14,466,250
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	0	0	0

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Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows YTD December 31, 2001

	CSW ENERGY	ESI	CSW INT'L.	CSW ENERSHOP	REP HOLDCO
CASH FLOWS - OPERATING ACTIVITIES:					
Consolidated Net Income	64,831,183	(23,649,238)	47,714,210	(1,977,153)	(1,427,747)
Adj. to Recon. N/I to Cash Flow:					
Depreciation & Amortization	5,438,894	1,423,392	235,169	242,409	0
Prov for Def Income Taxes (net)	(12,018,380)	5,482,798	16,395,778	0	0
Def Invest Tax Credits (net)	0	0	0	0	0
AFUDC - Equity	0	0	0	0	0
Equity/Undist. Subs. Earnings	(15,082,963)	0	(17,035,280)	0	0
Decrease (Increase) in:	0	0	0	0	0
Accounts Rec. Affiliated West	158,870,576	694,305	0	1,225	0
Accounts Rec. Affiliated East	0	0	(21,748,189)	0	(440,730)
Accounts Rec. - Factored West	0	0	0	0	0
Accounts Rec. - Factored East	0	0	0	0	0
Accounts Rec. - Nonaffiliated	(7,547,083)	14,435,876	67,147,235	673,654	(147)
Dividends Receivable	0	0	0	0	0
Fuel, Materials & Supplies	0	7,513,543	0	0	0
Accrued Utility Revenues	0	0	0	0	0
Accounts Payable - Affiliated West	0	(56,994)	0	0	0
Accounts Payable - Affiliated East	0	(69,478,954)	(134,105,248)	105,551	2,457,459
Accounts Payable - Nonaffiliated	(9,945,307)	(37,798,394)	(30,161)	12,898	0
Interest Payable - Affiliated West	0	0	92,678	0	0
Interest Payable - Affiliated East	(1,437,360)	0	33,865	0	0
Mark to market Energy Trading	0	0	0	0	0
Other Oper. Items Assets (Sch 1)	0	0	0	0	0
Other Oper. Items Liab. (Sch 1)	(63,787,907)	(3,652,426)	(12,100,215)	(1,050,589)	(1,194,835)
NET CASH PROVIDED (USED) OPERATING	119,321,653	(105,086,092)	(53,400,158)	(1,992,005)	(606,000)
CASH FLOWS - INVESTING ACTIVITIES:					
Plant & Property Additions:					
Gross Additions to Utility Plant	(147,206,346)	(7,572,498)	2,306,227	(5,110)	0
Other Gross Additions	0	0	0	236,424	0
Total Gross Additions	(147,206,346)	(7,572,498)	2,306,227	231,314	0
AFUDC - Equity	0	0	0	0	0
Cash Used Plant & Prop. Adds	(147,206,346)	(7,572,498)	2,306,227	231,314	0
Invest in Subs - Equity & Debt	0	(15,526,453)	(83,341,785)	0	0
Proceeds - Sales of Property	0	0	0	0	0
Proceeds - Sale of Frontera	264,731,214	0	0	0	0
Proceeds - Sale & Leaseback Trans	0	0	0	0	0
Other Investing Activities	3,808,454	0	85,894,689	0	0
NET CASH PROVIDED (USED) INVESTING	121,333,322	(23,098,951)	4,859,131	231,314	0
CASH FLOWS - FINANCING ACTIVITIES:					
Proceeds from Issuances of:					
Capital Contributions from Parent	0	0	0	0	0
Common Stock	0	0	0	0	303,000
Preferred Stock	0	0	0	0	0
Minority Interest	0	0	0	0	0
Long-term Debt	0	1,300,149	0	0	0
Long-Term Debt - Affiliated Cos.	100,000,000	60,094,078	0	15,000,000	0
Money Pool Payable - East	(108,688,360)	0	46,104,068	(13,190,423)	0
Money Pool Payable - West	0	16,333,629	0	0	0
Short-term Debt (net)	0	49,412,575	0	0	0
Total Issuances	(8,688,360)	127,140,431	46,104,068	1,809,577	303,000
Cash Paid To Retire:					
Preferred Stock	0	0	0	0	0
Long-term Debt	(200,000,000)	0	0	0	0
Long-term Debt - Affiliated Cos.	(50,000,000)	0	0	0	0
Total Retirements	(250,000,000)	0	0	0	0
Dividends Paid on Common Stock	0	0	0	0	0
Dividends Paid on Preferred Stock	0	0	0	0	0
NET CASH PROVIDED (USED) FINANCING	(258,688,360)	127,140,431	46,104,068	1,809,577	303,000
EFFECT OF EXCHANGE RATE CHANGES	0	0	(1,111,009)	0	0
NET INCREASE (DECREASE) IN CASH	(18,033,385)	(1,044,612)	(3,547,968)	48,885	(303,000)
CASH AT BEGINNING OF PERIOD	20,387,603	0	4,407,399	(48,885)	0
CASH AT END OF PERIOD	2,354,218	(1,044,612)	859,431	0	(303,000)
CASH PAID DURING THE PERIOD FOR:					
Interest (net of ABFUDC)	25,205,018	0	10,059,417	1,224,895	0
Income Taxes (State & Federal)	31,071,800	0	19,520,010	0	0
NONCASH INVESTING ACTIVITIES:					
Utility Assets - Capital Leases	0	0	0	0	0
NonUtility Assets - Capital Leases	0	0	0	0	0
Total Capital Leases	0	0	0	0	0

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APPALACHIAN POWER COMPANY   Consolidated Statement of Cash Flows

	APCo Cons.	ELIM & ADJ	APCo Corp.	CACCo	Cedar	SACCo	WVPCo
CASH FLOWS - OPERATING ACTIVITIES:							
Consolidated Net Income	161,818,276	(631,383)	161,818,276	24,022	100,307	500,201	6,853
Adj. to Recon. N/I to Cash Flow:							
Depreciation & Amortization	180,505,480	0	180,505,480	0	0	0	0
Prov for Def Income Taxes (net)	42,498,113	0	42,584,901	66,036	(385,493)	232,669	0
Def Invest Tax Credits (net)	(4,764,823)	0	(4,764,823)	0	0	0	0
AFUDC - Equity	5,338	0	5,338	0	0	0	0
Equity/Undist. Subs. Earnings	0	631,383	(631,383)	0	0	0	0
Decrease (Increase) in:							
Accounts Receivable (net)	134,098,915	3,424,859	136,166,621	(501,847)	(3,232,663)	(1,756,258)	(1,796)
Fuel, Materials & Supplies	(19,956,663)	(497)	(19,956,166)	0	0	0	0
Accrued Utility Revenues	35,591,132	0	35,591,132	0	0	0	0
Incr (Decr) in Accounts Payable	(45,073,190)	(4,223,023)	(41,729,686)	87,206	(292,914)	1,082,745	2,481
Mark to market	(68,254,000)	(68,254,000)					
Other Oper. Items Assets (Sch 1)	(64,626,669)	(64,626,669)					
Other Oper. Items Liabilities (Sch 1)	33,578,572	133,679,330	(107,387,053)	324,155	4,557,978	2,409,138	(4,976)
NET CASH PROVIDED (USED) OPERATING	385,420,481	(0)	382,202,637	(429)	747,215	2,468,495	2,562
CASH FLOWS - INVESTING ACTIVITIES:							
Plant & Property Additions:							
Gross Additions to Utility Plant	(305,603,150)	0	(305,603,150)	0	0	0	0
Other Gross Additions	(437,755)	0	(437,755)	0	0	0	0
Total Gross Additions	(306,040,905)	0	(306,040,905)	0	0	0	0
AFUDC - Equity	(5,338)	0	(5,338)	0	0	0	0
Cash Used Plant & Prop. Adds	(306,046,242)	0	(306,046,242)	0	0	0	0
Invest in Subs - Equity & Debt	0	0	0	0	0	0	0
Proceeds - Sales of Property	1,181,969	0	1,181,969	0	0	0	0
Proceeds - Sale & Leaseback Trans	0	0	0	0	0	0	0
Other Investing Activities	0	0	0	0	0	0	0
NET CASH PROVIDED (USED) INVESTING	(304,864,273)	0	(304,864,273)	0	0	0	0
CASH FLOWS - FINANCING ACTIVITIES:							
Proceeds from Issuances of:							
Capital Contributions from Parent	0	0	0	0	0	0	0
Common Stock	0	0	0	0	0	0	0
Preferred Stock	0	0	0	0	0	0	0
Long-term Debt	124,587,500	0	124,587,500	0	0	0	0
Short-term Debt (net)	(191,495,000)	0	(191,495,000)	0	0	0	0
Change in Money Pool	300,204,241	0	303,226,867	(22,413)	(642,553)	(2,354,933)	(2,727)
Total Issuances	233,296,741	0	236,319,367	(22,413)	(642,553)	(2,354,933)	(2,727)
Cash Paid To Retire:							
Preferred Stock	0	0	0	0	0	0	0
Long-term Debt	(175,000,000)	0	(175,000,000)	0	0	0	0
Total Retirements	(175,000,000)	0	(175,000,000)	0	0	0	0
Dividends Paid on Common Stock	(129,594,120)	0	(129,594,120)	0	0	0	0
Dividends Paid on Preferred Stock	(1,442,543)	0	(1,442,543)	0	0	0	0
NET CASH PROVIDED (USED) FINANCING	(72,739,922)	0	(69,717,296)	(22,413)	(642,553)	(2,354,933)	(2,727)
NET INCREASE (DECREASE) IN CASH	7,816,286	(0)	7,621,068	(22,841)	104,662	113,563	(165)
CASH AT BEGINNING OF PERIOD	5,846,710	0	5,815,829	23,487	5,533	78	1,783
CASH AT END OF PERIOD	13,662,996	0	13,436,897	646	110,194	113,641	1,618
CASH PAID DURING THE PERIOD FOR:							
INTEREST (net of ABFUDC)	117,283,027	(605)	117,283,632	0	0	0	0
INCOME TAXES (State & Federal)	56,981,200	0	56,474,100	(74,100)	248,100	327,900	5,200
NONCASH INVESTING ACTIVITIES:							
Utility Plant - Capital Leases	2,510,162	0	2,510,162	0	0	0	0
Nonutility Plant - Capital Leases	0	0	0	0	0	0	0

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COLUMBUS SOUTHERN POWER COMPANY
Consolidated Statement of Cash Flows
YTD December 2001

	CSPCo Cons.	ELIM & ADJ	CSPCo Corp.	CCPC	Simco	Colomet
CASH FLOWS - OPERATING ACTIVITIES:						
Consolidated Net Income	161,876,319	(164,785)	161,876,319	70,000	91,338	3,447
Adj. to Recon. N/I to Cash Flow:						
Depreciation & Amortization	105,354,069	0	104,292,297	992,676	69,096	0
Amort Regulatory Debits	23,146,054	0	23,146,054	0	0	0
Prov for Def Income Taxes (net)	24,107,869	0	24,330,283	(210,494)	(11,920)	0
Def Invest Tax Credits (net)	(4,058,087)	0	(4,052,867)	0	(5,220)	0
AFUDC - Equity (4191000)	297,939	0	297,939	0	0	0
Equity/Undist. Subs. Earnings	0	(35,215)	35,215	0	0	0
Decrease (Increase) in:						
Accounts Receivable (net)	19,985,865	(6,521,207)	25,778,347	612,085	(15,148)	131,788
Fuel, Materials & Supplies	(7,780,073)	0	(7,393,033)	(387,040)	0	0
Accrued Utility Revenues	2,551,640	0	2,551,640	0	0	0
Incr (Decr) in Accounts Payable	(16,248,484)	6,619,433	(22,476,948)	(237,818)	(5,346)	(147,805)
Mark to market	(44,680,000)	(44,680,000)	0	0	0	0
Other Oper. Items Assets (Sch 1)	1,735,369	1,735,369	0	0	0	0
Other Oper. Items Liabilities (Sch 1)	(32,844,669)	42,846,405	(72,002,565)	(689,658)	(24,335)	(2,974,516)
NET CASH PROVIDED (USED) OPERATING	233,443,811	(200,000)	236,382,681	149,751	98,465	(2,987,086)
CASH FLOWS - INVESTING ACTIVITIES:						
Plant & Property Additions:						
Gross Additions to Utility Plant	(122,476,192)	0	(122,187,063)	0	0	(289,129)
Other Gross Additions	(9,757,500)	0	0	(9,757,500)	0	0
Total Gross Additions	(132,233,692)	0	(122,187,063)	(9,757,500)	0	(289,129)
AFUDC - Equity	(297,939)	0	(297,939)	0	0	0
Cash Used Plant & Prop. Adds	(132,531,631)	0	(122,485,002)	(9,757,500)	0	(289,129)
Invest in Subs - Equity & Debt	0	2,822,302	(2,822,302)	0	0	0
Proceeds - Sales of Property	10,840,454	0	1,594,758	9,245,696	0	0
Proceeds - Sale & Leaseback Trans	0	0	0	0	0	0
Other Investing Activities	0	0	0	0	0	0
NET CASH PROVIDED (USED) INVESTING	(121,691,177)	2,822,302	(123,712,546)	(511,804)	0	(289,129)
CASH FLOWS - FINANCING ACTIVITIES:						
Proceeds from Issuances of:						
Capital Contributions from Parent	0	0	0	0	0	0
Common Stock	0	0	0	0	0	0
Preferred Stock	0	0	0	0	0	0
Long-term Debt	200,000,000	(2,822,302)	200,000,000	0	0	2,822,302
Change in Money Pool	92,652,315	0	91,697,703	370,575	1,535	582,502
Short-term Debt (net)	0	0	0	0	0	0
Total Issuances	292,652,315	(2,822,302)	291,697,703	370,575	1,535	3,404,804
Cash Paid To Retire:						
Preferred Stock	(5,000,000)	0	(5,000,000)	0	0	0
Long-term Debt	(314,733,231)	0	(314,733,231)	0	0	0
Total Retirements	(319,733,231)	0	(319,733,231)	0	0	0
Dividends Paid on Common Stock	(82,952,078)	200,000	(82,952,078)	0	(100,000)	(100,000)
Dividends Paid on Preferred Stock	(962,500)	0	(962,500)	0	0	0
NET CASH PROVIDED (USED) FINANCING	(110,995,494)	(2,622,302)	(111,950,106)	370,575	(98,465)	3,304,804
NET INCREASE (DECREASE) IN CASH	757,140	0	720,029	8,522	0	28,589
CASH AT BEGINNING OF PERIOD	11,600,207	0	11,593,077	6,830	0	300
CASH AT END OF PERIOD	12,357,347	0	12,313,106	15,352	0	28,889
CASH PAID DURING THE PERIOD FOR:						
INTEREST (net of ABFUDC)	68,595,700	(606)	68,561,462	34,844	0	0
INCOME TAXES (State & Federal)	80,484,500	0	79,547,000	666,800	78,000	192,700
NONCASH INVESTING ACTIVITIES:						
Utility Assets - Capital Lease	1,019,036	0	1,019,036	0	0	0
Nonutility Assets - Capital Lease	0	0	0	0	0	0

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INDIANA MICHIGAN POWER COMPANY
Consolidating Statement of Cash Flows
PERIOD ENDING December 2001

CASH FLOWS - OPERATING ACTIVITIES:	I&M Consolidated	Eliminations & Adjustments	I&M Corporation	Blackhawk Coal Co.	Price River Coal Co.
Consolidated Net Income	75,787,950.62	(996,352.00)	75,787,950.62	996,352.00	0.00
Adj. to Recon. N/I to Cash Flow:					
Depreciation & Amortization	166,360,007.05	0.00	166,360,007.05	0.00	0.00
Prov for Def Income Taxes (net)	(29,204,810.00)	0.00	(29,397,795.00)	192,985.00	0.00
Def Invest Tax Credits (net)	(8,324,685.00)	0.00	(8,324,685.00)	0.00	0.00
AFUDC - Equity	45,777.79	0.00	45,777.79	0.00	0.00
Equity/Undist. Subs. Earnings	0.00	(5,292,690.61)	5,292,690.61	0.00	0.00
Decrease (Increase) in:					
Accounts Receivable (net)	64,842,213.36	118,336.75	63,259,112.20	1,464,764.41	0.00
Fuel, Materials & Supplies	(19,425,760.59)	0.00	(19,425,760.59)	0.00	0.00
Accrued Utility Revenues	(2,071,505.45)	0.00	(2,071,505.45)	0.00	0.00
Incr (Decr) in Accounts Payable	(60,185,498.67)	(117,986.66)	(60,165,466.46)	97,954.45	0.00
Mark to Market Trading Contracts	(19,502,000.00)	(19,502,000.00)			
Other Oper. Items Assets (Sch 1)	15,962,866.14	15,962,866.14			
Other Oper. Items Liabilities (Sch 1)	51,923,158.54	3,527,783.77	46,938,607.34	1,456,767.43	0.00
NET CASH PROVIDED (USED) OPERATING	236,207,713.79	(6,300,042.61)	238,298,933.11	4,208,823.29	0.00
CASH FLOWS - INVESTING ACTIVITIES:					
Plant & Property Additions:					
Gross Additions to Utility Plant	(90,796,081.93)	0.00	(90,796,081.93)	0.00	0.00
Other Gross Additions	(210,349.83)	0.00	(210,349.83)	0.00	0.00
Total Gross Additions	(91,006,431.76)	0.00	(91,006,431.76)	0.00	0.00
AFUDC - Equity	(45,777.79)	0.00	(45,777.79)	0.00	0.00
Cash Used Plant & Prop. Adds	(91,052,209.55)	0.00	(91,052,209.55)	0.00	0.00
Invest in Subs - Equity & Debt	0.00	0.00	0.00	0.00	0.00
Proceeds - Sales of Property	1,074,349.00	0.00	1,074,349.00	0.00	0.00
Proceeds - Sale & Leaseback Trans	0.00	0.00	0.00	0.00	0.00
Other Investing Activities	(92,615,924.47)	0.00	(92,615,924.47)	0.00	0.00
NET CASH PROVIDED (USED) INVESTING	(182,593,785.02)	0.00	(182,593,785.02)	0.00	0.00
CASH FLOWS - FINANCING ACTIVITIES:					
Proceeds from Issuances of:					
Capital Contributions from Parent	0.00	0.00	0.00	0.00	0.00
Common Stock	0.00	0.00	0.00	0.00	0.00
Preferred Stock	0.00	0.00	0.00	0.00	0.00
Long-term Debt	297,655,636.00	0.00	297,655,636.00	0.00	0.00
Change in Money Pool	(299,891,219.34)	0.00	(302,016,110.19)	2,124,890.85	0.00
Short-term Debt (net)	0.00	0.00	0.00	0.00	0.00
Total Issuances	(2,235,583.34)	0.00	(4,360,474.19)	2,124,890.85	0.00
Cash Paid To Retire:					
Preferred Stock	0.00	0.00	0.00	0.00	0.00
Long-term Debt	(44,922,491.40)	0.00	(44,922,491.40)	0.00	0.00
Total Retirements	(44,922,491.40)	0.00	(44,922,491.40)	0.00	0.00
Dividends Paid on Common Stock	0.00	6,300,042.61	0.00	(6,300,042.61)	0.00
Dividends Paid on Preferred Stock	(4,486,826.58)	0.00	(4,486,826.58)	0.00	0.00
NET CASH PROVIDED (USED) FINANCING	(51,644,901.32)	6,300,042.61	(53,769,792.17)	(4,175,151.76)	0.00
NET INCREASE (DECREASE) IN CASH	1,969,027.45	0.00	1,935,355.92	33,671.53	0.00
CASH AT BEGINNING OF PERIOD	14,835,222.31	0.00	14,818,007.28	17,215.03	0.00
CASH AT END OF PERIOD	16,804,249.76	0.00	16,753,363.20	50,886.56	0.00
CASH PAID DURING THE PERIOD FOR:					
Interest (net of ABFUDC)	92,139,686.15	0.00	92,139,686.15	0.00	0.00
Income Taxes (State & Federal)	100,469,900.00	0.00	99,212,900.00	1,257,000.00	0.00
Noncash Investing Activities:					
Utility Assets - Capital Lease	1,022,905.80	0.00	1,022,905.80	0.00	0.00
NonUtility Assets - Capital Lease	0.00	0.00	0.00	0.00	0.00

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OHIO POWER COMPANY
Consolidated Statement of Cash Flow as of 12/31/2001

	OPCo Cons.	ELIM & ADJ	OPCo Corp.	COCCo	SOCCo	WCCo
CASH FLOWS - OPERATING ACTIVITIES:						
Consolidated Net Income	147,445,368	(7,133,891)	147,445,368	(7,244,116)	6,919,078	7,458,929
Adj. to Recon. N/I to Cash Flow:						
Depreciation & Amortization	178,793,020	--	166,651,116	--	11,843,052	298,852
Transition Asset Amortization	73,330,383	--	73,330,383	--	--	--
Prov for Def Income Taxes (net)	215,832,825	--	38,140,205	52,697,230	93,461,992	31,533,398
Def Invest Tax Credits (net)	(3,288,192)	--	(3,288,192)	--	--	--
AFUDC - Equity	(29,564)	--	(29,564)	--	--	--
Equity/Undist. Subs. Earnings	--	7,076,903	(7,076,903)	--	--	--
Decrease (Increase) in:	--	--				
Accounts Receivable (net)	51,638,892	(95,830,305)	38,094,700	24,446,881	77,144,091	7,783,525
Fuel, Materials & Supplies	4,852,315	(484)	(16,380,122)	6,363,327	10,850,099	4,019,495
Accrued Utility Revenues	263,690	--	263,690	--	--	--
Incr (Decr) in Accounts Payable	9,886,755	93,583,724	(61,734,458)	(2,483,625)	(14,538,337)	(4,940,549)
COLI Tax	--	--	--	--	--	--
Mark to Market trading	(59,833,000)	(59,833,000)	--	--	--	--
Other Oper. Items Assets (Sch 1)	84,091,540	84,091,540	--	--	--	--
Other Oper. Items Liab. (Sch 1)	(616,228,265)	(22,011,475)	(118,799,449)	(124,876,953)	(265,235,090)	(85,305,298)
NET CASH PROVIDED (USED) OPERATING	86,755,767	(56,988)	256,616,774	(51,097,256)	(79,555,115)	(39,151,648)
CASH FLOWS - INVESTING ACTIVITIES:						
Plant & Property Additions:						
Gross Additions to Utility Plant	(343,796,191)	--	(343,708,149)	--	(88,042)	--
Other Gross Additions	(804,446)	--	(804,446)	--	--	--
Total Gross Additions	(344,600,637)	--	(344,512,595)	--	(88,042)	--
AFUDC - Equity	29,564	--	29,564	--	--	--
Cash Used Plant & Prop. Adds	(344,571,073)	--	(344,483,031)	--	(88,042)	--
Invest in Subs - Equity & Debt	171,928	(62,471,092)	62,643,020	--	--	--
Proceeds - Sales of Property	16,583,079	--	2,738,469	637,454	12,577,938	629,218
Proceeds - Sale & Leaseback Trans	23,420	--	23,420	--	--	--
Other Investing Activities	(32,115,000)	--	(32,115,000)	--	--	--
NET CASH PROVIDED (USED) INVESTING	(359,907,646)	(62,471,092)	(311,193,122)	637,454	12,489,896	629,218
CASH FLOWS - FINANCING ACTIVITIES:						
Proceeds from Issuances of:						
Capital Contributions from Parent	--	62,458,786	--	7,244,234	(62,247,041)	(7,455,979)
Common Stock	--	12,306	--	(6,900)	(5,000)	(406)
Preferred Stock	--	--	--	--	--	--
Long-term Debt	300,000,000	--	300,000,000	--	--	--
Short-term Debt (net)	--	--	--	--	--	--
Change in Money Pool	392,699,157	--	133,023,307	43,021,738	171,619,082	45,035,030
Total Issuances	692,699,157	62,471,092	433,023,307	50,259,072	109,367,041	37,578,645
Cash Paid To Retire:						
Preferred Stock	--	--	--	--	--	--
Long-term Debt	(297,858,040)	--	(255,351,672)	--	(42,506,368)	--
Total Retirements	(297,858,040)	--	(255,351,672)	--	(42,506,368)	--
Dividends Paid on Common Stock	(142,975,781)	56,988	(142,975,781)	(2,951)	(252)	(53,785)
Dividends Paid on Preferred Stock	(1,258,738)	--	(1,258,738)	--	--	--
NET CASH PROVIDED (USED) FINANCING	250,606,598	62,528,080	33,437,116	50,256,121	66,860,421	37,524,860
NET INCREASE (DECREASE) IN CASH	(22,545,281)	--	(21,139,232)	(203,681)	(204,798)	(997,570)
CASH AT BEGINNING OF PERIOD	31,392,958	--	29,986,909	203,681	204,798	997,570
CASH AT END OF PERIOD	8,847,677	--	8,847,677	--	--	--
CASH PAID DURING THE PERIOD FOR:						
INTEREST (net of ABFUDC)	94,746,680	532,395	91,699,176	20	2,515,089	--
INCOME TAXES (State & Federal)	(22,416,867)	--	63,456,300	(32,665,192)	(20,345,675)	(32,862,300)
NONCASH INVESTING ACTIVITIES:						
Utility Assets - Capital Lease	2,284,894	--	2,284,894	--	--	--
Non-Utility plant-Capital Lease	95,168	--	95,168	--	--	--

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SWEPCo Consolidated STATEMENT OF CASH FLOWS
PERIOD ENDING DECEMBER 31, 2001

	SWEPCO Consolidated	Eliminations	SWEPCO	Dolet Hills
CASH FLOWS FROM OPERATING ACTIVITIES:				
1. Consolidated Net Income	89,366,586	(1,632,379)	89,366,586	1,632,379
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:				
2.Depreciation, Depletion and Amortization.	121,814,226	--	116,137,240	5,676,986
3.Provision for Deferred Income Taxes (net).	(31,396,485)	--	(31,396,485)	--
4.Deferred Investment Tax Credits (net)	(4,452,888)	--	(4,452,888)	--
5.Allowance for Equity Funds Used During Con.	(571,968)	--	(571,968)	--
6.Equity in Undistributed Earnings of Subsidiary	--	699,591	(699,591)	--
7.Decrease (Increase) in:				
Accounts Receivable (net)..	(9,992,291)	5,316,724	(4,109,151)	(11,199,864)
Fuel, Materials and Supplies ..	(15,806,843)	3,771,537	(10,761,798)	(8,816,582)
Accrued Utility Revenues .	--	--	--	--
Increase (Decrease) in Accounts Payable	(34,490,432)	(2,482,208)	(34,718,535)	2,710,311
Mark to Market	(3,472,000)	(3,472,000)	--	--
Other Operating Items Assets (See Schedule 1.)	28,353,924	28,353,924	--	--
Other Operating Items Liabilities (See Schedule 1.)	30,259,223	7,689,013	50,305,328	(27,735,118)
Net Cash Provided (Used) By Operating Activities	169,611,052	38,244,202	169,098,738	(37,731,888)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Plant and Property Additions:				
9. Gross Additions to Utility Plant.	(112,296,858)	46,240,598	(111,486,266)	(47,051,190)
10. Gross Other Additions .	(411,540)	--	(411,540)	--
Total Gross Additions . . .	(112,708,398)	46,240,598	(111,897,806)	(47,051,190)
11. Allowance for Equity Funds Used During Con.	571,968	--	571,968	--
Cash Used for Plant and Property Additions.	(112,136,430)	46,240,598	(111,325,838)	(47,051,190)
12.Investments in Associated Companies Equity/Debt	(85,716,367)	--	(85,716,367)	--
13.Proceeds from Sales of Property	--	--	--	--
14.Proceeds from Sale and Leaseback Transaction	--	--	--	--
15.Other Investing Activities.	--	--	--	--
Net Cash Provided (Used) By Investing Activities	(197,852,797)	46,240,598	(197,042,205)	(47,051,190)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
16. Capital Contributions from (returned to) Parent	--	(25,210,449)	--	25,210,449
17. Common Stock.	--	--	--	--
18. Cumulative Preferred Stock.	--	--	--	--
19. Long-term Debt.	--	--	--	--
20. Advances to/from Affiliates (Money Pool) (net).	106,786,869	(60,505,918)	106,786,869	60,505,918
21.Short-term Debt (net)	--	--	--	--
Total Issuances .	106,786,869	(85,716,367)	106,786,869	85,716,367
Cash Paid to Retire:	--	--	--	--
22. Cumulative Preferred Stocks .	--	--	--	--
23. Long-term Debt.	(595,000)	--	(595,000)	--
Total Retirements	(595,000)	--	(595,000)	--
24.Dividends Paid on Common Stock.	(74,212,088)	932,788	(74,212,088)	(932,788)
25.Dividends Paid on Preferred Stocks.	(229,055)	--	(229,055)	--
Net Cash Provided (Used) By Financing	31,750,726	(84,783,579)	31,750,726	84,783,579
26.Effect on Foreign Exchange Rate on Cash	--	--	--	--
27.NET INCREASE (DECREASE) IN CASH	3,508,981	(298,779)	3,807,259	501
28.Cash and Cash Equivalents at Beginning of Period	1,906,269	--	1,906,269	--
29.Cash and Cash Equivalents at End of Period.	5,415,250	(298,779)	5,713,528	501
Supplemental Disclosure:				
Cash Paid During the Period For:				
30. Interest (net of Allowance for Borrowed Funds	--	--	--	--
Used During Construction)	51,125,534	--	51,125,534	--
31. Income Taxes.	49,176,363	--	49,176,363	--
Noncash Investing Activities:	--	--	--	--
32. Utility Plant Acquired Under Capital Lease	--	--	--	--
33. Nonutility Plant Acquired Under Capital Leases	--	--	--	--

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
BALANCE AT BEGINNING OF YEAR	3,090,051,634.74	(2,491,773,799.19)	3,090,051,634.74	120,583,783.72
Preferred Stock Dividend Req of Subsidiaries	(9,773,227.84)	(9,773,227.84)		
Net Income (Loss)	980,601,520.95	(1,016,383,354.79)	970,828,267.06	161,818,276.05
NET INCOME (LOSS)	970,828,293.11	(1,026,156,582.63)	970,828,267.06	161,818,276.05
TOTAL	4,060,879,927.85	(3,517,930,381.82)	4,060,879,901.80	282,402,059.77
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	0.00	395,322,373.48	0.00	(129,594,120.04)
Div Declrd - Common - NonAssoc	(773,168,114.38)	0.00	(773,168,114.40)	0.00
DIVIDEND DECLARED ON COMMON	(773,168,114.38)	395,322,373.48	(773,168,114.40)	(129,594,120.04)
Dividends Decl-Preferred Stock	0.00	8,063,107.29	0.00	(1,442,542.51)
DIVIDEND DECLARED ON PREFERRED	0.00	8,063,107.29	0.00	(1,442,542.51)
ADJUSTMENT RETAINED EARNINGS	8,410,267.03	(5,889,426.06	8,410,267.03	(568,747.08)
TOTAL DEDUCTIONS	(764,757,847.35)	397,496,234.71	(764,757,847.37)	(131,605,409.63)
BALANCE AT END OF PERIOD	3,296,122,080.50	(3,120,434,147.11)	3,296,122,054.43	150,796,650.14

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO
BALANCE AT BEGINNING OF YEAR	99,068,911.36	3,443,259.42	57,513,179.25	5,219,330.67
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	161,876,319.67	75,787,950.62	21,564,540.76	3,406,249.26
NET INCOME (LOSS)	161,876,319.67	75,787,950.62	21,564,540.76	3,406,249.26
TOTAL	260,945,231.03	79,231,210.04	79,077,720.01	8,625,579.93
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	(82,952,077.76)	0.00	(30,244,395.60)	(2,743,998.80)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(82,952,077.76)	0.00	(30,244,395.60)	(2,743,998.80)
Dividends Decl-Preferred Stock	(875,000.00)	(4,486,826.58)	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	(875,000.00)	(4,486,826.58)	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	(1,015,380.36)	(139,113.86)	0.00	0.00
TOTAL DEDUCTIONS	(84,842,458.12)	(4,625,940.44)	(30,244,395.60)	(2,743,998.80)
BALANCE AT END OF PERIOD	176,102,772.91	74,605,269.60	48,833,324.41	5,881,581.13

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ERICAN ELECTRIC POWER COMPANY, INC.
D SUBSIDIARY COMPANIES
NSOLIDATING STATEMENT OF RETAINED EARNINGS
AR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	WPCO	AEGCO	AEPSC	CCCO
LANCE AT BEGINNING OF YEAR	398,086,502.58	8,721,597.74	9,722,442.59	0.00	0.00
eferred Stock Dividend Req of Subsidiaries					
t Income (Loss)	147,445,368.28	4,068,001.66	7,874,666.12	0.00	0.00
T INCOME (LOSS)	147,445,368.28	4,068,001.66	7,874,666.12	0.00	0.00
TAL	545,531,870.86	12,789,599.40	17,597,108.71	0.00	0.00
DUCTIONS:					
v Declrd - Common Stk - Asso	(142,975,781.28)	(2,976,000.00)	(3,836,000.00)	0.00	0.00
v Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00	0.00
VIDEND DECLARED ON COMMON	(142,975,781.28)	(2,976,000.00)	(3,836,000.00)	0.00	0.00
ividends Decl-Preferred Stock	(1,258,738.20)	0.00	0.00	0.00	0.00
IVIDEND DECLARED ON PREFERRED	(1,258,738.20)	0.00	0.00	0.00	0.00
DJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00	0.00
OTAL DEDUCTIONS	(144,234,519.48)	(2,976,000.00)	(3,836,000.00)	0.00	0.00
ALANCE AT END OF PERIOD	401,297,351.38	9,813,599.40	13,761,108.71	0.00	0.00

MERICAN ELECTRIC POWER COMPANY, INC.
ND SUBSIDIARY COMPANIES
ONSOLIDATING STATEMENT OF RETAINED EARNINGS
EAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	FRECO	IFRI	AEPPM	AEPES	AEPINV CONSOLIDATED
ALANCE AT BEGINNING OF YEAR	19,968.85	0.00	(152.00)	(40,438,374.55)	(10,179,671.03)
referred Stock Dividend Req of Subsidiaries					
et Income (Loss)	0.00	0.00	(221.34)	82,224,895.12	306,122.97
ET INCOME (LOSS)	0.00	0.00	(221.34)	82,224,895.12	306,122.97
OTAL	19,968.85	0.00	(373.34)	41,786,520.57	(9,873,548.06)
EDUCTIONS:					
Div Declrd - Common Stk - Asso	0.00	0.00	0.00	0.00	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00	0.00	0.00
Dividends Decl-Preferred Stock	0.00	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00	0.00	0.00
BALANCE AT END OF PERIOD	19,968.85	0.00	(373.34)	41,786,520.57	(9,873,548.06)

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPR CONSOLIDATED	AEPPRO	AEPC CONSOLIDATED	CSW CONSOLIDATED
BALANCE AT BEGINNING OF YEAR	(32,737,617.48)	(5,092,242.82)	(40,389,865.31)	1,918,345,472.81
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	(62,841,782.06)	292,589.16	(34,836,439.82)	476,791,903.32
NET INCOME (LOSS)	(62,841,782.06)	292,589.16	(34,836,439.82)	476,791,903.32
TOTAL	(95,579,399.54)	(4,799,653.66)	(75,226,305.13)	2,395,137,376.13
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	0.00	0.00	0.00	(0.00)
Div Declrd - Common - NonAssoc	0.02	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.02	0.00	0.00	(0.00)
Dividends Decl-Preferred Stock	0.00	0.00	0.00	(0.00)
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00	(0.00)
ADJUSTMENT RETAINED EARNINGS	(10.01)	0.00	0.00	7,612,497.37
TOTAL DEDUCTIONS	(9.99)	0.00	0.00	7,612,497.37
BALANCE AT END OF PERIOD	(95,579,409.53)	(4,799,653.66)	(75,226,305.13)	2,402,749,873.50

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	AEPC&I CONSOLIDATED	AEP T&D SVC	AEPTEXASGP	MESA LP CONSOLIDATED
BALANCE AT BEGINNING OF YEAR	0.00	0.00	0.00	0.00
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	(3,267,095.65)	(76,815.33)	(1,855.40)	0.00
NET INCOME (LOSS)	(3,267,095.65)	(76,815.33)	(1,855.40)	0.00
TOTAL	(3,267,095.65)	(76,815.33)	(1,855.40)	0.00
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	0.00	0.00	0.00	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00	0.00
Dividends Decl-Preferred Stock	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00	0.00
BALANCE AT END OF PERIOD	(3,267,095.65)	(76,815.33)	(1,855.40)	0.00

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	MUTUALENER CONSOLIDATED	AEPCOAL CONSOLIDATED	AEPRELLC
<S>	<C>	<C>	<C>
BALANCE AT BEGINNING OF YEAR	0.00	0.00	(112,726.61)
Preferred Stock Dividend Req of Subsidiaries			
Net Income (Loss)	(8,082,292.23)	634,548.00	(111,480.25)
NET INCOME (LOSS)	(8,082,292.23)	634,548.00	(111,480.25)
TOTAL	(8,082,292.23)	634,548.00	(224,206.86)
DEDUCTIONS:			
Div Declrd - Common Stk - Asso	0.00	0.00	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00
Dividends Decl-Preferred Stock	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00
BALANCE AT END OF PERIOD	(8,082,292.23)	634,548.00	(224,206.86)

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CENTRAL AND SOUTHWEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSW CONSOLIDATED	CSW ELIMINATIONS	CSW	CPL
BALANCE AT BEGINNING OF YEAR	1,918,345,472.81	(1,256,423,407.83)	1,918,345,472.81	792,218,830.15
NET INCOME (LOSS)	476,791,903.32	(498,776,456.36)	482,171,465.22	182,277,198.63
TOTAL	2,395,137,376.13	(1,755,199,864.19)	2,400,516,938.03	974,496,028.78
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	0.00	341,709,105.76	0.00	(148,057,007.28)
Div Declrd - Common - NonAssoc	0.00	6,000,000.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	347,709,105.76	0.00	(148,057,007.28)
Dividends Decl-Preferred Stock	(0.00)	787,399.21	0.00	(241,551.21)
DIVIDEND DECLARED ON PREFERRED	(0.00)	787,399.21	0.00	(241,551.21)
ADJUSTMENT RETAINED EARNINGS	7,612,497.37	(263,915,920.47)	7,612,497.37	0.00
TOTAL DEDUCTIONS	7,612,497.37	84,580,584.50	7,612,497.37	(148,298,558.49)
BALANCE AT END OF PERIOD	2,402,749,873.50	(1,670,619,279.69)	2,408,129,435.40	826,197,470.29

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CENTRAL AND SOUTHWEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	PSO	SWEPCO CONSOLIDATED	WTU	SEEBOARD
BALANCE AT BEGINNING OF YEAR	137,688,382.92	293,989,298.21	122,587,707.55	0.00
NET INCOME (LOSS)	57,758,861.10	89,366,585.98	12,310,608.61	88,118,636.00
TOTAL	195,447,244.02	383,355,884.19	134,898,316.16	88,118,636.00
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	(52,240,069.04)	(74,212,088.20)	(28,823,941.24)	(14,376,000.00)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(52,240,069.04)	(74,212,088.20)	(28,823,941.24)	(14,376,000.00)
Dividends Decl-Preferred Stock	(212,636.56)	(229,054.64)	(104,156.80)	0.00
DIVIDEND DECLARED ON PREFERRED	(212,636.56)	(229,054.64)	(104,156.80)	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	266,870,320.00
TOTAL DEDUCTIONS	(52,452,705.60)	(74,441,142.84)	(28,928,098.04)	252,494,320.00
BALANCE AT END OF PERIOD	142,994,538.42	308,914,741.35	105,970,218.12	340,612,956.00

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CENTRAL AND SOUTHWEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSWI	CSWE	ENERSHOP	CSWL
<S>	<C>	<C>	<C>	<C>
BALANCE AT BEGINNING OF YEAR	0.00	0.00	(15,982,836.34)	2,341,433.64
NET INCOME (LOSS)	47,714,208.00	64,831,183.00	(1,977,153.03)	(6,205,074.68)
TOTAL	47,714,208.00	64,831,183.00	(17,959,989.37)	(3,863,641.04)
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	0.00	0.00	0.00	(24,000,000.00)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	(6,000,000.00)
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00	(30,000,000.00)
Dividends Decl-Preferred Stock	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	(26,523,231.00)	50,774,430.00	0.00	0.00
TOTAL DEDUCTIONS	(26,523,231.00)	50,774,430.00	0.00	(30,000,000.00)
BALANCE AT END OF PERIOD	21,190,977.00	115,605,613.00	(17,959,989.37)	(33,863,641.04)

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CENTRAL AND SOUTHWEST CORPORATION
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	C3 COMM CONSOLIDATED	CSWESI CONSOLIDATED	CSWPWRMKT	REPHLD CONSOLIDATED	AEP CREDIT
<S>	<C>	<C>	<C>	<C>	<C>
BALANCE AT BEGINNING OF YEAR	(52,904,933.90)	(23,514,474.40)	0.00	0.00	0.00
NET INCOME (LOSS)	(42,926,774.08)	(23,649,237.55)	0.00	(1,427,746.05)	27,205,598.53
TOTAL	(95,831,707.98)	(47,163,711.95)	0.00	(1,427,746.05)	27,205,598.53
DEDUCTIONS:					
Div Declrd - Common Stk - Asso	0.00	0.00	0.00	0.00	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00	0.00	0.00
Dividends Decl-Preferred Stock	0.00	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00	(27,205,598.53)
TOTAL DEDUCTIONS	0.00	0.00	0.00	0.00	(27,205,598.53)
BALANCE AT END OF PERIOD	(95,831,707.98)	(47,163,711.95)	0.00	(1,427,746.05)	0.00

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APPALACHIAN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	APCO CONSOLIDATED	APCO ELIMINATIONS	APCO	CACCO
BALANCE AT BEGINNING OF YEAR	120,583,783.72	(512,507.73)	120,583,783.72	283,081.00
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	161,818,276.05	(631,382.86)	161,818,276.05	24,022.00
NET INCOME (LOSS)	161,818,276.05	(631,382.86)	161,818,276.05	24,022.00
TOTAL	282,402,059.77	(1,143,890.59)	282,402,059.77	307,103.00
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	(129,594,120.04)	0.00	(129,594,120.04)	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(129,594,120.04)	0.00	(129,594,120.04)	0.00
Dividends Decl-Preferred Stock	(1,442,542.51)	0.00	(1,442,542.51)	0.00
DIVIDEND DECLARED ON PREFERRED	(1,442,542.51)	0.00	(1,442,542.51)	0.00
ADJUSTMENT RETAINED EARNINGS	(568,747.08)	0.00	(568,747.08)	0.00
TOTAL DEDUCTIONS	(131,605,409.63)	0.00	(131,605,409.63)	0.00
BALANCE AT END OF PERIOD	150,796,650.14	(1,143,890.59)	150,796,650.14	307,103.00

APPALACHIAN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CECCO	SACCO	WVPCO
BALANCE AT BEGINNING OF YEAR	(215,115.32)	379,092.00	65,450.05
Preferred Stock Dividend Req of Subsidiaries			
Net Income (Loss)	100,307.00	500,201.00	6,852.86
NET INCOME (LOSS)	100,307.00	500,201.00	6,852.86
TOTAL	(114,808.32)	879,293.00	72,302.91
DEDUCTIONS:			
Div Declrd - Common Stk - Asso	0.00	0.00	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00
Dividends Decl-Preferred Stock	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00
BALANCE AT END OF PERIOD	(114,808.32)	879,293.00	72,302.91

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COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	CSPCO CONSOLIDATED	CSPCO ELIMINATIONS	CSPCO
BALANCE AT BEGINNING OF YEAR	99,068,911.36	(1,967,703.05)	99,068,911.36
Preferred Stock Dividend Req of Subsidiaries			
Net Income (Loss)	161,876,319.67	(164,783.61)	161,876,318.67
NET INCOME (LOSS)	161,876,319.67	(164,783.61)	161,876,318.67
TOTAL	260,945,231.03	(2,132,486.66)	260,945,230.03
DEDUCTIONS:			
Div Declrd - Common Stk - Asso	(82,952,077.76)	199,999.91	(82,952,077.76)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(82,952,077.76)	199,999.91	(82,952,077.76)
Dividends Decl-Preferred Stock	(875,000.00)	0.00	(875,000.00)
DIVIDEND DECLARED ON PREFERRED	(875,000.00)	0.00	(875,000.00)
ADJUSTMENT RETAINED EARNINGS	(1,015,380.36)	0.00	(1,015,380.36)
TOTAL DEDUCTIONS	(84,842,458.12)	199,999.91	(84,842,458.12)
BALANCE AT END OF PERIOD	176,102,772.91	(1,932,486.75)	176,102,771.91

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	COLM	CCPC	SIMCO
BALANCE AT BEGINNING OF YEAR	843,734.71	1,029,983.00	93,985.34
Preferred Stock Dividend Req of Subsidiaries			
Net Income (Loss)	3,446.84	70,000.00	91,337.77
NET INCOME (LOSS)	3,446.84	70,000.00	91,337.77
TOTAL	847,181.55	1,099,983.00	185,323.11
DEDUCTIONS:			
Div Declrd - Common Stk - Asso	(100,000.01)	0.00	(99,999.90)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(100,000.01)	0.00	(99,999.90)
Dividends Decl-Preferred Stock	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00
TOTAL DEDUCTIONS	(100,000.01)	0.00	(99,999.90)
BALANCE AT END OF PERIOD	747,181.54	1,099,983.00	85,323.21

<PAGE>
INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	I&M CONSOLIDATED	I&M ELIMINATIONS	I&M	BHCCO	PRCCO
BALANCE AT BEGINNING OF YEAR	3,443,259.42	(15,140,513.44)	3,443,259.42	15,140,513.44	0.0
Preferred Stock Dividend Req of Subsidiaries					
Net Income (Loss)	75,787,950.62	(996,352.00)	75,787,950.62	996,352.00	0.0
NET INCOME (LOSS)	75,787,950.62	(996,352.00)	75,787,950.62	996,352.00	0.0
TOTAL	79,231,210.04	(16,136,865.44)	79,231,210.04	16,136,865.44	0.0
DEDUCTIONS:					
Div Declrd - Common Stk - Asso	0.00	6,300,042.61	0.00	(6,300,042.61)	0.0
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00	0.0
DIVIDEND DECLARED ON COMMON	0.00	6,300,042.61	0.00	(6,300,042.61)	0.0
Dividends Decl-Preferred Stock	(4,486,826.58)	0.00	(4,486,826.58)	0.00	0.0
DIVIDEND DECLARED ON PREFERRED	(4,486,826.58)	0.00	(4,486,826.58)	0.00	0.0
ADJUSTMENT RETAINED EARNINGS	(139,113.86)	0.00	(139,113.86)	0.00	0.0
TOTAL DEDUCTIONS	(4,625,940.44)	6,300,042.61	(4,625,940.44)	(6,300,042.61)	0.0
BALANCE AT END OF PERIOD	74,605,269.60	(9,836,822.83)	74,605,269.60	9,836,822.83	0.0

</TABLE>

<PAGE>
OHIO POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	OPCO CONSOLIDATED	OPCO ELIMINATIONS	OPCO
BALANCE AT BEGINNING OF YEAR	398,086,502.58	(26,499,341.00)	398,086,502.58
Preferred Stock Dividend Req of Subsidiaries			
Net Income (Loss)	147,445,368.28	(7,133,891.00)	147,445,368.28
NET INCOME (LOSS)	147,445,368.28	(7,133,891.00)	147,445,368.28
TOTAL	545,531,870.86	(33,633,232.00)	545,531,870.86
DEDUCTIONS:			
Div Declrd - Common Stk - Asso	(142,975,781.28)	56,988.00	(142,975,781.28)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(142,975,781.28)	56,988.00	(142,975,781.28)
Dividends Decl-Preferred Stock	(1,258,738.20)	0.00	(1,258,738.20)
DIVIDEND DECLARED ON PREFERRED	(1,258,738.20)	0.00	(1,258,738.20)
ADJUSTMENT RETAINED EARNINGS	0.00	33,576,244.00	0.00
TOTAL DEDUCTIONS	(144,234,519.48)	33,633,232.00	(144,234,519.48)
BALANCE AT END OF PERIOD	401,297,351.38	0.00	401,297,351.38

OHIO POWER COMPANY
AND SUBSIDIARY COMPANIES
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	COCCO	SOCCO	WCCO
BALANCE AT BEGINNING OF YEAR	2,833.00	26,445,673.00	50,835.00
Preferred Stock Dividend Req of Subsidiaries			
Net Income (Loss)	(7,244,116.00)	6,919,078.00	7,458,929.00
NET INCOME (LOSS)	(7,244,116.00)	6,919,078.00	7,458,929.00
TOTAL	(7,241,283.00)	33,364,751.00	7,509,764.00
DEDUCTIONS:			
Div Declrd - Common Stk - Asso	(2,951.00)	(252.00)	(53,785.00)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(2,951.00)	(252.00)	(53,785.00)
Dividends Decl-Preferred Stock	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	7,244,234.00	(33,364,499.00)	(7,455,979.00)
TOTAL DEDUCTIONS	7,241,283.00	(33,364,751.00)	(7,509,764.00)
BALANCE AT END OF PERIOD	0.00	0.00	0.00

</TABLE>

<PAGE>
SOUTHWESTERN ELECTRIC POWER COMPANY
CONSOLIDATING STATEMENT OF RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2001

DESCRIPTION	SWEPCO CONSOLIDATED	SWEPCO ELIMINATIONS	SWEPCO	DOLETHILLS
BALANCE AT BEGINNING OF YEAR	293,989,298.21	0.00	293,989,298.21	0.00
NET INCOME (LOSS)	89,366,585.98	(1,632,379.00)	89,366,585.98	1,632,379.00
TOTAL	383,355,884.19	(1,632,379.00)	383,355,884.19	1,632,379.00
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	(74,212,088.20)	932,788.00	(74,212,088.20)	(932,788.00)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(74,212,088.20)	932,788.00	(74,212,088.20)	(932,788.00)
Dividends Decl-Preferred Stock	(229,054.64)	0.00	(229,054.64)	0.00
DIVIDEND DECLARED ON PREFERRED	(229,054.64)	0.00	(229,054.64)	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00
TOTAL DEDUCTIONS	(74,441,142.84)	932,788.00	(74,441,142.84)	(932,788.00)
BALANCE AT END OF PERIOD	308,914,741.35	(699,591.00)	308,914,741.35	699,591.00

</TABLE>

Notes to Consolidating Financial Statements.

Notes to financial statements are incorporated herein by reference to the 2001 Annual Report on Form 10-K filed by the respective companies reporting to the Securities and Exchange Commission pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2001
(in thousands)
(UNAUDITED)

OPERATING REVENUES	$318,132
OPERATING EXPENSES:	
Fuel	81,311
Purchased Power	170,344
Other Operation	24,498
Maintenance	20,527
Depreciation	11,034
Taxes Other Than Federal Income Taxes	2,857
Federal Income Taxes	657
TOTAL OPERATING EXPENSES	311,228
OPERATING INCOME	6,904
NONOPERATING INCOME	308
INCOME BEFORE INTEREST CHARGES	7,212
INTEREST CHARGES	5,025
NET INCOME	$ 2,187

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF RETAINED EARNINGS
YEAR ENDED DECEMBER 31, 2001
(in thousands)
(UNAUDITED)

RETAINED EARNINGS JANUARY 1	$1,933
NET INCOME	2,187
CASH DIVIDENDS DECLARED	2,200
RETAINED EARNINGS DECEMBER 31	$1,920

OHIO VALLEY ELECTRIC CORPORATION
BALANCE SHEET
DECEMBER 31, 2001
(in thousands)
(UNAUDITED)

ASSETS

ELECTRIC UTILITY PLANT:	
Electric Plant (at cost)	$312,978
Construction Work in Progress	34,084
Total Electric Utility Plant	347,062
Accumulated Depreciation and Amortization	302,400
NET ELECTRIC UTILITY PLANT	44,662
INVESTMENTS AND OTHER	70,073
CURRENT ASSETS:	
Cash and Cash Equivalents	13,794
Investments Held by Trustee	194,735
Accounts Receivable	25,639
Coal in Storage - at average cost	8,269
Materials and Supplies - at average cost	9,473
Prepayments and Other	3,205
TOTAL CURRENT ASSETS	255,115
FUTURE FEDERAL INCOME TAX BENEFITS	27,127
REGULATORY ASSETS	45,404
TOTAL	$442,381

OHIO VALLEY ELECTRIC CORPORATION
BALANCE SHEET
DECEMBER 31, 2001
(in thousands)
(UNAUDITED)

CAPITALIZATION AND LIABILITIES

SHAREHOLDERS' EQUITY:	
Common Stock - Par Value $100:	
Authorized - 300,000 Shares	
Outstanding - 100,000 Shares	$ 10,000
Retained Earnings	1,920
Total Shareowners' Equity	11,920
Long-term Debt - Notes Payable	332,734
TOTAL CAPITALIZATION	344,654
CURRENT LIABILITIES:	
Long-term Debt Due Within One Year	8,369
Accounts Payable	20,526
Taxes Accrued	6,268
Interest Accrued and Other	3,249
TOTAL CURRENT LIABILITIES	38,412
INVESTMENT TAX CREDITS	10,610
POSTRETIREMENT BENEFIT OBLIGATION	25,030
AMOUNTS DUE TO CUSTOMERS FOR FEDERAL INCOME TAXES	17,263
OTHER REGULATORY LIABILITIES AND DEFERRED CREDITS	6,412
TOTAL	$442,381

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2001
(in thousands)
(UNAUDITED)

OPERATING ACTIVITIES:	
Net Income	$ 2,187
Adjustments for Noncash Items:	
Depreciation	11,034
Future Federal Income Tax Benefits	(5,273)
Changes in Certain Current Assets and Liabilities:	
Accounts Receivable	14,036
Coal, Materials and Supplies	(4,063)
Accounts Payable	11,238
Accrued Taxes	(4,858)
Other (net)	1,498
Net Cash Flows From Operating Activities	25,799
INVESTING ACTIVITIES:	
Construction Expenditures	(36,273)
Purchase of Investments	(194,735)
Advances from Sponsoring Companies	198
Advances to Subsidiary	(22,903)
Net Cash Flows Used For Investing Activities	(253,713)
FINANCING ACTIVITIES:	
Issuance of Long-term Debt	294,107
Retirement of Long-term Debt	(13,946)
Change in Short-term Debt	(40,000)
Dividends Paid	(2,200)
Net Cash Flows From Financing Activities	237,961
Net Increase in Cash and Cash Equivalents	10,047
Cash and Cash Equivalents January 1	3,747
Cash and Cash Equivalents December 31	$ 13,794
Supplemental Disclosure:	
Interest Paid (net of capitalized amounts)	$6,522
Income Taxes Paid	$5,672

EXHIBIT A

Incorporation by Reference
Form 10K
Annual Report

	Year	File Number
AEP	2001	1-3525
AEGCo	2001	0-18135
APCo	2001	1-3457
CPL	2001	0-346
CSP	2001	1-2680
I&M	2001	1-3570
KPCo	2001	1-6858
OPCo	2001	1-6543
PSO	2001	0-343
SWEPCo	2001	1-3146
WTU	2001	0-340

KPSC CASE NO. 99-149
ITEM NO. 1
ATTACHMENT 3B

2001 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

Appalachian Power Company

Central Power and Light Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

West Texas Utilities Company

Audited Financial Statements and
Management's Discussion and Analysis

AEP AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

Contents

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
2004 True-up Proceeding	A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and the recovery of such costs.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned subsidiaries consolidated.
AEP Credit,Inc.	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated and unaffiliated domestic electric utility companies.
AEP East electric operating companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP Power Pool	AEP System Power Pool. Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
AEP West electric operating companies	CPL, PSO, SWEPCo and WTU.
AFUDC	Allowance for funds used during construction, a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.
Alliance RTO	Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities.
Amos Plant	John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Arkansas Commission	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
CLECO	Central Louisiana Electric Company, Inc., an unaffiliated corporation.
COLI	Corporate owned life insurance program.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CPL	Central Power and Light Company, an AEP electric utility subsidiary.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP.
CSW Energy.	CSW Energy, Inc., an AEP subsidiary which invests in energy projects and builds power plants.
CSW International	CSW International, Inc., an AEP subsidiary which invests in energy projects and entities outside the United States.
D.C. Circuit Court	The United States Court of Appeals for the District of Columbia Circuit.
DHMV	Dolet Hills Mining Venture.
DOE	United States Department of Energy.
ECOM	Excess Cost Over Market.
ENEC	Expanded Net Energy Costs.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	The Electric Reliability Council of Texas.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FMB	First Mortgage Bond.

FUCOs	Foreign Utility Companies.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPC	Installment Purchase Contract.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
ISO	Independent system operator.
Joint Stipulation	Joint Stipulation and Agreement for Settlement of APCo's WV rate proceeding.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas.
Michigan Legislation	The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
Midwest ISO	An independent operator of transmission assets in the Midwest.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
Money Pool	AEP System's Money Pool.
MPSC	Michigan Public Service Commission.
MTN	Medium Term Notes.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited.
Nox	Nitrogen oxide.
NOx Rule	A final rules issued by Federal EPA which requires NOx reductions in 22 eastern states including seven of the states in which AEP companies operates.
NP	Notes Payable.
NRC	Nuclear Regulatory Commission.
Ohio Act	The Ohio Electric Restructuring Act of 1999.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated Biphenyls.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PRP	Potentially Responsible Party.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	The Public Utilities Commission of Ohio.
PUCT	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act of 1935, as amended.
PURPA	The Public Utility Regulatory Policies Act of 1978.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation.

SFAS 101 .... Statement of Financial Accounting Standards No. 101, Accounting for the Discontinuance of Application of Statement 71.
SFAS 121 .... Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.
SFAS 133 .... Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SNF.. Spent Nuclear Fuel.
SPP.. Southwest Power Pool.
STP.. South Texas Project Nuclear Generating Plant, owned 25.2% by Central Power and Light Company, an AEP electric utility subsidiary .
STPNOC.................................. STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including CPL.
Superfund .... The Comprehensive Environmental, Response, Compensation and Liability Act.
SWEPCo .... Southwestern Electric Power Company, an AEP electric utility subsidiary.
Texas Appeals Court .... The Third District of Texas Court of Appeals.
Texas Legislation..................... Legislation enacted in 1999 to restructure the electric utility industry in Texas.
Travis District Court................. State District Court of Travis County, Texas.
TVA .... Tennessee Valley Authority.
U.K.. The United Kingdom.
UN.. Unsecured Note.
VaR... Value at Risk, a method to quantify risk exposure.
Virginia SCC .... Virginia State Corporation Commission.
WV.. West Virginia.
WVPSC .... Public Service Commission of West Virginia.
WPCo .... Wheeling Power Company, an AEP electric distribution subsidiary.
WTU .... West Texas Utilities Company, an AEP electric utility subsidiary.
Yorkshire................................. Yorkshire Electricity Group plc, a U.K. regional electricity company owned jointly by AEP and New Century Energies until April 2001.
Zimmer Plant .... William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

FORWARD LOOKING INFORMATION

This discussion includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors both foreign and domestic that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources of and prices for coal and gas; availability of generating capacity; risks related to energy trading and construction under contract; the speed and degree to which competition is introduced to our power generation business; the structure and timing of a competitive market for electricity and its impact on prices, the ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states; the timing of the implementation of AEP's restructuring plan; new legislation and government regulations; the ability to successfully control costs; the success of new business ventures; international developments affecting our foreign investments; the economic climate and growth in our service and trading territories both domestic and foreign; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; inflationary trends; litigation concerning AEP's merger with CSW; changes in electricity and gas market prices and interest rates; fluctuations in foreign currency exchange rates, and other risks and unforeseen events.

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AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Selected Consolidated Financial Data

Year Ended December 31,	2001	2000	1999	1998	1997
INCOME STATEMENTS DATA (in millions):					
Total Revenues	$61,257	$36,706	$24,745	$18,420	$11,427
Operating Income	2,395	2,004	2,304	2,258	2,180
Income Before Extraordinary Items and Cumulative Effect	1,003	302	986	975	949
Extraordinary Losses	(50)	(35)	(14)	-	(285)
Cumulative Effect of Accounting Change	18	-	-	-	-
Net Income	971	267	972	975	664

Year Ended December 31,	2001	2000	1999	1998	1997
BALANCE SHEETS DATA (in millions):					
Property, Plant and Equipment	$40,709	$38,088	$36,938	$35,655	$33,496
Accumulated Depreciation and Amortization	16,166	15,695	15,073	14,136	13,229
Net Property, Plant and Equipment	$24,543	$22,393	$21,865	$21,519	$20,267
Total Assets	$47,281	$53,350	$35,693	$33,418	$30,092
Common Shareholders' Equity	8,229	8,054	8,673	8,452	8,220
Cumulative Preferred Stocks of Subsidiaries*	156	161	182	350	377
Trust Preferred Securities	321	334	335	335	335
Long-term Debt*	12,053	10,754	11,524	11,113	9,354
Obligations Under Capital Leases*	451	614	610	539	549

Year Ended December 31,	2001	2000	1999	1998	1997
COMMON STOCK DATA:					
Earnings per Common Share:					
Before Extraordinary Item and Cumulative Effect	$ 3.11	$0.94	$3.07	$3.06	$2.99
Extraordinary Losses	(0.16)	(.11)	(.04)	-	(.90)
Cumulative Effect of Accounting Change	0.06	-	-	-	-
Earnings Per Share	$ 3.01	$0.83	$3.03	$3.06	$2.09
Average Number of Shares Outstanding (in millions)	322	322	321	318	316
Market Price Range: High	$51.20	$48-15/16	$48-3/16	$53-5/16	$ 52
Low	39.25	25-15/16	30-9/16	42-1/16	39-1/8
Year-end Market Price	43.53	46-1/2	32-1/8	47-1/16	51-5/8
Cash Dividends on Common**	$2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio**	79.7%	289.2%	79.2%	78.4%	114.8%
Book Value per Share	$25.54	$25.01	$26.96	$26.46	$25.91

The consolidated financial statements give retroactive effect to AEP's merger with CSW, which was accounted for as a pooling of interests.

*Including portion due within one year
**Based on AEP historical dividend rate.

Management's Discussion and Analysis of Results of Operations

American Electric Power Company, Inc. (AEP) is one of the largest investor owned electric public utility holding companies in the US. We provide generation, transmission and distribution service to over 4.9 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies. We market and trade electricity and natural gas in the US and Europe.

We have a significant presence throughout the domestic energy value chain. Our US electric assets include:
- 38,000 megawatts of generating capacity (the largest US generation portfolio with a significant cost advantage in the Midwest and Southwest markets);
- 38,000 miles of transmission lines and
- 186,000 miles of distribution lines

Our natural gas assets include:
- 128 Bcf of gas storage facilities
- 6,400 miles of gas pipelines in Louisiana and Texas which provide a basis for market knowledge.

With our coal and transportation assets we:
- control over 7,000 railcars
- control over 1,800 barges and 37 tug boats
- operate two coal handling terminals with 20 million tons of capacity.
- produce over 7 million tons of coal annually in the US.

AEP is one of the largest traders of electricity and natural gas in the US:
- over 576 million MWH of electricity trades in 2001
- over 3,800 billion cubic feet (Bcf) of gas trades in 2001

In addition we:
- consume 80 million tons of coal annually
- consume 310 Bcf of natural gas annually

AEP's focus is in the US but we also have smaller footprints in other parts of the world:
- a growing energy trading operation in Europe based in the UK.
- 4,000 megawatts of generating capacity in the United Kingdom which represents 16% of the UK's total generation capacity.

Other foreign investments include distribution operations in the U.K., Australia, and Brazil. We have additional generating facilities in China and Mexico. We also offer engineering and construction services worldwide.

Business Strategy

Our strategy is a balanced business model of regulated and unregulated businesses backed by assets, supported by enterprise-wide risk management and a strong balance sheet. We have been focused on the wholesale side of the business since it provides the greater growth opportunities. But, this is complemented by a robust regulated business that has a predictable earnings stream and cash flows. Strong risk management and a disciplined analysis of markets protected us from the California energy crisis and Enron's bankruptcy filing.

Our balanced business model is one where AEP integrates its assets, marketing, trading and market analysis and resources to create a superior knowledge about the commodity markets which keeps us a step ahead of our competition. Our power, gas, coal, and barging assets and operations provide us with market knowledge and customer connectivity giving us the ability to make informed marketing and trading decision and to customize our products and services.

AEP provides investors with a balanced portfolio since it has:
- a growing unregulated wholesale energy marketing and trading business
- predictable cash flow and earnings

streams from the regulated electricity business, and

- a high dividend yield relative to today's low-interest rate environment.

We are currently in the process of restructuring our assets and operations to separate the regulated operations from the non-regulated operations.

We filed with the SEC for approval to form two separate legal holding company subsidiaries of AEP Co. Inc., the parent company. Approval is needed from the SEC under the PUHCA and the FERC to make these organizational changes. Certain state regulatory commissions have intervened in the FERC proceedings. We have reached a settlement with those state commissions and are awaiting the FERC's approval before the SEC will make a final ruling on our filing.

We are implementing a corporate separation restructuring plan to support our objective of unlocking shareholder value for our domestic businesses. Our plan provides for:

- transparency and clarity to investors,
- a simpler structure to conduct business, and to anticipate and monitor performance,
- compliance with states' restructuring laws promoting customer choice, and
- more efficient financing.

The new corporate structure will consist of a regulated holding company and an unregulated holding company. The regulated holding company's investments will be in integrated utilities and Ohio and Texas wires. The unregulated holding company's investments will be in Ohio and Texas generation, independent power producers, gas pipe line and storage, UK generation, barging, coal mining and marketing and trading.

The risks in our business are:

- Margin erosion on electric trading as markets mature,
- Diminished opportunities for significant gains as volatility declines,
- Retail price reductions mandated with the implementation of customer choice in Texas and Ohio,
- Movement towards re-regulation in California through market caps and other challenges to the continuation of deregulation of the retail electricity supply business in the U.S.,
- The continued negative impact of a slowly recovering economy.

Our business plan considers these risks and we believe that we can deliver earnings growth of 6-8% annually across the energy value chain through the disciplined integration of strategic assets and intellectual capital to generate these returns for our shareholders.

Our strategies to achieve our business plan are:

- Unregulated
    - Disciplined approach to asset acquisition and disposition
    - Value-driven asset optimization through the linkage of superior commercial, analytical and technical skills
    - Broad participation across all energy markets with a disciplined and opportunistic allocation of risk capital
    - Continued investment in both technology and process improvement to enhance our competitive advantage
    - Continued expansion of intellectual capital through ongoing recruiting, performance-linked compensation and the development of a structure that promotes sound decision-making and innovation at all levels.

- Regulated
    - Maintain moderate but steady earnings growth
    - Maximize value of transmission assets and protect revenue stream through RTO/Alliance membership
    - Continue process improvement to maintain distribution service quality while enhancing financial performance
    - Optimize generation assets through enhanced availability of off-system sales

- Manage regulatory process to maximize retention of earnings improvement

Our significant accomplishments in 2001 were :

- Adding the following assets to integrate with and support our trading and marketing competitive advantage:
  - 4,200 miles of gas pipeline, 118 Bcf gas storage and related gas marketing contracts
  - 1,200 hopper barges and 30 tugboats
  - 4,000 megawatts of coal-fired generation in England
  - 160 megawatts of wind generation in Texas
  - coal mining properties, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia
- Entering into new markets through the acquisition of existing contracts and hiring key staff including 57 employees from Enron's London based international coal trading group in December 2001 and Enron's Nordic energy trading group in January 2002. We now trade power and gas in the UK, France, Germany, and the Netherlands and coal throughout the world
- Adding other energy-related commodities to our power and gas portfolio i.e. coal, SO2 allowances, natural gas liquids (NGLs) and oil
- Disposing of the following assets that did not fit our strategy:
  - 120 MWs of generation in Mexico,
  - Above market coal mines in Ohio and West Virginia,
  - A 50 % investment in Yorkshire, a U.K. electric supply and distribution company,
  - An investment in a Chilean electric company
  - Datapult, an energy information data and analysis tool.

In addition we sold 500 MWs of generating capacity in Texas under a FERC order that approved our merger with CSW.

Our divesture of non-strategic assets is somewhat limited by the pooling of interest accounting requirements applied to the merger of CSW and AEP in June 2000. We are presently evaluating certain telecommunications and foreign investments for possible disposal and have not yet decided whether to dispose of such investments. Disposal of investments determined to be non-strategic will be considered in accordance with the pooling of interests restrictions which end in June 2002. We are committed to continually evaluate the need to reallocate resources to areas with greater potential, to match investments with our strategy and to pare investments that do not produce sufficient return and shareholder value. Any investment dispositions could affect future results of operations.

Outlook for 2002

Growth in 2002 will be driven in part by our continued strategic development of wholesale products and geographies, as demonstrated in recent months by our move into global coal markets and Nordic energy. A full year of operation of assets acquired in 2001 – Houston Pipe Line, Quaker Coal, the MEMCO barge line and two power plants in the United Kingdom – will also contribute to growth in 2002 earnings.

Although we expect that the future outlook for results of operations is excellent there are contingencies and challenges. We discuss these matters in detail in the Notes to Financial Statements and in this Management's Discussion and Analysis. We intend to work diligently to resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our shareholders.

As discussed above we expect to continue evaluating certain investments for possible disposal due to either their non-strategic nature or limited future earnings potential for AEP. Any dispositions could result in gains or losses being recorded in our income statement.

Results of Operations

In 2001 AEP's principal operating business segments and their major activities were:

- Wholesale:
  - Generation of electricity for sale to retail and wholesale customers
  - Gas pipeline and storage services
  - Marketing and trading of electricity, gas and coal
  - Coal mining, bulk commodity barging operations and other energy supply related business.
- Energy Delivery
  - Domestic electricity transmission,
  - Domestic electricity distribution
- Other Investments
  - Foreign electric distribution and supply investments,
  - Telecommunication services.

Net Income

Net income increased to $971 million or $3.01 per share from $267 million or $0.83 per share. The increase of $704 million or $2.18 per share was due to the growth of AEP's wholesale marketing and trading business, increased revenues and the controlling of our operating and maintenance costs in the energy delivery business, and declining capital costs. Also contributing to the earnings improvement in 2001 was the effect of 2000 charges for a disallowance of COLI-related tax deductions, expenses of the merger with CSW, write-offs related to non-regulated investments and restart costs of the Cook Nuclear Plant. The favorable effect on comparative net income of these 2000 charges was offset in part by current year losses from Enron's bankruptcy and extraordinary losses for the effects of deregulation and a loss on reacquired debt.

The decline in net income to $267 million or $0.83 per share in 2000 from $972 million or $3.03 per share in 1999 was primarily due to the 2000 charges described above and an extraordinary losses from the discontinuance of regulatory accounting for generation in certain states.

A strong performance in the first nine months of 2001 was partially offset by unfavorable operating conditions in the fourth quarter. Extremely mild November and December weather combined with weak economic conditions in the fourth quarter, reduced retail energy sales and wholesale margins. Heating degree days in the fourth quarter were down 33% from the same period in 2000. Although the fourth quarter was disappointing, 2001 net income before extraordinary items and cumulative effect of accounting change reached the $1 billion mark.

Our wholesale business continues to perform well despite a slowing economy that reduced both wholesale energy margins and energy use by industrial customers. Our wholesale business, which includes generation, retail and wholesale sales of power and natural gas and trading of power and natural gas and natural gas pipeline and storage services, contributed to the earnings increase by successfully returning the Cook Plant to service in 2000 and by growing AEP's wholesale business.

Our energy delivery business, which consists of domestic electricity transmission and distribution services, contributed to the increase in earnings by controlling operating and maintenance expenses and by increasing revenues.

Capital costs decreased due primarily to interest paid to the IRS in 2000 on a COLI deduction disallowance and declining short-term market interest rate conditions.

Critical Accounting Policies

Revenue Recognition – *Traditional Electricity Supply and Delivery Activities* - As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s consolidated financial statements recognize revenues on an accrual basis for traditional electricity supply sales and for electricity transmission and distribution delivery services. These revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when incurred. As a result of our cost based rate regulated operations, our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching in the same accounting period regulated expenses with their recovery through regulated revenues.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

We discontinued application of SFAS 71 for the generation portion of our business in Ohio for OPCo and CSPCo in September 2000, in Virginia and West Virginia for APCo in June 2000, in Texas for CPL, WTU, and SWEPCo in September 1999 and in Arkansas for SWEPCo in September 1999 in recognition of the passage of legislation to transition to customer choice and market pricing for the supply of electricity. We recorded extraordinary losses when we discontinued the application of SFAS 71. See Note 2, "Extraordinary Items and Cumulative Effect" for additional information.

Wholesale Energy Marketing and Trading Activities - We engage in non-regulated wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities involve the purchase and sale of energy under forward contracts at fixed and variable prices and buying and selling financial energy contracts which includes exchange futures and options and over-the-counter options and swaps. Although trading contracts are generally short-term, there are also long-term trading contracts. We recognize revenues from trading activities generally based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts as revenues prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt and net settle in cash, the unrealized gain or loss is reversed out of revenues and the actual realized cash gain or loss is recognized in revenues for a sale or in purchased energy expense for a purchase.

Therefore, over the term of the trading contracts an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading and derivative contract assets or liabilities as appropriate.

The majority of our trading activities represent physical forward electricity and gas contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity or gas in July. At the end of each month until the contract settles in July, we would record any difference between the contract price and the market price as an unrealized gain or loss in revenues. In July when the contract settles, we would realize the gain or loss in cash and reverse to revenues the previously recorded unrealized gain or loss. Prior to settlement, the change in the fair value of physical forward sale and purchase contracts is included in revenues on a net basis. Upon settlement of a forward trading contract, the amount realized is included in revenues for a sales contract and realized costs are included in purchased energy expense for a purchase contract with the prior change in unrealized fair value reversed in revenues.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity or gas in July. If we do nothing else with these contracts until settlement in July and if the commodity type, volumes, delivery point, schedule and other key terms match then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on operating results but has an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to commodity type, volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on revenues from recording additional changes in fair values using mark-to-market accounting.

Trading of electricity and gas options, futures and swaps, represents financial transactions with unrealized gains and losses from changes in fair values reported net in revenues until the contracts settle. When these contracts settle, we record the net proceeds in revenues and reverse to revenues the prior unrealized gain or loss.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on Company-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the Company-developed price models.

We also mark to market derivatives that are not trading contracts in accordance with generally accepted accounting principles. Derivatives are contracts whose value is derived from the market value of an underlying commodity.

Our revenues of $61 billion for 2001 included $257 million of unrealized net gains from marking to market open trading and derivative contracts. AEP's net revenues, (revenues less fuel and energy purchases) excluding mark-to-market revenues totaled $8.3 billion and were realized during 2001. Unrealized net mark-to-market revenues are only 3% of total net revenues. A significant portion of the net unrealized revenues from marking to market trading contracts and derivatives included in our balance sheet at December 31, 2001 as energy trading and derivative contract assets and liabilities, will be realized in 2002.

We defer as regulatory assets or liabilities the effect on net income of marking to market open electricity trading contracts in our regulated jurisdictions since these transactions are included in cost of service on a settlement basis for ratemaking purposes. Changes in mark-to-market valuations impact net income in our non-regulated business.

Volatility in energy commodities markets affects the fair values of all of our open trading and derivative contracts exposing AEP to market risk causing our results of operations to be more volatile. See "Market Risks" section below for a discussion of the policies and procedures AEP uses to manage its exposure to market and other risks from trading activities.

Revenues Increase

Our revenues have increased significantly from the marketing and trading of electricity and natural gas. The level of electricity trading transactions tends to fluctuate due to the highly competitive nature of the short-term (spot) energy market and other factors, such as affiliated and unaffiliated generating plant availability, weather conditions and the economy. The FERC's introduction of a greater degree of competition into the wholesale energy market, has had a major effect on the volume of wholesale power marketing and trading especially in the short-term market.

AEP's total revenues increased 66.9% in 2001 and 48.3% in 2000. The following table shows the components of revenues in millions.

	For The Year Ended December 31		
	2001	2000	1999
	(in millions)		
WHOLESALE BUSINESS:			
Residential	$ 3,553	$ 3,511	$ 3,290
Commercial	2,328	2,249	2,083
Industrial	2,388	2,444	2,515
Other Retail Customers	419	414	394
Electricity Marketing and Trading	35,339	18,858	11,417
Gas Marketing and Trading	14,369	6,127	2,290
Unrealized MTM Income:			
Electric	210	38	2
Gas	47	132	21
Other	632	838	599
Less Transmission and Distribution Revenues Assigned to Energy Delivery*	(3,356)	(3,174)	(3,068)
TOTAL WHOLESALE BUSINESS	55,929	31,437	19,543
ENERGY DELIVERY BUSINESS:			
Transmission	1,029	1,009	960
Distribution	2,327	2,165	2,108
TOTAL ENERGY DELIVERY	3,356	3,174	3,068
OTHER INVESTMENTS:			
SEEBOARD	1,451	1,596	1,705
CITIPOWER	350	338	318
Other	171	161	111
TOTAL OTHER INVESTMENTS	1,972	2,095	2,134
TOTAL REVENUES	$61,257	$36,706	$24,745

*Certain revenues in Wholesale business include energy delivery revenues due primarily to bundled tariffs that are assignable to the Energy Delivery business.

The $25 billion increase in 2001 revenues was due to substantial increases in electric and gas trading volumes. The increase in sales of purchased power and purchased gas during the past two years reflect AEP's intention to be a leading national wholesale energy merchant. Wholesale natural gas trading volume for 2001 was 3,874 Bcf, a 178% increase from 2000 volume of 1,391 Bcf. Electric trading volume increased 48% to 576 million MWH. We have invested in resources required to optimize our assets and emerge as a leader in the industry. The maturing of the Intercontinental Exchange, the development of proprietary tools, and the increased staffing of energy traders have faciliated increased power and gas sales. Our June 2001 purchase of Houston Pipe Line enhanced our gas trading and marketing operation. Although we will trade and market only when we believe profitable opportunites exist, we expect the increased level of activity to continue.

While wholesale marketing and trading volumes rose, kilowatthour sales to industrial customers decreased by 5% in 2001. This decrease was due to the economic recession. In the fourth quarter, sales to residential, commercial and wholesale customers declined 9%. The recession reduced demand and wholesale prices especially in the fourth quarter.

While margins available from selling power that the company generates generally are higher than from selling purchased power, such sales are limited by the amount of generating assets owned. Furthermore, the profit available from simply selling excess generation is reduced by the inherent market transparency of such sales. The coordinated sales of excess generation in conjunction with trading and marketing activity optimizes assets, mitigates risk, and increases overall profit.

The $12 billion increase in 2000 revenues was primarily due to a 27% increase in wholesale electricity trading volume and increased retail fuel revenues as a result of higher gas prices used to generate electricity. The reduction in industrial revenues in 2000 is attributable to the expiration of a long-term contract on December 31, 1999. The significant increase in 2000 electricity trading volume, which accounted for a 66% increase in electricity trading revenues, resulted from:

- efforts to grow AEP's energy marketing and trading operations,
- favorable market conditions, and
- the availability of additional generation

Generation availability improved due to the return to service of one of the Cook Plant nuclear units in June 2000 and to improved outage management. The second Cook Plant unit which returned to service in December 2000 did not have a significant impact on 2000 revenues. Gas revenues increased in 2000 due to increased natural gas and gas liquid product prices.

Operating Expenses Increase

Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	2001		2000	
	Amount	%	Amount	%
Fuel and Purchased Energy	$24,035	83.7	$11,474	66.5
Maintenance and Other Operation	196	5.1	565	17.2
Non-recoverable Merger Costs	(182)	(89.7)	203	N.M.
Depreciation and Amortization	133	10.6	38	3.1
Taxes Other Than Income Taxes	(22)	(3.2)	(19)	(2.7)
Total	$24,160	69.6	$12,261	54.6

Our fuel and purchased energy expense in 2001 increased 84% due to increased trading volume and an increase in nuclear generation cost. The return to service of the Cook Plant's two nuclear generating units in June 2000 and December 2000 accounted for the increase in nuclear generation costs.

Fuel and purchased energy expense increased 67% in 2000 due to increased trading volume and a significant increase in the cost of natural gas used for generation. Natural gas usage for generation declined 5% while the cost of natural gas consumed rose 60%. Net income was not impacted by this significant cost increase due to the operation of fuel recovery rate mechanisms. These fuel recovery rate mechanisms generally provide for the deferral of fuel costs above the amounts included in existing rates or the accrual of revenues for fuel costs not yet recovered. Upon regulatory commission review and approval of the unrecovered fuel costs, the accrued or deferred amounts are billed to customers. With the introduction of customer choice of electricity supplier and a transition to market-based generation rates, the protection offered by fuel recovery mechanisms against changes in fuel costs was eliminated in Ohio effective January 1, 2001 and in the ERCOT area of Texas effective January 1, 2002. As a result, AEP's exposure to the risk of fuel price increases that could adversely affect future results of operations and cash flows is increasing. See Note 1 for applicability of fuel recovery mechanisms by jurisdiction.

Maintenance and other operation expense rose in 2001 mainly as a result of additional traders' incentive compensation and accruals for severance costs related to corporate restructuring.

The increase in maintenance and other operation expense in 2000 was mainly due to increased expenditures to prepare the Cook Plant nuclear units for restart following an extended NRC monitored outage and increased usage and prices of emissions allowances. The increase in Cook Plant restart costs resulted from the effect of deferring restart costs in 1999 and an increase in the restart expenditure level in 2000. Cook Plant began its extended outage in September 1997 when both nuclear generating units were shut down because of questions regarding the operability of certain safety systems. In 1999 a portion of incremental restart expenses were deferred in accordance with IURC and MPSC settlement agreements which resolved all jurisdictional rate-related issues related to the Cook Plant's extended outage. With NRC approval Unit 2 returned to service in June and achieved full power operation on July 5, 2000 and Unit 1 returned to service in December and achieved full power operation on January 3, 2001. The increase in emission allowance usage and prices resulted from the stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments, which became effective on January 1, 2000.

With the consummation of the merger with CSW, certain deferred merger costs were expensed in 2000. The merger costs charged to expense included transaction and transition costs not allocable to and recoverable from ratepayers under regulatory commission approved settlement agreements to share net merger savings. As expected merger costs declined in 2001 after the merger was consummated.

Depreciation and amortization expense increased in 2001 primarily as a result of the commencement of amortization of transition generation regulatory assets in the Ohio, Virginia and West Virginia jurisdictions due to passage of restructuring legislation, the new businesses acquired in 2001 and additional investments in property, plant and equipment.

Interest, Preferred Stock Dividends, Minority Interest

Interest expense deceased 15% in 2001 due to the effect of interest paid the IRS on a COLI deduction disallowance in 2000 and lower average outstanding short-term debt balances and a decrease in average short-term interest rates.

In 2001 we issued a preferred member interest to finance the acquisition of HPL and paid a preferred return of $13 million to the preferred member interest.

In 2000 interest increased by 17% due to additional interest expense from the ruling disallowing COLI tax deductions and AEP's effort to maintain flexibility for corporate separation by issuing short-term debt at flexible rates. The use of fixed interest rate swaps has been employed to mitigate the risk from floating interest rates.

Other Income

Other income increased $166 million in 2001. This increase was primarily caused by the sale in March 2001 of Frontera, a generating plant required to be divested under a FERC approved merger settlement agreement, which produced a pretax $73 million gain and the effect from the December 2000 impairment writedown of $43 million to reflect the pending sale of AEP's Yorkshire investment.

Other income decreased $66 million in 2000 primarily due to a loss in equity earnings from the 2000 write-down of the Yorkshire investment and losses from certain non-regulated subsidiaries accounted for on an equity basis. Other expenses increased in 2000 mainly from a charge for the discontinuance of an electric storage water heater demand side management program of the regulated business.

Income Taxes

Although pre-tax book income increased considerably, income taxes decreased due to the effect of recording in 2000 prior year federal income taxes as a result of the disallowance of COLI interest deductions by the IRS and nondeductible merger related costs in 2000.

Income taxes increased in 2000 over 1999 levels primarily due to the disallowance of the COLI interest deductions and the non-deductible merger related costs discussed above.

Extraordinary Losses and Cumulative Effect

In 2001 we recorded an extraordinary loss of $48 million net of tax to write-off prepaid Ohio excise taxes stranded by Ohio deregulation. The application of regulatory accounting for generation was discontinued in 2000 for the Ohio, Virginia and West Virginia jurisdictions which resulted in the after tax extraordinary loss of $35 million.

New accounting rules that became effective in 2001 regarding accounting for derivatives required us to mark to market certain fuel supply contracts that qualify as financial derivatives. The effect of initially adopting the new rules at July 1, 2001 was a favorable earnings effect of $18 million, net of tax, which is reported as a cumulative effect of accounting change.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Consolidated Statements of Income

(in millions - except per share amounts)

	Year Ended December 31, 2001	2000	1999
REVENUES:			
Electricity Marketing and Trading	$41,513	$25,178	$17,232
Gas Marketing and Trading	14,416	6,259	2,311
Domestic Electricity Delivery	3,356	3,174	3,068
Other Investment	1,972	2,095	2,134
TOTAL REVENUES	61,257	36,706	24,745
EXPENSES:			
Fuel and Purchased Energy:			
Electricity Marketing and Trading	37,558	21,246	13,646
Gas Marketing and Trading	14,004	6,227	2,305
Other Investment	1,191	1,245	1,293
TOTAL FUEL AND PURCHASED ENERGY	52,753	28,718	17,244
Maintenance and Other Operation	4,037	3,841	3,276
Non-recoverable Merger Costs	21	203	-
Depreciation and Amortization	1,383	1,250	1,212
Taxes Other Than Income Taxes	668	690	709
TOTAL EXPENSES	58,862	34,702	22,441
OPERATING INCOME	2,395	2,004	2,304
OTHER INCOME	302	136	202
OTHER EXPENSES	130	81	42
LESS: INTEREST	972	1,149	977
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	10	11	19
MINORITY INTEREST IN FINANCE SUBSIDIARY	13	-	-
INCOME BEFORE INCOME TAXES	1,572	899	1,468
INCOME TAXES	569	597	482
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT	1,003	302	986
EXTRAORDINARY LOSSES (NET OF TAX):			
DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION	(48)	(35)	(8)
LOSS ON REACQUIRED DEBT	(2)	-	(6)
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	18	-	-
NET INCOME	$ 971	$ 267	$ 972
AVERAGE NUMBER OF SHARES OUTSTANDING	322	322	321
EARNINGS PER SHARE:			
Income Before Extraordinary Item and Cumulative Effect	$ 3.11	$0.94	$3.07
Extraordinary Losses	(0.16)	(.11)	(.04)
Cumulative Effect of Accounting Change	.06	-	-
Earnings Per Share (Basic and Dilutive)	$ 3.01	$0.83	$3.03
CASH DIVIDENDS PAID PER SHARE	$2.40	$2.40	$2.40

See Notes to Consolidated Financial Statements beginning on page L-1.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Consolidated Balance Sheets

(in millions - except share data)

	December 31, 2001	December 31, 2000
ASSETS		
CURRENT ASSETS:		
Cash and Cash Equivalents	$ 333	$ 342
Accounts Receivable:		
Customers	626	888
Miscellaneous	1,365	2,883
Allowance for Uncollectible Accounts	(109)	(72)
Energy Trading and Derivative Contracts	8,572	15,497
Other	1,776	1,363
TOTAL CURRENT ASSETS	12,563	20,901
PROPERTY PLANT AND EQUIPMENT:		
Electric:		
Production	17,477	16,328
Transmission	5,879	5,609
Distribution	11,310	10,843
Other (including gas and coal mining assets And nuclear fuel)	4,941	4,077
Construction Work in Progress	1,102	1,231
Total Property, Plant and Equipment	40,709	38,088
Accumulated Depreciation and Amortization	16,166	15,695
NET PROPERTY, PLANT AND EQUIPMENT	24,543	22,393
REGULATORY ASSETS	3,162	3,698
INVESTMENTS IN POWER, DISTRIBUTION AND COMMUNICATIONS PROJECTS	677	782
GOODWILL (NET OF AMORTIZATION)	1,494	1,382
LONG-TERM ENERGY TRADING AND DERIVATIVE CONTRACTS	2,370	1,552
OTHER ASSETS	2,472	2,642
TOTAL	$47,281	$53,350

See Notes to Consolidated Financial Statements beginning on page L-1.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts Payable	$ 2,245	$ 2,627
Short-term Debt	3,155	4,333
Long-term Debt Due Within One Year*	2,300	1,152
Energy Trading and Derivative Contracts	8,311	15,671
Other	2,088	2,154
TOTAL CURRENT LIABILITIES	18,099	25,937
LONG-TERM DEBT*	9,753	9,602
LONG-TERM ENERGY TRADING AND DERIVATIVE CONTRACTS	2,183	1,313
DEFERRED INCOME TAXES	4,823	4,875
DEFERRED INVESTMENT TAX CREDITS	491	528
DEFERRED CREDITS AND REGULATORY LIABILITIES	948	637
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	194	203
OTHER NONCURRENT LIABILITIES	1,334	1,706
COMMITMENTS AND CONTINGENCIES (Note 8)		
CERTAIN SUBSIDIARY OBLIGATED, MANDATORILY REDEEMABLE, PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING SOLELY JUNIOR SUBORDINATED DEBENTURES OF SUCH SUBSIDIARIES	321	334
MINORITY INTEREST IN FINANCE SUBSIDIARY	750	-
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES*	156	161
COMMON SHAREHOLDERS' EQUITY:		
Common Stock-Par Value $6.50: (2001 / 2000) Shares Authorized. .600,000,000 / 600,000,000; Shares Issued. . . .331,234,997 / 331,019,146 (8,999,992 shares were held in treasury at December 31, 2001 and 2000)	2,153	2,152
Paid-in Capital	2,906	2,915
Accumulated Other Comprehensive Income (Loss)	(126)	(103)
Retained Earnings	3,296	3,090
TOTAL COMMON SHAREHOLDERS' EQUITY	8,229	8,054
TOTAL	$47,281	$53,350

*See Accompanying Schedules.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Consolidated Statements of Cash Flows
(in millions)

	Year Ended December 31,		
	2001	2000	1999
OPERATING ACTIVITIES:			
Net Income	$ 971	$ 267	$ 972
Adjustments for Noncash Items:			
Depreciation and Amortization	1,413	1,299	1,294
Deferred Federal Income Taxes	163	(170)	180
Deferred Investment Tax Credits	(29)	(36)	(38)
Amortization (Deferral) of Operating Expenses and Carrying Charges (net)	40	48	(151)
Equity in Earnings of Yorkshire Electricity Group plc	-	(44)	(45)
Extraordinary Loss	50	35	14
Cumulative Effect of Accounting Change	(18)	-	-
Deferred Costs Under Fuel Clause Mechanisms	340	(449)	(191)
Mark to Market of Energy Trading Contracts	(257)	(170)	(23)
Miscellaneous Accrued Expenses	(384)	217	101
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	1,764	(1,632)	(80)
Fuel, Materials and Supplies	(82)	147	(162)
Accrued Utility Revenues	26	(79)	(35)
Accounts Payable	(461)	1,322	74
Taxes Accrued	(147)	172	29
Premium Options	(76)	74	8
Payment of Disputed Tax and Interest Related to COLI	-	319	(16)
Change in Other Assets	(213)	(92)	(87)
Change in Other Liabilities	(147)	205	(245)
Net Cash Flows From Operating Activities	2,953	1,433	1,599
INVESTING ACTIVITIES:			
Construction Expenditures	(1,832)	(1,773)	(1,680)
Purchase of Houston Pipe Line	(727)	-	-
Purchase of U.K. Generation	(943)	-	-
Purchase of Quaker Coal Co.	(101)	-	-
Purchase of Memco	(266)	-	-
Purchase of Indian Mesa	(175)	-	-
Sale of Yorkshire	383	-	-
Sale of Frontera	265	-	-
Other	(36)	19	7
Net Cash Flows Used For Investing Activities	(3,432)	(1,754)	(1,673)
FINANCING ACTIVITIES:			
Issuance of Common Stock	10	14	93
Issuance of Minority Interest	747	-	-
Issuance of Long-term Debt	2,931	1,124	1,391
Retirement of Cumulative Preferred Stock	(5)	(20)	(170)
Retirement of Long-term Debt	(1,835)	(1,565)	(915)
Change in Short-term Debt (net)	(597)	1,308	812
Dividends Paid on Common Stock	(773)	(805)	(833)
Dividends on Minority Interest in Subsidiary	(5)	-	-
Other Financing Activities	-	-	(43)
Net Cash Flows From Financing Activities	473	56	335
Effect of Exchange Rate Change on Cash	(3)	23	(2)
Net Increase (Decrease) in Cash and Cash Equivalents	(9)	(242)	259
Cash and Cash Equivalents January 1	342	584	325
Cash and Cash Equivalents December 31	$ 333	$ 342	$ 584

See Notes to Consolidated Financial Statements beginning on page L-1.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Consolidated Statements of Common Shareholders' Equity and Comprehensive Income

(in millions)

	Common Shares	Stock Amount	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 1999	328	$2,134	$2,818	$3,493	$ 7	$8,452
Issuances	3	15	77	-	-	92
Retirements and Other	-	-	3	-	-	3
Cash Dividends Declared	-	-	-	(833)	-	(833)
Other	-	-	-	(2)	-	(2)
						7,712
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(13)	(13)
Minimum Pension Liability	-	-	-	-	2	2
Net Income	-	-	-	972	-	972
Total Comprehensive Income						961
DECEMBER 31, 1999	331	2,149	2,898	3,630	(4)	8,673
Issuances	-	3	11	-	-	14
Cash Dividends Declared	-	-	-	(805)	-	(805)
Other	-	-	6	(2)	-	4
						7,886
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(119)	(119)
Reclassification Adjustment For Loss Included in Net Income	-	-	-	-	20	20
Net Income	-	-	-	267		267
Total Comprehensive Income						168
DECEMBER 31, 2000	331	2,152	2,915	3,090	(103)	$8,054
Issuances	-	1	9	-	-	10
Cash Dividends Declared	-	-	-	(773)	-	(773)
Other	-	-	(18)	8	-	(10)
						7,281
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(14)	(14)
Unrealized Gain (Loss) on Hedged Derivatives					(3)	(3)
Minimum Pension Liability	-	-	-	-	(6)	(6)
Net Income	-	-	-	971		971
Total Comprehensive Income						948
DECEMBER 31, 2001	331	$2,153	$2,906	$3,296	$(126)	$8,229

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries

	December 31, 2001			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(f)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	614,608	$61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	333,100	$33
6.02% - 6-7/8% (c)	$100	1,650,000	513,450	52
7% (e)	(e)	250,000	100,000	10
Total Subject to Mandatory Redemption (c)				$95

	December 31, 2000			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(f)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	614,608	$61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	333,100	$ 33
6.02% - 6-7/8% (c)	$100	1,650,000	513,450	52
7% (e)	(e)	250,000	150,000	15
Total Subject to Mandatory Redemption (c)				$100

NOTES TO SCHEDULE OF CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

(a) At the option of the subsidiary the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.
(b) As of December 31, 2001 the subsidiaries had 13,642,750, 22,200,000 and 7,713,495 shares of $100, $25 and no par value preferred stock, respectively, that were authorized but unissued.
(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds(generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed. The sinking fund provisions of the series subject to mandatory redemption aggregate (after deducting sinking fund requirements) of $5 million in 2002 and $5 million in 2003.
(d) Not callable prior to 2003; after that the call price is $100 per share.
(e) With sinking fund.
(f) The number of shares of preferred stock redeemed is 50,000 shares in 2001, 209,563 shares in 2000 and 1,698,276 shares in 1999.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Schedule of Consolidated Long-term Debt of Subsidiaries

Maturity	Weighted Average Interest Rate December 31, 2001	Interest Rates at December 31, 2001	2000	December 31, 2001 (in millions)	2000
FIRST MORTGAGE BONDS (a)					
2001-2003	6.95%	6.00%-7.70%	5.91%-8.95%	$ 852	$ 1,247
2004-2008	6.98%	6-1/8%-8.00%	6-1/8%-8%	1,092	1,140
2020-2025	7.66%	6-7/8%-8.80%	6-7/8%-8.80%	850	1,104
INSTALLMENT PURCHASE CONTRACTS (b)					
2001-2009	4.30%	1.80%-7.70%	4.90%-7.70%	446	234
2011-2030	5.88%	1.55%-8.20%	4.875%-8.20%	1,234	1,447
NOTES PAYABLE (c)					
2001-2021	5.41%	4.0483%-9.60%	6.20%-9.60%	2,237	1,181
SENIOR UNSECURED NOTES					
2001-2004	4.81%	2.31%-7.45%	6.50%-7.45%	1,874	2,049
2005-2009	6.24%	6.125%-6.91%	6.24%-6.91%	1,763	475
2038	7.30%	7.20%-7-3/8%	7.20%-7-3/8%	340	340
JUNIOR DEBENTURES					
2025-2038	8.05%	7.60%-8.72%	7.60%-8.72%	618	620
YANKEE BONDS AND EURO BONDS					
2001-2006	8.71%	8.50%-8.875%	7.98%-8.875%	479	684
OTHER LONG-TERM DEBT (d)				308	280
Unamortized Discount (net)				(40)	(47)
Total Long-term Debt Outstanding (e)				12,053	10,754
Less Portion Due Within One Year				2,300	1,152
Long-term Portion				$ 9,753	$ 9,602

NOTES TO SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

(a) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment.
(b) For certain series of installment purchase contracts interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest-adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) Other long-term debt consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 8 of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.
(e) Long-term debt outstanding at December 31, 2001 is payable as follows:

	Principal Amount (in millions)
2002	$ 2,300
2003	2,086
2004	902
2005	616
2006	1,943
Later Years	4,246
Total Principal Amount	12,093
Unamortized Discount	40
Total	$12,053

AMERICAN ELECTRIC POWER COMPANY INC. AND SUBSIDIARY COMPANIES

Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

MANAGEMENT'S RESPONSIBILITY

The management of American Electric Power Company, Inc. is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with generally accepted accounting principles, using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets regularly with management, Deloitte & Touche LLP - independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee.

The financial statements have been audited by Deloitte & Touche LLP, whose report appears on the next page. The auditors provide an objective, independent review as to management's discharge of its responsibilities insofar as they relate to the fairness of the Company's reported financial condition and results of operations. Their audit includes procedures believed by them to provide reasonable assurance that the financial statements are free of material misstatement and includes an evaluation of the Company's internal control structure over financial reporting.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of American Electric Power Company, Inc.:

We have audited the consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements give retroactive effect to the merger of American Electric Power Company, Inc. and its subsidiaries and Central and South West Corporation and its subsidiaries, which has been accounted for as a pooling of interests as described in Note 3 to the consolidated financial statements. We did not audit the consolidated statements of income, and cash flows, and stockholder's equity and comprehensive income of Central and South West Corporation and its subsidiaries for the year ended December 31, 1999, which statements reflect total revenues of $5,516,000,000 for the year ended December 31, 1999. Those consolidated statements, before the restatement described in Note 3, were audited by other auditors whose report, dated February 25, 2000, has been furnished to us, and our opinion, insofar as it relates to those amounts included for Central and South West Corporation and its subsidiaries for 1999, is based solely on the report of such other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 financial statements to give retroactive effect to the change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

Deloitte & Touche LLP
Columbus, Ohio
February 22, 2002

AEP GENERATING COMPANY

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AEP GENERATING COMPANY
Selected Financial Data

	Year Ended December 31,				
	2001	2000	1999	1998	1997
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$227,548	$228,516	$217,189	$224,146	$227,868
Operating Expenses	220,571	220,092	211,849	215,415	218,828
Operating Income	6,977	8,424	5,340	8,731	9,040
Nonoperating Income	3,484	3,429	3,659	3,364	3,603
Interest Charges	2,586	3,869	2,804	3,149	3,857
Net Income	$ 7,875	$ 7,984	$ 6,195	$ 8,946	$ 8,786

	December 31,				
	2001	2000	1999	1998	1997
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$648,254	$642,302	$640,093	$636,460	$633,450
Accumulated Depreciation	337,151	315,566	295,065	277,855	257,191
Net Electric Utility Plant	$311,103	$326,736	$345,028	$358,605	$376,259
Total Assets	$361,341	$374,602	$398,640	$403,892	$419,058
Common Stock and Paid-in Capital	$ 24,434	$ 24,434	$ 30,235	$ 36,235	$ 40,235
Retained Earnings	13,761	9,722	3,673	2,770	2,528
Total Common Shareholder's Equity	$ 38,195	$ 34,156	$ 33,908	$ 39,005	$ 42,763
Long-term Debt (a)	$ 44,793	$ 44,808	$ 44,800	$ 44,792	$ 69,570
Total Capitalization And Liabilities	$361,341	$374,602	$398,640	$403,892	$419,058

(a) Including portion due within one year.

AEP GENERATING COMPANY
Management's Narrative Analysis of Results of Operations

AEP Generating Company is engaged in the generation and wholesale sale of electric power to two affiliates under long-term agreements.

Operating revenues are derived from the sale of Rockport Plant energy and capacity to two affiliated companies, I&M and KPCo pursuant to FERC approved long-term unit power agreements. Under the terms of its unit power agreement, I&M is required to buy all of AEGCo's Rockport capacity when the unit power agreement with KPCo expires in 2004. The unit power agreements provide for recovery of costs including a FERC approved rate of return on common equity and a return on other capital net of temporary cash investments. Under terms of the unit power agreements, AEGCo accumulates all expenses monthly and prepares the bills for its affiliates. In the month the expenses are incurred, AEGCo recognizes the billing revenues and establishes a receivable from the affiliated companies.

Net income decreased $0.1 million or 1% as a result of a slight decrease in the return on other capital. Lower interest charges caused the return on other capital to decrease.

Income statement items which changed significantly were:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Operating Revenues	$(1.0)	N.M.
Other Operation Expense	0.7	7
Maintenance Expense	(0.8)	(8)
Taxes Other Than Income Taxes	0.4	10
Interest Charges	(1.3)	(33)

N.M. = Not Meaningful

The decrease in operating revenues reflects a decrease in the return on other capital reflecting a decline in interest charges.

Other operation expense increased due to the costs of an air quality test project and increased benefits and compensation costs.

The decrease in maintenance expense can be attributed to a shorter duration of maintenance outages for boiler inspection and repair in 2001.

Taxes other than income taxes increased due to an increase in Indiana real and personal property taxes reflecting an unfavorable accrual adjustment and a higher estimated liability accrued in 2001.

The decrease in interest charges was primarily due to a decline in interest rates in 2001. The Federal Reserve reduced short-term interest rates eleven times in 2001. AEGCo benefited from the declining short-term interest rates since its short-term borrowings and through July 13, 2001 its long-term debt were based on short-term interest rates. AEGCo's long-term debt interest rates varied daily until July 2001 when we chose to fix the rate at 4.05% for five years.

AEP GENERATING COMPANY
Statements of Income

	Year Ended December 31,		
	2001	2000	1999
	(in thousands)		
OPERATING REVENUES:			
Sales to AEP Affiliates	$227,338	$227,983	$152,559
Other	210	533	64,630
TOTAL OPERATING REVENUES	227,548	228,516	217,189
OPERATING EXPENSES:			
Fuel	102,828	102,978	94,481
Rent - Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	11,025	10,295	10,451
Maintenance	8,853	9,616	10,492
Depreciation	22,423	22,162	21,845
Taxes Other Than Income Taxes	4,257	3,854	3,866
Income Taxes	2,902	2,904	2,431
TOTAL OPERATING EXPENSES	220,571	220,092	211,849
OPERATING INCOME	6,977	8,424	5,340
NONOPERATING INCOME	30	6	92
NONOPERATING EXPENSES	16	17	27
NONOPERATING INCOME TAX CREDITS	3,470	3,440	3,594
INTEREST CHARGES	2,586	3,869	2,804
NET INCOME	$ 7,875	$ 7,984	$ 6,195

Statements of Retained Earnings

	Year Ended December 31,		
	2001	2000	1999
	(in thousands)		
RETAINED EARNINGS JANUARY 1	$ 9,722	$3,673	$2,770
NET INCOME	7,875	7,984	6,195
CASH DIVIDENDS DECLARED	3,836	1,935	5,292
RETAINED EARNINGS DECEMBER 31	$13,761	$9,722	$3,673

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY

Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$638,297	$635,215
General	3,012	2,795
Construction Work in Progress	6,945	4,292
Total Electric Utility Plant	648,254	642,302
Accumulated Depreciation	337,151	315,566
NET ELECTRIC UTILITY PLANT	311,103	326,736
OTHER PROPERTY AND INVESTMENTS	119	6
CURRENT ASSETS:		
Cash and Cash Equivalents	983	2,757
Accounts Receivable:		
Affiliated Companies	22,344	21,374
Miscellaneous	147	2,341
Fuel - at average cost	15,243	11,006
Materials and Supplies - at average cost	4,480	3,979
Prepayments	244	145
TOTAL CURRENT ASSETS	43,441	41,602
REGULATORY ASSETS	5,207	5,504
DEFERRED CHARGES	1,471	754
TOTAL	$361,341	$374,602

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - Par Value $1,000:		
Authorized and Outstanding - 1,000 Shares	$ 1,000	$ 1,000
Paid-in Capital	23,434	23,434
Retained Earnings	13,761	9,722
Total Common Shareholder's Equity	38,195	34,156
Long-term Debt	44,793	-
TOTAL CAPITALIZATION	82,988	34,156
OTHER NONCURRENT LIABILITIES	76	358
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	-	44,808
Advances from Affiliates	32,049	28,068
Accounts Payable:		
General	7,582	6,109
Affiliated Companies	1,654	7,724
Taxes Accrued	4,777	4,993
Rent Accrued - Rockport Plant Unit 2	4,963	4,963
Other	3,481	4,443
Total CURRENT LIABILITIES	54,506	101,108
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	116,617	122,188
REGULATORY LIABILITIES:		
Deferred Investment Tax Credits	56,304	59,718
Amounts Due to Customers for Income Taxes	22,725	23,996
Total REGULATORY LIABILITIES	79,029	83,714
DEFERRED INCOME TAXES	27,975	32,928
DEFERRED CREDITS	150	150
CONTINGENCIES (Note 8)		
TOTAL	$361,341	$374,602

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
Statements of Cash Flows

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 7,875	$ 7,984	$ 6,195
Adjustments for Noncash Items:			
Depreciation	22,423	22,162	21,845
Deferred Federal Income Taxes	(6,224)	(5,842)	(5,282)
Deferred Investment Tax Credits	(3,414)	(3,396)	(3,448)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Change in Certain Current Assets and Liabilities:			
Accounts Receivable	1,224	1,392	(2,213)
Fuel, Materials and Supplies	(4,738)	6,486	(6,263)
Accounts Payable	(4,597)	(13,157)	14,394
Taxes Accrued	(216)	708	1,058
Other Assets	(569)	1,636	(6)
Other Liabilities	(1,244)	(404)	(1,564)
Net Cash Flows From Operating Activities	4,949	11,998	19,145
INVESTING ACTIVITIES:			
Construction Expenditures	(6,868)	(5,190)	(8,349)
Proceeds From Sales of Property	-	-	331
Net Cash Flows Used For Investing Activities	(6,868)	(5,190)	(8,018)
FINANCING ACTIVITIES:			
Return of Capital to Parent Company	-	(5,801)	(6,000)
Change in Short-term Debt (net)	-	(24,700)	250
Change in Advances From Affiliates (net)	3,981	28,068	-
Dividends Paid	(3,836)	(1,935)	(5,292)
Net Cash Flows From (Used For) Financing Activities	145	(4,368)	(11,042)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,774)	2,440	85
Cash and Cash Equivalents January 1	2,757	317	232
Cash and Cash Equivalents December 31	$ 983	$ 2,757	$ 317

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $1,509,000, $3,531,000 and $2,468,000 and for income taxes was $8,597,000, $6,820,000 and $6,565,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY

Statements of Capitalization

	December 31, 2001	December 31, 2000
	(in thousands)	
COMMON STOCK EQUITY (a)	$38,195	$ 34,156
LONG-TERM DEBT		
Installment Purchase Contracts - City of Rockport (b)		
Series / Due Date		
1995 A, 2025 (c)	22,500	22,500
1995 B, 2025 (c)	22,500	22,500
Unamortized Discount	(207)	(192)
Amount Due Within One Year	-	(44,808)
Long-term Debt Excluding Amount Due Within One Year	44,793	-
TOTAL CAPITALIZATION	$82,988	$ 34,156

(a) In 2000 and 1999, AEGCo returned capital to AEP in the amounts of $5.8 million and $6 million, respectively. There were no other material transactions affecting common stock and paid-in capital in 2001, 2000 and 1999.

(b) Installment purchase contracts were entered into in connection with the issuance of pollution control revenue bonds by the City of Rockport, Indiana. The terms of the installment purchase contracts require AEGCo to pay amounts sufficient to enable the payment of interest and principal on the related pollution control revenue bonds issued to refinance the construction costs of pollution control facilities at the Rockport Plant.

(c) These series have an adjustable interest rate that can be a daily, weekly, commercial paper or term rate as designated by AEGCo. Prior to July 13, 2001, AEGCo selected a daily rate which ranged from 0.9% to 5.6% during 2001 and from 1.65% to 6.1% during 2000 and averaged 2.8% in 2001 and 4.1% in 2000. Effective July 13, 2001, AEGCo selected a term rate of 4.05% for five years ending July 12, 2006. The interest rates were 5% for Series A and 4.9% for Series B at December 31, 2000.

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY

Index to Notes to Financial Statements

The notes to AEGCo's financial statements are combined with the notes to financial statements for AEP and its other subisidiary registrants. Listed below are the combined notes that apply to AEGCo. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors
of AEP Generating Company:

We have audited the accompanying balance sheets and statements of capitalization of AEP Generating Company as of December 31, 2001 and 2000, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP
Columbus, Ohio
February 22, 2002

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES

Selected Consolidated Financial Data

	2001	2000	1999	1998	1997
	Year Ended December 31, (in thousands)				
INCOME STATEMENTS DATA:					
Operating Revenues	$6,999,430	$5,087,308	$3,970,647	$3,291,385	$1,720,010
Operating Expenses	6,724,444	4,886,154	3,729,411	3,062,842	1,480,016
Operating Income	274,986	201,154	241,236	228,543	239,994
Nonoperating Income (Loss)	6,868	11,752	8,096	(8,301)	(222)
Interest Charges	120,036	148,000	128,840	126,912	119,258
Income Before Extraordinary Item	161,818	64,906	120,492	93,330	120,514
Extraordinary Gain	-	8,938	-	-	-
Net Income	161,818	73,844	120,492	93,330	120,514
Preferred Stock Dividend Requirements	2,011	2,504	2,706	2,497	7,006
Earnings Applicable to Common Stock	$ 159,807	$ 71,340	$ 117,786	$ 90,833	$ 113,508

	2001	2000	1999	1998	1997
	December 31, (in thousands)				
BALANCE SHEETS DATA:					
Electric Utility Plant	$5,664,657	$5,418,278	$5,262,951	$5,087,359	$4,901,046
Accumulated Depreciation and Amortization	2,296,481	2,188,796	2,079,490	1,984,856	1,869,057
Net Electric Utility Plant	$3,368,176	$3,229,482	$3,183,461	$3,102,503	$3,031,989
Total Assets	$5,107,938	$6,633,724	$4,354,400	$4,047,038	$3,883,430
Common Stock and Paid-in Capital	$ 976,244	$ 975,676	$ 974,717	$ 924,091	$ 873,506
Accumulated Other Comprehensive Income (Loss)	(340)	-	-	-	-
Retained Earnings	150,797	120,584	175,854	179,461	207,544
Total Common Shareholder's Equity	$1,126,701	$1,096,260	$1,150,571	$1,103,552	$1,081,050
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 17,790	$ 17,790	$ 18,491	$ 19,359	$ 19,747
Subject to Mandatory Redemption	10,860	10,860	20,310	22,310	22,310
Total Cumulative Preferred Stock	$ 28,650	$ 28,650	$ 38,801	$ 41,669	$ 42,057
Long-term Debt (a)	$1,556,559	$1,605,818	$1,665,307	$1,552,455	$1,494,535
Obligations Under Capital Leases (a)	$ 46,285	$ 63,160	$ 64,645	$ 65,175	$ 60,110
Total Capitalization And Liabilities	$5,107,938	$6,633,724	$4,354,400	$4,047,038	$3,883,430

(a) Including portion due within one year.

APCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 917,000 retail customers in southwestern Virginia and southern West Virginia. APCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers including power trading transactions. APCo also sells wholesale power to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among the Pool members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of revenues and costs.

Critical Accounting Policies - Revenue Recognition

Regulatory Accounting - As a result of our cost-based rate-regulated transmission and distribution operations, our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities – We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to APCo as a member of the AEP Power Pool. Trading activities involve the purchase and sale of energy under physical forward contracts at fixed and variable prices and buying and selling financial energy contracts which includes exchange traded futures and options and over-the-counter options and swaps. Although trading contracts are generally short-term, there are also long-term trading contracts. We recognize revenues from trading activities generally based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt of electricity and net settle in cash, the unrealized gain or loss is reversed and the actual realized cash gain or loss is recognized. Therefore, over the trading contract's term an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

The majority of our trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity in July. At the end of each month until the contract settles in July, we would record our share of any difference between the contract price and the market price as an unrealized gain or loss. In July when the contract settles, we would realize our share of the gain or loss in cash and reverse the previously recorded unrealized gain or loss.

Depending on whether the delivery point for the electricity is in AEP's traditional marketing area or not determines where the contract is reported on APCo's income statement. AEP's traditional marketing area is up to two transmission systems from the AEP service territory. Physical forward trading sale contracts with delivery points in AEP's traditional marketing area are included in revenues when the contracts settle. Physical forward trading purchase contracts with delivery points in AEP's traditional marketing area are included in purchased power expense when they settle. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in AEP's traditional marketing area are included in revenues on a net basis. Physical forward sales contracts for delivery outside of AEP's traditional marketing area are included in nonoperating income when the contract settles. Physical forward purchase contracts for delivery outside of AEP's traditional marketing area are included in nonoperating expenses when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of AEP's traditional marketing area are included in nonoperating income on a net basis.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity in July. If we do nothing else with these contracts until settlement in July and if the volumes, delivery point, schedule and other key terms match then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on results of operations but will have an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on results of operations from recording additional changes in fair values using mark-to-market accounting.

Trading of electricity options, futures and swaps, represents financial transactions with unrealized gains and losses from changes in fair values reported net in nonoperating income until the contracts settle. When these financial contracts settle, we record our share of the net proceeds in nonoperating income and reverse to nonoperating income the prior unrealized gain or loss.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models.

These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing APCo to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Results of Operations

Net Income

Net income increased $88 million or 119% in 2001 primarily due to the effect of a court decision related to a corporate owned life insurance (COLI) program recorded in 2000. In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including APCo, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to COLI. In 1998 and 1999 APCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. Also contributing to the increase in net income was growth in and strong performance by the wholesale marketing and trading business in the first half of 2001 offset in part by the effect of extremely mild November and December weather combined with weak economic conditions which reduced retail energy sales.

The adverse court decision on COLI caused the $47 million decrease in 2000's net income. Income before extraordinary items decreased $56 million or 46% in 2000 primarily due to the COLI decision. An extraordinary gain from the discontinuance of SFAS 71 regulatory accounting of $9 million after tax was recorded in June 2000. (See Note 2, "Extraordinary Items and Cumulative Effect".)

Operating Revenues

Operating revenues increased 38% in 2001 and 28% in 2000 mainly due to a significant increase in wholesale marketing and trading volume. The changes in the components of revenues were as follows:

	Increase (Decrease) From Previous Year (dollars in millions)			
	2001		2000	
	Amount	%	Amount	%
Retail*	$ (38.9)	(5)	$ 2	N.M.
Wholesale Marketing and Trading	1,859.1	52	1,091.2	44
Unrealized MTM	46.3	272	(22.0)	N.M.
Other	8.9	14	(18.2)	(22)
Total Marketing and Trading	1,875.4	43	1,053.0	32
Energy Delivery*	20.1	3	9.3	2
Sales to AEP Affiliates	16.6	11	54.4	54
Total Revenues	$1,912.1	38	$1,116.7	28

N.M. = Not Meaningful

*Reflects the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

Wholesale marketing and trading revenues increased significantly in 2001 and 2000 as a result of an increase in electric marketing and trading volume (39% in 2001 and 42% in 2000). The maturing of the Intercontinental Exchange, the development of proprietary tools, and increased staffing of energy traders have resulted in an increase in the number of forward electricity purchase and sale contracts in AEP's traditional marketing area.

While wholesale marketing and trading volumes rose, kilowatthour sales to industrial customers decreased in 2001. This decrease was due to the economic recession. Also, in the fourth quarter, sales to residential and commercial customers declined. The recession reduced demand, especially, in the fourth quarter.

The increase in sales to AEP affiliates in 2000 is due to a significant increase in AEP Power Pool transactions. As the quantity of energy sold by the AEP Power Pool rose, APCo's contribution of energy to the Pool rose, accounting for the increase in APCo's revenues from sales to AEP affiliates. The AEP Power Pool was able to make additional sales to third parties in 2000 as a result of an affiliated company's major industrial customer's decision not to continue its purchased power agreement.

Operating Expenses

The increase in operating expenses in 2001 of 38% is due to increases in electricity marketing and trading expense and depreciation and amortization expenses partially offset by decreases in income taxes, other operation expense and fuel expenses. Operating expenses increased 31% in 2000 due to an increase in electricity marketing and trading expense, power purchases from AEP affiliates, other operation expense and income taxes offset in part by a decrease in fuel expense. Changes in the components of operating expenses are as follows:

	Increase (Decrease) From Previous Year (dollars in millions)			
	2001		2000	
	Amount	%	Amount	%
Fuel	$ (17.6)	(5)	$ (75.6)	(17)
Marketing and Trading Purchases	1,904.7	57	906.4	37
AEP Affiliate Purchases	(8.9)	(3)	224.8	172
Other Operation	(18.8)	(7)	33.0	13
Maintenance	7.9	6	0.7	1
Depreciation and Amortization	17.3	11	14.2	10
Taxes Other Than Income Taxes	(11.8)	(11)	(1.0)	(1)
Income Taxes	(34.5)	(27)	54.2	72
Total	$1,838.3	38	$1,156.7	31

The decrease in fuel expense in 2001 is due to a decline in generation as a result of scheduled plant maintenance. Fuel expense decreased in 2000 due to the combined effect of the discontinuance of deferral accounting for over or under recovery of fuel costs in the West Virginia jurisdiction effective January 1, 2000 under the terms of a rate settlement agreement and a decline in generation due to scheduled plant maintenance.

Electricity marketing and trading purchased power expense increased substantially in 2001 and 2000 due to increases in trading volume and wholesale electricity prices.

Purchased power from AEP affiliates decreased in 2001 as the result of a decrease in AEP Power Pool capacity charges due to a reduction in APCo's MLR. The significant increase in purchased power from AEP affiliates in 2000 reflects additional purchases of power from the AEP Power Pool as a result of increased availability of generation. The AEP Power Pool was able to supply more power to APCo since an affiliate's nuclear unit returned to service in June 2000, a major industrial customer discontinued purchasing power from an affiliate in January 2000, and generating unit outage management improved.

Other operation expense decreased in 2001 mainly due to the effect of AEPSC billings in 2000 for the disallowance of the COLI program interest deduction. Additionally, the decrease was the result of a gain recorded on the disposition of SO2 emission allowances offset in part by increased wholesale power trading incentive compensation expense. The increase in other operation expense in 2000 was due to increased wholesale marketing and trading costs including increased accruals for incentive compensation, increased use of emission allowances due to stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments which became effective January 1, 2000 and AEPSC billings for the COLI disallowance.

During June 2000 we discontinued the application of SFAS 71 in the Virginia and West Virginia jurisdictions. Consequently net generation-related regulatory assets were transferred to the energy delivery business' regulated distribution business where the Virginia and West Virginia jurisdictions authorized the recovery of these transition regulatory assets through regulated rates. Depreciation and amortization expense increased in 2001 and 2000 due to accelerated amortization, beginning in July 2000, of the transition regulatory assets. Additional investments in the energy delivery business' distribution and transmission plant also contributed to the increases in depreciation and amortization expense.

The decrease in taxes other than income taxes in 2001 is due to the elimination of the Virginia gross receipts tax as a result of a tax law change due to deregulation in that state.

Income taxes attributable to operations decreased in 2001 due to the effect of the disallowance of COLI interest deductions in 2000 offset in part by an increase in pre-tax operating income. The increase in income taxes attributable to operations in 2000 was due to the disallowance of COLI interest deductions.

Nonoperating Income and Nonoperating Expenses

The increase in nonoperating income and nonoperating expenses for both 2001 and 2000 is due to considerable increases in the wholesale business' trading transactions outside of the AEP System's traditional marketing area.

Interest Charges

Interest charges decreased in 2001 primarily due to the effect of recognizing in 2000 previously deferred interest payments to the IRS related to the COLI disallowances and interest on resultant state income tax deficiencies. Additionally, the decrease in 2001 is due to the retirement of first mortgage bonds in 2000. The increase in interest charges in 2000 was due to the recognition of deferred interest payments related to the COLI disallowances and interest on the resultant prior years state income taxes.

Extraordinary Gain

The extraordinary gain recorded in June 2000 was the result of the discontinuance of SFAS 71 for the generation portion of APCo's business.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Income

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
OPERATING REVENUES:			
Electricity Marketing and Trading	$6,233,109	$4,357,712	$3,304,755
Energy Delivery	595,036	574,918	565,660
Sales to AEP Affiliates	171,285	154,678	100,232
Total Operating Revenues	6,999,430	5,087,308	3,970,647
OPERATING EXPENSES:			
Fuel	351,557	369,161	444,711
Purchased Power:			
Electricity Marketing and Trading	5,253,983	3,349,279	2,442,819
AEP Affiliates	346,878	355,774	130,991
Other Operation	263,798	282,610	249,616
Maintenance	132,373	124,493	123,834
Depreciation and Amortization	180,393	163,089	148,874
Taxes Other Than Income Taxes	99,878	111,692	112,722
Income Taxes	95,584	130,056	75,844
Total Operating Expenses	6,724,444	4,886,154	3,729,411
OPERATING INCOME	274,986	201,154	241,236
NONOPERATING INCOME	2,320,649	1,415,530	684,080
NONOPERATING EXPENSES	2,312,642	1,400,655	675,793
NONOPERATING INCOME TAX EXPENSE	1,139	3,123	191
INTEREST CHARGES	120,036	148,000	128,840
INCOME BEFORE EXTRAORDINARY ITEM	161,818	64,906	120,492
EXTRAORDINARY GAIN - DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION (Inclusive of Tax Benefit of $7,872,000)	-	8,938	-
NET INCOME	161,818	73,844	120,492
PREFERRED STOCK DIVIDEND REQUIREMENTS	2,011	2,504	2,706
EARNINGS APPLICABLE TO COMMON STOCK	$ 159,807	$ 71,340	$ 117,786

Consolidated Statements of Comprehensive Income

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
NET INCOME	$161,818	$73,844	$120,492
OTHER COMPREHENSIVE INCOME (LOSS)			
Foreign Currency Exchange Rate Hedge	(340)	-	-
COMPREHENSIVE INCOME	$161,478	$73,844	$120,492

See Notes to Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,093,532	$2,058,952
Transmission	1,222,226	1,177,079
Distribution	1,887,020	1,816,925
General	257,957	254,371
Construction Work in Progress	203,922	110,951
Total Electric Utility Plant	5,664,657	5,418,278
Accumulated Depreciation and Amortization	2,296,481	2,188,796
NET ELECTRIC UTILITY PLANT	3,368,176	3,229,482
OTHER PROPERTY AND INVESTMENTS	53,736	56,967
LONG-TERM ENERGY TRADING CONTRACTS	316,249	322,038
CURRENT ASSETS:		
Cash and Cash Equivalents	13,663	5,847
Advances to Affiliates	-	8,387
Accounts Receivable:		
Customers	113,371	243,298
Affiliated Companies	63,368	63,919
Miscellaneous	11,847	16,179
Allowance for Uncollectible Accounts	(1,877)	(2,588)
Fuel - at average cost	56,699	39,076
Materials and Supplies - at average cost	59,849	57,515
Accrued Utility Revenues	30,907	66,499
Energy Trading Contracts	566,284	2,024,222
Prepayments	16,018	6,307
TOTAL CURRENT ASSETS	930,129	2,528,661
REGULATORY ASSETS	397,383	447,750
DEFERRED CHARGES	42,265	48,826
TOTAL	$5,107,938	$6,633,724

See Notes to Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 30,000,000 Shares		
Outstanding - 13,499,500 Shares	$ 260,458	$ 260,458
Paid-in Capital	715,786	715,218
Accumulated Other Comprehensive Income (Loss)	(340)	-
Retained Earnings	150,797	120,584
Total Common Shareholder's Equity	1,126,701	1,096,260
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	17,790	17,790
Subject to Mandatory Redemption	10,860	10,860
Long-term Debt	1,476,552	1,430,812
TOTAL CAPITALIZATION	2,631,903	2,555,722
OTHER NONCURRENT LIABILITIES	84,104	105,883
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	80,007	175,006
Short-term Debt	-	191,495
Advances From Affiliates	291,817	-
Accounts Payable - General	131,387	153,422
Accounts Payable - Affiliated Companies	84,518	107,556
Taxes Accrued	55,583	63,258
Customer Deposits	13,177	12,612
Interest Accrued	21,770	21,555
Energy Trading Contracts	549,703	2,080,025
Other	75,299	85,378
Total CURRENT LIABILITIES	1,303,261	2,890,307
DEFERRED INCOME TAXES	703,575	682,474
DEFERRED INVESTMENT TAX CREDITS	38,328	43,093
LONG-TERM ENERGY TRADING CONTRACTS	257,129	258,788
REGULATORY LIABILITIES AND DEFERRED CREDITS	89,638	97,457
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$5,107,938	$6,633,724

See Notes to Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2001	2000	1999
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 161,818	$ 73,844	$ 120,492
Adjustments for Noncash Items:			
Depreciation and Amortization	180,505	163,202	149,791
Deferred Federal Income Taxes	42,498	8,602	13,033
Deferred Investment Tax Credits	(4,765)	(4,915)	(4,972)
Deferred Power Supply Costs (net)	1,411	(84,408)	35,955
Mark-to-Market of Energy Trading Contracts	(68,254)	(1,843)	(8,939)
Provision for Rate Refunds	-	(4,818)	4,818
Extraordinary Gain	-	(8,938)	-
Change in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	134,099	(166,911)	10,989
Fuel, Materials and Supplies	(19,957)	18,487	(4,812)
Accrued Utility Revenues	35,592	(13,081)	(7,433)
Accounts Payable	(45,073)	159,369	(9,273)
Taxes Accrued	(7,675)	14,220	13,319
Revenue Refunds Accrued	-	181	(95,267)
Incentive Plan Accrued	(2,451)	10,662	1,507
Disputed Tax and Interest Related to COLI	-	72,440	(4,124)
Change in Operating Reserves	(5,358)	(19,770)	7,451
Rate Stabilization Deferral	-	75,601	-
Change in Other Assets	19,418	(13,021)	(8,669)
Change in Other Liabilities	(27,954)	9,817	(22,455)
Net Cash Flows From Operating Activities	393,854	288,720	191,411
INVESTING ACTIVITIES:			
Construction Expenditures	(306,046)	(199,285)	(211,416)
Proceeds From Sales of Property and Other	1,182	159	19,296
Net Cost of Removal and Other	(8,434)	(7,500)	(24,373)
Net Cash Flows Used For Investing Activities	(313,298)	(206,626)	(216,493)
FINANCING ACTIVITIES:			
Capital Contributions from Parent Company	-	-	50,000
Issuance of Long-term Debt	124,588	74,788	227,236
Retirement of Cumulative Preferred Stock	-	(9,924)	(2,675)
Retirement of Long-term Debt	(175,000)	(136,166)	(116,688)
Change in Short-term Debt (net)	(191,495)	68,015	47,080
Change in Advances From Affiliates	300,204	(8,387)	-
Dividends Paid on Common Stock	(129,594)	(126,612)	(121,392)
Dividends Paid on Cumulative Preferred Stock	(1,443)	(1,938)	(2,257)
Net Cash Flows From (Used For) Financing Activities	(72,740)	(140,224)	81,304
Net Increase (Decrease) in Cash and Cash Equivalents	7,816	(58,130)	56,222
Cash and Cash Equivalents January 1	5,847	63,977	7,755
Cash and Cash Equivalents December 31	$ 13,663	$ 5,847	$ 63,977

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $117,283,000, $124,579,000 and $125,900,000 and for income taxes was $56,981,000, $63,682,000 and $55,157,000 in 2001, 2000 and 1999, respectively. Noncash acquisitions under capital leases were $2,510,000, $14,116,000 and $13,868,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2001	2000 (in thousands)	1999
Retained Earnings January 1	$120,584	$175,854	$179,461
Net Income	161,818	73,844	120,492
	282,402	249,698	299,953
Deductions:			
Cash Dividends Declared:			
Common Stock	129,594	126,612	121,392
Cumulative Preferred Stock:			
4-1/2% Series	801	811	850
5.90% Series	278	307	425
5.92% Series	364	364	364
6.85% Series	-	289	579
Total Cash Dividends Declared	131,037	128,383	123,610
Capital Stock Expense	568	731	489
Total Deductions	131,605	129,114	124,099
Retained Earnings December 31	$150,797	$120,584	$175,854

See Notes to Financial Statements Beginning on Page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Capitalization

						December 31, 2001	December 31, 2000
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$1,126,701	$1,096,260
PREFERRED STOCK: No par value - authorized shares 8,000,000							
Series(a)	Call Price December 31, 2001 (b)	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001		
Not Subject to Mandatory Redemption:							
4-1/2%	$110	-	7,011	8,671	177,905	17,790	17,790
Subject to Mandatory Redemption:							
5.90% (c)	(d)	-	10,000	20,000	47,100	4,710	4,710
5.92% (c)	(d)	-	-	-	61,500	6,150	6,150
						10,860	10,860
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						639,365	739,015
Installment Purchase Contracts						234,904	234,782
Senior Unsecured Notes						518,247	468,113
Junior Debentures						161,507	161,367
Other Long-term Debt						2,536	2,541
Less Portion Due Within One Year						(80,007)	(175,006)
Long-term Debt Excluding Portion Due Within One Year						1,476,552	1,430,812
TOTAL CAPITALIZATION						$2,631,903	$2,555,722

(a) The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of the due date. APCo redeemed 84,500 shares of the 6.85% series of preferred stock subject to mandatory redemption in 2000.
(b) The cumulative preferred stock is callable at the price indicated plus accrued dividends. The involuntary liquidation preference is $100 per share. The aggregate involuntary liquidation price for all shares of cumulative preferred stock may not exceed $300 million. The unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance.
(c) Commencing in 2003 and continuing through 2007 APCo may redeem at $100 per share 25,000 shares of the 5.90% series and 30,000 shares of the 5.92% series outstanding under sinking fund provisions at its option and all outstanding shares must be reacquired in 2008. Shares previously redeemed may be applied to meet the sinking fund requirement.
(d) Not callable until after 2002.

See Notes to Financial Statements beginning on page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
6-3/8	2001 - March 1	$ -	$100,000
7.38	2002 - August 15	50,000	50,000
7.40	2002 - December 1	30,000	30,000
6.65	2003 - May 1	40,000	40,000
6.85	2003 - June 1	30,000	30,000
6.00	2003 - November 1	30,000	30,000
7.70	2004 - September 1	21,000	21,000
7.85	2004 - November 1	50,000	50,000
8.00	2005 - May 1	50,000	50,000
6.89	2005 - June 22	30,000	30,000
6.80	2006 - March 1	100,000	100,000
8.50	2022 - December 1	70,000	70,000
7.80	2023 - May 1	30,237	30,237
7.15	2023 - November 1	20,000	20,000
7.125	2024 - May 1	45,000	45,000
8.00	2025 - June 1	45,000	45,000
Unamortized Discount		(1,872)	(2,222)
Total		$639,365	$739,015

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
Industrial Development Authority of Russell County, Virginia:			
7.70	2007 - November 1	$ 17,500	$ 17,500
5.00	2021 - November 1	19,500	19,500
Putnam County, West Virginia:			
5.45	2019 - June 1	40,000	40,000
6.60	2019 - July 1	30,000	30,000
Mason County, West Virginia:			
7-7/8	2013 - November 1	10,000	10,000
6.85	2022 - June 1	40,000	40,000
6.60	2022 - October 1	50,000	50,000
6.05	2024 - December 1	30,000	30,000
Unamortized Discount		(2,096)	(2,218)
Total		$234,904	$234,782

Under the terms of the installment purchase contracts, APCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
(a)	2001 - June 27	$ -	$ 75,000
(a)	2003 - August 20	125,000	-
7.45	2004 - November 1	50,000	50,000
6.60	2009 - May 1	150,000	150,000
7.20	2038 - March 31	100,000	100,000
7.30	2038 - June 30	100,000	100,000
Unamortized Discount		(6,753)	(6,887)
Total		$518,247	$468,113

(a) A floating interest rate is determined monthly. The rate on December 31, 2001 and 2000 was 2.839% and 6.95%, respectively.

Junior debentures outstanding were as follows:

	December 31, 2001	December 31, 2000
	(in thousands)	
8-1/4% Series A due 2026 - September 30	$ 75,000	$ 75,000
8% Series B due 2027 - March 31	90,000	90,000
Unamortized Discount	(3,493)	(3,633)
Total	$161,507	$161,367

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$ 80,007
2003	225,007
2004	121,008
2005	80,010
2006	100,011
Later Years	964,730
Total Principal Amount	1,570,773
Unamortized Discount	(14,214)
Total	$1,556,559

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

Index to Notes to Consolidated Financial Statements

The notes to APCo's financial statements are combined with the notes to financial statements for AEP and its other subsidiary registrants. Listed below are the combined notes that apply to APCo. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Appalachian Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Appalachian Power Company and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and its subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

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CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	2001	2000	1999	1998	1997
	Year Ended December 31, (in thousands)				
INCOME STATEMENTS DATA:					
Operating Revenues	$3,321,727	$2,349,503	$1,482,475	$1,406,117	$1,376,282
Operating Expenses	3,025,996	2,042,405	1,188,490	1,123,330	1,124,963
Operating Income	295,731	307,098	293,985	282,787	251,319
Nonoperating Income (Loss)	5,324	7,235	8,113	760	8,277
Interest Charges	116,268	124,766	114,380	122,036	131,173
Income Before Extraordinary Item	184,787	189,567	187,718	161,511	128,423
Extraordinary Loss	(2,509)	-	(5,517)	-	-
Net Income	182,278	189,567	182,201	161,511	128,423
Preferred Stock Dividend Requirements	242	241	6,931	6,901	9,523
Gain (Loss) on Reacquired Preferred Stock	-	-	(2,763)	-	2,402
Earnings Applicable To Common Stock	$ 182,036	$ 189,326	$ 172,507	$ 154,610	$ 121,302

	2001	2000	1999	1998	1997
	Year Ended December 31, (in thousands)				
BALANCE SHEETS DATA:					
Electric Utility Plant	$5,769,707	$5,592,444	$5,511,894	$5,336,191	$5,215,749
Accumulated Depreciation And Amortization	2,446,027	2,297,189	2,247,225	2,072,686	1,891,406
Net Electric Utility Plant	$3,323,680	$3,295,255	$3,264,669	$3,263,505	$3,324,343
Total Assets	$5,115,986	$5,467,684	$4,847,850	$4,735,476	$4,897,380
Common Stock and Paid-in Capital	$ 573,888	$ 573,888	$ 573,888	$ 573,888	$ 573,888
Retained Earnings	826,197	792,219	758,894	734,387	828,777
Total Common Shareholder's Equity	$1,400,085	$1,366,107	$1,332,782	$1,308,275	$1,402,665
Preferred Stock	$ 5,967	$ 5,967	$ 5,967	$ 163,204	$ 163,204
CPL - Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Dentures of CPL	$ 136,250	$ 148,500	$ 150,000	$ 150,000	$ 150,000
Long-term Debt (a)	$1,253,768	$1,454,559	$1,454,541	$1,350,706	$1,414,335
Total Capitalization And Liabilities	$5,115,986	$5,467,684	$4,847,850	$4,735,476	$4,897,380

(a) Including portion due within one year.

CPL is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to approximately 689,000 retail customers in southern Texas. CPL also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Wholesale power marketing and trading activities are conducted on CPL's behalf by AEP. CPL shares in the revenues and costs of the AEP Power Pool's wholesale sales to and forward trades with other utility systems and power marketers.

Critical Accounting Policies - Revenue Recognition

Regulatory Accounting - As a result of our cost-based rate-regulated transmission and distribution operations, our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities – We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to CPL. Trading activities allocated to CPL involve the purchase and sale of energy under physical forward contracts at fixed and variable prices. Although trading contracts are generally short-term, there are also long-term trading contracts. We recognize revenues from trading activities generally based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts as revenues prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt of electricity and net settle in cash, the unrealized gain or loss is reversed out of revenues and the actual realized cash gain or loss is recognized in revenues for a sale or in purchased power expense for a purchase. Therefore, over the trading contract's term an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

Our trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity in July. At the end of each month until the contract settles in July, we would record our share of any difference between the contract price and the market price as an unrealized gain or loss in revenues. In July when the contract settles, we would realize our share of the gain or loss in cash and reverse to revenues the previously recorded unrealized gain or loss. Prior to settlement, the change in the fair value of physical forward sale and purchase contracts is included in revenues on a net basis. Upon settlement of a forward trading contract, the amount realized is included in revenues for a sales contract and realized costs are included in purchased power expense for a purchase contract with the prior change in unrealized fair value reversed in revenues.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity in July. If we do nothing else with these contracts until settlement in July and if the volumes, delivery point, schedule and other key terms match then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on results of operations but will have an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on revenues from recording additional changes in fair values using mark-to-market accounting.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing CPL to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

<u>Results of Operations</u>

Although operating revenues increased, income before extraordinary item decreased $5 million or 3% in 2001. The decrease was primarily a result of a settlement of Texas municipal franchise fees (see Note 8) and increased maintenance expense.

Income before extraordinary item increased $2 million or 1% in 2000 primarily as a result of increased retail energy sales, the post merger sharing of AEP's power marketing and trading operations which increased wholesale sales to neighboring utilities and power marketers and the effect of an unfavorable adjustment in 1999 as a result of FERC's approval of a transmission coordination agreement. These items were offset in part by a rise in interest expense.

Operating Revenues Rise

Operating revenues increased 41% in 2001 and 58% in 2000. Both increases are primarily due to an increase in wholesale marketing and trading activities.

The following analyzes the changes in operating revenues:

	Increase (Decrease) From Previous Year (dollars in millions)			
	2001		2000	
	Amount	%	Amount	%
Retail*	$ 4.2	-	$193.6	23
Wholesale Marketing and Trading	924.6	127	651.4	859
Unrealized MTM	28.1	343	(8.2)	-
Other	16.9	27	(8.9)	(12)
Total Marketing and Trading	973.8	53	827.9	82
Energy Delivery*	(5.6)	(1)	29.1	6
Sales to AEP Affiliates	4.0	11	10.0	36
Total Revenues	$972.2	41	$867.0	58

*Reflects the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

Retail operating revenues increased 23% in 2000 due to an increase in fuel and purchased power related revenues, reflecting rising prices for natural gas and purchased power, and an increase in weather-related demand for electricity. Through December 31, 2001 the Texas fuel and purchased power clause recovery mechanism provides for the accrual of revenues to recover fuel and purchased power cost increases until reviewed and approved for billing to customers by the PUCT. As a result increases in fuel and purchased power expenses and related accrued revenues do not adversely affect results of opertions.

The significant increase in wholesale marketing and trading revenues in 2001 is attributable to a full year of participation in AEP's power marketing and trading operations. Trading involves the purchase and sale of substantial amounts of electricity with non-affiliated parties.

The significant increase in wholesale marketing and trading revenues in 2000 is primarily attributable to CPL's initial participation in AEP's power marketing and trading operations. Since becoming a subsidiary of AEP as a result of the merger in June 2000, CPL shares in AEP's power marketing and trading transactions with other non-affiliated entities.

Operating Expenses Increase

Total operating expenses increased 48% in 2001 and 72% in 2000. The 2001 increase is due primarily to purchased power, taxes and maintenance, partially offset by a decrease in fuel costs. The 2000 increase was primarily due to increased costs of fuel and purchased power and a rise in other operation expense. The changes in the components of operating expenses were:

	Increase (Decrease) From Previous Year (dollars in millions)			
	2001		2000	
	Amount	%	Amount	%
Fuel	$(58.8)	(11)	$146.9	36
Marketing And Trading Purchases	987.6	137	671.6	N.M.
AEP Affiliate Purchases	26.0	80	15.9	95
Other Operation	1.7	1	28.4	10
Maintenance	10.7	18	(9.6)	(14)
Depreciation And Amortization	(10.4)	(6)	1.1	1
Taxes Other Than Income Taxes	14.4	19	2.7	4
Income Taxes	12.4	12	(3.1)	(3)
Total	$983.6	48	$853.9	72

N.M. = Not Meaningful

The decrease in fuel expense in 2001 was primarily due to a reduction in the average cost of fuel primarily from a decline in natural gas prices. CPL uses natural gas as fuel for 71% of its generating capacity. The nature of the natural gas market is such that both long-term and short-term contracts are generally based on the current spot market price. Changes in natural gas prices affect CPL's fuel expense, however, as explained above, they generally do not impact results of operations.

Fuel expense increased in 2000 primarily due to a rise in the average cost of fuel reflecting large increases in natural gas prices.

The significant increase in electricity marketing and trading purchased power in 2001 and 2000 was attributable to our participation in AEP's power marketing and trading operation.

Purchased power from AEP affiliates increased largely due to higher natural gas prices. Although gas prices declined in 2001, they were higher during the first half of 2001 when CPL was making most of its purchases. Throughout 2000 gas prices were increasing accounting for the rise in AEP affiliated purchased power expense.

Other operation expense increased in 2000 due primarily to an increase in transmission expenses that resulted from new prices for the ERCOT transmission grid. Each year ERCOT establishes new rates to allocate the costs of the Texas transmission system to Texas electric utilities. In addition to higher transmission expenses, other operation expense increased due to higher administrative expenses resulting from the Company's share of STP voluntary severance expenses and Texas regulatory expenses.

The principal cause of the increase in maintenance expense in 2001 was two refueling outages at the STP verses one in 2000. Also contributing to the increase in maintenance expense were scheduled major overhauls of four power plants.

Maintenance expense decreased in 2000 as a result of a 10-year service inspection and refueling of STP Units 1 and 2 performed in 1999.

Taxes other than income taxes increased in 2001 due primarily to an increase in franchise related taxes, including a settlement of disputed franchise fees (see Note 8), and a new tax levied by the PUCT, the Texas System Benefit Fund Assessment.

The increase in income tax expense was primarily due to adjustments associated with prior year tax returns and an increase in pre-tax book income.

Interest Charges

The decrease in interest charges in 2001 was attributable to lower average interest rates associated with short-term and long-term debt.

The increase in interest charges in 2000 can be attributed to higher average interest rates on debt.

Extraordinary Loss

The extraordinary loss on reacquired debt recorded in 2001 was the result of reacquisition of installment purchase contracts for Matagorda County, Navigation District, Texas.

Preferred Stock Dividends

Preferred stock dividends decreased in 2000 as a result of the redemption of preferred stock in the fourth quarter of 1999, which resulted in a loss on reacquired preferred stock recorded in 1999.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

Consolidated Statements of Income

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
OPERATING REVENUES:			
Electricity Marketing and Trading	$2,806,783	$1,832,937	$1,005,037
Energy Delivery	473,182	478,814	449,667
Sales to AEP Affiliates	41,762	37,752	27,771
TOTAL REVENUES	3,321,727	2,349,503	1,482,475
OPERATING EXPENSES:			
Fuel	492,057	550,903	403,989
Purchased Power:			
Electricity Marketing and Trading	1,710,706	723,122	51,482
AEP Affiliates	58,641	32,591	16,673
Other Operation	321,227	319,539	291,131
Maintenance	71,212	60,528	70,165
Depreciation and Amortization	168,341	178,786	177,702
Taxes Other Than Income Taxes	90,916	76,477	73,823
Income Taxes	112,896	100,459	103,525
Total Operating Expenses	3,025,996	2,042,405	1,188,490
OPERATING INCOME	295,731	307,098	293,985
NONOPERATING INCOME	22,552	5,830	6,420
NONOPERATING EXPENSES	17,626	3,668	3,593
NONOPERATING INCOME TAX EXPENSE (CREDIT)	(398)	(5,073)	(5,286)
INTEREST CHARGES	116,268	124,766	114,380
INCOME BEFORE EXTRAORDINARY ITEM	184,787	189,567	187,718
EXTRAORDINARY LOSS ON REACQUIRED DEBT (Inclusive of Tax $1,351,000 and $2,971,000 for 2001 and 1999, respectively)	(2,509)	-	(5,517)
NET INCOME	182,278	189,567	182,201
PREFERRED STOCK DIVIDEND REQUIREMENTS	242	241	6,931
LOSS ON REACQUIRED PREFERRED STOCK	-	-	(2,763)
EARNINGS APPLICABLE TO COMMON STOCK	$ 182,036	$ 189,326	$ 172,507

See Notes to Financial Statements Beginning on Page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$3,169,421	$3,175,867
Transmission	663,655	581,931
Distribution	1,279,037	1,221,750
General	241,137	237,764
Construction Work in Progress	169,075	138,273
Nuclear Fuel	247,382	236,859
Total Electric Utility Plant	5,769,707	5,592,444
Accumulated Depreciation and Amortization	2,446,027	2,297,189
NET ELECTRIC UTILITY PLANT	3,323,680	3,295,255
OTHER PROPERTY AND INVESTMENTS	47,950	44,225
LONG-TERM ENERGY TRADING CONTRACTS	72,502	65,786
CURRENT ASSETS:		
Cash and Cash Equivalents	10,909	14,253
Accounts Receivable:		
General	38,459	67,787
Affiliated Companies	6,249	31,272
Allowance for Uncollectible Accounts	(186)	(1,675)
Fuel Inventory - at LIFO cost	38,690	22,842
Materials and Supplies - at average cost	55,475	53,108
Under-recovered Fuel Costs	-	127,295
Energy Trading Contracts	212,979	476,839
Prepayments	2,742	3,014
TOTAL CURRENT ASSETS	365,317	794,735
REGULATORY ASSETS	226,806	202,440
REGULATORY ASSETS DESIGNATED FOR SECURITIZATION	959,294	953,249
NUCLEAR DECOMMISSIONING TRUST FUND	98,600	93,592
DEFERRED CHARGES	21,837	18,402
TOTAL	$5,115,986	$5,467,684

See Notes to Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $25 Par Value:		
Authorized - 12,000,000 Shares		
Outstanding - 6,755,535 Shares	$ 168,888	$ 168,888
Paid-in Capital	405,000	405,000
Retained Earnings	826,197	792,219
Total Common Shareholder's Equity	1,400,085	1,366,107
Preferred Stock	5,967	5,967
CPL - Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of CPL	136,250	148,500
Long-term Debt	988,768	1,254,559
TOTAL CAPITALIZATION	2,531,070	2,775,133
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	265,000	200,000
Advances from Affiliates	354,277	269,712
Accounts Payable - General	65,307	128,957
Accounts Payable - Affiliated Companies	49,301	40,962
Over-Recovered Fuel	57,762	-
Taxes Accrued	83,512	55,526
Interest Accrued	18,524	26,217
Energy Trading Contracts	219,486	485,521
Other	49,512	40,630
Total CURRENT LIABILITIES	1,162,681	1,247,525
DEFERRED INCOME TAXES	1,163,795	1,242,797
DEFERRED INVESTMENT TAX CREDITS	122,892	128,100
LONG-TERM ENERGY TRADING CONTRACTS	62,138	65,295
DEFERRED CREDITS	73,410	8,834
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$5,115,986	$5,467,684

See Notes to Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31, 2001	2000 (in thousands)	1999
OPERATING ACTIVITIES:			
Net Income	$ 182,278	$ 189,567	$ 182,201
Adjustments for Noncash Items:			
Depreciation and Amortization	168,341	178,786	177,702
Extraordinary Loss on Reacquired Debt	2,509	-	5,517
Deferred Income Taxes	(72,568)	16,263	19,938
Deferred Investment Tax Credits	(5,208)	(5,207)	(5,207)
Mark-to-Market of Energy Trading Contracts	(12,048)	8,191	-
Change in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	52,862	(32,902)	(13,426)
Fuel, Materials and Supplies	(18,215)	8,680	(4,476)
Interest Accrued	(7,693)	11,494	(12,313)
Fuel Recovery	185,057	(96,872)	(40,046)
Accounts Payable	(55,311)	45,873	(3,061)
Taxes Accrued	27,986	14,405	(5,734)
Transmission Coordination Agreement Settlement	-	15,519	(15,519)
Change in Other Assets	10,756	599	19,974
Change in Other Liabilities	11,174	12,233	(554)
Net Cash Flows From Operating Activities	469,920	366,629	304,996
INVESTING ACTIVITIES:			
Construction Expenditures	(193,732)	(199,484)	(210,823)
Proceeds From Sales of Property and Other	(354)	-	15,063
Net Cash Flows Used For Investing Activities	(194,086)	(199,484)	(195,760)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	260,162	149,248	358,887
Retirement of Preferred Stock	-	-	(160,001)
Retirement of Long-term Debt	(475,606)	(151,440)	(261,700)
Change in Advances from Affiliates (net)	84,565	(52,446)	161,860
Special Deposit for Reacquisition of Long-term Debt	-	50,000	(50,000)
Dividends Paid on Common Stock	(148,057)	(156,000)	(148,000)
Dividends Paid on Cumulative Preferred Stock	(242)	(249)	(7,835)
Net Cash Flows Used For Financing Activities	(279,178)	(160,887)	(106,789)
Net Increased (Decrease) in Cash and Cash Equivalents	(3,344)	6,258	2,447
Cash and Cash Equivalents January 1	14,253	7,995	5,548
Cash and Cash Equivalents December 31	$ 10,909	$ 14,253	$ 7,995

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts (including distributions on Trust Preferred Securities) was $109,835,000, $110,010,000 and $125,222,000 and for income taxes was $161,529,000, $48,141,000 and $78,393,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2001	2000 (in thousands)	1999
BEGINNING OF PERIOD	$792,219	$758,894	$734,387
NET INCOME	182,278	189,567	182,201
DEDUCTIONS:			
Cash Dividends Declared:			
Common Stock	148,057	156,000	148,000
Preferred Stock	242	241	6,931
Other	1	1	-
LOSS ON REACQUIRED PREFERRED STOCK	-	-	(2,763)
BALANCE AT END OF PERIOD	$826,197	$792,219	$758,894

See Notes to Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

Consolidated Statements of Capitalization

						December 31, 2001	December 31, 2000
						(in thousands)	
COMMON SHAREHOLDERS' EQUITY						$1,400,085	$1,366,107
PREFERRED STOCK - authorized shares 3,035,000 $100 par value							
Series	Call Price December 31, 2001	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001		
Not Subject to Mandatory Redemption:							
4.00%	$105.75	-	-	-	42,038	4,204	4,204
4.20%	103.75	-	-	-	17,476	1,748	1,748
Premium						15	15
Total Preferred Stock						5,967	5,967
TRUST PREFERRED SECURITIES:							
CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL, 8.00%, due April 30, 2037						136,250	148,500
LONG-TERM (See Schedule of Long-term Debt):							
First Mortgage Bonds						614,200	615,000
Installment Purchase Contracts						489,568	489,559
Senior Unsecured Notes						150,000	350,000
Less Portion Due Within One year						(265,000)	(200,000)
Long-term Debt Excluding Portion Due Within One Year						988,768	1,254,559
TOTAL CAPITALIZATION						$2,531,070	$2,775,133

See Notes to Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
7.25	2004 - October 1	$100,000	$100,000
7.50	2002 - December 1	115,000	115,000
6-7/8	2003 - February 1	49,200	50,000
7-1/8	2008 - February 1	75,000	75,000
7.50	2023 - April 1	75,000	75,000
6-5/8	2005 - July 1	200,000	200,000
Unamortized Discount		-	-
Total		$614,200	$615,000

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
Matagorda County Navigation District, Texas:			
6.00	2028 - July 1	$120,265	$120,265
6.10	2028 - July 1	-	100,635
6-1/8	2030 - May 1	60,000	60,000
4.90	2030 - May 1	-	111,700
4.95	2030 - May 1	-	50,000
3.75	2030(a) - May 1	111,700	-
4.00	2030(a) - May 1	50,000	-
4.55	2029(a) - Nov 1	100,635	-
Guadalupe-Blanco River Authority District, Texas:			
(b)	2015 - November 1	40,890	40,890
Red River Authority District, Texas:			
6.00	2020 - June 1	6,330	6,330
Unamortized Discount		(252)	(261)
Total		$489,568	$489,559

(a)Installment Purchase Contract provides for bonds to be tendered in 2003 for 3.75% and 4.00% series and in 2006 for 4.55% series. Therefore, these installment purchase contracts have been classified for payments in those years.
(b) A floating interest rate is determined monthly. The rate on December 31, 2001 was 1.9%.

Under the terms of the installment purchase contracts, CPL is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
	2001 - November 23	$ -	$200,000
(c)	2002 - February 22	150,000	150,000
Total		$150,000	$350,000

(c) A floating interest rate is determined monthly. The rate on December 31, 2001 and 2000 was 2.56% and 7.20%, respectively.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$ 265,000
2003	210,900
2004	100,000
2005	200,000
2006	100,635
Later Years	377,485
Total Principal Amount	1,254,020
Unamortized Discount	(252)
Total	$1,253,768

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

Index to Notes to Consolidated Financial Statements

The notes to CPL financial statements are combined with the notes to financial statements for AEP and its other subsidiary registrants. Listed below are the combined notes that apply to CPL. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of Central Power and Light Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Central Power and Light Company and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements of the Company for the year ended December 31, 1999, before the restatement described in Note 3 to the consolidated financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2001 and 2000 consolidated financial statements present fairly, in all material respects, the financial position of Central Power and Light Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 consolidated financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

Deloitte & Touche LLP
Columbus, Ohio
February 22, 2002

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COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31,				
	2001	2000	1999	1998	1997
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$4,299,863	$3,165,615	$2,631,739	$2,102,295	$1,139,604
Operating Expenses	4,047,686	2,969,738	2,408,949	1,890,084	944,477
Operating Income	252,177	195,877	222,790	212,211	195,127
Nonoperating Income (Loss)	7,738	5,153	2,709	(1,343)	3,137
Interest Charges	68,015	80,828	75,229	77,824	78,885
Income Before Extraordinary Item	191,900	120,202	150,270	133,044	119,379
Extraordinary Loss	(30,024)	(25,236)	-	-	-
Net Income	161,876	94,966	150,270	133,044	119,379
Preferred Stock Dividend Requirements	1,095	1,783	2,131	2,131	2,442
Earnings Applicable to Common Stock	$ 160,781	$ 93,183	$ 148,139	$ 130,913	$ 116,937

	Year Ended December 31,				
	2001	2000	1999	1998	1997
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$3,354,320	$3,266,794	$3,151,619	$3,053,565	$2,976,110
Accumulated Depreciation	1,377,032	1,299,697	1,210,994	1,134,348	1,074,588
Net Electric Utility Plant	$1,977,288	$1,967,097	$1,940,625	$1,919,217	$1,901,522
Total Assets	$3,105,868	$3,888,302	$2,809,990	$2,681,690	$2,613,860
Common Stock and Paid-in Capital	$ 615,395	$ 614,380	$ 613,899	$ 613,518	$ 613,138
Retained Earnings	176,103	99,069	246,584	186,441	138,172
Total Common Shareholder's Equity	$ 791,498	$ 713,449	$ 860,483	$ 799,959	$ 751,310
Cumulative Preferred Stock - Subject to Mandatory Redemption (a)	$ 10,000	$ 15,000	$ 25,000	$ 25,000	$ 25,000
Long-term Debt (a)	$ 791,848	$ 899,615	$ 924,545	$ 959,786	$ 969,600
Obligations Under Capital Leases (a)	$ 34,887	$ 42,932	$ 40,270	$ 42,362	$ 38,587
Total Capitalization and Liabilities	$3,105,868	$3,888,302	$2,809,990	$2,681,690	$2,613,860

(a) Including portion due within one year.

Columbus Southern Power Company is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 678,000 retail customers in central and southern Ohio. CSPCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers including power trading transactions. CSPCo also sells wholesale power to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among the Pool members based on their relative peak demands and generating reserves through the payment of capacity charges and receipt of capacity credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing AEP Power Pool revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of AEP Power Pool revenues and costs.

Critical Accounting Policies – Revenue Recognition

Regulatory Accounting - As a result of our cost-based rate-regulated transmission and distribution operations, our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities – We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to CSPCo as a member of the AEP Power Pool. Trading activities involve the purchase and sale of energy under physical forward contracts at fixed and variable prices and buying and selling financial energy contracts which includes exchange traded futures and options and over-the-counter options and swaps. Although trading contracts are generally short-term, there are also long-term trading contracts. We recognize revenues from trading activities generally based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt and net settle in cash, the unrealized gain or loss is reversed and the actual realized cash gain or loss is recognized. Therefore, over the trading contract's term an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

The majority of our trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity in July. At the end of each month until the contract settles in July, we would record our share of any difference between the contract price and the market price as an unrealized gain or loss. In July when the contract settles, we would realize our share of the gain or loss in cash and reverse the previously recorded unrealized gain or loss.

Depending on whether the delivery point for the electricity is in AEP's traditional marketing area or not determines where the contract is reported on CSPCo's income statement. AEP's traditional marketing area is up to two transmission systems from the AEP service territory. Physical forward trading sale contracts with delivery points in AEP's traditional marketing area are included in revenues when the contracts settle. Physical forward trading purchase contracts with delivery points in AEP's traditional marketing area are included in purchased power expense when they settle. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in AEP's traditional marketing area are included in revenues on a net basis. Physical forward sales contracts for delivery outside of AEP's traditional marketing area are included in nonoperating income when the contract settles. Physical forward purchase contracts for delivery outside of AEP's traditional marketing area are included in nonoperating expenses when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of AEP's traditional marketing area are included in nonoperating income on a net basis.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity in July. If we do nothing else with these contracts until settlement in July and if the volumes, delivery point, schedule and other key terms match then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on results of operations but will have an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on results of operations from recording additional changes in fair values using mark-to-market accounting.

Trading of electricity options, futures and swaps, represents financial transactions with unrealized gains and losses from changes in fair values reported net in nonoperating income until the contracts settle. When these financial contracts settle, we record our share of the net proceeds in nonoperating income and reverse to nonoperating income the prior unrealized gain or loss.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing CSPCo to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Results of Operations
Net Income Increases

Income before extraordinary item increased by $72 million or 60% in 2001 primarily due to the effect of a court decision related to a corporate owned life insurance (COLI) program recorded in 2000. In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including CSPCo, in a suit over the deductibility of interest claimed in AEP's consolidated tax return related to COLI. In 1998 and 1999 CSPCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. Also contributing to the increase in net income in 2001 was growth in and strong performance by the wholesale business in the first half of 2001 offset in part by the effect of extremely mild weather in November and December combined with weak economic conditions which reduced retail energy sales.

Operating Revenues Increase

Operating revenues increased 36% in 2001 due to the significant increase in wholesale marketing and trading volume. Changes in the components of operating revenues were as follows:

	Increase (Decrease) From Previous Year (dollars in millions) Amount	%
Retail*	$ (65.1)	(10)
Wholesale Marketing and Trading	1,072.1	53
Unrealized MTM	23.1	N.M.
Other	0.8	2
Total Marketing and Trading	1,030.9	38
Energy Delivery*	85.2	21
Sales to AEP Affiliates	18.1	37
Total Revenues	$1,134.2	36

N.M. = Not Meaningful

*Reflects the allocation in 2000 of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

The significant increase in wholesale marketing and trading revenues was caused by a 46% volume increase in 2001. The maturing of the Intercontinental Exchange, the development of proprietary tools, and increased staffing of energy traders has resulted in an increase in the number of forward electricity purchase and sales contracts in AEP's traditional marketing area.

Operating Expenses Rise

Operating expenses increased by 36% in 2001 due primarily to a significant increase in purchased power expense. Changes in the components of operating expenses were:

	Increase (Decrease) From Previous Year (dollars in millions) Amount	%
Fuel	$ (14.0)	(7)
Marketing and Trading Purchases	1,089.5	58
AEP Affiliate Purchases	4.4	2
Other Operation Expense	(0.4)	-
Maintenance Expense	(7.2)	(10)
Depreciation and Amortization	27.7	28
Taxes Other Than Income Taxes	(11.7)	(10)
Income Taxes	(10.3)	(9)
Total	$1,078.0	36

Fuel costs decreased by $14 million due to a 12.5% decrease in generation partially offset by increased coal prices of 6.3%

The increase in marketing and trading purchases is reflective of the increase in trading volume.

Reversal of a quality of service regulatory liability accrual and reduced maintenance of overhead distribution lines accounted for the decease in maintenance expense.

Depreciation and amortization expense increased significantly due to amortization of transition regulatory assets which began in January 2001. With the implementation of customer choice in Ohio on January 1, 2001, the PUCO approved the Company's plan for recovery of generation-related regulatory assets through frozen transition rates. Concurrent with the start of the transition period, we began amortization of the transition regulatory assets. Depreciation expense also increased due to additional plant investment.

The decrease in taxes other than income taxes in 2001 is due to a decrease in property tax rates on generation property partially offset by a new state excise tax.

The decrease in income tax expense was primarily due to an unfavorable ruling in AEP's suit against the government over interest deductions claimed relating to AEP's COLI program which was recorded in 2000 offset in part by an increase in pre-tax income.

Nonoperating Income and Nonoperating Expense

The increase in nonoperating income and nonoperating expense in 2001 was due to a significant increase in the wholesale business trading transactions outside of AEP's traditional marketing area.

Interest Charges Decrease

Interest charges for 2001 decreased as a result of the recognition in 2000 of deferred interest payments to the IRS related to the COLI disallowances as well as reduced debt in 2001.

Extraordinary Loss

In 2001 we recorded an extraordinary loss of $30 million net of tax to write-off prepaid Ohio excise taxes stranded by Ohio deregulation (see Note 2, "Extraordinary Items and Cumulative Effect").

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Income

	Year Ended December 31,		
	2001	2000 (in thousands)	1999
OPERATING REVENUES:			
Electricity Marketing and Trading	$3,749,133	$2,718,204	$2,222,741
Energy Delivery	483,219	398,046	389,280
Sales to AEP Affiliates	67,511	49,365	19,718
Total Operating Revenues	4,299,863	3,165,615	2,631,739
OPERATING EXPENSES:			
Fuel	175,153	189,155	185,511
Purchased Power:			
Electricity Marketing and Trading	2,958,656	1,869,150	1,467,628
AEP Affiliates	292,199	287,750	199,574
Other Operation	221,342	221,775	190,614
Maintenance	62,454	69,676	65,229
Depreciation and Amortization	127,364	99,640	94,532
Taxes Other Than Income Taxes	111,481	123,223	120,146
Income Taxes	99,037	109,369	85,715
TOTAL OPERATING EXPENSES	4,047,686	2,969,738	2,408,949
OPERATING INCOME	252,177	195,877	222,790
NONOPERATING INCOME	1,334,302	780,159	410,226
NONOPERATING EXPENSES	1,322,641	767,649	410,457
NONOPERATING INCOME TAX EXPENSE (CREDIT)	3,923	7,357	(2,940)
INTEREST CHARGES	68,015	80,828	75,229
INCOME BEFORE EXTRAORDINARY ITEM	191,900	120,202	150,270
EXTRAORDINARY LOSS - DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION - Net of tax (Note 2)	(30,024)	(25,236)	-
NET INCOME	161,876	94,966	150,270
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,095	1,783	2,131
EARNINGS APPLICABLE TO COMMON STOCK	$ 160,781	$ 93,183	$ 148,139

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2001	2000 (in thousands)	1999
Retained Earnings January 1	$ 99,069	$246,584	$186,441
Net Income	161,876	94,966	150,270
	260,945	341,550	336,711
Deductions:			
Cash Dividends Declared:			
Common Stock	82,952	240,600	87,996
Cumulative Preferred Stock - 7% Series	875	1,400	1,750
Total Cash Dividends Declared	83,827	242,000	89,746
Capital Stock Expense	1,015	481	381
Total Deductions	84,842	242,481	90,127
Retained Earnings December 31	$176,103	$ 99,069	$246,584

See Notes to Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$1,574,506	$1,564,254
Transmission	401,405	360,302
Distribution	1,159,105	1,096,365
General	146,732	156,534
Construction Work in Progress	72,572	89,339
Total Electric Utility Plant	3,354,320	3,266,794
Accumulated Depreciation	1,377,032	1,299,697
NET ELECTRIC UTILITY PLANT	1,977,288	1,967,097
OTHER PROPERTY AND INVESTMENTS	40,369	39,848
LONG-TERM ENERGY TRADING CONTRACTS	193,915	171,820
CURRENT ASSETS:		
Cash and Cash Equivalents	12,358	11,600
Accounts Receivable:		
Customers	41,770	73,711
Affiliated Companies	63,470	49,591
Miscellaneous	16,968	18,807
Allowance for Uncollectible Accounts	(745)	(659)
Fuel - at average cost	20,019	13,126
Materials and Supplies - at average cost	38,984	38,097
Accrued Utility Revenues	7,087	9,638
Energy Trading Contracts	347,198	1,079,704
Prepayments	28,733	46,735
TOTAL CURRENT ASSETS	575,842	1,340,350
REGULATORY ASSETS	262,267	291,553
DEFERRED CHARGES	56,187	77,634
TOTAL	$3,105,868	$3,888,302

See Notes to Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 24,000,000 Shares		
Outstanding - 16,410,426 Shares	$ 41,026	$ 41,026
Paid-in Capital	574,369	573,354
Retained Earnings	176,103	99,069
Total Common Shareholder's Equity	791,498	713,449
Cumulative Preferred Stock - Subject to Mandatory Redemption	10,000	15,000
Long-term Debt	571,348	899,615
TOTAL CAPITALIZATION	1,372,846	1,628,064
OTHER NONCURRENT LIABILITIES	36,715	47,584
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	220,500	-
Advances from Affiliates	181,384	88,732
Accounts Payable - General	62,393	89,846
Accounts Payable - Affiliated Companies	83,697	72,493
Taxes Accrued	116,364	162,904
Interest Accrued	10,907	13,369
Energy Trading Contracts	334,958	1,109,682
Other	34,600	60,701
TOTAL CURRENT LIABILITIES	1,044,803	1,597,727
DEFERRED INCOME TAXES	443,722	422,759
DEFERRED INVESTMENT TAX CREDITS	37,176	41,234
LONG-TERM ENERGY TRADING CONTRACTS	157,706	138,073
DEFERRED CREDITS	12,900	12,861
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$3,105,868	$3,888,302

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	2001	2000	1999
	Year Ended December 31, (in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 161,876	$ 94,966	$ 150,270
Adjustments for Noncash Items:			
Depreciation and Amortization	128,500	100,182	94,962
Deferred Federal Income Taxes	24,108	(4,063)	10,481
Deferred Investment Tax Credits	(4,058)	(3,482)	(3,994)
Deferred Fuel Costs (net)	-	5,352	8,889
Mark to Market of Energy Trading Contracts	(44,680)	(3,393)	(2,369)
Extraordinary Loss	30,024	25,236	-
Change in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	19,987	(29,737)	5,166
Fuel, Materials and Supplies	(7,780)	11,957	(7,777)
Accrued Utility Revenues	2,551	38,479	(7,990)
Accounts Payable	(16,249)	81,284	9,292
Disputed Tax and Interest Related to COLI	-	39,483	(2,240)
Change in Other Assets	(42,066)	(121,115)	(14,898)
Change in Other Liabilities	(18,769)	132,441	3,388
Net Cash Flows From Operating Activities	233,444	367,590	243,180
INVESTING ACTIVITIES:			
Construction Expenditures	(132,532)	(127,987)	(115,321)
Proceeds From Sales and Leaseback Transactions and Other	10,841	1,560	1,858
Net Cash Flows Used For Investing Activities	(121,691)	(126,427)	(113,463)
FINANCING ACTIVITIES:			
Change in Advances from Affiliates (net)	92,652	88,732	-
Issuance of Affiliated Long-term Debt	200,000	-	-
Retirement of Preferred Stock	(5,000)	(10,000)	-
Retirement of Long-term Debt	(314,733)	(25,274)	(35,523)
Change in Short-term Debt (net)	-	(45,500)	(7,000)
Dividends Paid on Common Stock	(82,952)	(240,600)	(87,996)
Dividends Paid on Cumulative Preferred Stock	(962)	(1,575)	(1,750)
Net Cash Flows Used For Financing Activities	(110,995)	(234,217)	(132,269)
Net Increase (Decrease) in Cash and Cash Equivalents	758	6,946	(2,552)
Cash and Cash Equivalents January 1	11,600	4,654	7,206
Cash and Cash Equivalents December 31	$ 12,358	$ 11,600	$ 4,654

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $68,596,000, $68,506,000 and $72,007,000 and for income taxes was $80,485,000, $81,109,000 and $71,809,000 in 2001, 2000 and 1999, respectively. Noncash acquisitions under capital leases were $1,019,000, $10,777,000 and $6,855,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

							December 31, 2001	December 31, 2000
							(in thousands)	
COMMON SHAREHOLDER'S EQUITY							$ 791,498	$ 713,449
PREFERRED STOCK: $100 par value - authorized shares 2,500,000; $25 par value - authorized shares 7,000,000								
Series	Call Price December 31, 2001	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001			
Subject to Mandatory Redemption:								
7.00%	(a)	50,000	100,000	-	100,000		10,000	15,000
LONG-TERM DEBT (See Schedule of Long-term Debt):								
Notes - Affiliated							200,000	
First Mortgage Bonds							243,197	537,119
Installment Purchase Contracts							91,220	91,166
Senior Unsecured Notes							147,458	159,318
Junior Debentures							109,973	112,012
Less Portion Due Within One Years							(220,500)	-
Total Long-term Debt Excluding Portion Due Within One Year							571,348	899,615
TOTAL CAPITALIZATION							$1,372,846	$1,628,064

(a) A sinking fund requires the redemption of 50,000 shares at $100 a share on or before August 1 of each year. The Company has the right, on each sinking fund date, to redeem an additional 50,000 shares which the Company did in August 2000. The sinking fund provisions of the 7% series aggregate $5,000,000 in 2002 and 2003.

See Notes to Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
7.25	2002 - October 1	$ 14,000	$ 56,500
7.15	2002 - November 1	6,500	20,000
6.80	2003 - May 1	13,000	45,000
6.60	2003 - August 1	25,000	40,000
6.10	2003 - November 1	5,000	20,000
6.55	2004 - March 1	26,500	50,000
6.75	2004 - May 1	26,000	50,000
8.70	2022 - July 1	2,000	35,000
8.40	2022 - August 1	-	15,000
8.55	2022 - August 1	15,000	15,000
8.40	2022 - August 15	14,000	25,500
8.40	2022 - October 15	13,000	13,000
7.90	2023 - May 1	40,000	50,000
7.75	2023 - August 1	33,000	33,000
7.45	2024 - March 1	-	30,000
7.60	2024 - May 1	11,000	41,000
Unamortized Discount		(803)	(1,881)
Total		$243,197	$537,119

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by the Ohio Air Quality Development Authority:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
6-3/8	2020 - December 1	$48,550	$48,550
6-1/4	2020 - December 1	43,695	43,695
Unamortized Discount		(1,025)	(1,079)
Total		$91,220	$91,166

Under the terms of the installment purchase contracts, CSPCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at the Zimmer Plant.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
6.85	2005 - October 3	$ 36,000	$ 48,000
6.51	2008 - February 1	52,000	52,000
6.55	2008 - June 26	60,000	60,000
Unamortized Discount		(542)	(682)
Total		$147,458	$159,318

Notes payable to parent company were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
Variable	2002 - Sept 25	$200,000	$ -

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
8-3/8	2025 - Sept 30	$ 72,843	$ 75,000
7.92	2027 - March 31	40,000	40,000
Unamortized Discount		(2,870)	(2,988)
Total		$109,973	$112,012

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$220,500
2003	43,000
2004	52,500
2005	36,000
2006	-
Later Years	445,088
Total Principal Amount	797,088
Unamortized Discount	(5,240)
Total	$791,848

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

Index to Notes to Consolidated Financial Statements

The notes to CSPCo's financial statements are combined with the notes to financial statements for AEP and its other subsidiary registrants. Listed below are the combined notes that apply to CSPCo. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Columbus Southern Power Company and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and its subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP
Columbus, Ohio
February 22, 2002

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

Selected Consolidated Financial Data

	Year Ended December 31, 2001	2000	1999 (in thousands)	1998	1997
INCOME STATEMENTS DATA:					
Operating Revenues	$4,803,625	$3,542,084	$2,920,187	$2,435,646	$1,391,917
Operating Expenses	4,643,920	3,576,786	2,811,535	2,269,639	1,184,129
Operating Income (Loss)	159,705	(34,702)	108,652	166,007	207,788
Nonoperating Income (Loss)	9,730	9,933	4,530	(839)	4,415
Interest Charges	93,647	107,263	80,406	68,540	65,463
Net Income (Loss)	75,788	(132,032)	32,776	96,628	146,740
Preferred Stock Dividend Requirements	4,621	4,624	4,885	4,824	5,736
Earnings (Loss) Applicable to Common Stock	$ 71,167	$ (136,656)	$ 27,891	$ 91,804	$ 141,004

	December 31, 2001	2000	1999 (in thousands)	1998	1997
BALANCE SHEETS DATA:					
Electric Utility Plant	$4,923,721	$4,871,473	$4,770,027	$4,631,848	$4,514,497
Accumulated Depreciation and Amortization	2,436,972	2,280,521	2,194,397	2,081,355	1,973,937
Net Electric Utility Plant	$2,486,749	$2,590,952	$2,575,630	$2,550,493	$2,540,560
Total Assets	$4,817,008	$5,811,038	$4,576,696	$4,148,523	$3,967,798
Common Stock and Paid-in Capital	$ 789,800	$ 789,656	$ 789,323	$ 789,189	$ 789,056
Accumulated Other Comprehensive Income (Loss)	(3,835)	-	-	-	-
Retained Earnings	74,605	3,443	166,389	253,154	278,814
Total Common Shareholder's Equity	$ 860,570	$ 793,099	$ 955,712	$1,042,343	$1,067,870
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 8,736	$ 8,736	$ 9,248	$ 9,273	$ 9,435
Subject to Mandatory Redemption (a)	64,945	64,945	64,945	68,445	68,445
Total Cumulative Preferred Stock	$ 73,681	$ 73,681	$ 74,193	$ 77,718	$ 77,880
Long-term Debt (a)	$1,652,082	$1,388,939	$1,324,326	$1,175,789	$1,049,237
Obligations Under Capital Leases (a)	$ 61,933	$ 163,173	$ 187,965	$ 186,427	$ 195,227
Total Capitalization And Liabilities	$4,817,008	$5,811,038	$4,576,696	$4,148,523	$3,967,798

(a) Including portion due within one year.

I&M is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 567,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan. As a member of the AEP Power Pool, I&M shares the revenues and the costs of the AEP Power Pool's wholesale sales to neighboring utilities and power marketers including power trading transactions. I&M also sells wholesale power to municipalities and electric cooperatives.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is each company's member load ratio (MLR) which determines each company's percentage share of revenues and costs.

I&M is committed under unit power agreements to purchase all of AEGCo's 50% share of the 2,600 MW Rockport Plant capacity unless it is sold to other utilities. AEGCo is an affiliate that is not a member of the AEP Power Pool. A long-term unit power agreement with an unaffiliated utility expired at the end of 1999 for the sale of 455 MW of AEGCo's Rockport Plant capacity. An agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2004. Therefore, effective January 1, 2000, I&M began purchasing 910 MW of AEGCo's 50% share of Rockport Plant capacity.

Critical Accounting Policies – Revenue Recognition

Regulatory Accounting - As a cost-based rate-regulated electric public utility company, I&M's consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities - We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to I&M as a member of the AEP Power Pool. Trading activities involve the purchase and sale of energy under physical forward contracts at fixed and variable prices and buying and selling financial energy contracts which includes exchange traded futures and options and over-the-counter options and swaps. The majority of trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting physical contracts. Although trading contracts are generally short-term, there are also long-term trading contracts.

Accounting standards applicable to trading activities require that changes in the fair value of trading contacts be recognized in revenues prior to settlement and is commonly referred to as mark-to-market (MTM) accounting. Since I&M is a cost-based rate-regulated entity, changes in the fair value of physical forward sale and purchase contracts in AEP's traditional marketing area are deferred as regulatory liabilities (gains) or regulatory assets (losses). The deferral reflects the fact that power sales and purchases are included in regulated rates on a settlement basis. AEP's traditional marketing area is up to two transmission systems from the AEP service territory. The change in the fair value of physical forward sale and purchase contracts outside AEP's traditional marketing area is included in nonoperating income on a net basis.

Mark-to-market accounting represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt of electricity and net settle in cash, the unrealized gain or loss is reversed and the actual realized cash gain or loss is recognized in the income statement. Therefore, as the contract's market value changes over the contract's term an unrealized gain or loss is deferred for contracts with delivery points in AEP's traditional marketing area and for contracts with delivery points outside of AEP's traditional marketing area the unrealized gain or loss is recognized as nonoperating income. When the contract settles the total gain or loss is realized in cash and the impact on the income statement depends on whether the contract's delivery points are within or outside of AEP's traditional marketing area. For contracts with delivery points in AEP's traditional marketing area, the total gain or loss realized in cash is recognized in the income statement. Physical forward trading sale contracts with delivery points in AEP's traditional marketing area are included in revenues when the contracts settle. Physical forward trading purchase contracts with delivery points in AEP's traditional marketing area are included in purchased power expense when they settle. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in AEP's traditional marketing area are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contacts with delivery points outside of AEP's traditional marketing area only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized in the income statement. Physical forward sales contracts for delivery outside of AEP's traditional marketing area are included in nonoperating income when the contract settles. Physical forward purchase contracts for delivery outside of AEP's traditional marketing area are included in nonoperating expenses when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of AEP's traditional marketing area are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

Trading of electricity options, futures and swaps, represents financial transactions with unrealized gains and losses from changes in fair values reported net in non-operating income until the contracts settle. When these financial contracts settle, we record our share of the net proceeds in non-operating income and reverse to nonoperating income the prior unrealized gain or loss.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing I&M to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Results of Operations

During 2000 both of the Cook Plant nuclear units were successfully restarted after being shutdown in September 1997 due to questions regarding the operability of certain safety systems which arose during a NRC architect engineer design inspection. See discussion in Note 4 of the Notes to Financial Statements.

A reduction in other operation and maintenance expense in 2001 reflects the completion of restart work on the Cook Plant and was the primary reason for a $208 million increase in net income. As a result of the costs incurred in 2000 to restart the Cook Plant nuclear units and a disallowance of interest deductions for a corporate owned life insurance (COLI) program, net income declined $165 million in 2000. In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including I&M, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to COLI. In 1998 and 1999 I&M paid the disputed taxes and interest attributable to the COLI interest deductions for the taxable years 1991-98 and deferred them.

Operating Revenues Increase

Operating revenues increased 36% in 2001 and 21% in 2000 due to increased wholesale marketing and trading sales. The following analyzes the changes in operating revenues:

	Increase (Decrease) From Previous Year (dollars in millions)			
	2001		2000	
	Amount	%	Amount	%
Retail*	$ (2.3)	N.M.	$(88.6)	(12)
Marketing and Trading	1,210.7	52	564.0	32
Other	5.0	13	(13.0)	(26)
	1,213.4	40	462.4	18
Energy Delivery*	3.4	1	0.1	N.M.
Sales to AEP Affiliates	44.7	21	159.4	313
Total	$1,261.5	36	$621.9	21

N.M. = Not Meaningful

*Reflects the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

The increase in operating revenues in 2001 and 2000 is primarily due to an increase in wholesale marketing and trading activities. The maturing of the Intercontinental Exchange, the development of proprietary tools, and increased staffing of energy traders have resulted in an increase in the number of forward electricity purchase and sale contracts in AEP's traditional marketing area. A decline in retail revenues partly offset the increase in wholesale marketing and trading revenues. Retail revenues decreased in 2000 when the accrual of power supply recovery revenues ceased at the end of 1999 pursuant to Cook Plant settlement agreements. The accrued power supply recovery revenues are being amortized over a five-year period ending December 31, 2003.

I&M increased its sales to AEP affiliates in 2000 when additional electricity became available. The return to service of the Cook Plant units and purchasing more power from AEGCo due to the expiration of AEGCo's contract to sell power to an unaffiliated entity, increased the amount of power I&M could sell to its affiliates in the AEP Power Pool.

Operating Expenses Increase

Total operating expenses increased 30% in 2001 and 27% in 2000 primarily due to additional purchases of power for marketing and trading and due to the expiration of an AEGCo unit power agreement to sell part of its Rockport Plant generation to an unaffiliated utility. Also contributing to the increase in operating expenses in 2000 was the unfavorable COLI tax ruling and costs related to the extended Cook Plant outage and restart efforts. The changes in the components of operating expenses were:

	Increase (Decrease) From Previous Year (dollars in millions)			
	2001		2000	
	Amount	%	Amount	%
Fuel	$ 39.2	19	$ 25.5	14
Marketing and Trading Purchases	1,227.7	59	462.9	29
AEP Affiliate Purchases	(27.2)	(10)	65.1	32
Other Operation	(147.8)	(25)	137.5	30
Maintenance	(92.6)	(42)	84.5	62
Depreciation and Amortization	9.3	6	4.9	3
Taxes Other Than Income Taxes	4.9	8	(5.2)	(8)
Income Taxes	53.6	N.M.	(9.9)	(95)
Total	$1,067.1	30	$765.3	27

N.M. = Not Meaningful

The increase in fuel expense in 2001 and 2000 reflects an increase in nuclear generation as the Cook Plant units returned to service following the extended outage.

Electricity marketing and trading purchased power expense increased in 2001 and 2000 due to AEP's effort to grow its wholesale marketing and trading business. The decline in purchased power from AEP affiliates in 2001 reflects generation from the Cook Plant replacing purchases from the AEP Power Pool. Purchases from the AEP Power Pool declined 21% in 2001. As a result of the expiration of AEGCo's power sale contract with an unaffiliated utility on December 31, 1999, I&M was obligated to buy more of AEGCo's share of Rockport Plant power. Purchases from AEGCo increased 91% in 2000.

The decrease in other operation and maintenance expenses in 2001 was primarily due to the cessation of expenditures to prepare the Cook Plant nuclear units for restart with their return to service in 2000. Other operation and maintenance expenses increased in 2000 primarily due to expenditures to prepare the Cook Plant units for restart. In 1999 the IURC and MPSC approved settlement agreements which allowed the deferral of $200 million of Cook Plant restart costs in 1999 for amortization over five years from 1999 through 2003. As a result, other operation and maintenance expense in 1999 reflected a net deferral of $160 million. See discussion in Note 4 of the Notes to Financial Statements.

The increase in depreciation and amortization charges in 2001 reflects increased generation and distribution plant investments and amortization of I&M's share of deferred merger costs.

Taxes other than income taxes increased in 2001 due to higher real and personal property tax expense from the effect of a favorable accrual adjustment recorded in December 2000 to match estimated amounts with actual expenses. The decrease in taxes other than income tax in 2000 is primarily attributable to decreases in real and personal property taxes reflecting the favorable accrual adjustment and Indiana gross receipts taxes reflecting an unfavorable accrual adjustment related to the 1998 tax year recorded in 1999 for gross receipts tax.

The significant increase in income taxes attributable to operations in 2001 is due to an increase in pre-tax operating income. Income taxes attributable to operations decreased in 2000 due to a decrease in pre-tax operating income.

Nonoperating Income and Expenses Increase

The increases in nonoperating income and expenses in 2001 and 2000 is primarily due to increased volume of forward electricity trading transactions outside AEP's traditional marketing area. Nonoperating power trading revenues increased 70% in 2001 and 95% in 2000. Nonoperating power trading expenses increased 70% in 2001 and 93% in 2000.

Interest Charges

The decrease in 2001 interest charges reflects the recognition in 2000 of deferred interest payments to the IRS on disputed income taxes from the disallowance of tax deductions for COLI interest for the years 1991-1998. Interest charges increased in 2000 due to increased borrowings to support expenditures for the Cook Plant restart effort and the recognition of deferred interest payments to the IRS on the disputed taxes.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Income

	Year Ended December 31,		
	2001	2000 (in thousands)	1999
OPERATING REVENUES:			
Electricity Marketing and Trading	$4,234,176	$3,020,757	$2,558,338
Energy Delivery	314,410	311,019	310,880
Sales to AEP Affiliates	255,039	210,308	50,969
TOTAL OPERATING REVENUES	4,803,625	3,542,084	2,920,187
OPERATING EXPENSES:			
Fuel	250,098	210,870	185,419
Purchased Power:			
Electricity Marketing and Trading	3,293,255	2,065,509	1,602,658
AEP Affiliates	238,237	265,475	200,372
Other Operation	451,195	599,012	461,494
Maintenance	127,263	219,854	135,331
Depreciation and Amortization	164,230	154,920	149,988
Taxes Other Than Income Taxes	65,518	60,622	65,843
Income Taxes	54,124	524	10,430
TOTAL OPERATING EXPENSES	4,643,920	3,576,786	2,811,535
OPERATING INCOME (LOSS)	159,705	(34,702)	108,652
NONOPERATING INCOME	1,474,572	869,895	452,019
NONOPERATING EXPENSES	1,459,799	855,773	446,183
NONOPERATING INCOME TAX EXPENSE	5,043	4,189	1,306
INTEREST CHARGES	93,647	107,263	80,406
NET INCOME (LOSS)	75,788	(132,032)	32,776
PREFERRED STOCK DIVIDEND REQUIREMENTS	4,621	4,624	4,885
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ 71,167	$ (136,656)	$ 27,891

Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2001	2000 (in thousands)	1999
NET INCOME (LOSS)	$75,788	$(132,032)	$32,776
OTHER COMPREHENSIVE INCOME (LOSS)			
Cash Flows Interest Rate Hedge	(3,835)	-	-
COMPREHENSIVE INCOME (LOSS)	$71,953	$(132,032)	$32,776

See Notes to Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,758,160	$2,708,436
Transmission	957,336	945,709
Distribution	900,921	863,736
General (including nuclear fuel)	233,005	257,152
Construction Work in Progress	74,299	96,440
Total Electric Utility Plant	4,923,721	4,871,473
Accumulated Depreciation and Amortization	2,436,972	2,280,521
NET ELECTRIC UTILITY PLANT	2,486,749	2,590,952
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	834,109	778,720
LONG-TERM ENERGY TRADING CONTRACTS	215,544	194,554
OTHER PROPERTY AND INVESTMENTS	127,977	131,417
CURRENT ASSETS:		
Cash and Cash Equivalents	16,804	14,835
Advances to Affiliates	46,309	-
Accounts Receivable:		
Customers	60,864	106,832
Affiliated Companies	31,908	48,706
Miscellaneous	25,398	27,491
Allowance for Uncollectible Accounts	(741)	(759)
Fuel - at average cost	28,989	16,532
Materials and Supplies - at average cost	91,440	84,471
Energy Trading Contracts	399,195	1,222,925
Accrued Utility Revenues	2,072	-
Prepayments	6,497	6,066
TOTAL CURRENT ASSETS	708,735	1,527,099
REGULATORY ASSETS	408,927	552,140
DEFERRED CHARGES	34,967	36,156
TOTAL	$4,817,008	$5,811,038

See Notes to Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 2,500,000 Shares		
Outstanding - 1,400,000 Shares	$ 56,584	$ 56,584
Paid-in Capital	733,216	733,072
Accumulated Other Comprehensive Income (Loss)	(3,835)	-
Retained Earnings	74,605	3,443
Total Common Shareholder's Equity	860,570	793,099
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	8,736	8,736
Subject to Mandatory Redemption	64,945	64,945
Long-term Debt	1,312,082	1,298,939
TOTAL CAPITALIZATION	2,246,333	2,165,719
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	600,244	560,628
Other	87,025	108,600
TOTAL OTHER NONCURRENT LIABILITIES	687,269	669,228
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	340,000	90,000
Advances from Affiliates	-	253,582
Accounts Payable - General	90,817	119,472
Accounts Payable - Affiliated Companies	43,956	75,486
Taxes Accrued	69,761	68,416
Interest Accrued	20,691	21,639
Obligations Under Capital Leases	10,840	100,848
Energy Trading and Derivative Contracts	383,714	1,267,981
Other	72,435	97,070
TOTAL CURRENT LIABILITIES	1,032,214	2,094,494
DEFERRED INCOME TAXES	400,531	487,945
DEFERRED INVESTMENT TAX CREDITS	105,449	113,773
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	77,592	81,299
LONG-TERM ENERGY TRADING CONTRACTS	175,581	156,343
DEFERRED CREDITS	92,039	42,237
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$4,817,008	$5,811,038

See Notes to Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2001	December 31, 2000
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$ 860,570	$ 793,099
PREFERRED STOCK:							
$100 Par Value - Authorized 2,250,000 shares							
$25 Par Value - Authorized 11,200,000 shares							
Series	Call Price December 31, 2001	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001		
Not Subject to Mandatory Redemption:							
4-1/8%	106.125	-	3,750	97	55,389	5,539	5,539
4.56%	102	-	-	150	14,412	1,441	1,441
4.12%	102.728	-	1,375	-	17,556	1,756	1,756
						8,736	8,736
Subject to Mandatory Redemption:							
5.90% (a,b)		-	-	15,000	152,000	15,200	15,200
6-1/4% (a,b)		-	-	10,000	192,500	19,250	19,250
6.30% (a,b)		-	-	-	132,450	13,245	13,245
6-7/8% (a,c)		-	-	10,000	172,500	17,250	17,250
						64,945	64,945
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						264,141	308,976
Installment Purchase Contracts						310,239	309,717
Senior Unsecured Notes						696,144	397,435
Other Long-term Debt						219,947	211,307
Junior Debentures						161,611	161,504
Less Portion Due Within One Year						(340,000)	(90,000)
Long-term Debt Excluding Portion Due Within One Year						1,312,082	1,298,939
TOTAL CAPITALIZATION						$2,246,333	$2,165,719

(a) Not callable until after 2002. There are no aggregate sinking fund provisions through 2002. Sinking fund provisions require the redemption of 15,000 shares in 2003 and 67,500 shares each year in 2004, 2005 and 2006. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of the due date.
(b) Commencing in 2004 and continuing through 2008 the Company may redeem, at $100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. Shares previously redeemed may be applied to meet the sinking fund requirement.
(c) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at $100 per share. Shares previously redeemed may be applied to meet the sinking fund requirement.

See Notes to Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
7.63	2001 - June 1	$ -	$ 40,000
7.60	2002 - November 1	50,000	50,000
7.70	2002 - December 15	40,000	40,000
6.10	2003 - November 1	30,000	30,000
8.50	2022 - December 15	75,000	75,000
7.35	2023 - October 1	15,000	20,000
7.20	2024 - February 1	30,000	30,000
7.50	2024 - March 1	25,000	25,000
Unamortized Discount		(859)	(1,024)
		$264,141	$308,976

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
City of Lawrenceburg, Indiana:			
7.00	2015 - April 1	$ 25,000	$ 25,000
5.90	2019 - November 1	52,000	52,000
City of Rockport, Indiana:			
(a)	2014 - August 1	50,000	50,000
7.60	2016 - March 1	40,000	40,000
6.55	2025 - June 1	50,000	50,000
(b)	2025 - June 1	50,000	50,000
City of Sullivan, Indiana:			
5.95	2009 - May 1	45,000	45,000
Unamortized Discount		(1,761)	(2,283)
		$310,239	$309,717

(a) A variable interest rate is determined weekly. The average weighted interest rate was 2.4% for 2001 and 4.5% for 2000.

(b) In June 2001 an auction rate was established. Auction rates are determined by standard procedures every 35 days. The auction rate for June through December 2001 ranged from 1.55% to 2.9% and averaged 2.4%. Prior to June 25, 2001, an adjustable interest rate was a daily, weekly, commercial paper or term rate as designated by I&M. A weekly rate was selected which ranged from 1.9% to 4.9% in 2001 and from 2.9% to 5.9% in 2000 and averaged 3.3% during 2001 and 4.2% during 2000.

The terms of the installment purchase contracts require I&M to pay amounts sufficient for the cities to pay interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. On the variable rate series the principal is payable at the stated maturities or on the demand of the bondholders at periodic interest adjustment dates which occur weekly. The variable rate bonds due in 2014 are supported by a bank letter of credit which expires in 2002. Accordingly, the variable rate installment purchase contracts have been classified for repayment purposes based on the expiration date of the letter of credit.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
(a)	2002 - September 3	$200,000	$200,000
6-7/8	2004 - July 1	150,000	150,000
6.125	2006 - December 15	300,000	-
6.45	2008 - November 10	50,000	50,000
Unamortized Discount		(3,856)	(2,565)
		$696,144	$397,435

(a) A floating interest rate is determined quarterly. The rate on December 31, 2001 and 2000 was 2.71% and 7.31%, respectively. The average interest rate was 5.1% in 2001 and 7.3% in 2000.

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
8.00	2026 - March 31	$ 40,000	$ 40,000
7.60	2038 - June 30	125,000	125,000
Unamortized Discount		(3,389)	(3,496)
Total		$161,611	$161,504

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of I&M.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$ 340,000
2003	30,000
2004	150,000
2005	-
2006	300,000
Later Years	841,947
Total Principal Amount	1,661,947
Unamortized Discount	(9,865)
Total	$1,652,082

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

Index to Notes to Financial Statements

The notes to I&M's financial statements are combined with the notes to financial statements for AEP and its other subisidiary registrants. Listed below are the combined notes that apply to I&M. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Indiana Michigan Power Company and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, comprehensive income, retained earnings and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and its subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
Selected Financial Data

	Year Ended December 31,				
	2001	2000	1999	1998	1997
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,659,395	$1,176,867	$918,121	$705,562	$359,543
Operating Expenses	1,611,717	1,127,129	863,446	653,669	312,687
Operating Income	47,678	49,738	54,675	51,893	46,856
Nonoperating Income (Loss)	1,248	2,070	(327)	(1,726)	(464)
Interest Charges	27,361	31,045	28,918	28,491	25,646
Net Income	$ 21,565	$ 20,763	$ 25,430	$ 21,676	$ 20,746

	Year Ended December 31,				
	2001	2000	1999	1998	1997
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$1,128,415	$1,103,064	$1,079,048	$1,043,711	$1,006,955
Accumulated Depreciation and Amortization	384,104	360,648	340,008	315,546	296,318
Net Electric Utility Plant	$ 744,311	$ 742,416	$ 739,040	$ 728,165	$ 710,637
Total Assets	$1,153,243	$1,509,064	$ 986,638	$ 921,847	$ 886,671
Common Stock and Paid-in Capital	$ 209,200	$ 209,200	$ 209,200	$ 199,200	$ 179,200
Accumulated Other Comprehensive Income (Loss)	(1,903)				
Retained Earnings	48,833	57,513	67,110	71,452	78,076
Total Common Shareholder's Equity	$ 256,130	$ 266,713	$ 276,310	$ 270,652	$ 257,276
Long-term Debt (a)	$ 346,093	$ 330,880	$ 365,782	$ 368,838	$ 341,051
Obligations Under Capital Leases(a)	$ 9,583	$ 14,184	$ 15,141	$ 18,977	$ 18,725
Total Capitalization and Liabilities	$1,153,243	$1,509,064	$ 986,638	$ 921,847	$ 886,671

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
Management's Narrative Analysis of Results of Operations

KPCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power serving 172,000 retail customers in eastern Kentucky. KPCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers including power trading transactions. KPCo also sells wholesale power to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among the Pool members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of AEP Power Pool revenues and costs.

Critical Accounting Policies – Revenue Recognition

Regulatory Accounting - As a cost-based rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities - We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to KPCO as a member of the AEP Power Pool. Trading activities involve the purchase and sale of energy under physical forward contracts at fixed and variable prices and buying and selling financial energy contracts which includes exchange traded futures and options and over-the-counter options and swaps. The majority of trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting physical contracts. Although trading contracts are generally short-term, there are also long-term trading contracts.

Accounting standards applicable to trading activities require that changes in the fair value of trading contacts be recognized in revenues prior to settlement and is commonly referred to as mark-to-market (MTM) accounting. Since KPCO is a cost-based rate-regulated entity, changes in the fair value of physical forward sale and purchase contracts in AEP's traditional marketing area are deferred as regulatory liabilities (gains) or regulatory assets (losses). AEP's traditional marketing area is up to two transmission systems from the AEP Service territory. The change in the fair value of physical forward sale and purchase contracts outside AEP's traditional marketing area is included in nonoperating income on a net basis.

Mark-to-market accounting represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt of electricity and net settle in cash, the unrealized gain or loss is reversed and the actual realized cash gain or loss is recognized in the income statement. Therefore, as the contract's market value changes over the contract's term an unrealized gain or loss is deferred for contracts with delivery points in AEP's traditional marketing area and for contracts with delivery points outside of AEP's traditional marketing area the unrealized gain or loss is recognized as nonoperating income. When the contract settles the total gain or loss is realized in cash and the impact on the income statement depends on whether the contract's delivery points are within or outside of AEP's traditional marketing area. For contracts with delivery points in AEP's traditional marketing area, the total gain or loss realized in cash is recognized in the income statement. Physical forward trading sale contracts with delivery points in AEP's traditional marketing area are included in revenues when the contracts settle. Physical forward trading purchase contracts with delivery points in AEP's traditional marketing area are included in purchased power expense when they settle. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in AEP's traditional marketing area are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contacts with delivery points outside of AEP's traditional marketing area only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized in the income statement. Physical forward sales contracts for delivery outside of AEP's traditional marketing area are included in nonoperating income when the contract settles. Physical forward purchase contracts for delivery outside of AEP's traditional marketing area are included in nonoperating expenses when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of AEP's traditional marketing area are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading assets or liabilities as appropriate.

Trading of electricity options, futures and swaps, represents financial transactions with unrealized gains and losses from changes in fair values reported net in nonoperating income until the contracts settle. When these financial contracts settle, we record our share of the net proceeds in nonoperating income and reverse to nonoperating income the prior unrealized gain or loss.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing KPCO to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Net Income Increases

Net income increased $802 thousand or 4% in 2001 primarily due to the effect of a court decision related to a corporate owned life insurance (COLI) program recorded in 2000. In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including KPCo, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to COLI. In 1998 and 1999 KPCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1992-98. The payments were included in Other Property and Investments pending the resolution of this matter.

Operating Revenues Increase

Operating revenues increased $482.5 million or 41% in 2001 as a result of significant increases in trading activities in AEP's traditional marketing area. Changes in the components of operating revenues were as follows:

	Increase (Decrease) From Previous Year (dollars in millions) Amount	%
Retail*	$(13.5)	(9)
Wholesale Marketing and Trading	486.4	57
Other	(0.7)	(4)
Subtotal	472.2	47
Energy Delivery*	9.8	8
Sales to AEP Affiliates	0.5	1
Total	$482.5	41

*Reflects the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

Retail revenues decreased as a result of mild weather conditions. Usage by residential customers declined in response to warmer temperatures during November and December 2001. Commercial and industrial sales were stable.

The increase in wholesale marketing and trading revenues is driven by increased trading volume. The maturing of the Intercontinental Exchange, the development of propriety tools, and increased staffing of energy traders have resulted in an increase in the number of forward electricity purchase and sale contracts in AEP's traditional marketing area.

Energy delivery revenues rose largely from providing additional transmission services as a result of increased wholesale marketing and trading transactions and from increased assignment of fees for transmission and distribution delivery services.

Operating Expenses Increase

Operating expenses increased $484.6 million in 2001 primarily due to increases in purchased power for trading activity. Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year (dollars in millions) Amount	%
Fuel	$ (4.0)	(5)
Marketing and Trading Purchases	491.4	62
AEP Affiliate Purchases	2.5	2
Other Operation	5.9	11
Maintenance	(3.4)	(13)
Depreciation and Amortization	1.5	5
Taxes Other Than Income Taxes	0.6	8
Income Taxes	(9.9)	(51)
Total	$484.6	43

The decrease in fuel expense is a result of sharing profits from the trading of power with customers in accordance with the Kentucky Public Service Commission's fuel clause mechanism. Under this mechanism, the profits from KPCo's portion of AEP's wholesale marketing and trading activities are shared with retail customers. This sharing is recognized through credits to fuel expense, thus reducing fuel expense.

Increases in wholesale marketing and trading volume accounted for the significant increase in purchased power expense.

The increase in other operation expense is attributable to increased trading incentive compensation expense, reduced AEP transmission equalization credits and expenses for a full year of factoring accounts receivable. Under the AEP East Region Transmission Agreement, KPCo and certain affiliates share the costs associated with the ownership of their transmission system based upon each company's peak demand and investment. An increase in KPCo's peak demand relative to its affiliates' peak demand was the main reason for the decline in transmission equalization credits. Factoring of accounts receivable began in June 2000. In 2001 we incurred a full year of factoring expenses compared with a partial year in 2000.

Lower maintenance expense in 2001 is a result of performing significant planned maintenance at the Big Sandy Plant in 2000 for which there was no comparable activity in the current year.

Additions to property, plant and equipment accounted for the increase in depreciation expense. These additions included capitalized software and general distribution equipment upgrades and improvements.

Taxes other than income taxes rose as a result of increases in real and personal property tax accruals reflecting higher taxable property values.

The decrease in income tax expense was primarily due to a decrease in pre-tax book income and the effect of an unfavorable ruling in 2000 in AEP's suit against the government over interest deductions claimed in prior years related to AEP's COLI program.

Nonoperating Income and Nonoperating Expenses Increase

The increase in nonoperating income and nonoperating expenses was due to an increase in nonregulated electric trading activities outside AEP's traditional marketing area.

Interest Charges Decrease

The decline in interest expense was due to the effect of recognizing in 2000 previously deferred interest payments to the IRS related to the COLI disallowances and interest on resultant state income tax deficiencies.

KENTUCKY POWER COMPANY
Statements of Income

	Year Ended December 31, 2001	2000 (in thousands)	1999
OPERATING REVENUES:			
Electricity Marketing and Trading	$1,485,846	$1,013,700	$744,706
Energy Delivery	131,183	121,346	129,113
Sales to AEP Affiliates	42,366	41,821	44,302
TOTAL REVENUES	1,659,395	1,176,867	918,121
OPERATING EXPENSES:			
Fuel	70,635	74,638	84,369
Purchased Power:			
Electricity Marketing and Trading	1,279,556	788,102	567,902
AEP Affiliates	130,204	127,707	84,000
Other Operation	59,175	53,325	52,468
Maintenance	22,444	25,866	21,452
Depreciation and Amortization	32,491	31,028	29,221
Taxes Other Than Income Taxes	7,854	7,251	8,091
Income Taxes	9,358	19,212	15,943
TOTAL OPERATING EXPENSES	1,611,717	1,127,129	863,446
OPERATING INCOME	47,678	49,738	54,675
NONOPERATING INCOME	569,603	334,950	156,783
NONOPERATING EXPENSES	567,679	331,751	157,276
NONOPERATING INCOME TAX EXPENSE (CREDIT)	684	1,129	(166)
INTEREST CHARGES	27,361	31,045	28,918
NET INCOME	$ 21,565	$ 20,763	$ 25,430

Statements of Comprehensive Income

	Year Ended December 31, 2001	2000 (in thousands)	1999
NET INCOME	$21,565	$20,763	$25,430
OTHER COMPREHENSIVE INCOME (LOSS)			
Cash Flow Interest Rate Hedge	(1,903)	-	-
COMPREHENSIVE INCOME	$19,662	$20,763	$25,430

Statements of Retained Earnings

	Year Ended December 31, 2001	2000 (in thousands)	1999
RETAINED EARNINGS JANUARY 1	$57,513	$67,110	$71,452
NET INCOME	21,565	20,763	25,430
CASH DIVIDENDS DECLARED	30,245	30,360	29,772
RETAINED EARNINGS DECEMBER 31	$48,833	$57,513	$67,110

See Notes to Financial Statements Beginning on Page L-1.

KENTUCKY POWER COMPANY
Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$ 271,070	$ 271,107
Transmission	374,116	360,563
Distribution	402,537	387,499
General	65,059	67,476
Construction Work in Progress	15,633	16,419
Total Electric Utility Plant	1,128,415	1,103,064
Accumulated Depreciation and Amortization	384,104	360,648
NET ELECTRIC UTILITY PLANT	744,311	742,416
OTHER PROPERTY AND INVESTMENTS	6,492	6,559
LONG-TERM ENERGY TRADING CONTRACTS	77,972	76,503
CURRENT ASSETS:		
Cash and Cash Equivalents	1,947	2,270
Accounts Receivable:		
Customers	20,036	34,555
Affiliated Companies	16,012	22,119
Miscellaneous	3,333	6,419
Allowance for Uncollectible Accounts	(264)	(282)
Fuel - at average cost	12,060	4,760
Materials and Supplies - at average cost	15,766	15,408
Accrued Utility Revenues	5,395	6,500
Energy Trading Contracts	139,605	480,739
Prepayments	1,314	766
TOTAL CURRENT ASSETS	215,204	573,254
REGULATORY ASSETS	97,692	98,515
DEFERRED CHARGES	11 572	11,817
TOTAL	$1,153,243	$1,509,064

See Notes to Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - Par Value $50:		
Authorized - 2,000,000 Shares		
Outstanding - 1,009,000 Shares	$ 50,450	$ 50,450
Paid-in Capital	158,750	158,750
Accumulated Other Comprehensive Income (Loss)	(1,903)	-
Retained Earnings	48,833	57,513
Total Common Shareholder's Equity	256,130	266,713
Long-term Debt	251,093	270,880
TOTAL CAPITALIZATION	507,223	537,593
OTHER NONCURRENT LIABILITIES	11,929	18,348
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	95,000	60,000
Advances from Affiliates	66,200	47,636
Accounts Payable - General	24,050	32,043
Accounts Payable - Affiliated Companies	22,557	37,506
Customer Deposits	4,461	4,389
Taxes Accrued	10,305	11,885
Interest Accrued	5,269	5,610
Energy Trading and Derivative Contracts	144,364	494,086
Other	12,296	14,517
Total CURRENT LIABILITIES	384,502	707,672
DEFERRED INCOME TAXES	168,304	165,935
DEFERRED INVESTMENT TAX CREDITS	10,405	11,656
LONG-TERM ENERGY TRADING CONTRACTS	63,412	61,478
DEFERRED CREDITS	7,468	6,382
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$1,153,243	$1,509,064

See Notes to Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
Statements of Cash Flows

	2001	2000	1999
	Year Ended December 31, (in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 21,565	$ 20,763	$ 25,430
Adjustments for Noncash Items:			
Depreciation and Amortization	32,491	31,034	29,228
Deferred Income Taxes	6,293	3,765	2,596
Deferred Investment Tax Credits	(1,251)	(1,252)	(1,292)
Deferred Fuel Costs (net)	(4,707)	2,948	828
Mark-to-Market of Energy Trading Contracts	(1,454)	(4,376)	(863)
Change in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	23,694	(20,930)	(6,618)
Fuel, Materials and Supplies	(7,658)	8,386	(7,014)
Accrued Utility Revenues	1,105	7,237	(177)
Accounts Payable	(22,942)	39,883	4,935
Taxes Accrued	(1,580)	2,025	2,604
Disputed Tax and Interest Related to COLI	-	5,943	(567)
Change in Other Assets	(2,762)	62,653	11,547
Change in Other Liabilities	(9,446)	(62,702)	(13,837)
Net Cash Flows From Operating Activities	33,348	95,377	46,800
INVESTING ACTIVITIES:			
Construction Expenditures	(37,206)	(36,209)	(44,339)
Proceeds From Sales of Property	216	266	168
Net Cash Flows Used For Investing Activities	(36,990)	(35,943)	(44,171)
FINANCING ACTIVITIES:			
Capital Contributions from Parent Company	-	-	10,000
Issuance of Long-term Debt	75,000	69,685	79,740
Retirement of Long-term Debt	(60,000)	(105,000)	(83,307)
Change in Short-term Debt (net)	-	(39,665)	19,315
Change in Advances From Affiliates (net)	18,564	47,636	-
Dividends Paid	(30,245)	(30,360)	(29,772)
Net Cash Flows From (Used For) Financing Activities	3,319	(57,704)	(4,024)
Net Increase (Decrease) in Cash and Cash Equivalents	(323)	1,730	(1,395)
Cash and Cash Equivalents January 1	2,270	540	1,935
Cash and Cash Equivalents December 31	$ 1,947	$ 2,270	$ 540

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $27,090,000, $28,619,000 and $29,845,000 and for income taxes was $7,549,000, $7,923,000 and $12,050,000 in 2001, 2000 and 1999, respectively. Noncash acquisitions under capital leases were $817,000, $2,817,000 and $2,219,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY

Statements of Capitalization

	December 31, 2001	December 31, 2000
	(in thousands)	
COMMON SHAREHOLDER'S EQUITY	$256,130	$266,713
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	59,383	119,341
Senior Unsecured Notes	147,625	147,490
Notes Payable	100,000	25,000
Junior Debentures	39,085	39,049
Less Portion Due Within One Year	(95,000)	(60,000)
Long-term Debt Excluding Portion Due Within One Year	251,093	270,880
TOTAL CAPITALIZATION	$507,223	$537,593

See Notes to Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
8.95	2001 - May 10	$ -	$ 20,000
8.90	2001 - May 21	-	40,000
6.65	2003 - May 1	15,000	15,000
6.70	2003 - June 1	15,000	15,000
6.70	2003 - July 1	15,000	15,000
7.90	2023 - June 1	14,500	14,500
Unamortized Discount		(117)	(159)
		$ 59,383	$119,341

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
(a)	2002 - November 19	$ 70,000	$ 70,000
6.91	2007 - October 1	48,000	48,000
6.45	2008 - November 10	30,000	30,000
Unamortized Discount		(375)	(510)
		147,625	147,490
Less Portion Due Within One Year		70,000	-
Total		$ 77,625	$147,490

(a) A floating interest rate is determined monthly. The rate on December 31, 2001 was 4.3% and on December 31, 2000 was 7.4%.

Notes payable to parent company were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
4.336	2003 - May 15	$15,000	$ -
6.501	2006 - May 15	60,000	-
		$75,000	$ -

Notes payable to banks outstandings were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
7.45	2002 - September 20	$25,000	$25,000

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
8.72	2025 - June 30	$40,000	$40,000
Unamortized Discount		(915)	(951)
Total		$39,085	$39,049

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$ 95,000
2003	60,000
2004	-
2005	-
2006	60,000
Later Years	132,500
Total Principal Amount	347,500
Unamortized Discount	1,407
Total	$346,093

KENTUCKY POWER COMPANY
Index to Notes to Financial Statements

The notes to KPCo's financial statements are combined with the notes to financial statements for AEP and its other subisidiary registrants. Listed below are the combined notes that apply to KPCo. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of
Directors of Kentucky Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Kentucky Power Company as of December 31, 2001 and 2000, and the related statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

OHIO POWER COMPANY AND SUBSIDIARIES

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OHIO POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31, 2001	2000	1999 (in thousands)	1998	1997
INCOME STATEMENTS DATA:					
Operating Revenues	$6,262,402	$4,992,100	$4,196,893	$3,572,125	$1,965,818
Operating Expenses	6,021,692	4,765,273	3,908,064	3,282,753	1,689,425
Operating Income	240,710	226,827	288,829	289,372	276,393
Nonoperating Income (Loss)	18,686	(5,004)	7,000	588	14,822
Interest Charges	93,603	119,210	83,672	80,035	82,526
Income Before Extraordinary Item	165,793	102,613	212,157	209,925	208,689
Extraordinary Loss	(18,348)	(18,876)	-	-	-
Net Income	147,445	83,737	212,157	209,925	208,689
Preferred Stock Dividend Requirements	1,258	1,266	1,417	1,474	2,647
Earnings Applicable To Common Stock	$ 146,187	$ 82,471	$ 210,740	$ 208,451	$ 206,042

	Year Ended December 31, 2001	2000	1999 (in thousands)	1998	1997
BALANCE SHEETS DATA:					
Electric Utility Plant	$5,390,576	$5,577,631	$5,400,917	$5,257,841	$5,155,797
Accumulated Depreciation	2,452,571	2,764,130	2,621,711	2,461,376	2,349,995
Net Electric Utility Plant	$2,938,005	$2,813,501	$2,779,206	$2,796,465	$2,805,802
Total Assets	$4,916,067	$6,242,557	$4,677,209	$4,344,680	$4,163,202
Common Stock and Paid-in Capital	$ 783,684	$ 783,684	$ 783,577	$ 783,536	$ 783,497
Accumulated Other Comprehensive Income (Loss)	(196)				
Retained Earnings	401,297	398,086	587,424	587,500	590,151
Total Common Shareholder's Equity	$1,184,785	$1,181,770	$1,371,001	$1,371,036	$1,373,648
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 16,648	$ 16,648	$ 16,937	$ 17,370	$ 17,542
Subject to Mandatory Redemption (a)	8,850	8,850	8,850	11,850	11,850
Total Cumulative Preferred Stock	$ 25,498	$ 25,498	$ 25,787	$ 29,220	$ 29,392
Long-term Debt (a)	$1,203,841	$1,195,493	$1,151,511	$1,084,928	$1,095,226
Obligations Under Capital Leases (a)	$ 80,666	$ 116,581	$ 136,543	$ 142,635	$ 157,487
Total Capitalization and Liabilities	$4,916,067	$6,242,557	$4,677,209	$4,344,680	$4,163,202

(a) Including portion due within one year.

OPCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 698,000 retail customers in northwestern, east central, eastern and southern sections of Ohio. OPCo supplies electric power to the AEP Power Pool and shares the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers including power trading transactions. OPCo also sells wholesale power to municipalities and cooperatives.

The cost of the AEP Power Pool's generating capacity is allocated among Pool members based on their relative peak demands and generating reserves through the payment of capacity charges or the receipt of capacity credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of AEP Power Pool revenues and costs.

Critical Accounting Policies - Revenue Recognition

Regulatory Accounting - As a result of our cost-based rate-regulated transmission and distribution operations, our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities – We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to OPCo as a member of the AEP Power Pool. Trading activities involve the purchase and sale of energy under physical forward contracts at fixed and variable prices and buying and selling financial energy contracts which includes exchange traded futures and options and over-the-counter options and swaps. Although trading contracts are generally short-term, there are also long-term trading contracts. We recognize revenues from trading activities generally based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt of electricity and net settle in cash, the unrealized gain or loss is reversed and the actual realized cash gain or loss is recognized. Therefore, over the trading contract's term an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

The majority of our trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity in July. At the end of each month until the contract settles in July, we would record our share of any difference between the contract price and the market price as an unrealized gain or loss. In July when the contract settles, we would realize our share of the gain or loss in cash and reverse the previously recorded unrealized gain or loss.

Depending on whether the delivery point for the electricity is in AEP's traditional marketing area or not determines where the contract is reported on OPCo's income statement. AEP's tradititonal marketing area is up to two transmission systems from the AEP service territory. Physical forward trading sale contracts with delivery points in AEP's traditional marketing area are included in revenues when the contracts settle. Physical forward trading purchase contracts with delivery points in AEP's traditional marketing area are included in purchased power expense when they settle. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in AEP's traditional marketing area are included in revenues on a net basis. Physical forward sales contracts for delivery outside of AEP's traditional marketing area are included in nonoperating income when the contract settles. Physical forward purchase contracts for delivery outside of AEP's traditional marketing area are included in nonoperating expenses when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of AEP's traditional marketing area are included in nonoperating income on a net basis.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity in July. If we do nothing else with these contracts until settlement in July and if the volumes, delivery point, schedule and other key terms match then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on results of operations but will have an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on results of operations from recording additional changes in fair values using mark-to-market accounting.

Trading of electricity options, futures and swaps, represents financial transactions with unrealized gains and losses from changes in fair values reported net in nonoperating income until the contracts settle. When these financial contracts settle, we record our share of the net proceeds in nonoperating income and reverse to nonoperating income the prior unrealized gain or loss.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing OPCo to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Results of Operations

Income before extraordinary item increased $63 million or 62% in 2001 primarily due to the effect of a court decision related to a corporate owned life insurance (COLI) program recorded in 2000. In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including OPCo, in a suit over deductibility of interest claimed in AEP's consolidated tax returns related to COLI. In 1998 and 1999 OPCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. Net income was also favorably impacted by the growth in and strong performance by the wholesale business. The favorable effects of the COLI decision and wholesale business were offset in part by the commencement of the amortization of transition regulatory assets in 2001, the effect of mild winter weather and the recent economic downturn.

Income before extraordinary item decreased $110 million or 52% in 2000 due predominantly to the unfavorable COLI decision.

Operating Revenues

Operating revenues increased 25% in 2001 and 19% in 2000 because of the significant increase in wholesale marketing and trading volume. The changes in the components of revenues were as follows:

	Increase (Decrease) From Previous Year (Dollars in Millions) 2001 Amount	%	2000 Amount	%
Retail*	$ (66.0)	(8)	$(135.7)	(15)
Wholesale Marketing and Trading	1,294.0	42	738.0	32
Unrealized MTM	32.6	N.M.	(10.3)	N.M.
Other	(4.3)	(5)	2.8	4
Total Marketing and Trading	1,256.3	32	594.8	18
Energy Delivery*	85.1	18	7.4	2
Sale to AEP Affiliates	(71.1)	(12)	193.0	50
Total	$1,270.3	25	$ 795.2	19

* Reflects for 2000 the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

The increase in operating revenues in 2001 and 2000 resulted from increased marketing and trading volume (32% in 2001 and 21% in 2000). The maturing of the Intercontinental Exchange, the development of proprietory tools, and increased staffing of energy traders has resulted in an increase in the number of forward electricity purchase and sale contracts in AEP's traditional marketing area.

Sales to AEP affiliates decreased in 2001 because an affiliate was able to supply more power to the Power Pool from two nuclear units that returned to service in June and December 2000.

As a result of one of OPCo's major industrial customers deciding not to continue its power purchase agreement, OPCo was able to deliver additional power to the power pool in 2000. This accounted for the increase in sales to AEP affiliates in 2000.

Operating Expenses

Operating expenses increased by 26% in 2001 mostly due to a significant increase in wholesale trading purchases and the amortization of transition regulatory assets partly offset by decreases in fuel expense and income taxes. Operating expenses increased by 22% in 2000 mostly due to increases in fuel expense, wholesale trading purchases, other operation expense and income taxes.

Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year (dollars in millions) 2001 Amount	%	2000 Amount	%
Fuel	$ (85.4)	(11)	$ 84.3	12
Marketing and Trading Purchases	1,327.7	46	597.6	26
AEP Affiliate Purchases	11.8	23	29.9	143
Other Operation	(4.0)	(1)	80.2	25
Maintenance	18.1	15	3.4	3
Depreciation and Amortization	84.0	54	6.9	5
Taxes Other Than Income Taxes	(9.7)	(6)	5.3	3
Income Taxes	(86.1)	(46)	49.6	36
Total Operating Expenses	$1,256.4	26	$857.2	22

Fuel expense decreased 11% in 2001 mainly due to a 9% decrease in net generation because of decreased sales to the AEP Power Pool caused by an affiliate's two nuclear units returning to service. Fuel expense increased in 2000 due to increases in generation and the average cost of fuel consumed reflecting shutdown costs included in the cost of coal delivered from affiliated mining operations.

Marketing and trading purchases expense increased substantially in 2001 and 2000 due to increases in trading volume. The increases in purchased power from AEP affiliates were due to a significnt increase in AEP Power Pool transactions in 2001 and 2000.

Other operation expense increased in 2000 mainly due to increased power generation costs. Increased emission allowance consumption and allowance prices and increased costs of AEP's growing power marketing and trading operation, including trader incentive compensation, accounted for the increase in power generation costs. The increase in emission allowance usage and prices resulted from the stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments which became effective on January 1, 2000.

Maintenance expense increased in 2001 mainly due to boiler repairs at Amos, Cardinal, Kammer, Mitchell, Muskingum and Sporn plants, and boiler inspections at the Amos and Cardinal plants.

The commencement of amortization of transition regulatory assets in connection with the transition to customer choice and market-based pricing of retail electricity supply under Ohio deregulation accounted for the significant increase in depreciation and amortization expense in 2001.

The decrease in taxes other than income taxes in 2001 was due to a decrease in property tax expense reflecting a reduction in rates on generation property under the Ohio Restructuring law partially offset by a new state excise tax.

Income taxes decreased in 2001 due to an unfavorable ruling in AEP's suit against the government over interest deductions claimed relating to AEP's COLI program, which was recorded in 2000 and a decrease in pre-tax book income. The increase in income tax expense in 2000 was primarily due to the unfavorable ruling relating to AEP's COLI program.

Nonoperating Income and Nonoperating Expense

The increases in nonoperating income and nonoperating expenses in 2001 and 2000 were due to an increase in trading transactions outside of the AEP System's traditional marketing area.

Interest Charges

The major reason for the decrease in interest expense in 2001 was the recognition in 2000 of deferred interest payments to the IRS related to COLI disallowances. The increase in interest expense in 2000 was due to the recognition of deferred interest payments related to the COLI disallowance.

Extraordinary Loss

In the second quarter of 2001 an extraordinary loss of $18 million net of tax was recorded to write-off prepaid Ohio excise taxes stranded by Ohio deregulation. In 2000 the application of regulatory accounting for generation under SFAS 71 was discontinued which resulted in an after tax extraordinary loss of $19 million.

OHIO POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Income

	2001	2000	1999
		Year Ended December 31, (in thousands)	
OPERATING REVENUES:			
Electricity Marketing and Trading	$5,198,323	$3,942,066	$3,347,219
Energy Delivery	552,713	467,587	460,182
Sales to AEP Affiliates	511,366	582,447	389,492
TOTAL OPERATING REVENUES	6,262,402	4,992,100	4,196,893
OPERATING EXPENSES:			
Fuel	686,568	771,969	687,672
Purchased Power:			
Electricity Marketing and Trading	4,225,124	2,897,461	2,299,909
AEP Affiliates	62,585	50,741	20,864
Other Operation	403,404	407,375	327,132
Maintenance	142,878	124,735	121,299
Depreciation and Amortization	239,982	155,944	149,055
Taxes Other Than Income Taxes	159,778	169,527	164,213
Income Taxes	101,373	187,521	137,920
TOTAL OPERATING EXPENSES	6,021,692	4,765,273	3,908,064
OPERATING INCOME	240,710	226,827	288,829
NONOPERATING INCOME	1,880,294	1,208,437	630,295
NONOPERATING EXPENSES	1,863,988	1,195,283	628,723
NONOPERATING INCOME TAX EXPENSE (CREDIT)	(2,380)	18,158	(5,428)
INTEREST CHARGES	93,603	119,210	83,672
INCOME BEFORE EXTRAORDINARY ITEM	165,793	102,613	212,157
EXTRAORDINARY LOSS - DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION - Net of tax (See Note 2)	(18,348)	(18,876)	-
NET INCOME	147,445	83,737	212,157
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,258	1,266	1,417
EARNINGS APPLICABLE TO COMMON STOCK	$ 146,187	$ 82,471	$ 210,740

Consolidated Statements of Comprehensive Income

	2001	2000	1999
		Year Ended December 31,	
NET INCOME	$147,445	$83,737	$212,157
OTHER COMPREHENSIVE INCOME (LOSS)			
Foreign Currency Exchange Rate Hedge	(196)	-	-
COMPREHENSIVE INCOME	$147,249	$83,737	$212,157

The common stock of the Company is wholly owned by AEP.

See Notes to Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$3,007,866	$2,764,155
Transmission	891,283	870,033
Distribution	1,081,122	1,040,940
General (including mining assets at December 31, 2000)	245,232	707,417
Construction Work in Progress	165,073	195,086
Total Electric Utility Plant	5,390,576	5,577,631
Accumulated Depreciation and Amortization	2,452,571	2,764,130
NET ELECTRIC UTILITY PLANT	2,938,005	2,813,501
OTHER PROPERTY AND INVESTMENTS	62,303	109,124
LONG-TERM ENERGY TRADING CONTRACTS	263,734	255,938
CURRENT ASSETS:		
Cash and Cash Equivalents	8,848	31,393
Advances to Affiliates	-	92,486
Accounts Receivable:		
Customers	84,694	139,732
Affiliated Companies	148,563	126,203
Miscellaneous	20,409	39,046
Allowance for Uncollectible Accounts	(1,379)	(1,054)
Fuel - at average cost	84,724	82,291
Materials and Supplies - at average cost	88,768	96,053
Accrued Utility Revenues	-	264
Energy Trading Contracts	472,246	1,608,298
Prepayments and Other	20,865	32,882
TOTAL CURRENT ASSETS	927,738	2,247,594
REGULATORY ASSETS	644,625	714,710
DEFERRED CHARGES	79,662	101,690
TOTAL	$4,916,067	$6,242,557

See Notes to Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 40,000,000 Shares		
Outstanding - 27,952,473 Shares	$ 321,201	$ 321,201
Paid-in Capital	462,483	462,483
Accumulated Other Comprehensive Income (Loss)	(196)	-
Retained Earnings	401,297	398,086
Total Common Shareholder's Equity	1,184,785	1,181,770
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	16,648	16,648
Subject to Mandatory Redemption	8,850	8,850
Long-term Debt	1,203,841	1,077,987
TOTAL CAPITALIZATION	2,414,124	2,285,255
OTHER NONCURRENT LIABILITIES	130,386	542,017
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	-	117,506
Advances From Affiliates	300,213	-
Accounts Payable - General	134,418	179,691
Accounts Payable - Affiliated Companies	176,520	121,360
Customer Deposits	5,452	39,736
Taxes Accrued	126,770	223,101
Interest Accrued	17,679	20,458
Obligations Under Capital Leases	16,405	32,716
Energy Trading Contracts	456,047	1,652,953
Other	87,070	151,934
Total CURRENT LIABILITIES	1,320,574	2,539,455
DEFERRED INCOME TAXES	797,889	621,941
DEFERRED INVESTMENT TAX CREDITS	21,925	25,214
LONG-TERM ENERGY TRADING CONTRACTS	214,487	205,670
DEFERRED CREDITS	16,682	23,005
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$4,916,067	$6,242,557

See Notes to Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	2001	2000	1999
	Year Ended December 31, (in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 147,445	$ 83,737	$ 212,157
Adjustments for Noncash Items:			
Depreciation, Depletion and Amortization	252,123	200,350	193,780
Deferred Income Taxes	215,833	(65,956)	3,666
Deferred Investment Tax Credits	(3,289)	(3,399)	(3,458)
Deferred Fuel Costs (net)	-	(56,869)	(76,978)
Extraordinary Loss	18,348	18,876	-
Mark to Market of Energy Trading Contracts	(59,833)	(5,614)	(4,234)
Change in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	51,640	51,430	(49,309)
Fuel, Materials and Supplies	4,852	46,645	(60,500)
Accrued Utility Revenues	264	45,311	(2,074)
Accounts Payable	9,887	56,069	9,195
Disputed Tax and Interest Related to COLI	-	110,494	(6,272)
Accumulated Provisions - Noncurrent	(392,026)	145,573	66,573
Taxes Accrued	(96,331)	60,919	(776)
Customer Deposits	(34,284)	31,540	(3,763)
Change in Other Assets	79,831	(439,448)	(67,515)
Change in Other Liabilities	(107,704)	359,640	127,288
Net Cash Flows From Operating Activities	86,756	639,298	337,780
INVESTING ACTIVITIES:			
Construction Expenditures	(344,571)	(254,016)	(193,870)
Proceeds From Sales of Property and Other	16,778	6,354	5,900
Investment in Coal Companies	(32,115)	-	-
Net Cash Flows Used For Investing Activities	(359,908)	(247,662)	(187,970)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	300,000	74,748	222,308
Change in Advances From Affiliates (net)	392,699	(92,486)	-
Retirement of Cumulative Preferred Stock	-	(182)	(3,392)
Retirement of Long-term Debt	(297,858)	(30,663)	(158,638)
Change in Short-term Debt (net)	-	(194,918)	71,913
Dividends Paid on Common Stock	(142,976)	(271,813)	(210,813)
Dividends Paid on Cumulative Preferred Stock	(1,258)	(1,262)	(1,420)
Net Cash Flows Used For Financing Activities	250,607	(516,576)	(80,042)
Net Increase (Decrease) in Cash and Cash Equivalents	(22,545)	(124,940)	69,768
Cash and Cash Equivalents January 1	31,393	156,333	86,565
Cash and Cash Equivalents December 31	$ 8,848	$ 31,393	$ 156,333

Supplemental Disclosure:

Cash paid (received) for interest net of capitalized amounts was $94,747,000, $87,120,000 and $78,739,000 and for income taxes was $(22,417,000), $142,710,000 and $94,606,000 in 2001, 2000 and 1999, respectively. Noncash acquisitions under capital leases were $2,380,000, $17,005,000 and $28,561,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Statement of Retained Earnings

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
Retained Earnings January 1	$398,086	$587,424	$587,500
Net Income	147,445	83,737	212,157
	545,531	671,161	799,657
Deductions:			
Cash Dividends Declared:			
Common Stock	142,976	271,813	210,813
Cumulative Preferred Stock:			
4.08% Series	58	59	61
4.20% Series	96	96	97
4.40% Series	139	139	142
4-1/2% Series	439	442	460
5.90% Series	428	428	472
6.02% Series	66	66	156
6.35% Series	32	32	32
Total Dividends	144,234	273,075	212,233
Retained Earnings December 31	$401,297	$398,086	$587,424

See Notes to Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

							December 31, 2001	December 31, 2000
							(in thousands)	
COMMON SHAREHOLDER'S EQUITY							$1,184,785	$1,181,770

PREFERRED STOCK: $100 par value - authorized shares 3,762,403
$25 par value - authorized shares 4,000,000

Series(a)	Call Price December 31, 2001	Par Value	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001	2001	2000
Not Subject to Mandatory Redemption:								
4.08%	$103	$100	-	-	373	14,595	1,460	1,460
4.20%	103.20	100	-	276	-	22,824	2,282	2,282
4.40%	104	100	-	432	330	31,512	3,151	3,151
4-1/2%	110	100	-	2,181	3,631	97,546	9,755	9,755
							16,648	16,648
Subject to Mandatory Redemption:								
5.90% (b)	-	$100	-	-	10,000	72,500	7,250	7,250
6.02% (c)	-	100	-	-	20,000	11,000	1,100	1,100
6.35% (c)	-	100	-	-	-	5,000	500	500
							8,850	8,850
LONG-TERM DEBT (See Schedule of Long-term Debt):								
First Mortgage Bonds							141,544	316,294
Installment Purchase Contracts							233,235	233,130
Senior Unsecured Notes							396,962	471,583
Notes Payable to Affiliated Company							300,000	-
Notes Payable							-	30,000
Junior Debentures							132,100	131,980
Other Long-term Debt							-	12,506
Less Portion Due Within One Year							-	(117,506)
Long-term Debt Excluding Portion Due Within One Year							1,203,841	1,077,987
TOTAL CAPITALIZATION							$2,414,124	$2,285,255

(a) The series subject to mandatory redemption are not callable until after 2002. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of the due date.
(b) Commencing in 2004 and continuing through the year 2008, a sinking fund for the 5.90% cumulative preferred stock will require the redemption of 22,500 shares each year and the redemption of the remaining shares outstanding on January 1, 2009, in each case at $100 per share. Shares previously redeemed may be applied to meet sinking fund requirements.
(c) Commencing in 2003 and continuing through 2007 cumulative preferred stock sinking funds will require the redemption of 20,000 shares each year of the 6.02% series and 15,000 shares each year of the 6.35% series, in each case at $100 per share. All remaining outstanding shares must be redeemed in 2008. Shares previously redeemed may be applied to meet the sinking fund requirements.

See Notes to Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
6.75	2003 - April 1	$ 29,850	$ 38,850
6.55	2003 - October 1	27,315	32,135
6.00	2003 - November 1	12,500	25,000
6.15	2003 - December 1	20,000	50,000
8.80	2022 - February 10	5,000	50,000
7.75	2023 - April 1	5,000	40,000
7.375	2023 - October 1	20,250	40,000
7.10	2023 - November 1	12,000	20,000
7.30	2024 - April 1	10,000	21,500
Unamortized Discount		(371)	(1,191)
Total		$141,544	$316,294

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
Mason County, West Virginia:			
5.45%	2016 - December 1	$ 50,000	$ 50,000
Marshall County, West Virginia:			
5.45%	2014 - July 1	50,000	50,000
5.90%	2022 - April 1	35,000	35,000
6.85%	2022 - June 1	50,000	50,000
Ohio Air Quality Development			
5.15%	2026 - May 1	50,000	50,000
Unamortized Discount		(1,765)	(1,870)
Total		$233,235	$233,130

Under the terms of the installment purchase contracts, OPCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
(a)	2001 - May 16	$ -	$ 75,000
6.75	2004 - July 1	100,000	100,000
7.00	2004 - July 1	75,000	75,000
6.73	2004 - November 1	48,000	48,000
6.24	2008 - December 4	37,225	37,225
7-3/8	2038 - June 30	140,000	140,000
Unamortized Discount		(3,263)	(3,642)
Total		$396,962	$471,583

(a) Redeemed on 5/16/01.

Notes payable to parent company were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
4.336%	2003 - May 15	$ 60,000	$ -
6.501%	2006 - May 15	240,000	-
Total		$300,000	$ -

Notes payable outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
6.20	2001 - January 31	$ -	$ 5,000
6.20	2001 - January 31	-	7,000
6.20	2001 - January 31	-	18,000
Total		$ -	$30,000

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2001	December 31, 2000
		(in thousands)	
8.16	2025 - September 30	$ 85,000	$ 85,000
7.92	2027 - March 31	50,000	50,000
Unamortized Discount		(2,900)	(3,020)
Total		$132,100	$131,980

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

Finance obligations were entered into by the Company's coal mining subsidiaries for mining facilities and equipment through sale and leaseback transactions. In accordance with SFAS 98, the transactions did not qualify as sales and leasebacks for accounting purposes and therefore are shown as other long-term debt. The remaining long-term debt obligation was paid off in the first quarter of 2001.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$ -
2003	149,665
2004	223,000
2005	-
2006	240,000
Later Years	599,475
Total Principal Amount	1,212,140
Unamortized Discount	8,299
Total	$1,203,841

OHIO POWER COMPANY AND SUBSIDIARIES
Index to Notes to Consolidated Financial Statements

The notes to OPCo's financial statements are combined with the notes to financial statements for AEP and its other subisidiary registrants. Listed below are the combined notes that apply to OPCo. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Ohio Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Ohio Power Company and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company and its subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

PUBLIC SERVICE COMPANY OF OKLAHOMA
AND SUBSIDIARIES

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PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES

Selected Consolidated Financial Data

	Year Ended December 31,				
	2001	2000	1999	1998	1997
	(in thousands)				
INCOME STATEMENTS DATA:					
Operating Revenues	$2,201,249	$1,430,019	$749,390	$780,159	$712,690
Operating Expenses	2,104,261	1,333,350	650,677	665,085	630,666
Operating Income	96,988	96,669	98,713	115,074	82,024
Nonoperating Income (Loss)	20	8,974	946	(91)	1,649
Interest Charges	39,249	38,980	38,151	38,074	37,218
Net Income	57,759	66,663	61,508	76,909	46,455
Preferred Stock Dividend Requirements	213	212	212	213	364
Gain On Reacquired Preferred Stock	-	-	-	-	4,211
Earnings Applicable to Common Stock	$ 57,546	$ 66,451	$ 61,296	$ 76,696	$ 50,302

	December 31,				
	2001	2000	1999	1998	1997
	(in thousands)				
BALANCE SHEETS DATA:					
Electric Utility Plant	$2,695,099	$2,604,670	$2,459,705	$2,391,722	$2,339,908
Accumulated Depreciation and Amortization	1,184,443	1,150,253	1,114,255	1,082,081	1,031,322
Net Electric Utility Plant	$1,510,656	$1,454,417	$1,345,450	$1,309,641	$1,308,586
Total Assets	$1,917,897	$2,138,333	$1,524,726	$1,470,939	$1,464,562
Common Stock and Paid-in Capital	$ 337,230	$ 337,230	$ 337,230	$ 337,230	$ 337,230
Retained Earnings	142,994	137,688	139,237	142,941	135,245
Total Common Shareholder's Equity	$ 480,224	$ 474,918	$ 476,467	$ 480,171	$ 472,475
Cumulative Preferred Stock: Not Subject to Mandatory Redemption	$ 5,283	$ 5,283	$ 5,286	$ 5,287	$ 5,287
Preferred Securities of Subsidiary Trust	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Long-term Debt (a)	$ 451,129	$ 470,822	$ 384,516	$ 384,064	$ 438,703
Total Capitalization and Liabilities	$1,917,897	$2,138,333	$1,524,726	$1,470,939	$1,464,562

(a) Including portion due within one year.

PSO is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to approximately 502,000 retail customers in eastern and southwestern Oklahoma. PSO also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Wholesale power marketing and trading activities are conducted on PSO's behalf by AEP. PSO, along with the other AEP electric operating subsidiaries, shares in the revenues and costs of AEP's wholesale sales to and forward trades with other utility systems and power marketers.

Critical Accounting Policies - Revenue Recognition

Regulatory Accounting - As a cost-based rate-regulated electric public utility company, PSO's consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities - We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to PSO. Trading activities allocated to PSO involve the purchase and sale of energy under physical forward contracts at fixed and variable prices. Although trading contracts are generally short-term, there are also long-term trading contracts.

Accounting standards applicable to trading activities require that changes in the fair value of trading contracts be recognized in revenues prior to settlement and is commonly referred to as mark-to-market (MTM) accounting. Since PSO is a cost-based rate-regulated entity,whose revenues are based on settled transaction, unrealized changes in the fair value of physical forward sale and purchase contracts are deferred as regulatory liabilities (gains) or regulatory assets (losses).

Mark-to-market accounting represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt and net settle in cash, the unrealized gain or loss is reversed and the actual realized cash gain or loss is recognized in the income statement. Therefore, as the contract's market value changes over the contract's term an unrealized gain or loss is deferred as a regulatory liability or a regulatory asset. When the contract settles the total gain or loss is realized in cash and recognized in the income statement. Physical forward trading sale contracts are included in revenues when the contracts settle. Physical forward trading purchase contracts are included in purchased power expense when they settle. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts are deferred as regulatory liabilities (gains) or regulatory assets (losses). Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing PSO to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Results of Operations

Net income decreased $8.9 million or 13.4% in 2001 due primarily due to the effect of a gain on the sale of a minority interest in Scientech, Inc. recorded in year 2000.

Operating Revenues

The 54% increase in operating revenues for the year resulted from increased trading volumes of the wholesale electric marketing and trading business. The increase in revenues is primarily attributable to our sharing in AEP's power marketing and trading operations. Revenues also increased as a result of favorable fuel-related revenues associated with the Oklahoma fuel clause recovery mechanism.

	Increase From Previous Year	
(dollars in millions)	Amount	%
Retail*	$ 49.1	8
Wholesale Marketing and Trading	675.3	124
Other	7.9	41
Total Marketing and Trading	732.3	63
Energy Delivery*	16.8	7
Sales to AEP Affiliates	22.1	151
Total Revenues	$771.2	54

*Reflects the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

Revenues from retail customers increased primarily as a result of an increase in fuel-related revenues. Rising prices for natural gas used for generation and higher purchased power prices accounted for the increase in fuel-related revenues. The Oklahoma fuel clause recovery mechanism provides for the accrual of fuel-related revenues until reviewed and approved for billing to customers by the Oklahoma Corporation Commission. The accrual of additional fuel and purchased power revenues is offset by increases in fuel and purchased power expenses. As a result, accrued fuel-related revenues do not impact results of operations.

The increase in wholesale electric marketing and trading revenues is attributable to PSO's sharing in the AEP System's power marketing and trading operations for a full year. In June 2000 as a result of a merger with CSW, PSO started sharing in the AEP System's power marketing and trading transactions.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$1,034,711	$ 914,096
Transmission	427,110	396,695
Distribution	972,806	938,053
General	203,572	206,731
Construction Work in Progress	56,900	149,095
Total Electric Utility Plant	2,695,099	2,604,670
Accumulated Depreciation and Amortization	1,184,443	1,150,253
NET ELECTRIC UTILITY PLANT	1,510,656	1,454,417
OTHER PROPERTY AND INVESTMENTS	41,020	38,211
LONG-TERM ENERGY TRADING CONTRACTS	55,215	52,275
CURRENT ASSETS:		
Cash and Cash Equivalents	5,795	11,301
Accounts Receivable:		
Customers	31,144	60,424
Affiliated Companies	10,905	3,453
Allowance for Uncollectible Accounts	(44)	(467)
Fuel - at LIFO cost	21,559	28,113
Materials and Supplies - at average cost	36,785	29,642
Under-recovered Fuel Costs	-	43,267
Energy Trading Contracts	162,200	378,911
Prepayments	2,368	1,559
TOTAL CURRENT ASSETS	270,712	556,203
REGULATORY ASSETS	35,004	29,338
DEFERRED CHARGES	5,290	7,889
TOTAL	$1,917,897	$2,138,333

See Notes to Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $15 Par Value:		
Authorized Shares: 11,000,000		
Issued Shares: 10,482,000		
Outstanding Shares: 9,013,000	$ 157,230	$ 157,230
Paid-in Capital	180,000	180,000
Retained Earnings	142,994	137,688
Total Common Shareholder's Equity	480,224	474,918
Cumulative Preferred Stock Not Subject To Mandatory Redemption	5,283	5,283
PSO-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO	75,000	75,000
Long-term Debt	345,129	450,822
TOTAL CAPITALIZATION	905,636	1,006,023
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	106,000	20,000
Advances from Affiliates	123,087	81,120
Accounts Payable - General	72,759	104,379
Accounts Payable - Affiliated Companies	40,857	64,556
Customer Deposits	21,041	19,294
Over-Recovered Fuel	8,720	-
Taxes Accrued	18,150	1,659
Interest Accrued	7,298	8,336
Energy Trading Contracts	167,658	385,809
Other	12,296	12,137
TOTAL CURRENT LIABILITIES	577,866	697,290
DEFERRED INCOME TAXES	296,877	312,060
DEFERRED INVESTMENT TAX CREDITS	33,992	35,783
REGULATORY LIABILITIES AND DEFERRED CREDITS	56,203	35,292
LONG-TERM ENERGY TRADING CONTRACTS	47,323	51,885
TOTAL	$1,917,897	$2,138,333

See Notes to Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES

Consolidated Statements of Cash Flows

	2001	2000	1999
	Year Ended December 31, (in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 57,759	$ 66,663	$ 61,508
Adjustments for Noncash Items:			
Depreciation and Amortization	80,245	76,418	74,736
Deferred Income Taxes	(17,751)	25,453	14,521
Deferred Investment Tax Credits	(1,791)	(1,791)	(1,791)
Changes in Certain Assets and Liabilities:			
Accounts Receivable (net)	21,405	(28,826)	(1,668)
Fuel, Materials and Supplies	(589)	677	(8,985)
Other Property and Investments	(2,809)	7,994	(2,108)
Accounts Payable	(55,319)	89,330	(8,000)
Taxes Accrued	16,491	(16,821)	(4,615)
Fuel Recovery	51,987	(36,798)	(21,709)
Transmission Coordination Agreement Settlement	-	(15,063)	15,063
Changes in Other Assets	(9,150)	4,452	10,227
Changes in Other Liabilities	9,381	(6,073)	(15,736)
Net Cash Flows From Operating Activities	149,859	165,615	111,443
INVESTING ACTIVITIES:			
Construction Expenditures	(124,520)	(176,851)	(103,122)
Other Items	(359)	-	(8,659)
Net Cash Flows Used For Investing Activities	(124,879)	(176,851)	(111,781)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	-	105,625	33,232
Retirement of Long-term Debt	(20,000)	(20,000)	(33,700)
Change in Advances From Affiliates (net)	41,967	1,951	63,277
Dividends Paid on Common Stock	(52,240)	(68,000)	(65,000)
Dividends Paid on Cumulative Preferred Stock	(213)	(212)	(212)
Net Cash Flows (Used For) From Financing Activities	(30,486)	19,364	(2,403)
Net Increase (Decrease) in Cash and Cash Equivalents	(5,506)	8,128	(2,741)
Cash and Cash Equivalents January 1	11,301	3,173	5,914
Cash and Cash Equivalents December 31	$ 5,795	$ 11,301	$ 3,173

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $38,250,000, $33,732,000 and $37,081,000 and for income taxes was $38,653,000, $25,786,000 and $23,871,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2001	December 31, 2000
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$ 480,224	$ 474,918
PREFERRED STOCK: Cumulative $100 par value - authorized shares 700,000, redeemable at the option of PSO upon 30 days notice.							
Series	Call Price December 31, 2001	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001		
Not Subject to Mandatory Redemption:							
4.00%	$105.75	-	25	9	44,606	4,460	4,460
4.24%	103.19	-	-	-	8,069	807	807
Premium						16	16
						5,283	5,283
TRUST PREFERRED SECURITIES							
PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO, 8.00%, due April 30, 2037						75,000	75,000
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						297,772	317,465
Installment Purchase Contracts						47,357	47,357
Senior Unsecured Notes						106,000	106,000
Less Portion Due Within One Year						(106,000)	(20,000)
Long-term Debt Excluding Portion Due Within One Year						345,129	450,822
TOTAL CAPITALIZATION						$ 905,636	$1,006,023

See Notes to Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES

Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
5.91	2001 - March 1	$ -	$ 6,000
6.02	2001 - March 1	-	5,000
6.02	2001 - March 1	-	9,000
6.25	2003 - April 1	35,000	35,000
7.25	2003 - July 1	65,000	65,000
7.38	2004 - December 1	50,000	50,000
6.50	2005 - June 1	50,000	50,000
7.38	2023 - April 1	100,000	100,000
Unamortized Discount		(2,228)	(2,535)
		$297,772	$317,465

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
Oklahoma Environmental Finance Authority (OEFA):			
5.90	2007 - December 1	$ 1,000	$ 1,000
Oklahoma Development Finance Authority (ODFA):			
4.875	2014 - June 1	33,700	33,700
Red River Authority of Texas:			
6.00	2020 - June 1	12,660	12,660
Unamortized Discount		(3)	(3)
Total		$47,357	$47,357

Under the terms of the installment purchase contracts, PSO is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
(a)	2002 - November 21	$106,000	$106,000

(a) A floating interest rate is determined monthly. The rate on December 31, 2001 and 2000 was 2.775% and 7.376%.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$106,000
2003	100,000
2004	50,000
2005	50,000
2006	-
Later Years	147,360
Total Principal Amount	453,360
Unamortized Discount	(2,231)
Total	$451,129

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
Index to Notes to Consolidated Financial Statements

The notes to PSO's financial statements are combined with the notes to financial statements for AEP and its other subisidiary registrants. Listed below are the combined notes that apply to PSO. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Public Service Company of Oklahoma:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Public Service Company of Oklahoma and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements of the Company for the year ended December 31, 1999, before the restatement described in Note 3 to the consolidated financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2001 and 2000 consolidated financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 consolidated financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31,				
	2001	2000	1999	1998	1997
	(in thousands)				
INCOME STATEMENTS DATA:					
Operating Revenues	$2,574,448	$1,682,726	$971,527	$952,952	$939,869
Operating Expenses	2,428,241	1,554,448	824,465	802,274	800,396
Operating Income	146,207	128,278	147,062	150,678	139,473
Nonoperating Income (Loss)	741	3,851	(1,965)	2,451	4,029
Interest Charges	57,581	59,457	58,892	55,135	50,536
Income Before Extraordinary Item	89,367	72,672	86,205	97,994	92,966
Extraordinary Loss	-	-	(3,011)	-	-
Net Income	89,367	72,672	83,194	97,994	92,966
Preferred Stock Dividend Requirements	229	229	229	705	2,467
Gain (Loss) on Reacquired Preferred Stock	-	-	-	(856)	1,819
Earnings Applicable to Common Stock	$ 89,138	$ 72,443	$ 82,965	$ 96,433	$ 92,318

	December 31,				
	2001	2000	1999	1998	1997
	(in thousands)				
BALANCE SHEETS DATA:					
Electric Utility Plant	$3,460,764	$3,319,024	$3,231,431	$3,157,911	$3,081,443
Accumulated Depreciation and Amortization	1,550,618	1,457,005	1,384,242	1,317,057	1,225,865
Net Electric Utility Plant	$1,910,146	$1,862,019	$1,847,189	$1,840,854	$1,855,578
Total Assets	$2,496,600	$2,657,956	$2,106,215	$2,081,454	$2,134,618
Common Stock and Paid-in Capital	$ 380,660	$ 380,660	$ 380,660	$ 380,660	$ 380,660
Retained Earnings	308,915	293,989	283,546	296,581	320,148
Total Common Shareholder's Equity	$ 689,575	$ 674,649	$ 664,206	$ 677,241	$ 700,808
Preferred Stock	$ 4,704	$ 4,704	$ 4,706	$ 4,707	$ 30,639
Trust Preferred Securities	$ 110,000	$ 110,000	$ 110,000	$ 110,000	$ 110,000
Long-term Debt (a)	$ 645,283	$ 645,963	$ 541,568	$ 587,673	$ 589,980
Total Capitalization and Liabilities	$2,496,600	$2,657,956	$2,106,215	$2,081,454	$2,134,618

(a) Including portion due within one year.

SWEPCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to approximately 431,000 retail customers in northeastern Texas, northwestern Louisiana, and western Arkansas. SWEPCo also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Wholesale power marketing and trading activities are conducted on SWEPCo's behalf by AEP. SWEPCo, along with the other AEP electric operating subsidiaries, shares in the revenues and costs of AEP's wholesale sales to and forward trades with other utility systems and power marketers.

Critical Accounting Policies - Revenue Recognition

Regulatory Accounting - Our financial statements reflect the actions of regulators since our electricity supply sales in the Louisiana jurisdiction and our transmission and distribution operations our cost-based rate-regulated. As a result of the regulators' actions our financial statements can recognize revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

Traditional Electricity Supply and Delivery Activities – We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to SWEPCo. Trading activities allocated to SWEPCo involve the purchase and sale of energy under physical forward contracts at fixed and variable prices. Although trading contracts are generally short-term, there are also long-term trading contracts. We generally recognize revenues from trading activities based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts as revenues prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt and net settle in cash, the unrealized gain or loss is reversed out of revenues and the actual realized cash gain or loss is recognized in revenues for a sale or in purchased power expense for a purchase. Therefore, over the trading contract's term an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

Our trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity in July. At the end of each month until the contract settles in July, we would record any difference between the contract price and the market price as an unrealized gain or loss in revenues. In July when the contract settles, we would realize the gain or loss in cash and reverse to revenues the previously recorded unrealized gain or loss. Prior to settlement, the change in the fair value of physical forward sale and purchase contracts is included in revenues on a net basis. Upon settlement of a forward trading contract, the amount realized is included in revenues for a sales contract and realized costs are included in purchased power expense for a purchase contract with the prior change in unrealized fair value reversed in revenues.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity in July. If we do nothing else with these contracts until settlement in July and if the volumes, delivery point, schedule and other key terms match then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on results of operations but will have an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on revenues from recording additional changes in fair values using mark-to-market accounting.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading and derivative contracts exposing SWEPCo to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Results of Operations

Net income increased $16.7 million or 23% for the year resulting from the favorable impact of our sharing in AEP's power marketing and trading activities for a full year. The $10.5 million or 13% decrease in net income in 2000 is due to increased operating expenses.

Operating Revenues

The significant increase in 2001 operating revenues resulted from increased trading volumes of the wholesale business and a full year of our participation in AEP's power marketing and trading operations since the merger in June 2000.

Operating revenues significantly increased in 2000 due to the post merger sharing of AEP's power marketing and trading sales, and offset an unfavorable revenue adjustment in 1999 as a result of FERC's approval of a transmission coordination agreement. The transmission coordination agreement provides the means by which the AEP West electric operating companies plan, operate and maintain their separate transmission assets as a single system. The agreement also establishes the method by which these companies allocate transmission revenues received under open access transmission tariffs.

The following analyzes the changes in operating revenues:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2001		2000	
	Amount	%	Amount	%
Retail*	$ 14.3	3	$ 29.9	6
Wholesale				
Marketing and Trading	822.3	111	622.9	N.M.
Mark to Market	15.5	N.M.	(4.7)	N.M.
Other	35.4	113	8.5	37
Total Marketing and Trading	887.5	70	656.6	106
Energy Delivery*	(11.9)	(3)	45.6	15
Sales to AEP Affiliates	16.1	26	9.0	17
Total Revenues	$891.7	53	$711.2	73

N.M. = Not Meaningful

* Reflects the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

The significant increase in wholesale revenues in 2001 and 2000 is attributable to SWEPCo's participation in AEP's power marketing and trading operations after the merger of CSW and AEP. Revenues also increased in 2000 because of additional fuel and purchased power revenues and a rise in sales volume caused by warmer summer temperatures. The increase in fuel and purchased power revenues reflects rising prices for natural gas used for generation and related higher costs for purchased power. The Texas and Arkansas fuel clause recovery mechanisms provide for the accrual of fuel-related revenues until reviewed and approved for billing to customers by the regulator. The accrual of additional fuel-related revenues is generally offset by increases in fuel and purchased power expenses. As a result fuel-related revenues do not impact results of operations. Since SWEPCo became a subsidiary of AEP as a result of the merger in June 2000, SWEPCo shares in the AEP System's power marketing and trading transactions with other entities. Trading transactions involve the purchase and sale of substantial amounts of electricity.

Operating Expenses Increase

Total operating expenses increased 56% in 2001 and 89% for 2000. These increases are mainly attributable to our sharing in AEP's power marketing and trading activities since the merger in June 2000. The changes in the components of operating expenses were:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2001		2000	
	Amount	%	Amount	%
Fuel	$(41.2)	(8)	$119.2	31
Electricity Marketing and Trading Purchases	840.4	135	593.1	N.M.
Affiliated Purchases	27.9	N.M.	5.8	77
Other Operation	14.3	9	17.2	12
Maintenance	(.4)	N.M.	10.9	17
Depreciation and Amortization	14.9	14	(4.2)	(4)
Taxes Other Than Income Taxes	2.0	4	N.M.	N.M.
Income Taxes	15.9	60	(12.0)	(31)
Total	$873.8	56	$730.0	89

N.M. = Not Meaningful

Fuel expense decreased in 2001 from lower natural gas prices and a mild summer resulting in a reduction in generation. Fuel expense increased in 2000 due to an increase in the average unit cost of fuel as a result of an increase in the spot market price for natural gas and an increase in generation to meet the rise in demand for electricity.

The major increases in purchased power expense in 2001 and 2000 were primarily caused by our sharing in AEP's power marketing and trading activities.

Due to the acquisition of Dolet Hills mining operation in June 2001, other operation expense increased for the year. Other operation expense increased in 2000 due primarily to increased regulatory and consulting expenses.

Maintenance expense increased in 2000 as a result of costs to restore service and make repairs following a severe ice storm.

Depreciation and amortization expense increased in 2001 due primarily to an increase in excess earnings accruals under the Texas restructuring legislation and the acquisition of Dolet Hills mining operation.

The increase in 2001 income tax expense was primarily due to an increase in pre-tax book income. The decrease in income tax expense attributable to operations in 2000 was primarily due to a decrease in pre-tax operating income.

Nonoperating Expense

The decrease in nonoperating expense in 2000 was due to the effect of a 1999 write off of acquisition expenses following CSW's decision not to continue to pursue the acquisition of Cajun Electric Power Cooperatives non-nuclear assets.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Income

	Year Ended December 31, 2001	2000	1999
		(in thousands)	
OPERATING REVENUES:			
Electricity Marketing and Trading	$2,162,207	$1,274,652	$618,040
Energy Delivery	333,004	344,950	299,369
Sales to AEP Affiliates	79,237	63,124	54,118
TOTAL OPERATING REVENUES	2,574,448	1,682,726	971,527
OPERATING EXPENSES:			
Fuel	457,613	498,805	379,597
Purchased Power:			
Electricity Marketing and Trading	1,463,377	622,970	29,820
AEP Affiliates	41,250	13,338	7,551
Other Operation	173,831	159,459	142,385
Maintenance	74,677	75,123	64,241
Depreciation and Amortization	119,543	104,679	108,831
Taxes Other Than Income Taxes	55,834	53,830	53,783
Income Taxes	42,116	26,244	38,257
TOTAL OPERATING EXPENSES	2,428,241	1,554,448	824,465
OPERATING INCOME	146,207	128,278	147,062
NONOPERATING INCOME	4,512	5,487	2,550
NONOPERATING EXPENSES	3,229	3,112	9,341
NONOPERATING INCOME TAX EXPENSE (CREDIT)	542	(1,476)	(4,826)
INTEREST CHARGES	57,581	59,457	58,892
INCOME BEFORE EXTRAORDINARY ITEM	89,367	72,672	86,205
EXTRAORDINARY LOSS (net of tax of $1,621,000)	-	-	(3,011)
NET INCOME	89,367	72,672	83,194
PREFERRED STOCK DIVIDEND REQUIREMENTS	229	229	229
EARNINGS APPLICABLE TO COMMON STOCK	$ 89,138	$ 72,443	$ 82,965

Consolidated Statements of Retained Earnings

	2001	2000	1999
BALANCE AT BEGINNING OF PERIOD	$293,989	$283,546	$296,581
NET INCOME	89,367	72,672	83,194
DEDUCTIONS:			
Cash Dividends Declared:			
Common Stock	74,212	62,000	96,000
Preferred Stock	229	229	229
BALANCE AT END OF PERIOD	$308,915	$293,989	$283,546

See Notes to Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$1,429,356	$1,414,527
Transmission	538,749	519,317
Distribution	1,042,523	1,001,237
General	376,016	325,948
Construction Work in Progress	74,120	57,995
Total Electric Utility Plant	3,460,764	3,319,024
Accumulated Depreciation and Amortization	1,550,618	1,457,005
NET ELECTRIC UTILITY PLANT	1,910,146	1,862,019
OTHER PROPERTY AND INVESTMENTS	43,000	39,627
LONG-TERM ENERGY TRADING CONTRACTS	63,372	62,605
CURRENT ASSETS:		
Cash and Cash Equivalents	5,415	1,907
Accounts Receivable:		
Customers	42,326	42,310
Affiliated Companies	20,573	11,419
Allowance for Uncollectible Accounts	(89)	(911)
Fuel Inventory - at average cost	52,212	40,024
Materials and Supplies - at average cost	32,527	25,137
Under-recovered Fuel Costs	2,501	35,469
Energy Trading Contracts	186,159	453,781
Prepayments	18,716	16,780
TOTAL CURRENT ASSETS	360,340	625,916
REGULATORY ASSETS	51,989	57,082
DEFERRED CHARGES	67,753	10,707
TOTAL	$2,496,600	$2,657,956

See Notes to Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $18 Par Value:		
Authorized - 7,600,000 Shares		
Outstanding - 7,536,640 Shares	$ 135,660	$ 135,660
Paid-in Capital	245,000	245,000
Retained Earnings	308,915	293,989
Total Common Shareholder's Equity	689,575	674,649
Preferred Stock	4,704	4,704
SWEPCO-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of SWEPCO	110,000	110,000
Long-term Debt	494,688	645,368
TOTAL CAPITALIZATION	1,298,967	1,434,721
OTHER NONCURRENT LIABILITIES	34,997	11,290
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	150,595	595
Advances from Affiliates	123,609	16,823
Accounts Payable - General	71,810	107,747
Accounts Payable - Affiliated Companies	37,469	36,021
Customer Deposits	19,880	16,433
Taxes Accrued	36,522	11,224
Interest Accrued	13,631	13,198
Energy Trading Contracts	192,318	462,043
Other	26,166	15,064
TOTAL CURRENT LIABILITIES	672,000	679,148
DEFERRED INCOME TAXES	369,781	399,204
DEFERRED INVESTMENT TAX CREDITS	48,714	53,167
REGULATORY LIABILITIES AND DEFERRED CREDITS	17,828	18,288
LONG-TERM ENERGY TRADING CONTRACTS	54,313	62,138
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$2,496,600	$2,657,956

See Notes to Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 89,367	$ 72,672	$ 83,194
Adjustments for Noncash Items:			
Depreciation and Amortization	119,543	104,679	108,831
Deferred Income Taxes	(31,396)	14,653	(17,347)
Deferred Investment Tax Credits	(4,453)	(4,482)	(4,565)
Mark-to-Market of Energy Trading Contracts	(3,472)	4,677	-
Changes in Certain Assets and Liabilities:			
Accounts Receivable (net)	(9,992)	(1,254)	(11,134)
Fuel, Materials and Supplies	(19,578)	22,103	(21,891)
Accounts Payable	(34,489)	43,962	(12,953)
Taxes Accrued	25,298	(13,150)	1,185
Transmission Coordination Agreement Settlement	-	(24,406)	24,406
Fuel Recovery	32,968	(38,357)	(2,490)
Change in Other Assets	856	57,418	24,500
Change in Other Liabilities	4,958	(36,887)	(15,769)
Net Cash Flows From Operating Activities	169,610	201,628	155,967
INVESTING ACTIVITIES:			
Construction Expenditures	(111,725)	(120,671)	(111,019)
Purchase of Dolet Hills Mining Operations	(85,716)	-	-
Other	(411)	446	(4,167)
Net Cash Flows Used For Investing Activities	(197,852)	(120,225)	(115,186)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	-	149,360	-
Redemption of Preferred Stock	-	(1)	(1)
Retirement of Long-term Debt	(595)	(45,595)	(46,144)
Change in Advances From Affiliates (net)	106,786	(124,074)	100,192
Dividends Paid on Common Stock	(74,212)	(62,000)	(96,000)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows From (Used For) Financing Activities	31,750	(82,539)	(42,182)
Net Increase (Decrease) in Cash and Cash Equivalents	3,508	(1,136)	(1,401)
Cash and Cash Equivalents January 1	1,907	3,043	4,444
Cash and Cash Equivalents December 31	$ 5,415	$ 1,907	$ 3,043

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $51,126,000, $51,111,000 and $55,254,000 and for income taxes was $49,901,000, $27,994,000 and $55,677,000 in 2001, 2000, and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
COMMON SHAREHOLDER'S EQUITY						$ 689,575	$ 674,649
PREFERRED STOCK: $100 par value - authorized shares 1,860,000							
Series	Call Price December 31, 2001	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001		
Not Subject to Mandatory Redemption:							
4.28%	$103.90	-	-	-	7,386	739	739
4.65%	$102.75	-	-	1	1,907	190	190
5.00%	$109	-	12	2	37,715	3,771	3,771
Premium						4	4
						4,704	4,704
TRUST PREFERRED SECURITIES SWEPCo-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCo, 7.875%, due April 30, 2037						110,000	110,000
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						315,449	315,477
Installment Purchase Contracts						179,834	180,486
Senior Unsecured Notes						150,000	150,000
Less Portion Due Within One Year						(150,595)	(595)
Long-term Debt Excluding Portion Due Within One Year						494,688	645,368
TOTAL CAPITALIZATION						$1,298,967	$1,434,721

See Notes to Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
6-5/8	2003 - February 1	$ 55,000	$ 55,000
7-3/4	2004 - June 1	40,000	40,000
6.20	2006 - November 1	5,650	5,795
6.20	2006 - November 1	1,000	1,000
7.00	2007 - September 1	90,000	90,000
7-1/4	2023 - July 1	45,000	45,000
6-7/8	2025 - October 1	80,000	80,000
Unamortized Discount		(1,201)	(1,318)
		$315,449	$315,477

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
DeSoto County:			
7.60	2019 - January 1	$ 53,500	$ 53,500
Sabine:			
6.10	2018 - April 1	81,700	81,700
Titus County:			
6.90	2004 - November 1	12,290	12,290
6.00	2008 - January 1	13,070	13,520
8.20	2011 - August 1	17,125	17,125
Unamortized Premium		2,149	2,351
		$179,834	$180,486

Under the terms of the installment purchase contracts, SWEPCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2001 (in thousands)	December 31, 2000 (in thousands)
(a)	2002 - March 1	$150,000	$150,000

(a) A floating interest rate is determined monthly. The rate on December 31, 2001 and 2000 was 2.311% and 6.97%.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$150,595
2003	55,595
2004	52,885
2005	595
2006	6,520
Later Years	378,145
Total Principal Amount	644,335
Unamortized Premium	948
Total	$645,283

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES

Index to Notes to Consolidated Financial Statements

The notes to SWEPCo's financial statements are combined with the notes to financial statements for AEP and its other subisidiary registrants. Listed below are the combined notes that apply to SWEPCo. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southwestern Electric Power Company and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements of the Company for the year ended December 31, 1999, before the restatement described in Note 3 to the consolidated financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2001 and 2000 consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 consolidated financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

WEST TEXAS UTILITIES COMPANY

WEST TEXAS UTILITIES COMPANY

Selected Financial Data

	2001	2000	1999	1998	1997
			Year Ended December 31, (in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,064,271	$759,562	$445,709	$424,953	$397,779
Operating Expenses	1,030,881	707,221	391,910	365,677	353,195
Operating Income	33,390	52,341	53,799	59,276	44,584
Nonoperating Income (Loss)	2,195	(1,675)	2,488	2,712	1,463
Interest Charges	23,275	23,216	24,420	24,263	24,570
Income Before Extraordinary Item	12,310	27,450	31,867	37,725	21,477
Extraordinary Loss	-	-	(5,461)	-	-
Net Income	12,310	27,450	26,406	37,725	21,477
Preferred Stock Dividend Requirements	104	104	104	104	144
Gain on Reacquired Preferred Stock	-	-	-	-	1,085
Earnings Applicable to Common Stock	$ 12,206	$ 27,346	$ 26,302	$ 37,621	$ 22,418

	2001	2000	1999	1998	1997
			December 31, (in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$1,260,872	$1,229,339	$1,182,544	$1,146,582	$1,108,845
Accumulated Depreciation and Amortization	546,162	515,041	495,847	473,503	441,281
Net Electric Utility Plant	$ 714,710	$ 714,298	$ 686,697	$ 673,079	$ 667,564
Total Assets	$ 923,420	$1,087,411	$ 861,205	$ 819,446	$ 826,858
Common Stock and Paid-in Capital	$ 139,450	$ 139,450	$ 139,450	$ 139,450	$ 139,450
Retained Earnings	105,970	122,588	113,242	114,940	117,319
Total Common Shareholder's Equity	$ 245,420	$ 262,038	$ 252,692	$ 254,390	$ 256,769
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 2,482	$ 2,482	$ 2,482	$ 2,482	$ 2,483
Long-term Debt (a)	$ 255,967	$ 255,843	$ 303,686	$ 303,518	$ 303,351
Total Capitalization And Liabilities	$ 923,420	$1,087,411	$ 861,205	$ 819,446	$ 826,858

(a) Including portion due within one year.

WTU is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power and provides electric power to approximately 189,000 retail customers in west and central Texas. WTU also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Wholesale power marketing and trading activities are conducted on WTU's behalf by AEP. WTU, along with the other AEP electric operating subsidiaries, shares in the revenues and costs of AEP's wholesale sales to and forward trades with other utility systems and power marketers.

Critical Accounting Policies – Revenue Recognition

Regulatory Accounting - As a result of our cost-based rate-regulated transmission and distribution operations, our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities – We recognize revenues on an accrual basis for electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general expenses are recorded when incurred.

Energy Marketing and Trading Activities – AEP engages in wholesale electricity marketing and trading transactions (trading activities). A portion of the revenues and costs of AEP's trading activities are allocated to WTU. Trading activities allocated to WTU involve the purchase and sale of energy under physical forward contracts at fixed and variable prices. Although trading contracts are generally short-term, there are also long-term trading contracts. We recognize revenues from trading activities generally based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts as revenues prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt of electricity and net settle in cash, the unrealized gain or loss is reversed out of revenues and the actual realized cash gain or loss is recognized in revenues for a sale or in purchased power expense for a purchase. Therefore, over the trading contract's term an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading contract assets or liabilities as appropriate.

Our trading activities represent physical forward electricity contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity in July. At the end of each month until the contract settles in July, we would record our share of any difference between the contract price and the market price as an unrealized gain or loss in revenues. In July when the contract settles, we would realize our share of the gain or loss in cash and reverse to revenues the previously recorded unrealized gain or loss. Prior to settlement, the change in the fair value of physical forward sale and purchase contracts is included in revenues on a net basis. Upon settlement of a forward trading contract, the amount realized is included in revenues for a sales contract and realized costs are included in purchased power expense for a purchase contract with the prior change in unrealized fair value reversed in revenues.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity in July. If we do nothing else with these contracts until settlement in July and if the volumes, delivery point, schedule and other key terms match, then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on results of operations but will have an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on revenues from recording additional changes in fair values using mark-to-market accounting.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on AEP-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. AEP has independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the AEP-developed price models.

Volatility in commodities markets affects the fair values of all of our open trading contracts exposing WTU to market risk. See "Market Risks" section of MD&A for a discussion of the policies and procedures used to manage exposure to risk from trading activities.

Results of Operations

Income before extraordinary items decreased $15.1 million or 55% during 2001, due mostly to a significant increase in other operation expense. The significant increase in other operation expense is partially due to the effect of a 2001 increase in energy delivery's transmission expenses that resulted from new prices for the Electric Reliability Council of Texas (ERCOT) transmission grid. Other operation expense also increased due to the effect of a favorable adjustment made in 2000 related to a FERC-approved

Transmission Coordination Agreement.

Operating Revenues

Operating revenues increased 40% in 2001, as the result of increased trading volumes of AEP's wholesale business. This increase in revenues is attributable to our sharing in AEP's power marketing and trading transactions since the merger of AEP and CSW in June 2000.

Changes in the components of operating revenues were as follows:

	Increase (Decrease) From Previous Year	
(dollars in millions)	Amount	%
Retail*	$ (3.1)	(2)
Wholesale Electric		
Marketing and Trading	301.9	91
Unrealized MTM	6.3	N.M.
Other	6.8	18
Total Marketing and Trading	311.9	55
Energy Delivery*	(7.2)	(4)
Total Revenues	$304.7	40

*Reflects the allocation of certain transmission and distribution revenues included in bundled retail rates to energy delivery.

Revenues from retail customers decreased slightly in 2001 due to milder than normal summer and winter weather.

The significant increase in wholesale marketing and trading revenues is attributable to WTU's increased sharing in AEP's power marketing and trading operations. Since WTU became a subsidiary of AEP as the result of the merger in June 2000, WTU shares in AEP's power marketing and trading transactions. Trading involves the sale and purchase of substantial amounts of electricity to and from non-affiliated parties.

Operating Expenses

Due mostly to an increase in purchased power expense, operating expenses were $323.7 million or 46% higher than 2000. Charges in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year	
(dollars in millions)	Amount	%
Fuel	$ (6.0)	(3)
Marketing and		
Trading Purchases	321.6	125
Affiliate Purchases	(1.1)	(2)
Other Operation	18.2	20
Maintenance	1.1	5
Depreciation and Amortization	(4.5)	(8)
Taxes Other Than Income Taxes	3.0	12
Income Taxes	(8.6)	(58)
Total	$323.7	46

Fuel expense decreased in 2001 due to a decrease in generation offset in part by an increase in the average spot market price for natural gas. The decrease in generation reflects milder than normal summer and winter weather.

The significant increase in electricity marketing and trading purchases is the result of our full year of sharing in AEP's power marketing and trading activities.

Other operation expense increased from the prior year primarily due to the effect of two items. First, energy delivery's transmission expenses increased as a result of new prices for the ERCOT transmission grid. The increase in other operation expense is also attributable to a favorable adjustment made in 2000 related to the FERC-approved Transmission Coordination Agreement.

An increase in maintenance expense is the result of an overhaul in 2001 of the Oklaunion Power Plant.

Due to the recordation of increased accruals in 2000 for estimated excess earnings under the Texas Legislation, depreciation and amortization expense decreased during 2001.

The increase in taxes other than income taxes is the result of an increase in Texas franchise tax assessments and an increase in the Texas PUCT benefit assessment tax, a new tax in the state of Texas.

Income taxes decreased in 2001, reflecting a decrease in pre-tax income.

Nonoperating Income

Nonoperating income increased $2.7 million due to an increase in interest income earned on under-recovered fuel during 2001.

Nonoperating Expense

The decrease in nonoperating expenses is mainly due to the effect of a loss provision that was recorded in 2000 for the termination of merchandise sales and the cost of phasing out the merchandising sales programs.

WEST TEXAS UTILITIES COMPANY
Statements of Income

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
OPERATING REVENUES			
Electricity Marketing and Trading	$ 876,554	$ 564,704	$256,033
Energy Delivery	169,036	176,204	174,909
Sales to AEP Affiliates	18,681	18,654	14,767
Total Operating Revenues	1,064,271	759,562	445,709
OPERATING EXPENSES:			
Fuel	177,140	183,154	123,348
Purchased Power:			
Electricity Marketing and Trading	578,193	256,578	34,941
AEP Affiliates	56,656	57,773	26,591
Other Operation	111,263	93,078	94,290
Maintenance	22,343	21,241	19,604
Depreciation and Amortization	50,705	55,172	50,789
Taxes Other Than Income Taxes	28,319	25,321	28,268
Income Taxes	6,262	14,904	14,079
TOTAL OPERATING EXPENSES	1,030,881	707,221	391,910
OPERATING INCOME	33,390	52,341	53,799
NONOPERATING INCOME	12,199	9,530	14,515
NONOPERATING EXPENSES	10,695	12,664	11,169
NONOPERATING INCOME TAX EXPENSE (CREDIT)	(691)	(1,459)	858
INTEREST CHARGES	23,275	23,216	24,420
INCOME BEFORE EXTRAORDINARY ITEMS	12,310	27,450	31,867
EXTRAORDINARY LOSS (net of tax of $2,941,000)	-	-	(5,461)
NET INCOME	12,310	27,450	26,406
PREFERRED STOCK DIVIDEND REQUIREMENTS	104	104	104
EARNINGS APPLICABLE TO COMMON STOCK	$ 12,206	$ 27,346	$ 26,302

Statements of Retained Earnings

	2001	2000	1999
BEGINNING OF PERIOD	$122,588	$113,242	$114,940
NET INCOME	12,310	27,450	26,406
DEDUCTIONS:			
Cash Dividends Declared:			
Common Stock	28,824	18,000	28,000
Preferred Stock	104	104	104
BALANCE AT END OF PERIOD	$105,970	$122,588	$113,242

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY
Balance Sheets

	December 31, 2001	December 31, 2000
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$ 443,508	$ 431,793
Transmission	250,023	235,303
Distribution	431,969	416,587
General	112,797	110,832
Construction Work in Progress	22,575	34,824
Total Electric Utility Plant	1,260,872	1,229,339
Accumulated Depreciation and Amortization	546,162	515,041
NET ELECTRIC UTILITY PLANT	714,710	714,298
OTHER PROPERTY AND INVESTMENTS	24,933	23,154
LONG-TERM ENERGY TRADING CONTRACTS	21,532	20,804
CURRENT ASSETS:		
Cash and Cash Equivalents	2,454	6,941
Accounts Receivable:		
Customers	18,720	36,217
Affiliated Companies	8,656	16,095
Allowance for Uncollectible Accounts	(196)	(288)
Fuel - at average cost	8,307	12,174
Materials and Supplies - at average cost	11,190	10,510
Under-recovered Fuel Costs	32,791	68,107
Energy Trading Contracts	63,252	150,793
Prepayments	966	851
TOTAL CURRENT ASSETS	146,140	301,400
REGULATORY ASSETS	13,659	24,808
DEFERRED CHARGES	2,446	2,947
TOTAL	$ 923,420	$1,087,411

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY

	December 31, 2001	December 31, 2000
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $25 Par Value:		
Authorized - 7,800,000 Shares		
Outstanding - 5,488,560 Shares	$137,214	$ 137,214
Paid-in Capital	2,236	2,236
Retained Earnings	105,970	122,588
Total Common Shareholder's Equity	245,420	262,038
Cumulative Preferred Stock		
Not Subject to Mandatory Redemption	2,482	2,482
Long-term Debt	220,967	255,843
TOTAL CAPITALIZATION	468,869	520,363
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	35,000	-
Advances from Affiliates	50,448	58,578
Accounts Payable - General	33,782	45,562
Accounts Payable - Affiliated Companies	11,388	42,212
Customer Deposits	4,191	2,659
Taxes Accrued	17,358	18,901
Interest Accrued	1,244	3,717
Energy Trading Contracts	65,414	153,539
Other	12,001	7,906
TOTAL CURRENT LIABILITIES	230,826	333,074
DEFERRED INCOME TAXES	145,049	157,038
DEFERRED INVESTMENT TAX CREDITS	22,781	24,052
LONG-TERM ENERGY TRADING CONTRACTS	18,455	20,648
REGULATORY LIABILITIES AND DEFERRED CREDITS	37,440	32,236
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$923,420	$1,087,411

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY
Statements of Cash Flows

	Year Ended December 31, 2001	2000	1999
	(in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 12,310	$ 27,450	$ 26,406
Adjustments for Noncash Items:			
Depreciation and Amortization	50,705	55,172	50,789
Deferred Federal Income Taxes	(11,891)	8,164	12,026
Deferred Investment Tax Credits	(1,271)	(1,271)	(1,275)
Extraordinary Loss - Discontinuance of SFAS 71	-	-	5,461
Mark-to-Market of Energy Trading Contracts	(1,818)	1,871	-
CHANGES IN CERTAIN ASSETS AND LIABILITIES:			
Accounts Receivable (net)	24,844	(1,445)	(18,890)
Fuel, Materials and Supplies	3,187	8,478	(3,785)
Accounts Payable	(42,604)	28,393	7,229
Taxes Accrued	(1,543)	6,443	2,427
Fuel Recovery	35,316	(53,841)	(10,101)
Transmission Coordination Agreement Settlement	-	15,465	(15,465)
Change in Other Assets	(1,519)	3,361	5,615
Change in Other Liabilities	6,644	(3,962)	2,205
Net Cash Flows From Operating Activities	72,360	94,278	62,642
INVESTING ACTIVITIES:			
Construction Expenditures	(39,662)	(64,477)	(49,443)
Other	(127)	-	(3,832)
Net Cash Used For Investing Activities	(39,789)	(64,477)	(53,275)
FINANCING ACTIVITIES:			
Retirement of Long-term Debt	-	(48,000)	-
Change in Advances From Affiliates (net)	(8,130)	37,170	16,835
Dividends Paid on Common Stock	(28,824)	(18,000)	(28,000)
Dividends Paid on Cumulative Preferred Stock	(104)	(104)	(105)
Net Cash Used For Financing Activities	(37,058)	(28,934)	(11,270)
Net Increase (Decrease) in Cash and Cash Equivalents	(4,487)	867	(1,903)
Cash and Cash Equivalents at Beginning of Period	6,941	6,074	7,977
Cash and Cash Equivalents at End of Period	$ 2,454	$ 6,941	$ 6,074

Supplemental Disclosure:
Cash paid (received) for interest net of capitalized amounts was $19,279,000, $19,088,000 and $17,577,000 and for income taxes was $21,997,000, $(906,000) and $3,309,000 in 2001, 2000 and 1999, respectively.

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY
Statements of Capitalization

						December 31, 2001	December 31, 2000
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$245,420	$262,038
PREFERRED STOCK: $100 par value - authorized shares 810,000							
Series	Call Price December 31, 2001	Number of Shares Redeemed Year Ended December 31, 2001	2000	1999	Shares Outstanding December 31, 2001		
Not Subject to Mandatory Redemption:							
4.40%	$107	-	1	2	23,672	2,367	2,367
Premium						115	115
						2,482	2,482
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						211,657	211,533
Installment Purchase Contracts						44,310	44,310
Less Portion Due Within One Year						(35,000)	-
Long-term Debt Excluding Portion Due Within One Year						220,967	255,843
TOTAL CAPITALIZATION						$468,869	$520,363

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY
Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2001	2000
		(in thousands)	
7-3/4	2007 - June 1	$ 25,000	$ 25,000
6-7/8	2002 - October 1	35,000	35,000
7	2004 - October 1	40,000	40,000
6-1/8	2004 - February 1	40,000	40,000
6-3/8	2005 - October 1	72,000	72,000
Unamortized Discount		(343)	(467)
		$211,657	$211,533

First mortgage bonds are secured by first mortgage liens on electric utility plant. Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2001	2000
		(in thousands)	
Red River Authority of Texas:			
6	2020 - June 1	$44,310	$44,310

Under the terms of the installment purchase contracts, WTU is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

At December 31, 2001, future annual long-term debt payments are as follows:

	Amount (in thousands)
2002	$ 35,000
2003	-
2004	80,000
2005	72,000
2006	-
Later Years	69,310
Principal Amount	256,310
Unamortized Discount	(343)
Total	$255,967

WEST TEXAS UTILITIES COMPANY
Index to Notes to Financial Statements

The notes to WTU's financial statements are combined with the notes to financial statements for AEP and its other subisidiary registrants. Listed below are the combined notes that apply to WTU. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of West Texas Utilities Company:

We have audited the accompanying balance sheets and statements of capitalization of West Texas Utilities Company as of December 31, 2001 and 2000, and the related statements of income, retained earnings, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The financial statements of the Company for the year ended December 31, 1999, before the restatement described in Note 3 to the financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2001 and 2000 financial statements present fairly, in all material respects, the financial position of West Texas Utilities Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2002

NOTES TO FINANCIAL STATEMENTS

The notes to financial statements that follow are a combined presentation for AEP and its subsidiary registrants. The following list of footnotes shows the registrant to which they apply:

1. Significant Accounting Policies	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
2. Extraordinary Items and Cumulative Effect	AEP, APCo, CPL, CSPCo, OPCo, SWEPCo, WTU
3. Merger	AEP, CPL, I&M, KPCo, PSO, SWEPCo, WTU
4. Nuclear Plant Restart	AEP, I&M
5. Rate Matters	AEP, APCo, CPL, PSO, SWEPCo, WTU
6. Effects of Regulation	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
7. Customer Choice and Industry Restructuring	AEP, APCo, CPL, CSPCo, I&M, OPCo, PSO, SWEPCo, WTU
8. Commitments and Contingencies	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
9. Acquisitions and Dispositions	AEP, OPCo, SWEPCo
10. Benefit Plans	AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
11. Stock-Based Compensation	AEP
12. Business Segments	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
13. Risk Management, Financial Instruments and Derivatives	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
14. Income Taxes	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
15. Basic and Diluted Earnings Per Share	AEP
16. Supplementary Information	AEP, APCo, CSPCo, I&M, OPCo
17. Power, Distribution and Communications Projects	AEP
18. Leases	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
19. Lines of Credit and Sale of Receivables	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU

20. Unaudited Quarterly Financial Information	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
21. Trust Preferred Securities	AEP, CPL, PSO, SWEPCo
22. Minority Interest in Finance Subsidiary	AEP
23. Jointly Owned Electric Utility Plant	CPL, CSPCo, PSO, SWEPCo, WTU
24. Related Party Transactions	AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU

1. Significant Accounting Policies:

Business Operations – AEP's principal business conducted by its eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. Nine of AEP's eleven domestic electric utility operating companies, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU, are SEC registrants. AEGCo is a domestic generating company wholly-owned by AEP that is an SEC registrant. These companies are subject to regulation by the FERC under the Federal Power Act and follow the Uniform System of Accounts prescribed by FERC. They are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP also engages in wholesale marketing and trading of electricity, natural gas and to a lesser extent coal, oil, natural gas liquids and emission allowances in the United States and Europe. In addition the Company's domestic operations includes non-regulated independent power and cogeneration facilities, coal mining and intra-state midstream natural gas operations in Louisiana and Texas.

International operations include regulated supply and distribution of electricity and other non-regulated power generation projects in the United Kingdom, Australia, Mexico, South America and China.

The Company also operates domestic barging, provides energy services worldwide and furnishes communications related services domestically.

Rate Regulation – AEP is subject to regulation by the SEC under the PUHCA. The rates charged by the domestic utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates. The prices charged by foreign subsidiaries located in the UK, Australia, China, Mexico and Brazil are regulated by the authorities of that country and are generally subject to price controls.

Principles of Consolidation – AEP's consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned or substantially controlled subsidiaries. The consolidated financial statements for APCo, CPL, CSPCo, I&M, OPCo, PSO and SWEPCo include the registrant and its wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method with their equity earnings included in Other Income for AEP and nonoperating income for the registrant subsidiaries.

Basis of Accounting - As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. Application of SFAS 71 for the generation portion of the business was discontinued as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by CPL, WTU, and SWEPCo in September 1999 and in Arkansas by SWEPCo in September 1999. See Note 7, "Customer Choice and Industry Restructuring" for additional information.

Use of Estimates - The preparation of these financial statements in conformity with generally accepted accounting principles necessarily includes the use of estimates and assumptions by management. Actual results could differ from those estimates.

Property, Plant and Equipment – Domestic electric utility property, plant and equipment are stated at original cost of the acquirer. Property, plant and equipment of the non-regulated domestic operations and other investments are stated at their fair market value at acquisition plus as domestic barging, telecommunications and related services. The revenues associated with these activities are recorded when earned as physical commodities are delivered to contractual meter points or services are provided. These revenues also include the accrual of earned, but unbilled and/or not yet metered revenues. Such revenues are based on contract prices or tariffs and presented on a gross basis consistent with generally accepted accounting principles and industry practice. Revenue recognition for energy marketing and trading transactions is further discussed within the *Energy Marketing and Trading Transactions* section below. The Company follows EITF 98-10 and marks to market energy trading activities, which includes the net change in fair value of open trading contracts in earnings. Mark-to-market gains and losses on open contracts and net settlements of financial contracts (see below) are included in revenues on a net basis. The net basis of reporting for open contracts is permitted by EITF 98-10 and for settled financial contracts is consistent with industry practice. Settled physical forward trading transactions are reported on a gross basis, as permitted by EITF 98-10. Management believes that the gross basis of reporting for settled physical forward trading contracts is a better indication of the scope and significance of energy trading activities to the Company.

Energy Marketing and Trading Transactions – AEP engages in wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities inolve the purchase and sale of energy under forward contracts at fixed and variable prices and the trading of financial energy contracts which includes exchange futures and options and over-the-counter options and swaps. Although trading contracts are generally short-term, there are long-term trading contracts.

The majority of trading activities represent forward electricity and gas contracts that are typically settled by entering into offsetting physical contracts. Forward trading sale contracts are included in AEP's revenues when the contracts settle. Forward trading purchase contracts are included in AEP's fuel and purchased energy expenses when they settle. Prior to settlement the change in fair values of forward sale and purchase contracts are included in AEP's revenues.

All of the registrant subsidiaries except AEGCo participate in AEP's wholesale marketing and trading of electricity. APCo, CSPCo, I&M, KPCo and OPCo record forward electricity trading sale contracts in operating revenues when the contracts settle for contracts with delivery points in AEP's traditional marketing area and in nonoperating income for forward electricity trading sale contracts outside AEP's traditional marketing area. APCo, CSPCo, I&M, KPCo and OPCo record forward electricity trading purchase contracts in purchased power expense when the contracts settle for contracts with delivery points in AEP's traditional marketing area and in nonoperating expense for forward electricity trading purchase contracts outside AEP's traditional marketing area. CPL, PSO, SWEPCo and WTU record revenues from forward electricity trading sale contracts in operating revenues. CPL, PSO, SWEPCo and WTU record purchased power expense for forward electricity trading purchase contracts when they settle.

APCo, CSPCo and OPCo account for open forward electricity sale and purchase contracts on a mark-to-market basis and include the mark-to-market change in operating revenues for open contracts in AEP's traditional marketing area and in nonoperating income for open contracts beyond AEP's traditional marketing area.

I&M and KPCo account for open forward electricity sale and purchase contracts on a mark-to-market basis and defer the mark-to-market change as regulatory assets or liabilities for those open contracts in AEP's traditional marketing area and include the mark-to-market change in nonoperating income for open contracts beyond AEP's traditional marketing area.

CPL, PSO, SWEPCo and WTU account for open forward electricity sale and purchase contracts on a mark-to-market basis. CPL includes the mark-to-market change for open electricity trading contracts in revenues. PSO defers as regulatory assets or liabilities the mark-to-market change for open forward electricity trading contracts that are included in cost of service on a settlement basis for ratemaking purposes. SWEPCo and WTU include the jurisdictional share of the mark-to-market change in revenues for open electricity trading contracts for those jurisdictions that are not subject to SFAS 71 cost based rate regulation and defer as regulatory assets or liabilities the jurisdictional share of the mark-to-market change for open contracts that are included in cost of service on a settlement basis for ratemaking purposes.

Trading purchases and sales through electricity and gas options, futures and swaps, represent financial transactions with the net proceeds reported in AEP's revenues at fair value upon entering the contracts.

APCo, CSPCo, I&M, KPCo and OPCo share in AEP's trading sales and purchases through electricity options, futures and swaps, which represent financial transactions. Changes in fair values of these financial contracts are reported net in nonoperating income. When these contracts settle, the net proceeds are recorded in nonoperating income and the prior unrealized gain or loss in reversed.

Recording of the net changes in fair value of open trading contracts is commonly referred to a mark-to-market accounting.

All open contracts from trading activities are marked to market in accordance with EITF 98-10. Except as noted above, the net mark-to-market (change in fair value) amount included in results of operations on a net discounted basis. The fair values of open short-term trading contracts are based on exchange prices and broker quotes. Open long-term trading contracts are marked to market based mainly on AEP developed valuation models. The valuation models produce an extimated fair value for open long-term trading contracts. The short-term and long-term fair values are present valued and reduced by appropriate reserves for counterparty credit risks and liquidity risk. The models are derived from internally assessed market prices with the exception of the NYMEX gas curve, where we use daily settled prices. Bid/ask price curves are developed for inclusion in the model based on broker quotes and other available market data. The curves are within the range between the bid and ask price. The end of the month liquidity reserve is based on the difference in price between the price curve and the bid side of the bid ask if we have a long position and the ask side if we have a short position. This provides for a conservative valuation net of the reserves. The use of these models to fair value open trading contracts has inherent risks relating to the underlying assumptions employed by such models. Independent controls are in place to evaluate the reasonableness of the price curve models. Significant adverse or favorable effects on future results of operations and cash flows could occur if market risks, at the time of settlement, do not correlate with AEP developed price models.

The effect on AEP's Consolidated Statements of Income of marking to market open electricity trading contracts in AEP's regulated jurisdictions is deferred as regulatory assets or liabilities since these transactions are included in cost of service on a settlement basis for ratemaking purposes. Unrealized mark-to-market gains and losses from trading activities whether deferred or recognized in revenues are part of Energy Trading and Derivative Contracts assets or liabilities as appropriate.

Hedging and Related Activities – In order to mitigate the risks of market price and interest rate fluctuations, AEP's foreign subsidiaries, SEEBOARD and CitiPower, utilize interest swaps, and currency swaps to hedge such market fluctuations. Changes in the market value of these swaps are deferred until the gain or loss is realized on the underlying hedged asset, liability or commodity. To qualify as a hedge, these transactions must be designated as a hedge and changes in their fair value must correlate with changes in the price and interest rate movement of the underlying asset, liability or commodity. This in effect reduces AEP's exposure to the effects of market fluctuations related to price and interest rates.

AEP, APCo, CSPCo, I&M, and OPCo enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2001 or 2000. See Note 13 – "Risk Management, Financial Instruments and Derivatives" for further discussion of the accounting for risk management transactions.

Levelization of Nuclear Refueling Outage Costs - In order to match costs with regulated revenues, incremental operation and maintenance costs associated with periodic refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

Maintenance Costs – Maintenance costs are expensed as incurred except where SFAS 71 requires the recordation of a regulatory asset to match the expensing of maintenance costs with their recovery in cost based regulated revenues. See below for an explanation of costs deferred in connection with an extended outage at I&M's Cook Plant.

Amortization of Cook Plant Deferred Restart Costs - Pursuant to settlement agreements approved by the IURC and the MPSC to resolve all issues related to an extended outage of the Cook Plant, I&M deferred $200 million of incremental operation and maintenance costs during 1999. The deferred amount is being amortized to expense on a straight-line basis over five years from January 1, 1999 to December 31, 2003. I&M amortized $40 million in 2001, 2000 and 1999 leaving $80 million as an SFAS 71 regulatory asset at December 31, 2001 on the Consolidated Balance Sheets of AEP and I&M.

Other Income and Other Expenses – Other Income includes equity earnings of non-consolidated subsidiaries, gains on dispositions of property, interest and dividends, an allowance for equity funds used during construction (explained above) and various other non-operating and miscellaneous income. Other Expenses includes losses on dispositions of property, miscellaneous amortization, donations and various other non-operating and miscellaneous expenses.

Income Taxes - The AEP System follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established in accordance with SFAS 71 to match the regulated revenues and tax expense.

Investment Tax Credits - Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes – AEP and its subsidiary registrants, as an agent for a state or local government, collect from customers certain excise taxes levied by the state or local government upon the customer. These taxes are not recorded as revenue or expense, but only as a pass-through billing to the customer to be remitted to the government entity. Excise tax collections and payments related to taxes imposed upon the customer are not presented in the income statement.

Debt and Preferred Stock – Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment. If debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting under SFAS 71 are generally deferred and amortized over the term of the replacement debt commensurate with their recovery in rates. Gains and losses on the reacquisition of debt for operations not subject to SFAS 71 are reported as a component of net income.

Debt discount or premium and debt issuance expenses are deferred and amortized over the term of the related debt, with the amortization included in interest charges.

Where rates are regulated redemption premiums paid to reacquire preferred stock of the domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets – The amount of acquisition cost in excess of the fair value allocated to tangible and identifiable intangible assets obtained through an acquisition accounted for as a purchase combination is recorded as goodwill on AEP's consolidated balance sheet. Goodwill recognized in connection with purchase combinations acquired after June 30, 2001 was determined in accordance with SFAS 141 "Business Combinations." (see also Note 9, "Acquisitions and Dispositions"). For goodwill associated with purchase combinations before July 1, 2001, amortization is on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which is being amortized on a straight-line basis over 10 years. Accumulated amortization of goodwill was $199 million and $166 million at December 31, 2001 and 2000, respectively. In accordance with SFAS 142, "Goodwill and Other Intangible Assets," goodwill acquired after June 30, 2001 is not subject to amortization. The amortization of goodwill which predates July 1, 2001 ceased on December 31, 2001.

SFAS 142 requires that other intangible assets be separately identified and if they have finite lives they must be amortized over that life. Other intangible assets of $441 million net of accumulated amortization of $38 million at December 31, 2001 are included in other assets and represent retail and wholesale distribution licenses for CitiPower operating franchises which are currently being amortized on a straight-line basis over 20 and 40 years, respectively.

Also SFAS 142 provides that goodwill and other intangible assets with indefinite lives be tested for impairment annually and not be subjected to amortization. For AEP's goodwill recognized prior to July 1, 2001 and other intangible assets, these requirements will apply beginning January 1, 2002. For the year 2001, the amortization of goodwill reduced AEP's net income by $50 million. AEP is still evaluating the impact of adopting the impairment tests required by SFAS 142.

Nuclear Trust Funds – Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC established investment limitations and general risk management guidelines to protect their ratepayers' funds and to allow those funds to earn a reasonable return. In general, limitations include:

- Acceptable investments (rated investment grade or above)
- Maximum percentage invested in a specific type of investment
- Prohibition of investment in obligations of the applicable company or its affiliates.

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-tax earnings of the Trust, giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Other Assets at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and

Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. In accordance with SFAS 71, unrealized gains and losses from securities in these trust funds are not reported in equity but result in adjustments to the liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income - Comprehensive income is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income has two components, net income and other comprehensive income. There were no material differences between net income and comprehensive income for AEGCo, CPL, CSPCo, PSO, SWEPCo and WTU.

Components of Other Comprehensive Income – Other comprehensive income is included on the balance sheet in the equity section. The following table provides the components that comprise the balance sheet amount in Accumulated Other Comprehensive Income for AEP.

Components	December 31, 2001	2000	1999
	(millions)		
Foreign Currency Adjustments	$(113)	$ (99)	$ 20
Unrealized Losses On Securities	-	-	(20)
Unrealized Gain on Hedged Derivatives	(3)	-	-
Minimum Pension Liability	(10)	(4)	(4)
	$(126)	$(103)	$ (4)

Accumulated Other Comprehensive Income for AEP registrant subsidiaries as of December 31, 2001, is shown in the following table. Registrant subsidiary balances for Accumulated Other Comprehensive Income for the two years ended December 31, 2000 and 1999 were zero.

Components	December 31, 2001
	(thousands)
Foreign Currency Rate Hedge	
APCo	$ (340)
I&M	(3,835)
KPCo	(1,903)
OPCo	(196)

Segment Reporting – The AEP System has adopted SFAS No. 131, which requires disclosure of selected financial information by business segment as viewed by the chief operating decision-maker. See Note 12 "Business Segments" for further discussion and details regarding segments.

Common Stock Options – AEP follows Accounting Principles Board Opinion 25 to account for stock options. Compensation expense is not recognized at the date of grant or when exercised, because the exercise price of stock options awarded under the stock option plan equals the market price of the underlying stock on the date of grant.

EPS – AEP's basic earnings per share is determined based upon the weighted average number of common shares outstanding during the years presented. Diluted earnings per share for AEP is based upon the weighted average number of common shares and stock options outstanding during the years presented. Basic and diluted EPS are the same in 2001, 2000 and 1999.

AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, and WTU are wholly-owned subsidiaries of AEP and are not required to report EPS.

Reclassification - Certain prior year financial statement items have been reclassified to conform to current year presentation. Such reclassification had no impact on previously reported net income. Certain settled forward energy transactions of the trading operation were reclassified from a net to a gross basis of presentation in order to better reflect the scope and nature of the AEP System's energy sales and purchases. All financially net settled trading transactions, such as swaps, futures, and unexercised options, and all marked-to-market values on open trading contracts continue to be reported on a net basis, reflecting the financial nature of these transactions. As applicable, prior year amounts of realized physical purchases from settled purchase trading contracts were reclassified from revenues to purchased power expense to present the prior period on a comparable gross basis.

2. Extraordinary Items and Cumulative Effect:

Extraordinary Items – Extraordinary items were recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio, Virginia, West Virginia, Texas and Arkansas state jurisdictions. See Note 7 "Customer Choice and Industry Restructuring" for descriptions of the restructuring plans and related accounting effects. OPCo and CSPCo recognized an extraordinary loss for stranded Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits during the quarter ended June 30, 2001. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies have appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. The Ohio Supreme Court decision is expected in 2002.

In October 2001 CPL reacquired $101 million of pollution control bonds in advance of their maturity. Since these pollution control bonds were used to finance generation assets, a loss of $2 million after tax was recorded.

The following table shows the components of the extraordinary items reported on the consolidated statements of income:

	Year Ended December 31,		
	2001	2000	1999
	(in millions)		
Extraordinary Items:			
Discontinuance of Regulatory Accounting for Generation:			
Ohio Jurisdiction (Net of Tax of $20 million in 2001 and $35 Million in 2000)	$(48)	$(44)	$ -
Virginia and West Virginia Jurisdictions (Inclusive of Tax Benefit of $8 Million)	-	9	-
Texas and Arkansas Jurisdictions (Net of Tax of $5 Million)	-	-	(8)
Loss on Reacquired Debt (Net of Tax of $1 Million in 2001 and $3 Million in 1999)	(2)	-	(6)
Extraordinary Items	$(50)	$(35)	$(14)

Cumulative Effect of Accounting Change - The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when electricity capacity contracts can qualify as a normal purchase or sale.

Predominantly all of AEP's fuel supply contracts for coal and gas and contracts for electricity capacity, which are recorded on a settlement basis, do not meet the criteria of a financial derivative instrument or qualify as a normal purchase or sale. Therefore, AEP's contracts are generally exempt from the DIG guidance described above. Beginning July 1, 2001, the effective date of the DIG guidance, certain of AEP's fuel supply contracts with volumetric optionality that qualify as financial derivative instruments are marked to market with any gain or loss recognized in the income statement. The effect of initially adopting the DIG guidance at July 1, 2001, for AEP is a favorable earnings mark-to-market effect of $18 million, net of tax of $2 million, is reported as a cumulative effect of an accounting change on the income statement.

3. Merger:

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. Under the terms of the merger agreement, approximately 127.9 million shares of AEP Common Stock were issued in exchange for all the outstanding shares of CSW Common Stock based upon an exchange ratio of 0.6 share of AEP Common Stock for each share of CSW Common Stock. Following the exchange, former shareholders of AEP owned approximately 61.4 percent of the corporation, while former CSW shareholders owned approximately 38.6 percent of the corporation.

The merger was accounted for as a pooling of interests. Accordingly, AEP's consolidated financial statements give retroactive effect to the merger, with all periods presented as if AEP and CSW had always been combined. Certain reclassifications have been made to conform the historical financial statement presentation of AEP and CSW.

The following table sets forth revenues, extraordinary items and net income previously reported by AEP and CSW and the combined amounts shown in the accompanying financial statements for 1999:

	Year Ended December 31, 1999 (in millions)
Revenues:	
AEP	$19,229
CSW	5,516
AEP After Pooling	$24,745
Extraordinary Items:	
AEP	$ -
CSW	(14)
AEP After Pooling	$(14)
Net Income:	
AEP	$520
CSW	455
Conforming Adjustment	(3)
AEP After Pooling	$972

The combined financial statements include an adjustment to conform CSW's accounting for vacation pay accruals with AEP's accounting. The effect of the conforming adjustment was to reduce net assets by $16 million at December 31, 1999 and reduce net income by $3 million for the year ended December 31, 1999.

The following table shows the vacation accrual conforming adjustment for CSW's registrant utility subsidiaries:

	Net Asset Reduction at December 31, 1999	Net Income Reductions Year Ended December 31, 1999
	(in millions)	
CPL	$5.3	$0.7
PSO	2.8	1.1
SWEPCo	4.5	0.5
WTU	2.6	0.4

In connection with the merger, $21 million ($14 million after tax) and $203 million ($180 million after tax) of non-recoverable merger costs were expensed in 2001 and 2000. Such cost included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs of $51 million recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements through December 31, 2001. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization ($8 million and $4 million for the years 2001 and 2000) included in depreciation and amortization expense.

The following tables show the deferred merger cost and amortization expense of the applicable subsidiary registrants:

	Merger Cost Deferral at December 31, 2000	Amortization Expense for the Year Ended December 31, 2000
	(in millions)	
CPL	$14.4	$1.3
I&M	6.9	0.7
KPCo	2.5	0.3
PSO	7.9	0.5
SWEPCo	6.1	0.5
WTU	4.2	0.4

	Merger Cost Deferral at December 31, 2001	Amortization Expense for the Year Ended December 31, 2001
	(in millions)	
CPL	$11.8	$2.6
I&M	9.1	1.7
KPCo	3.2	0.6
PSO	6.6	1.2
SWEPCo	5.0	1.1
WTU	3.5	0.8

Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas - CPL, SWEPCo WTU	$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana - I&M	$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan - I&M	Customer billing credits of approximately $14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky - KPCo	Rate reductions of approximately $28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma - PSO	Rate reductions of approximately $28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas - SWEPCo	Rate reductions of $6 million over 5 years.
Louisiana - SWEPCo	Rate reductions of $18 million over 8 years. Base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

The current annual dividend rate per share of AEP common stock is $2.40. The dividends per share reported on the statements of income for 2000 and 1999 represent pro forma amounts and are based on AEP's historical annual dividend rate of $2.40 per share. If the dividends per share reported for prior periods were based on the sum of the historical dividends declared by AEP and CSW, the annual dividend rate would be $2.60 per combined share for the year ended December 31, 1999.

See Note 8, "Commitments and Contingencies" for information on a recent court decision concerning the merger.

4. Nuclear Plant Restart:

I&M completed the restart of both units of the Cook Plant in 2000. Cook Plant is a 2,110 MW two-unit plant owned and operated by I&M under licenses granted by the NRC. I&M shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a NRC architect engineer design inspection.

Settlement agreements in the Indiana and Michigan retail jurisdictions that address recovery of Cook Plant related outage costs were approved in 1999. The IURC approved a settlement agreement that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and related issues during the extended outage of the Cook Plant. The MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases that resolved all issues related to the Cook Plant extended outage. The settlement agreements allowed:

- deferral of $200 million of non-fuel restart-related nuclear operation and maintenance expense for amortization over five years ending December 31, 2003,
- deferral of certain unrecovered fuel and power supply costs for amortization over five years ending December 31, 2003,
- a freeze in base rates through December 31, 2003 and a fixed fuel recovery charge through March 1, 2004 in the Indiana jurisdiction, and
- a freeze in base rates and fixed power supply costs recovery factors until January 1, 2004 for the Michigan jurisdiction.

The amounts of restart costs charged to other operation and maintenance expenses were as follows:

	Year Ended December 31,		
	2001	2000	1999
Costs Incurred	$ 1	$297	$ 289
Deferred Pursuant to Settlement Agreements	-	-	(200)
Amortization of Deferrals	40	40	40
Charged to O&M Expense	$41	$337	$ 129

At December 31, 2001 and 2000, deferred restart costs of $80 million and $120 million, respectively, remained in regulatory assets to be amortized through 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of $38 million in 2001 and 2000 and $37 million in 1999 were amortized. At December 31, 2001 and 2000, fuel-related revenues of $75 million and $113 million, respectively, were included in regulatory assets and will be amortized through December 31, 2003 for both jurisdictions.

The amortization of restart costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements will adversely affect results of operations through December 31, 2003 when the amortization period ends. The annual amortization of restart cost and fuel-related revenue deferrals is $78 million.

5. Rate Matters:

Texas Jurisdictional Fuel Filings – AEP's Texas electric operating companies experienced significant natural gas price increases in the second half of 2000 and early 2001 which resulted in under-recovery of fuel costs and the need to seek increases in fuel rates and surcharges to recover these under-recoveries. During 2001 gas price declines and PUCT-approved fuel rate and fuel surcharge increases resulted in lower unrecovered fuel balances for SWEPCo and WTU and an overrecovered balance for CPL at the end of 2001.

Fuel recovery for Texas utilities is a multi-step procedure. When fuel costs change, utilities file with the PUCT for authority to adjust fuel factors. If a utility's prior fuel factors result in an over- or under-recovery of fuel, the utility will also request a surcharge factor to refund or collect that amount. While fuel factors are intended to recover all fuel-related costs, final settlement of these accounts are subject to reconciliation and approval by the PUCT.

Fuel reconciliation proceedings determine whether fuel costs incurred and collected during the reconciliation period were reasonable and necessary. All fuel costs incurred since the prior reconciliation date are subject to PUCT review and approval. If material amounts are determined to be unreasonable and ordered to be refunded to customers, results of operations and cash flows would be negatively impacted.

According to Texas Restructuring Legislation, fuel cost in the Texas jurisdiction after 2001 will no longer be subject to PUCT review and reconciliation. During 2002 CPL and WTU will file final fuel reconciliations with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. The ultimate recovery of deferred fuel balances at December 31, 2001 will be decided as part of their 2004 true-up proceedings. If the final under-recovered fuel balances or any amounts incurred but not yet reconciled are disallowed, it would have a negative impact on results of operations and cash flows.

In October 2001 the PUCT delayed the start of customer choice in the SPP area of Texas. All of SWEPCo's Texas service territory and a small portion of WTU's service territory are in the SPP. SWEPCo's fuel cost recovery procedures will continue until competition begins. SWEPCo will continue to set fuel factors and determine final fuel costs in fuel reconciliation proceedings during the SPP delay period. The PUCT has ruled that WTU fuel factors in the SPP area will be based upon the price to beat fuel factors offered by the WTU retail electric provider in the ERCOT portion of WTU's service territory. The PUCT has initiated a proceeding to determine the most appropriate method to reconcile fuel costs in WTU's SPP area.

The following table lists the status of Texas jurisdictional reconciliation, fuel cost subject to reconciliation and under(over)-recovered fuel balances:

Company	Reconciliation completed through	Fuel cost subject to reconciliation at December 31, 2001
CPL	June 30, 1998	$1.6 billion
SWEPCo	December 31, 1999	314 million
WTU	June 30, 2000	303 million

Company	Under (Over) -recovered fuel balances at December 31, 2001
CPL	$(58) million
SWEPCo	7 million
WTU	34 million

During 2001 CPL, SWEPCo and WTU requested and received approval to increase their fuel rates. In orders issued in 2001 the PUCT delayed consideration of fuel surcharges for CPL and WTU to recover their underrecovered fuel until the 2004 true-up proceedings. CPL's net underrecovered position was eliminated between the order date and year end 2001 as gas prices declined. For SWEPCo the PUCT deferred $6.8 million of Texas jurisdictional unrecovered fuel for consideration in a future proceeding.

Under Texas restructuring, newly organized retail electric providers will make sales to consumers beginning January 1, 2002. These sales will be at fixed rates during a transition period from 2002 through 2006. However, the fuel cost component of a retail electric providers' fixed rates will be subject to prospective adjustment twice a year based upon changes in a natural gas price index. As part of the preparation for customer choice, CPL, SWEPCo and WTU filed their proposed fuel factors to be implemented as part of the fixed rates effective January 1, 2002. Fuel factors approved for CPL's and WTU's retail electric providers were effective January 1, 2002. Due to the SPP area competition delay, SWEPCo's proceeding was postponed.

WTU Fuel Filings - In December 2000 WTU filed with the PUCT an application to reconcile fuel costs. During the reconciliation period of July 1, 1997 through June 30, 2000, WTU incurred $348 million of Texas jurisdiction eligible fuel and fuel-related expenses. In February 2002 the PUCT approved WTU's fuel cost for the reconciliation period except for a disallowance of less than $50,000.

Texas Transmission Rates – On June 28, 2001, the Supreme Court of Texas ruled that the transmission pricing mechanism created by the PUCT in 1996 was invalid. The court upheld an appeal filed by unaffiliated Texas utilities that the PUCT exceeded its statutory authority to set such rates for the period January 1, 1997 through August 31, 1999. Effective September 1, 1999, the legislature granted this authority to the PUCT. CPL and WTU were not parties to the case. However, the companies' transmission sales and purchases were priced using the invalid rates. It is unclear what action the PUCT will take to respond to the court's ruling. If the PUCT changes rates retroactively, the result could have a material impact on results of operations and cash flows for CPL and WTU.

FERC Wholesale Fuel Complaints – In May 2000 certain WTU wholesale customers filed a complaint with FERC alleging that WTU had overcharged them through the fuel adjustment clause for certain purchased power costs related to 1999 unplanned outages at WTU's Oklaunion generation station. In November 2001 certain WTU wholesale customers filed an additional complaint at FERC asserting that since 1997 WTU had billed wholesale customers for not only the 1999 Oklaunion outage costs, but also certain additional costs that are not permissible under the fuel adjustment clause.

In December 2001 FERC issued an order requiring WTU to refund, with interest, amounts associated with the May 2000 complaint that were previously billed to wholesale customers. The effects of this order were recorded in 2001 and management believes that as of December 31, 2001, it has fully provided for that over billing. In response to the November 2001 complaint, management is working to determine amounts of additional costs inappropriately billed to wholesale customers, which could result in refunds, with interest. At this time, management is unable to predict the negative impact this complaint will have on future results of operations, cash flow and financial condition.

FERC Transmission Rates – In November 2001 FERC issued an order requiring CPL, PSO, SWEPCo and WTU to submit revised open access transmission tariffs, and calculate and issue refunds for overcharges from January 1, 1997. The order resulted from a remand by an appeals court of a tariff compliance filing order issued in November 1998 that had been appealed by certain customers. CPL and WTU recorded refund provisions of $1.7 million and $0.7 million, respectively, including interest in 2001 for this order. PSO and SWEPCo recorded $100,000 each for this order making the AEP total $2.6 million.

West Virginia - On June 2, 2000, the WVPSC approved a Joint Stipulation between APCo and other parties related to base rates and ENEC recoveries. The Joint Stipulation allows for recovery of regulatory assets including any generation-related regulatory assets through the following provisions:

- Frozen transition rates and a wires charge of 0.5 mills per KWH.
- The retention, as a regulatory liability, on the books of a net cumulative deferred ENEC over-recovery balance of $66 million to be used to offset the cost of deregulation when generation is deregulated in WV.
- The retention of net merger savings prior to December 31, 2004 resulting from the merger of AEP and CSW.
- A 0.5 mills per KWH wires charge for departing customers provided for in the WV Restructuring Plan (see Note 7 "Customer Choice and Industry Restructuring" for discussion of the WV Restructuring Plan)

Management expects that the approved Joint Stipulation, plus the provisions of pending restructuring legislation will, if the legislation becomes effective, provide for the recovery of existing regulatory assets, other stranded costs and the cost of deregulation in WV.

6. Effects of Regulation:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the AEP System's regulated rates be cost-based and the recovery of regulatory assets be probable. Management has reviewed all the evidence currently available and concluded that the requirements to apply SFAS 71 continue to be met for all electric operations in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee.

When the generation portion of the Company's business in Arkansas, Ohio, Texas, Virginia and WV no longer met the requirements to apply SFAS 71, net regulatory assets were written off for that portion of the business unless they were determined to be recoverable as a stranded cost through regulated distribution rates or wire charges in accordance with SFAS 101 and EITF 97-4. In the Ohio and WV jurisdictions generation-related regulatory assets that are recoverable through transition rates have been transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As discussed in Note 7, "Customer Choice and Industry Restructing" the Virginia SCC ordered the generation-related regulatory assets in the Virginia jurisdiction to remain with the generation portion of the business. Generation-related regulatory assets in the Virginia jurisdiction are being amortized concurrent with their recovery through capped rates. In the Texas jurisdiction generation-related regulatory assets that have been tentatively approved for recovery through securitization have been classified as "regulatory assets designated for securitization." (See Note 7 "Customer Choice and Industry Restructuring" for further details.)

AEP's recognized regulatory assets and liabilities are comprised of the following at:

	December 31, 2001	December 31, 2000
	(in millions)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$ 814	$ 914
Transition - Regulatory Assets	847	963
Regulatory Assets Designated for Securitization	959	953
Deferred Fuel Costs	139	407
Unamortized Loss on Reacquired Debt	99	113
Cook Plant Restart Costs	80	120
DOE Decontamination and Decommissioning Assessment	31	35
Other	193	193
Total Regulatory Assets	$3,162	$3,698
Regulatory Liabilities:		
Deferred Investment Tax Credits	$491	$528
Other	393	208
Total Regulatory Liabilities	$884	$736

The recognized regulatory assets and liabilities for the registrant subsidiaries are of two types: those earning a return and those not earning a return. Items not earning a return have their recovery period end date indicated. Regulatory assets and liabilities are comprised of the following items:

	AEGCo			APCo		
	2001	2000	Recovery Period	2001	2000	Recovery Period
			(in thousands)			
Regulatory Assets:						
Amounts Due From Customers For Future Income Taxes	$(22,725)	$(23,996)	Note 1	$189,794	$217,540	Note 1
Transition - Regulatory Assets Virginia				46,981	55,523	Jun. 2007
Transition - Regulatory Assets West Virginia				127,998	135,946	Jun. 2011
Deferred Fuel Costs				11,732	14,669	
Unamortized Loss on Reacquired Debt	5,207	5,504	Note 2	10,421	11,676	Note 2
Deferred Storm Damage				6	1,244	Apr. 2002
Other				71,890	11,152	Note 3
Total Regulatory Assets	$(17,518)	$(18,492)		$458,822	$447,750	
Regulatory Liabilities:						
Deferred Investment Tax Credits	$56,304	$59,718		$ 38,328	$ 43,093	
WV Rate Stabilization				75,601	75,601	
Other				61,552	2,614	
Total Regulatory Liabilities	$56,304	$59,718		$175,481	$121,308	

Note 1: This amount fluctuates from month to month and has no fixed recovery period.
Note 2: Unamortized loss on reacquired debt varies in its recovery period for each registrant and ranges from one to thirty-seven years recovery period across all registrants.
Note 3: Other may include items not earning a return and would have various recovery periods.

	CPL			CSPCo		
	2001	2000	Recovery Period	2001	2000	Recovery Period
			(in thousands)			
Regulatory Assets:						
Amounts Due From Customers For Future Income Taxes	$200,496	$ 206,930	Note 1	$ 28,361	$ 31,853	Note 1
Transition - Regulatory Assets				223,830	247,852	Dec. 2008
Excess Earnings	(62,852)	(39,700)				
Regulatory Assets - Designated For Securitization	959,294	953,249				
Deferred Fuel Costs	(57,762)	127,295		-	-	
Unamortized Loss on Reacquired Debt	11,180	12,773	Note 2	7,010	8,340	Note 2
DOE Decontamination and Decommissioning Assessment	3,170	3,622	Dec. 2004			
Other	11,961	18,815	Note 3	3,066	3,508	Note 3
Total Regulatory Assets	$1,065,487	$1,282,984		$262,267	$291,553	
Regulatory Liabilities:						
Deferred Investment Tax Credits	$122,893	$128,100		$37,176	$41,234	
Other				31	11,510	
Total Regulatory Liabilities	$122,893	$128,100		$37,207	$52,744	

Note 1: This amount fluctuates from month to month and has no fixed recovery period.
Note 2: Unamortized loss on reacquired debt varies in its recovery period for each registrant and ranges from one to thirty-seven years recovery period across all registrants.
Note 3: Other may include items not earning a return and would have various recovery periods.

	I&M			KPCo		
	2001	2000	Recovery Period	2001	2000	Recovery Period
			(in thousands)			
Regulatory Assets:						
Amounts Due From Customers For Future Income Taxes	$171,605	$229,466	Note 1	$83,027	$85,926	Note 1
Deferred Fuel Costs	75,002	112,503	Dec. 2003	1,542	-	Feb. 2002
Unamortized Loss on Reacquired Debt	16,255	17,740	Note 2	51	459	Note 2
Cook Plant Restart Costs	80,000	120,000	Dec. 2003			
DOE Decontamination and Decommissioning Assessment	27,784	31,744	Dec. 2008			
Other	38,281	40,687	Note 3	13,073	12,130	Note 3
Total Regulatory Assets	$408,927	$552,140		$97,693	$98,515	
Regulatory Liabilities:						
Deferred Investment Tax Credits	$105,449	$113,773		$10,405	$11,656	
Other	52,479	9,930		6,551	3,172	
Total Regulatory Liabilities	$157,928	$123,703		$16,956	$14,828	

Note 1: This amount fluctuates from month to month and has no fixed recovery period.
Note 2: Unamortized loss on reacquired debt varies in its recovery period for each registrant and ranges from one to thirty-seven years recovery period across all registrants.
Note 3: Other may include items not earning a return and would have various recovery periods.

	OPCo			PSO		
	2001	2000	Recovery Period	2001	2000	Recovery Period
			(in thousands)			
Regulatory Assets:						
Amounts Due From Customers For Future Income Taxes	$186,740	$180,602	Note 1	$(26,085)	$(28,652)	Note 1
Transition - Regulatory Assets	442,707	517,851	Dec. 2007			
Deferred Fuel Costs				11,732	43,267	
Unamortized Loss on Reacquired Debt	5,502	6,106	Note 2	12,321	13,600	Note 2
Other	9,676	10,151	Note 3	11,707	15,738	Note 3
Total Regulatory Assets	$644,625	$714,710		$ 9,675	$ 43,953	
Regulatory Liabilities:						
Deferred Investment Tax Credits	$21,925	$25,214		$33,992	$35,783	
Other	1,237	10,994		31,858	2,015	
Total Regulatory Liabilities	$23,162	$36,208		$65,850	$37,798	

Note 1: This amount fluctuates from month to month and has no fixed recovery period.
Note 2: Unamortized loss on reacquired debt varies in its recovery period for each registrant and ranges from one to thirty-seven years recovery period across all registrants.
Note 3: Other may include items not earning a return and would have various recovery periods.

	SWEPCo			WTU		
	2001	2000	Recovery Period	2001	2000	Recovery Period
			(in thousands)			
Regulatory Assets:						
Amounts Due From Customers For Future Income Taxes	$16,553	$14,558	Note 1	$(13,591)	$(13,493)	Note 1
Deferred Fuel Costs	7,384	35,469		36,872	67,655	
Unamortized Loss on Reacquired Debt	19,726	22,626	Note 2	8,198	11,204	Note 2
Other	15,711	19,898	Note 3	5,460	13,604	Note 3
Total Regulatory Assets	$59,374	$92,551		$ 36,939	$ 78,970	
Regulatory Liabilities:						
Deferred Investment Tax Credits	$48,714	$53,167		$22,781	$24,052	
Excess Earnings		500		17,300	15,100	
Other	15,454	8,140		5,700	-	
Total Regulatory Liabilities	$64,168	$61,807		$45,781	$39,152	

Note 1: This amount fluctuates from month to month and has no fixed recovery period.
Note 2: Unamortized loss on reacquired debt varies in its recovery period for each registrant and ranges from one to thirty-seven years recovery period across all registrants.
Note 3: Other may include items not earning a return and would have various recovery periods.

7. Customer Choice and Industry Restructuring:

Prior to 2001 customer choice/industry restructuring legislation was passed in Ohio, Texas, Virginia and Michigan allowing retail customers to select alternative generation suppliers. Customer choice began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan, Virginia and in the ERCOT area of Texas. AEP's subsidiaries operate in both the ERCOT and SPP areas of Texas.

Legislation enacted in Oklahoma, Arkansas and WV to allow retail customers to choose their electricity supplier is not yet effective. In 2001 Oklahoma delayed implementation of customer choice indefinitely. Arkansas delayed the start of customer choice until as late as October 2005. The Arkansas Commission has recommended further delays of the start date or repeal of the restructuring legislation. Before West Virginia's choice plan can be effective, tax legislation must be passed to continue consistent funding for state and local government. No further legislation has been passed related to restructuring in Arkansas or West Virginia.

In general, state restructuring legislation provides for a transition from cost-based rate regulated bundled electric service to unbundled cost-based rates for transmission and distribution service and market pricing for the supply of electricity with customer choice of supplier.

Ohio Restructuring – Affecting AEP, CSPCo and OPCo

Customer choice of electricity supplier and restructuring began on January 1, 2001, under the Ohio Act. During 2001 alternative suppliers registered and were approved by the PUCO as required by the Ohio Act. At January 1, 2002, virtually all customers continue to receive supply service from CSPCo and OPCo with a legislatively required residential generation rate reduction of 5%. All customers continue to be served by CSPCo and OPCo for transmission and distribution services.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for electric generation supply services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressed certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act made several changes in the taxation of electric companies. Effective January 1, 2001 the assessment percentage for property taxes on all electric company property other than transmission and distribution was lowered from 100% to 25%. The assessment percentage applicable to transmission and distribution property remains at 88%. Also, electric companies were exempted from the excise tax based on receipts. To make up for these tax reductions electric distribution companies became subject to a new KWH based excise tax. Since electric companies no longer paid the gross receipts tax, they became liable, as of January 1, 2002 for the corporation franchise tax and municipal income taxes.

In preparation for the January 1, 2001 start of the transition period, CSPCo and OPCo filed a transition plan in December 1999. After negotiations with interested parties including the PUCO staff, the PUCO approved a stipulation agreement for CSPCo's and OPCo's transition plans. The approved plans included, among other things, recovery of generation-related regulatory assets over seven years for OPCo and over eight years for CSPCo through frozen transition rates for the first five years of the recovery period and through a wires charge for the remaining years. At December 31, 2000, the amount of regulatory assets to be amortized as recovered was $518 million for OPCo and $248 million for CSPCo.

The stipulation agreement required the PUCO to consider implementation of a gross receipts tax credit rider as the parties could not reach an agreement.

As of May 1, 2001, electric distribution companies became subject to an excise tax based on KWH sold to Ohio customers. The last tax year for which Ohio electric utilities will pay the excise tax based on gross receipts is May 1, 2001 through April 30, 2002. As required by law, the gross receipts tax is paid in advance of the tax year for which the utility exercises its privilege to conduct business. CSPCo and OPCo treat the tax payment as a prepaid expense and amortized it to expense during the tax year.

Following a hearing on the gross receipts tax issue, the PUCO determined that there was no duplicate tax overlap period. The PUCO ordered the gross receipts tax credit rider to be effective May 1, 2001 instead of May 1, 2002 as proposed by the companies. This order reduced CSPCo's and OPCo's revenues by approximately $90 million. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was also denied by the PUCO. A decision on an appeal of this issue to the Ohio Supreme Court is pending.

As described in Note 2, the PUCO's denial of the request for recovery of the final year's gross receipts tax and the tax liability affixing on May 1, 2001 stranded the prepaid asset. As a result, an extraordinary loss was recorded in 2001.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) filed with the Ohio Supreme Court for review of the settlement agreement. During 2001 that intervenor withdrew from competing in Ohio. The Court dismissed the intervenor's appeal.

CSPCo's and OPCo's fuel costs were no longer subject to PUCO fuel clause recovery proceedings beginning January 1, 2001. The elimination of fuel clause recoveries in Ohio subjects AEP, CSPCo and OPCo to risk of fuel market price variations and could adversely affect their results of operations and cash flows.

Virginia Restructuring – Affecting AEP and APCo

In Virginia, choice of electricity supplier for retail customers began on January 1, 2002 under its restructuring law. A finding by the Virginia SCC that an effective competitive market exists would be required to end the transition period.

The restructuring law provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. Capped rates are the rates in effect at July 1, 1999 if no rate change request was made by the utility. APCo did not request new rates; therefore, its current rates are its capped rates. Virginia's restructuring law does not permit the Virginia SCC to change generation rates during the transition period except for changes in fuel costs, changes in state gross receipts taxes, or to address financial distress of the utility.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC. The Virginia SCC approved settlement agreements that resolved most issues except the assignment of generation–related regulatory assets among functionally separated generation, transmission and distribution organizations. The Virginia SCC determined that generation–related regulatory assets and related amortization expense should be assigned to APCo's generation function. Presently, capped rates are sufficient to recover generation–related regulatory assets. Therefore, management determined that recovery of APCo's generation–related regulatory assets remains probable. APCo will not collect a wires charge in 2002 per the settlement agreements. The settlement agreements and related Virginia SCC order addressed functional separation leaving decisions related to corporate separation for later consideration. The Virginia SCC order approving the settlement agreements requires several compliance filings, including a fuel/replacement power cost report during an extended outage of an affiliate's nuclear plant. Management is unable to predict the outcome of the Virginia SCC's review of APCo's compliance filings.

Texas Restructuring – Affecting AEP, CPL, SWEPCo and WTU

On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in other areas of Texas including the SPP area. All of SWEPCo's Texas service territory and a small portion of WTU's service territory are located in the SPP. CPL operates entirely in the ERCOT area of Texas.

Texas restructuring legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- freezes rates until January 1, 2002;
- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity continues to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In 2000 CPL, SWEPCo and WTU filed and the PUCT approved business separation plans. The business separation plans provided for CPL and WTU to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. In February 2002 the PUCT approved amendments to SWEPCo's plan. The amended plan separates SWEPCo's Texas jurisdictional transmission and distribution assets and operations into two new regulated transmission and distribution subsidiaries. In addition, a retail electric provider was established by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers. Until competition commences in the SPP, SWEPCo's assets will not be separated and the SWEPCo retail electric provider will not commence operation.

Due to the SPP area delay in the start of competition, only CPL's and WTU's retail electric providers commenced operations on January 1, 2002. Operations for CPL, SWEPCo and WTU have been functionally separated.

Under the Texas Legislation, electric utilities are allowed to recover stranded generation costs including generation-related regulatory assets. The stranded costs can be refinanced through securitization (a financing structure designed to provide lower financing costs than are available through conventional financings).

In 1999 CPL filed with the PUCT to securitize \$1.27 billion of its retail generation-related regulatory assets and \$47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to \$797 million of securitization bonds (\$949 million of generation-related regulatory assets and \$33 million of qualified refinancing costs offset by \$185 million of customer benefits for accumulated deferred income taxes). Four parties appealed to the Supreme Court of Texas which upheld the PUCT's securitization order. CPL issued its securitization bonds in February 2002.

CPL included regulatory assets not approved for securitization in its request for recovery of \$1.1 billion of stranded costs. The \$1.1 billion request included \$800 million of STP costs included in property, plant and equipment-electric on the

Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes. They are earning a lower return and being amortized on an accelerated basis for rate-making purposes.

After hearings on the issue of stranded costs, the PUCT ruled in October 2001 that its current estimate of CPL's stranded costs was negative $615 million. CPL disagrees with the ruling. The ruling indicated that CPL's costs were below market after securitization of regulatory assets. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In 2001 the PUCT issued an order requiring CPL to reduce distribution rates by $54.8 million plus accrued interest over a five-year period beginning January 1, 2002 in order to return estimated excess earnings for 1999, 2000 and 2001. The Texas Legislation intended that excess earnings reduce stranded costs. Final stranded cost amounts and the treatment of excess earnings will be determined in the 2004 true-up proceeding. Currently the PUCT estimates that CPL will have no stranded costs and has ordered the rate reduction to return excess earnings. Since CPL expensed excess earnings amounts in 1999, 2000 and 2001, the order has no additional effect on reported net income but will reduce cash flows for the five year refund period. The amount to be refunded is recorded as a regulatory liability.

Management believes that CPL will have stranded costs in 2004, and that the current treatment of excess earnings will be amended at that time. CPL has appealed the PUCT's estimate of stranded costs and refund of excess earnings to the Travis County District Court. Unaffiliated parties also appealed the PUCT's refund order contending the entire $615 million of negative stranded costs should be refunded presently. Management is unable to predict the outcome of this litigation. An unfavorable ruling would have a negative impact on results of operations, cash flows and possibly financial condition.

The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of an ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the additional amount recoverable can also be securitized.

The Texas Legislation provides for an earnings test each year of the 1999 through 2001 rate freeze period. For CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Companies without stranded costs, including SWEPCo and WTU, must pay any excess earnings to customers, invest them in improvements to transmission or distribution facilities or invest them to improve air quality at generating facilities. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The PUCT issued a final order for the 1999 earnings test in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. SWEPCo had no excess earnings in 1999. The PUCT issued a final order in September 2001 for the 2000 excess earnings. CPL's, SWEPCo's and WTU's excess 2000 earnings were $23 million, $1 million and $17 million, respectively. An estimate of 2001 excess earnings of $8 million for CPL, $2 million for SWEPCo and none for WTU has been recorded and will be adjusted, if necessary, in 2002 when the PUCT issues its final order regarding 2001 excess earnings.

Due to the companies' disagreement with the PUCT, its staff and the Office of Public Utility Counsel related to the proper determination of 2000 excess earnings, the companies filed in district court in October 2001 seeking judicial review of the PUCT's determination of excess earnings. A decision from the court is not expected until later in 2002.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings for CPL and WTU's ERCOT customers. Consequently, CPL and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Due to the delay of competition for the SPP area, SWEPCo, which operates in the SPP area, continues to record and request recovery of fuel costs under the Texas fuel reconciliation proceeding. For WTU's SPP area customers, the PUCT will determine a method to reconcile their fuel costs beginning in 2002 (see Note 5 "Rate Matters"). Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled are not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in the ERCOT area of Texas will subject AEP and the retail electric providers of CPL and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric providers of CPL, SWEPCo and WTU are required by the Texas Legislation to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a price-to-beat rate until January 1, 2007. In December 2001 the PUCT approved price-to-beat rates for CPL's and WTU's retail electric providers. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect changes in fuel and purchased energy costs using a natural gas price index.

Due to the delay in the start of competition in the SPP areas of Texas, several issues are pending before the PUCT. These issues impact SWEPCo's and WTU's Texas SPP operations. WTU's Texas SPP operations are estimated to be less than 5% of WTU's total operations.

West Virginia Restructuring – Affecting AEP and APCo

In 2000 the WVPSC issued an order approving an electricity restructuring plan which the WV Legislature approved by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes tax law changes necessary to preserve the revenues of state and local governments. Since the WV Legislature has not passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The WV restructuring plan provides for:

- deregulation of generation assets
- separation of the generation, transmission and distribution businesses
- a transition period with capped and fixed rates for up to 13 years
- establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period.

APCo's Joint Stipulation, discussed in Note 5 "Rate Matters" and approved by the WVPSC in 2000 in connection with a base rate filing, provides additional mechanisms to recover transition generation-related regulatory assets.

In order for customer choice to become effective in WV, the WV Legislature must enact tax legislation. Management is unable to predict the timing of the passage of such legislation.

Arkansas Restructuring – Affecting AEP and SWEPCo

In 1999 Arkansas enacted legislation to restructure its electric utility industry. Major provisions of the legislation as amended are:

- retail competition delayed until as late as October 2005;

- transmission facilities must be operated by an ISO if owned by a company which also owns generating facilities;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

Based on recommendations in the annual progress report filed by the Arkansas Commission, the Arkansas General Assembly passed and the Governor signed legislation in 2001 changing the start date of electric retail competition to October 1, 2003, and providing the Arkansas Commission with authority to delay that date for up to an additional two years.

The Arkansas Commission in December 2001 recommended further delays of the start date or repeal of the restructuring legislation.

Discontinuance of the Application of SFAS 71 Regulatory Accounting in Arkansas, Ohio, Texas, Virginia and West Virginia – Affecting AEP, APCo, CPL, CSPCo, OPCo, SWEPCo and WTU

The enactment of restructuring legislation and the ability to determine transition rates, wires charges and any resultant gain or loss under restructuring legislation in Arkansas, Ohio, Texas, Virginia and West Virginia enabled AEP and certain subsidiaries to discontinue regulatory accounting under SFAS 71 for the generation portion of their business in those states. Under the provisions of SFAS 71, regulatory assets and regulatory liabilities are recorded to reflect the economic effects of regulation by matching expenses with related regulated revenues.

The discontinuance of the application of SFAS 71 in Arkansas, Ohio, Texas, Virginia and West Virginia in accordance with the provisions of SFAS 101 and EITF Issue 97-4 resulted in recognition of extraordinary gains or losses in 2000 and 1999. The discontinuance of SFAS 71 can require the write-off of regulatory assets and liabilities related to the deregulated operations, unless their recovery is provided through cost-based regulated rates to be collected in a portion of operations which continues to be rate regulated. Additionally, a company must determine if any plant assets are impaired when they discontinue SFAS 71 accounting. At the time the companies discontinued SFAS 71, the analysis showed that there was no accounting impairment of generation assets.

Prior to 1999, all of the domestic electric utility subsidiaries' financial statements reflected the economic effects of regulation under the requirements of SFAS 71. As a result of deregulation of generation, the application of SFAS 71 for the generation portion of the business in Arkansas, Ohio, Texas, Virginia and West Virginia was discontinued. Remaining generation-related regulatory assets will be amortized as they are recovered under terms of transition plans. Management believes that substantially all generation-related regulatory assets and stranded costs will be recovered under terms of the transition plans. If future events including the 2004 true-up proceeding in Texas were to make their recovery no longer probable, the Company would write-off the portion of such regulatory assets and stranded costs deemed unrecoverable as a non-cash extraordinary charge to earnings. If any write-off of regulatory assets or stranded costs occurred, it could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

Michigan Restructuring - Affecting AEP and I&M

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. In compliance with MPSC orders, on June 5, 2001, I&M filed its proposed unbundled rates, open access tariffs and terms of service. On October 11, 2001, the

MPSC approved a settlement agreement which generally approved I&M's June 5, 2001 filing except for agreed upon modifications. In accordance with the settlement agreement, I&M agreed that recovery of implementation costs and regulatory assets would be determined in future proceedings. The settlement agreement did not modify the procedure for review of decommissioning costs recoveries. Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total rates in Michigan remain unchanged and reflect cost of service. At this time, none of I&M's customers have elected to change suppliers and no competing suppliers are active in I&M's Michigan service territory.

Management has concluded that as of December 31, 2001 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated. As a result I&M has not yet discontinued regulatory accounting under SFAS 71.

Oklahoma Restructuring – Affecting AEP and PSO

Under Oklahoma restructuring legislation passed in 1997 retail open access and customer choice was scheduled to begin by July 1, 2002.

In June 2001 the Oklahoma Governor signed into law a bill to delay, indefinitely, the implementation of the transition to customer choice and market based pricing under restructuring legislation. Consequently, PSO, the AEP subsidiary doing business in Oklahoma, will remain rate-regulated until further legislation passes and continues the application of SFAS 71 regulatory accounting.

8. Commitments and Contingencies:

Construction and Other Commitments - The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2002-2004 for consolidated domestic and foreign operations are estimated to be $5.4 billion.

The following table shows the estimated construction expenditures of the subsidiary registrants for 2002 – 2004:

	(in millions)
AEGCo	$ 171.9
APCo	815.5
CPL	573.1
CSPCo	408.7
I&M	556.9
KPCo	223.3
OPCo	1,008.0
PSO	364.9
SWEPCo	321.4
WTU	169.6

APCo, AEP's subsidiary which operates in Virginia and West Virginia, has been seeking regulatory approval to build a new high voltage transmission line for over a decade. Through December 31, 2001 we had invested approximately $40 million in this effort. If the required regulatory approvals are not obtained and the line is not constructed, the $40 million investment would be written off adversely affecting future results of operations and cash flows.

Long-term contracts to acquire fuel for electric generation have been entered into for various terms, the longest of which extends to the year 2014 for the AEP System. The expiration date of the longest fuel contract is 2006 for APCo, 2005 for CSPCo, 2014 for I&M, 2004 for KPCo, 2012 for OPCo, 2014 for PSO, 2006 for SWEPCo and 2006 for WTU. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,300 MW of capacity domestically on a long-term basis to unaffiliated utilities. Certain of these contracts totaling 250 MW of capacity are unit power agreements requiring the delivery of energy only if the unit capacity is available. The power sales contracts expire from 2002 to 2012.

In connection with a lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the obligations of the mining contractor. The contractor's actual obligation outstanding at

December 31, 2001 was $75 million.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2001 the cost to reclaim the mine is estimated to be approximately $36 million.

AEP, through certain subsidiaries, has entered into agreements with an unrelated, unconsolidated special purpose entity (SPE) to develop, construct, finance and lease a power generation facility. The SPE will own the power generation facility and lease it to an AEP consolidated subsidiary after construction is completed. The lease will be accounted for as an operating lease with the payment obligations included in the lease footnote. Payments under the operating lease are expected to commence in the first quarter of 2004. AEP will in turn sublease the facility to an unrelated industrial company which will both use the energy produced by the facility and sell excess energy. Another affiliate of AEP has agreed to purchase the excess energy from the subleasee for resale.

The SPE has an aggregate financing commitment from equity and debt participants (Investors) of $427 million. AEP, in its role as construction agent for the SPE, is responsible for completing construction by December 31, 2003. In the event the project is terminated before completion of construction, AEP has the option to either purchase the project for 100% of project costs or terminate the project and make a payment to the Lessor for 89.9% of project costs.

The term of the operating lease between the SPE and the AEP subsidiary is five years with multiple extension options. If all extension options are exercised the total term of the lease would be 30 years. AEP's lease payments to the SPE are sufficient to provide a return to the Investors. At the end of the first five-year lease term or any extension, AEP may renew the lease at fair market value subject to Investor approval; purchase the facility at its original construction cost; or sell the facility, on behalf of the SPE, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the Investors, AEP may be required to make a payment to the Lessor of up to 85% of the project's cost. AEP has guaranteed a portion of the obligations of its subsidiaries to the SPE during the construction and post-construction periods.

As of December 31, 2001, project costs subject to these agreements totaled $168 million, and total costs for the completed facility are expected to be approximately $450 million. Since the lease is accounted for as an operating lease for financial accounting purposes, neither the facility nor the related obligations are reported on AEP's balance sheets. The lease is a variable rate obligation indexed to three-month LIBOR. Consequently as market interest rates increase, the payments under this operating lease will also increase. Annual payments of approximately $12 million represent future minimum payments under the first five-year lease term calculated using the indexed LIBOR rate of 2.85% at December 31, 2001.

OPCo has entered into a purchased power agreement to purchase electricity produced by an unaffiliated entity's three-unit natural gas fired plant that is under construction. The first unit is anticipated to be completed in October 2002 and the agreement will terminate 30 years after the third unit begins operation. Under the terms of the agreement OPCo has the options to run the plant until December 31, 2005 taking 100% of the power generated. For the remainder of the 30 year contract term, OPCo will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity. The estimated fixed payments through December 2005 are $55 million.

Nuclear Plants – Affecting AEP, CPL and I&M

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. CPL owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and CPL are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery in rates is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability – Affecting AEP, CPL and I&M

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $9.5 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $200 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $88 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $176 million per nuclear incident payable in annual installments of $20 million. CPL could be assessed $44 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. Cook Plant and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $36 million for I&M and $3 million for CPL which is assessable if the insurer's financial resources would be inadequate to pay for losses.

SNF Disposal – Affecting AEP, CPL, and I&M

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $220 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2001, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and approximate the liability. CPL is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal – Affecting AEP, CPL and I&M

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. After expiration of the licenses, Cook Plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $783 million to $1,481 million in 2000 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in

2001 and $28 million in 2000 and 1999.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the decontamination method. CPL estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. CPL is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2001 and 2000 I&M deposited in its decommissioning trust an additional $12 million and $6 million, respectively, related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in other operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in other operation expense, interest income of the trusts are recorded in nonoperating income and interest expense of the trust funds are included in interest charges.

On the AEP Consolidated Balance Sheets, nuclear decommissioning trust assets are included in other assets and a corresponding nuclear decommissioning liability is included in other noncurrent liabilities. On CPL's balance sheets, the nuclear decommissioning liability of $99 million is included in electric utility plant-accumulated depreciation and amortization. At December 31, 2001 and 2000, the decommissioning liability for Cook Plant and STP combined totals $699 million and $654 million, respectively.

Shareholders' Litigation – Affecting AEP

On December 21, 2001, the U.S. District Court for the Southern District of Ohio dismissed a class action lawsuit against AEP and four former or present officers. The class consisted of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997 and June 25, 1999. The complaint alleged that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements related to the extended Cook Plant outage.

Municipal Franchise Fee Litigation – Affecting AEP and CPL

In 2001 CPL settled litigation regarding municipal franchise fees in Texas. CPL paid $11 million to settle the litigation and be released from any further liability. The City of San Juan, Texas had filed a class action suit in 1996 seeking $300 million in damages.

Texas Base Rate Litigation – Affecting AEP and CPL

In 2001 the Texas Supreme Court denied CPL's request to review a case resulting from a 1997 PUCT base rate order. The Court also denied CPL's rehearing request.

The primary issues were:
- the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property;
- and an $18 million disallowance of an affiliate service billings.

Lignite Mining Agreement Litigation – Affecting AEP and SWEPCo

In 2001 SWEPCo settled ongoing litigation concerning lignite mining in Louisiana. Since 1997 SWEPCo has been involved in litigation concerning the mining of lignite from jointly owned lignite reserves. SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. Under terms of a settlement, SWEPCo purchased an unaffiliated mine operator's interest in the mining operations and related debt and other obligations for $86 million.

Federal EPA Complaint and Notice of Violation – Affecting AEP, APCo, CSPCo, I&M, and OPCo

Since 1999 AEP, APCo, CSPCo, I&M, and OPCo have been involved in litigation regarding generating plant emissions under the Clean Air Act. Federal EPA and a number of states alleged that AEP System companies and eleven unaffiliated utilities modified certain units at coal fired generating plants in violation of the Clean Air Act. Federal EPA filed complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20 year period.

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In March 2001 the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

In February 2001 the government filed a motion requesting a determination that four projects undertaken on units at Sporn, Cardinal and Clinch River plants do not constitute "routine maintenance, repair and replacement" as used in the Clean Air Act. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

In January 2002 the U.S. Court of Appeals for the 11th Circuit ruled that TVA may pursue its court challenge of a Federal EPA administrative order charging similar violations to those in the complaints against AEP and other utilities.
Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. In the event the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.

In December 2000 Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its results of operations and cash flows.

NOx Reductions – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo and SWEPCo

Federal EPA issued a NOx Rule requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The NOx Rule has been upheld on appeal. The compliance date for the NOx Rule is May 31, 2004.

The NOx Rule required states to submit plans to comply with its provisions. In 2000 Federal EPA ruled that eleven states, including states in which AEGCo's, APCo's, CSPCo's, I&M's, KPCo's and OPCo's generating units are located, failed to submit approvable compliance plans. Those states could face stringent sanctions including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs. AEP subsidiaries and other utilities requested that the D.C. Circuit Court review this ruling.

In 2000 Federal EPA also adopted a revised rule (the Section 126 Rule) granting petitions filed by certain northeastern states under the Clean Air Act. The rule imposes emissions reduction requirements comparable to the NOx Rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Affected utilities including certain AEP operating companies, petitioned the D.C. Circuit Court to review the Section 126 Rule.

After review, the D.C. Circuit Court instructed Federal EPA to justify the methods it used to allocate allowances and project growth for both the NOx Rule and the Section 126 Rule. AEP subsidiaries and other utilities requested that the D.C. Circuit Court vacate the Section 126 Rule or suspend its May 2003 compliance date. On August 24, 2001, the D.C. Circuit Court issued an order tolling the compliance schedule until Federal EPA responds to the Court's remand. Federal EPA has announced that it intends to adopt May 31, 2004, as the compliance date for the Section 126 Rule when it finalizes the NOx budgets for both rules.

In 2000 the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including CPL and SWEPCo. The compliance date is May 2003 for CPL and May 2005 for SWEPCo.

During 2001 selective catalytic reduction (SCR) technology to reduce NOx emissions on OPCo's Gavin Plant commenced operations. Construction of SCR technology at certain other AEP generating units continues with completion scheduled in 2002 through 2006.

Our estimates indicate that compliance with the NOx Rule, the Texas Natural Resource Conservation Commission rule and the Section 126 Rule could result in required capital expenditures of approximately $1.6 billion of which approximately $450 million has been spent through December 31, 2001 for the AEP System. Estimated compliance costs and amounts spent by registrant subsidiaries are as follows:

	Estimated Compliance Cost	Amount Spent
	(in millions)	
AEGCo	$125	$ -
APCo	365	130
CPL	57	4
CSPCo	106	1
I&M	202	-
KPCo	140	13
OPCo	606	277
SWEPCo	28	21

Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers, they will have an adverse effect on results of operations, cash flows and possibly financial condition.

Merger Litigation – On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUCHA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the appeals court said that the SEC failed to explain its conclusions that the transmission integration and single region requirements are satisfied.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy – Affecting AEP, APCo, CSPCo, I&M, KPCo and OPCo

At the date of Enron's bankruptcy AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line from Enron and entered into a lease arrangement with a subsidiary of Enron for a gas storage facility. At the date of Enron's bankruptcy various HPL related contingencies and indemnities remained unsettled. In the fourth quarter of 2001 AEP provided $47 million ($31 million net of tax) for our estimated loss from the Enron bankruptcy. The amounts for certain subsidiary registrants were:

Registrant	Amounts Provided	Amounts Net of Tax
	(in millions)	
APCo	$5.2	$3.4
CSPCo	3.2	2.1
I&M	3.4	2.2
KPCo	1.3	0.8
OPCo	4.3	2.8

The amounts provided were based on an analysis of contracts where AEP and Enron are counterparties, the offsetting of receivables and payables, the application of deposits from Enron and management's analysis of the HPL related purchase contingencies and indemnifications. If there are any adverse unforeseen developments in the bankruptcy proceedings, our future results of operations, cash flows and possibly financial condition could be adversely impacted.

Other – AEP and its registrant subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the ultimate outcome of these matters, it is not expected that their resolution will have a material adverse effect on results of operations, cash flows or financial condition.

9. Acquisitions and Dispositions:

On June 1, 2001, AEP, through a wholly owned subsidiary, purchased Houston Pipe Line Company and Lodisco LLC for $727 million from Enron. The acquired assets include 4,200 miles of gas pipeline, a 30-year $274 million prepaid lease of a gas storage facility and certain gas marketing contracts. The purchase method of accounting was used to record the acquisition. According to APB Opinion No. 16 "Business Combinations" AEP recorded the assets acquired and liabilities assumed at their estimated fair values as determined by the Company's management based on information currently available and on current assumptions as to future operations. Based on a preliminary purchase price allocation the excess of cost over fair value of the net assets acquired was approximately $190 million and is recorded as goodwill. SFAS 142 "Goodwill and Other Intangible Assets" treats goodwill as a non-amortized, non-wasting asset effective January 1, 2002. Therefore, goodwill was amortized for only seven months in 2001 on a straight-line basis over 30 years. The purchase method results in the assets, liabilities and earnings of the acquired operations being included in AEP's consolidated financial statements from the purchase date.

SFAS 141 "Business Combinations" apply to all business combinations initiated and consummated after June 30, 2001.

AEP also purchased the following assets or acquired the following businesses from July 1, 2001 through December 31, 2001 for an aggregate total of $1,651 million:

- SWEPCo, an AEP subsidiary, purchased the Dolet Hills mining operations including existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana. The purchase resulted from a litigation settlement discussed in Note 8, "Commitments and Contingencies". Management expects the acquisition to have minimal impact on results of operations.
- Quaker Coal Company as part of a bankruptcy proceeding settlement and assumed additional liabilities of approximately $58 million. The acquisition

includes property, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia. AEP will continue to operate the mines and facilities which employ over 800 individuals.

- MEMCO Barge Line that adds 1,200 hopper barges and 30 towboats to AEP's existing barging fleet. MEMCO's 450 employees will continue to operate the barge line. MEMCO also adds major barging operations on the Mississippi and Ohio rivers to AEP's barging operations on the Ohio and Kanawha rivers.
- 4,000 megawatts of UK coal-fired generation that includes Fiddler's Ferry, a four-unit, 2,000-megawatt station on the River Mersey in northwest England, approximately 200 miles from London and Ferrybridge, a four-unit, 2,000-megawatt station on the River Aire in northeast England, approximately 200 miles from London and related coal stocks.
- A 20% equity interest in Caiua, a Brazilian electric operating company which is a subsidiary of Vale. See Note 17, "Power, Distribution and Communications Projects". The Company converted a total of $66 million on an existing loan and accrued interest on that loan into Caiua equity.
- Indian Mesa Wind Project consisting of 160 megawatts of wind generation located near Fort Stockton, Texas.
- Acquired existing contracts and hired 22 key staff from Enron's London-based international coal trading group.

Regarding the 2001 acquisitions management has recorded the assets acquired and liabilities assumed at their estimated fair values in accordance with APB Opinion No. 16 and SFAS 141 as appropriate based on currently available information and on current assumptions as to future operations. Management is in the process of obtaining independent appraisals regarding certain of these acquisitions and evaluating others to refine its determination of fair values. Accordingly the allocation of the purchase prices are subject to revision based on the final determinations.

Dispositions

In March 2001 CSWE, a subsidiary company, completed the sale of Frontera, a generating plant that the FERC required to be divested in connection with the merger of AEP and CSW. The sale proceeds were $265 million and resulted in an after tax gain of $46 million.

In July 2001 AEP, through a wholly owned subsidiary, sold its 50% interest in a 120-megawatt generating plant located in Mexico. The sale resulted in an after tax gain of approximately $11 million.

In July 2001 OPCo, an AEP subsidiary, sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale is expected to have a nominal impact on results of operations and cash flows.

In December 2001 AEP completed the sale of its ownership interests in the Virginia and West Virginia PCS (personal communications services) Alliances for stock. AEP recorded a 25% valuation provision on the stock received and is restricted from selling this stock until after January 1, 2003. In addition, the number of shares AEP can sell each month is limited in order to prevent large swings in the stock price. The sales resulted in an after tax gain of approximately $7 million.

In December 2000 the Company, through a wholly owned subsidiary, committed to negotiate a sale of its 50% investment in Yorkshire, a U.K. electricity supply and distribution company. As a result a $43 million impairment writedown ($30 million after tax) was recorded in the fourth quarter of 2000 to reflect the net loss from the expected sale in the first quarter of 2001. The impairment writedown is included in Other Income on AEP's Consolidated Statements of Income. On February 26, 2001 an agreement to sell the Company's 50% interest in Yorkshire was signed. On April 2, 2001, following the approval of the buyer's shareholders, the sale was completed without further impact on AEP's consolidated earnings.

In December 2000, CSW International, a subsidiary company sold its investment in a

Chilean electric company for $67 million. A net loss on the sale of $13 million ($9 million after tax) is included in Other Income, and includes $26 million ($17 million net of tax) of losses from foreign exchange rate changes that were previously reflected in other comprehensive income. In the second quarter of 2000 management determined that the then existing decline in market value of the shares was other than temporary. As a result the investment was written down by $33 million ($21 million after tax) in June 2000. The total loss from both the write down of the Chilean investment to market in the second quarter and from the sale in the fourth quarter was $46 million ($30 million net of tax).

10. Benefit Plans:

In the U.S. AEP sponsors two qualified pension plans and two nonqualified pension plans. Substantially all employees in the U.S., are covered by one or both of the pension plans. OPEB plans are sponsored by the AEP System to provide medical and death benefits for retired employees in the U.S.

The foreign pension plans are for employees of SEEBOARD in the U.K. and CitiPower in Australia. The majority of SEEBOARD's employees joined a pension plan that is administered for the U.K.'s electricity industry. The assets of this plan are actuarially valued every three years. SEEBOARD and its participating employees both contribute to the plan. Subsequent to July 1, 1995, new employees were no longer able to participate in that plan and two new pension plans were made available to new employees of SEEBOARD. CitiPower sponsors a defined benefit pension plan that covers all employees.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2001, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		Foreign Pension Plans (in millions)		U.S. OPEB Plans	
	2001	2000	2001	2000	2001	2000
Reconciliation of benefit obligation:						
Obligation at January 1	$3,161	$2,934	$1,179	$1,176	$1,668	$1,365
Service Cost	69	60	12	13	30	29
Interest Cost	232	227	60	64	114	106
Participant Contributions	-	-	4	5	8	7
Plan Amendments	-	(71)(a)	-	-	17 (b)	(67) (c)
Foreign Currency Translation Adjustment	-	-	(36)	(95)	-	-
Actuarial (Gain) Loss	121	218	(62)	80	192	262
Divestures	-	-	-	-	(287) (d)	-
Benefit Payments	(291)	(207)	(58)	(64)	(88)	(85)
Curtailments	-	-	-	-	1	51 (e)
Obligation at December 31	$3,292	$3,161	$1,099	$1,179	$1,655	$1,668
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$3,911	$3,866	$1,290	$1,405	$704	$668
Actual Return on Plan Assets	(182)	250	(131)	55	(31)	2
Company Contributions	-	2	7	-	118	112
Participant Contributions	-	-	4	5	8	7
Foreign Currency Translation Adjustment	-	-	(40)	(111)	-	-
Benefit Payments	(291)	(207)	(58)	(64)	(88)	(85)
Fair value of plan assets at December 31	$3,438	$3,911	$1,072	$1,290	$711	$704
Funded status:						
Funded status at December 31	$146	$ 750	$(27)	$111	$(944)	$(964)
Unrecognized Net Transition (Asset) Obligation	(15)	(23)	-	-	263	298
Unrecognized Prior-Service Cost	(12)	(12)	9	10	17	-
Unrecognized Actuarial (Gain) Loss	35	(628)	74	(67)	649	448
Prepaid Benefit (Accrued Liability)	$154	$ 87	$ 56	$ 54	$ (15)	$(218)

(a) One of the qualified pension plans converted to the cash balance pension formula from a final average pay formula.
(b) Related to the purchase of Houston Pipe Line Company and MEMCO Barge Line.
(c) Change to a service-related formula for retirement health care costs and a 50% of pay life insurance benefit for retiree life insurance.
(d) Related to the sale of Central Ohio Coal Company, Southern Ohio Coal Company and Windsor Coal Company.
(e) Related to the shutdown of Central Ohio Coal Company, Southern Ohio Coal Company and Windsor Coal Company.

The following table provides the amounts for prepaid benefit costs and accrued benefit liability recognized in the consolidated balance sheets as of December 31 of both years. The amounts for additional minimum liability, intangible asset and accumulated other comprehensive income for 2000 were recorded in 2001 and the amounts for 2001 will be recorded in 2002.

	U.S. Pension Plan		Foreign Pension Plans (in millions)		U.S. OPEB Plans	
	2001	2000	2001	2000	2001	2000
Prepaid Benefit Costs	$ 205	$ 159	$57	$54	$ 1	$ 3
Accrued Benefit Liability	(51)	(72)	(1)	-	(16)	(221)
Additional Minimum Liability	(15)	(24)	-	-	N/A	N/A
Intangible Asset	9	14	-	-	N/A	N/A
Accumulated Other Comprehensive Income	6	10	-	-	N/A	N/A
Net Asset (Liability)	$ 154	$ 87	$56	$54	$(15)	$(218)
Other Comprehensive (Income) Expense Attributable to Change in Additional Pension Liability Recognition	$(4)	$4	-	-	N/A	N/A

N/A = Not Applicable

Both of the AEP System's nonqualified pension plans had accumulated benefit obligations in excess of plan assets of $40 million and $26 million at December 31, 2001 and $41 million and $26 million at December 31, 2000. There are no plan assets in the nonqualified plans.

The AEP System's OPEB plans had accumulated benefit obligations in excess of plan assets of $944 million and $964 million at December 31, 2001 and 2000, respectively.

In late December 2001 AEP purchased generation plants in the UK (see Note 9, "Acquisitions and Dispositions"). The purchase included the pension plan of the existing generation plant employees. In connection with the acquisition, a $10 million liability for the accumulated benefit obligation in excess of plan assets was assumed.

The following table provides the components of AEP's net periodic benefit cost for the plans for fiscal years 2001, 2000 and 1999:

	U.S. Pension Plans			Foreign Pension Plans			U.S. OPEB Plans		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
					(in millions)				
Service cost	$ 69	$ 60	$ 71	$ 12	$ 13	$ 15	$ 30	$ 29	$ 33
Interest cost	232	227	211	60	64	59	114	106	90
Expected return on plan assets	(338)	(321)	(299)	(69)	(75)	(71)	(61)	(57)	(49)
Amortization of transition (asset) obligation	(8)	(8)	(8)	-	-	-	30	41	43
Amortization of prior-service cost	-	13	12	1	1	-	-	-	-
Amortization of net actuarial (gain) loss	(24)	(39)	(15)	-	-	-	18	4	5
Net periodic benefit cost (credit)	(69)	(68)	(28)	4	3	3	131	123	122
Curtailment loss(a)	-	-	-	-	-	-	1	79	18
Net periodic benefit cost (credit) after curtailments	$(69)	$ (68)	$ (28)	$ 4	$ 3	$ 3	$132	$202	$140

(a) Curtailment charges were recognized during 2000 and 1999 for the shutdown of Central Ohio Coal Company, Southern Ohio Coal Company and Windsor Coal Company.

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for fiscal years 2001, 2000 and 1999:

	U.S. Pension Plans			U.S OPEB Plans		
	2001	2000	1999	2001	2000	1999
			(in thousands)			
APCo	$(13,645)	$(14,047)	$(3,925)	$22,810	$ 22,139	$19,431
CPL	(3,411)	(2,986)	(4,270)	8,214	6,656	7,595
CSPCo	(10,624)	(10,905)	(4,893)	10,328	9,643	8,623
I&M	(7,805)	(8,565)	(1,259)	15,077	14,155	13,664
KPCo	(1,922)	(2,075)	(393)	2,438	2,364	2,652
OPCo	(14,879)	(15,041)	(4,979)	34,444	116,205	52,518
PSO	(2,480)	(2,196)	(3,129)	6,187	4,277	5,516
SWEPCo	(3,051)	(2,606)	(3,734)	6,399	4,152	4,913
WTU	(1,664)	(1,585)	(2,221)	3,729	2,929	3,377

The weighted-average assumptions as of December 31, used in the measurement of the Company's benefit obligations are shown in the following tables:

	U.S. Pension Plans			Foreign Pension Plans			U.S. OPEB Plans		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
	%	%	%	%	%	%	%	%	%
Discount rate	7.25	7.50	8.00	5-5.8	5-5.5	5.5-6	7.25	7.50	8.00
Expected return on plan assets	9.00	9.00	9.00	6.1-7.5	6-7.5	6.5-7.5	8.75	8.75	8.75
Rate of compensation increase	3.7	3.2	3.8	4.0	3.5-4.0	4-4.5	N/A	N/A	N/A

For OPEB measurement purposes, an 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2002. The rate was assumed to decrease gradually each year to a rate of 5% through 2005 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

(in millions)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement health care benefit cost	$ 18	$(15)
Effect on the health care Component of the Accumulated Postretirement Benefit obligation	189	(156)

AEP Savings Plans - The AEP Savings Plans are defined contribution plans offered to non-UMWA U.S. employees. The cost for contributions to these plans totaled $55 million in 2001, $37 million in 2000 and $36 million in 1999. Beginning in 2001 AEP's contributions to the plans increased to 4.5% of the initial 6% of employee pay contributed from the previous 3% of the initial 6% of employee base pay contributed.

The following table provides the cost for contributions to the savings plans by the following AEP registrant subsidiaries for fiscal years 2001, 2000 and 1999:

	2001	2000	1999
	(in thousands)		
APCo	$7,031	$3,988	$4,091
CPL	3,046	3,161	3,284
CSPCo	2,789	1,638	1,679
I&M	7,833	4,231	3,996
KPCo	1,016	544	561
OPCo	6,398	3,713	3,744
PSO	2,235	2,306	2,435
SWEPCo	2,776	2,880	2,961
WTU	1,558	1,708	1,766

Other UMWA Benefits – AEP and OPCo provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. The benefits are administered by UMWA trustees and contributions are made to their trust funds. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2001, 2000 and 1999.

11. Stock-Based Compensation:

AEP has a Long-term Incentive Plan under which a maximum of 15,700,000 shares of common stock can be issued to key employees. The plan was adopted in 2000.

Under the plan, the exercise price of each option granted equals the market price of AEP's common stock on the date of grant. These options will vest in equal increments, annually, over a three-year period with a maximum exercise term of ten years.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. The provisions of the CSW stock option plan will continue in effect until all options expire or there are no longer options outstanding. Under the CSW stock option plan, the option exercise price was equal to the stock's market price on the date of grant. The grant vested over three years, one-third on each of the first three anniversary dates of the grant, and expires 10 years after the original grant date. All CSW stock options are fully vested.

The following table summarizes share activity in the above plans, and the weighted-average exercise price:

	2001		2000		1999	
	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price
Outstanding at beginning of year	6,610	$36	825	$40	866	$40
Granted	645	$45	6,046	$36	-	$ -
Exercised	(216)	$38	(26)	$36	(22)	$38
Forfeited	(217)	$37	(235)	$39	(19)	$43
Outstanding at end of year	6,822	$37	6,610	$36	825	$40
Options Exercisable at end of year	395	$43	588	$41	707	$42

The weighted-average grant-date fair value of options granted in 2001 and 2000 was $8.01 and $5.50 per share. There were no options granted in 1999. Shares outstanding under the stock option plan have exercise prices ranging from $35 to $49 and a weighted-average remaining contractual life of 8.5 years.

If compensation expense for stock options had been determined based on the fair value at the grant date, net income and earnings per share would have been the pro forma amounts shown below:

	2001	2000	1999
Pro forma net income (in millions)	$959	$264	$972
Pro forma earnings per Share:			
Basic	$2.98	$0.82	$3.03
Diluted	$2.97	$0.82	$3.03

The proceeds received from exercised stock options are included in common stock and paid-in capital.

The pro forma amounts are not representative of the effects on reported net income for future years.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used to estimate the fair value of options granted:

	2001	2000
Risk Free Interest Rate	4.87%	5.02%
Expected Life	7 years	7 years
Expected Volatility	28.40%	24.75%
Expected Dividend Yield	6.05%	6.02%

12. Business Segments:

In fiscal year 2000, AEP reported the following four business segments: Domestic Electric Utilities; Foreign Energy Delivery; Worldwide Energy Investments; and Other. With this structure, our regulated domestic utility companies were considered single, vertically integrated units, and were reported collectively in the Domestic Electric Utilities segment.

In 2001, we moved toward our goal of functionally and structurally segregating our businesses. The ensuing realignment of our operations resulted in our current business segments, Wholesale, Energy Delivery and Other. The business activities of each of these segments are as follows:

Wholesale
- Generation of electricity for sale to retail and wholesale customers,
- Marketing and trading of electricity and gas worldwide.
- Gas pipeline and storage services and other energy supply related business

Energy Delivery
- Domestic electricity transmission
- Domestic electricity distribution

Other
- Foreign electricity generation investments
- Foreign electricity distribution and supply investments
- Telecommunication services

Segment results of operations for the twelve months ended December 31, 2001, 2000 and 1999 are shown below. These amounts include certain estimates and allocations where necessary.

We have used Earnings before Interest and Income Taxes (EBIT) as a measure of segment operating performance. The EBIT measure is total operating revenues net of total operating expenses and other routine income and deductions from income. It differs from net income in that it does not take into account interest expense or income taxes. EBIT is believed to be a reasonable gauge of results of operations. By excluding interest and income taxes, EBIT does not give guidance regarding the demand of debt service or other interest requirements, or tax liabilities or taxation rates. The effects of interest expense and taxes on overall corporate performance can be seen in the consolidated income statement.

Year	Wholesale	Energy Delivery	Other	Reconciling Adjustments	AEP Consolidated
		(in millions)			
2001					
Revenues from:					
External unaffiliated customers	$55,929	$ 3,356	$ 1,972	$ -	$61,257
Transactions with other operating segments	2,708	20	1,155	(3,883)	-
Segment EBIT	1,418	986	278	(115)	2,567
Depreciation, depletion and amortization expense	597	632	154	-	1,383
Total assets	31,459	12,455	4,541	(1,174)(a)	47,281
Investments in equity method subsidiaries	242	-	414	-	656
Gross property additions	640	844	348	-	1,832

(a) Reconciling adjustments for Total Assets:	
Eliminate intercompany balances	(1,558)
Corporate assets	404
Other	(20)
	(1,174)

Year	Wholesale	Energy Delivery	Other	Reconciling Adjustments	AEP Consolidated
2000					
Revenues from:					
External unaffiliated customers	$31,437	$ 3,174	$2,095	$ -	$36,706
Transactions with other operating segments	1,726	2	750	(2,478)	-
Segment EBIT	1,006	1,017	358	(322)	2,059
Depreciation, depletion and amortization expense	559	506	188	(3)	1,250
Total assets	32,216	14,876	7,124	(866)(b)	53,350
Investments in equity method subsidiaries	140	-	724	-	864
Gross property additions	493	961	319	-	1,773

(b) Reconciling adjustments for Total Assets:	
Eliminate intercompany balances	(955)
Corporate assets	93
Other	(4)
	(866)

Year	Wholesale	Energy Delivery	Other	Reconciling Adjustments	AEP Consolidated
1999					
Revenues from:					
External unaffiliated customers	$19,543	$3,068	$2,134	$ -	$24,745
Transactions with other operating segments	1,038	-	573	(1,611)	-
Segment EBIT	1,146	1,008	392	(82)	2,464
Depreciation, depletion and amortization expense	565	454	196	(3)	1,212
Total assets	18,408	11,224	6,396	(335)(c)	35,693
Investments in equity method subsidiaries	134	-	755	-	889
Gross property additions	390	815	475	-	1,680

(c) Reconciling adjustments for Total Assets:	
Eliminate intercompany balances	(345)
Other	10
	(335)

Geographically our business is transacted primarily in the United States and the United Kingdom with other holdings in a small number of other counties. Results of operations by geographic area are as follows:

Geographic Areas	Revenues			
	United States	United Kingdom	Other Foreign	AEP Consolidated
	(in millions)			
2001	$53,650	$7,201	$406	$61,257
2000	34,300	2,011	395	36,706
1999	22,694	1,705	346	24,745

	Long-Lived Assets			
	United States	United Kingdom	Other Foreign	AEP Consolidated
	(in millions)			
2001	$21,726	$2,158	$659	$24,543
2000	20,463	1,220	710	22,393
1999	19,958	1,124	783	21,865

Of the registrant operating company subsidiaries, all of the registrant subsidiaries except AEGCo have two business segments. The segment results for each of these subsidiaries are reported in the table below. AEGCo has one segment, a wholesale generation business. AEGCo's results of operations are reported in AEGCo's financial statements.

	Twelve Months Ended December 31, 2001			Twelve Months Ended December 31, 2000		
	Revenues From External Customers	Segment EBIT	Total Assets	Revenues From External Customers	Segment EBIT	Total Assets
	(in thousands)			(in thousands)		
Wholesale Segment						
APCo	$6,404,394	$164,844	$2,855,337	$4,512,390	$ 154,525	$3,708,252
CPL	2,848,545	303,926	2,977,504	1,870,689	273,650	3,182,192
CSPCo	3,816,644	232,372	1,987,756	2,767,569	235,860	2,488,513
I&M	4,489,215	117,396	3,318,919	3,231,065	(146,297)	4,003,805
KPCo	1,528,212	4,935	585,847	1,055,521	22,379	766,605
OPCo	5,709,689	240,128	3,156,115	4,524,513	289,084	4,007,722
PSO	1,939,372	52,086	907,165	1,184,895	54,072	1,011,432
SWEPCo	2,241,444	82,409	1,223,334	1,337,776	27,055	1,302,398
WTU	895,235	7,930	396,147	583,358	13,910	466,499
Energy Delivery Segment						
APCo	$595,036	$213,733	$2,252,601	$574,918	$191,560	$2,925,472
CPL	473,182	109,587	2,138,482	478,814	136,069	2,285,492
CSPCo	483,219	130,503	1,118,112	398,046	81,896	1,399,789
I&M	314,410	111,206	1,498,089	311,019	126,241	1,807,233
KPCo	131,183	54,033	567,396	121,346	49,770	742,459
OPCo	552,713	118,261	1,759,952	467,587	138,418	2,234,835
PSO	261,877	79,787	1,010,732	245,124	85,524	1,126,901
SWEPCo	333,004	107,197	1,273,266	344,950	129,842	1,355,558
WTU	169,036	33,226	527,273	176,204	50,201	620,912
Registrant Subsidiaries Company Total						
APCo	$6,999,430	$378,577	$5,107,938	$5,087,308	$346,085	$6,633,724
CPL	3,321,727	413,513	5,115,986	2,349,503	409,719	5,467,684
CSPCo	4,299,863	362,875	3,105,868	3,165,615	317,756	3,888,302
I&M	4,803,625	228,602	4,817,008	3,542,084	(20,056)	5,811,038
KPCo	1,659,395	58,968	1,153,243	1,176,867	72,149	1,509,064
OPCo	6,262,402	358,389	4,916,067	4,992,100	427,502	6,242,557
PSO	2,201,249	131,873	1,917,897	1,430,019	139,596	2,138,333
SWEPCo	2,574,448	189,606	2,496,600	1,682,726	156,897	2,657,956
WTU	1,064,271	41,156	923,420	759,562	64,111	1,087,411

prices at which transactions can be executed in the market. The forward price curve includes the market's expectations for prices of a delivered commodity at that future date. The forward price curve is developed from the market bid price, which is the highest price which traders are willing to pay for a contract, and the ask or offer price, which is the lowest price traders are willing to receive for selling a contract.

Options contracts, consisting primarily of options on forwards and spread options, are valued using models, which are variations on Black-Scholes option models. The market-related inputs are the interest rate curve, the underlying commodity forward price curve, and the implied volatility curve. Option prices or volatilities may be quoted in the market. Significant estimates in valuing these contracts include forward price curves, volumes, and other volatilities.

Futures and futures options traded on futures exchanges (primarily oil and gas on Nymex) are valued at the exchange price.

Market prices utilized in valuing all forward contracts, OTC options, swaps and structured transactions represent mid-market price, which is the average of the bid and ask prices. These bids and offers come from brokers, on-line exchanges such as the Intercontinental Exchange, and directly from other counterparties. These prices exist for delivery periods and locations being traded or quoted and vary by period, location and commodity. For periods and locations that are not liquid and for which external information is not readily available, management uses the best information available to develop bid and ask prices and forward curves.

Electricity and gas markets in particular have primary trading hubs or delivery points/regions and less liquid secondary delivery points. In North American natural gas markets, the primary delivery points are generally traded from Henry Hub, Louisiana. The less liquid gas or power trading points may trade as a spread (based on transportation costs, constraints, etc.) from the nearest liquid trading hub. Also, some commodities trade more often and therefore are more liquid than others. For example, peak electricity is a more liquid product than off-peak electricity. Henry Hub gas trades in monthly blocks for up to 36 months and after that only trades in seasonal or calendar blocks. In the near term, forward price curves for gas have a seasonal shape. They are based on market quotes beyond that.

For all these factors, the curve used for valuation is the mid-point. At times bids or offers may not be available due to market events, volatility, constraints, long-dated part of the curve, etc. When this occurs, the Company uses its best judgment to estimate the curve values until actual values are available again. The value used will be based on various factors such as last trade price, recent price trend, product spreads, location spreads (including transportation costs), cross commodity spreads (e.g., heat rate conversion of gas to power), time spreads, cost of carry (e.g., cost of gas storage), marginal production cost, cost of new entrant capacity, and alternative fuel costs. Also, an energy commodity contract's price volatility generally increases as it approaches the delivery month. Spot price volatility (e.g., daily or hourly prices) can cause contract values to change substantially as open positions settle against spot prices. When a portion of a curve has been estimated for a period of time and market changes occur, assumptions are updated to align the company's curve to the market.

The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is based on credit ratings of counterparties and represents the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. The liquidity reserve essentially reserves half of the difference between bids and offers for each open position, such that the wider the bid-offer spread (indicating lower liquidity), the greater the reserve.

We also mark to market derivatives that are not trading contracts in accordance with generally accepted accounting principles.

There may be unique models for these transactions, but the curves the company inputs into the models are the same forward curves, which are described above.

We have developed independent controls to evaluate the reasonableness of our valuation models and curves. However, there are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. Therefore, there could be a significant favorable or adverse effect on future results of operations and cash flows if market prices at settlement differ from the price models and curves.

AEP limits credit risk by extending unsecured credit to entities based on internal ratings. AEP uses Moody's Investor Service, Standard and Poor's and qualitative and quantitative data to independently assess the financial health of counterparties on an ongoing basis. This data, in conjunction with the ratings information, is used to determine appropriate risk parameters. AEP also requires cash deposits, letters of credit and parental/affiliate guarantees as security from certain below investment grade counterparties in our normal course of business.

We trade electricity and gas contracts with numerous counterparties. Since our open energy trading contracts are valued based on changes in market prices of the related commodities, our exposures change daily. We believe that our credit and market exposures with any one counterparty is not material to financial condition at December 31, 2001. At December 31, 2001 less than 5% of the counterparties were below investment grade as expressed in terms of Net Mark to Market Assets. Net Mark to Market Assets represents the aggregate difference (either positive or negative) between the forward market price for the remaining term of the contract and the contractual price. The following table approximates counterparty credit quality and exposure for AEP.

Counterparty Credit Quality:	Futures, Forward and Swap Contracts	Options	Total
Year Ending December 31, 2001			
		(in millions)	
AAA/Exchanges	$ 147	$ -	$ 147
AA	140	4	144
A	304	7	311
BBB	932	34	966
Below Investment Grade	56	23	79
Total	$1,579	$68	$1,647

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

We enter into transactions for electricity and natural gas as part of wholesale trading operations. Electric and gas transactions are executed over-the-counter with counterparties or through brokers. Gas transactions are also executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers and counterparties require cash or cash related instruments to be deposited on these transactions as margin against open positions. The combined margin deposits at December 31, 2001 and 2000 was $55 million and $95 million. These magin accounts are restricted and therefore are not included in cash and cash equivalents on the Balance Sheet. AEP and its subsidiaries can be subject to further margin requirements should related commodity prices change.

The margin deposits at December 31, 2001 for the registrants were:

	(in thousands)
APCo	$2,832
CPL	299
CSP	1,736
I&M	1,879
KPCo	698
OPCo	2,862
PSO	247
SWEPCo	299
WTU	99

Financial Derivatives and Hedging

In the first quarter of 2001, AEP adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS 137 and SFAS 138. SFAS 133 requires that entities recognize all derivatives including fair value hedges as either assets or liabilities and measure such derivatives at fair value. Changes in the fair value of derivatives are included in earnings unless designated as a cash flow hedge. This practice is commonly referred to as mark-to-market accounting. Changes in the fair value of derivatives that are designated as effective cash flow hedges are included in other comprehensive income. AEP recorded a favorable transition adjustment to accumulated other comprehensive income of $27 million at January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures.

Most of the derivatives identified in the transition adjustment were designated as cash flow hedges and relate to foreign operations.

The amounts of net revenue margins (sales less purchases) in 2001, 2000, and 1999 for trading activities were:

	2001	2000 (in millions)	1999
Net Revenue Margin	$609	$435	$91

The amounts of revenues recorded in 2001, 2000 and 1999 for the registrant subsidiaries were:

	2001	2000 (in thousands)	1999
APCo	$78,521	$72,649	$28,970
CPL	15,711	3,385	-
CSPCo	51,765	48,142	14,800
I&M	36,089	58,909	16,147
KPCo	12,466	23,417	5,563
OPCo	65,118	73,474	24,389
PSO	(2,483)	9,268	-
SWEPCo	7,897	6,404	-
WTU	(1,491)	1,821	-

The fair value of open trading contracts that are marked-to-market are based on management's best estimates using over-the-counter quotations and exchange prices for short-term open trading contracts, and Company developed price curves for open long-term trading contracts. The fair values of trading contracts at December 31 are:

	2001 Fair Value (in millions)	2000 Fair Value (in millions)
Trading Assets		
Electric		
Futures and Options-NYMEX	$ 11	$ -
Physicals	3,588	8,791
Options - OTC	182	215
Swaps	117	164
Total Trading Assets	$3,898	$9,170
Gas		
Futures and Options-NYMEX	$ 143	$ -
Physicals	238	454
Options - OTC	978	1,266
Swaps	5,646	6,185
Total Trading Assets	$7,005	$7,905
Trading Liabilities		
Electric		
Futures and Options-NYMEX	$ -	$ -
Physicals	(3,382)	(8,852)
Options - OTC	(101)	(133)
Swaps	(126)	(144)
Total Trading Liabilities	$(3,609)	$(9,129)
Gas		
Futures and Options-NYMEX	$ (92)	$ (81)
Physicals	(80)	(419)
Options - OTC	(1,076)	(934)
Swaps	(5,598)	(6,449)
Total Trading Liabilities	$(6,846)	$(7,883)

	2001 Fair Value (in thousands)	2000 Fair Value (in thousands)
APCo		
Trading Assets		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	801,306	2,234,522
Options - OTC	46,649	59,814
Swaps	34,578	51,470
Trading Liabilities		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	(748,016)	(2,258,596)
Options - OTC	(21,895)	(35,955)
Swaps	(36,921)	(44,855)
KPCo		
Trading Assets		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	197,545	530,828
Options - OTC	11,503	14,207
Swaps	8,529	12,227

Trading Liabilities		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	(190,389)	(536,512)
Options - OTC	(5,372)	(8,521)
Swaps	(9,106)	(10,656)

	2001 Fair Value (in thousands)	2000 Fair Value (in thousands)
I&M		
Trading Assets		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	560,393	1,349,950
Options - OTC	31,397	36,139
Swaps	22,950	31,095
Trading Liabilities		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	(513,026)	(1,371,793)
Options - OTC	(15,864)	(25,807)
Swaps	(24,505)	(27,099)
OPCo		
Trading Assets		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	668,142	1,776,259
Options - OTC	38,108	46,731
Swaps	29,730	41,788
Trading Liabilities		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	(619,756)	(1,792,417)
Options - OTC	(18,227)	(29,350)
Swaps	(32,551)	(37,398)
CSPCo		
Trading Assets		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	491,290	1,192,203
Options - OTC	28,612	31,918
Swaps	21,211	27,461
Trading Liabilities		
Electric		
Futures and Options-NYMEX (net)	$ -	$ -
Physicals	(456,613)	(1,204,948)
Options - OTC	(13,403)	(19,220)
Swaps	(22,648)	(23,932)

	2001 Fair Value (in thousands)	2000 Fair Value (in thousands)
CPL		
Trading Assets		
Electric Physicals	$285,481	$ 542,626
Trading Liabilities		
Electric Physicals	(281,624)	(550,817)
PSO		
Trading Assets		
Electric Physicals	217,415	431,186
Trading Liabilities		
Electric Physicals	(214,981)	(437,694)
SWEPCo		
Trading Assets		
Electric Physicals	249,531	516,385
Trading Liabilities		
Electric Physicals	(246,631)	(524,180)
WTU		
Trading Assets		
Electric Physicals	84,784	171,597
Trading Liabilities		
Electric Physicals	(83,869)	(174,187)

The FASB's Derivatives Implementation Group (DIG) Issued guidance, effective in the third quarter of 2001, regarding the implementation of SFAS 133 for certain fuel supply contracts with volume optionality and electricity capacity contracts. The guidance concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when electricity capacity conracts can qualify as normal purchases or sales.

Predominantly all of AEP's contracts for coal, gas and electricity, which are recorded on a settlement basis, do not meet the criteria of a financial derivative instrument and qualify as normal purchases or sales. As a result they are exempt from the DIG guidance described above and have not been marked-to-market. Beginning July 1, 2001, the effective date of the DIG guidance, certain of AEP's fuel supply contracts with volumetric optionality that qualify as financial derivative instruments are marked to market with any gain or loss recognized in the income statement. The effect of initially adopting the DIG guidance at July 1, 2001, a favorable earnings mark-to-market effect of $18 million, net of tax, is reported as a cumulative effect of an accounting change on the income statement.

Cash flows from both derivative instruments and trading activities are included in net cash flows from operating activities.

Certain derivatives may be designated for accounting purposes as a hedge of either the fair value of an asset, liability or firm commitment, or a hedge of the variability of cash flows related to a variable-priced asset, liability, commitment or forecasted transaction. To qualify for hedge accounting, the relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy for use of the hedge instrument. At the inception of the hedge and on an ongoing basis, the effectiveness of the hedge is assessed as to whether the hedge is highly effective in offsetting changes in fair value or cash flows of the item being hedged. Changes in the fair value that result from ineffectiveness of a hedge under SFAS 133 are recognized currently in earnings through mark-to-market accounting. Changes in the fair value of effective cash flow hedges are reported in accumulated other comprehensive income if documented at inception. Gains and losses from cash flow hedges in other comprehensive income are reclassified to earnings in the accounting periods in which the variability of cash flows of the hedged items affect earnings.

Cash flow hedges included in Accumulated Other Comprehensive income on the Balance Sheet at December 31, 2001 are:

	Hedging Assets	Hedging Liabilities	Other Comprehensive Income (Loss) After Tax
		(in millions)	
Electric	$16	$ (6)	$ 4
Interest Rate	-	(21)	(12)
Foreign Currency	-	-	5
			$ (3)

The following table represents the activity in Other Comprehensive Income related to the effect of adopting SFAS 133 for derivative contracts that qualify as cash flow hedges at December 31, 2001:

	(in millions)
AEP consolidated	
Transition Adjustment, January 1, 2001	$ 27
Changes in fair value	(1)
Reclasses from OCI to net income	(29)
Accumulated OCI derivative loss, December 31, 2001	$ (3)

	(in thousands)
APCo	
Transition Adjustment, January 1, 2001	$ -
Effective portion of changes in fair value	(340)
Reclasses from OCI to net income	-
Accumulated OCI derivative gain, December 31, 2001	$(340)
KPCo	
Transition Adjustment, January 1, 2001	$ (557)
Effective portion of changes in fair value	(2,348)
Reclasses from OCI to net income	1,002
Accumulated OCI derivative gain, December 31, 2001	$(1,903)
I&M	
Transition Adjustment, January 1, 2001	$ (317)
Effective portion of changes in fair value	(5,368)
Reclasses from OCI to net income	1,850
Accumulated OCI derivative gain, December 31, 2001	$(3,835)
OPCo	
Transition Adjustment, January 1, 2001	$ -
Effective portion of changes in fair value	(196)
Reclasses from OCI to net income	-
Accumulated OCI derivative gain, December 31, 2001	$(196)

Approximately $15 million of net losses from cash flow hedges in accumulated other comprehensive income at December 31, 2001 are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from accumulated other comprehensive income to net income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is 5 years.

We have derivatives under SFAS 133 that do not employ hedge accounting and are not energy trading. The derivative's mark to market value at December 31, 2001 was a $22.7 million asset and a $13.1 million liability.

FINANCIAL INSTRUMENTS

Market Valuation of Non-Derivative Financial Instrument

The book values of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

The fair values of long-term debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange. The book values and fair values of significant financial instruments for AEP and its registrant subsidiaries December 31, 2001 and 2000 are summarized in the following tables.

	2001 Book Value	2001 Fair Value	2000 Book Value	2000 Fair Value
	(in millions)		(in millions)	
AEP Consolidated				
Long-term Debt	$12,053	$12,002	$10,754	$10,812
Preferred Stock	95	93	100	98
Trust Preferred Securities	321	320	334	326
	(in thousands)		(in thousands)	
AEGCo				
Long-term Debt	$45,000	$45,268	$45,000	$45,000
APCo				
Long-term Debt	$1,556,559	$1,439,531	$1,605,818	$1,601,313
Preferred Stock	10,860	10,860	10,860	10,725
CPL				
Long-term Debt	$1,253,768	$1,278,644	$1,454,559	$1,463,690
Trust Preferred Securities	136,250	135,760	148,500	147,431
CSPCo				
Long-term Debt	$791,848	$802,194	$899,615	$908,620
Preferred Stock	10,000	10,100	15,000	14,892
I&M				
Long-term Debt	$1,652,082	$1,672,392	$1,388,939	$1,377,230
Preferred Stock	64,945	62,795	64,945	63,941
KPCo				
Long-term Debt	$346,093	$350,233	$330,880	$335,408
OPCo				
Long-term Debt	$1,203,841	$1,227,880	$1,195,493	$1,176,367
Preferred Stock	8,850	8,837	8,850	8,780
PSO				
Long-term Debt	$451,129	$462,903	$470,822	$476,964
Trust Preferred Securities	75,000	74,730	75,000	72,180
SWEPCo				
Long-term Debt	$645,283	$656,998	$645,963	$651,586
Trust Preferred Securities	110,000	109,780	110,000	106,700
WTU				
Long-term Debt	$255,967	$266,846	$255,843	$261,315

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value - The trust investments which are classified as held for sale for decommissioning and SNF disposal, reported in other assets, are recorded at market value in accordance with SFAS 115. At December 31, 2001 and 2000 the fair values of the trust investments were $933 million and $873 million, respectively, and had a cost basis of $839 million and $768 million, respectively. The change in market value in 2001, 2000, and 1999 was a net unrealized holding loss of $11 million, and net unrealized holding gain of $6 million, and $18 million, respectively.

14. Income Taxes:

The details of AEP's consolidated income taxes as reported are as follows:

	Year Ended December 31,		
	2001	2000	1999
	(in millions)		
Federal:			
Current	$406	$ 766	$308
Deferred	60	(237)	129
Total	466	529	437
State:			
Current	61	50	25
Deferred	35	(9)	-
Total	96	41	25
International:			
Current	1	6	3
Deferred	6	21	17
Total	7	27	20
Total Income Tax as Reported	$569	$ 597	$482

The details of the registrant subsidiaries income taxes as reported are as follows:

Year Ended December 31, 2001	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 9,126	$ 71,623	$190,671	$ 88,013	$ 107,286
Deferred	(6,224)	27,198	(72,568)	14,923	(45,785)
Deferred Investment Tax Credits	-	(3,237)	(5,207)	(3,899)	(7,377)
Total	2,902	95,584	112,896	99,037	54,124
Charged (Credited) to Nonoperating Income (net):					
Current	(56)	(19,165)	(398)	(13,803)	(10,590)
Deferred	-	21,832	-	17,885	16,580
Deferred Investment Tax Credits	(3,414)	(1,528)	-	(159)	(947)
Total	(3,470)	1,139	(398)	3,923	5,043
Total Income Tax as Reported	$ (568)	$ 96,723	$112,498	$102,960	$ 59,167

Year Ended December 31, 2001	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 7,726	$(62,298)	$ 53,030	$ 77,965	$ 19,424
Deferred	2,812	166,166	(16,726)	(31,396)	(11,891)
Deferred Investment Tax Credits	(1,180)	(2,495)	(1,791)	(4,453)	(1,271)
Total	9,358	101,373	34,513	42,116	6,262
Charged (Credited) to Nonoperating Income (net):					
Current	(2,725)	(21,600)	352	542	(691)
Deferred	3,481	20,014	-	-	-
Deferred Investment Tax Credits	(72)	(794)	-	-	-
Total	684	(2,380)	352	542	(691)
Total Income Tax as Reported	$10,042	$ 98,993	$ 34,865	$ 42,658	$ 5,571

Year Ended December 31, 2000	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 8,746	$129,165	$ 89,403	$120,494	$ 134,796
Deferred	(5,842)	3,838	16,263	(7,746)	(126,748)
Deferred Investment Tax Credits	-	(2,947)	(5,207)	(3,379)	(7,524)
Total	2,904	130,056	100,459	109,369	524
Charged (Credited) to Nonoperating Income (net):					
Current	(44)	327	(5,073)	3,777	2,950
Deferred	-	4,764	-	3,683	1,569
Deferred Investment Tax Credits	(3,396)	(1,968)	-	(103)	(330)
Total	(3,440)	3,123	(5,073)	7,357	4,189
Total Income Tax as Reported	$ (536)	$133,179	$95,386	$116,726	$ 4,713

Year Ended December 31, 2000	KPCo	OPCo	PSO (in thousands)	SWEPCo	WTU
Charged (Credited) to Operating Expenses (net):					
Current	$17,878	$259,608	$11,597	$16,073	$ 6,774
Deferred	2,521	(70,263)	25,453	14,653	9,401
Deferred Investment Tax Credits	(1,187)	(1,824)	(1,791)	(4,482)	(1,271)
Total	19,212	187,521	35,259	26,244	14,904
Charged (Credited) to Nonoperating Income (net):					
Current	(50)	15,426	(1,306)	(1,476)	(222)
Deferred	1,244	4,307	-	-	(1,237)
Deferred Investment Tax Credits	(65)	(1,575)	-	-	-
Total	1,129	18,158	(1,306)	(1,476)	(1,459)
Total Income Tax as Reported	$20,341	$205,679	$33,953	$24,768	$13,445

Year Ended December 31, 1999	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M
Charged (Credited) to Operating Expenses (net):					
Current	$ 7,713	$69,522	$ 89,112	$79,410	$(67,368)
Deferred	(5,282)	8,981	19,620	9,737	85,345
Deferred Investment Tax Credits	-	(2,659)	(5,207)	(3,432)	(7,547)
Total	2,431	75,844	103,525	85,715	10,430
Charged (Credited) to Nonoperating Income (net):					
Current	(146)	(1,548)	(5,604)	(3,122)	1,529
Deferred	-	4,052	318	744	382
Deferred Investment Tax Credits	(3,448)	(2,313)	-	(562)	(605)
Total	(3,594)	191	(5,286)	(2,940)	1,306
Total Income Taxes as Reported	$(1,163)	$76,035	$ 98,239	$82,775	$ 11,736

Year Ended December 31, 1999	KPCo	OPCo	PSO (in thousands)	SWEPCo	WTU
Charged (Credited) to Operating Expenses (net):					
Current	$14,897	$135,540	$20,777	$ 60,169	$ 3,328
Deferred	2,239	4,205	14,521	(17,347)	12,026
Deferred Investment Tax Credits	(1,193)	(1,825)	(1,791)	(4,565)	(1,275)
Total	15,943	137,920	33,507	38,257	14,079
Charged (Credited) to Nonoperating Income (net):					
Current	(424)	(3,256)	(2,215)	(4,826)	858
Deferred	357	(539)	-	-	-
Deferred Investment Tax Credits	(99)	(1,633)	-	-	-
Total	(166)	(5,428)	(2,215)	(4,826)	858
Total Income Taxes as Reported	$15,777	$132,492	$31,292	$ 33,431	$14,937

The following is a reconciliation for AEP Consolidated of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory tax rate, and the amount of income taxes reported.

	Year Ended December 31, 2001	2000 (in millions)	1999
Net Income	$ 971	$267	$ 972
Extraordinary Items (net of income tax $20 million in 2001, $44 million in 2000 and $8 million in 1999)	50	35	14
Cumulative Effect of Accounting Change (net of income tax $2 million in 2001)	(18)	-	-
Preferred Stock Dividends	10	11	19
Income Before Preferred Stock Dividends of Subsidiaries	1,013	313	1,005
Income Taxes	569	597	482
Pre-Tax Income	$1,582	$910	$1,487
Income Tax on Pre-Tax Income at Statutory Rate (35%)	$554	$319	$520
Increase (Decrease) in Income Tax Resulting from the Following Items:			
Depreciation	48	77	71
Corporate Owned Life Insurance	4	247	2
Investment Tax Credits (net)	(37)	(36)	(38)
Tax Effects of Foreign Operations	(27)	(29)	(54)
Merger Transaction Costs	-	49	-
State Income Taxes	62	26	16
Other	(35)	(56)	(35)
Total Income Taxes as Reported	$569	$597	$482
Effective Income Tax Rate	36.0%	65.5%	32.5%

Shown below is a reconciliation for each AEP registrant subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory rate, and the amount of income taxes reported.

	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Year Ended December 31, 2001					
Net Income (Loss)	$7,875	$161,818	$182,278	$161,876	$ 75,788
Extraordinary (Gains) Loss	-	-	2,509	30,024	-
Income Tax Benefit	-	-	-	-	-
Income Taxes	(568)	96,723	112,498	102,960	59,167
Pre-Tax Income (Loss)	$7,307	$258,541	$297,285	$294,860	$134,955
Income Tax on Pre-Tax Income (Loss) at Statutory Rate (35%)	$ 2,557	$ 90,490	$104,050	$103,201	$ 47,234
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	230	2,977	8,477	2,757	21,224
Corporate Owned Life Insurance	-	450	-	544	(148)
Nuclear Fuel Disposal Costs	-	-	-	-	(3,292)
Allowance for Funds Used During Construction	(1,078)	-	-	-	(1,606)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	-
Investment Tax Credits (net)	(3,414)	(4,765)	(5,207)	(4,058)	(8,324)
State Income Taxes	1,050	9,613	9,652	5,727	6,137
Other	(287)	(2,042)	(4,474)	(5,211)	(2,058)
Total Income Taxes as Reported	$ (568)	$ 96,723	$112,498	$102,960	$ 59,167
Effective Income Tax Rate	N.M.	37.4%	37.9%	34.9%	43.8%

	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Year Ended December 31, 2001					
Net Income	$21,565	$147,445	$ 57,759	$ 89,367	$12,310
Extraordinary Loss	-	18,348	-	-	-
Income Tax Benefit	-	-	-	-	-
Income Taxes	10,042	98,993	34,865	42,658	5,571
Pre-Tax Income	$31,607	$264,786	$ 92,624	$132,025	$17,881
Income Tax on Pre-Tax Income at Statutory Rate (35%)	$11,062	$ 92,675	$32,418	$ 46,209	$ 6,259
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	1,581	7,972	-	-	1,463
Corporate Owned Life Insurance	334	1,852	-	-	-
Nuclear Fuel Disposal Costs	-	-	-	-	-
Allowance for Funds Used During Construction	-	-	-	-	-
Rockport Plant Unit 2 Investment Tax Credit	-	-	-	-	-
Removal Costs	(420)	-	-	-	-
Investment Tax Credits (net)	(1,252)	(3,289)	(1,791)	(4,453)	(1,271)
State Income Taxes	318	9,752	5,137	5,451	1,283
Other	(1,581)	(9,969)	(899)	(4,549)	(2,163)
Total Income Taxes as Reported	$10,042	$ 98,993	$34,865	$ 42,658	$ 5,571
Effective Income Tax Rate	31.8%	37.4%	37.6%	32.3%	31.2%

	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Year Ended December 31, 2000					
Net Income (Loss)	$7,984	$ 73,844	$189,567	$ 94,966	$(132,032)
Extraordinary (Gains) Loss		(1,066)		39,384	
Income Tax Benefit	-	(7,872)	-	(14,148)	-
Income Taxes	(536)	133,179	95,386	116,726	4,713
Pre-Tax Income (Loss)	$7,448	$198,085	$284,953	$236,928	$(127,319)
Income Tax on Pre-Tax Income (Loss) at Statutory Rate (35%)	$ 2,607	$ 69,330	$99,733	$ 82,925	$(44,561)
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	452	7,606	7,556	10,529	20,378
Corporate Owned Life Insurance	-	54,824	-	29,259	42,587
Nuclear Fuel Disposal Costs	-	-	-	-	(3,957)
Allowance for Funds Used During Construction	(1,070)	-	-	-	(2,211)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	(1,197)	-	-	-
Investment Tax Credits (net)	(3,396)	(4,915)	(5,207)	(3,482)	(7,854)
State Income Taxes	784	9,950	2,296	89	6,004
Other	(287)	(2,419)	(8,992)	(2,594)	(5,673)
Total Income Taxes as Reported	$ (536)	$133,179	$95,386	$116,726	$ 4,713
Effective Income Tax Rate	N.M.	67.2%	33.5%	49.3%	N.M.

Year Ended December 31, 2000	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Net Income	$20,763	$ 83,737	$ 66,663	$72,672	$27,450
Extraordinary Loss		40,157			
Income Tax Benefit	-	(21,281)	-	-	-
Income Taxes	20,342	205,679	33,953	24,768	13,445
Pre-Tax Income	$41,105	$308,292	$100,616	$97,440	$40,895
Income Tax on Pre-Tax Income at Statutory Rate (35%)	$14,387	$107,903	$35,216	$ 34,104	$14,313
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	1,827	27,577	-	-	1,204
Corporate Owned Life Insurance	5,149	84,453	-	-	-
Nuclear Fuel Disposal Costs	-	-	-	-	-
Allowance for Funds Used During Construction	-	-	-	-	-
Rockport Plant Unit 2 Investment Tax Credit	-	-	-	-	-
Removal Costs	(420)	-	-	-	-
Investment Tax Credits (net)	(1,252)	(3,398)	(1,791)	(4,482)	(1,271)
State Income Taxes	1,597	(1,988)	3,037	1,650	-
Other	(946)	(8,868)	(2,509)	(6,504)	(801)
Total Income Taxes as Reported	$20,342	$205,679	$33,953	$ 24,768	$13,445
Effective Income Tax Rate	49.5%	66.8%	33.8%	25.4%	32.9%

Year Ended December 31, 1999	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Net Income	$ 6,195	$120,492	$182,201	$150,270	$32,776
Extraordinary Loss			8,488		
Income Tax Benefit	-	-	(2,971)	-	-
Income Taxes	(1,163)	76,035	98,239	82,775	11,736
Pre-Tax Income	$ 5,032	$196,527	$285,957	$233,045	$44,512
Income Tax on Pre-Tax Income at Statutory Rate (35%)	$ 1,762	$ 68,785	$100,085	$ 81,566	$15,580
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	446	12,593	7,981	8,846	19,966
Corporate Owned Life Insurance	-	-	-	-	594
Nuclear Fuel Disposal Costs	-	-	-	-	(3,347)
Allowance for Funds Used During Construction	(1,069)	-	-	-	(2,174)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	(3,220)	-	-	-
Investment Tax Credits (net)	(3,448)	(4,972)	(5,207)	(3,994)	(8,152)
State Income Taxes	467	3,305	6,965	58	(4,635)
Other	305	(456)	(11,585)	(3,701)	(6,096)
Total Income Taxes as Reported	$(1,163)	$ 76,035	$ 98,239	$ 82,775	$11,736
Effective Income Tax Rate	N.M.	38.7%	34.4%	35.6%	26.4%

Year Ended December 31, 1999	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Net Income	$25,430	$212,157	$61,508	$83,194	$26,406
Extraordinary Loss				4,632	8,402
Income Tax Benefit	-	-	-	(1,621)	(2,941)
Income Taxes	15,777	132,492	31,292	33,431	14,937
Pre-Tax Income	$41,207	$344,649	$92,800	$119,636	$46,804
Income Tax on Pre-Tax Income at Statutory Rate (35%)	$14,423	$120,628	$ 32,480	$ 41,873	$16,382
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	1,843	17,517	-	-	1,120
Corporate Owned Life Insurance	-	198	-	-	-
Removal Costs	(420)	-	-	-	-
Investment Tax Credits (net)	(1,292)	(3,458)	(1,791)	(4,565)	(1,275)
State Income Taxes	1,809	1,090	3,054	2,924	-
Other	(586)	(3,483)	(2,451)	(6,801)	(1,290)
Total Income Taxes as Reported	$15,777	$132,492	$ 31,292	$ 33,431	$14,937
Effective Income Tax Rate	38.3%	38.5%	33.8%	28.0%	32.0%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for AEP Consolidated and each registrant subsidiary:

	December 31, 2001	December 31, 2000
	(in millions)	
Deferred Tax Assets	$ 1,248	$ 1,248
Deferred Tax Liabilities	(6,071)	(6,123)
Net Deferred Tax Liabilities	$(4,823)	$(4,875)
Property Related Temporary Differences	$(3,963)	$(3,935)
Amounts Due From Customers For Future Federal Income Taxes	(245)	(252)
Deferred State Income Taxes	(160)	(251)
Transition Regulatory Assets	(268)	(163)
Regulatory Assets Designated for Securitization	(332)	(332)
All Other (net)	145	58
Net Deferred Tax Liabilities	$(4,823)	$(4,875)

December 31, 2001	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Deferred Tax Assets	$ 75,856	$ 162,334	$ 130,863	$ 74,767	$ 332,225
Deferred Tax Liabilities	(103,831)	(865,909)	(1,294,658)	(518,489)	(732,756)
Net Deferred Tax Liabilities	$ (27,975)	$(703,575)	$(1,163,795)	$(443,722)	$(400,531)
Property Related Temporary Differences	$ (70,581)	$(530,298)	$ (808,922)	$(323,139)	$(306,151)
Amounts Due From Customers For Future Federal Income Taxes	9,292	(55,206)	(70,174)	(9,839)	(46,756)
Deferred State Income Taxes	(3,822)	(56,747)	-	(8,968)	(38,015)
Translation Regulatory Assets	-	(34,783)	-	(78,298)	-
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	40,816	-	-	-	27,157
Accrued Nuclear Decommissioning Expense	-	-	-	-	43,707
Deferred Fuel and Purchased Power	-	-	-	-	(26,270)
Deferred Cook Plant Restart Costs	-	-	-	-	(28,000)
Nuclear Fuel	-	-	-	-	(16,062)
Regulatory Assets Designated for Securitization	-	-	(332,198)	-	-
All Other (net)	(3,680)	(26,541)	47,499	(23,478)	(10,141)
Net Deferred Tax Liabilities	$ (27,975)	$(703,575)	$(1,163,795)	$(443,722)	$(400,531)

December 31, 2001	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Deferred Tax Assets	$ 30,927	$ 135,938	$ 59,421	$ 56,189	$ 22,888
Deferred Tax Liabilities	(199,231)	(933,827)	(356,298)	(425,970)	(167,937)
Net Deferred Tax Liabilities	$(168,304)	$(797,889)	$(296,877)	$(369,781)	$(145,049)
Property Related Temporary Differences	$(118,147)	$(595,974)	$(320,900)	$(362,884)	$(149,309)
Amounts Due From Customers For Future Federal Income Taxes	(20,215)	(61,130)	10,199	(6,441)	4,757
Deferred State Income Taxes	(25,267)	(18,440)	-	-	-
Translation Regulatory Assets	-	(154,947)	-	-	-
Deferred Fuel and Purchased Power	-	20,323	-	-	-
Provision for Mine Shutdown Costs	-	18,365	-	-	-
All Other (net)	(4,675)	(6,086)	13,824	(456)	(497)
Net Deferred Tax Liabilities	$(168,304)	$(797,889)	$(296,877)	$(369,781)	$(145,049)

December 31, 2000	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Deferred Tax Assets	$ 81,480	$ 178,487	$ 67,184	$ 88,198	$ 342,900
Deferred Tax Liabilities	(114,408)	(860,961)	(1,309,981)	(510,957)	(830,845)
Net Deferred Tax Liabilities	$ (32,928)	$(682,474)	$(1,242,797)	$(422,759)	$(487,945)
Property Related Temporary Differences	$ (78,113)	$(510,950)	$ (773,454)	$(343,045)	$(324,198)
Amounts Due From Customers For Future Federal Income Taxes	10,317	(55,085)	(72,426)	(11,142)	(55,218)
Deferred State Income Taxes	(5,478)	(86,351)	-	-	(69,982)
Translation Regulatory Asset	-	(40,554)	-	(68,817)	-
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	42,766	-	-	-	28,454
Accrued Nuclear Decommissioning Expense	-	-	-	-	34,702
Deferred Fuel and Purchased Power	-	-	-	-	(39,395)
Deferred Cook Plant Restart Costs	-	-	-	-	(42,000)
Nuclear Fuel	-	-	-	-	(28,319)
Regulatory Assets Designated for Securitization	-	-	(332,198)	-	-
All Other (net)	(2,420)	10,466	(64,719)	245	8,011
Net Deferred Tax Liabilities	$ (32,928)	$(682,474)	$(1,242,797)	$(422,759)	$(487,945)

December 31, 2000	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Deferred Tax Assets	$ 32,807	$ 330,878	$ 60,010	$ 47,615	$ 16,604
Deferred Tax Liabilities	(198,742)	(952,819)	(372,070)	(446,819)	(173,642)
Net Deferred Tax Liabilities	$(165,935)	$(621,941)	$(312,060)	$(399,204)	$(157,038)
Property Related Temporary Differences	$(116,109)	$(586,039)	$(313,248)	$(375,427)	$(150,264)
Amounts Due From Customers For Future Federal Income Taxes	(19,680)	(57,759)	11,082	(6,015)	4,723
Deferred State Income Taxes	(29,695)	(14,282)	(36,487)	-	-
Translation Regulatory Asset	-	(53,149)	-	-	-
Deferred Fuel and Purchased Power	-	(116,224)	-	-	-
Provision for Mine Shutdown Costs	-	63,995	-	-	-
Postretirement Benefits	-	93,306	-	-	-
All Other (net)	(451)	48,211	26,593	(17,762)	(11,497)
Net Deferred Tax Liabilities	$(165,935)	$(621,941)	$(312,060)	$(399,204)	$(157,038)

We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

COLI Litigation - On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax returns related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 the Company paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced by $319 million in 2000. The Company has filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit.

The earnings reductions for affected registrant subsidiaries are as follows:

	(in millions)
APCo	$ 82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

The Company has not recognized a deferred tax liability for temporary differences related to investments in certain subsidiaries located outside of the United States because such differences are deemed to be essentially permanent in duration. If the investments were sold, the temporary differences may become taxable resulting in a tax liability of approximately $66 million.

The Company joins in the filing of a consolidated federal income tax return with its affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determing their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

15. Basic and Diluted Earnings Per Share:

The calculation of basic and diluted earnings per share is based on the amounts of income and weighted average shares shown in the table below.

	2001	2000	1999
	(in millions - except per share amounts)		
Income:			
Income before Extraordinary Item and Cumulative Effect	$1,003	$302	$986
Extraordinary Losses (net of tax)	(50)	(35)	(14)
Cumulative Effect of Accounting Change (net of tax)	18	-	-
Net Income	$ 971	$267	$972
Weighted Average Shares:			
Average common Shares outstanding	322	322	321
Assumed conversion of stock options (see Note 11)	1	-	-
Diluted average comon shares outstanding	323	322	321
Basic and Diluted Earnings Per Share:			
Income before Extraordinary item and cumulative effect	$3.11	$ 0.94	$ 3.07
Extraordinary losses (net of tax)	(0.16)	(0.11)	(0.04)
Cumulative effect of accounting change (net of tax)	0.06	-	-
	$3.01	$ 0.83	$ 3.03

The assumed conversion of stock options does not affect income for purposes of calculating diluted earnings per share. Basic and diluted EPS are the same in 2001, 2000 and 1999 since the effect on weighted average shares outstanding is little or nil.

16. Supplementary Information:

	Year Ended December 31,		
	2001	2000	1999
	(in millions)		
AEP Consolidated Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System)	$127	$86	$64
Cash was paid for:			
Interest (net of capitalized amounts)	$972	$842	$979
Income Taxes	$569	$449	$270
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$17	$118	$80
Assumption of Liabilities Related to Acquisitions	$171	-	-
Exchange of Communication Investment for Common Stock	$5	-	-

The amounts of power purchased by the registrant subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP System, for the years ended December 31, 2001, 2000, and 1999 were:

	APCo	CSPCo	I&M	OPCo
	(in thousands)			
Year Ended December 31, 2001	$45,542	$12,626	$20,723	$47,757
Year Ended December 31, 2000	30,998	8,706	15,204	31,134
Year Ended December 31, 1999	21,774	6,006	10,227	25,623

17. Power, Distribution and Communications Projects:

Power Projects

AEP owns interests of 50% or less in domestic unregulated power plants with a capacity of 1,483 MW located in Colorado, Florida and Texas. In addition to the domestic projects, AEP has equity interests in international power plants totaling 1,788 MW. AEP has other projects in various stages of development.

Investments in power projects that are 50% or less owned are accounted for by the equity method and reported in investments in power, distribution and communications projects on the balance sheet. At December 31, 2001, six domestic and four international power projects are accounted for under the equity method. The six domestic projects are combined cycle gas turbines that provide steam to a host commercial customer and are considered Qualifying Facilities (QF) under the Public Utilities Regulatory Policies Act of 1978. The four international power plants are classified as Foreign Utility Companies (FUCO) under the Energy Policies Act of 1992. All of the power projects accounted for under the equity method have unrelated third-party partners.

All of the above power projects have project-level financing, which is non-recourse to AEP. AEP or AEP subsidiaries have guaranteed $30 million of domestic partnership obligations for performance under power purchase agreements and for debt service reserves in lieu of cash deposits. AEP has guaranteed $94 million of additional equity for two projects.

Distribution Projects

We own a 44% equity interest in Vale, a Brazilian electric operating company which was purchased for a total of $149 million. On December 1, 2001 we converted a $66 million note receivable and accrued interest into a 20% equity interest in Caiua (Brazilian electric operating company), a subsidiary of Vale. Vale and Caiua have experienced losses from operations and our investment has been affected by the devaluation of the Brazilian Real. The cumulative equity share of operating and foreign currency translation losses through December 31, 2001 is approximately $46 million and $54 million, respectively, net of tax. The cumulative equity share of operating and foreign currency translation losses through December 31, 2000 is approximately $33 million and $49 million, respectively, net of tax. Both investments are covered by a put option, which, if exercised, requires our partners in Vale to purchase our Vale and Caiua shares at a minimum price equal to the U.S. dollar equivalent of the original purchase price. As a result, management has concluded that the investment carrying amount should not be reduced below the put option value unless it is deemed to be an other than temporary impairment and our partners in Vale are deemed unable to fulfill their responsibilities under the put option. Management has evaluated through an independent third-party, the ability of its Vale partners to fulfill their responsibilities under the put option agreement and has concluded that our partners should be able to fulfill their responsibilities.

Management believes that the decline in the value of its investment in Vale in US dollars is not other than temporary. As a result and pursuant to the put option agreement, these losses have not been applied to reduce the carrying values of the Vale and Caiua investments. As a result we will not recognize any future earnings from Vale and Caiua until the operating losses are recovered. Should the impairment of our investment become other than temporary due to our partners in Vale becoming unable to fulfill their responsibilities, it would have an adverse effect on future results of operations.

Management will continue to monitor both the status of the losses and of its partners ability to fulfill its obligations under the put.

Communication Projects

AEP provides telecommunication services to businesses and telecommunication companies through a broadband fiber optic network. AEP's investment in the network include fiber optic cable, electronic equipment and colocation facilities that house the equipment. The investments are both owned and leased with a majority of the leased investments being indefeasible rights of use (IRUs) for fiber optic cable for periods ranging from 20 to 30 years. Telecommunication revenue is accounted for using the accrual method of accounting as service is rendered over the contractual term. Lease obligations related to these investment are included in the lease payment amounts disclosed in the lease note.

AEP has a 46.25% ownership interest in a joint venture, AFN networks, LLC (AFN), which is engaged in the operation and construction of a fiber optic network. AFN both owns and leases fiber optic cable and electronic equipment with the majority of leases being IRUs of fiber optic cable for periods ranging from 20 to 25 years. AEP accounts for AFN under the equity method of accounting and has recorded its pro rata share of the losses during the start up phase. AEP has a credit agreement with AFN that enables AFN to borrow up to $91.5 million at market interest rates to finance their construction and operations. The amount available to AFN at December 31, 2001 is $61 million.

AEP has a 50% ownership interest in a joint venture, American Fiber Touch, LLC (AFT), that is constructing a fiber optic line from Missouri to Illinois. AEP accounts for AFT under the equity method of accounting and has recorded its pro rata share of the losses of AFT during the start up phase. AEP has recently decided to withdraw from this venture and fully provided for the expected loss in exiting the joint venture in December 2001.

18. Leases:

Leases of property, plant and equipment are for periods up to 35 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Year Ended December 31, 2001	AEP	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M	KPCo
Lease Payments on Operating Leases	$296,000	$76,262	$ 6,142	$5,948	$ 7,063	$104,574	$1,191
Amortization of Capital Leases	85,000	281	12,099	-	7,206	17,933	2,740
Interest on Capital Leases	22,000	55	3,789	-	2,396	4,424	808
Total Lease Rental Costs	$403,000	$76,598	$22,030	$5,948	$16,665	$126,931	$4,739

Year Ended December 31, 2001	OPCo	PSO (in thousands)	SWEPCo	WTU
Lease Payments on Operating Leases	$63,913	$4,010	$2,277	$1,534
Amortization of Capital Leases	14,443	-	-	-
Interest on Capital Leases	5,818	-	-	-
Total Lease Rental Costs	$84,174	$4,010	$2,277	$1,534

Year Ended December 31, 2000	AEP	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M	KPCo
Lease Payments on Operating Leases	$237,000	$73,858	$ 7,128	$ -	$ 7,683	$ 81,446	$1,978
Amortization of Capital Leases	121,000	281	13,900	-	7,776	26,341	3,931
Interest on Capital Leases	38,000	55	3,930	-	2,690	10,908	1,054
Total Lease Rental Costs	$396,000	$74,194	$24,958	$ -	$18,149	$118,695	$6,963

Year Ended December 31, 2000	OPCo	PSO (in thousands)	SWEPCo	WTU
Lease Payments on Operating Leases	$51,981	$ -	$ -	$ -
Amortization of Capital Leases	37,280	-	-	-
Interest on Capital Leases	9,584	-	-	-
Total Lease Rental Costs	$98,845	$ -	$ -	$ -

Year Ended December 31, 1999	AEP	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M	KPCo
Lease Payments on Operating Leases	$247,000	$74,269	$ 5,647	$ -	$ 5,687	$ 81,611	$ 199
Amortization of Capital Leases	97,000	364	13,749	-	7,427	11,320	4,299
Interest on Capital Leases	35,000	64	4,267	-	2,720	9,338	1,162
Total Lease Rental Costs	$379,000	$74,697	$23,663	$ -	$15,834	$102,269	$5,660

Year Ended December 31, 1999	OPCo	PSO (in thousands)	SWEPCo	WTU
Lease Payments on Operating Leases	$ 60,026	$ -	$ -	$ -
Amortization of Capital Leases	35,622	-	-	-
Interest on Capital Leases	9,552	-	-	-
Total Lease Rental Costs	$105,200	$ -	$ -	$ -

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

Year Ended December 31, 2001	AEP	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo	OPCo
Property, Plant and Equipment Under Capital Leases							
Production	$ 40,000	$1,983	$ 2,712	$ 6,380	$ 4,826	$ 1,138	$ 22,477
Distribution	177,000				14,593		
Other:							
Mining Assets and Other	722,000	129	82,292	$54,999	86,267	17,658	114,944
Total Property, Plant and Equipment	939,000	2,112	85,004	61,379	105,686	18,796	137,421
Accumulated Amortization	256,000	1,801	38,745	26,044	43,768	9,213	57,429
Net Property, Plant and Equipment Under Capital Leases	$683,000	$ 311	$46,259	$35,335	$ 61,918	$ 9,583	$ 79,992
Obligations Under Capital Leases:							
Noncurrent Liability	$356,000	$ 76	$33,928	$27,052	$ 51,093	$ 6,742	$ 64,261
Liability Due Within One Year	95,000	235	12,357	7,835	10,840	2,841	16,405
Total Obligations Under Capital Leases	$451,000	$ 311	$46,285	$34,887	$ 61,933	$ 9,583	$ 80,666

Year Ended December 31, 2000	AEP	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)				
Property, Plant and Equipment Under Capital Leases							
Production	$ 42,000	$2,017	$ 6,276	$ 2	$ 7,023	$ 1,730	$ 24,709
Distribution	151,000				14,595		
Other:							
Nuclear Fuel (net of amortization)	90,000				89,872		
Mining Assets and Other	619,000	177	93,437	$68,352	97,383	22,072	200,308
Total Property, Plant and Equipment	902,000	2,194	99,713	68,354	208,873	23,802	225,017
Accumulated Amortization	288,000	1,603	36,553	25,422	45,700	9,618	108,436
Net Property, Plant and Equipment Under Capital Leases	$614,000	$ 591	$63,160	$42,932	$163,173	$14,184	$116,581
Obligations Under Capital Leases:							
Noncurrent Liability	$419,000	$ 358	$50,350	$35,199	$ 62,325	$11,091	$ 83,866
Liability Due Within One Year	195,000	233	12,810	7,733	100,848	3,093	32,715
Total Obligations Under Capital Leases	$614,000	$ 591	$63,160	$42,932	$163,173	$14,184	$116,581

Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

CPL, PSO, SWEPCo and WTU do not lease property, plant and equipment under capital leases.

Future minimum lease payments consisted of the following at December 31, 2001:

	AEP	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)				
Capital							
2002	$ 96,000	$217	$13,718	$ 8,932	$11,759	$ 3,093	$ 18,516
2003	81,000	132	11,625	7,284	10,028	2,441	17,521
2004	63,000	20	9,371	6,111	7,947	1,824	14,701
2005	49,000	6	6,440	5,248	6,282	1,449	11,520
2006	42,000	1	4,690	3,903	5,335	891	10,305
Later Years	397,000	-	7,613	11,400	17,882	1,548	28,948
Total Future Minimum Lease Payments	728,000	376	53,457	42,878	59,233	11,246	101,511
Less Estimated Interest Element	277,000	65	7,172	7,991	(2,700)	1,663	20,845
Estimated Present Value of Future Minimum Lease Payments	$451,000	$311	$46,285	$34,887	$61,933	$ 9,583	$ 80,666

	AEP	AEGCo	APCo	CPL	CSPCo	I&M	KPCo
				(in thousands)			
Noncancellable Operating Leases							
2002	$ 286,000	$ 73,854	$ 3,193	$ 5,948	$ 2,104	$ 82,627	$ 717
2003	271,000	73,854	3,108	5,948	1,991	79,923	691
2004	255,000	73,854	2,402	5,948	1,623	77,104	571
2005	245,000	73,854	2,155	5,948	1,308	75,736	544
2006	243,000	73,854	1,887	5,948	1,279	75,595	398
Later Years	2,671,000	1,181,664	4,563	-	3,198	1,186,678	1,842
Total Future Minimum Lease Payments	$3,971,000	$1,550,934	$17,308	$29,740	$11,503	$1,577,663	$4,763

	OPCo	PSO	SWEPCo	WTU
		(in thousands)		
Noncancellable Operating Leases				
2002	$ 62,945	$4,010	$ 2,277	$1,534
2003	62,914	4,010	2,277	1,534
2004	63,323	4,010	2,277	1,534
2005	62,836	4,010	2,277	1,534
2006	63,242	4,010	2,277	1,534
Later Years	244,069	-	-	-
Total Future Minimum Lease Payments	$559,329	$20,050	$11,385	$7,670

Operating leases include lease agreements with special purpose entities related to Rockport Plant Unit 2 and the Gavin Plant's flue gas desulfurization system (Gavin Scrubbers). The Rockport Plant lease resulted from a sale and leaseback transaction in 1989. The gain from the sale was deferred and is being amortized over the term of the lease which expires in 2022. The Gavin Scrubber lease expires in 2009. AEP has no ownership interest in the special purpose entities and does not guarantee their debt. The special purpose entities are not consolidated in AEP's financial statements in accordance with applicable accounting standards. As a result, neither the leased plant and equipment nor the debt of the special purpose entities is included on AEP's balance sheet. The future lease payment obligations to the special purpose entities are included in the above table of future minimum lease payments under noncancellable operating leases.

19. Lines of Credit and Sale of Receivables:

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a money pool to coordinate short-term borrowings for certain subsidiaries, including AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU and also incurs borrowings outside the money pool for other subsidiaries. As of December 31, 2001, AEP had revolving credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2001, AEP had $3.2 billion outstanding in short-term borrowings of which $2.9 billion was under these credit facilities. The maximum amount of such short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 4.95%, was $3.3 billion during March 2001.

The registrant subsidiaries incurred interest expense for amounts borrowed from the AEP money pool as follows:

	Year Ended December 31,		
	2001	2000	1999
	(in millions)		
AEGCo	0.8	-	-
APCo	9.8	-	-
CPL	11.4	16.9	14.1
CSPCo	5.0	1.4	-
I&M	13.1	0.8	-
KPCo	2.3	-	-
OPCo	14.6	9.2	-
PSO	6.3	7.5	2.0
SWEPCo	3.4	4.2	4.7
WTU	3.1	2.7	0.6

Interest income earned from amounts advanced to the AEP money pool by the registrant subsidiaries were:

	Year Ended December 31,		
	2001	2000	1999
	(in millions)		
APCo	1.7	-	-
CPL	0.1	-	-
CSPCo	0.8	1.1	-
I&M	1.6	9.0	-
KPCo	0.1	1.8	-
OPCo	8.6	3.4	-
SWEPCo	0.1	-	0.1
WTU	-	-	0.2

Outstanding short-term debt for AEP Consolidated consisted of:

	December 31,	
	2001	2000
	(in millions)	
Balance Outstanding:		
Notes Payable	$ 207	$ 193
Commercial paper	2,948	4,140
Total	$3,155	$4,333

AEP Credit, which does not participate in the money pool, issued commercial paper on a stand-alone basis up to May 30, 2001. AEP Credit provides low-cost financing for utilities, including both AEP's electric utility operating companies and non-affiliates, through factoring receivables which arise primarily from the sale and delivery of electricity in the ordinary course of business. In January 2002 AEP Credit stopped purchasing accounts receivable from non-affiliated electric utility companies.

On May 30, 2001, AEP Credit stopped issuing commercial paper and allowed its $2 billion unsecured revolving credit facility to mature. Funding needs were replaced on May 30, 2001 by a $1.5 billion variable funding note. The variable funding note was, in turn, replaced on December 31, 2001 when AEP Credit entered into a sale of receivables agreement with a group of banks and commercial paper conduits.

Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquired from its clients to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140 allowing the receivables to be taken off of AEP Credit's balance sheet. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. At December 31, 2001, the banks had a $1.2 billion commitment under the sale of receivables agreement to purchase receivables from AEP Credit of which $1 billion was outstanding. Of the $1 billion of receivables sold, $485 million respresented non-affiliate receivables. The commitment available under the sale of receivables agreement declines to $1.1 billion on January 31, 2002 and to $900 million on February 28, 2002, where it remains until the expiration of the commitment on May 30, 2002. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

At year ended December 31, 2001, AEP Credit had:

	$ Millions
Accounts Receivable Sold	1,045
Accounts Receivable Retained Interest Less Uncollectible Accounts and Pledged as Collateral	143
Deferred Revenue from Servicing Accounts Receivable	5
Loss on Sale of Accounts Receivable	8
Initial Variable Discount Rate	2.28%
Retained Interest if 10% Adverse change in Uncollectible Accounts	142
Retained Interest if 20% Adverse change in Uncollectible Accounts	140

Historical loss and delinquency amount for the Customer Accounts Receivable managed portfolio for the year ended December 31, 2001.

	Face Value December 31, 2001 $ Millions
Customer Accounts Receivable Retained	$ 626
Miscellaneous Accounts Receivable Retained	1,365
Allowance for Uncollectible Accounts Retained	(109)
Total Net Balance Sheet Accounts Receivable	1,882
Customer Accounts Receivable Securitized (Affiliate)	560
Customer Accounts Receivable Securitized (Non-Affiliate)	485
Total Accounts Receivable managed	$2,927
Net Uncollectible Accounts Written off for the Year Ended December 31, 2001	87

Customer Accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit as a pool between affiliate and non-affiliate accounts receivable. Miscellaneous Account Receivable have been fully retained and not securitized.

Delinquent Customer Accounts Receivable over 60 days old at December 31, 2001:

	(in millions)
Affiliated	$ 92
Non-Affiliated	17
Total	$109

Under the factoring arrangement the registrant subsidiaries (excluding AEGCo) sell without recourse certain of their customer accounts receivable and accrued utility revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable is reported as an operating expense. At December 31, 2001 the amount of factored accounts receivable and accrued utility revenues for each registrant subsidiary was as follows:

Company	(in millions)
APCo	$ 61
CPL	89
CSPCo	106
I&M	95
KPCo	26
OPCo	100
PSO	43
SWEPCo	47
WTU	23

The fees paid by the registrant subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2001	2000	1999
	(in millions)		
APCo	$ 5.2	$ -	$ -
CPL	14.7	15.7	14.7
CSPCo	15.2	10.8	-
I&M	8.5	6.8	-
KPCo	2.7	1.9	-
OPCo	12.8	8.4	-
PSO	9.6	8.3	6.5
SWEPCo	7.4	9.2	9.3
WTU	3.8	4.0	3.5

20. Unaudited Quarterly Financial Information:

The unaudited quarterly financial information for AEP Consolidated follows:

(In Millions - Except Per Share Amounts)	2001 Quarterly Periods Ended March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$14,165	$14,528	$18,385	$14,179
Operating Income	601	672	862	260
Income Before Extraordinary Items and Cumulative Effect	266	280	403	54
Net Income	266	232	421	52
Earnings per Share Before Extraordinary Items And Cumulative Effect*	0.83	0.87	1.25	0.17
Earnings per Share**	0.83	0.72	1.31	0.16

(In Millions - Except Per Share Amounts)	2000 Quarterly Periods Ended March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$6,117	$8,137	$11,608	$10,844
Operating Income	428	308	873	395
Income (Loss) Before Extraordinary Items and Cumulative Effect	140	(18)	403	(223)
Net Income (Loss)	140	(9)	359	(223)
Earnings (Loss) per Share Before Extraordinary Items and Cumulative Effect	0.43	(0.06)	1.25	(0.68)
Earnings (Loss) per Share	0.43	(0.03)	1.11	(0.68)

* Amounts for 2001 do not add to $3.11 earnings per share before extraordinary items and cumulative effect due to rounding.
** Amounts for 2001 do not add to $3.01 earnings per share due to rounding.

The unaudited quarterly financial information for each AEP registrant subsidiary follows:

Quarterly Periods Ended	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M
2001					
March 31					
Operating Revenues	$60,507	$1,974,127	$603,412	$1,125,573	$1,291,538
Operating Income	1,807	88,152	64,152	51,932	52,698
Income (Loss) Before Extraordinary Items	1,980	61,787	35,031	37,671	32,363
Net Income (Loss)	1,980	61,787	35,031	37,671	32,363
June 30					
Operating Revenues	$52,217	$1,849,304	$648,499	$1,109,095	$1,259,874
Operating Income	1,882	59,362	82,351	62,894	47,340
Income (Loss) Before Extraordinary Items	2,063	36,419	52,518	47,418	27,374
Net Income (Loss)	2,063	36,419	52,518	21,011	27,374
September 30					
Operating Revenues	$57,417	$2,017,159	$1,235,941	$1,297,704	$1,402,178
Operating Income	1,615	60,381	112,598	76,920	44,509
Income Before Extraordinary Items	2,051	30,317	83,702	65,318	25,064
Net Income	2,051	30,317	83,702	65,318	25,064
December 31					
Operating Revenues	$57,407	$1,158,840	$833,875	$767,491	$850,035
Operating Income	1,673	67,091	36,630	60,431	15,158
Income (Loss) Before Extraordinary Items	1,781	33,295	13,536	41,493	(9,013)
Net Income (Loss)	1,781	33,295	11,027	37,876	(9,013)

Quarterly Periods Ended	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
2001					
March 31					
Operating Revenues	$459,157	$1,699,665	$356,139	$425,689	$195,006
Operating Income	12,604	64,756	8,340	33,986	5,392
Income Before Extraordinary Items	7,075	53,397	(1,560)	19,869	891
Net Income	7,075	53,397	(1,560)	19,869	891
June 30					
Operating Revenues	$439,131	$1,627,177	$398,194	$434,795	$192,839
Operating Income	8,364	47,067	21,942	32,649	12,428
Income Before Extraordinary Items	2,742	32,094	11,921	17,784	6,133
Net Income	2,742	10,579	11,921	17,784	6,133
September 30					
Operating Revenues	$485,820	$1,819,792	$910,428	$1,028,742	$429,623
Operating Income	12,587	69,668	59,914	60,194	17,745
Income Before Extraordinary Items	5,312	51,378	51,069	46,357	14,067
Net Income	5,312	51,378	51,069	46,357	14,067
December 31					
Operating Revenues	$275,287	$1,115,768	$536,488	$685,222	$246,803
Operating Income	14,123	59,219	6,793	19,378	(2,175)
Income (Loss) Before Extraordinary Items	6,436	28,924	(3,670)	5,357	(8,781)
Net Income (Loss)	6,436	32,091	(3,670)	5,357	(8,781)

Quarterly Periods Ended	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
2000					
March 31					
Operating Revenues	$56,866	$1,021,678	$316,328	$633,305	$708,150
Operating Income	2,395	78,246	38,650	44,124	(15,251)
Income Before Extraordinary Items	2,445	47,664	8,139	27,471	(36,553)
Net Income	2,445	47,664	8,139	27,471	(36,553)
June 30					
Operating Revenues	$56,928	$1,460,774	$437,911	$928,332	$1,011,706
Operating Income	1,746	58,208	95,717	50,798	(18,599)
Income Before Extraordinary Items	1,653	30,240	67,553	35,335	(39,181)
Net Income	1,653	39,178	67,553	35,335	(39,181)
September 30					
Operating Revenues	$55,658	$1,538,340	$795,794	$960,837	$1,060,654
Operating Income	2,209	65,750	120,653	83,562	36,056
Income Before Extraordinary Items	1,972	36,112	89,974	65,542	15,190
Net Income	1,972	36,112	89,974	40,306	15,190
December 31					
Operating Revenues	$59,064	$1,066,516	$799,470	$643,141	$ 761,574
Operating Income	2,074	(1,050)	52,078	17,393	(36,908)
Income (Loss) Before Extraordinary Items	1,914	(49,110)	23,901	(8,146)	(71,488)
Net Income (Loss)	1,914	(49,110)	23,901	(8,146)	(71,488)

Quarterly Periods Ended	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
2000					
March 31					
Operating Revenues	$231,454	$1,047,837	$161,329	$207,756	$ 93,335
Operating Income	15,557	65,113	10,860	22,731	9,781
Income Before Extraordinary Items	8,052	46,216	1,165	7,663	3,833
Net Income	8,052	46,216	1,165	7,663	3,833
June 30					
Operating Revenues	$342,660	$1,436,330	$209,172	$272,409	$130,742
Operating Income	9,456	79,968	24,502	33,296	16,938
Income Before Extraordinary Items	2,449	58,233	14,700	18,786	8,070
Net Income	2,449	58,233	14,700	18,786	8,070
September 30					
Operating Revenues	$359,296	$1,484,663	$555,236	$573,891	$249,330
Operating Income	13,790	96,652	56,437	61,312	16,565
Income Before Extraordinary Items	6,761	77,061	54,329	47,537	10,670
Net Income	6,761	58,185	54,329	47,537	10,670
December 31					
Operating Revenues	$243,457	$1,023,270	$504,282	$628,670	$286,155
Operating Income	10,935	(14,906)	4,870	10,939	9,057
Income (Loss) Before Extraordinary Items	3,501	(78,897)	(3,531)	(1,314)	4,877
Net Income (Loss)	3,501	(78,897)	(3,531)	(1,314)	4,877

Earnings for the fourth quarter 2001 increased $275 million from the prior year primarily due to the effect of charges recorded in 2000 from a ruling by the IRS disallowing interest deductions from AEP's COLI program and a write down for the proposed sale of Yorkshire. Fourth quarter 2001 earnings were also favorably impacted by the return to service in December 2000 of Unit 1 of the Cook Plant after an extended outage and the receipt of a contract cancellation fee from a non-affiliated factoring client of AEP Credit.

21. Trust Preferred Securities:

The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of CPL, PSO and SWEPCo were outstanding at December 31, 2001 and December 31, 2000. They are classified on the balance sheets as Certain Subsidiaries Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries. The Junior Subordinated Debentures mature on April 30, 2037. CPL reacquired 490,000 and 60,000 trust preferred units during 2001 and 2000, respectively.

Business Trust	Security	Units issued/ Outstanding At 12/31/01	Amount at December 31, 2001	2000	Description of Underlying Debentures of Registrant
			(in millions)		
CPL Capital I	8.00%, Series A	5,450,000	$136	$149	CPL, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	75	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	4,400,000	110	110	SWEPCO, $113 million, 7.875%, Series A
		12,850,000	$321	$334	

Each of the business trusts is treated as a subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

22. Minority Interest in Finance Subsidiary:

In August 2001, AEP formed Caddis Partners, LLC (Caddis), a consolidated subsidiary, and sold a non-controlling preferred member interest in Caddis to an unconsolidated special purpose entity (Steelhead) for $750 million. Under the provisions of the Caddis formation agreements, the preferred member interest receives quarterly a preferred return equal to an adjusted floating reference rate (4.413% at December 31, 2001). The $750 million received replaces interim funding used to acquire Houston Pipe Line Company in June 2001.

The preferred interest is supported by natural gas pipeline assets and $321.4 million of preferred stock issued by an AEP subsidiary to the AEP affiliate which has the managing member interest in Caddis. Such preferred stock is convertible into common stock of AEP upon the occurrence of certain events. AEP can elect not to have the transaction supported by such preferred stock if the preferred interest were reduced by $225 million. In addition, Caddis has the right to redeem the preferred member interest at any time.

The initial period of the preferred interest is through August 2006. At the end of the initial period, Caddis will either reset the preferred rate, re-market the preferred member interests to new investors, redeem the preferred member interests, in whole or in part including accrued return, or liquidate in accordance with the provisions of applicable agreements.

Steelhead has the right to terminate the transaction and liquidate Caddis upon the occurrence of certain events including a default in the payment of the preferred return. Steelhead's rights include:

forcing a liquidation of Caddis and acting as the liquidator, and requiring the conversion of the $321.4 million of AEP subsidiary preferred stock into AEP common stock. If the preferred member interest exercised its rights to liquidate under these conditions, then AEP would evaluate whether to refinance at that time or relinquish the assets that support the preferred member interest. Liquidation of the preferred interest or of Caddis could impact AEP's liquidity.

Caddis and the AEP subsidiary which acts as its managing member are each a limited liability company, with a separate existence and identity from its members, and the assets of each are separate and legally distinct from AEP. The results of operations, cash flows and financial position of Caddis and such managing member are consolidated with AEP for financial reporting purposes. The preferred member interest and payments of the preferred return are reported on AEP's income statement and balance sheet as Minority Interest in Finance Subsidiary.

23. Jointly Owned Electric Utility Plant:

CPL, CSPCo, PSO, SWEPCo and WTU have generating units that are jointly owned with unaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each AEP registrant subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of income and the investments are reflected in its balance sheets under utility plant as follows:

		Company's Share December 31,			
		2001		2000	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in thousands)		(in thousands)	
CPL:					
Oklaunion Generating Station (Unit No. 1)	7.8	$ 37,728	$ 318	$ 37,236	$ 395
South Texas Project Generating Station (Units No. 1 and 2)	25.2	2,360,452	41,571	2,373,575	19,292
		$2,398,180	$41,889	$2,410,811	$19,687
CSP:					
W.C. Beckjord Generating Station (Unit No. 6)	12.5	$ 14,292	$ 884	$ 14,108	$ 178
Conesville Generating Station (Unit No. 4)	43.5	81,697	494	80,103	261
J.M. Stuart Generating Station	26.0	193,760	27,758	191,875	10,086
Wm. H. Zimmer Generating Station	25.4	704,951	2,634	706,549	5,265
Transmission	(a)	61,476	91	61,820	451
		$1,056,176	$31,861	$1,054,455	$16,241
PSO:					
Oklaunion Generating Station (Unit No. 1)	15.6	$ 82,646	$ 634	$ 81,185	$ 817
SWEPCo:					
Dolet Hills Generating Station (Unit No. 1)	40.2	$ 234,747	$ 675	$ 231,442	$ 1,984
Flint Creek Generating Station (Unit No. 1)	50.0	83,953	213	82,899	852
Pirkey Generating Station (Unit No. 1)	85.9	439,430	10,577	437,069	435
		$ 758,130	$11,465	$ 751,410	$ 3,271
WTU:					
Oklaunion Generating Station (Unit No. 1)	54.7	$ 279,419	$ 1,651	$ 277,624	$ 3,295

(a) Varying percentages of ownership.

The accumulated depreciation with respect to each AEP registrant subsidiary's share of jointly owned facilities is shown below:

	December 31, 2001	December 31, 2000
	(in thousands)	
CPL	$863,130	$834,722
CSPCo	410,756	389,558
PSO	35,653	33,669
SWEPCo	392,728	367,558
WTU	100,430	98,045

24. Related Party Transactions

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO2 Allowances associated with transactions under the Interconnection Agreement. As part of AEP's restructuring settlement agreement filed with FERC, CSPCo and OPCo would no longer be parties to the Interconnection agreement and certain other modifications to its terms would also be made.

Power marketing and trading transactions (trading activities) are conducted by the AEP Power Pool and shared among the parties under the Interconnection Agreement. Trading activities involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. The regulated physical forward contracts are recorded on a gross basis in the month when the contract settles.

In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CPL, PSO, SWEPCo, WTU and AEP Service Corporation are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the operating companies of the west zone to maintain specified annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP subsidiaries as capacity commitments. The CSW Operating Agreement also delegates to AEP Service Corporation the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. The CSW Operating Agreement has been accepted for filing and allowed to become effective by FERC.

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone.

The following table shows the revenues derived from sales to the Pools and direct sales to affiliates for years ended December 31, 2001, 2000 and 1999:

Related Party Revenues		APCo	CSPCo	I&M (in thousands)	KPCo	OPCo	AEGCo
2001	Sales to East System Pool	$ 91,977	$44,185	$239,277	$34,735	$431,637	$ -
	Sales to West System Pool	24,892	13,971	15,596	6,117	19,797	-
	Direct Sales To East Affiliates	54,777	-	-	-	55,450	227,338
	Direct Sales To West Affiliates	(3,133)	(1,705)	(1,905)	(744)	(2,590)	-
	Other	2,772	11,060	2,071	2,258	7,072	-
	Total Revenues	$171,285	$67,511	$255,039	$42,366	$511,366	$227,338
2000	Sales to East System Pool	$ 81,013	$36,884	$200,474	$36,554	$502,140	$ -
	Sales to West System Pool	7,697	4,095	4,614	1,829	6,356	-
	Direct Sales To East Affiliates	59,106	-	-	-	66,487	227,983
	Direct Sales To West Affiliates	4,092	2,262	2,510	972	3,421	-
	Other	2,770	6,124	2,710	2,466	4,043	-
	Total Revenues	$154,678	$49,365	$210,308	$41,821	$582,447	$227,983
1999	Sales to East System Pool	$ 41,869	$15,136	$50,624	$43,157	$337,699	$ -
	Direct Sales To East Affiliates	57,201	-	-	-	50,968	152,559
	Other	1,162	4,582	345	1,145	825	-
	Total Revenues	$100,232	$19,718	$50,969	$44,302	$389,492	$152,559

Related Party Revenues		CPL	PSO (in thousands)	SWEPCo	WTU
2001	Sales to East System Pool	$ -	$ 4	$ -	$ -
	Sales to West System Pool	19,865	3,317	8,073	322
	Direct Sales To East Affiliates	3,697	2,833	3,238	1,228
	Direct Sales To West Affiliates	12,617	30,668	67,930	9,350
	Other	5,583	(51)	(3)	7,781
	Total Revenues	$41,762	$36,771	$79,238	$18,681
2000	Sales to East System Pool	$ -	$ -	$ -	$ -
	Sales to West System Pool	23,421	7,323	5,546	194
	Direct Sales To East Affiliates	(3,348)	(1,990)	(3,008)	(1,116)
	Direct Sales To West Affiliates	12,516	21,995	62,178	7,645
	Other	5,163	(12,680)	(1,592)	11,931
	Total Revenues	$37,752	$14,648	$63,124	$18,654
1999	Sales to West System Pool	$ 6,124	$ 3,097	$ 4,527	$ 401
	Direct Sales To West Affiliates	7,470	7,968	49,542	2,576
	Other	14,177	2,652	48	11,790
	Total Revenues	$27,771	$13,717	$54,117	$14,767

The following table shows the purchased power expense incurred from purchases from the Pools and affiliates for the years ended December 31, 2001, 2000, and 1999:

Related Party Purchases		APCo	CSPCo	I&M (in thousands)	KPCo	OPCo
2001	Purchases from East System Pool	$346,582	$292,034	$ 79,030	$ 61,816	$62,350
	Purchases from West System Pool	296	165	185	72	235
	Direct Purchases from East Affiliates	-	-	159,022	68,316	-
	Direct Purchases from West Affiliates	-	-	-	-	-
	Total Purchases	$346,878	$292,199	$238,237	$130,204	$62,585
2000	Purchases from East System Pool	$355,305	$287,482	$106,644	$ 58,150	$50,339
	Purchases from West System Pool	455	260	285	108	390
	Direct Purchases from East Affiliates	-	-	158,537	69,446	-
	Direct Purchases from West Affiliates	14	8	9	3	12
	Total Purchases	$355,774	$287,750	$265,475	$127,707	$50,741
1999	Purchases from East System Pool	$130,991	$199,574	$112,350	$19,502	$ 20,864
	Direct Purchases from East Affiliates	-	-	88,022	64,498	-
	Total Purchases	$130,991	$199,574	$200,372	$84,000	$ 20,864

Related Party Purchases		CPL	PSO	SWEPCo	WTU
			(in thousands)		
2001	Purchases from East System Pool	$ -	$ 1,327	$ -	$ 4
	Purchases from West System Pool	415	5,877	3,810	11,689
	Direct Purchases from East Affiliates	12,657	37,445	27,744	4,614
	Direct Purchases from West Affiliates	45,569	34,603	9,696	40,349
	Total Purchases	$58,641	$79,252	$41,250	$56,656
2000	Purchases from East System Pool	$ -	$20,100	$ -	$ -
	Purchases from West System Pool	1,696	5,386	4,379	18,444
	Direct Purchases from East Affiliates	251	2,117	695	71
	Direct Purchases from West Affiliates	30,644	33,185	8,264	39,258
	Total Purchases	$32,591	$60,788	$13,338	$57,773
1999	Purchases from West System Pool	$ 895	$ 6,992	$1,295	$ 7,266
	Direct Purchases from West Affiliates	15,778	27,627	6,256	19,325
	Total Purchases	$16,673	$34,619	$7,551	$26,591

The above summarized related party revenues and expenses are reported in their entirely, without elimination, and are presented as operating revenues affiliated and purchased power affiliated on the income statement of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

AEP System Transmission Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kv and above) and certain facilities operated at lower voltages (138 kv and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 1998, 1999 and 2000:

	1999	2000	2001
		(in thousands)	
APCo	$ (8,300)	$ (3,400)	$ (3,100)
CSPCo	39,000	38,300	40,200
I&M	(43,900)	(43,800)	(41,300)
KPCo	(4,300)	(6,000)	(4,600)
OPCo	17,500	14,900	8,800

CPL, PSO, SWEPCo, WTU and AEP Service Corporation are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA established a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEP Service Corporation the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT.

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone operating subsidiaries. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

Unit Power Agreements and Other

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which

I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement expires on December 31, 2004.

APCo and OPCo, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on each company's consolidated statements of income. Each company's investment in these plants is included in electric utility plant on its consolidated balance sheets.

I&M provides barging services to AEGCo, APCo and OPCo. I&M records revenues from barging services as nonoperating income. AEGCo, APCo and OPCo record costs paid to I&M for barging services as fuel expense. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
Company	2001	2000	1999
	(in millions)		
I&M - revenues	$30.2	$23.5	$28.1
AEGCo - expense	8.5	8.8	8.5
APCo - expense	11.5	7.8	10.5
OPCo - expense	10.2	6.9	9.1

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the 1935 Act.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION, CONTINGENCIES AND OTHER MATTERS

The following is a combined presentation of management's discussion and analysis of financial condition, contingencies and other matters for AEP and certain of its registrant subsidiaries. Management's discussion and analysis of results of operations for AEP and each of its subsidiary registrants is presented with their financial statements earlier in this document. The following is a list of sections of management's discussion and analysis of financial condition, contingencies and other matters and the registrant to which they apply:

Financial Condition	AEP, APCo, CPL, I&M, OPCo, SWEPCo
Market Risks	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
Industry Restructuring	AEP, APCo, CPL, CSPCo, I&M, OPCo, PSO, SWEPCo, WTU
Litigation	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
Environmental Concerns and Issues	AEP, APCo, CPL, CSPCo, I&M, OPCo, SWEPCo
Other Matters	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU

Financial Condition – Affecting AEP, APCo, CPL, I&M, OPCo and SWEPCo

We measure our financial condition by the strength of the balance sheet and the liquidity provided by cash flows and earnings.

Balance sheet capitalization ratios and cash flow ratios are principal determinants of our credit quality.

Year-end ratings of AEP's subsidiaries' first mortgage bonds are listed in the following table:

Company	Moody's	S&P	Fitch
APCo	A3	A	A-
CPL	A3	A-	A
CSPCo	A3	A-	A
I&M	Baa1	A-	BBB+
KPCo	Baa1	A-	BBB+
OPCo	A3	A-	A-
PSO	A1	A	A+
SWEPCO	A1	A	A+
WTU	A2	A-	A

The ratings at the end of the year for senior unsecured debt are listed in the following table:

Company	Moody's	S&P	Fitch
AEP	Baa1	BBB+	BBB+
AEP Resources*	Baa1	BBB+	BBB+
APCo	Baa1	BBB+	BBB+
CPL	Baa1	BBB+	A-
CSPCo	A3	BBB+	A-
I&M	Baa2	BBB+	BBB
KPCo	Baa2	BBB+	BBB
OPCo	A3	BBB+	BBB+
PSO	A2	BBB+	A
SWEPCO	A2	BBB+	A

* The rating is for a series of senior notes issued with a Support Agreement from AEP.

The ratings are presently stable. AEP's commercial paper program has short-term ratings of A2 and P2 by Moody's and Standard and Poor's, respectively.

AEP's common equity to total capitalization declined to 33% in 2001 from 34% in 2000. Total capitalization includes long-term debt due within one year, minority interests and short-term debt. Preferred stock at 1% remained unchanged. Long-term debt increased from 47% to 50% while short-term debt decreased from 18% to 13% and minority interest in finance subsidiary increased to 3%. In 2001 and 2000, AEP did not issue any shares of common stock to meet the requirements of the Dividend Reinvestment and Direct Stock Purchase Plan and the Employee Savings Plan.

We plan to strengthen the balance sheet in 2002 by issuing AEP common stock and mandatory convertible preferred stock and using the proceeds from asset sales to reduce debt. The issuance of common stock has the potential to dilute future earnings per share but will enhance the equity to capitalization ratio.

Rating agencies have become more focused in their evaluation of credit quality as a result of the Enron bankruptcy. They are focusing especially on the composition of the balance sheet (off-balance sheet leases, debt and special purpose financing structures), the cash liquidity profile and the impact of credit quality downgrades on financing transactions. We have worked closely with the agencies to provide them with all the information they need, but we are unable to predict what actions, if any, they may take regarding our current ratings.

During 2001 AEP's cash flow from operations was $2.9 billion, including $971 million from net income and $1.5 billion from depreciation, amortization and deferred taxes. Capital expenditures including acquisitions were $4 billion and dividends on common stock were $773 million. Cash from operations less dividends on common stock financed 52% of capital expenditures.

During 2001, the proceeds of AEP's $1.25 billion global notes issuance and proceeds from the sale of a UK distribution company and two generating plants provided cash to purchase assets, fund construction, retire debt and pay dividends. Major construction expenditures include amounts for a wind generating facility and emission control technology on several coal-fired generating units (see discussion in Note 8). Asset purchases include HPL, coal mines, a barge line, a wind generating facility and two coal-fired generating plants in the UK. These acquisitions accounted for the increase in total debt in 2001. During the third quarter of 2001, permanent financing was completed for the acquisition of HPL by the issuance of a minority interest which provided $735 million net of expenses (See Note 22 for discussion of the terms). HPL's permanent financing increased funds available for other corporate purposes. Long-term financings for the other acquisitions will be announced as arranged. Long-term funding arrangements for specific assets are often complex and typically not completed until after the acquisition.

Earnings for 2001 resulted in a dividend payout ratio of 80%, a considerable improvement over the 289% payout ratio in 2000. The abnormally high ratio in 2000 was the result of the adverse impact on 2000 earnings from the Cook Plant extended outage and related restart expenditures, merger costs and the write-off related to COLI and non-regulated subsidiaries. We expect continued improvement of the payout ratio as a result of earnings growth in 2002.

Cash from operations and short-term borrowings provide working capital and meet other short-term cash needs. We generally use short-term borrowings to fund property acquisitions and construction until long-term funding mechanisms are arranged. Some acquisitions of existing business entities include the assumption of their outstanding debt and certain liabilities. Sources of long-term funding include issuance of AEP common stock, minority interest or long-term debt and sale-leaseback or leasing arrangements. The domestic electric subsidiaries generally issue short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt and additional capital contributions from their parent company. We operate a money pool and sell accounts receivables to provide liquidity for the domestic electric subsidiaries. Short-term borrowings in the U.S. are supported by two revolving credit agreements. At December 31, 2001, approximately $554 million remained available for short-term borrowings in the US.

Subsidiaries that trade energy commodities in Europe have a separate multicurrency revolving loan and letters of credit agreement allowing them to borrow up to 150 million Euros of which 42 million Euros were available on December 31, 2001. In February 2002 they also originated a temporary second line of 50 million Euros for three months which is expected to be replaced with a 150 million Euro line, providing for a total of 300 million Euros. SEEBOARD, Nanyang and Citipower which operate in the UK, China and Australia, respectively, each have independent financing arrangements which provide for borrowing in the local currency. SEEBOARD has a 320 million pound revolving credit agreement it uses for short-term funding purposes. At December 31, 2001, SEEBOARD had 117 million pounds available.

Our revolving credit agreements include covenants that require us to maintain specified financial ratios and describe non-performance of certain actions as events of default. At December 31, 2001 we complied with the covenants of these agreements. In general, a default in excess of $50 million under one agreement is considered a default under the other agreements. In the case of a default on payments under these agreements, all amounts outstanding would be immediately payable.

The contractual obligations of AEP include amounts reported on the balance sheet and other obligations disclosed in our footnotes. The following table summarizes AEP's contractual cash obligations at December 31, 2001:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Long-term Debt	$2,300	$2,988	$2,559	$ 4,246	$12,093
Short-term Debt	3,155	-	-	-	3,155
Trust Preferred Securities	-	-	-	321	321
Minority Interest In Finance Subsidiary (a)	-	-	750	-	750
Preferred Stock Subject to Mandatory Redemption	-	24	4	67	95
Capital Lease Obligations	96	144	91	397	728
Unconditional Purchase Obligations (b)	317	1,658	1,299	3,559	6,833
Noncancellable Operating Leases	286	526	488	2,671	3,971
Other Long-term Obligations (c)	31	30	-	-	61
Total Contractual Cash Obligations	$6,185	$5,370	$5,191	$11,261	$28,007

(a) The initial period of the preferred interest is through August 2006. At the end of the initial period, the preferred rate may be reset, the preferred member interests may be re-marketed to new investors, the preferred member interests may be redeemed, in whole or in part including accrued return, or the preferred member interest may be liquidated.
(b) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(c) Represents contractual obligations to loan funds to a joint venture accounted for under the equity method.

For the subsidiary registrants, please see each registrant's schedules of capitalization and long-term debt included with each registrants' financial statements in sections B through J for the timing of debt payment obligations and the lease footnote (Note 18) in section L for the timing of rent payments.

Special purpose entities have been employed for some of the contractual cash obligations reported in the above table. The lease of Rockport Plant Unit 2 and the Gavin Plant's flue gas desulfurization system (Gavin Scrubbers), the permanent financing of HPL and the sale of accounts receivable use special purpose entities. Neither AEP nor any AEP related parties has an ownership interest in the special purpose entities. AEP does not guarantee the debt of these entities. These special purpose entities are not consolidated in AEP's financial statements in accordance with generally accepted accounting principles. As a result, neither the assets nor the debt of the special purpose entities is included on AEP's balance sheet. The future cash obligations payable to the special purpose entities are included in the above table

In addition to the amounts disclosed in the contractual cash obligations table above, AEP and certain subsidiaries make commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds, and other commitments. AEP's commitments outstanding at December 31, 2001 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in millions)				
Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit	$ 101	$ 53	-	$36	$ 190
Guarantees	815	161	-	15	991
Construction of Generating and Transmission Facilities for Third Parties (a)	168	540	-	-	708
Other Commercial Commitments (b)	6	45	40	24	115
Total Commercial Commitments	$1,090	$799	$40	$75	$2,004

(a) As construction agent for third party owners of power plants and transmission facilities, the Company has committed by contract terms to complete construction by dates specified in the contracts. Should the Company default on these obligations, financial payments could be up to 100% of contract value (amount shown in table) or other remedies required by contract terms.
(b) Represents estimated future payments for power to be generated at facilities under construction.

With the exceptions of SWEPCo's guarantanee of an unaffiliated mine operator's obligations (payable upon their default) of $111 million at December 31, 2001, and OPCo's obligations under a power purchase agreement of $6 million in 2002 and $16 million each year in 2003 through 2005, the obligations in the above table are commitments of AEP and its non-registrant subsidiaries.

AEP, through certain subsidiaries, has entered into agreements with an unrelated, unconsolidated special purpose entity (SPE) to develop, construct, finance and lease a power generation facility. The SPE will own the power generation facility and lease it to an AEP consolidated subsidiary after construction is completed. The lease will be accounted for as an operating lease with the payment obligations included in the lease footnote. Payments under the operating lease are expected to commence in the first quarter of 2004. AEP will in turn sublease the facility to an unrelated industrial company which will both use the energy produced by the facility and sell excess energy. Another affiliate of AEP has agreed to purchase the excess energy from the subleasee for resale.

The SPE has an aggregate financing commitment from equity and debt participants (Investors) of $427 million. AEP, in its role as construction agent for the SPE, is responsible for completing construction by December 31, 2003. In the event the project is terminated before completion of construction, AEP has the option to either purchase the project for 100% of project costs or terminate the project and make a payment to the Lessor for 89.9% of project costs.

The term of the operating lease between the SPE and the AEP subsidiary is five years with multiple extension options. If all extension options are exercised the total term of the lease would be 30 years. AEP's lease payments to the SPE are sufficient to provide a return to the Investors. At the end of the first five-year lease term or any extension, AEP may renew the lease at fair market value subject to Investor approval; purchase the facility at its original construction cost; or sell the facility, on behalf of the SPE, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the Investors, AEP may be required to make a payment to the Lessor of up to 85% of the project's cost. AEP has guaranteed a portion of the obligations of its subsidiaries to the SPE during the construction and post-construction periods.

As of December 31, 2001, project costs subject to these agreements totaled $168 million, and total costs for the completed facility are expected to be approximately $450 million. Since the lease is accounted for as an operating lease for financial accounting purposes, neither the facility nor the related obligations are reported on AEP's balance sheets. The lease is a variable rate obligation indexed to three-month LIBOR. Consequently as market interest rates increase, the payments under this operating lease will also increase. Annual payments of approximately $12 million represent future minimum payments under the first five-year lease term calculated using the indexed LIBOR rate of 2.85% at December 31, 2001.

The lease payments and the guarantee of construction commitments are included in the Other Commercial Commitments table above.

OPCo has entered into a purchased power agreement to purchase electricity produced by an unaffiliated entity's three-unit natural gas fired plant that is under construction. The first unit is anticipated to be completed in October 2002 and the agreement will terminate 30 years after the third unit begins operation. Under the terms of the agreement OPCo has the option to run the plant until December 31, 2005 taking 100% of the power generated. For the remainder of the 30 year contract term, OPCo will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity. The estimated fixed payments through December 2005 are $55 million and are included in the Other Commercial Commitments table shown above.

Minority Interest in Finance Subsidiary

In August 2001, AEP formed Caddis Partners, LLC (Caddis), a consolidated subsidiary, and sold a non-controlling preferred member interest in Caddis to an unconsolidated special purpose entity (Steelhead) for $750 million. Under the provisions of the Caddis formation agreements, the preferred member interest receives quarterly a preferred return equal to an adjusted floating reference rate (4.413% at December 31, 2001). The $750 million received replaced interim funding used to acquire Houston Pipe Line Company in June 2001.

The preferred interest is supported by natural gas pipeline assets and $321.4 million of preferred stock issued by an AEP subsidiary to the AEP affiliate which has the managing member interest in Caddis. Such preferred stock is convertible into common stock of AEP upon the occurrence of certain events. AEP can elect not to have the transaction supported by such preferred stock if the preferred interest were reduced by $225 million. In addition, Caddis has the right to redeem the preferred member interest at any time.

The initial period of the preferred interest is through August 2006. At the end of the initial period, Caddis will either reset the preferred rate, re-market the preferred member interests to new investors, redeem the preferred member interests, in whole or in part including accrued return, or liquidate in accordance with the provisions of applicable agreements.

The credit agreement between Caddis and the AEP subsidiary that acts as its managing member contains covenants that restrict incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. Financial covenants impose minimum financial ratios. At December 31, 2001, we satisfied all of the financial ratio requirements. In general, a default in excess of $50 million under another agreement is considered a default under this agreement.

Steelhead has the right to terminate the transaction and liquidate Caddis upon the occurrence of certain events including a default in the payment of the preferred return. Steelhead's rights include: forcing a liquidation of Caddis and acting as the liquidator, and requiring the conversion of the $321.4 million of AEP subsidiary preferred stock into AEP common stock. If the preferred member interest exercised its rights to liquidate under these conditions, then AEP would evaluate whether to refinance at that time or relinquish the assets that support the preferred member interest. Liquidation of the preferred interest or of Caddis could impact AEP's liquidity.

Caddis and the AEP subsidiary which acts as its managing member are each a limited liability company, with a separate existence and identity from its members, and the assets of each are separate and legally distinct from AEP. The results of operations, cash flows and financial position of Caddis and such managing member are consolidated with AEP for financial reporting purposes. The preferred member interest and payments of the preferred return are reported on AEP's income statement and balance sheet as Minority Interest in Finance Subsidiary.

Expenditures for domestic electric utility construction are estimated to be $4.6 billion for the next three years. Approximately 100% of those construction expenditures are expected to be financed by internally generated funds.

Construction expenditures for the registrant subsidiaries for the next three years excluding AFUDC are:

	Projected Construction Expenditures (in millions)	Construction Expenditures Financed with Internal Funds
APCo	$ 815.5	92%
CPL	573.1	80%
I&M	556.9	ALL
OPCo	1,008.0	68%
SWEPCo	321.4	92%

In 1998 SEEBOARD's 80% owned subsidiary, SEEBOARD Powerlink, signed a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London

Underground transportation system. SEEBOARD Powerlink will be responsible for distributing high voltage electricity to supply 270 London Underground stations and 250 miles of the rail system's track. SEEBOARD's partners in Powerlink are an international electrical engineering group and an international cable and construction group.

Financing Activity

AEP issued $1.25 billion of global notes in May 2001 (with intermediate maturities). The proceeds were loaned to regulated and non-regulated subsidiaries.

In 2001 CSPCo and OPCo, AEP's Ohio subsidiaries, reacquired $295.5 million and $175.6 million, respectively, of first mortgage bonds in preparation for corporate separation.

AEP Credit purchases, without recourse, the accounts receivable of most of the domestic utility operating companies and certain non-affiliated electric utility companies. AEP Credit's financing for the purchase of receivables changed during 2001. Starting December 31, 2001, AEP Credit entered into a sale of receivables agreement. The agreement allows AEP Credit to sell certain receivables and receive cash meeting the requirements of SFAS 140 for the receivables to be removed from the balance sheet. The agreement expires in May 2002 and is expected to be renewed. At December 31, 2001, AEP Credit had $1.0 billion sold under this agreement of which $485 million are non-affiliated receivables. In January 2002, AEP Credit stopped purchasing accounts receivables from non-affiliated electric utility companies.

In February 2002 CPL issued $797 million of securitization notes that were approved by the PUCT as part of Texas restructuring to help decrease rates and recover regulatory assets. The proceeds were used to reduce CPL's debt and equity.

In 2002 AEP plans to continue restructuring its debt for corporate separation assuming receipt of all necessary regulatory approvals. Corporate separation will require the transfer of assets between legal entities. With corporate separation, a newly created holding company for the unregulated business is expected to issue all debt needed to fund the wholesale business and unregulated generating companies. The size and maturity lengths of the original offering is presently being determined.

The regulated holding company is expected to issue the debt needed by the wires companies in Ohio and Texas. The regulated integrated utility companies will continue their current debt structure until the regulatory commissions approve changes. At that time, the regulated holding company may also issue the debt for the regulated companies' funding needs.

We have requested credit ratings for the holding companies consistent with our existing credit quality, but we cannot predict what the outcome will be.

AEP uses a money pool to meet the short-term borrowings for certain of its subsidiaries, primarily the domestic electric utility operations. Following corporate separation, management will evaluate the advantages of establishing a money pool for the unregulated business subsidiaries. The current money pool which was approved by the appropriate regulatory authorities will continue to service the regulated business subsidiaries. Presently, AEP also funds the short-term debt requirements of other subsidiaries that are not included in the money pool. As of December 31, 2001, AEP had credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2001, AEP had $2.9 billion outstanding in short-term borrowing subject to these credit facilities.

Market Risks – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU

As a major power producer and trader of wholesale electricity and natural gas, we have certain market risks inherent in our business activities. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Policies and procedures are established to identify, assess, and manage market risk exposures in our day to day operations. Our risk policies have been reviewed with the Board of Directors, approved by a Risk Management Committee and administered by a Chief Risk Officer. The Risk Management Committee establishes risk limits, approves risk policies, assigns responsibilities regarding the oversight and management of risk and monitors risk levels. This committee receives daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. The committee meets monthly and consists of the Chief Risk Officer, Chief Credit Officer, V.P. Market Risk Oversight, and senior financial and operating managers.

We use a risk measurement model which calculates Value at Risk (VaR) to measure our commodity price risk. The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assuming a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2001 a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition. The following table shows the high, average, and low market risk as measured by VaR at:

	December 31,					
	2001			2000		
	High	Average	Low	High	Average	Low
	(in millions)					
AEP	$28	$14	$5	$32	$10	$1
APCo	4	1	-	6	2	-
CPL	3	1	-	4	1	-
CSPCo	2	1	-	3	1	-
I&M	3	1	-	4	1	-
KPCo	1	-	-	1	-	-
OPCo	3	1	-	5	2	-
PSO	2	1	-	3	1	-
SWEPCo	3	1	-	4	1	-
WTU	1	1	-	1	-	-

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one year holding period. The volatilities and correlations were based on three years of weekly prices. The risk of potential loss in fair value attributable to AEP's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $673 million at December 31, 2001 and $998 million at December 31, 2000. However, since we would not expect to liquidate our entire debt portfolio in a one year holding period, a near term change in interest rates should not materially affect results of operations or consolidated financial position.

The following table shows the potential loss in fair value as measured by VaR allocated to the AEP registrant subsidiaries based upon debt outstanding:

VaR for Registrant Subsidiaries:

	December 31,	
	2001	2000
	(in millions)	
Company		
AEGCo	$ 5	$ 4
APCo	100	149
CPL	80	135
CSPCo	60	84
I&M	86	129
KPCo	16	31
OPCo	59	112
PSO	17	44
SWEPCo	36	60
WTU	20	24

AEGCo is not exposed to risk from changes in interest rates on short-term and long-term borrowings used to finance operations since financing costs are recovered through the unit power agreements.

AEP is exposed to risk from changes in the market prices of coal and natural gas used to generate electricity where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The protection afforded by fuel clause recovery mechanisms has either been eliminated by the implementation of customer choice in Ohio (effective January 1, 2001 for CSPCo and OPCo) and in the ERCOT area of Texas (effective January 1, 2002 for CPL and WTU) or frozen by settlement agreements in Indiana, Michigan and West Virginia. To the extent the fuel supply of the generating units in these states is not under fixed price long-term contracts AEP is subject to market price risk. AEP continues to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas.

We employ physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. However, we engage in trading of electricity, gas and to a lesser degree coal, oil, natural gas liquids, and emission allowances and as a result the Company is subject to price risk. The amount of risk taken by the traders is controlled by the management of the trading operations and the Company's Chief Risk Officer and his staff. When the risk from trading activities exceeds certain pre-determined limits, the positions are modified or hedged to reduce the risk to the limits unless specifically approved by the Risk Management Committee.

We employ fair value hedges, cash flow hedges and swaps to mitigate changes in interest rates or fair values on short and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

We employ cash flow forward hedge contracts to lock-in prices on transactions denominated in foreign currencies where deemed necessary. International subsidiaries use currency swaps to hedge exchange rate fluctuations in debt denominated in foreign currencies. We do not hedge all foreign currency exposure.

AEP limits credit risk by extending unsecured credit to entities based on internal ratings. In addition, AEP uses Moody's Investor Service, Standard and Poor's and qualitative and quantitative data to independently assess the financial health of counterparties on an ongoing basis. This data, in conjunction with the ratings information, is used to determine appropriate risk parameters. AEP also requires cash deposits, letters of credit and parental/affiliate guarantees as security from certain below investment grade counterparties in our normal course of business.

We trade electricity and gas contracts with numerous counterparties. Since our open energy trading contracts are valued based on changes in market prices of the related commodities, our exposures change daily. We believe that our credit and market exposures with any one counterparty is not material to financial condition at December 31, 2001. At December 31, 2001 less than 5% of the counterparties were below investment grade as expressed in terms of Net Mark to Market Assets. Net Mark to Market Assets represents the aggregate difference (either positive or negative) between the forward market price for the remaining term of the contract and the contractual price. The following table approximates counterparty credit quality and exposure for AEP.

Counterparty Credit Quality: December 31, 2001	Futures, Forward and Swap Contracts	Options	Total
	(in millions)		
AAA/Exchanges	$ 147	$ -	$ 147
AA	140	4	144
A	304	7	311
BBB	932	34	966
Below Investment Grade	56	23	79
Total	$1,579	$68	$1,647

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

We enter into transactions for electricity and natural gas as part of wholesale trading operations. Electric and gas transactions are executed over the counter with counterparties or through brokers. Gas transactions are also executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers and counterparties require cash or cash related instruments to be deposited on these transactions as margin against open positions. The combined margin deposits at December 31, 2001 and 2000 was $55 million and $95 million. These margin accounts are restricted and therefore are not included in cash and cash equivalents on the Balance Sheet. We can be subject to further margin requirements should related commodity prices change.

We recognize the net change in the fair value of all open trading contracts, a practice commonly called mark-to-market accounting, in accordance with generally accepted accounting principles and include the net change in mark-to-market amounts on a net discounted basis in revenues. Unrealized mark-to-market revenues totaled $257 million in 2001. The fair values of open short-term trading contracts are based on exchange prices and broker quotes. The fair value of open long-term trading contracts are based mainly on Company developed valuation models. The valuation models produce an estimated fair value for open long-term trading contracts. This fair value is present valued and reduced by appropriate reserves for counterparty credit risks and liquidity risk. The models are derived from internally assessed market prices with the exception of the NYMEX gas curve, where we use daily settled prices. Forward price curves are developed for inclusion in the model based on broker quotes and other available market data. The curves are within the range between the bid and ask prices. The end of the month liquidity reserve is based on the difference in price between the price curve and the bid price of the bid ask prices if we have a long position and the ask side if we have a short position. This provides for a conservative valuation net of the reserves.

The use of these models to fair value open trading contracts has inherent risks relating to the underlying assumptions employed by such models. Independent controls are in place to evaluate the reasonableness of the price curve models. Significant adverse or favorable effects on future results of operations and cash flows could occur if market risks, at the time of settlement, do not correlate with the Company developed price models.

The effect on the Consolidated Statements of Income of marking to market open electricity trading contracts in the Company's regulated jurisdictions is deferred as regulatory assets or liabilities since these transactions are included in cost of service on a settlement basis for ratemaking purposes. Unrealized mark-to-market gains and losses from trading are reported as assets or liabilities.

The following table shows net revenues (revenues less fuel and purchased energy expense) and their relationship to the mark-to-market revenues (the change in fair value of open trading contracts).

	December 31,		
	2001	2000	1999
	(in millions)		
Revenues (including mark- to-market adjustment)	$61,257	$36,706	$24,745
Fuel and Purchased Energy Expense	52,753	28,718	17,244
Net Revenues	$ 8,504	$ 7,988	$ 7,501
Mark-to-Market Revenues	$257	$170	$23
Percentage of Net Revenues Represented by Mark-to-Market	3%	2%	-%

The following tables analyze the changes in fair values of trading assets and liabilities. The first table "Net Fair Value of Energy Trading Contracts" shows how the net fair value of energy trading contracts was derived from the amounts included in the balance sheet line item "energy trading and derivative contracts." The next table "Energy Trading Contracts" disaggregates realized and unrealized changes in fair value; identifies changes in fair value as a result of changes in valuation methodologies; and reconciles the net fair value of energy trading contracts at the beginning of the year of $63 million to the end of the year of $448 million. Contracts realized/settled during the period include both sales and purchase contracts. The third table "Energy Trading Contract Maturities" shows exposures to changes in fair values and realization periods over time for each method used to determine fair value.

Net Fair Value of Energy Trading Contracts

	December 31, 2001	December 31, 2000
	(in millions)	
Energy Trading Contracts:		
Current Asset	$ 8,536	$ 15,495
Long-term Asset	2,367	1,552
Current Liability	(8,279)	(15,671)
Long-term Liability	(2,176)	(1,313)
Net Fair Value of Energy Trading Contracts	$ 448	$ 63

The net fair value of energy trading contracts includes $257 million at December 31, 2001 and $170 million at December 31, 2000 of unrealized mark-to-market gains that are recognized in the income statement. Also included in the above net fair value of energy trading contracts are option premiums that are deferred until the related contracts settle and the portion of changes in fair values of electricity trading contracts that are deferred for ratemaking purposes.

Energy Trading Contracts AEP Consolidated
(in millions)

	Total	
Net Fair Value of Energy Trading Contracts at December 31, 2000	$ 63	
Gain from Contracts realized/settled during period	(352)	(a)
Fair Value of new open contracts when entered into during period	73	(b)
Adjustments for Contracts entered into and settled during period	310	(a)
Net option premium payments	24	
Change in fair value due to Valuation Methodology changes	(1)	(c)
Changes in market value of contracts	331	(d)
Net Fair Value of Energy Trading Contracts at December 31, 2001	$ 448	(e)

(a) Gains from Contracts Realized or Otherwise Settled During the Period" include realized gains from energy trading contracts that settled during 2001 that were entered into prior to 2001, as well as during 2001. "Adjustment for Contracts Entered into and Settled During the Period" discloses the realized gains from settled energy trading contracts that were both entered into and closed within 2001 that are included in the total gains of $352 million, but not included in the ending balance of open contracts.
(b) The "Fair Value of New Open Contracts When Entered Into during period" represents the fair value of long-term contracts entered into with customers during 2001. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves representative of the delivery location.
(c) The Company changed its methodology for calculating and reporting load based transactions. The previous methodology estimated a baseload volume based on historical takes and sold a call option for potential load increases from the baseload. The current methodology uses a modified version of a straddle load follow model to estimate the baseload volume and call option volume. This methodogy change more accurately estimates the load volume forecast. The dollar impact on existing deals was a decrease of in fair value of $1.2 million.
(d) "Change in market Value of Contracts" represents the fair value change in the trading portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(e) The net change in the fair value of energy trading contracts for 2001 that resulted in an increase of $385 million ($448 million less $63 million) represents the balance sheet change. The net mark-to-market gain on energy trading contracts of $257 million represents the impact on earnings. The difference is related primarily to regulatory deferrals of certain mark-to-market gains that were recorded as regulatory liabilities and not reflected in the income statement for those companies that operate in regulated jurisdictions, and deferrals of option premiums included in the above analysis, which do not have a mark-to-market income statement impact.

Energy Trading Contracts
(in thousand)

	APCo	CPL	CSPCo
Net Fair Value of Energy Trading Contracts at December 31, 2000	$ 7,447	$(8,191)	$ 3,769
Loss/(Gain) from Contracts Realized/settled during period	(12,478)	4,221	(11,522)
Fair Value of new open Contracts when entered into during period	13,441	9,635	8,245
Adjustments for Contracts Entered into and settled during period	40,755	2,602	24,998
Net option premium payments	1,072	-	658
Change in fair value due to Valuation Methodology changes	(220)	(158)	(135)
Changes in market value of Contracts	25,684	(4,252)	22,436
Net Fair Value of Energy Trading Contracts at December 31, 2001	$ 75,701	$ 3,857	$ 48,449

Energy Trading Contracts
(in thousands)

	I&M	KPCo	OPCo
Net Fair Value of Energy Trading Contracts at December 31, 2000	$ (6,845)	$ 1,678	$ 5,613
Loss/(Gain) from Contracts Realized/settled during period	(10,982)	(3,298)	(10,861)
Fair Value of new open Contracts when entered into During period	8,921	3,315	11,213
Adjustments for Contracts Entered into and settled During period	27,049	10,051	34,001
Net option premium payments	712	264	894
Change in fair value due to Valuation Methodology changes	(146)	(54)	(183)
Changes in market value of Contracts	42,636	773	24,769
Net Fair Value of Energy Trading Contracts at December 31, 2001	$ 61,345	$12,729	$ 65,446

Energy Trading Contracts
(in thousands)

	PSO	SWEPCo	WTU
Net Fair Value of Energy Trading Contracts at December 31, 2000	$(6,508)	$(7,795)	$(2,590)
Loss/(Gain) from Contracts Realized/settled during period	2,483	2,938	5,881
Fair Value of new open Contracts when entered into During period	7,338	8,422	2,861
Adjustments for Contracts Entered into and settled during period	1,981	2,274	773
Net option premium payments	-	-	-
Change in fair value due to Valuation Methodology changes	(120)	(138)	(46)
Changes in market value of Contracts	(2,740)	(2,801)	(5,964)
Net Fair Value of Energy Trading Contracts at December 31, 2001	$ 2,434	$ 2,900	$ 915

Energy Trading Contract Maturities

AEP Consolidated Source of Fair Value	Fair Value of Contracts at December 31,2001 Maturities (in millions) Less than 1 year	1-3 years	4-5 years	In Excess of 5 years	Total Fair Value
Prices actively quoted (a)	$ 46	$ 8	$ -	$ -	$ 54
Prices provided by other external Sources (b)	152	33	-	-	185
Prices based on models and other valuation methods (c)	13	133	35	28	209
Total	$211	$174	$35	$28	$448

Energy Trading Contract Maturities

Source of Fair Value	Fair Value of Contracts at December 31,2001 Maturities (in thousands) Less than 1 year	1-3 years	4-5 years	In Excess of 5 years	Total Fair Value
APCo					
Other External Sources	13,366	9,588	-	-	22,954
Models/Other Valuation	3,215	34,318	8,413	6,801	52,747
Total	16,581	43,906	8,413	6,801	75,701
CPL					
Other External Sources	(5,245)	1,681	-	-	(3,564)
Models/Other Valuation	(1,262)	6,016	1,475	1,192	7,421
Total	(6,507)	7,697	1,475	1,192	3,857
CSP					
Other External Sources	9,867	5,872	-	-	15,739
Models/Other Valuation	2,373	21,018	5,153	4,166	32,710
Total	12,240	26,890	5,153	4,166	48,449
KEPCo					
Other External Sources	(1,475)	2,361	-	-	886
Models/Other Valuation	(355)	8,451	2,072	1,675	11,843
Total	(1,830)	10,812	2,072	1,675	12,729
I&M					
Other External Sources	17,237	6,481	-	-	23,718
Models/Other Valuation	4,146	23,197	5,687	4,597	37,627
Total	21,383	29,678	5,687	4,597	61,345
OPCo					
Other External Sources	13,058	7,987	-	-	21,045
Models/Other Valuation	3,141	28,587	7,008	5,665	44,401
Total	16,199	36,574	7,008	5,665	65,446
PSO					
Other External Sources	(4,400)	1,280	-	-	(3,120)
Models/Other Valuation	(1,058)	4,581	1,123	908	5,554
Total	(5,458)	5,861	1,123	908	2,434
SWEPCo					
Other External Sources	(4,965)	1,469	-	-	(3,496)
Models/Other Valuation	(1,194)	5,259	1,289	1,042	6,396
Total	(6,159)	6,728	1,289	1,042	2,900
WTU					
Other External Sources	(1,743)	499	-	-	(1,244)
Models/Other Valuation	(419)	1,786	438	354	2,159
Total	(2,162)	2,285	438	354	915

(a) "Prices Actively Quoted" represents the Company's exchange traded futures positions in natural gas.

(b) "Prices Provided by Other External Sources" represents the Company's positions in natural gas, power, and coal at points where over-the-counter broker quotes are available. Prices for these various commodities can generally be obtained on the over-the-counter market through 2003. Some prices from external sources are quoted as strips (one bid/ask for Nov-Mar, Apr-Oct, etc). Such transactions have also been included in this category.

(c) "Prices Based on Models and Other Valuation Methods" contain the following: the value of the Company's adjustments for liquidity and counterparty credit exposure, the value of contracts not quoted by an exchange or an over-the-counter broker, the value of transactions for which an internally developed price curve was developed as a result of the long dated nature of certain transactions, and the value of certain structured transactions.

We have investments in debt and equity securities which are held in nuclear trust funds. The trust investments and their fair value are discussed in Note 13, "Risk Management, Financial Instruments and Derivatives." Financial instruments in these trust funds have not been included in the market risk calculation for interest rates as these instruments are marked-to-market and changes in market value of these instruments are reflected in a corresponding decommissioning liability. Any differences between the trust fund assets and the ultimate liability are expected to be recovered through regulated rates from our regulated customers.

Inflation affects our cost of replacing utility plant and the cost of operating and maintaining plant. The rate-making process limits recovery to the historical cost of assets, resulting in economic losses when the effects of inflation are not recovered from customers on a timely basis. However, economic gains that result from the repayment of long-term debt with inflated dollars partly offset such losses.

Industry Restructuring

In 2000 California's deregulated electricity market suffered problems including high energy prices mainly due to short energy supplies and financial difficulties for retail distribution companies. This energy crisis has highlighted the importance of risk management and has contributed to certain state regulatory and legislative actions which have delayed the start of customer choice and the transition to competitive, market based pricing for retail electricity supply in some of the states in which AEP operates. Seven of the eleven state retail jurisdictions in which the AEP domestic electric utility companies operate have enacted restructuring legislation. In general, the legislation provides for a transition from cost-based regulation of bundled electric service to customer choice and market pricing for the supply of electricity. As legislative and regulatory proceedings evolved, six AEP electric operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU) doing business in five of the seven states that have passed restructuring legislation have discontinued the application of SFAS 71 regulatory accounting for the generation business. The seven states in various stages of restructuring to transition power generation and supply to market based pricing are Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia. AEP has not discontinued its regulatory accounting for its subsidiaries doing business in Michigan and Oklahoma pending the effective implementation of the legislation. Restructuring legislation, the status of the transition plans and the status of the electric utility companies' accounting to comply with the changes in each of AEP's seven state regulatory jurisdictions affected by restructuring legislation is presented in the Note 7 of the Notes to Financial Statements.

RTO Formation

FERC Order No. 2000 and many of the settlement agreements with the FERC and state regulatory commissions to approve the AEP-CSW Merger have provisions for the transfer of functional control of our transmission system to an RTO. Certain AEP subsidiaries are participating in the formation of the Alliance RTO. Other subsidiaries are a member of ERCOT or SPP.

In 2001 the Alliance companies and MISO entered into a settlement addressing transmission pricing and other "seam" issues between the two RTOs. The FERC subsequently expressed its opinion that four large RTO regions serving the continental US would best support competition and reliability of electric service. Certain state regulatory commissions have taken exception to the FERC's RTO actions. Louisiana's commission ordered utilities it regulates, including SWEPCo, to show the advantage of large RTOs to their customers.

On December 19, 2001 the FERC approved the proposal of the Midwest ISO for a regional transmission organization and told the Alliance companies, which had submitted a separate RTO proposal, to explore joining the Midwest ISO organization. The FERC's order is intended to facilitate the establishment of a single RTO in the Midwest and to support the establishment of viable, for-profit transmission companies under an RTO umbrella and concluded that the RTO proposed by Alliance companies lacks sufficient scope to exist as a stand-alone RTO and thus directed the Alliance companies to explore how their business plan can be accommodated within the Midwest ISO.

Management is unable to predict the outcome of these transmission regulatory actions and proceedings or their impact on the timing and operation of RTOs, AEP's transmission operations or future results of operations and cash flows.

Litigation

AEP is involved in various litigation. The details of significant litigation contingencies are disclosed in Note 8 and summarized below.

COLI – Affecting AEP, APCo, CSPCo, I&M, KPCo and OPCo

A decision by U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to its COLI program resulted in a $319 million reduction in net income for 2000. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 AEP and the impacted subsidiaries paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 for APCo, CSPCo, I&M and OPCo and 1992-98 for KPCo to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets on AEP's balance sheet and other property and investments on the subsidiaries' balance sheets pending the resolution of this matter. AEP has appealed the Court's decision.

The earnings reductions for affected registrant subsidiaries are as follows:

	(in millions)
APCo	$ 82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

Shareholders' Litigation – Affecting AEP

On December 21, 2001, the U.S. District Court for the Southern District of Ohio dismissed a class action lawsuit against AEP and four former or present officers. The complaint alleged violation of federal securities laws by disseminating materially false and misleading statements related to the extended Cook Plant outage.

FERC Wholesale Fuel Complaints – Affecting AEP and WTU

In November 2001 certain WTU wholesale customers filed a complaint with FERC alleging that WTU has overcharged them since 1997 through the fuel adjustment clause. The customers allege inappropriate costs related to purchased power were included in the fuel adjustment clause. Management is working to compute if any overcharges occurred and is unable to predict their impact on results of operations, cash flow and financial condition.

Municipal Franchise Fee Litigation – Affecting AEP and CPL

In 2001 CPL paid $11 million to settle class action litigation regarding municipal franchise fees in Texas. The City of San Juan, Texas had filed a class action lawsuit in 1996 seeking $300 million in damages.

Texas Base Rate Litigation – Affecting AEP and CPL

In 2001 the Texas Supreme Court denied CPL's request for the court to review a 1997 PUCT base rate order. Subsequently the Court also denied CPL's rehearing request.

The primary issues CPL requested the Court to review were:

- the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property;
- and an $18 million disallowance of affiliated service billings.

Lignite Mining Agreement Litigation – Affecting AEP and SWEPCo

In 2001 SWEPCo settled litigation concerning lignite mining in Louisiana. Since 1997 SWEPCo has been involved in litigation concerning the mining of lignite from jointly owned lignite reserves. SWEPCo and CLECO, an unaffiliated utility, are each a 50% owner of the Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. Under terms of a settlement, SWEPCo purchased an unaffiliated mine operator's interest in the mining operations and related debt and other obligations for $86 million.

Merger Litigation – Affecting AEP and all Subsidiary Registrants

In January 2002, a federal court ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Other – Affecting AEP and all Subsidiary Registrants

AEP and its registrant subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

Environmental Concerns and Issues

The U.S. continues to debate an array of environmental issues affecting the electric utility industry including new emission limitations recommended by the Bush Administration in February 2002. Most of the policies are aimed at reducing air emissions citing alleged impacts of such emissions on public health, sensitive ecosystems or the global climate.

AEP and its subsidiaries' policy on the environment continues to be the development and application of long-term economically feasible measures to improve air and water quality, limit emissions and protect the health of employees, customers, neighbors and others impacted by their operations. In support of this policy, AEP and its subsidiaries continue to invest in research through groups like the Electric Power Research Institute and directly through demonstration projects for new technology for the capture and storage of carbon dioxide, mercury, NOx and other emissions. The AEP System intends to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices.

AEP and its subsidiaries have a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. AEP and its subsidiaries have spent billions of dollars to equip their facilities with the latest cost effective clean air and water technologies and to research new technologies. We are proud of our award winning efforts to reclaim our mining properties.

The introduction of multi-pollutant control legislation is being discussed by members of Congress and the Bush Administration. The legislation being considered may regulate carbon dioxide, NOx, sulfur dioxide, mercury and other emissions from electric generating plants. Management will continue to support solutions which are based on sound science, economics and demonstrated control technologies. Management is unable to predict the timing or magnitude of additional pollution control laws or regulations. If additional control technology is required on facilities owned by the electric utility companies and their costs were not recoverable from ratepayers or through market based prices or volumes of product sold, they could adversely affect future results of operations and cash flows. The following discussions explains existing control efforts, litigation and other pending matters related to environmental issues for AEP companies.

Federal EPA Complaint and Notice of Violation – Affecting AEP, APCo, CSPCo, I&M and OPCo

Since 1999 AEP, APCo, CSPCo, I&M and OPCo have been involved in litigation regarding generating plant emissions under the Clean Air Act. Federal EPA, a number of states and certain special interest grups alleged that APCo, CSPCo, I&M and OPCo modified certain generating units over a 20 year period in violation of the Clean Air Act.

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. We believe our maintenance, repair and replacement activities were in conformity with the Clean Air Act and intend to vigorously pursue our defense.

The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In March 2001 the District Court ruled that claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

Management is unable to estimate a loss or predict the timing of the resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition.

An unaffiliated utility which operates certain plants jointly owned by CSPCo reached a tentative agreement to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing and a settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NOx Reduction – Affecting AEP, APCo, CPL, I&M, OPCo and SWEPCo

Federal EPA issued a NOx rule (the Nox Rule) and granted petitions filed by certain northeastern states (the Section 126 Rule) requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located.

Federal EPA ruled that eleven states, including certain states in which AEP's generating units are located, failed to submit approvable plans to comply with the NOx Rule. This ruling means that those states could face stringent sanctions including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs. A request for the D.C. Circuit Court to review this ruling is pending. The compliance date for the NOx Rule is May 31, 2004.

The D.C. Circuit Court instructed Federal EPA to justify methods used to allocate allowances and project growth for both the NOx Rule and the Section 126 Rule. In response to AEP and other utilities request for the D.C. Circuit Court to suspend the May 2003 compliance date of the Section 126 Rule, the D.C. Circuit Court issued an order tolling the compliance schedule until Federal EPA responds to the Court's remand.

In April 2000 the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including CPL and SWEPCo. The compliance date is May 2003 for CPL and May 2005 for SWEPCo.

In 2001 selective catalytic reduction (SCR) technology to reduce NOx emissions on OPCo's Gavin Plant commenced operation. Construction of SCR technology at certain other generating units continues with completion scheduled in 2002 through 2006.

Our estimates indicate that compliance with the NOx Rule, the Texas Natural Resource Conservation Commission rule and the Section 126 Rule could result in required capital expenditures of approximately $1.6 billion of which approximately $450 million has been spent for the AEP System.

The following table shows the estimated compliance cost and amounts spent for certain of AEP's registrant subsidiaries.

Company	Estimated Compliance Costs (in millions)	Amounts Spent (in millions)
APCo	$365	$130
CPL	57	4
I&M	202	-
OPCo	606	277
SWEPCo	28	21

Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

Superfund – Affecting AEP, APCo, CPL, CSPCo, I&M, OPCo and SWEPCo

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. We are currently incurring costs to safely dispose of these substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized Federal EPA to administer the clean-up programs. As of year-end 2001, subsidiaries of AEP have been named by the Federal EPA as a PRP for five sites. APCo, CSPCo, and OPCo each have one PRP site and I&M has two PRP sites. There are four additional sites for which AEP, APCo, CSPCo, I&M, OPCo and SWEPCo have received information requests which could lead to PRP designation. CPL, OPCo and SWEPCo have also been named a PRP at two sites under state law. Our liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where AEP or its subsidiaries have been named a PRP or defendant, their disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding AEP's and its subsidiaries' potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although liability is joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs are attributed to AEP or its subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

Global Climate Change – Affecting AEP and all Registrant Subsidiaries

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997 more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide, which many scientists believe are contributing to global climate change. Although the U.S. signed the Kyoto Protocol on November 12, 1998, the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001 President Bush announced his opposition to the treaty and its U.S. ratification. At the Seventh Conference of the Parties in November 2001, the parties finalized the rules, procedures and guidelines required to facilitate ratification of the protocol. The protocol is expected to become effective by 2003. U.S. representatives attended the Seventh Conference but they did not take any positions on issues being negotiated or attempt to block the approval of any issue. AEP does not support the Kyoto Protocol but intends to work with the Bush Administration and U.S. Congress to develop responsible public policy on this issue. Management expects due to President Bush's opposition to legislation mandating greenhouse gas emissions controls, any policies developed and implemented in the near future are likely to encourage voluntary measures to reduce, avoid or sequester such emissions.

The acquisition of 4,000 MW of coal-fired generation in the United Kingdom in December 2001 exposes these assets to potential carbon dioxide emission control obligations since the U.K. is expected to be a party to the Kyoto Protocol.

Costs for Spent Nuclear Fuel and Decommissioning – Affecting AEP, CPL and I&M

I&M, as the owner of the Cook Plant, and CPL, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law CPL and I&M participate in the DOE's SNF disposal program which is described in Note 8 of the Notes to Financial Statements. Since 1983 I&M has collected $288 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $116 million of these funds have been deposited in external trust funds to provide for the future disposal of SNF and $172 million has been remitted to the DOE. CPL has collected and remitted to the DOE, $49 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of CPL and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's *partial material breach* of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. AEP's and I&M's suit has been stayed pending further action by the U.S. Court of Federal Claims. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage and the cost of decommissioning will continue to increase.

In January 2001, I&M and STPNOC, on behalf of STP's joint owners, joined a lawsuit against DOE, filed in November 2000 by unaffiliated utilities, related to DOE's nuclear waste fund cost recovery settlement with PECO Energy Corporation. The settlement allows PECO to skip two payments to the DOE for disposal of SNF due to the lack of progress towards development of a permanent repository for SNF. The companies believe the settlement is unlawful as the settlement would force other utilities to make up any shortfall in DOE's SNF disposal funds.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2000 estimate the cost to decommission the Cook Plant ranges from $783 million to $1,481 million in 2000 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2001, the total decommissioning trust fund balance for Cook Plant was $598 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate CPL's share of decommissioning cost to be $289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2001, the total decommissioning trust fund for CPL's share of STP was $99 million which includes earnings on the trust investments. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. We will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, AEP's, CPL's and I&M's future results of operations, cash flows and possibly their financial conditions would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

AEP and its subsidiaries are exposed to other environmental concerns which are not considered to be material or potentially material at this time. Should they become significant or should any new concerns be uncovered that are material they could have a material adverse effect on results of operations and possibly financial condition. AEP performs environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues.

APCo, AEP's subsidiary which operates in Virginia and West Virginia, has been seeking regulatory approval to build a new high voltage transmission line for over a decade. Through December 31, 2001 we have invested approximately $40 million in this effort. If the required regulatory approvals are not obtained and the line is not constructed, the $40 million investment would be written off adversely affecting AEP's and APCo's future results of operations and cash flows.

OTHER MATTERS

Enron Bankruptcy – Affecting AEP, APCo, CSPCo, I&M, KPCo and OPCo

At the date of Enron's bankruptcy AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line from Enron and entered into a lease arrangement with a subsidiary of Enron for a gas storage facility. At the date of Enron's bankruptcy various HPL related contingencies and indemnities remained unsettled. In the fourth quarter of 2001 AEP provided $47 million ($31 million net of tax) for our estimated losses from the Enron bankruptcy.

The amounts for certain subsidiary registrants were:

Registrant	Amounts Provided	Amounts Net of Tax
	(in millions)	
APCo	$5.2	3.4
CSPCo	3.2	2.1
I&M	3.4	2.2
KPCo	1.3	0.8
OPCo	4.3	2.8

The amounts provided were based on an analysis of contracts where AEP and Enron are counterparties, the offsetting of receivables and payables, the application of deposits from Enron and management's analysis of the HPL related purchase contingencies and indemnifications. If there are any adverse unforeseen developments in the bankruptcy proceedings, our future results of operations, cash flows and possibly financial condition could be adversely impacted.

International Investments – Affecting AEP

We own a 44% equity interest in Vale, a Brazilian electric operating company which was purchased for a total of $149 million. On December 1, 2001 we converted a $66 million note receivable and accrued interest into a 20% equity interest in Caiua (Brazilian electric operating company), a subsidiary of Vale. Vale and Caiua have experienced losses from operations and our investment has been affected by the devaluation of the Brazilian Real. The cumulative equity share of operating and foreign currency translation losses through December 31, 2001 is approximately $46 million and $54 million, respectively net of tax. The cumulative equity share of operating and foreign currency translation losses through December 31, 2000 is approximately $33 million and $49 million, respectively net of tax. Both investments are covered by a put option, which, if exercised, requires our partners in Vale to purchase our Vale and Caiua shares at a minimum price equal to the U.S. dollar equivalent of the original purchase price. As a result, management has concluded that the investment carrying amount should not be reduced below the put option value unless it is deemed to be an other than temporary impairment and our partners in Vale are deemed unable to fulfill their responsibilities under the put option. Management has evaluated through an independent third-party, the ability of its Vale partners to fulfill their responsibilities under the put option agreement and has concluded that our partners should be able to fulfill their responsibilities.

Management believes that the decline in the value of its investment in Vale in US dollars is not other than temporary. As a result and pursuant to the put option agreement, these losses have not been applied to reduce the carrying values of the Vale and Caiua investments. As a result we will not recognize any future earnings from Vale and Caiua until the operating losses are recovered. Should the impairment of our investment become other than temporary due to our partners in Vale becoming unable to fulfill their responsibilities, it would have an adverse effect on future results of operations.

Management will continue to monitor both the status of the losses and the ability of its partners to fulfill their obligations under the put.

Investments Limitations – Affecting AEP

Our investment, including guarantees of debt, in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits us to issuing and selling securities in an amount up to 100% of our average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2001, AEP's investment in EWGs and FUCOs was $2.9 billion, including guarantees of debt, compared to AEP's limit of $3.3 billion.

SEC rules under PUHCA permit AEP to invest up to 15% of consolidated capitalization (such amount was $3.6 billion at December 31, 2001) in energy-related companies, including marketing and/or trading of electricity, gas and other energy commodities. Our gas trading business and our interest in domestic cogeneration projects are reported as investments under this rule and at December 31, 2001, such investment was $2.2 billion.

New Accounting Standards – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU

The FASB recently issued SFAS 141, "Business Combinations" and SFAS 142, "Goodwill And Other Intangible Assets." SFAS 141 requires that the purchase method of accounting be used to account for all business combinations entered into after June 30, 2001. SFAS 142 requires that goodwill

Common Stock and Dividend Information

The quarterly high and low sales prices for AEP common stock and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Dividend
March 2001	$48.10	$39.25	$0.60
June 2001	51.20	45.10	0.60
September 2001	48.90	41.50	0.60
December 2001	46.95	39.70	0.60
March 2000	34.94	25.94	0.60
June 2000	38.50	29.44	0.60
September 2000	40.00	29.94	0.60
December 2000	48.94	36.19	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2001, AEP had approximately 150,000 shareholders of record.

amortization cease and that goodwill and other intangible assets with indefinite lives be tested for impairment upon SFAS 142 implementation and annually thereafter. We must implement these new standards in the first quarter of 2002. Amortization of goodwill and other intangible assets with indefinite lives will cease with our implementation of SFAS 142 beginning January 1, 2002. The amortization of goodwill reduced AEP's net income by $50 million for the twelve months ended December 31, 2001. The registrant subsidiaries did not have any goodwill at December 31, 2001. We are currently in the process of fair valuing our reporting units with goodwill in order to determined potential goodwill impairment. As such we have not yet determined the impact on first quarter 2002 results of operations of adopting the provision of these standards.

SFAS 143, "Accounting for Asset Retirement Obligations," will become effective for us beginning January 1, 2003. SFAS 143 established accounting and reporting for legal obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. We are currently in the process of evaluating the provisions of the standard and determining its impact on future results of operations and financial condition. To the extent AEP or it registrant subsidiaries are regulated entities, we anticipate that the cumulative effect of this accounting change on future results of operations will be significantly offset by a regulatory asset representing the right to recover legal asset retirement obligations (ARO) relative to regulated long lived assets included in rate base. The impact on future results of operations from the implementation of this new standard on non-regulated long lived assets has not yet been determined. We anticipate that the considerable effort to identify all long lived assets with legal ARO and to determine the required discounted legal ARO will take the remainder of 2002.

In August 2001 the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" which sets forth the accounting to recognize and measure an impairment loss. This standard replaces the previous standard, SFAS 121, "Accounting for the Long-lived Assets and for Long-lived Assets to be Disposed Of." SFAS 144 will apply to us beginning January 1, 2002. We do not expect that the implementation of SFAS 144 will materially affect results of operations or financial condition.

The FASB recently revised its prior guidance related to SFAS 133, "Accounting for Deriviative Instruments and Hedging Activities" with regard to certain power option and forward contracts. The revised guidance states that power contracts, including both forward and option contracts, that include certain qualitative characteristics are considered capacity contracts, and qualify for the normal purchases and normal sales exception from being marked to market even if they are subject to being booked out, or scheduled to be booked out. As normal purchases and sales these open energy contracts are not marked to market. Rather they are accounted for on a settlement basis. Most of AEP's power contracts that are not marked to market as trading transactions do not qualify as derivatives and thus are not subject to the revised guidance. The few contracts that are derivatives qualified for the exception under the previous guidance and will continue to qualify under the new guidance.

INVESTOR INQUIRIES
Investors should direct inquiries to Investor Relations using the toll free number, 1-800-237-2667 or by writing to:
Bette Jo Rozsa
Managing Director of Investor Relations
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT
The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 2002 at no cost to shareholders. Please address requests for copies to:
Geoffrey C. Dean
Director of Financial Reporting
American Electric Power Service Corporation
26th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

TRANSFER AGENT AND REGISTRAR OF CUMULATIVE PREFERRED STOCK
EquiServe Trust Company, N.A.
P.O. Box 2500
Jersey City, NJ 07303-2500
Phone number: 1-800-328-6955

STITES & HARBISON
ATTORNEYS

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com

November 26, 2001

Mark R. Overstreet
[502] 209-1219
moverstreet@stites.com

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
NOV 26 2001
PUBLIC SERVICE COMMISSION

RE: P.S.C. Case No. 99-149

Dear Mr. Dorman:

Please find enclosed and accept for filing the supplementary Responses of Kentucky Power Company d/b/a American Electric Power to the Data Requests set forth in the Commission's Order dated June 14, 1999 in the above-styled action. The Responses are for the period ended September 30, 2001.

Copies of this letter and the supplementary Responses have been served this day on the persons listed below.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

Mark R. Overstreet

Enclosure

cc: David F. Boehm
Elizabeth E. Blackford
William H. Jones, Jr.

KE057:KE131:6494:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER	)
COMPANY, AMERICAN ELECTRIC POWER	)
COMPANY, INC. AND CENTRAL AND SOUTH	) CASE NO. 99-149
WEST CORPORATION REGARDING A	)
PROPOSED MERGER	)

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

Reporting Period: 3rd Quarter 2001

Filing Date: 26 November 2001

1

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Please see the Company's response to Item No. 1 filed with the Commission on May 15, 2001.

WTNESS: Errol K. Wagner

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

Please see the Company's response to Item No. 2 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

3

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

Please see the Company's response to Item No. 3 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

4

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

Below is the information detailing Kentucky Power's Proportionate Share of AEP's total operating revenues, operating and maintenance expenses and the number of employees for the 3rd Quarter ending September 30, 2001.

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	Three Months September 30, 2001				Nine Months September 30 2001		
	AEP	KPCO	SHARE		AEP	KPCO	SHARE
Revenues	$18,385	$475	2.6%		$47,078	$1,351	2.9%
Operating/Maintenance Expense	$16,979	$428	2.5%		$43,360	$1,212	2.8%
Number of Employees At 9 /30/01*	22,106	441	2.0%		22,106	441	2.0%

* See Response to Item No. 6

WITNESS: Errol K. Wagner

5

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

During the three month period ending September 30, 2001, there were 19 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $159,846.85. The smallest dollar value transferred was one meter at a value of $39.00. The largest dollar value transferred was 586 meters at a value of $29,618.00.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

3rd Quarter 2001 – Please see attached page.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT BY LEGAL ENTITY

EFFECTIVE 09/30/2001

	COMPANY	Employee Count
01	KINGSPORT POWER COMPANY	58
02	APPALACHIAN POWER COMPANY	2765
03	KENTUCKY POWER POWER COMPANY	441
04	INDIANA MICHIGAN POWER COMPANY	2656
06	WHEELING POWER POWER COMPANY	70
07	OHIO POWER COMPANY	2402
10	COLUMBUS SOUTHERN POWER COMPANY	1225
36	LA INTRASTATE GAS CO, LLC	66
39	LIG LIQUIDS COMPANY, LLC	34
48	RIVER TRANSPORTATION DIV-I&M	337
54	CONESVILLE COAL PREPARATOIN COMPANY	37
59	ENERGY SERVICES	179
61	AEP SERVICE CORPORATION	7197
69	AEP RESOURCES SERVICE COMPANY	72
CC	CENTRAL POWER & LIGHT	1427
DG	DATAPULT LLC	33
EE	CSW ENERGY, INC	88
H	ENERSHOP, INC.	6
MM	C3 COMMUNICATIONS	58
PP	PUBLIC SERVICE CO OF OK	999
SS	SOUTHWESTERN ELECTRIC POWER COMPANY	1244
TD	AEP T&D SERVICES, LLC	1
WW	WEST TEXAS UTILITIES	711
	TOTAL	22106

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Please see the Company's response to Item No. 7 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

Please see the Company's response to Item No. 8 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

The cost allocations in effect for the three months ending September 30, 2001 were in accordance with the Company's Cost Allocation Manual (CAM) as filed with the Kentucky Commission on May 15, 2001.

The Company had requested the Securities and Exchange Commission (SEC) for authorization to utilize twelve new cost allocation factors that we believe will result in a more fair and equitable allocation of costs by applying better cost drivers. This information was filed with the Kentucky Commission in memo form on January 30, 2001 (Case No. 99-149). The Company received approval from the Securities and Exchange Commission on September 18, 2001 for eleven new cost allocations. Please see the attached page.

WITNESS: Errol K. Wagner

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

OFFICE OF
PUBLIC UTILITY REGULATION

September 18, 2001

Leonard V. Assante
Vice President Deputy Controller
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373

Dear Mr. Assante:

I have received your response letter dated August 9, 2001 to my May 18, 2001 letter providing information as to the following four methods of allocation:

(1) The number of Contracts and Service Orders written.
(2) Number of Nonelectric OAR invoices.
(3) Total Assets/Total Revenues/Total Payroll.
(4) Number of Banking Transactions.

Based on the analysis presented by American Electric Power in the April 18, 2001 sixty-day letter and the August 9, 2001 response, I now agree that all eleven new methods of allocation will allow American Electric Power Service Corporation's shared services to be billed based on the most equitable method of allocation for each service performed.

Any and all questions concerning the subject of this letter are to be directed to my attention at (202) 942-0543.

Sincerely,

R.P. Wason

Robert P. Wason
Chief Financial Analyst

RPW:kn

cc Joseph M. Buonaituo

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

Please see the Company's response to Item No. 10 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

Please see the Company's response to Item No. 13 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

14

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE:

Please see the Company's response to Item No. 14 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

15

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2000. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE:

Please see the Company's response to Item No. 15 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

16

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2000. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE:

Please see the Company's response to Item No. 16 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

17

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2000.[Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE:

Please see the Company's response to Item No. 17 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

18

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impact of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages. [Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE:

Please see the Company's response to Item No. 18 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE:

Please see the Company's response to Item No. 19 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

20

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE:

Please see the Company's response to Item No. 20 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

21

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE:

Please see the Company's response to Item No. 21 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

22

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE:

Please see the Company's response to Item No. 22 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

23

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE:

Please see the Company's response to Item No. 23 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

STITES & HARBISON

ATTORNEYS

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com

August 10, 2001

Mark R. Overstreet
[502] 209-1219
moverstreet@stites.com

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED

AUG 1 0 2001

PUBLIC SERVICE
COMMISSION

RE: P.S.C. Case No. 99-149

Dear Mr. Dorman:

Please find enclosed and accept for filing Kentucky Power Company d/b/a American Electric Power's Reports for the periods ending March 31, 2001 and June 30, 2001 in the above styled case.

As indicated on the attached service list, copies have been served this day on the parties to the proceeding.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

Mark R. Overstreet

KE057:KE131:5621:FRANKFORT

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that a copy of the foregoing Reports for the Period Ending March 31, 2001 and June 30, 2001 was served by first class mail, postage prepaid, on this 10th day of August, 2001 upon:

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, Kentucky 40601

David F. Boehm
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

RECEIVED
AUG 10 2001
PUBLIC SERVICE COMMISSION

William H. Jones, Jr.
VanAntwerp, Monge, Jones & Edwards, LLP
1544 Winchester Avenue
Fifth Floor
Ashland, Kentucky 41105-1111

Mark R. Overstreet

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER	)
COMPANY, AMERICAN ELECTRIC POWER	)
COMPANY, INC. AND CENTRAL AND SOUTH	) CASE NO. 99-149
WEST CORPORATION REGARDING A	)
PROPOSED MERGER	)

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

Reporting Period: 1st and 2nd Quarter 2001

Filing Date: August 10, 2001

1

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Please see the Company's response to Item No. 1 filed with the Commission on May 15, 2001.

WTNESS: **Errol K. Wagner**

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

Please see the Company's response to Item No. 2 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

3

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

Please see the Company's response to Item No. 3 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

1st Quarter 2001

Below is the information detailing Kentucky Power's Proportionate Share of AEP's total operating revenues, operating and maintenance expenses and the number of employees for the 1st Quarter ending March 31, 2001.

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

Three Months
March 31, 2001

	AEP	KPCO	SHARE
Revenues	$14,238	$449	3.2%
Operating/Maintenance Expense	$13,060	$396	3.0%
Number of Employees At 3/31/01*	22,847	449	2.0%

* See Response to Item No. 6

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

2nd Quarter 2001

Below is the information detailing Kentucky Power's Proportionate Share of AEP's total operating revenues, operating and maintenance expenses and the number of employees for the 2nd Quarter ending June 30, 2001.

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	Three Months June 30, 2001				Six Months June 30, 2001		
	AEP	KPCO	SHARE		AEP	KPCO	SHARE
Revenues	$14,455	$427	3.0%		$28,693	$876	3.1%
Operating/Maintenance Expense	$13,333	$386	2.9%		$26,393	$782	3.0%
Number of Employees At 6/30/01*	23,231	446	1.9%		23,231	446	1.9%

* See Response to Item No. 6

WITNESS: Errol K. Wagner

5

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

1st Quarter 2001:

During the three month period ending March 31, 2001 there were 10 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $49,591.37. The smallest dollar value transferred was one meter at a value of $35.00. The largest dollar value transferred was 470 meters at a value of $16,406.00.

2nd Quarter 2001:

During the three month period ending June 30, 2001 there were 15 different transactions in which AEP/Kentucky sold assets to its affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $130,000.69. The smallest dollar value transferred was one meter at a value of $33.00. The largest dollar value transferred was 70 meters at a value of $25,783.00.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

1st Quarter 2001 – Please see page 2 of this response.

2nd Quarter 2001 – Please see page 3 of this response.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT BY LEGAL ENTITY

EFFECTIVE 03/31/2001

	COMPANY	Employee Count
01	KINGSPORT POWER COMPANY	58
02	APPALACHIAN POWER COMPANY	2838
03	KENTUCKY POWER POWER COMPANY	449
04	INDIANA MICHIGAN POWER COMPANY	2693
06	WHEELING POWER POWER COMPANY	75
07	OHIO POWER COMPANY	2439
09	AEP FIBER VENTURE LLC	80
10	COLUMBUS SOUTHERN POWER COMPANY	1216
36	LA INTRASTATE GAS CO, LLC	66
39	LIG LIQUIDS COMPANY, LLC	35
42	CENTRAL OHIO COAL COMPANY	63
43	WINDSOR COAL COMPANY	67
44	SOUTHERN OHIO COAL COMPANY	705
48	RIVER TRANSPORTATION DIV-I&M	314
54	CONESVILLE COAL PREPARATOIN COMPANY	37
59	ENERGY SERVICES	88
61	AEP SERVICE CORPORATION	6951
	AEP RESOURCES SERVICE COMPANY	73
CC	CENTRAL POWER & LIGHT	1447
DG	DATAPULT LLC	57
EE	CSW ENERGY, INC	80
HH	ENERSHOP, INC.	6
MM	C3 COMMUNICATIONS	41
PP	PUBLIC SERVICE CO OF OK	1010
SS	SOUTHWESTERN ELECTRIC POWER COMPANY	1239
WW	WEST TEXAS UTILITIES	720
	TOTAL	22847

EMPLOYEE COUNT BY LEGAL ENTITY

EFFECTIVE 06/30/2001

	COMPANY	Employee Count
01	KINGSPORT POWER COMPANY	60
02	APPALACHIAN POWER COMPANY	2815
03	KENTUCKY POWER POWER COMPANY	446
04	INDIANA MICHIGAN POWER COMPANY	2718
06	WHEELING POWER POWER COMPANY	73
07	OHIO POWER COMPANY	2421
09	AEP FIBER VENTURE LLC	99
10	COLUMBUS SOUTHERN POWER COMPANY	1227
36	LA INTRASTATE GAS CO, LLC	74
39	LIG LIQUIDS COMPANY, LLC	36
42	CENTRAL OHIO COAL COMPANY	93
43	WINDSOR COAL COMPANY	94
44	SOUTHERN OHIO COAL COMPANY	672
48	RIVER TRANSPORTATION DIV-I&M	330
54	CONESVILLE COAL PREPARATOIN COMPANY	37
59	ENERGY SERVICES	166
61	AEP SERVICE CORPORATION	7169
[illegible]	AEP RESOURCES SERVICE COMPANY	72
CC	CENTRAL POWER & LIGHT	1450
DG	DATAPULT LLC	58
EE	CSW ENERGY, INC	81
HH	ENERSHOP, INC.	6
MM	C3 COMMUNICATIONS	44
PP	PUBLIC SERVICE CO OF OK	1019
SS	SOUTHWESTERN ELECTRIC POWER COMPANY	1246
TD	AEP T&D SERVICES, LLC	1
WW	WEST TEXAS UTILITIES	724
	TOTAL	23231

7

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Please see the Company's response to Item No. 7 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

Please see the Company's response to Item No. 8 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

1st Quarter 2001

The cost allocations in effect for the three months ending March 31, 2001 were in accordance with the Company's Cost Allocation Manual (CAM) as filed with the Kentucky Commission on May 15, 2001.

The Company has requested the Securities and Exchange Commission (SEC) for authorization to utilize twelve new cost allocation factors that will result in a more fair and equitable allocation of costs by applying better cost drivers. This information was filed with the Kentucky Commission in memo form on January 30, 2001 (Case No. 99-149). The Company is awaiting SEC approval.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4].

RESPONSE:

2nd Quarter 2001

The cost allocations in effect for the three months ending June 30, 2001 were in accordance with the Company's Cost Allocation Manual (CAM) as filed with the Kentucky Commission on May 15, 2001.

The Company has requested the Securities and Exchange Commission (SEC) for authorization to utilize twelve new cost allocation factors that we believe will result in a more fair and equitable allocation of costs by applying better cost drivers. This information was filed with the Kentucky Commission in memo form on January 30, 2001 (Case No. 99-149). The Company is awaiting SEC approval.

WITNESS: Errol K. Wagner

10

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

Please see the Company's response to Item No. 10 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

12

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item No. 11 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

Please see the Company's response to Item No. 13 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE:

Please see the Company's response to Item No. 14 filed with the Commission on December 8, 2000.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2000. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE:

Please see the Company's response to Item No. 15 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

16

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2000. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE:

Please see the Company's response to Item No. 16 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

17

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2000.[Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE:

Please see the Company's response to Item No. 17 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impact of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages. [Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE:

Please see the Company's response to Item No. 18 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

19

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE:

Please see the Company's response to Item No. 19 filed with the Commission on May 15, 2001.

WITNESS: **Errol K. Wagner**

20

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE:

Please see the Company's response to Item No. 20 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

21

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE:

Please see the Company's response to Item No. 21 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE:

Please see the Company's response to Item No. 22 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

23

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE:

Please see the Company's response to Item No. 23 filed with the Commission on May 15, 2001.

WITNESS: Errol K. Wagner

STITES & HARBISON

ATTORNEYS

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May 15, 2001

Mark R. Overstreet
[502] 209-1219
moverstreet@stites.com

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
MAY 15 2001
PUBLIC SERVICE COMMISSION

RE: P.S.C. Case No. 99-149

Dear Mr. Dorman:

Please find enclosed and accept for filing the supplementary Responses of Kentucky Power Company d/b/a American Electric Power to the Data Requests set forth in the Commission's Order dated June 14, 1999 in the above-styled action.

As indicated on the attached service list, copies have been served this day on the parties to the proceeding.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

Mark R. Overstreet

KE057:KE131:5621:FRANKFORT

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Supplementary Responses were served by first class mail, postage prepaid, on this 15th day of May, 2001 upon:

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, Kentucky 40601

David F. Boehm
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

William H. Jones, Jr.
VanAntwerp, Monge, Jones & Edwards, LLP
1544 Winchester Avenue
Fifth Floor
Ashland, Kentucky 41105-1111

Mark R. Overstreet

RECEIVED

MAY 15 2001

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER	)
COMPANY, AMERICAN ELECTRIC POWER	)
COMPANY, INC. AND CENTRAL AND SOUTH	) CASE NO. 99-149
WEST CORPORATION REGARDING A	)
PROPOSED MERGER	)

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a/
AMERICAN ELECTRIC POWER

May 15, 2001

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg 10 (Periodic Reports)]

RESPONSE:

Attached you will find a copy of AEP's 2000 combined annual financial statements and the SEC Form 10K (Attachment 1), Form U-13-60 (Attachment 2) and Form U5S (Attachment 3) also for the year 2000. The Form U5S contains the consolidating financial statements of AEP including the consolidation adjustments of AEP and its subsidiaries.

WTNESS: Errol K. Wagner

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE:

A general description of the nature of inter-company transactions is contained in the Cost Allocation Manual (CAM) filed as Attachment 1. There have been no changes to the procedures used to price inter-company transactions from those used in the prior year. Unless exempted, inter-company transactions conducted by or with Kentucky Power Company are priced at fully-allocated cost in accordance with Rules 90 and 91 prescribed by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935.

WITNESS: Errol K. Wagner

3

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE:

A copy of the Kentucky Power employees transferred during the twelve months ending 12/31/00 is attached.

WITNESS: Errol K. Wagner

Kentucky Power Transferees - 12 months ending 12/31/2000

03

02 APPALACHIAN POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
FUGATE,MARVIN	08/16/2000	SENIOR CLERK	T&D DISPATCHER III
GREEN,DAVID R	11/01/2000	PRODUCTION SERVICES LEADER	INSTRUCTOR-OPERATOR TRAINING
ROBINSON,MICHAEL	08/26/2000	METER READER	EXPRESS DRIVER

04 INDIANA MICHIGAN POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
COFFEY,JOHN A,,III	07/16/2000	MGR DISTRIBUTION SYSTEM	MGR DISTRIBUTION SYSTEM

07 OHIO POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
DUMMITT,JEFFERY M	09/16/2000	TRANSMISSION LINE MECHANIC-A	TRANSMISSION LINE MECHANIC-A

10 COLUMBUS SOUTHERN POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
COFFEY,MICHAEL W	01/16/2000	STATION CREW SUPERVISOR - NE	STATION SUPERVISOR
MAGGARD,JACKIE D	01/01/2000	DISTRIBUTION LINE COORDINATOR	TECHNICIAN I

61 AEP SERVICE CORPORATION

Name	Eff Date	Job Title - Old	Job Title - New
BAYES,MICHAEL D	10/16/2000	ENV AUDIT CONSULTANT	ENV AUDIT CONSULTANT
COLEMAN,CHARLES R	10/01/2000	BUYER/ANALYST III	BUYER/ANALYST III

COOKMAN,JOHN C	09/16/2000	SR ENGINEERING TECHNOLOGIST	SR ENGINEERING TECHNOLOGIST
FITZGERALD,MARY A	09/01/2000	TECHNICIAN SENIOR	TECHNICIAN SENIOR
KEYSER,LLOYD E	02/01/2000	TRADE ALLY TECHNICAL REP-SR	BUS SRVCS-SMALL BUS REP I
MCCLEAN,DONALD R,,	09/01/2000	PRODUCTION SERVICES LEADER	IT ARCHITECT II
SEAGRAVES,JOY M	01/29/2000	SENIOR CLERK	SR CALL CTR CUSTOMER SVCS REP
YOUNGMAN,TERRY L	11/01/2000	EQUIPMENT OPERATOR	STAFF AUDITOR

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

RESPONSE:

Below is the information detailing Kentucky Power's Proportionate Share of AEP's total operating revenues, operating and maintenance expenses and the number of employees.

Kentucky Power Company
Report Proportionate Share of AEP
(in millions, except number of employees)

	Three Months December 31, 2000			Twelve Months December 31, 2000		
	AEP	KPCo	Share	AEP	KPCo	Share
Revenues	3,560	99	2.8%	13,694	369	2.7%
Operating/ Maintenance Expenses	(7,017)	64	2.4%		234	2.4%
Number of Employees	22,895	459	1.7%	22,895	459	1.7%

At 12/31/00*

* See Response to Item No. 6

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11 (Special Reports)]

RESPONSE:

During the three month period ending December 31, 2000 there were 16 different transactions in which AEP/Kentucky sold assets to it affiliates. The assets transferred were various meters and transformers. The total dollar value of the assets transferred was $155,128.47. The smallest dollar value transferred was two meters at a value of $472.00. The largest dollar value transferred was 763 meters at a value of $49,495.00.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

RESPONSE:

Attached is the quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assigned.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT BY LEGAL ENTITY

EFFECTIVE 12/31/2000

	COMPANY	Employee Count
01	KINGSPORT POWER COMPANY	58
02	APPALACHIAN POWER COMPANY	2947
03	KENTUCKY POWER POWER COMPANY	459
04	INDIANA MICHIGAN POWER COMPANY	2746
06	WHEELING POWER POWER COMPANY	75
07	OHIO POWER COMPANY	2492
09	AEP FIBER VENTURE LLC	61
10	COLUMBUS SOUTHERN POWER COMPANY	1284
36	LA INTRASTATE GAS CO, LLC	66
39	LIG LIQUIDS COMPANY, LLC	37
42	CENTRAL OHIO COAL COMPANY	153
43	WINDSOR COAL COMPANY	208
44	SOUTHERN OHIO COAL COMPANY	724
48	RIVER TRANSPORTATION DIV-I&M	309
54	CONESVILLE COAL PREPARATOIN COMPANY	37
59	ENERGY SERVICES	74
61	AEP SERVICE CORPORATION	6484
69	AEP RESOURCES SERVICE COMPANY	73
CC	CENTRAL POWER & LIGHT	1453
DG	DATAPULT LLC	37
EE	CSW ENERGY, INC	79
HH	ENERSHOP, INC.	7
MM	C3 COMMUNICATIONS	42
PP	PUBLIC SERVICE CO OF OK	1021
SS	SOUTHWESTERN ELECTRIC POWER COMPANY	1248
WW	WEST TEXAS UTILITIES	721
	TOTAL	22895

U:\count - status.rpt

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE:

Attached is an annual report containing the years of service at Kentucky Power and the salaries of the professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with Item Number 3.

WITNESS: Errol K. Wagner

Kentucky Power Transferees - 12 months ending 12/31/2000

03

02 APPALACHIAN POWER COMPANY

Name	Eff Date	Total Years of Service	Annual Salary
FUGATE,MARVIN	08/16/2000	23	43,500.00
GREEN,DAVID R	11/01/2000	25	67,400.00
ROBINSON,MICHAEL R	08/26/2000	14	33,508.80

04 INDIANA MICHIGAN POWER COMPANY

Name	Eff Date	Total Years of Service	Annual Salary
COFFEY,JOHN A,,III	07/16/2000	13	88,700.00

07 OHIO POWER COMPANY

Name	Eff Date	Total Years of Service	Annual Salary
DUMMITT,JEFFERY M	09/16/2000	16	47,673.60

10 COLUMBUS SOUTHERN POWER COMP

Name	Eff Date	Total Years of Service	Annual Salary
COFFEY,MICHAEL W	01/16/2000	21	56,000.00
MAGGARD,JACKIE D	01/01/2000	24	48,660.04

61 AEP SERVICE CORPORATION

Name	Eff Date	Total Years of Service	Annual Salary
BAYES,MICHAEL D	10/16/2000	15	66,000.00
COLEMAN,CHARLES R	10/01/2000	16	44,500.00

COOKMAN,JOHN C	09/16/2000	24	69,000.00
FITZGERALD,MARY A	09/01/2000	26	45,600.00
KEYSER,LLOYD E	02/01/2000	21	54,900.00
MCCLEAN,DONALD R,,JR	09/01/2000	20	64,700.00
SEAGRAVES,JOY M	01/29/2000	32	36,237.24
YOUNGMAN,TERRY L	11/01/2000	17	43,600.00

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12 Item 3]

RESPONSE:

The cost allocation factors used by Kentucky Power Company and other AEP System companies are described in the Cost Allocation Manual (CAM) filed as Attachment 1, Item No. 2. There were no significant changes in 2000 to the cost allocation factors described in the CAM.

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

RESPONSE:

Kentucky Power Company did not perform any cost allocation studies during the year ended December 31, 2000.

WITNESS: Errol K. Wagner

10

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE:

The methods used to update or revise the cost allocation factors used by Kentucky Power Company and other AEP System companies were not significantly changed during the year ended December 31, 2000. Allocation factors are revised periodically each year (e.g., monthly, quarterly, semi-annually and annually) based on the most current statistics available for each factor. The allocation factors in use are documented in the Cost Allocation Manual (CAM) filed as Attachment 1, Item No. 2.

WITNESS: Errol K. Wagner

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP.[Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE:

Please see the Company's response to Item 11 in the December 8, 2000 filing.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business.
[Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE:

See the Company's response to Item 11 in the December 8, 2000 filing.

WITNESS: Errol K. Wagner

13

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE:

There were no changes to the terms and conditions of the settlement in any jurisdiction, which would adversely affect the settlement reached in the Commonwealth of Kentucky or cause additional benefits to flow through the favored nation clause.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein.[Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14 Item 7]

RESPONSE:

See the Company's response to Item 14 in the December 8, 2000 filing.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2000. [Reference: Merger Agt., Attachment C, Pg. 1 Item l]

RESPONSE:

The overall Customer Average Interruption Duration Index (CAIDI), including major events, for Kentucky Power Company customers during calendar 2000 was 3.77 hours. The overall System Average Interruption Frequency Index (SAIFI), including major events, for Kentucky Power Company customers during calendar 2000 was 1.435 interruptions.

Both of these indices are better than the 1995-1998 averages for these customers. This is mainly due to the fact that major events had only a small contribution to the overall reliability indices in calendar 2000.

WITNESS: Errol K. Wagner

16

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2000. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE:

A summary of AEP's Call Center Performance Measures for Kentucky customer calls in calendar year 2000:

Measure	Value
Average Speed of answer	30.72 seconds
Abandonment	3.24%
Network Blockage	.33%

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2000.[Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE:

Note: This is not a new reporting requirement – the Company has been conducting inspections and making necessary improvements for years.

In calendar 2000, American Electric Power performed the work necessary to completely inspect its Kentucky electric facilities over the past two years. AEP continue to perform tree trimming, lightning arrester replacement, animal guarding, and pole and crossarm replacements as needed.

AEP provides the following statistics for work done in its Kentucky service territory in 2000:

- Performed walking inspections of approximately 76,573 poles as part of the program to inspect facilities every two years. Equipment was repaired or replaced as necessary.
- Inspected 13,175 poles as part of the ground-line treatment program. Poles were replaced or refurbished as necessary.
- Completed right-of-way clearing work o 869 miles of distribution line.

AEP continues its asset management programs to review the performance of its facilities and to make prudent improvements to continue providing reliable and cost-effective electric service to it Kentucky customers.

WITNESS: Errol K. Wagner

18

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impact of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages. [Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE:

AEP-Ky continues to compile outage data detailing each circuit's reliability performance. Worst performing circuits are identified considering CAIDI SAIFI, and repeat outages, as well as those with outage causes that can be addressed through newly created asset improvement programs targeting animal, lightning, small conductor failure, and tree caused outages. This allows for the identification of areas needing reliability improvements and for the development of work plans to optimize system performance.

Work plans are developed by, combining reliability performance with input from field personnel to identify area that do not satisfy ranking criteria alone. Work plans include ground line treatment of poles; improved faulty isolation by installing additional sectionalizing devices; recloser maintenance; and system improvements required due to facility loading, voltage control, and reliability performance.

WITNESS: Errol K. Wagner

19

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE:

The Company has maintained a high quality workforce which met the customers needs in providing electrical service.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall designate an employee who will act as a contact for State Commissions and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by a State Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s) subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE:

The Kentucky Regulatory Services Director is the contact for the Kentucky State Commissioners and staff and the Kentucky Attorney General's Office seeking the above requested information.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE:

The Company would like customers to first call the company's Call Centers for answers to the above requested information. However, the Regulatory Services Department and the Regulatory Service Director specifically are able to deal with billing, maintenance and service reliability issues.

WITNESS: Errol K. Wagner

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Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE:

The Kentucky State Regulatory Services Director and staff are the designated employees to work with Kentucky Public Service Commission and the Kentucky Attorney General's Office concerning state regulatory matters, including, but not limited to rate cases, consumer complaints, billing and retail competition issues.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST: The company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers. [Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE:

The Company has maintained a sufficient management team in Kentucky to ensure that safe, reliable and efficient electric service is provided and the Company has responded to the needs and inquires of its customers.

WITNESS: Errol K. Wagner

SECURITIES AND EXCHANGE C

WASHINGTON, D. C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2000

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________ to ____________

Commission File Number	Registrant; State of Incorporation; Address and Telephone Number	I.R.S. Employer Identification No.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 223-1000	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 223-1000	31-1033833
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation) 40 Franklin Road, Roanoke, Virginia 24011 Telephone (540) 985-2300	54-0124790
0-346	CENTRAL POWER AND LIGHT COMPANY (A Texas Corporation) 539 North Carancahua Street, Corpus Christi, Texas 78401-2802 Telephone (361) 881-5300	74-0550600
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 223-1000	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation) One Summit Square, P. O. Box 60, Fort Wayne, Indiana 46801 Telephone (219) 425-2111	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation) 1701 Central Avenue, Ashland, Kentucky 41101 Telephone (800) 572-1141	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation) 301 Cleveland Avenue, S.W., Canton, Ohio 44701 Telephone (330) 456-8173	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation) 212 East 6th Street, Tulsa, Oklahoma 74119-1212 Telephone (918) 599-2000	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation) 428 Travis Street, Shreveport, Louisiana 71156-0001 Telephone (318) 673-3000	72-0323455
0-340	WEST TEXAS UTILITIES COMPANY (A Texas Corporation) 301 Cypress Street, Abilene, Texas 79601-5820 Telephone (915) 674-7000	75-0646790

AEP Generating Company, Columbus Southern Power Company, Kentucky Power Company, Public Service Company of Oklahoma and West Texas Utilities Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of each exchange on which registered
AEP Generating Company	None	
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	4-1/2% Cumulative Preferred Stock, Voting, no par value	Philadelphia Stock Exchange
	8-1/4% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026	New York Stock Exchange
	8% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027	New York Stock Exchange
	7.20% Senior Notes, Series A, Due 2038	New York Stock Exchange
	7.30% Senior Notes, Series B, Due 2038	New York Stock Exchange
Columbus Southern Power Company	8-3/8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New York Stock Exchange
	7.92% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2027	New York Stock Exchange
CPL Capital I	8.00% Cumulative Quarterly Income Preferred Securities, Series A, Liquidation Preference $25 per Preferred Security	New York Stock Exchange
Indiana Michigan Power Company	8% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2026	New York Stock Exchange
	7.60% Junior Subordinated Deferrable Interest Debentures, Series B, Due 2038	New York Stock Exchange
Kentucky Power Company	8.72% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New York Stock Exchange
Ohio Power Company	8.16% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New York Stock Exchange
	7.92% Junior Subordinated Deferrable Interest Debentures Series B, Due 2027	New York Stock Exchange
	7 3/8% Senior Notes, Series A, Due 2038	New York Stock Exchange
PSO Capital I	8.00% Trust Originated Preferred Securities, Series A, Liquidation Preference $25 per Preferred Security	New York Stock Exchange
SWEPCo Capital I	7.875% Trust Preferred Securities, Series A, Liquidation amount $25 per Preferred Security	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of each class
AEP Generating Company	None
American Electric Power Company, Inc.	None
Appalachian Power Company	None
Central Power and Light Company	4.00% Cumulative Preferred Stock, Non-Voting, $100 par value
	4.20% Cumulative Preferred Stock, Non-Voting, $100 par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	4-1/8% Cumulative Preferred Stock, Non-Voting, $100 par value
Kentucky Power Company	None
Ohio Power Company	4-1/2% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Non-Voting, $100 par value
	4.65% Cumulative Preferred Stock, Non-Voting, $100 par value
	5.00% Cumulative Preferred Stock, Non-Voting, $100 par value
West Texas Utilities Company	None

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants at February 1, 2001	Number of shares of common stock outstanding of the registrants at February 1, 2001
AEP Generating Company	None	1,000 ($1,000 par value)
American Electric Power Company, Inc.	$13,853,503,196	322,024,714 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Central Power and Light Company	None	6,755,535 ($25 par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)
West Texas Utilities Company	None	5,488,560 ($25 par value)

NOTE ON MARKET VALUE OF COMMON EQUITY HELD BY NON-AFFILIATES

American Electric Power Company, Inc. owns all of the common stock of AEP Generating Company, Appalachian Power Company, Central Power and Light Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company (see Item 12 herein).

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ✓. No.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ✓

DOCUMENTS INCORPORATED BY REFERENCE

Description	Part of Form 10-K Into Which Document Is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2000: AEP Generating Company American Electric Power Company, Inc. Appalachian Power Company Central Power and Light Company Columbus Southern Power Company Indiana Michigan Power Company Kentucky Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company West Texas Utilities Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2001 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2000	Part III
Portions of Information Statements of the following companies for 2001 Annual Meeting of Shareholders, to be filed within 120 days after December 31, 2000 Appalachian Power Company Ohio Power Company	Part III

This combined Form 10-K is separately filed by AEP Generating Company, American Electric Power Company, Inc., Appalachian Power Company, Central Power and Light Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AFUDC	Allowance for funds used during construction. Defined in regulatory systems of accounts as the net cost of borrowed funds used for construction and a reasonable rate of return on other funds when so used.
APCo	Appalachian Power Company, an electric utility subsidiary of AEP.
Btu	British thermal unit.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
C3	C3 Communications, Inc.
CAA	Clean Air Act.
CAAA	Clean Air Act Amendments of 1990.
CCD Group	CSPCo, CG&E and DP&L.
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CG&E	The Cincinnati Gas & Electric Company, an unaffiliated utility company.
CO_2	Carbon dioxide.
Cook Plant	The Donald C. Cook Nuclear Plant, owned by I&M, located near Bridgman, Michigan.
CPL	Central Power and Light Company, an electric utility subsidiary of AEP.
CSPCo	Columbus Southern Power Company, an electric utility subsidiary of AEP.
CSW	Central and South West Corporation.
DOE	United States Department of Energy.
DP&L	The Dayton Power and Light Company, an unaffiliated utility company.
East Zone Companies of AEP	APCo, CSPCo, I&M, KEPCo and OPCo.
EWG	Exempt wholesale generator.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission (an independent commission within the DOE).
FUCO	Foreign utility company as defined by PUHCA.
I&M	Indiana Michigan Power Company, an electric utility subsidiary of AEP.
IURC	Indiana Utility Regulatory Commission.
KEPCo	Kentucky Power Company, an electric utility subsidiary of AEP.
NO_x	Nitrogen oxide.
NPDES	National Pollutant Discharge Elimination System.
NRC	Nuclear Regulatory Commission.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an electric utility subsidiary of AEP.
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated biphenyls.
PSO	Public Service Company of Oklahoma, an electric utility subsidiary of AEP.
PUCO	The Public Utilities Commission of Ohio.

Abbreviation or Acronym	Definition
PUHCA	Public Utility Holding Company Act of 1935, as amended.
QF	Qualifying facility as defined in the Public Utility Regulatory Policies Act of 1978.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Rockport Plant	A generating plant, consisting of two 1,300,000-kilowatt coal-fired generating units, near Rockport, Indiana.
SEC	Securities and Exchange Commission.
SEEBOARD	SEEBOARD Group plc, Crawley, West Sussex, United Kingdom.
Service Corporation	American Electric Power Service Corporation, a service subsidiary of AEP.
SO_2	Sulfur dioxide.
SO_2 Allowance	An allowance to emit one ton of sulfur dioxide granted under the Clean Air Act Amendments of 1990.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by CPL, located near Bay City, Texas.
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including CPL.
SWEPCo	Southwestern Electric Power Company, an electric utility subsidiary of AEP.
TVA	Tennessee Valley Authority.
Vale	Empresa De Electricidade Vale Paranapanema SA, a Brazilian Electric Distribution Company.
VEPCo	Virginia Electric and Power Company, an unaffiliated utility company.
Virginia SCC	Virginia State Corporation Commission.
West Virginia PSC	Public Service Commission of West Virginia.
West Zone Companies of AEP	CPL, PSO, SWEPCo and WTU.
WTU	West Texas Utilities Company, an electric utility subsidiary of AEP.
Zimmer or Zimmer Plant	Wm. H. Zimmer Generating Station, commonly owned by CSPCo, CG&E and DP&L.

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its subsidiaries includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward-looking statements are:

- Electric load and customer growth.
- Abnormal weather conditions.
- Available sources of and prices for coal and gas.
- Availability of generating capacity.
- The impact of the merger with CSW, including the ability of the combined companies to realize the synergies expected as a result of the combination.
- The timing of the implementation of AEP's restructuring plan.
- Risks related to energy trading and construction under contract.
- The speed and degree to which competition is introduced to our power generation business.
- The structure and timing of a competitive market for electricity and its impact on prices.
- The ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states.
- New legislation and government regulations.
- The ability of AEP to successfully control its costs.
- The success of new business ventures.
- International developments affecting AEP's foreign investments.
- The effects of fluctuations in foreign currency exchange rates.
- The economic climate and growth in AEP's service and trading territories, both domestic and foreign.
- The ability of AEP to comply with or to challenge successfully new environmental regulations and to litigate successfully claims that AEP violated the CAA.
- Inflationary trends.
- Changes in electricity and gas market prices.
- Successful resolution of litigation regarding municipal franchise fees in Texas.
- Successful appeal of decision in connection with COLI litigation.
- Interest rates.
- Other risks and unforeseen events.

PART I

Item 1. **Business**

General

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company which owns, directly or indirectly, all of the outstanding common stock of its domestic electric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. In addition, in recent years AEP has been pursuing various unregulated business opportunities worldwide as discussed in *New Business Development.*

The service area of AEP's domestic electric utility subsidiaries covers portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's subsidiaries are physically interconnected, and their operations are coordinated, as a single integrated electric utility system. Transmission networks are interconnected with extensive distribution facilities in the territories served. The electric utility subsidiaries of AEP, which do business as "American Electric Power," have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers.

At December 31, 2000, the subsidiaries of AEP had a total of 26,376 employees. AEP, as such, has no employees. The operating subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 909,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying electric power at wholesale to other electric utility companies and municipalities in those states and in Tennessee. At December 31, 2000, APCo and its wholly owned subsidiaries had 2,846 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and VEPCo. A comparatively small part of the properties and business of APCo is located in the northeastern end of the Tennessee Valley. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems.

CPL (organized in Texas in 1945) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 680,000 customers in southern Texas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2000, CPL had 1,444 employees. Among the principal industries served by CPL are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 668,000 customers in Ohio, and in supplying electric power at wholesale to other electric utilities and to municipally owned distribution systems within its service area. At December 31, 2000, CSPCo had 1,264 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Approximately 80% of CSPCo's retail revenues are derived from the Columbus area. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP

System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company.

I&M (organized in Indiana in 1925) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 565,000 customers in northern and eastern Indiana and southwestern Michigan, and in supplying electric power at wholesale to other electric utility companies, rural electric cooperatives and municipalities. At December 31, 2000, I&M had 2,965 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company.

KEPCo (organized in Kentucky in 1919) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 172,000 customers in an area in eastern Kentucky, and in supplying electric power at wholesale to other utilities and municipalities in Kentucky. At December 31, 2000, KEPCo had 451 employees. In addition to its AEP System interconnections, KEPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KEPCo is also interconnected with TVA.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 45,000 customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from APCo. At December 31, 2000, Kingsport Power Company had 62 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 696,000 customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying electric power at wholesale to other electric utility companies and municipalities. At December 31, 2000, OPCo and its wholly owned subsidiaries had 3,532 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company.

PSO (organized in Oklahoma in 1913) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 499,000 customers in eastern and southwestern Oklahoma, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2000, PSO had 1,005 employees. Among the principal industries served by PSO are natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications, and rubber goods.

SWEPCo (organized in Oklahoma in 1912) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 428,000 customers in northeastern Texas, northwestern Louisiana, and western Arkansas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2000, SWEPCo had 1,243 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges, and universities.

Wheeling Power Company (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 42,000 customers in northern West Virginia. Wheeling Power Company has no generating facilities of its own. It purchases electric power distributed to its customers from OPCo. At December 31, 2000, Wheeling Power Company had 75 employees.

WTU (organized in Texas in 1927) is engaged in the generation, sale, purchase, transmission and distribution of electric power to approximately 190,000 customers in west and central Texas, and in supplying electric power at wholesale to other utilities, municipalities and rural electric cooperatives. At December 31, 2000, WTU had 718 employees. The principal industry served by WTU is agriculture. The territory served by WTU also includes several military installations and correctional facilities.

Another principal electric utility subsidiary of AEP is AEGCo, which was organized in Ohio in 1982 as an electric generating company. AEGCo sells power at wholesale to I&M and KEPCo. AEGCo has no employees.

See Item 2 for information concerning the properties of the subsidiaries of AEP.

The Service Corporation provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP System companies. The executive officers of AEP and its public utility subsidiaries are all employees of the Service Corporation.

The AEP System is an integrated electric utility system and, as a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity, transportation and handling of fuel, sales or rentals of property and interest or dividend payments on the securities held by the companies' respective parents.

AEP-CSW Merger

On June 15, 2000, CSW merged with and into a wholly owned merger subsidiary of AEP with CSW being the surviving corporation. The merger was pursuant to an Agreement and Plan of Merger, dated as of December 21, 1997, that AEP and CSW had entered into. As a result of the merger, each outstanding share of common stock, par value $3.50 per share, of CSW (other than shares owned by AEP or CSW) was converted into 0.6 of a share of common stock, par value $6.50 per share, of AEP.

CSW's four wholly-owned domestic electric utility subsidiaries are CPL, PSO, SWEPCo and WTU. CSW also has the following principal subsidiaries: CSW International, CSW Energy, SEEBOARD, AEP Credit, Inc., C3 and CSW Energy Services, Inc.

AEP intends to comply with the following conditions imposed by the FERC as part of the FERC's order approving the merger:

- Transfer operational control of AEP's east and west transmission systems to fully-functioning, FERC-approved regional transmission organizations by December 15, 2001. See *Transmission Services for Non-Affiliates.*

- Two interim transmission-related mitigation measures consisting of market monitoring and independent calculation and posting of available transmission capacity to monitor the operation of AEP's east transmission system.

- Divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in the Southwest Power Pool (SPP) and 250 MW of capacity in the Electric Reliability Council of Texas (ERCOT). AEP must complete divestiture of the SPP capacity by

July 1, 2002. AEP has completed divestiture of the ERCOT capacity.

The FERC found that certain energy sales of SPP and ERCOT capacity would be reasonable and effective interim mitigation measures until completion of the required SPP and ERCOT divestitures. As required by the FERC, the proposed interim energy sales were in effect when the merger was consummated.

Regulation

General

AEP and its subsidiaries are subject to the broad regulatory provisions of PUHCA administered by the SEC. The public utility subsidiaries' retail rates and certain other matters are subject to regulation by the public utility commissions of the states in which they operate. Such subsidiaries are also subject to regulation by the FERC under the Federal Power Act in respect of rates for interstate sale at wholesale and transmission of electric power, accounting and other matters and construction and operation of hydroelectric projects. I&M and CPL are subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant and STP, respectively.

Possible Change to PUHCA

The provisions of PUHCA, administered by the SEC, regulate all aspects of a registered holding company system, such as the AEP System. PUHCA requires that the operations of a registered holding company system be limited to a single integrated public utility system and such other businesses as are incidental or necessary to the operations of the system. In addition, PUHCA governs, among other things, financings, sales or acquisitions of assets and intra-system transactions.

On June 20, 1995, the SEC released a report from its Division of Investment Management recommending a conditional repeal of PUHCA, including its limits on financing and on geographic and business diversification. Specific federal authority, however, would be preserved over access to the books and records of registered holding company systems, audit authority over registered holding companies and their subsidiaries and oversight over affiliate transactions. This authority would be transferred to the FERC. Following the report, legislation was introduced in Congress to repeal PUHCA and transfer certain federal authority to the FERC as recommended in the SEC report. Since 1997, such PUHCA repeal language has been part of broader legislation regarding changes in the electric industry. Such legislation, both as a separate bill and as part of broader electricity restructuring legislation, was reintroduced in 1999 and 2000. Legislative hearings were held but no PUHCA repeal legislation was passed by either the House of Representatives or Senate. It is expected that a number of bills contemplating PUHCA repeal separately and the restructuring of the electric utility industry will be introduced in the current Congress. See *Competition and Business Change.* If PUHCA is repealed, registered holding company systems, including the AEP System, will be able to compete in the changing industry without the constraints of PUHCA. Management of AEP believes that removal of these constraints would be beneficial to the AEP System.

PUHCA and the rules and orders of the SEC currently require that transactions between associated companies in a registered holding company system be performed at cost with limited exceptions. Over the years, the AEP System has developed numerous affiliated service, sales and construction relationships and, in some cases, invested significant capital and developed significant operations in reliance upon the ability to recover its full costs under these provisions.

Legislation has been introduced in Congress to repeal PUHCA or modify its provisions governing intra-system transactions. The effect of repeal or amendment of PUHCA on AEP's intra-system transactions depends on whether the assurance of full cost recovery is eliminated immediately or phased in and whether it is eliminated for all intra-system transactions or only some. If the cost recovery assurance is eliminated immediately for all intra-system transactions, it could have a material adverse effect on results of operations and financial condition of AEP and OPCo. Current legislation grandfathers transactions legally authorized on the effective date of PUHCA repeal.

Conflict of Regulation

Public utility subsidiaries of AEP can be subject to regulation of the same subject matter by two or more jurisdictions. In such situations, it is possible that the decisions of such regulatory bodies may conflict or that the decision of one such body may affect the cost of providing service, and so the rates, in another jurisdiction. In a case involving OPCo, the U.S. Court of Appeals for the District of Columbia held that the determination of costs to be charged to associated companies by the SEC under PUHCA precluded the FERC from determining that such costs were unreasonable for ratemaking purposes. The U.S. Supreme Court also has held that a state commission may not conclude that a FERC approved wholesale power agreement is unreasonable for state ratemaking purposes. Certain actions that would overturn these decisions or otherwise affect the jurisdiction of the SEC and FERC are under consideration by the U.S. Congress and these regulatory bodies. Such conflicts of jurisdiction often result in litigation and, if resolved adversely to a public utility subsidiary of AEP, could have a material adverse effect on the results of operations or financial condition of such subsidiary or AEP.

Classes of Service

The principal classes of service from which the domestic electric utility subsidiaries of AEP derive revenues and the amount of such revenues (from kilowatt-hour sales) during the year ended December 31, 2000 are as follows:

	AEP System(a)	AEGCo	APCo (in thousands)	CPL	CSPCo
Retail					
Residential	$ 3,517,058	$ 0	$ 593,636	$ 651,580	$ 473,986
Commercial	2,451,068	0	310,478	460,433	434,785
Industrial	2,443,750	0	362,303	370,161	145,326
Miscellaneous	213,620	0	37,070	49,204	18,176
Total Retail	8,625,496	0	1,303,487	1,531,378	1,072,273
Wholesale (sales for resale)	1,795,041	228,304	506,365	140,671	243,827
Total from KWH Sales	10,420,537	228,304	1,809,852	1,672,049	1,316,100
Other Operating Revenues and Refunds	406,895	212	54,135	99,128	42,250
Total Electric Operating Revenues	$ 10,827,432	$ 228,516	$ 1,863,987	$ 1,771,177	$ 1,358,350

	I&M	KEPCo	OPCo (in thousands)	PSO	SWEPCo	WTU
Retail						
Residential	$ 340,484	$ 112,707	$ 429,491	$ 361,853	$ 328,873	$ 164,973
Commercial	269,650	62,431	278,224	278,940	219,318	97,583
Industrial	334,622	93,111	548,599	198,498	273,430	65,517
Miscellaneous	6,689	950	8,426	11,372	31,782	46,060
Total Retail	951,445	269,199	1,264,740	850,663	853,403	374,133
Wholesale (sales for resale)	557,235	120,482	894,253	93,993	240,792	150,986
Total from KWH Sales	1,508,680	389,681	2,158,993	944,656	1,094,195	525,119
Other Operating Revenues and Refunds	41,907	20,722	80,638	17,953	30,015	47,675
Total Electric Operating Revenues	$ 1,550,587	$ 410,403	$ 2,239,631	$ 962,609	$ 1,124,210	$ 572,794

(a) Includes revenues of other subsidiaries not shown and elimination of intercompany transactions.

Sale of Power

AEP's electric utility subsidiaries own or lease generating stations with total generating capacity of 38,033 megawatts. See Item 2 for more information regarding the generating stations. They operate their generating plants as a single interconnected and coordinated electric utility system and, in the east zone, share the costs and benefits in the AEP System Power Pool. Most of the electric power generated at these stations is sold, in combination with transmission and distribution services, to retail customers of AEP's utility subsidiaries in their service territories. These sales are made at rates that are established by the public utility commissions of the state in which they operate. See *Rates and*

Regulation. Some of the electric power is sold at wholesale to non-affiliated companies.

AEP System Power Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KEPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO_2 Allowances associated with transactions under the Interconnection Agreement.

Power marketing and trading transactions (trading activities) are conducted by the AEP Power Pool and shared among the parties under the Interconnection Agreement. Trading activities involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. The regulated physical forward contracts are recorded on a net basis in the month when the contract settles.

In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

The following table shows the net credits or (charges) allocated among the parties under the Interconnection Agreement and Interim Allowance Agreement during the years ended December 31, 1998, 1999 and 2000:

	1998(a)	1999(a)	2000(a)
		(in thousands)	
APCo	$(142,500)	$(89,100)	$(274,000)
CSPCo	(146,800)	(184,500)	(250,400)
I&M	(86,100)	(61,700)	93,900
KEPCo	34,000	23,700	(21,500)
OPCo	341,400	311,600	452,000

(a) Includes credits and charges from allowance transfers related to the transactions.

CPL, PSO, SWEPCo, WTU, and AEP Service Corporation are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the operating companies of the west zone to maintain specified annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP subsidiaries as capacity commitments. The CSW Operating Agreement also delegates to AEP Service Corporation the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. The CSW Operating Agreement has been accepted for filing and allowed to become effective by the FERC.

Wholesale Sales of Power to Non-Affiliates

AEP's electric utility subsidiaries also sell electric power on a wholesale basis to non-affiliated electric utilities and power marketers. Such sales are either made by the AEP System Power Pool and then allocated among APCo, CSPCo, I&M, KEPCo and OPCo based on member-load-ratios or made by individual companies pursuant to various long-term power agreements.

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* that is incorporated by reference in Item 8 for information with respect to AEP's long-term agreements to sell power.

Transmission Services

AEP's electric utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 for more information regarding the transmission and distribution lines. AEP's electric utility subsidiaries operate their transmission lines as a single interconnected and coordinated system and share the cost and benefits in the AEP System Transmission Pool. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's utility subsidiaries in their service territories. These sales are made at rates that are established by the public utility commissions of the state in which they operate. See *Rates and Regulation*. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP System Transmission Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kv and above) and certain facilities operated at lower voltages (138 kv and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio." See *Sale of Power*.

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 1998, 1999 and 2000:

	1998	1999	2000
		(in thousands)	
APCo	$(2,400)	$(8,300)	$(3,400)
CSPCo	35,600	39,000	38,300
I&M	(44,100)	(43,900)	(43,800)
KEPCo	(6,000)	(4,300)	(6,000)
OPCo	16,900	17,500	14,900

CPL, PSO, SWEPCo, WTU, and AEP Service Corporation are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA establishes a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEP Service Corporation the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT. The TCA has been accepted for filing by the FERC effective as of January 1, 1997, and is the subject of proceedings commenced to consider the reasonableness of its terms and conditions.

Transmission Services for Non-Affiliates

AEP's electric utility subsidiaries and other System companies also provide transmission services for non-affiliated companies.

On April 24, 1996, the FERC issued orders 888 and 889. These orders require each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also require utilities to functionally unbundle their services, by requiring them to use their own tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a *pro-forma* tariff which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. In addition, the orders require all transmitting utilities to establish an Open Access Same-time Information System (OASIS) which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct which prohibit utilities' system operators from providing non-public transmission information to the utility's merchant employees. The orders also allow a utility to seek recovery of certain prudently-incurred stranded costs that result from unbundled transmission service.

In December 1999, FERC issued Order 2000, which provides for the voluntary formation of regional transmission organizations (RTOs), entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals.

On July 9, 1996, the AEP System companies filed a tariff conforming with the FERC's *pro-forma* transmission tariff.

During 1998 and 1999 AEP engaged in discussions with Consumers Energy Company, FirstEnergy Corp., Detroit Edison Company and VEPCo regarding the development of the Alliance RTO which may take the form of an ISO or an independent transmission company (Transco), depending upon the occurrence of certain conditions. The Transco, if formed, would operate transmission assets that it would own, and also would operate other owners' transmission assets on a contractual basis. In 1999, these companies filed with the FERC a proposal to form the RTO. In December 1999, the FERC approved the Alliance RTO, conditioned upon certain changes to the proposal relating to governance of the RTO, resolution of intra-RTO conflicts and establishment of a rate structure. On January 24, 2001, the FERC approved the compliance filing made by the Alliance RTO in September 2000 and generally accepted the responses to the changes proposed in the December 1999 FERC order. The January 2001 FERC order also directed the Alliance companies to file their actual rates no later than 120 days prior to the commencement of operations by the Alliance RTO.

Coordination of East and West Zone Operating Subsidiaries

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone.

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone operating subsidiaries. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

OVEC

AEP, CSPCo and several unaffiliated utility companies jointly own OVEC, which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio, owned by the DOE. The aggregate equity participation of AEP and CSPCo in OVEC is 44.2%. The DOE demand under OVEC's power agreement, which is subject to change from time to time, is 800,000 kilowatts. On April 1, 2001, it is scheduled to decrease to approximately 600,000 kilowatts. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. APCo, CSPCo, I&M and OPCo, as sponsoring companies, are entitled to receive from OVEC, and are obligated to pay for, the power not required by DOE, which averaged 42.1% in 2000. On September 29, 2000, DOE issued a notice of cancellation of the power agreement. DOE will therefore not be entitled to any OVEC capacity beyond August 31, 2001. The sponsoring companies will be entitled to all OVEC capacity in proportion to their power participation ratios (approximately 2,200MW) beginning September 1, 2001.

Buckeye

Contractual arrangements among OPCo, Buckeye and other investor-owned electric utility companies in Ohio provide for the transmission and delivery, over facilities of OPCo and of other investor-owned utility companies, of power generated by the two units at the Cardinal Station owned by Buckeye and back-up power to which Buckeye is entitled from OPCo under such contractual arrangements, to facilities owned by 25 of the rural electric cooperatives which operate in the State of Ohio at 331 delivery points. Buckeye is entitled under such arrangements to receive, and is obligated to pay for, the excess of its maximum one-hour coincident peak demand plus a 15% reserve margin over the 1,226,500 kilowatts of capacity of the generating units which Buckeye currently owns in the Cardinal Station. Such demand, which occurred on December 22, 2000, was recorded at 1,304,134 kilowatts.

In January 2000, OPCo and National Power Cooperative, Inc. (NPC), an affiliate of Buckeye, entered into an agreement, subject to specified conditions, relating to construction and operation of a 510 mw gas-fired electric generating peaking facility to be owned by NPC. From the commercial operation date (expected in early 2002) until the end of 2005, OPCo will be entitled to the power generated by the facility, and responsible for the fuel and other costs of the facility. After 2005, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the facility, and both parties will generally be responsible for the fuel and other costs of the facility. OPCo will also provide certain back-up power to NPC. AEP Pro Serv, Inc. will provide engineering, procurement and construction for the facility.

Certain Industrial Customers

Century Aluminum of West Virginia, Inc. (formerly Ravenswood Aluminum Corporation), operates a major aluminum reduction plant in the Ohio River Valley at Ravenswood, West Virginia. The power requirement of such plant presently is approximately 357,000 kilowatts. OPCo is providing electric service pursuant to a contract approved by the PUCO for the period July 1, 1996 through July 31, 2003.

AEGCo

Since its formation in 1982, AEGCo's business has consisted of the ownership and financing of its 50% interest in the Rockport Plant and, since 1989, leasing of its 50% interest in Unit 2 of the Rockport Plant. The operating revenues of AEGCo are derived from the sale of capacity and energy associated with its interest in the Rockport Plant to I&M and KEPCo pursuant to unit power agreements. Pursuant to these unit power agreements, AEGCo is entitled to recover its full cost of service from the purchasers and will be entitled to recover future increases in such costs, including increases in fuel and capital costs. See *Unit Power Agreements*. Pursuant to a capital funds agreement, AEP has agreed to provide cash capital contributions, or in certain circumstances subordinated loans, to AEGCo, to the extent necessary to enable AEGCo, among other things, to provide its proportionate share of funds required to permit continuation of the commercial operation of the Rockport Plant and to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party. See *Capital Funds Agreement.*

Unit Power Agreements

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the date that the last of the lease terms of Unit 2 of the Rockport Plant has expired unless extended in specified circumstances.

Pursuant to an assignment between I&M and KEPCo, and a unit power agreement between KEPCo and AEGCo, AEGCo sells KEPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KEPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KEPCo unit power agreement expires on December 31, 2004.

Capital Funds Agreement

AEGCo and AEP have entered into a capital funds agreement pursuant to which, among other things, AEP has unconditionally agreed to make cash capital contributions, or in certain circumstances subordinated loans, to AEGCo to the extent necessary to enable AEGCo to (i) maintain such an equity component of capitalization as required by governmental regulatory authorities, (ii) provide its proportionate share of the funds required to permit commercial operation of the Rockport Plant, (iii) enable AEGCo to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party (AEGCo Agreements), and (iv) pay all indebtedness, obligations and liabilities of AEGCo (AEGCo Obligations) under the AEGCo Agreements, other than indebtedness, obligations or liabilities owing to AEP. The Capital Funds Agreement will terminate after all AEGCo Obligations have been paid in full.

Seasonality

Sales of electricity by the AEP System tend to increase and decrease because of the use of electricity by residential and commercial customers for cooling and heating and relative changes in temperature.

Franchises

The operating companies of the AEP System hold franchises to provide electric service in various municipalities in their service areas. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

Competition and Business Change

General

The public utility subsidiaries of AEP, like many other electric utilities, have traditionally provided electric generation and energy delivery, consisting of transmission and distribution services, as a single product to their retail customers. Proposals are being made and legislation has been enacted in Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia and West Virginia that would also require electric utilities to sell distribution services separately. These measures generally allow competition in the generation and sale of electric power, but not in its transmission and distribution.

Competition in the generation and sale of electric power will require resolution of complex issues, including who will pay for the unused generating plant of, and other stranded costs incurred by, the utility when a customer stops buying power from the utility; will all customers have access to the benefits of competition; how will the rules of competition be established; what will happen to conservation and other regulatory-imposed programs; how will the reliability of the transmission system be ensured; and how will the utility's obligation to serve be changed. As competition in generation and sale of electric power is instituted, the public utility subsidiaries of AEP believe that they have a favorable competitive position because of their relatively low costs. If stranded costs are not recovered from customers, however, the public utility subsidiaries of AEP, like all electric utilities, will be required by existing accounting standards to recognize any stranded investment losses.

Reference is made to *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* and the footnote to the financial statements entitled *Industry Restructuring* incorporated by reference in Items 7 and 8, respectively, for further information with respect to competition and business change.

AEP Position on Competition

AEP favors freedom for customers to purchase electric power from anyone that they choose. Generation and sale of electric power would be in the competitive marketplace. To facilitate reliable, safe and efficient service, AEP supports creation of independent system operators to operate the transmission system in a region of the United States. AEP's working model for industry restructuring envisions a progressive transition to full customer choice. Implementation of these measures would require legislative changes and regulatory approvals.

The legislatures and/or the regulatory commissions in many states, including some in AEP's service territory, are considering or have adopted "retail customer choice" which, in general terms, means the transmission by an electric utility of electric power generated by an entity of the customer's choice over its transmission and distribution system to a retail customer in such utility's service territory. A requirement to transmit directly to retail customers would have the result of permitting retail customers to purchase electric power, at the election of such customers, not only from the electric utility in whose service area they are located but from another electric utility, an independent power producer or an intermediary, such as a power marketer. Although AEP's power generation would have competitors under some of these proposals, its transmission and distribution would not. If competition develops in retail power generation, the public utility subsidiaries of AEP believe that they should have a favorable competitive position because of their relatively low costs.

Legislation to provide for retail competition among electric energy suppliers has been introduced in both the U.S. Senate and House of Representatives.

Wholesale

The public utility subsidiaries of AEP, like the electric industry generally, face increasing competition to sell available power on a wholesale basis, primarily to other public utilities and also to power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market (a) through amendments to PUHCA, facilitating the ownership and operation of generating facilities by "exempt wholesale generators" (which may include independent power producers as well as affiliates of electric utilities) and (b) through amendments to the Federal Power Act, authorizing the FERC under certain conditions to order utilities which own transmission facilities to provide wholesale transmission services for other utilities and entities generating electric power. The principal factors in competing for such sales are price (including fuel costs), availability of capacity and reliability of service. The public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. However, because of the availability of capacity of other utilities and the lower fuel prices in recent years, price competition has been, and is expected for the next few years to be, particularly important.

FERC orders 888 and 889, issued in April 1996, provide that utilities must functionally unbundle their transmission services, by requiring them to use their own tariffs in making off-system and third-party sales. See *Transmission Services.* The public utility subsidiaries of AEP have functionally separated their wholesale power sales from their transmission functions, as required by orders 888 and 889.

Retail

The public utility subsidiaries of AEP generally (except in Ohio) have the exclusive right to sell electric power at retail within their service areas, with the exception of Virginia and Texas beginning in 2002 and Ohio. However, they do compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to self-generation, the public utility subsidiaries of AEP believe that they maintain a favorable competitive position on the basis of all of these factors. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy in recent years have led to increased price competition for industrial companies in the United States, including those served by the AEP System. Such industrial companies have requested price reductions from their suppliers, including their suppliers of electric power. In addition, industrial companies which are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, various off-peak or interruptible supply options and believe that, as low cost suppliers of electric power, they should be less likely to be materially adversely affected by this competition and may be benefited by attracting new industrial customers to their service territories.

AEP Restructuring Plan

As a result of deregulating legislation that has been enacted or is being considered in most of the states in which the AEP public utility subsidiaries provide service, AEP has reassessed the corporate ownership of its public utility subsidiaries' assets. Deregulating legislation in some of the states requires the separation of generation assets from transmission and distribution assets. On November 1, 2000, AEP filed with the SEC under PUHCA for approval of a restructuring plan in part to meet the requirements of this legislation.

AEP's restructuring plan is designed to align its legal structure and business activities with the requirements of deregulation. AEP's plan contemplates the formation of two first tier subsidiaries that would hold the following public utility assets:

- A subsidiary would hold the assets of (i) public utility subsidiaries that remain subject to regulation by at least one state utility commission and (ii) foreign utility subsidiaries subject to regulation as to rates or tariffs. AEP intends for this subsidiary ultimately to hold all transmission and distribution assets.

- A subsidiary would hold public utility and non-utility subsidiaries that derive their revenues from competitive activity. AEP intends for this subsidiary to ultimately hold all generation assets not subject to regulation.

New Business Development

AEP has expanded its business to non-regulated energy activities through several subsidiaries, including AEP Energy Services, Inc. (AEPES), AEP Resources, Inc. (Resources), AEP Pro Serv, Inc. (formerly AEP Resources Service Company) (Pro Serv) and AEP Communications, LLC (AEP Communications).

Wholesale Business Operations

Various AEP subsidiaries, including AEPES, engage in wholesale business operations that focus primarily upon the following activities:

- Trade and market energy commodities, including electric power, natural gas, natural gas liquids, oil, coal, and SO_2 allowances in North America and Europe.

- Provide price-risk management services and liquidity through a variety of energy-related financial instruments, including exchange-traded futures and over-the-counter forward, option, and swap agreements.

- Enter into long-term transactions to buy or sell capacity, energy, and ancillary services of electric generating facilities, either existing or to be constructed, at various locations in North America and Europe.

- Optimize trading and marketing through a diversified portfolio of owned assets and structured third party arrangements, including:

  - Power generation facilities.

  - Natural gas pipeline, storage and processing facilities.

  - Coal mines and related facilities.

  - Other transportation and fuel supply related assets.

- Acquire, develop, engineer, construct, operate and maintain owned and third party exempt wholesale generation and cogeneration facilities and ancillary energy-related assets.

AEP's subsidiaries are engaged in the engineering and construction for third parties of three power plants in the U. S. with a capacity of 1,910 MW. These plants, which are listed below, will be natural gas-fired facilities that are scheduled to be completed from 2001 to 2003. These projects synchronize the wholesale business through the integration of trading, marketing, engineering, construction and operations.

- AEP subsidiaries reached agreement with The Dow Chemical Company to construct a 900MW cogeneration facility in Louisiana. Commercial operation is expected in 2003.

- AEP subsidiaries reached agreement with Buckeye (an Ohio electric cooperative) to construct and operate a 510 MW peaking facility in Ohio. This agreement entitles AEP to 100% of the facility's capacity and energy in the upfront operating years through 2005. Commercial operation is expected in 2002.

- AEP subsidiaries reached agreement with Twelvepole Creek, LLC, a subsidiary of Columbia Electric, which was subsequently acquired by Orion Power Holdings, Inc., to engineer, procure and construct a 500 MW peaking facility in West Virginia. Commercial operation is expected in May 2001.

Houston Pipe Line Company: AEP subsidiaries reached agreement to acquire Houston Pipe Line Company (HPL) and its Bammel Storage Facility (one of the largest natural gas storage facilities in North America). HPL is a Texas intrastate pipeline and, along with Resources' midstream gas assets discussed below which were acquired in 1998, will provide a daily gas capacity of approximately 3.5 billion cubic feet, more than 6,400 miles of natural gas pipeline and a total storage capacity of approximately 128 billion cubic feet of high injection and withdrawal capabilities.

ICEX: AEP subsidiaries reached agreement to participate and to make an equity investment in a new internet-based electronic trading system Intercontinental Exchange, L.L.C. (ICEX) that enables participants to initiate, negotiate, and execute trades in the crude oil, natural gas, and spot and forward energy markets. Other investors include global energy companies and leading investment banking firms. This interest, along with an earlier investment in Altra Energy Technologies, Inc., provides additional liquidity trading points for the wholesale trading and marketing platform.

CSW Energy: CSW Energy presently owns interests in operating power projects located in Colorado, Florida and Texas. In addition to these projects, CSW Energy has other projects in various stages of development.

- CSW Energy has entered into an agreement with Eastman Chemical Company to construct and operate a 440 MW cogeneration facility in Longview, Texas. This facility will be known as the Eastex Cogeneration Project. Construction of the facility began in the fourth quarter of 1999, with expected operation in the second or third quarter of 2001. Excess electricity generated by the plant will be sold in the wholesale market.

- In October 1999, GE Capital Structured Finance Group purchased 50% of the equity ownership of Sweeny Cogeneration Limited Partnership. CSW Energy's after-tax earnings from the proceeds of the transaction were approximately $33 million. The agreement between CSW Energy and GE Capital Structured Financial Group provides for additional payments to CSW Energy subject to completion of a planned expansion of the Sweeny cogeneration facility, which may be operational in the second quarter of 2001.

CSW International: CSW International currently holds investments in the United Kingdom, Mexico and South America.

CSW International and its 50% partner, Scottish Power plc, have entered into a joint venture to construct and operate the South Coast Power Project, a 400 MW combined cycle gas turbine power station in Shoreham, United Kingdom. CSW International has guaranteed approximately £19 million of the

£190 million construction financing. Both the guarantee and the construction financing are denominated in pounds sterling. The U. S. dollar equivalent at December 29, 2000 would be $28.4 million and $284.1 million respectively, using a conversion rate of £1.00 equals $1.4953. Construction of the project began in March 1999, and commercial operation has begun though it is not yet running at full capacity.

Through November 1999, CSW International had purchased a 36% equity interest in Vale for $80 million. In 1998, CSW International also extended $100 million of debt convertible into equity in Vale. In December 1999, CSW International converted $69 million of that $100 million of debt into equity, thereby raising its equity interest in Vale to 44%. CSW International anticipates converting the remaining debt and accrued interest to equity in Caiua, a subsidiary of Vale, on December 1, 2001.

CSW International invested $110 million from September through November 1997 for 5% of the common stock of Gener, a Chilean electric company. This investment was sold in December 2000 for $67 million.

Resources

Resources' primary business is development of, and investment in, exempt wholesale generators, foreign utility companies, qualifying cogeneration facilities and other energy-related domestic and international investment opportunities and projects. Resources has business development offices in London; Beijing; Columbus, Ohio; Sydney and Washington D.C.

Resources also indirectly owns CitiPower Pty., an electric distribution and retail sales company in Victoria, Australia. CitiPower serves approximately 250,000 customers in the city of Melbourne. With about 3,100 miles of distribution lines in a service area that covers approximately 100 square miles, CitiPower distributes about 4,800 gigawatt-hours annually.

Resources' indirect subsidiary, AEP Pushan Power LDC, has a 70% interest in Nanyang General Light Electric Co., Ltd. (Nanyang Electric), a joint venture organized to develop and build two 125 megawatt coal-fired generating units near Nanyang City in the Henan Province of The Peoples Republic of China. Nanyang Electric was established in 1996 by AEP Pushan Power LDC, Henan Electric Power Development Co. (15% interest) and Nanyang City Hengsheng Energy Development Company Limited (formerly Nanyang Municipal Finance Development Co.) (15% interest). Unit 1 went into service in February 1999 and Unit 2 went into service in June 1999. Resources' share of the total cost of the project of $185,000,000 was approximately $110,000,000.

In December 1999, Resources contributed $47,000,000 to acquire a 50% interest in the Bajio power project in Mexico. The Bajio project is a 600 megawatt natural gas-fired, combined cycle plant and related assets located approximately 160 miles from Mexico City. Bechtel Power Corporation, an affiliate of Resources' partner (InterGen), will build the facility, which is estimated to cost $430,000,000. Approximately 80% of the project costs will be provided by third party debt, some of which will be supported by letters of credit issued on behalf of Resources. The facility will be operated and managed by one or more companies jointly owned by Resources and InterGen. Bajio has a 25-year contract to sell 495 megawatts of the plant's output to Mexico's federally owned electric system; the remainder is expected to be sold to industrial customers in the region. The Bajio project was approximately 60% completed as of December 31, 2000 and construction is expected to be completed in the fall of 2001.

Resources, through AEP Resources Australia Pty., Ltd., a special purpose subsidiary of Resources, owns a 20% interest in Pacific Hydro Limited. Pacific Hydro is principally engaged in the development and operation of, and ownership of interests in, hydroelectric facilities in the Asia Pacific region. Currently, Pacific Hydro has interests in six hydroelectric units and one wind farm unit that operate or are under construction in Australia and the Philippines. The hydroelectric facilities in which Pacific Hydro had interests as of December 31, 2000 (including those under construction) had total design capacity of approximately 181 megawatts.

Resources owns midstream gas assets, including:

- A 2,000-mile intrastate pipeline system in Louisiana.
- Four natural gas processing plants that straddle the pipeline.
- A ten billion cubic foot underground natural gas storage facility directly connected to the Henry Hub, the most active gas trading area in North America.

The pipeline and storage facilities are interconnected to 15 interstate and 23 intrastate pipelines.

U. K. Electric: Resources and another AEP subsidiary have a 50% interest in Yorkshire Electric Group plc (Yorkshire Electricity) with an indirect wholly-owned subsidiary of Xcel Energy, Inc. Yorkshire Electricity is a United Kingdom independent regional electricity company. It is principally engaged in the supply and distribution of electricity. Yorkshire Electricity has two million distribution customers in its authorized service territory which is comprised of 3,860 square miles and located centrally in the east coast of England.

In February 2001, AEP entered into an agreement to sell its 50% interest in Yorkshire. The sale is anticipated to be completed in the second quarter of 2001.

SEEBOARD, a wholly-owned subsidiary of CSW International, is one of the 12 regional electricity companies formed as a result of the restructuring and subsequent privatization of the United Kingdom electricity industry in 1990. CSW acquired indirect control of SEEBOARD in April 1996. SEEBOARD's principal businesses are the distribution and supply of electricity. In addition, SEEBOARD is engaged in other businesses, including gas supply, electricity generation, and electrical contracting. SEEBOARD's service area covers approximately 3,000 square miles in Southeast England. The area has a population of approximately 4.7 million people with significant portions of the area, such as south London, having a high population density.

In a joint venture, SEEBOARD Powerlink won a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground, the largest metropolitan rail system in the world. SEEBOARD's partners in the Powerlink consortium are an international electrical engineering group and an international cable and construction group.

On June 30, 1999, SEEBOARD purchased the 50% interest in Beacon Gas held by BP Amoco. Beacon Gas was a joint venture between SEEBOARD and BP Amoco set up for the supply of gas.

Pro Serv

Pro Serv offers engineering, construction, project management and other consulting services for projects involving transmission, distribution or generation of electric power both domestically and internationally.

AEP Communications

AEP Communications markets wholesale, high capacity, fiber optic services, colocation, and wireless tower infrastructure services under the C3 brand. In addition to expanding its fiber optic network during 2000, AEP Communications joined with several other energy and telecommunications companies to form AFN Communications, LLC. (AFN). AFN is a super regional telecommunications company that provides long haul fiber optic capacity to competitive local exchange carriers, wireless carriers and long distance companies. AFN does business in New York, Pennsylvania, Virginia, West Virginia, Ohio, Indiana, Michigan, Illinois, and Kentucky, with plans to expand nationally, and has approximately 10,000 route miles of fiber optic network. C3, an entity that was acquired through the merger with CSW, is engaged in providing fiber optic and collocation services in Texas, Louisiana, Oklahoma, Arkansas, and Kansas. C3 does business as C3 Networks and has approximately 5,300 route miles of fiber optic network. AEP Communications also joined with Touch America, Inc. to form American Fiber Touch, LLC, an entity that will construct, own, and market a long haul fiber optic route that interconnects the AEP Communications and C3 through Illinois and Missouri.

AEP Communications and C3 also operate business units engaged in marketing energy information. AEP Communications offers a portfolio of energy information data and analysis tools designed to help customers identify energy and cost saving opportunities. C3's energy information services include:

- Meter reading, validation and settlement services.
- Automated meter reading equipment sales and leasing.
- Energy information services.
- Equipment sales and services.

Since the merger of AEP and CSW, a realignment of the energy information business units has taken place through the formation of Datapult Limited Partnership. Energy information services will be offered under the Datapult brand. Evaluation of partnerships and acquisitions will also be a key element of growth for Datapult Limited Partnership in 2001.

SEC Limitations

AEP has received approval from the SEC under PUHCA to issue and sell securities in an amount up to 100% of its average quarterly consolidated retained earnings balance (such average balance was approximately $3.4 billion for the twelve months ended December 31, 2000) for investment in exempt wholesale generators and foreign utility companies. Resources expects to continue its pursuit of new and existing energy generation and delivery projects worldwide.

SEC Rule 58 permits AEP and other registered holding companies to invest up to 15% of consolidated capitalization in energy-related companies. AEPES, an energy-related company under Rule 58, is authorized to engage in energy-related activities, including marketing electricity, gas and other energy commodities.

Risk

These continuing efforts to invest in and develop new business opportunities offer the potential of earning returns which may exceed those of traditional AEP rate-regulated operations. However, they also involve a higher degree of risk which must be carefully considered and assessed. AEP may make additional substantial investments in these and other new businesses.

Reference is made to *Market Risks* under Item 7A herein for a discussion of certain market risks inherent in AEP business activities.

Construction Program

New Generation

The AEP System is continuously involved in assessing the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. Thus, System reinforcement plans are subject to change, particularly with the restructuring of the electric utility industry and the move to increasing competition in the marketplace. See *Competition and Business Change*.

Committed or anticipated capability changes to the AEP System's generation resources include:

- Purchase from an independent power producer's hydro project with an expected capacity value of 28 megawatts, commencing June 1, 2001.
- Expiration of the Rockport Unit 2 sale of 250 megawatts to Carolina Power & Light Company, an unaffiliated company, on December 31, 2009.

Apart from these changes and temporary power purchases that can be arranged, there are no specific commitments for additions of new generation resources on the AEP System. Given the restructuring taking place in the industry, the extent of the need of AEP's operating companies for any additional generation resources in the foreseeable future is highly uncertain.

Proposed Transmission Facilities

On September 30, 1997, APCo refiled applications in Virginia and West Virginia for certificates to build the Wyoming-Cloverdale

765,000-volt Project. The preferred route for this line is approximately 132 miles in length, connecting APCo's Wyoming Station in southern West Virginia to APCo's Cloverdale Station near Roanoke, Virginia. APCo's estimated cost for the Wyoming-Cloverdale Project is $283,254,000, assuming a 2004 in-service date.

APCo announced this project in 1990. Since then it has been in the process of trying to obtain federal permits and state certificates. At the federal level, the U.S. Forest Service (Forest Service) is directing the preparation of an Environmental Impact Statement (EIS), which is required prior to granting permits for crossing lands under federal jurisdiction. Permits are needed from the (i) Forest Service to cross federal forests, (ii) Army Corps of Engineers to cross the New River and a watershed near the Wyoming Station, and (iii) National Park Service or Forest Service to cross the Appalachian National Scenic Trail.

In June 1996, the Forest Service released a Draft EIS and preliminarily identified a "No Action Alternative" as its preferred alternative. If this alternative were incorporated into the Final EIS, APCo would not be authorized to cross federal forests administered by the Forest Service. The Forest Service stated that it would not prepare the Final EIS until after Virginia and West Virginia determined need and routing issues.

West Virginia: On May 27, 1998, the West Virginia PSC issued an order granting APCo's application for a certificate with respect to the Wyoming-Cloverdale 765,000-volt Project. On October 27, 2000, APCo filed with the West Virginia PSC a request to amend the certificate by adding the alternative end point of Jacksons Ferry in Virginia as discussed below under *Virginia.*

Virginia: Following several procedural delays and Hearing Examiner's rulings, APCo filed a study in May 1999 identifying the Wyoming-Jacksons Ferry Project as an alternative project to the Wyoming-Cloverdale Project. The Jacksons Ferry Project proposes a line from Wyoming Station in West Virginia to APCo's existing 765,000-volt Jacksons Ferry Station in Virginia. APCo estimates that the Wyoming-Jacksons Ferry line would be between 82-100 miles in length, including 32 miles in West Virginia previously certified. In May 2000, the Virginia SCC held an evidentiary hearing to consider both projects. On October 2, 2000, the Hearing Examiner's report to the Virginia SCC recommended approval of the Wyoming-Jacksons Ferry Alternative Project. The matter is pending before the Virginia SCC. APCo's estimated cost for the Wyoming-Jacksons Ferry Project is $232,455,000, assuming a 2004 in-service date.

Proposed Completion Schedule: If the Virginia SCC and West Virginia PSC issue the required certificates, APCo will cooperate with the Forest Service to complete the EIS process and obtain the federal permits. The Forest Service has begun preliminary work on a supplement to the Draft EIS. APCo has also begun required consultation with the U.S. Fish and Wildlife Service under the Endangered Species Act.

Management estimates that neither project can be completed before the winter of 2004/2005. However, given the findings in the Draft EIS, APCo cannot presently predict the schedule for completion of the federal permitting process.

Construction Expenditures

The following table shows construction expenditures during 1998, 1999 and 2000 and current estimates of 2001 construction expenditures, in each case including AFUDC but excluding assets acquired under leases.

	1998 Actual	1999 Actual	2000 Actual	2001 Estimate
	(in thousands)			
AEP System (a)....	$792,100	$866,900	$1,773,400	$2,077,400
AEGCo............	6,600	8,300	5,200	3,200
APCo................	204,900	211,400	199,300	394,800
CPL..................	126,600	255,800	199,500	295,000
CSPCo..............	115,300	115,300	128,000	146,300
I&M..................	148,900	165,300	171,100	127,900
KEPCo.............	43,800	44,300	36,200	53,400
OPCo................	185,200	193,900	254,000	447,700
PSO..................	70,100	104,500	176,900	136,600
SWEPCo..........	84,500	112,900	120,200	123,700
WTU.................	37,600	52,600	64,500	77,500

(a) Includes expenditures of other subsidiaries not shown..

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* incorporated by reference in Item 8, for further information with respect to the construction plans of AEP and its operating subsidiaries for the next three years.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the System's construction program.

From time to time, as the System companies have encountered the industry problems described above, such companies also have encountered limitations on their ability to secure the capital necessary to finance construction expenditures.

Environmental Expenditures: Expenditures related to compliance with air and water quality standards, included in the gross additions to plant of the System, during 1998, 1999 and 2000 and the current estimate for 2001 are shown below. Substantial expenditures in addition to the amounts set forth below may be required by the System in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls in order to comply with air and water quality standards which have been or may be adopted.

	1998 Actual	1999 Actual	2000 Actual	2001 Estimate
		(in thousands)		
AEGCo	$ 800	$ 8	$ 70	$ 100
APCo	25,000	24,500	2,100	203,100
CPL	(a)	(a)	(a)	3,300
CSPCo	5,300	10,600	6,600	17,700
I&M	13,000	4,500	1,900	7,600
KEPCo	4,600	1,900	400	23,300
OPCo	27,100	37,400	91,200	271,900
PSO	(a)	(a)	(a)	1,000
SWEPCo	(a)	(a)	(a)	13,200
WTU	(a)	(a)	(a)	1,100
AEP System (a)	$75,800	$78,908	$102,270	$542,300

(a) Amounts not available for west zone companies of AEP prior to AEP-CSW merger.

Financing

It has been the practice of AEP's operating subsidiaries to finance current construction expenditures in excess of available internally generated funds by initially issuing unsecured short-term debt, principally commercial paper and bank loans, at times up to levels authorized by regulatory agencies, and then to reduce the short-term debt with the proceeds of subsequent sales by such subsidiaries of long-term debt securities and cash capital contributions by AEP. If one or more of the subsidiaries are unable to continue the issuance and sale of securities on an orderly basis, such company or companies will be required to consider the curtailment of construction and other outlays or the use of alternative financing arrangements, if available, which may be more costly.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as unsecured debt and leasing arrangements, including the leasing of utility assets and coal mining and transportation equipment and facilities. Pollution control revenue bonds have been used in the past and may be used in the future in connection with the construction of pollution control facilities; however, Federal tax law has limited the utilization of this type of financing except for purposes of certain financing of solid waste disposal facilities and of certain refunding of outstanding pollution control revenue bonds issued before August 16, 1986.

New projects undertaken by AEP's other unregulated subsidiaries are generally financed through equity funds provided by AEP, non-recourse debt incurred on a project-specific basis, debt issued by such subsidiaries or through a combination thereof. See *New Business Development* and Item 7 for additional information concerning AEP's other unregulated subsidiaries.

Rates and Regulation

General

The rates charged by the electric utility subsidiaries of AEP are approved by the FERC or one of the state utility commissions as applicable. The FERC regulates wholesale rates and the state commissions regulate retail rates. In recent years the number of rate increase applications filed by the operating subsidiaries of AEP with their respective state commissions and the FERC has decreased. Under current rate regulation, if increases in operating, construction and capital costs exceed increases in revenues resulting from previously granted rate increases and increased customer demand, then it may be appropriate for certain of AEP's electric utility subsidiaries to file rate increase applications in the future.

Generally the rates of AEP's operating subsidiaries are determined based upon the cost of providing service including a reasonable return on investment. Certain states served by the AEP System allow alternative forms of rate regulation in addition to the traditional cost-of-service approach. However, the rates of AEP's operating subsidiaries in those states continue to be cost-based. The IURC may approve alternative regulatory plans which could include setting customer rates based on market or average prices, price caps, index-based prices and prices based on performance and efficiency. The Virginia SCC may approve (i) special rates, contracts or incentives to individual customers or classes of customers and (ii) alternative forms of regulation including, but not limited to, the use of price regulation, ranges of authorized returns, categories of services and price indexing.

All of the eleven states served by the AEP System, as well as the FERC, either currently permit the incorporation of fuel adjustment clauses in a utility company's rates and tariffs, which are designed to permit upward or downward adjustments in revenues to reflect increases or decreases in fuel costs above or below the designated base cost of fuel set forth in the particular rate or tariff, or currently permit the inclusion of specified levels of fuel costs as part of such rate or tariff.

AEP cannot predict the timing or probability of approvals regarding applications for additional rate changes, the outcome of action by regulatory commissions or courts with respect to such matters, or the effect thereof on the earnings and business of the AEP System. In addition, current rate regulation may, and in the case of Ohio, Texas and Virginia will, be subject to significant revision. See *Competition and Business Change*.

Fuel Supply

The following table shows the sources of power generated by the AEP System:

	1996	1997	1998	1999	2000
Coal	73%	76%	79%	79%	78%
Gas	12%	12%	14%	15%	13%
Nuclear	11%	8%	3%	3%	5%
Hydroelectric and other	4%	4%	4%	3%	4%

Variations in the generation of nuclear power are primarily related to refueling outages and, in 1997 through 1999, the shutdown of the Cook Plant to respond to issues raised by the NRC.

Natural Gas

AEP consumed over 273 billion cubic feet of natural gas during 2000 for the system operating companies, which ranks them as the fourth largest consumer of natural gas in the United States. A majority of the gas fired electric generation plants are connected to at least two natural gas pipelines, which provides greater access to competitive supplies and improves reliability. Natural gas requirements for each plant are supplied by a portfolio of long-term and short-term purchase and transportation agreements which are acquired on a competitive basis and based on market prices.

Coal and Lignite

The Clean Air Act Amendments of 1990 provide for the issuance of annual allowance allocations covering sulfur dioxide emissions at levels below historic emission levels for many coal-fired generating units of the AEP System. Phase I of this program began in 1995 and Phase II began in 2000, with both phases requiring significant changes in coal supplies and suppliers. The full extent of such changes, particularly in regard to Phase II, however, has not been determined. See *Environmental and Other Matters — Air Pollution Control — Title IV Acid Rain Program* for the current compliance plan.

In order to meet emission standards for existing and new emission sources, the AEP System companies will, in any event, have to obtain coal supplies, in addition to coal reserves now owned by System companies, through the acquisition of additional coal reserves and/or by entering into additional supply agreements, either on a long-term or spot basis, at prices and upon terms which cannot now be predicted.

No representation is made that any of the coal rights owned or controlled by the System will, in future years, produce for the System any major portion of the overall coal supply needed for consumption at the coal-fired generating units of the System. Although AEP believes that in the long run it will be able to secure coal of adequate quality and in adequate quantities to enable existing and new units to comply with emission standards applicable to such sources, no assurance can be given that coal of such quality and quantity will in fact be available. No assurance can be given either that statutes or regulations limiting emissions from existing and new sources will not be further revised in future years to specify lower sulfur contents than now in effect or other restrictions. See *Environmental and Other Matters* herein.

The FERC has adopted regulations relating, among other things, to the circumstances under which, in the event of fuel emergencies or shortages, it might order electric utilities to generate and transmit electric power to other regions or systems experiencing fuel shortages, and to rate-making principles by which such electric utilities would be compensated. In addition, the Federal Government is authorized, under prescribed conditions, to allocate coal and to require the transportation thereof, for the use of power plants or major fuel-burning installations.

System companies have developed programs to conserve coal supplies at System plants which involve, on a progressive basis, limitations on sales of power and energy to neighboring utilities, appeals to customers for voluntary limitations of electric usage to essential needs, curtailment of sales to certain industrial customers, voltage reductions and, finally, mandatory reductions in cases where current coal supplies fall below minimum levels. Such programs have been filed and reviewed with officials of Federal and state agencies and, in some cases, the state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agencies.

The mining of coal reserves is subject to Federal requirements with respect to the development and operation of coal mines, and to state and Federal regulations relating to land reclamation and environmental protection, including Federal strip mining legislation enacted in August 1977. Continual evaluation and study is given to possible closure of existing coal mines and divestiture or acquisition of coal properties in light of Federal and state environmental and mining laws and regulations which may affect the System's need for or ability to mine such coal.

Western coal purchased by System companies is transported by rail to an affiliated terminal on the Ohio River for transloading to barges for delivery to generating stations on the river. Subsidiaries of AEP own 3,030 coal hopper cars and lease an additional 4,079 coal hopper cars to be used in unit train movements. Subsidiaries of AEP lease 15 towboats, 492 jumbo barges and 145 standard barges. Subsidiaries of AEP also own or lease coal transfer facilities at various other locations.

The System generating companies procure coal from coal reserves which are owned or mined by subsidiaries of AEP, and through purchases pursuant to long-term contracts, or on a spot purchase basis, from unaffiliated producers. The following table shows the amount of coal delivered to the AEP System during the past five years, the proportion of such coal which was obtained either from coal-mining subsidiaries, from unaffiliated suppliers under long-term contracts or through spot or short-term purchases, and the average delivered price of spot coal purchased by System companies:

	1996(a)	1997(a)	1998(a)	1999(a)	2000
Total coal delivered to					
AEP operated plants (thousands of tons)	51,030	54,292	54,004	54,306	73,259
Sources (percentage):					
Subsidiaries	13%	14%	14%	11%	9%
Long-term contracts	71%	66%	66%	64%	67%
Spot or short-term purchases	16%	20%	20%	24%	24%
Average price per ton of spot-purchased coal	$23.85	$24.38	$25.05	$27.18	$24.03

(a) Includes east zone companies only.

The average cost of coal consumed during the past five years by all AEP System companies is shown below. AEP System companies data for 1996 and 1997 includes only AEGCo, APCo, CSPCo, I&M, KEPCo and OPCo.

	1996	1997	1998	1999	2000
			Dollars per Ton		
AEP System Companies	$ 29.38	$ 29.68	$ 29.87	$ 30.01	$ 31.39
AEGCo	18.22	19.30	19.37	20.79	20.65
APCo	37.60	36.09	34.81	33.29	32.84
CPL	28.81	26.93	26.93	26.49	25.95
CSPCo	31.70	31.69	31.63	29.94	28.50
I&M	22.99	23.68	22.61	24.54	23.44
KEPCo	27.25	26.76	27.42	26.76	25.35
OPCo	35.96	36.00	38.94	40.56	46.52
PSO	21.84	21.11	20.37	20.94	21.21
SWEPCo	23.81	23.16	23.02	21.34	22.59
WTU	24.41	18.19	21.37	21.72	22.26

	1996	1997	1998	1999	2000
			Cents per Million BTU's		
AEP System Companies	139.44	140.13	142.17	141.95	149.12
AEGCo	109.25	115.21	112.63	116.90	116.23
APCo	152.54	146.54	141.76	135.40	134.86
CPL	143.12	136.40	137.00	135.78	137.86
CSPCo	134.60	134.44	134.15	127.42	120.83
I&M	121.16	123.36	118.02	121.90	117.99
KEPCo	114.42	110.37	112.15	109.91	104.88
OPCo	151.55	151.66	164.44	169.23	194.77
PSO	125.87	120.91	116.73	119.54	121.83
SWEPCo	155.88	152.79	150.62	143.34	144.96
WTU	146.26	109.13	126.22	129.13	131.56

The coal supplies at AEP System plants vary from time to time depending on various factors, including customers' usage of electric power, space limitations, the rate of consumption at particular plants, labor unrest and weather conditions which may interrupt deliveries. At December 31, 2000, the System's coal inventory was approximately 35 days of normal System usage. This estimate assumes that the total supply would be utilized by increasing or decreasing generation at particular plants.

The following tabulation shows the total consumption during 2000 of the coal-fired generating units of AEP's principal electric utility subsidiaries, coal requirements of these units over the remainder of their useful lives and the average sulfur content of coal delivered in 2000 to these units. Reference is made to *Environmental and Other Matters* for information concerning current emissions limitations in the AEP System's various jurisdictions and the effects of the Clean Air Act Amendments.

	Total Consumption During 2000 (In Thousands of Tons)	Estimated Requirements for Remainder of Useful Lives (In Millions of Tons)	Average Sulfur Content of Delivered Coal	
			By Weight	Pounds of SO_2 Per Million Btu's
AEGCo (a)	4,944	211	0.3%	0.7
APCo	11,662	384	0.8%	1.2
CPL	2,745	41	0.3%	0.7
CSPCo	6,368	222(b)	2.5%	4.2
I&M (c)	7,342	241	0.7%	1.4
KEPCo	2,794	82	0.9%	1.5
OPCo	20,723	533(d)	2.1%	3.5
PSO	4,199	47	0.2%	0.5
SWEPCo	12,720	151	0.5%	1.3
WTU	1,519	35	0.4%	0.8

(a) Reflects AEGCo's 50% interest in the Rockport Plant.
(b) Includes coal requirements for CSPCo's interest in Beckjord, Stuart and Zimmer Plants.
(c) Includes I&M's 50% interest in the Rockport Plant.
(d) Total does not include OPCo's portion of Sporn Plant.

AEGCo: See *Fuel Supply — I&M* for a discussion of the coal supply for the Rockport Plant.

APCo: Substantially all of the coal consumed at APCo's generating plants is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

The average sulfur content by weight of the coal received by APCo at its generating stations approximated 0.8% during 2000, whereas the maximum sulfur content permitted, for emission standard purposes, for existing plants in the regions in which APCo's generating stations are located ranged between 0.78% and 2% by weight depending in some circumstances on the calorific value of the coal which can be obtained for some generating stations.

CPL: CPL has coal supply agreements with four coal suppliers which delivered approximately 2,255,000 tons of coal during the year 2000. One contract for Colorado coal extends through 2001 and has 1,000,000 tons to be delivered during that year. Approximately one half of the coal delivered to Coleto Creek is from Wyoming with the other half from Colorado. Both sources supply low sulfur coal with a limit of 1.2 lbs/MMBtu.

CSPCo: CSPCo has coal supply agreements with unaffiliated suppliers for the delivery of approximately 3,120,000 tons per year through 2004. Some of this coal is washed to improve its quality and consistency for use principally at Unit 4 of the Conesville Plant.

CSPCo has been informed by CG&E and DP&L that, with respect to the CCD Group units partly owned but not operated by CSPCo, sufficient coal has been contracted for or is believed to be available for the approximate lives of the respective units operated by them. Under the terms of the operating agreements with respect to CCD Group units, each operating company is contractually responsible for obtaining the needed fuel.

I&M: I&M has two coal supply agreements with unaffiliated Wyoming suppliers for low sulfur coal from surface mines principally for consumption by the Rockport Plant. Under these agreements, the suppliers will sell to I&M, for consumption by I&M at the Rockport Plant or consignment to other System companies, coal with an average sulfur content not exceeding 1.2 pounds of sulfur dioxide per million Btu's of heat input. One contract with remaining deliveries of 45,138,543 tons expires on December 31, 2014 and another contract with remaining deliveries of 26,400,000 tons expires on December 31, 2004.

All of the coal consumed at I&M's Tanners Creek Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis.

KEPCo: Substantially all of the coal consumed at KEPCo's Big Sandy Plant is obtained from unaffiliated suppliers under long-term contracts and/or on a spot purchase basis. KEPCo has coal supply agreements with unaffiliated suppliers pursuant to which KEPCo will receive approximately 1,600,000 tons of coal in 2001. To the extent that KEPCo has additional coal requirements, it may purchase coal from the spot market and/or suppliers under contract to supply other System companies.

OPCo: The coal consumed at OPCo's generating plants is obtained from both affiliated and unaffiliated suppliers. The coal obtained from unaffiliated suppliers is purchased under long-term contracts and/or on a spot purchase basis.

OPCo and certain of its coal-mining subsidiaries own or control coal reserves in the State of Ohio containing approximately 145,000,000 tons of clean recoverable coal and ranging in sulfur content between 3.8% and 4.5% sulfur by weight (weighted average, 4.1%), which reserves are presently being mined. OPCo and certain of its mining subsidiaries own an additional 113,000,000 tons of clean recoverable coal in Ohio which ranges in sulfur content between 2.4% and 3.4% sulfur by weight (weighted average 2.7%). Recovery of this coal would require substantial development.

OPCo and certain of its coal-mining subsidiaries also own or control coal reserves in the State of West Virginia which contain approximately 96,000,000 tons of clean recoverable coal ranging in sulfur content between 1.4% and 4.0% sulfur by weight (weighted average, 2.0%) of which approximately 19,000,000 tons can be recovered based upon existing mining plans and projections and employing current mining practices and techniques.

PSO: The coal contract under which coal is supplied to PSO provides the entire plant requirements with at least 20,285,000 tons remaining to be delivered. The coal is supplied from Wyoming and has a maximum sulfur content of 1.2 lbs. SO_2 per MMBtu.

SWEPCo: SWEPCo has one coal contract with a Wyoming producer that provides the majority of its coal requirements. The coal is supplied from Wyoming and has a maximum sulfur content of 1.2 lbs. SO_2 per MMBtu. SWEPCo has remaining deliveries of approximately 31 million tons through 2006 under this contract. In 2000, the remaining coal requirements for SWEPCo were obtained under short term coal agreements with Wyoming producers. SWEPCo also has a mine-mouth lignite operation in East Texas that provides a low cost source to the Pirkey Plant. North American Coal Company's Sabine Mining Company operates the mine.

WTU: WTU has one coal contract designed to supply approximately two thirds of the coal requirements for the Oklaunion Power Station. This contract has approximately 10,920,000 tons remaining to be delivered between 2001 and the middle of 2006. The remaining one third of the coal requirements delivered in 2000 for Oklaunion were under two contracts with Wyoming suppliers. Both were low sulfur coal contracts.

Nuclear

I&M and STPNOC have made commitments to meet certain of the nuclear fuel requirements of the Cook Plant and STP, respectively. The nuclear fuel cycle consists of:

- Mining and milling of uranium ore to uranium concentrates.
- Conversion of uranium concentrates to uranium hexafluoride.
- Enrichment of uranium hexafluoride.
- Fabrication of fuel assemblies.
- Utilization of nuclear fuel in the reactor.
- Disposition of spent fuel.

Steps currently are being taken, based upon the planned fuel cycles for the Cook Plant, to review and evaluate I&M's requirements for the supply of nuclear fuel. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets until it decides that deliveries under long-term supply contracts are warranted.

CPL and the other STP participants have entered into contracts with suppliers for 100% of the uranium concentrate sufficient for the operation of both STP units through Fall 2005 and with an additional 50% of the uranium concentrate needed for STP through Spring 2006. In addition, CPL and the other STP participants have entered into contracts with suppliers for 100% of the nuclear fuel conversion service sufficient for the operation of both STP units through Spring 2003, with additional flexible contracts to provide at least 50% of the conversion service needed for STP through 2005. CPL and the other STP participants have entered into flexible contracts to provide for 100% of enrichment through Spring 2003, with additional flexible contracts to provide at least 40% of enrichment services through Fall 2005. Also, fuel fabrication services have been contracted for operation through 2028 for Unit 1 and 2029 for Unit 2.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M has completed modifications to its spent nuclear fuel storage pool. AEP anticipates that the Cook Plant has storage capacity to permit normal operations through 2012.

STP has on-site storage facilities with the capability to store the spent nuclear fuel generated by the STP units over their licensed lives.

The costs of nuclear fuel consumed by I&M and CPL do not assume any residual or salvage value for residual plutonium and uranium.

Nuclear Waste and Decommissioning

Reference is made to *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* in the financial statements and *Commitments and Contingencies* in the footnotes to these statements that are incorporated by reference in Items 7 and 8, respectively, for information with respect to nuclear waste and decommissioning and related litigation.

The ultimate cost of retiring the Cook Plant and STP may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected.
- Escalation of various cost elements (including, but not limited to, general inflation).
- Further development of regulatory requirements governing decommissioning.
- Limited availability to date of significant experience in decommissioning such facilities.
- Technology available at the time of decommissioning differing significantly from that assumed in these studies.
- Availability of nuclear waste disposal facilities.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant and STP will not be significantly greater than current projections.

Low-Level Waste: The Low-Level Waste Policy Act of 1980 (LLWPA) mandates that the responsibility for the disposal of low-level waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. To facilitate this approach, the LLWPA authorized states to enter into regional compacts for low-level waste disposal subject to Congressional approval. The LLWPA also specified that, beginning in 1986, approved compacts may prohibit the importation of low-level waste from other regions, thereby providing a strong incentive for states to enter into compacts. Michigan, the state where the Cook Plant is located, was a member of the Midwest Compact, but its membership was revoked in 1991. As a result, Michigan is responsible for developing a disposal site for the low-level waste generated in Michigan.

Although Michigan amended its law regarding low-level waste site development in 1994 to allow a volunteer to host a facility, little progress has been made to date. A bill was introduced in 1996 to further address the issue but no action was taken. Development of required legislation and progress with the site selection process has been inhibited by many factors, and management is unable to predict when a new disposal site for Michigan low-level waste will be available.

Texas is a member of the Texas Compact, which includes the states of Maine and Vermont. Texas had identified a disposal site in Hudspeth County for construction of a low-level waste disposal facility. During the licensing process for the Hudspeth site, that site was found to be unsuitable. No additional site has been considered. Several bills have been submitted in the Texas legislature in 2001 to address this issue. Management is unable to predict when a disposal site for Texas low-level waste will be available.

On July 1, 1995, the disposal site in South Carolina reopened to accept waste from most areas of the U.S., including Michigan and Texas. This was the first opportunity for the Cook Plant to dispose of low-level waste since 1990. To the extent practicable, the waste formerly placed in storage and the waste presently generated by the Cook Plant and STP are now being sent to the disposal site.

Under state law, the amounts of low-level radioactive waste being disposed of at the South Carolina facility from non-regional generators, such as the Cook Plant and STP, are limited and being reduced. Non-regional access to the South Carolina facility is currently allowed through the end of fiscal year 2008.

Environmental and Other Matters

AEP's subsidiaries are subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions.

It is expected that:

- Costs related to environmental requirements will eventually be reflected in the rates of AEP's electric utility subsidiaries, or where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.
- AEP's electric utility subsidiaries will be able to provide for required environmental controls.

However, some customers may curtail or cease operations as a consequence of higher energy costs. There can be no assurance that all such costs will be recovered. Moreover, legislation recently adopted by certain states and proposed at the state and federal level governing restructuring of the electric utility industry may also affect the recovery of certain costs. *See Competition and Business Change.*

Except as noted herein, AEP's subsidiaries that own or operate generating, transmission and distribution facilities are in substantial compliance with pollution control laws and regulations.

Reference is made to *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* and the footnote to the financial statements entitled *Commitments and Contingencies* incorporated by reference in Items 7 and 8, respectively, for further information with respect to environmental matters.

Air Pollution Control

For the AEP System operating companies, compliance with the CAA is requiring substantial expenditures that generally are being recovered through the rates of AEP's operating subsidiaries. Certain matters discussed below may require significant additional operating and capital expenditures. However, there can be no assurance that all such costs will be recovered. *See Construction Program — Construction Expenditures.*

Title I National Ambient Air Quality Standards Attainment: In July 1997, Federal EPA revised the ozone and particulate matter National Ambient Air Quality Standards (NAAQS), creating a new eight-hour ozone standard and establishing a new standard for particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Both of these new standards have the potential to affect adversely the operation of AEP System generating units. In May 1999, the U.S. Court of Appeals for the District of Columbia Circuit remanded the ozone and $PM_{2.5}$ NAAQS to Federal EPA. In February 2001, the U.S. Supreme Court issued an opinion reversing in part and affirming in part the Court of Appeals decision. The Supreme Court remanded the case to the Court of Appeals for further proceedings, including a review of whether adoption of the standards was arbitrary and capricious and directed Federal EPA to develop a policy for implementing the revised ozone standard in conformity with the CAA.

NO_x SIP Call: In October 1998, Federal EPA issued a final rule (NO_x transport SIP call or NO_x SIP Call) establishing state-by-state NO_x emission budgets for the five-month ozone season to be met beginning May 1, 2003. The NO_x budgets originally applied to 22 eastern states and the District of Columbia and are premised mainly on the assumption of controlling power plant NO_x emissions projected for the year 2007 to 0.15 lb. per million Btu (approximately 85% below 1990 levels), although the reductions could be substantially greater for certain State Implementation Plans. The SIP call was accompanied by a proposed Federal Implementation Plan, which could be implemented in any state that fails to submit an approvable SIP. The NO_x reductions called for by Federal EPA are targeted at coal-fired electric utilities and may adversely impact the ability of electric utilities to obtain new and modified source permits or to operate affected facilities without making significant capital expenditures.

In October 1998, the AEP System operating companies joined with certain other parties seeking a review of the final NO_x SIP Call rule in the U.S. Court of Appeals for the District of Columbia Circuit. In March 2000, the court issued a decision upholding the major provisions of the rule. The court subsequently extended the date for submission of SIP revisions until October 30, 2000, and the compliance deadline until May 31, 2004. On March 5, 2001, the U.S. Supreme Court denied petitions filed by industry petitioners, including AEP System operating companies, seeking review of the Court of Appeals decision. In December 2000, Federal EPA issued a determination that eleven states, including certain states in which AEP System operating companies have sources covered by the NO_x SIP Call rule, had failed to submit complying SIP revisions. This determination has been appealed by AEP System operating companies and unaffiliated utilities to the U.S. Court of Appeals for the District of Columbia Circuit.

In April 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NO_x emissions from utility sources, including those of CPL and SWEPCo. The rule compliance date is May 2003 for CPL and May 2005 for SWEPCo.

Preliminary estimates indicate that compliance with the revised NO_x SIP Call rule, and SIP revisions already adopted, could result in required capital expenditures for the AEP System of approximately $1.6 billion. AEP operating company estimates are as follows:

	(in millions)
AEGCo	$ 125
APCo	365
CPL	57
CSPCo	106
I&M	202
KEPCo	140
OPCo	606
SWEPCo	28

In June 2000 OPCo announced that it was beginning a $175 million installation of selective catalytic reduction technology (expected to be operational in 2001) to reduce NO_x emissions on its two-unit 2,600 MW Gavin Plant. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and APCo's Mountaineer Plant is scheduled to begin in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million. Management has undertaken the Gavin, Amos and Mountaineer projects to meet applicable NO_x emission reduction requirements.

Since compliance costs cannot be estimated with certainty, the actual costs to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NO_x emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers through regulated rates and/or future market prices for electricity where generation is deregulated, they will have a material adverse effect on future results of operations, cash flows and possibly financial condition of AEP and its affected subsidiaries.

Section 126 Petitions: In January 2000, Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the CAA. The petitions sought significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposes emission reduction requirements comparable to the NO_x SIP Call rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP System operating companies and other utilities filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit. Briefing has been completed and oral argument was held in December 2000. Cost estimates for compliance with Section 126 are projected to be somewhat less than those set forth above for the NO_x SIP Call rule reflecting the fact that Section 126 does not apply to I&M's Rockport Plant.

West Virginia SO_2 Limits: West Virginia promulgated SO_2 limitations, which Federal EPA approved in February 1978. The emission limitations for OPCo's Mitchell Plant have been approved by Federal EPA for primary ambient air quality (health-related) standards only. West Virginia is obligated to reanalyze SO_2 emission limits for the Mitchell Plant with respect to secondary ambient air quality (welfare-related) standards. Because the CAA provides no specific deadline for approval of emission limits to achieve secondary ambient air quality standards, it is not certain when Federal EPA will take dispositive action regarding the Mitchell Plant.

In August 1994, Federal EPA issued a Notice of Violation to OPCo alleging that Kammer Plant was operating in violation of the applicable federally enforceable SO_2 emission limit. In May 1996, the Notice of Violation and an enforcement action subsequently filed by Federal EPA were resolved through the entry of a consent decree in the U.S. District Court for the Northern District of West Virginia. Kammer Plant has achieved and maintained compliance with the applicable SO_2 emission limit for a period in excess of one year, pursuant to the provisions of the consent decree. OPCo is currently seeking the termination of the consent decree.

Short Term SO_2 Limits: In January 1997, Federal EPA proposed a new intervention level program under the authority of Section 303 of the CAA to address five-minute peak SO_2 concentrations believed to pose a health risk to certain segments of the population. The proposal establishes a "concern" level and an "endangerment" level. States must investigate exceedances of the concern level and decide whether to take corrective action. If the endangerment level is exceeded, the state must take action to reduce SO_2 levels. In January 2001, Federal EPA published a *Federal Register* notice inviting comment with respect to its decision not to promulgate a five-minute SO_2 NAAQS and intent to take final action on the intervention level program by the summer of 2001. The effect of this proposed intervention program on AEP operations cannot be predicted at this time.

Hazardous Air Pollutants: Hazardous air pollutant (HAP) emissions from utility boilers are potentially subject to control requirements under Title III of the CAAA which specifically directed Federal EPA to study potential public health impacts of HAPs emitted from electric utility steam generating units. In December 2000, Federal EPA announced its intent to regulate emissions of mercury from coal and oil-fired power plants, concluding that these emissions pose significant hazards to public health. A decision on whether to regulate other HAPs emissions from these sources was deferred.

Federal EPA added coal and oil-fired electric utility steam generating units to the list of "major sources" of HAPs under Section 112 (c) of the CAA, which compels the development of "Maximum Achievable Control Technology" (MACT) standards for these units. Listing under Section 112 (c) also compels a preconstruction permitting obligation to establish case-by-case MACT standards for each new, modified, or reconstructed source in the category. MACT standards for utility mercury emissions are scheduled to be proposed by December 2003 and finalized by December 2004. On February 16 and 20, 2001, utility industry groups filed petitions for review of Federal EPA's action in the U.S. Court of Appeals for the District of Columbia Circuit. On February 23, 2001, the Utility Air Regulatory Group (which includes AEP System operating companies as members) filed a petition with Federal EPA seeking reconsideration of the decision to regulate mercury emissions from power plants under Section 112(c) of the CAA.

In addition, Federal EPA is required to study the deposition of hazardous pollutants in the Great Lakes, the Chesapeake Bay, Lake Champlain, and other coastal waters. As part of this assessment, Federal EPA is authorized to adopt regulations to prevent serious adverse effects to public health and serious or widespread environmental effects. In 1998, Federal EPA determined that the CAA is adequate to address any adverse public health or environmental effects associated with the atmospheric deposition of hazardous air pollutants in the Great Lakes.

Title IV Acid Rain Program: The Acid Rain Program (Title IV) of the CAAA created an emission allowance program pursuant to which utilities are authorized to emit a designated quantity of SO_2, measured in tons per year.

Phase II of the Acid Rain Program, which affects all fossil fuel-fired steam generating units with capacity greater than 25 megawatts imposed more stringent SO_2 emission control requirements beginning January 1, 2000. If a unit emitted SO_2 in 1985 at a rate in excess of 1.2 pounds per million Btu heat input, the Phase II allowance allocation is premised upon an emission rate of 1.2 pounds at 1985 utilization levels. Future SO_2 allowance requirements will be met through accumulation, acquisition, the use of controls or fuels, or a combination thereof.

Title IV of the CAAA also regulates emissions of NO_x. Federal EPA has promulgated NO_x emission limitations for all boiler types in the AEP System at levels significantly below original design, which were to be achieved by January 1, 2000 on a unit-by-unit or System-wide average basis. AEP sources subject to Title IV of the CAAA are in compliance with the provisions thereof.

Regional Haze: In July 1999, Federal EPA finalized rules to regulate regional haze attributable to anthropogenic emissions. The primary goal of the new regional haze program is to address visibility impairment in and around "Class I" protected areas, such as national parks and wilderness areas. Because regional haze precursor emissions are believed by Federal EPA to travel long distances, Federal EPA proposes to regulate such precursor emissions in every state. Under the proposal, each state must develop a regional haze control program that imposes controls necessary to steadily reduce visibility impairment in Class I areas on the worst days and that ensures that visibility remains good on the best days.

The AEP System is a significant emitter of fine particulate matter and other precursors of regional haze. Federal EPA's regional haze rule may have an adverse financial impact on AEP as it may trigger the requirement to install costly new pollution control devices to control emissions of fine particulate matter and its precursors (including SO_2 and NO_x). The actual impact of the regional haze regulations cannot be determined at this time. AEP System operating companies and other utilities filed a petition seeking a review of the regional haze rule in the U.S. Court of Appeals for the District of Columbia Circuit in August 1999.

In January 2001, Federal EPA announced that it is considering the issuance of proposed guidelines for states to use in setting Best Available Retrofit Technology (BART) emission limits for power plants and other large emission sources. The proposal would call for technologies to reduce visibility-impairing emissions by 90 to 95 percent. Emission trading programs could be used in lieu of unit-by-unit BART requirements under the proposal, provided they yield greater visibility improvement and emission reductions.

Permitting and Enforcement: The CAAA expanded the enforcement authority of the federal government by:

- Increasing the range of civil and criminal penalties for violations of the CAA and enhancing administrative civil provisions.

In the event AEP does not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed could materially adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, wires charges and future market prices for energy.

Water Pollution Control

The Clean Water Act prohibits the discharge of pollutants to waters of the United States from point sources except pursuant to an NPDES permit issued by Federal EPA or a state under a federally authorized state program.

Under the Clean Water Act, effluent limitations requiring application of the best available technology economically achievable are to be applied, and those limitations require that no pollutants be discharged if Federal EPA finds elimination of such discharges is technologically and economically achievable.

The Clean Water Act provides citizens with a cause of action to enforce compliance with its pollution control requirements. Since 1982, many such actions against NPDES permit holders have been filed. To date, no AEP System plants have been named in such actions.

All AEP System generating plants are required to have NPDES permits and have received them. Under Federal EPA's regulations, operation under an expired NPDES permit is authorized provided an application is filed at least 180 days prior to expiration. Renewal applications are being prepared or have been filed for renewal of NPDES permits that expire in 2001.

The NPDES permits generally require that certain thermal impact study programs be undertaken. These studies have been completed for all System plants. Thermal variances are in effect for all plants with once-through cooling water. The thermal variances for CSPCo's Conesville and OPCo's Muskingum River plants impose thermal management conditions that could result in load curtailment under certain conditions, but the cost impacts are not expected to be significant. Based on favorable results of in-stream biological studies, the thermal limits for both Conesville and Muskingum River plants were raised in the renewed permits issued in 1996. Consequently, the potential for load curtailment and adverse cost impacts was further reduced.

Section 316(b) of the Clean Water Act requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Under a revised court established schedule, Federal EPA is required to develop regulations defining adverse impacts and BTA for new sources by November 2001. Regulations applicable to existing power plants are not required to be issued by Federal EPA until August 2003. As part of the rulemaking, Federal EPA has issued questionnaires to power plants, including AEP System plants, requesting information on impingement and entrainment of aquatic organisms from existing plant cooling water intakes. Federal EPA's rulemaking could result in a definition of BTA that would affect any new plant construction and could ultimately require retrofitting of certain existing plant intake structures. Such changes would involve costs for AEP System operating companies, but the significance of these costs cannot be determined at this time.

Certain mining operations conducted by System companies as discussed under *Fuel Supply* are also subject to federal and state water pollution control requirements, which may entail substantial expenditures for control facilities, not included at present in the System's construction cost estimates set forth herein.

Section 303 of the Federal Clean Water Act requires states to adopt stringent water quality standards for a large category of toxic pollutants and to identify specialized control measures for dischargers to waters where it is shown that water quality standards are not being met. In order to bring these waters back into compliance, total maximum daily load (TMDL) allocations of these pollutants will be made, and subsequently translated into discharge limits in NPDES permits. Federal EPA has also directed that states take action to adopt enhanced anti-degradation of water quality requirements. Implementation of these provisions could result in significant costs to the AEP System if biological monitoring requirements and water quality-based effluent limits and requirements are placed in NPDES permits.

In March 1995, Federal EPA finalized a set of rules that establish minimum water quality standards, anti-degradation policies and implementation procedures for more stringently controlling releases of toxic pollutants into the Great Lakes system. This regulatory package is called the Great Lakes Water Quality Initiative (GLWQI). The most direct compliance cost impact could be related to I&M's Cook Plant. Based on Federal EPA's current policy on intake credits and site specific variables and Michigan's implementation strategy, management does not presently expect the GLWQI will have a significant adverse impact on Cook Plant operations. If Indiana and Ohio eventually adopt the GLWQI criteria for statewide application, AEP System plants located in those states could be adversely affected, although the significance depends on the implementation strategy of those states.

Oil Pollution Act: The Oil Pollution Act of 1990 (OPA) defines certain facilities that, due to oil storage volume, and location, could reasonably be expected to cause significant and substantial harm to the environment by discharging oil. Such facilities must operate under approved spill response plans and implement spill response training and drill programs. OPA imposes substantial penalties for failure to comply. AEP System operating companies with oil handling and storage facilities meeting the OPA criteria have in place required response plans, training and drill programs.

Solid and Hazardous Waste

Section 311 of the Clean Water Act imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. CERCLA expanded the reporting requirement to cover the release of hazardous substances generally into the environment, including water, land and air. AEP's subsidiaries store and use some of these hazardous substances, including PCBs contained in certain capacitors and transformers, but the occurrence and ramifications of a spill or release of such substances cannot be predicted.

CERCLA, RCRA and similar state laws provide governmental agencies with the authority to require cleanup of hazardous waste sites and releases of hazardous substances into the environment and to seek compensation for damages to natural resources. Since liability under CERCLA is strict, joint and several, and can be applied retroactively, AEP System operating companies which previously disposed of PCB-containing electrical equipment and other hazardous substances may be required to participate in remedial activities at such disposal sites should environmental problems result.

AEP System operating companies are identified as Potentially Responsible Parties (PRPs) for five federal sites where remediation has not been completed, including APCo at one site, CSPCo at one site, I&M at two sites, and OPCo at one site. Management's present estimates do not anticipate material clean-up costs for identified sites for which AEP subsidiaries have been declared PRPs. However, if significant costs are incurred for cleanup, future results of operations and possibly financial condition could be adversely affected unless the costs can be recovered through rates and/or future market prices for electricity where generation is deregulated.

Regulations issued by Federal EPA under the Toxic Substances Control Act govern the use, distribution and disposal of PCBs, including PCBs in electrical equipment. Deadlines for removing certain PCB-containing electrical equipment from service have been met.

In addition to handling hazardous substances, the System companies generate solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash and flue gas desulfurization wastes. These wastes presently are considered to be non-hazardous under RCRA and applicable state law and the wastes are treated and disposed of in surface impoundments or landfills in accordance with state permits or authorization or are beneficially utilized. As required by RCRA, Federal EPA evaluated whether high volume coal combustion wastes (such as fly ash, bottom ash and flue gas desulfurization wastes) should be regulated as hazardous waste. In August 1993, Federal EPA issued a regulatory determination that such high volume coal combustion wastes should not be regulated as hazardous waste. Federal EPA chose to address separately the issue of low volume wastes (such as metal and boiler cleaning wastes) associated with burning coal and other fossil fuels. In May 2000, Federal EPA issued a regulatory determination that such low volume wastes are also excluded from regulation under the RCRA hazardous waste provisions when mixed and co-managed with high volume fossil fuel combustion wastes.

All presently generated hazardous waste is being disposed of at permitted off-site facilities in compliance with applicable federal and state laws and regulations. For System facilities that generate such wastes, System companies have filed the requisite notices and are complying with RCRA and applicable state regulations for generators. Nuclear waste produced at the Cook Plant and STP and regulated under the Atomic Energy Act is excluded from regulation under RCRA.

Underground Storage Tanks: Federal EPA's technical requirements for underground storage tanks containing petroleum required retrofitting or replacement of an appreciable number of tanks. Compliance costs for tank replacement were not significant. Some limited site remediation associated with tank removal is ongoing, but these costs are not expected to be significant.

Electric and Magnetic Fields (EMF)

EMF is found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF is created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances.

A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, the majority of studies have indicated no such association.

The Energy Policy Act of 1992 established a coordinated Federal EMF research program which ended in 1998. In 1999, the National Institute of Environmental Health Sciences (NIEHS), as required by the Act, provided a report to Congress summarizing the results of this program. The report concluded that "the probability that ...EMF is truly a health hazard is currently small" and that the evidence that exists for health effects is "insufficient to warrant aggressive regulatory actions." Nevertheless, the NIEHS identified several areas where further research might be warranted. AEP has supported EMF research through the years and continues to fund the Electric Power Research Institute's EMF research program, contributing over $400,000 to this program in 2000 and intending to contribute a similar amount in 2001. See *Research and Development.*

AEP's participation in these programs is a continuation of its efforts to monitor and support further research and to communicate with its customers and employees about this issue. Residential customers of AEP are provided information and field measurements on request, although there is no scientific basis for interpreting such measurements.

A number of lawsuits based on EMF-related grounds have been filed against electric utilities. A suit was filed on May 23, 1990 against I&M involving claims that EMF from a 345 KV transmission line caused adverse health effects. On March 23, 1998 the court ruled that the plaintiffs failed to prove that I&M caused any of the injuries claimed by the plaintiffs. This part of the trial court's decision was upheld on appeal. Certain issues unrelated to health effects are pending at the trial court. No specific amount has been requested for damages in this case. Mediation is scheduled for June, 2001.

Some states have enacted regulations to limit the strength of magnetic fields at the edge of transmission line rights-of-way. No state which the AEP System serves has done so.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from ratepayers.

Research and Development

AEP and its subsidiaries are involved in over 150 research projects that are directed to:

- Exploring new methods of generating electricity, such as through renewable sources (*e.g.*, wind, solar).
- Developing more efficient methods of operating generating plants.
- Reducing emissions resulting from the burning of fossil fuels (coal and natural gas).
- Improving the efficiency, utilization and reliability of the transmission and distribution systems.
- Exploring the application of new electrotechnologies.
- Exploring the use and application of distributed generation.

AEP System operating companies are members of the Electric Power Research Institute (EPRI), an organization founded in 1973 that manages research and development initiatives on behalf of its members. EPRI's members include investor owned and public utilities, independent power producers, international organizations and others.

AEP participates in EPRI programs that meet its research and development objectives. Total AEP dues to EPRI were $17,000,000 for 2000, $22,000,000 for 1999 and $23,000,000 for 1998. Of these amounts, the former CSW System paid approximately $7,000,000 in 2000, $8,000,00 in 1999 and $8,000,000 in 1998 for EPRI programs.

Total research and development expenditures by AEP and its subsidiaries, including EPRI dues, were approximately $20,000,000 for the year ended December 31, 2000, $25,000,000 for the year ended December 31, 1999 and $32,000,000 for the year ended December 31, 1998.

Item 2. **Properties**

At December 31, 2000, the subsidiaries of AEP owned (or leased where indicated) generating plants with the net power capabilities (winter rating) shown in the following table:

Company	Stations	Coal MW	Natural Gas MW	Hydro MW	Nuclear MW	Lignite MW	Other MW	Total MW
AEGCo	1(a)	1,300						1,300
APCo	17(b)	5,081		777				5,858
CPL	12(c)(d)	686	3,175	6	630			4,497
CSPCo	6(e)	2,595						2,595
I&M	10(a)	2,295		11	2,110			4,416
KEPCo	1	1,060						1,060
OPCo	8(b)(f)	8,464		48				8,512
PSO	8(c)	1,018	2,873				25(g)	3,916
SWEPCo	9	1,848	1,797			842		4,487
WTU	12(c)	377	999				16(g)	1,392
Totals:	79	24,724	8,862	842	2,740	842	41	38,033

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended.
(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.
(c) CPL, PSO, and WTU jointly own the Oklaunion power station. Their respective ownership interests are reflected in this table.
(d) Reflects CPL's interest in STP.
(e) CSPCo owns generating units in common with CG&E and DP&L. Its ownership interest of 1,330 MW is reflected in this table.
(f) The scrubber facilities at OPCo's General James M. Gavin Plant are leased. The lease terminates in 2010 unless extended.
(g) PSO and WTU have 25 MW and 10 MW respectively of facilities designed primarily to burn oil. WTU has one 6 MW wind farm facility.

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities, both foreign and domestic. Information concerning these facilities at December 31, 2000 is listed below.

Facility	Company	Location	Capacity Total MW	Ownership Interest	Status
Brush II	CSW Energy	Colorado	68	47%	QF
Fort Lupton	CSW Energy	Colorado	272	50%	QF
Mulberry	CSW Energy	Florida	120	50%	QF
Orange Cogen	CSW Energy	Florida	103	50%	QF
Newgulf	CSW Energy	Texas	85	100%	EWG
Sweeny (a)	CSW Energy	Texas	360	50%	QF
Total U.S.			1,008		
Medway	CSW International	United Kingdom	675	37.5%	n/a
Altamira	CSW International	Mexico	118	50%	FUCO
Total International			793		

(a) During 2001, additional development at the Sweeny facility is expected to add approximately 120 MW to current capacity.

See Item 1 under *Fuel Supply*, for information concerning coal reserves owned or controlled by subsidiaries of AEP.

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765,000-volt lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765,000-volt Lines
AEP System (a)	208,809(b)	2,023
APCo	50,187	642
CPL	31,125	---
CSPCo (a)	13,864	---
I&M	20,602	614
KEPCo	10,385	258
OPCo	29,620	509
PSO	18,565	---
SWEPCo	18,851	---
WTU	12,439	---

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes 73 miles of transmission lines not identified with an operating company.

Titles

The AEP System's electric generating stations are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of the System in the realty on which its facilities are located are considered by it to be adequate for its use in the conduct of its business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. System companies generally have the right of eminent domain whereby they may, if necessary, acquire, perfect or secure titles to or easements on privately-held lands used or to be used in their utility operations.

Substantially all the physical properties of the AEP System operating companies are subject to the lien of the mortgage and deed of trust securing the first mortgage bonds of each such company.

System Transmission Lines and Facility Siting

Legislation in the states of Arkansas, Indiana, Kentucky, Michigan, Ohio, Texas, Virginia, and West Virginia requires prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. Delays and additional costs in constructing facilities have been experienced as a result of proceedings conducted pursuant to such statutes, as well as in proceedings in which operating companies have sought to acquire rights-of-way through condemnation, and such proceedings may result in additional delays and costs in future years.

Peak Demand

The east zone system is interconnected through 121 high-voltage transmission interconnections with 25 neighboring electric utility systems. The all-time and 2000 one-hour peak system demands were 25,940,000 and 23,223,000 kilowatts, respectively (which included 7,314,000 and 5,341,000 kilowatts, respectively, of scheduled deliveries to unaffiliated systems which the system might, on appropriate notice, have elected not to schedule for delivery) and occurred on June 17, 1994 and August 7, 2000, respectively. The net dependable capacity to serve the system load on such date, including power available under contractual obligations, was 23,457,000 and 23,790,000 kilowatts, respectively. The all-time and 2000 one-hour internal peak demands were 19,952,000 and 19,167,000 kilowatts, respectively, and occurred on July 30, 1999 and January 28, 2000, respectively. The net dependable capacity to serve the system load on such date, including power dedicated under contractual arrangements, was 23,829,000 and 24,036,000 kilowatts, respectively. The all-time one-hour integrated and internal net system peak demands and 2000 peak demands for the east zone generating subsidiaries are shown in the following tabulation:

	All-time one-hour integrated net system peak demand		2000 one-hour integrated net system peak demand	
	(in thousands)			
	Number of Kilowatts	Date	Number of Kilowatts	Date
APCo	8,303	January 17, 1997	7,509	December 20, 2000
CSPCo	4,239	August 2, 2000	4,240	August 2, 2000
I&M	5,040	August 15, 2000	5,048	August 15, 2000
KEPCo	1,860	January 10, 2001	1,761	December 20, 2000
OPCo	7,291	June 17, 1994	6,199	August 2, 2000

	All-time one-hour integrated net internal peak demand		2000 one-hour integrated net internal peak demand	
	(in thousands)			
	Number of Kilowatts	Date	Number of Kilowatts	Date
APCo	6,908	February 5, 1996	6,558	January 28, 2000
CSPCo	3,804	July 30, 1999	3,499	August 31, 2000
I&M	4,127	July 30, 1999	3,949	August 30, 2000
KEPCo	1,579	January 3, 2001	1,558	January 27, 2000
OPCo	5,705	June 11, 1999	5,029	June 14, 2000

The all-time and 2000 one-hour internal peak demand for the west zone system was 14,234,000 kilowatts on August 31, 2000. The all-time one-hour internal net system peak demands and 2000 peak demands for the west zone generating subsidiaries are shown in the following tabulation:

	All-time one-hour integrated net internal peak demand		2000 one-hour integrated net internal peak demand	
	(in thousands)			
	Number of Kilowatts	Date	Number of Kilowatts	Date
CPL	4,623	September 5, 2000	4,623	September 5, 2000
PSO	3,823	August 30, 2000	3,823	August 30, 2000
SWEPCo	4,625	August 31, 2000	4,625	August 31, 2000
WTU	1,537	September 5, 2000	1,537	September 5, 2000

Hydroelectric Plants

AEP has 18 facilities, of which 16 are licensed through FERC. The new license for the Elkhart hydroelectric plant in Indiana was issued January 11, 2001 and extends for a period of thirty years. The license for the Mottville hydroelectric plant in Michigan expires in 2003. A notice of intent to relicense was filed in 1998. The application for new license will be filed in 2001.

Cook Nuclear Plant and STP

The following table provides operating information relating to the Cook Plant and STP.

	Cook Plant		STP(a)	
	Unit 1	Unit 2	Unit 1	Unit 2
Year Placed in Operation	1975	1978	1988	1989
Year of Expiration of NRC License (b)	2014	2017	2027	2028
Nominal Net Electrical Rating in Kilowatts	1,020,000	1,090,000	1,250,600	1,250,600
Net Capacity Factors				
2000 (c)	1.4%	50.0%	78.2%	96.1%
1999 (c)	0%	0%	88.0%	89.4%

(a) Reflects total plant.
(b) For economic or other reasons, operation of the Cook Plant and STP for the full term of their operating licenses cannot be assured.
(c) The Cook Plant was shut down in September 1997 to respond to issues raised regarding the operability of certain safety systems. The restart of both units of the Cook Plant was completed with Unit 2 reaching 100% power on July 5, 2000 and Unit 1 achieving 100% power on January 3, 2001.

Costs associated with the operation (excluding fuel), maintenance and retirement of nuclear plants continue to be of greater significance and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the construction and operation of nuclear facilities. I&M and CPL may also incur costs and experience reduced output at Cook Plant and STP, respectively, because of the design criteria prevailing at the time of construction and the age of the plant's systems and equipment. Nuclear industry-wide and Cook Plant and STP initiatives have contributed to slowing the growth of operating and maintenance costs at these plants. However, the ability of I&M and CPL to obtain adequate and timely recovery of costs associated with the Cook Plant and STP, respectively, including replacement power, any unamortized investment at the end of the useful life of the Cook Plant and STP (whether scheduled or premature), the carrying costs of that investment and retirement costs, is not assured. See *Competition and Business Change.*

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless allowed to be recovered through rates, could have a material adverse effect on results of operations and the financial condition of AEP, CPL, I&M and other AEP System companies.

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* that is incorporated by reference in Item 8 for information with respect to nuclear incident liability insurance.

Item 3. **Legal Proceedings**

Federal EPA Notice of Violation to OPCo: On August 31, 2000, Region V, Federal EPA, issued a Notice of Violation (NOV) to OPCo's Gavin Plant in connection with stack emissions. Among other alleged violations, the NOV alleges violation of the Federal EPA-approved Ohio air pollution nuisance rule. AEP has submitted a request for a conference to discuss the NOV with Region V representatives.

Municipal Franchise Fee Litigation: CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in 1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damages of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision awards a judgment against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaim vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

COLI Litigation: On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax return related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 AEP paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced in 2000 as follows:

	(in millions)
AEP System operating companies	$ 319
APCo	82
CSPCo	41
I&M	66
KEPCo	8
OPCo	118

The Company plans to appeal the decision.

See Item 1 for a discussion of certain environmental matters.

Reference is made to the footnote to the financial statements entitled *Commitments and Contingencies* incorporated by reference in Item 8 for further information with respect to other legal proceedings.

Item 4. Submission of Matters to a Vote of Security Holders

AEP, APCo, CPL, I&M, OPCo and SWEPCo. None.

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

Executive Officers of the Registrants

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of March 1, 2001.

Name	Age	Office (a)
E. Linn Draper, Jr.	59	Chairman of the Board, President and Chief Executive Officer of AEP and of the Service Corporation
Thomas V. Shockley, III	55	Vice Chairman of the Service Corporation
Paul D. Addis	47	Executive Vice President-Wholesale/Energy Services of the Service Corporation
Donald M. Clements, Jr.	51	Executive Vice President-Corporate Development of the Service Corporation
Henry W. Fayne	54	Executive Vice President-Finance and Analysis of the Service Corporation
William J. Lhota	61	Executive Vice President- Energy Delivery of the Service Corporation
Susan Tomasky	47	Executive Vice President-Legal, Policy and Corporate Communications of the Service Corporation
J. H. Vipperman	60	Executive Vice President-Shared Services of the Service Corporation

(a) All of the executive officers listed above have been employed by the Service Corporation or System companies in various capacities (AEP, as such, has no employees) during the past five years, except for Messrs. Addis and Shockley and Ms. Tomasky. Prior to joining the Service Corporation in February 1997 in his present position, Mr. Addis was Executive Vice President (1992-1993) and President (1993-January 1997) of Louis Dreyfus Electric Power, Inc. and President of Duke/Louis Dreyfus LLC (1995-January 1997). Mr. Addis became an executive officer of AEP effective January 1, 2000. Prior to joining the Service Corporation in July 1998 as Senior Vice President, Ms. Tomasky was a partner with the law firm of Hogan & Hartson (August 1997-July 1998) and General Counsel of the Federal Energy Regulatory Commission (May 1993-August 1997). Ms. Tomasky became an executive officer of AEP effective with her promotion to Executive Vice President on January 26, 2000. Prior to joining the Service Corporation in his current position upon the merger with CSW, Mr. Shockley was President and Chief Operating Officer of CSW (1997-2000) and Senior Vice President of CSW (1980-1997). All of the above officers are appointed annually for a one-year term by the board of directors of AEP, the board of directors of the Service Corporation, or both, as the case may be.

APCo, CPL, I&M, OPCo and SWEPCo. The names of the executive officers of APCo, CPL, I&M, OPCo and SWEPCo, the positions they hold with these companies, their ages as of March 1, 2001, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, CPL, I&M, OPCo and SWEPCo are elected annually to serve a one-year term.

Name	Age	Position (a)(b)	Period
E. Linn Draper, Jr.	59	Director of CPL and SWEPCo	2000-Present
		Chairman of the Board and Chief Executive Officer of CPL and SWEPCo	2000-Present
		Director of APCo, I&M and OPCo	1992-Present
		Chairman of the Board and Chief Executive Officer of APCo, I&M and OPCo	1993-Present
		Chairman of the Board, President and Chief Executive Officer of AEP and the Service Corporation	1993-Present
Thomas V. Shockley, III	55	Director and Vice President of APCo, CPL, I&M, OPCo and SWEPCo	2000-Present
		Vice Chairman of AEP and the Service Corporation	2000-Present
		President and Chief Operating Officer of CSW	1997-2000
		Executive Vice President of CSW	1990-1997
Henry W. Fayne	54	Director of CPL and SWEPCO	2000-Present
		Director of APCo	1995-Present
		Director of OPCo	1993-Present
		Director of I&M	1998-Present
		Vice President of CPL and SWEPCo	2000-Present
		Vice President of APCo, I&M and OPCo	1998-Present
		Vice President and Chief Financial Officer of AEP	1998-Present
		Executive Vice President-Finance and Analysis of the Service Corporation	2000-Present
		Executive Vice President-Financial Services of the Service Corporation	1998-2000
		Senior Vice President-Corporate Planning & Budgeting of the Service Corporation	1995-1998
William J. Lhota	61	Director of CPL and SWEPCo	2000-Present
		Director of APCo	1990-Present
		Director of I&M and OPCo	1989-Present
		President and Chief Operating Officer of CPL and SWEPCo	2000-Present
		President and Chief Operating Officer of APCo, I&M and OPCo	1996-Present
		Executive Vice President-Energy Delivery of the Service Corporation	2000-Present
		Executive Vice President of the Service Corporation	1993-2000
Susan Tomasky	47	Director and Vice President of APCo, CPL, I&M, OPCo and SWEPCo	2000-Present
		Executive Vice President-Legal, Policy and Corporate Communications and General Counsel of the Service Corporation	2000-Present
		Senior Vice President and General Counsel of the Service Corporation	1998-2000
		Hogan & Hartson (law firm)	1997-1998
		General Counsel of the FERC	1993-1997

Name	Age	Position (a)(b)	Period
J. H. Vipperman	60	Director of CPL and SWEPCo	2000-Present
		Director of APCo	1985-Present
		Director of I&M and OPCo	1996-Present
		Vice President of CPL and SWEPCo	2000-Present
		Vice President of APCo, I&M and OPCo	1996-Present
		Executive Vice President-Shared Services of the Service Corporation	2000-Present
		Executive Vice President-Corporate Services of the Service Corporation	1998-2000
		Executive Vice President-Energy Delivery of the Service Corporation	1996-1997

(a) Dr. Draper is a director of BCP Management, Inc., which is the general partner of Borden Chemicals and Plastics L.P., and Mr. Lhota is a director of Huntington Bancshares Incorporated and State Auto Financial Corporation.
(b) Dr. Draper, Messrs. Fayne, Lhota, Shockley and Vipperman and Ms. Tomasky are directors of AEGCo, CSPCo, KEPCo, PSO and WTU. Dr. Draper and Mr. Shockley are also directors of AEP.

PART II

Item 5. Market for Registrants' Common Equity and Related Stockholder Matters

AEP. AEP Common Stock is traded principally on the New York Stock Exchange. The following table sets forth for the calendar periods indicated the high and low sales prices for the Common Stock as reported on the New York Stock Exchange Composite Tape and the amount of cash dividends paid per share of Common Stock.

	Per Share Market Price		
Quarter Ended	High	Low	Dividend
March 1999	48-3/16	39-5/16	.60
June 1999	44-1/16	37-7/16	.60
September 1999	37-7/8	33-1/2	.60
December 1999	35-13/16	30-9/16	.60
March 2000	34-15/16	25-15/16	.60
June 2000	38-1/2	29-7/16	.60
September 2000	40	29-15/16	.60
December 2000	48-15/16	36-3/16	.60

At December 31, 2000, AEP had approximately 160,000 shareholders of record.

AEGCo, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU. The common stock of these companies is held solely by AEP. The amounts of cash dividends on common stock paid by these companies to AEP during 2000 and 1999 are incorporated by reference to the material under *Statement of Retained Earnings* in the 2000 Annual Reports.

Item 6. Selected Financial Data

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, CPL, I&M, OPCo and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2000 Annual Reports.

Item 7. Management's Discussion and Analysis of Results of Operations and Financial Condition

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under *Management's Narrative Analysis of Results of Operations* in the 2000 Annual Reports.

AEP, APCo, CPL, I&M, OPCo and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Management's Discussion and Analysis of Results of Operations* and *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* in the 2000 Annual Reports.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU. The information required by this item is incorporated herein by reference to the material under *Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters* in the 2000 Annual Reports.

Item 8. Financial Statements and Supplementary Data

AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU. The information required by this item is incorporated herein by reference to the financial statements and supplementary data described under Item 14 herein.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

AEGCo, AEP, APCo, CSPCo, I&M, KEPCo and OPCo. None.

CPL, PSO, SWEPCo and WTU. The information required by this item is incorporated herein by reference to each company's Current Report on Form 8-K dated July 5, 2000.

PART III

Item 10. **Directors and Executive Officers of the Registrants**

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Nominees for Director* of the definitive proxy statement of AEP for the 2001 annual meeting of shareholders, to be filed within 120 days after December 31, 2000. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Election of Directors* of the definitive information statement of each company for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

CPL and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Election of Directors* of the definitive information statement of APCo for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I of this report.

I&M. The names of the directors and executive officers of I&M, the positions they hold with I&M, their ages as of March 12, 2001, and a brief account of their business experience during the past five years appear below and under the caption *Executive Officers of the Registrants* in Part I of this report.

Name	Age	Position (a)	Period
K. G. Boyd	49	Director	1997-Present
		Vice President – Fort Wayne Distribution Operations	2000-Present
		Indiana Region Manager	1997-2000
		Fort Wayne District Manager	1994-1997
Marc E. Lewis	46	Director	2001-Present
		Assistant General Counsel of the Service Corporation	2001-Present
		Senior Counsel of the Service Corporation	2000-2001
		Senior Attorney of the Service Corporation	1994-2000
Susanne M. Moorman	51	Director	2000-Present
		General Manager, Community Services	2000-Present
		Manager, Customer Services Operations	1997-2000
		Director, Customer Services	1994-1997
John R. Sampson	48	Director and Vice President	1999-Present
		Indiana & Michigan State President	1999-Present
		Site Vice President, Cook Nuclear Plant	1998-1999
		Plant Manager, Cook Nuclear Plant	1996-1998
Jackie S. Siefker	47	Director	2000-Present
		Manager, Distribution Systems	2000-Present
		District Manager	1995-2000
D. B. Synowiec	57	Director	1995-Present
		Plant Manager, Rockport Plant	1990-Present
W. E. Walters	53	Director	1991-Present
		Michiana Region Manager	1994-2000
		Director of Projects	2000-Present

(a) Positions are with I&M unless otherwise indicated.

Item 11. **Executive Compensation**

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Directors Compensation and Stock Ownership Guidelines, Executive Compensation* and the performance graph of the definitive proxy statement of AEP for the 2001 annual meeting of shareholders to be filed within 120 days after December 31, 2000.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of each company for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

CPL, I&M and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of APCo for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

The following table sets forth the aggregate cash and other compensation for services rendered for the fiscal years of 2000, 1999 and 1998 paid or awarded to the presidents of CPL and SWEPCo.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation		
					Awards	Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation	Securities Underlying Options (#)	LTIP Payouts ($)(1)	All Other Compensation ($)(2)
J. Gonzalo Sandoval – General manager/president of CPL (3)	2000	143,323	38,153	0	6,250	14,656	7,068
	1999	138,863	31,268	0	0	19,661	7,200
	1998	138,115	34,955	0	0	9,961	6,580
Michael H. Madison – President of SWEPCo (3)	2000	179,922	78,937	0	15,000	192,444	198,211
	1999	186,944	91,065	5,544	0	19,661	8,103
	1998	178,953	87,380	28,914	0	9,961	7,900

(1) The awards reflected in this column are the value of restricted shares paid out under CSW's Long-Term Incentive Plan and, in the case of Mr. Madison, performance share units. Upon vesting, shares of AEP Common Stock were reissued without restrictions. The amounts reported in the Summary Compensation Table represent the market value of the shares at the date of grant.

(2) Detail of the 2000 amounts in the *All Other Compensation* column is shown below.

Item	Mr. Sandoval	Mr. Madison
Savings Plan Matching Contributions	$7,068	$ 7,650
Personal Liability Insurance	0	761
Change-in Control Payment	0	179,000
Vehicle Allowance	0	10,800
Total *All Other Compensation*	$7,068	$ 198,211

(3) Messrs. Sandoval and Madison resigned their positions on June 28, 2000, but remained employees of the AEP System.

Option Grants in 2000

Name	Individual Grants: Number of Securities Underlying Options Granted (#) (1)	Percent of Total Options Granted to Employees in 2000 (2)	Exercise or Base Price ($/Sh)	Expiration Date	Grant Date Present Value ($) (3)
J. Gonzalo Sandoval	6,250	0.1%	35.625	09-20-2010	36,783
Michael H. Madison	15,000	0.2%	35.625	09-20-2010	88,280

(1) Options were granted on September 20, 2000, pursuant to the AEP 2000 Long-Term Incentive Plan. All options granted on this date have an exercise price equal to the closing price of AEP Common Stock on the New York Stock Exchange Composite Transactions Tape on September 20, 2000. These options will vest in equal increments, annually, over a three-year period beginning on January 1, 2002. Options also fully vest upon termination due to retirement after one year from the grant date or due to disability or death and expire five years thereafter, or on their scheduled expiration date if earlier. Options expire upon termination of employment for reasons other than retirement, disability or death, unless the Human Resources Committee determines that circumstances warrant continuation of the options for up to five years. Options are nontransferable.

(2) A total of 6,046,000 options were granted in 2000.

(3) Value was calculated using the Black-Scholes option valuation model. The actual value, if any, ultimately realized depends on the market value of AEP's Common Stock at a future date. Significant assumptions are shown below:

Stock Price Volatility	24.75%	Dividend Yield	6.02%
Risk-Free Rate of Return	6.50%	Option Term	10 years

Aggregated Option Exercises in 2000 and Year-End Option Values

Name	Shares Acquired on Exercise (#) (1)	Value Realized ($) (1)	Number of Securities Underlying Unexercised Options at 12-31-00 (#)		Value of Unexercised In-The-Money Options at 12-31-00 ($) (2)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
J. Gonzalo Sandoval	—	—	1,750	6,250	0	67,969
Michael H. Madison	—	—	6,281	15,000	52,448	163,125

(1) Neither of these officers exercised options during 2000.

(2) Based on the difference between the closing price of AEP Common Stock on the New York Stock Exchange Composite Transactions Tape on December 29, 2000 ($46.50) and the option exercise price. "In-the-money" means the market price of the stock is greater than the exercise price of the option on the date indicated.

Cash Balance Retirement Plan

CPL and SWEPCo maintain the Cash Balance Plan for eligible employees. In addition, these companies maintain the Special Executive Retirement Plan (SERP), a non-qualified plan that provides benefits that cannot be payable under the Cash Balance Plan because of maximum limitations imposed on such plans by the Internal Revenue Code. Under the cash balance formula, each participant has an account for recordkeeping purposes only, to which dollar amount credits are allocated annually based on a percentage of the participant's pay. Pay for the Cash Balance Plan includes base pay, bonuses, overtime, and commissions. The applicable percentage is determined by the age and years of vesting service the participant has as of December 31 of each year.

The following table shows the percentage used to determine dollar amount credits at the age and years of service indicated:

Sum of Age Plus Years of Service	Applicable Percentage
<30	3.0%
30-39	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

As of December 31, 2000, the sum of age plus years of service of Messrs. Sandoval and Madison were 78 and 81, respectively.

At retirement or other termination of employment, an amount equal to the vested balance (including qualified and SERP benefit) then credited to the account is payable to the participant in the form of an immediate or deferred lump sum or annuity. Benefits (both from the Cash Balance Plan and the SERP) under the cash balance formula are not subject to reduction for Social Security benefits or other offset amounts. The estimated annual benefits payable to Messrs. Sandoval and Madison as a single life annuity at age 65 under the Cash Balance Plan and the SERP are $93,508 for Mr. Sandoval and $122,555 for Mr. Madision.

These amounts are based on the following assumptions:

- Salary used is base pay paid for calendar year 2000 assuming no future increases plus bonus at 2000 target level.
- Conversion of the lump-sum cash balance to a single life annuity at age 65, based on an interest rate of 5.78% and the 1983 Group Annuity Mortality Table.

Item 12. **Security Ownership of Certain Beneficial Owners and Management**

AEGCo, CSPCo, KEPCo, PSO and WTU. Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* of the definitive proxy statement of AEP for the 2001 annual meeting of shareholders to be filed within 120 days after December 31, 2000.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of each company for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

CPL and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of APCo for the 2001 annual meeting of stockholders, to be filed within 120 days after December 31, 2000.

I&M. All 1,400,000 outstanding shares of Common Stock, no par value, of I&M are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of I&M generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2001, by each director and nominee of I&M as of March 12, 2001 and each of the executive officers of I&M named in the summary compensation table, and by all directors and executive officers of I&M as a group. It is based on information provided to I&M by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of I&M. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares(a)	Stock Units(b)	Total
Karl G. Boyd	2,137	308	2,445
E. Linn Draper, Jr.	9,535(c)	106,181	115,716
Henry W. Fayne	5,590(d)	11,163	16,753
Marc E. Lewis	898	—	898
William J. Lhota	18,854(c)(d)	16,249	35,103
Susanne M. Moorman	685	—	685
John R. Sampson	430	338	768
Thomas V. Shockley, III	93,965(e)(f)	—	93,965
Jackie S. Siefker	3,093	—	3,093
David B. Synowiec	2,505	423	2,928
Susan Tomasky	1,744	98	1,842
Joseph H. Vipperman	12,460(c)(d)	4,871	17,331
William E. Walters	7,441	334	7,775
All Directors and Executive Officers	244,568(d)(g)	139,965	384,533

(a) Includes share equivalents held in the AEP Retirement Savings Plan (and for Mr. Shockley, the CSW Retirement Savings Plan) in the amounts listed below:

Name	AEP Retirement Savings Plan (Share Equivalents)	Name	AEP Retirement Savings Plan (Share Equivalents)
Mr. Boyd	2,137	Mr. Shockley	6,234
Dr. Draper	3,947	Ms. Siefker	3,093
Mr. Fayne	5,014	Mr. Synowiec	2,505
Mr. Lewis	898	Ms. Tomasky	1,744
Mr. Lhota	16,674	Mr. Vipperman	11,626
Ms. Moorman	685	Mr. Walters	7,441
Mr. Sampson	430	All Directors and Executive Officers	62,428

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan.

(b) This column includes amounts deferred in stock units and held under AEP's officer benefit plans.

(c) Includes the following numbers of shares held in joint tenancy with a family member: Dr. Draper, 5,588; Mr. Lhota, 2,180; and Mr. Vipperman, 76.

(d) Does not include, for Messrs. Fayne, Lhota and Vipperman, 85,231 shares in the American Electric Power System Educational Trust Fund over which Messrs. Fayne, Lhota and Vipperman share voting and investment power as trustees (they disclaim beneficial ownership). The amount of shares shown for all directors and executive officers as a group includes these shares

(e) Includes the following numbers of shares held by family members over which beneficial ownership is disclaimed: Mr. Shockley, 496.

(f) Includes 49, 938 shares for Mr. Shockley attributable to options exercisable within 60 days.

(g) Represents less than 1% of the total number of shares outstanding

Item 13. **Certain Relationships and Related Transactions**

AEP, APCo, CPL, I&M, OPCo and SWEPCo.
None.

AEGCo, CSPCo, KEPCo, PSO and WTU.
Omitted pursuant to Instruction I(2)(c).

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) The following documents are filed as a part of this report:

1. FINANCIAL STATEMENTS:

The following financial statements have been incorporated herein by reference pursuant to Item 8.

	Page
AEGCo:	
Independent Auditors' Report; Statements of Income for the years ended December 31, 2000, 1999 and 1998; Statements of Retained Earnings for the years ended December 31, 2000, 1999 and 1998; Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Balance Sheets as of December 31, 2000 and 1999; Statements of Capitalization as of December 31, 2000 and 1999; Combined Notes to Financial Statements.	
AEP and its subsidiaries consolidated:	
Consolidated Statements of Income for the years ended December 31, 2000, 1999 and 1998; Consolidated Balance Sheets as of December 31, 2000 and 1999; Consolidated Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Consolidated Statements of Common Shareholders' Equity for the years ended December 31, 2000, 1999 and 1998; Combined Notes to Financial Statements; Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries at December 31, 2000 and 1999; Schedule of Consolidated Long-term Debt of Subsidiaries at December 31, 2000 and 1999; Independent Auditors' Reports.	
APCo, CPL, CSPCo, I&M, OPCo, PSO and SWEPCo:	
Independent Auditors' Report(s); Consolidated Statements of Income for the years ended December 31, 2000, 1999 and 1998; Consolidated Balance Sheets as of December 31, 2000 and 1999; Consolidated Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Consolidated Statements of Retained Earnings for the years ended December 31, 2000, 1999 and 1998; Consolidated Statements of Capitalization as of December 31, 2000 and 1999; Schedule of Consolidated Long-term Debt as of December 31, 2000 and 1999; Combined Notes to Financial Statements.	
KEPCo and WTU:	
Independent Auditors' Report(s); Statements of Income for the years ended December 31, 2000, 1999 and 1998; Statements of Retained Earnings for the years ended December 31, 2000, 1999 and 1998; Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998; Balance Sheets as of December 31, 2000 and 1999; Statements of Capitalization as of December 31, 2000 and 1999; Schedule of Long-term Debt as of December 31, 2000 and 1999; Combined Notes to Financial Statements.	
2. FINANCIAL STATEMENT SCHEDULES:	
Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable).	S-1
Independent Auditors' Report	S-2
3. EXHIBITS:	
Exhibits for AEGCo, AEP, APCo, CPL, CSPCo, I&M, KEPCo, OPCo, PSO, SWEPCo and WTU are listed in the Exhibit Index and are incorporated herein by reference	E-1

(b) No Reports on Form 8-K were filed during the quarter ended December 31, 2000.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AMERICAN ELECTRIC POWER COMPANY, INC.

BY: /S/ H. W. FAYNE
(H. W. Fayne, Vice President and Chief Financial Officer)

Date: March 20, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) **Principal Executive Officer:**		
*E. LINN DRAPER, JR.	Chairman of the Board, President, Chief Executive Officer And Director	
(ii) **Principal Financial Officer:**		
/S/ H. W. FAYNE **(H. W. Fayne)**	Vice President and Chief Financial Officer	March 20, 2001
(iii) **Principal Accounting Officer:**		
/S/ L. V. ASSANTE **(L. V. Assante)**	Deputy Controller	March 20, 2001
(iv) **A Majority of the Directors:**		
*E. R. BROOKS *DONALD M. CARLTON *JOHN P. DESBARRES *ROBERT W. FRI *WILLIAM R. HOWELL *LESTER A. HUDSON, JR. *LEONARD J. KUJAWA *JAMES L. POWELL *RICHARD L. SANDOR *THOMAS V. SHOCKLEY, III *DONALD G. SMITH *LINDA GILLESPIE STUNTZ *KATHRYN D. SULLIVAN *MORRIS TANENBAUM		March 20, 2001

*By: /S/ H. W. FAYNE
(H. W. Fayne, Attorney-in-Fact)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP GENERATING COMPANY
APPALACHIAN POWER COMPANY
CENTRAL POWER AND LIGHT COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY
WEST TEXAS UTILITIES COMPANY

BY: /S/ A. A. PENA
(A. A. Pena, Vice President and Treasurer)

Date: March 20, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) **Principal Executive Officer:**		
*E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer And Director	
(ii) **Principal Financial Officer:**		
/S/ A. A. PENA **(A. A. Pena)**	Vice President, Treasurer, And Director	March 20, 2001
(iii) **Principal Accounting Officer:**		
/S/ L. V. ASSANTE **(L. V. Assante)**	Deputy Controller	March 20, 2001
(iv) **A Majority of the Directors:**		
*HENRY W. FAYNE *WM. J. LHOTA *THOMAS V. SHOCKLEY, III *SUSAN TOMASKY *J. H. VIPPERMAN		
*By: /S/ A. A. PENA **(A. A. Pena, Attorney-in-Fact)**		March 20, 2001

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

INDIANA MICHIGAN POWER COMPANY

BY: /S/ A. A. PENA
(A. A. Pena, Vice President and Treasurer)

Date: March 20, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
*E. LINN DRAPER, JR.	Chairman of the Board, Chief Executive Officer And Director	
(ii) Principal Financial Officer:		
/S/ A. A. PENA **(A. A. Pena)**	Vice President and Treasurer	March 20, 2001
(iii) Principal Accounting Officer:		
/S/ L. V. ASSANTE **(L. V. Assante)**	Deputy Controller	March 20, 2001
(iv) A Majority of the Directors:		
*K. G. BOYD * HENRY W. FAYNE *MARC E. LEWIS *WM. J. LHOTA *SUSANNE M. MOORMAN *JOHN R. SAMPSON *THOMAS V. SHOCKLEY, III *JACKIE S. SIEFKER *D. B. SYNOWIEC *SUSAN TOMASKY *J. H. VIPPERMAN *W. E. WALTERS		

*By: /s/ A. A. Pena
(A. A. Pena, Attorney-in-Fact)

March 20, 2001

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INDEX TO FINANCIAL STATEMENT SCHEDULES

INDEPENDENT AUDITORS' REPORT

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARIES:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and its subsidiaries and the financial statements of certain of its subsidiaries, listed in Item 14 herein, as of December 31, 2000 and 1999, and for each of the three years in the period ended December 31, 2000, and have issued our reports thereon dated February 26, 2001; such financial statements and reports are included in the 2000 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of American Electric Power Company, Inc. and its subsidiaries and of certain of its subsidiaries, listed in Item 14, except for the financial statement schedules of Central Power and Light Company and subsidiary, Public Service Company of Oklahoma and its subsidiaries, Southwestern Electric Power Company and subsidiaries, and West Texas Utilities Company for the years ended December 31, 1999 and 1998 and the financial information of Central and South West Corporation and its subsidiaries that is included in the financial statement schedule for American Electric Power Company, Inc. and its subsidiaries for the years ended December 31, 1999 and 1998. These financial statement schedules are the responsibility of the respective company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the corresponding basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000	$17,066	$14,878	$ 423(a)	$21,323(b)	$11,044
Year Ended December 31, 1999	$14,841	$24,165	$15,788(a)	$37,728(b)	$17,066
Year Ended December 31, 1998	$ 9,049	$28,809	$ 8,330(a)	$31,347(b)	$14,841

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000	$2,609	$6,592	$1,526(a)	$8,139(b)	$2,588
Year Ended December 31, 1999	$2,234	$5,492	$1,995(a)	$7,112(b)	$2,609
Year Ended December 31, 1998	$1,333	$5,093	$1,306(a)	$5,498(b)	$2,234

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

CENTRAL POWER AND LIGHT AND SUBSIDIARY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000	$ —	$1,675	$ — (a)	$ — (b)	$1,675
Year Ended December 31, 1999	$ —	$ —	$ — (a)	$ — (b)	$ —
Year Ended December 31, 1998	$ —	$ —	$ — (a)	$ — (b)	$ —

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000........	$3,045	$2,082	$ 1,405(a)	$ 5,873(b)	$ 659
Year Ended December 31, 1999........	$2,598	$3,334	$10,782(a)	$13,669(b)	$3,045
Year Ended December 31, 1998........	$1,058	$7,551	$ 5,278(a)	$11,289(b)	$2,598

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000........	$1,848	$ (235)	$ 907(a)	$1,761(b)	$ 759
Year Ended December 31, 1999........	$2,027	$3,966	$1,367(a)	$5,512(b)	$1,848
Year Ended December 31, 1998........	$1,188	$4,630	$ 221(a)	$4,012(b)	$2,027

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

KENTUCKY POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000........	$637	$ 187	$ 9(a)	$ 551(b)	$282
Year Ended December 31, 1999........	$848	$1,032	$467(a)	$1,710(b)	$637
Year Ended December 31, 1998........	$525	$1,280	$392(a)	$1,349(b)	$848

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

OHIO POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000........	$2,223	$ 472	$ 778(a)	$2,419(b)	$1,054
Year Ended December 31, 1999........	$1,678	$4,730	$1,273(a)	$5,458(b)	$2,223
Year Ended December 31, 1998........	$2,501	$3,255	$ 941(a)	$5,019(b)	$1,678

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000........	$—	$ 467	$ — (a)	$ — (b)	$ 467
Year Ended December 31, 1999........	$—	$ —	$ — (a)	$ — (b)	$—
Year Ended December 31, 1998........	$—	$ —	$ — (a)	$ — (b)	$—

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000........	$4,428	$ 911	$(4,428)(a)	$ — (b)	$ 911
Year Ended December 31, 1999........	$3,269	$5,415	$ — (a)	$4,256(b)	$4,428
Year Ended December 31, 1998........	$2,216	$4,547	$ — (a)	$3,494(b)	$3,269

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

WEST TEXAS UTILITIES COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2000........	$186	$1,499	$46(a)	$1,443(b)	$288
Year Ended December 31, 1999........	$497	$ (66)	$43(a)	$ 288(b)	$186
Year Ended December 31, 1998........	$ 73	$ 616	$40(a)	$ 232(b)	$497

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

EXHIBIT INDEX

Certain of the following exhibits, designated with an asterisk(*), are filed herewith. The exhibits not so designated have heretofore been filed with the Commission and, pursuant to 17 C.F.R. 229.10(d) and 240.12b-32, are incorporated herein by reference to the documents indicated in brackets following the descriptions of such exhibits. Exhibits, designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an exhibit to this form pursuant to Item 14(c) of this report.

Exhibit Number		Description
AEGCo		
3(a)	—	Copy of Articles of Incorporation of AEGCo [Registration Statement on Form 10 for the Common Shares of AEGCo, File No. 0-18135, Exhibit 3(a)].
*3(b)	—	Copy of the Code of Regulations of AEGCo (amended as of June 15, 2000).
10(a)	—	Copy of Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP [Registration Statement No. 33-32752, Exhibit 28(a)].
10(b)(1)	—	Copy of Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended [Registration Statement No. 33-32752, Exhibits 28(b)(1)(A) and 28(b)(1)(B)].
10(b)(2)	—	Copy of Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KEPCo [Registration Statement No. 33-32752, Exhibit 28(b)(2)].
10(b)(3)	—	Copy of Agreement, dated as of October 1, 1984, among AEGCo, I&M, APCo and Virginia Electric and Power Company [Registration Statement No. 33-32752, Exhibit 28(b)(3)].
10(c)	—	Copy of Lease Agreements, dated as of December 1, 1989, between AEGCo and Wilmington Trust Company, as amended [Registration Statement No. 33-32752, Exhibits 28(c)(1)(C), 28(c)(2)(C), 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1993, File No. 0-18135, Exhibits 10(c)(1)(B), 10(c)(2)(B), 10(c)(3)(B), 10(c)(4)(B), 10(c)(5)(B) and 10(c)(6)(B)].
*13	—	Copy of those portions of the AEGCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*24	—	Power of Attorney.
AEP‡		
3(a)	—	Copy of Restated Certificate of Incorporation of AEP, dated October 29, 1997 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1997, File No. 1-3525, Exhibit 3(a)].
3(b)	—	Copy of Certificate of Amendment of the Restated Certificate of Incorporation of AEP, dated January 13, 1999 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 3(b)].
3(c)	—	Composite copy of the Restated Certificate of Incorporation of AEP, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 3(c)].
3(d)	—	Copy of By-Laws of AEP, as amended through January 28, 1998 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 3(b)].
10(a)	—	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(b)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525,

Exhibit Number		Description
AEP‡ (continued)		
		Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(c)	—	Copy of Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended [Registration Statement No. 33-32752, Exhibits 28(c)(1)(C), 28(c)(2)(C), 28(c)(3)(C), 28(c)(4)(C), 28(c)(5)(C) and 28(c)(6)(C); Registration Statement No. 33-32753, Exhibits 28(a)(1)(C), 28(a)(2)(C), 28(a)(3)(C), 28(a)(4)(C), 28(a)(5)(C) and 28(a)(6)(C); and Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1993, File No. 0-18135, Exhibits 10(c)(1)(B), 10(c)(2)(B), 10(c)(3)(B), 10(c)(4)(B), 10(c)(5)(B) and 10(c)(6)(B); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibits 10(e)(1)(B), 10(e)(2)(B), 10(e)(3)(B), 10(e)(4)(B), 10(e)(5)(B) and 10(e)(6)(B)].
10(d)	—	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 10(l)(2)].
10(e)	—	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(f)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(f)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of AEP dated December 15, 1999, File No. 1-3525, Exhibit 10].
†10(g)(1)	—	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
†10(g)(2)	—	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
†10(h)	—	AEP Accident Coverage Insurance Plan for directors [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(g)].
*†10(i)(1)	—	AEP Deferred Compensation and Stock Plan for Non-Employee Directors, as amended June 1, 2000.
*†10(i)(2)	—	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended June 1, 2000.
*†10(j)(1)(A)	—	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.
†10(j)(1)(B)	—	Guaranty by AEP of the Service Corporation Excess Benefits Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(h)(1)(B)].
*†10(j)(2)	—	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified).
†10(j)(3)	—	Service Corporation Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
†10(k)	—	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
†10(l)	—	AEP System Senior Officer Annual Incentive Compensation Plan[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].

Exhibit Number		Description
AEP‡ (continued)		
†10(m)	—	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
†10(n)	—	Letter agreement between AEP and Donald M. Clements, Jr. dated August 19, 1994 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(n)].
†10(o)	—	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
†10(p)	—	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1999, File No. 1-3525, Exhibit 10(p)].
†10(q)	—	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
*†10(r)(1)	—	Employment Agreement between Paul Addis and the Service Corporation dated January 17, 1996.
*†10(r)(2)	—	Amending Agreement dated July 30, 1998 to Employment Agreement of Paul Addis.
*†10(r)(3)	—	AEP Energy Services Incentive Compensation Plan.
*†10(r)(4)	—	AEP Energy Services Phantom Equity Plan.
*†10(s)	—	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001.
*13	—	Copy of those portions of the AEP 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*21	—	List of subsidiaries of AEP.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*23(c)	—	Consent of KPMG Audit plc.
*24	—	Power of Attorney.
APCo‡		
3(a)	—	Copy of Restated Articles of Incorporation of APCo, and amendments thereto to November 4, 1993 [Registration Statement No. 33-50163, Exhibit 4(a); Registration Statement No. 33-53805, Exhibits 4(b) and 4(c)].
3(b)	—	Copy of Articles of Amendment to the Restated Articles of Incorporation of APCo, dated June 6, 1994 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1994, File No. 1-3457, Exhibit 3(b)].
3(c)	—	Copy of Articles of Amendment to the Restated Articles of Incorporation of APCo, dated March 6, 1997 [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 3(c)].
3(d)	—	Composite copy of the Restated Articles of Incorporation of APCo (amended as of March 7, 1997) [Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 3(d)].
*3(e)	—	Copy of By-Laws of APCo (amended as of June 15, 2000).
4(a)	—	Copy of Mortgage and Deed of Trust, dated as of December 1, 1940, between APCo and Bankers Trust Company and R. Gregory Page, as Trustees, as amended and supplemented [Registration Statement No. 2-7289, Exhibit 7(b); Registration Statement No. 2-19884, Exhibit 2(1); Registration Statement No. 2-24453, Exhibit2(n); Registration Statement No. 2-60015, Exhibits 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), 2(b)(6), 2(b)(7), 2(b)(8), 2(b)(9), 2(b)(10), 2(b)(12), 2(b)(14), 2(b)(15), 2(b)(16), 2(b)(17), 2(b)(18), 2(b)(19), 2(b)(20), 2(b)(21), 2(b)(22), 2(b)(23), 2(b)(24), 2(b)(25), 2(b)(26), 2(b)(27) and 2(b)(28); Registration Statement No. 2-64102, Exhibit 2(b)(29); Registration Statement No. 2-66457, Exhibits (2)(b)(30) and 2(b)(31); Registration Statement No. 2-69217, Exhibit 2(b)(32); Registration Statement No. 2-86237, Exhibit 4(b); Registration Statement No. 33-11723, Exhibit 4(b); Registration

Exhibit Number		Description
APCo‡ (continued)		Statement No. 33-17003, Exhibit 4(a)(ii), Registration Statement No. 33-30964, Exhibit 4(b); Registration Statement No. 33-40720, Exhibit 4(b); Registration Statement No. 33-45219, Exhibit 4(b); Registration Statement No. 33-46128, Exhibits 4(b) and 4(c); Registration Statement No. 33-53410, Exhibit 4(b); Registration Statement No. 33-59834, Exhibit 4(b); Registration Statement No. 33-50229, Exhibits 4(b) and 4(c); Registration Statement No. 33-58431, Exhibits 4(b), 4(c), 4(d) and 4(e); Registration Statement No. 333-01049, Exhibits 4(b) and 4(c); Registration Statement No. 333-20305, Exhibits 4(b) and4(c); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1996, File No. 1-3457, Exhibit 4(b); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1998, File No. 1-3457, Exhibit 4(b)].
4(b)	—	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee [Registration Statement No. 333-45927, Exhibit 4(a); Registration Statement No. 333-49071, Exhibit 4(b); Registration Statement No. 333-84061, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1999, File No. 1-3457, Exhibit 4(c)].
*4(c)	—	Company Order and Officers' Certificate, dated June 27, 2000, establishing certain terms of the Floating Rate Notes, Series A, due 2001.
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(e)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].

Exhibit Number		Description
APCo‡ (continued)		
10(e)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of APCo dated December 15, 1999, File No. 1-3457, Exhibit 10].
†10(f)(1)	—	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
†10(f)(2)	—	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
†10(g)	—	AEP System Senior Officer Annual Incentive Compensation Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].
†10(h)(1)	—	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(1)(A)].
†10(h)(2)	—	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified) [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(2)].
†10(h)(3)	—	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
†10(i)	—	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
†10(j)	—	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
†10(k)	—	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
†10(l)	—	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1999, File No. 1-3525, Exhibit 10(p)].
†10(m)	—	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
†10(n)	—	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(s)].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the APCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
21	—	List of subsidiaries of APCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 21].
*23	—	Consent of Deloitte & Touche LLP.
*24	—	Power of Attorney.
CPL‡		
3(a)	—	Restated Articles of Incorporation Without Amendment, Articles of Correction to Restated Articles of Incorporation Without Amendment, Articles of Amendment to Restated Articles of Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment to the Articles of Incorporation [Quarterly Report on Form 10-Q of CPL for the quarter ended March 31, 1997, File No. 0-346, Exhibit 3.1].
*3(b)	—	By-Laws of CPL (amended as of April 19, 2000).
4(a)	—	Indenture of Mortgage or Deed of Trust, dated November 1, 1943, between CPL and The First National Bank of Chicago and R. D. Manella, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.01; Registration

Exhibit Number		Description
CPL‡ (continued)		Statement No. 2-62271, Exhibit 2.02; Form U-1 No. 70-7003, Exhibit 17; Registration Statement No. 2-98944, Exhibit 4 (b); Form U-1 No. 70-7236, Exhibit 4; Form U-1 No. 70-7249, Exhibit 4; Form U-1 No. 70-7520, Exhibit 2; Form U-1 No. 70-7721, Exhibit 3; Form U-1 No. 70-7725, Exhibit 10; Form U-1 No. 70-8053, Exhibit 10 (a); Form U-1 No. 70-8053, Exhibit 10 (b); Form U-1 No. 70-8053, Exhibit 10 (c); Form U-1 No. 70-8053, Exhibit 10 (d); Form U-1 No. 70-8053, Exhibit 10 (e); Form U-1 No. 70-8053, Exhibit 10 (f)].
4(b)	—	CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL: (1) Indenture, dated as of May 1, 1997, between CPL and the Bank of New York, as Trustee [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibits 4.1 and 4.2]. (2) Amended and Restated Trust Agreement of CPL Capital I, dated as of May 1, 1997, among CPL, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.3]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by CPL for the benefit of the holders of CPL Capital I's Preferred Securities [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.4]. (4) Agreement as to Expenses and Liabilities dated as of May 1, 1997, between CPL and CPL Capital I [Quarterly Report on Form 10-Q of CPL dated March 31, 1997, File No. 0-346, Exhibit 4.5].
*4(c)	—	Indenture (for unsecured debt securities), dated as of November 15, 1999, between CPL and The Bank of New York, as Trustee.
*4(d)	—	First Supplemental Indenture, dated as of November 15, 1999, between CPL and The Bank of New York, as Trustee, for Floating Rate Notes due November 23, 2001.
*4(e)	—	Second Supplemental Indenture, dated as of February 16, 2000, between CPL and The Bank of New York, as Trustee, for Floating Rate Notes due February 22, 2002.
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the CPL 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*24	—	Power of Attorney.
CSPCo‡		
3(a)	—	Copy of Amended Articles of Incorporation of CSPCo, as amended to March 6, 1992 [Registration Statement No. 33-53377, Exhibit 4(a)].
3(b)	—	Copy of Certificate of Amendment to Amended Articles of Incorporation of CSPCo, dated May 19, 1994 [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1994, File No. 1-2680, Exhibit 3(b)].
3(c)	—	Composite copy of Amended Articles of Incorporation of CSPCo, as amended [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1994, File No. 1-2680, Exhibit 3(c)].
3(d)	—	Copy of Code of Regulations and By-Laws of CSPCo [Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1987, File No. 1-2680, Exhibit 3(d)].
4(a)	—	Copy of Indenture of Mortgage and Deed of Trust, dated September 1, 1940, between CSPCo and City Bank Farmers Trust Company (now Citibank, N.A.), as trustee, as supplemented and amended [Registration Statement No. 2-59411, Exhibits 2(B) and 2(C); Registration Statement No. 2-80535, Exhibit 4(b); Registration Statement No. 2-87091, Exhibit 4(b); Registration Statement No. 2-93208, Exhibit 4(b); Registration Statement No. 2-97652, Exhibit 4(b); Registration Statement No. 33-7081, Exhibit 4(b); Registration Statement No. 33-12389, Exhibit 4(b); Registration Statement No.

Exhibit Number		Description
CSPCo‡ (continued)		
		33-19227, Exhibits 4(b), 4(e), 4(f), 4(g) and 4(h); Registration Statement No. 33-35651, Exhibit 4(b); Registration Statement No. 33-46859, Exhibits 4(b) and 4(c); Registration Statement No. 33-50316, Exhibits 4(b) and 4(c); Registration Statement No. 33-60336, Exhibits 4(b), 4(c) and 4(d); Registration Statement No. 33-50447, Exhibits 4(b) and 4(c); Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1993, File No. 1-2680, Exhibit 4(b)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-54025, Exhibits 4(a), 4(b), 4(c) and 4(d); Annual Report on Form 10-K of CSPCo for the fiscal year ended December 31, 1998, File No. 1-2680, Exhibits 4(c) and 4(d)].
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, OPCo and I&M and the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo, and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(e)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(e)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of CSPCo dated December 15, 1999, File No. 1-2680, Exhibit 10].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the CSPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23	—	Consent of Deloitte & Touche LLP.
*24	—	Power of Attorney.

Exhibit Number		Description
I&M‡		
3(a)	—	Copy of the Amended Articles of Acceptance of I&M and amendments thereto [Annual Report on Form 10-K of I&M for fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 3(a)].
3(b)	—	Copy of Articles of Amendment to the Amended Articles of Acceptance of I&M, dated March 6, 1997 [Annual Report on Form 10-K of I&M for fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 3(b)].
3(c)	—	Composite Copy of the Amended Articles of Acceptance of I&M (amended as of March 7, 1997) [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 3(c)].
3(d)	—	Copy of the By-Laws of I&M (amended as of January 1, 1996) [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1995, File No. 1-3570, Exhibit 3(c)].
4(a)	—	Copy of Mortgage and Deed of Trust, dated as of June 1, 1939, between I&M and Irving Trust Company (now The Bank of New York) and various individuals, as Trustees, as amended and supplemented [Registration Statement No. 2-7597, Exhibit 7(a); Registration Statement No. 2-60665, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c)(7), 2(c)(8), 2(c)(9), 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), (2)(c)(16), and 2(c)(17); Registration Statement No. 2-63234, Exhibit 2(b)(18); Registration Statement No. 2-65389, Exhibit 2(a)(19); Registration Statement No. 2-67728, Exhibit 2(b)(20); Registration Statement No. 2-85016, Exhibit 4(b); Registration Statement No. 33-5728, Exhibit 4(c); Registration Statement No. 33-9280, Exhibit 4(b); Registration Statement No. 33-11230, Exhibit 4(b); Registration Statement No. 33-19620, Exhibits 4(a)(ii), 4(a)(iii), 4(a)(iv) and 4(a)(v); Registration Statement No. 33-46851, Exhibits 4(b)(i), 4(b)(ii) and 4(b)(iii); Registration Statement No. 33-54480, Exhibits 4(b)(I) and 4(b)(ii); Registration Statement No. 33-60886, Exhibit 4(b)(I); Registration Statement No. 33-50521, Exhibits 4(b)(I), 4(b)(ii) and 4(b)(iii); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 4(b); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1994, File No. 1-3570, Exhibit 4(b); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1996, File No. 1-3570, Exhibit 4(b)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee [Registration Statement No. 333-88523, Exhibits 4(a), 4(b) and 4(c); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1999, File No. 1-3570, Exhibit 4(c)].
* 4(c)	—	Copy of Company Order and Officers' Certificate, dated August 31, 2000, establishing certain terms of the Floating Rate Notes, Series B, due 2002.
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); and Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].

Exhibit Number		Description
I&M‡ (continued)		
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(a)(4)	—	Copy of Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(5)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M, and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 1, 1996, File No. 1-3525, Exhibit 10(l)].
10(e)	—	Copy of Nuclear Material Lease Agreement, dated as of December 1, 1990, between I&M and DCC Fuel Corporation [Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibit 10(d)].
10(f)	—	Copy of Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended [Registration Statement No. 33-32753, Exhibits 28(a)(1)(C), 28(a)(2)(C), 28(a)(3)(C), 28(a)(4)(C), 28(a)(5)(C) and 28(a)(6)(C); Annual Report on Form 10-K of I&M for the fiscal year ended December 31, 1993, File No. 1-3570, Exhibits 10(e)(1)(B), 10(e)(2)(B), 10(e)(3)(B), 10(e)(4)(B), 10(e)(5)(B) and 10(e)(6)(B)].
10(g)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(g)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of I&M dated December 15, 1999, File No. 1-3570, Exhibit 10].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the I&M 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
21	—	List of subsidiaries of I&M [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 21].
*24	—	Power of Attorney.
KEPCo‡		
3(a)	—	Copy of Restated Articles of Incorporation of KEPCo [Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 1991, File No. 1-6858, Exhibit 3(a)].
*3(b)	—	Copy of By-Laws of KEPCo (amended as of June 15, 2000).

Exhibit Number		Description
KEPCo‡ (continued)		
4(a)	—	Copy of Mortgage and Deed of Trust, dated May 1, 1949, between KEPCo and Bankers Trust Company, as supplemented and amended [Registration Statement No. 2-65820, Exhibits 2(b)(1), 2(b)(2), 2(b)(3), 2(b)(4), 2(b)(5), and 2(b)(6); Registration Statement No. 33-39394, Exhibits 4(b) and 4(c); Registration Statement No. 33-53226, Exhibits 4(b) and 4(c); Registration Statement No. 33-61808, Exhibits 4(b) and 4(c), Registration Statement No. 33-53007, Exhibits 4(b), 4(c) and 4(d)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between KEPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-75785, Exhibits 4(a), 4(b), 4(c) and 4(d); Annual Report on Form 10-K of KEPCo for the fiscal year ended December 31, 1999, File No. 1-6858, Exhibit 4(c)].
*4(c)	—	Copy of Company Order and Officers' Certificate, dated November 17, 2000, establishing certain terms of the Floating Rate Notes, Series B, due 2002.
10(a)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a);Registration Statement No. 2-61009, Exhibit 5(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File No. 1-3525, Exhibit 10(a)(3)].
10(b)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent, as amended [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); and Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(c)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].
10(d)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, By and Among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(d)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of KEPCo dated December 15, 1999, File No. 1-6858, Exhibit 10].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the KEPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*24	—	Power of Attorney.
OPCo‡		
3(a)	—	Copy of Amended Articles of Incorporation of OPCo, and amendments thereto to December 31, 1993 [Registration Statement No. 33-50139, Exhibit 4(a); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 3(b)].
3(b)	—	Certificate of Amendment to Amended Articles of Incorporation of OPCo, dated May 3, 1994 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 3(b)].
3(c)	—	Copy of Certificate of Amendment to Amended Articles of Incorporation of OPCo, dated March 6, 1997 [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1996, File No. 1-6543, Exhibit 3(c)].
3(d)	—	Composite copy of the Amended Articles of Incorporation of OPCo (amended as of March 7, 1997) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1996, File No. 1-6543, Exhibit 3(d)].
3(e)	—	Copy of Code of Regulations of OPCo [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1990, File No. 1-6543, Exhibit 3(d)].

Exhibit Number		Description
OPCo‡ (continued)		
4(a)	—	Copy of Mortgage and Deed of Trust, dated as of October 1, 1938, between OPCo and Manufacturers Hanover Trust Company (now Chemical Bank), as Trustee, as amended and supplemented [Registration Statement No. 2-3828, Exhibit B-4; Registration Statement No. 2-60721, Exhibits 2(c)(2), 2(c)(3), 2(c)(4), 2(c)(5), 2(c)(6), 2(c)(7), 2(c)(8), 2(c)(9), 2(c)(10), 2(c)(11), 2(c)(12), 2(c)(13), 2(c)(14), 2(c)(15), 2(c)(16), 2(c)(17), 2(c)(18), 2(c)(19), 2(c)(20), 2(c)(21), 2(c)(22), 2(c)(23), 2(c)(24), 2(c)(25), 2(c)(26), 2(c)(27), 2(c)(28), 2(c)(29), 2(c)(30), and 2(c)(31); Registration Statement No. 2-83591, Exhibit 4(b); Registration Statement No. 33-21208, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Registration Statement No. 33-31069, Exhibit 4(a)(ii); Registration Statement No. 33-44995, Exhibit 4(a)(ii); Registration Statement No. 33-59006, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Registration Statement No. 33-50373, Exhibits 4(a)(ii), 4(a)(iii) and 4(a)(iv); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 4(b)].
4(b)	—	Copy of Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company, as Trustee [Registration Statement No. 333-49595, Exhibits 4(a), 4(b) and 4(c); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1998, File No. 1-6543, Exhibits 4(c) and 4(d); Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1999, File No. 1-6543, Exhibits 4(c) and 4(d)].
*4(c)	—	Copy of Company Order and Officers' Certificate, dated May 22, 2000, establishing certain terms of the Floating Rate Notes, Series A, due 2001.
10(a)(1)	—	Copy of Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended [Registration Statement No. 2-60015, Exhibit 5(a); Registration Statement No. 2-63234, Exhibit 5(a)(1)(B); Registration Statement No. 2-66301, Exhibit 5(a)(1)(C); Registration Statement No. 2-67728, Exhibit 5(a)(1)(D); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1989, File No. 1-3457, Exhibit 10(a)(1)(F); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(1)(B)].
10(a)(2)	—	Copy of Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended [Registration Statement No. 2-60015, Exhibit 5(c); Registration Statement No. 2-67728, Exhibit 5(a)(3)(B); Annual Report on Form 10-K of APCo for the fiscal year ended December 31, 1992, File No. 1-3457, Exhibit 10(a)(2)(B)].
10(a)(3)	—	Copy of Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended [Registration Statement No. 2-60015, Exhibit 5(e)].
10(b)	—	Copy of Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KEPCo, I&M and OPCo and with the Service Corporation, as amended [Registration Statement No. 2-52910, Exhibit 5(a); Registration Statement No. 2-61009, Exhibit 5(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1990, File 1-3525, Exhibit 10(a)(3)].
10(c)	—	Copy of Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KEPCo, OPCo and with the Service Corporation as agent [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(b); Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1988, File No. 1-3525, Exhibit 10(b)(2)].
10(d)	—	Copy of Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KEPCo, OPCo and the Service Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(l)].

Exhibit Number		Description
OPCo‡ (continued)		
10(e)	—	Copy of Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1993, File No. 1-6543, Exhibit 10(f)].
10(f)	—	Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested) [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1994, File No. 1-6543, Exhibit 10(l)(2)].
10(g)(1)	—	Agreement and Plan of Merger, dated as of December 21, 1997, by and among American Electric Power Company, Inc., Augusta Acquisition Corporation and Central and South West Corporation [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1997, File No. 1-3525, Exhibit 10(f)].
10(g)(2)	—	Amendment No. 1, dated as of December 31, 1999, to the Agreement and Plan of Merger [Current Report on Form 8-K of OPCo dated December 15, 1999, File No. 1-6543, Exhibit 10].
†10(h)(1)	—	AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of OPCo for the fiscal year ended December 31, 1985, File No. 1-3525, Exhibit 10(e)].
†10(h)(2)	—	Amendment to AEP Deferred Compensation Agreement for certain executive officers [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1986, File No. 1-3525, Exhibit 10(d)(2)].
†10(i)	—	AEP System Senior Officer Annual Incentive Compensation Plan [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1996, File No. 1-3525, Exhibit 10(i)(1)].
†10(j)(1)	—	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(1)(A)].
†10(j)(2)	—	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2001 (Non-Qualified) [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(j)(2)].
†10(j)(3)	—	Umbrella Trust for Executives [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1993, File No. 1-3525, Exhibit 10(g)(3)].
†10(k)	—	Employment Agreement between E. Linn Draper, Jr. and AEP and the Service Corporation [Annual Report on Form 10-K of AEGCo for the fiscal year ended December 31, 1991, File No. 0-18135, Exhibit 10(g)(3)].
†10(l)	—	AEP System Survivor Benefit Plan, effective January 27, 1998 [Quarterly Report on Form 10-Q of AEP for the quarter ended September 30, 1998, File No. 1-3525, Exhibit 10].
†10(m)	—	AEP Senior Executive Severance Plan for Merger with Central and South West Corporation, effective March 1, 1999[Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1998, File No. 1-3525, Exhibit 10(o)].
†10(n)	—	AEP Change In Control Agreement [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 1999, File No. 1-3525, Exhibit 10(p)].
†10(o)	—	AEP System 2000 Long-Term Incentive Plan [Proxy Statement of AEP, March 10, 2000].
†10(p)	—	Memorandum of agreement between Susan Tomasky and the Service Corporation dated January 3, 2001 [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 10(s)].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the OPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
21	—	List of subsidiaries of OPCo [Annual Report on Form 10-K of AEP for the fiscal year ended December 31, 2000, File No. 1-3525, Exhibit 21].
*23	—	Consent of Deloitte & Touche LLP.

Exhibit Number		Description
OPCo‡ (continued)		
*24	—	Power of Attorney.
PSO‡		
3(a)	—	Restated Certificate of Incorporation of PSO [Annual Report on Form U5S of Central and South West Corporation for the fiscal year ended December 31, 1996, File No. 1-1443, Exhibit B-3.1].
*3(b)	—	By-Laws of PSO (amended as of June 28, 2000).
4(a)	—	Indenture, dated July 1, 1945, between PSO and Liberty Bank and Trust Company of Tulsa, National Association, as Trustee, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.03; Registration Statement No. 2-64432, Exhibit 2.02; Registration Statement No. 2-65871, Exhibit 2.02; Form U-1 No. 70-6822, Exhibit 2; Form U-1 No. 70-7234, Exhibit 3; Registration Statement No. 33-48650, Exhibit 4(b); Registration Statement No. 33-49143, Exhibit 4(c); Registration Statement No. 33-49575, Exhibit 4(b); Annual Report on Form 10-K of PSO for the fiscal year ended December 31, 1993, File No. 0-343, Exhibit 4(b); Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.01; Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.02; Current Report on Form 8-K of PSO dated March 4, 1996, No. 0-343, Exhibit 4.03].
4(b)	—	PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO: (1) Indenture, dated as of May 1, 1997, between PSO and The Bank of New York, as Trustee [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.6 and 4.7]. (2) Amended and Restated Trust Agreement of PSO Capital I, dated as of May 1, 1997, among PSO, as Depositor, The Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibit 4.8]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by PSO for the benefit of the holders of PSO Capital I's Preferred Securities [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.9]. (4) Agreement as to Expenses and Liabilities, dated as of May 1, 1997, between PSO and PSO Capital I [Quarterly Report on Form 10-Q of PSO dated March 31, 1997, File No. 0-343, Exhibits 4.10].
*4(c)	—	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.
*4(d)	—	First Supplemental Indenture, dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee, for Floating Rate Notes, Series A, due November 21, 2002.
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the PSO 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*24	—	Power of Attorney.
SWEPCo‡		
3(a)	—	Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation [Quarterly Report on Form 10-Q of SWEPCo for the quarter ended March 31, 1997, File No. 1-3146, Exhibit 3.4].
3(b)	—	By-Laws of SWEPCo (amended as of April 27, 2000) [Quarterly Report on Form 10-Q of SWEPCo for the quarter ended March 31, 2000, File No. 1-3146, Exhibit 3.3].

Exhibit Number		Description
SWEPCo‡ (continued)		
4(a)	—	Indenture, dated February 1, 1940, between SWEPCO and Continental Bank, National Association and M. J. Kruger, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.04; Registration Statement No. 2-61943, Exhibit 2.02; Registration Statement No. 2-66033, Exhibit 2.02; Registration Statement No. 2-71126, Exhibit 2.02; Registration Statement No. 2-77165, Exhibit 2.02; Form U-1 No. 70-7121, Exhibit 4; Form U-1 No. 70-7233, Exhibit 3; Form U-1 No. 70-7676, Exhibit 3; Form U-1 No. 70-7934, Exhibit 10; Form U-1 No. 72-8041, Exhibit 10(b); Form U-1 No. 70-8041, Exhibit 10(c); Form U-1 No. 70-8239, Exhibit 10(a)].
4(b)	—	SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCO: (1) Indenture, dated as of May 1, 1997, between SWEPCO and the Bank of New York, as Trustee [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibits 4.11 and 4.12]. (2) Amended and Restated Trust Agreement of SWEPCO Capital I, dated as of May 1, 1997, among SWEPCO, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as Delaware Trustee, and the Administrative Trustee [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibit 4.13]. (3) Guarantee Agreement, dated as of May 1, 1997, delivered by SWEPCO for the benefit of the holders of SWEPCO Capital I's Preferred Securities [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibit 4.14]. (4) Agreement as to Expenses and Liabilities, dated as of May 1, 1997 between SWEPCO and SWEPCO Capital I [Quarterly Report on Form 10-Q of SWEPCO dated March 31, 1997, File No. 1-3146, Exhibits 4.15].
*4(c)	—	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCO and The Bank of New York, as Trustee.
*4(d)	—	First Supplemental Indenture, dated as of February 25, 2000, between SWEPCO and The Bank of New York, as Trustee, for Floating Rate Notes due March 1, 2001.
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the SWEPCo 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.
*23(a)	—	Consent of Deloitte & Touche LLP.
*23(b)	—	Consent of Arthur Andersen LLP.
*24	—	Power of Attorney.
WTU‡		
3(a)	—	Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation [Annual Report on Form 10-K of WTU for the fiscal year ended December 31, 1996, File No. 0-340, Exhibit 3.5].
3(b)	—	By-Laws of WTU (amended as of May 1, 2000) [Quarterly Report on Form 10-Q of WTU for the quarter ended March 31, 2000, File No. 0-340, Exhibit 3.4].
4(a)	—	Indenture, dated August 1, 1943, between WTU and Harris Trust and Savings Bank and J. Bartolini, as Trustees, as amended and supplemented [Registration Statement No. 2-60712, Exhibit 5.05; Registration Statement No. 2-63931, Exhibit 2.02; Registration Statement No. 2-74408, Exhibit 4.02; Form U-1 No. 70-6820, Exhibit 12; Form U-1 No. 70-6925, Exhibit 13; Registration Statement No. 2-98843, Exhibit 4(b); Form U-1 No. 70-7237, Exhibit 4; Form U-1 No. 70-7719, Exhibit 3; Form U-1 No. 70-7936, Exhibit 10; Form U-1 No. 70-8057, Exhibit 10; Form U-1 No. 70-8265, Exhibit 10; Form U-1 No. 70-8057, Exhibit 10(b); Form U-1 No. 70-8057, Exhibit 10(c)].
*12	—	Statement re: Computation of Ratios.
*13	—	Copy of those portions of the WTU 2000 Annual Report (for the fiscal year ended December 31, 2000) which are incorporated by reference in this filing.

Exhibit Number		Description
WTU‡ (continued)		
*24	—	Power of Attorney.

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‡Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

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KPSC Case No. 99-149
Attachment 2
Item No. 1

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM U-13-60

ANNUAL REPORT

FOR THE PERIOD

Beginning January 1, 2000 and Ending December 31, 2000

TO THE

U.S. SECURITIES AND EXCHANGE COMMISSION

OF

AMERICAN ELECTRIC POWER SERVICE CORPORATION
(Exact Name of Reporting Company)

A Subsidiary Service Company
("Mutual" or "Subsidiary")

Date of Incorporation December 17, 1937 If not Incorporated, Date of Organization ________.

State or Sovereign Power under which Incorporated or Organized New York

Location of Principal Executive Offices of Reporting Company Columbus, Ohio

Name, title, and address of officer to whom correspondence concerning this report should be addressed:

G. E. Laurey	Assistant Controller Regulated Accounting	1 Riverside Plaza Columbus, Ohio 43215
(Name)	(Title)	(Address)

Name of Principal Holding Company under which Reporting Company is organized:

AMERICAN ELECTRIC POWER COMPANY, INC.

INSTRUCTIONS FOR USE OF FORM U-13-60

1. Time of Filing. Rule 94 provides that on or before the first day of May in each calendar year, each mutual service company and each subsidiary service company as to which the Commission shall have made a favorable finding pursuant to Rule 88, and every service company whose application for approval or declaration pursuant to Rule 88 is pending shall file with the Commission an annual report on Form U-13-60 and in accordance with the Instructions for that form.

2. Number of Copies. Each annual report shall be filed in duplicate. The company should prepare and retain at least one extra copy for itself in case correspondence with reference to the report becomes necessary.

3. Period Covered by Report. The first report filed by any company shall cover the period from the date the Uniform System of Accounts was required to be made effective as to that company under Rules 82 and 93 to the end of that calendar year. Subsequent reports should cover a calendar year.

4. Report Format. Reports shall be submitted on the forms prepared by the Commission. If the space provided on any sheet of such form is inadequate, additional sheets may be inserted of the same size as a sheet of the form or folded to each size.

5. Money Amounts Displayed. All money amounts required to be shown in financial statements may be expressed in whole dollars, in thousands of dollars or in hundred thousands of dollars, as appropriate and subject to provisions of Regulation S-X (210.3-01(b)).

6. Deficits Displayed. Deficits and other like entries shall be indicated by the use of either brackets or a parenthesis with corresponding reference in footnotes. (Regulation S-X,210.3-01(c))

7. Major Amendments or Corrections. Any company desiring to amend or correct a major omission or error in a report after it has been filed with the Commission shall submit an amended report including only those pages, schedules, and entries that are to be amended or corrected. A cover letter shall be submitted requesting the Commission to incorporate the amended report changes and shall be signed by a duly authorized officer of the company.

8. Definitions. Definitions contained in Instruction 01-8 to the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies, Public Utility Holding Company Act of 1935, as amended February 2, 1979 shall be applicable to words or terms used specifically within this Form U-13-60.

9. Organization Chart. The service company shall submit with each annual report a copy of its current organization chart.

10. Methods of Allocation. The service company shall submit with each annual report a listing of the currently effective methods of allocation being used by the service company and on file with the Securities and Exchange Commission pursuant to the Public Utility Holding Company Act of 1935.

11. Annual Statement of Compensation for Use of Capital Billed. The service company shall submit with each annual report a copy of the annual statement supplied to each associate company in support of the amount of compensation for use of capital billed during the calendar year.

LISTING OF SCHEDULES AND ANALYSIS OF ACCOUNTS

LISTING OF SCHEDULES AND ANALYSIS OF ACCOUNTS

SCHEDULE I - COMPARATIVE BALANCE SHEET
(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	ASSETS AND OTHER DEBITS	AS OF DECEMBER 31 2000	1999
	SERVICE COMPANY PROPERTY		
101-106	Service company property (Schedule II)	$ 370,090	$ 389,854
107	Construction work in progress (Schedule II)	26,381	77
	Total Property	396,471	389,931
108-111	Less: Accumulated provision for depreciation and amortization of service company property (Schedule III)	160,520	160,653
	Net Service Company Property	235,951	229,278
	INVESTMENTS		
123	Investments in associate companies (Schedule IV)	-	-
124	Other investments (Schedule IV)	89,027	115,834
	Total Investments	89,027	115,834
	CURRENT AND ACCRUED ASSETS		
131	Cash	2,266	428
134	Special deposits	76	87
135	Working funds	434	282
136	Temporary cash investments (Schedule IV)	-	-
141	Notes receivable	108	113
143	Accounts receivable	1,592	1,676
144	Accumulated provision for uncollectible accounts	-	-
146	Accounts receivable from associate companies (Schedule V)	259,695	100,415
152	Fuel stock expenses undistributed (Schedule VI)	-	-
154	Materials and supplies	-	-
163	Stores expense undistributed (Schedule VII)	-	-
165	Prepayments	1,663	26,050
174	Miscellaneous current and accrued assets (Schedule VIII)	9,402	4,051
	Total Current and Accrued Assets	275,236	133,102
	DEFERRED DEBITS		
181	Unamortized debt expense	3,416	3,843
184	Clearing accounts	370	123
186	Miscellaneous deferred debits (Schedule IX)	4,752	4,400
188	Research, development, or demonstration expenditures (Sch. X)	-	-
190	Accumulated deferred income taxes	73,105	57,719
	Total Deferred Debits	81,643	66,085
	TOTAL ASSETS AND OTHER DEBITS	$ 681,857	$ 544,299

Note: Unamortized Debt Expense includes unamortized loss on reacquired debt of $3,416,309 at December 31, 2000 and $3,843,348 at December 31, 1999.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE I - COMPARATIVE BALANCE SHEET
(In Thousands)

Instructions: Give balance sheet of the Company as of December 31 of the current and prior year.

ACCOUNT	LIABILITIES AND PROPRIETARY CAPITAL	AS OF DECEMBER 31 2000	1999
	PROPRIETARY CAPITAL		
201	Common stock issued (Schedule XI)	$ 1,450	$ 1,450
211	Miscellaneous paid-in-capital (Schedule XI)	-	-
215	Appropriated retained earnings (Schedule XI)	-	-
216	Unappropriated retained earnings (Schedule XI)	-	-
	Total Proprietary Capital	1,450	1,450
	LONG-TERM DEBT		
223	Advances from associate companies (Schedule XII)	1,100	1,100
224	Other long-term debt (Schedule XII)	58,000	60,000
225	Unamortized premium on long-term debt	-	-
226	Unamortized discount on long-term debt-debit	-	-
	Total Long-Term Debt	59,100	61,100
	OTHER NONCURRENT LIABILITIES		
227	Obligations under capital leases - Noncurrent	48,645	47,745
224.6	Other	114,187	92,594
	Total Other Noncurrent Liabilities	162,832	140,339
	CURRENT AND ACCRUED LIABILITIES		
228	Accumulated provision for pensions and benefits	-	-
231	Notes payable	-	39,900
232	Accounts payable	31,802	35,733
233	Notes payable to associate companies (Schedule XIII)	61,398	90,173
234	Accounts payable to associate companies (Schedule XIII)	78,101	15,993
236	Taxes accrued	48,695	1,759
237	Interest accrued	3,720	1,218
238	Dividends declared	-	-
241	Tax collections payable	3,982	1,017
242	Miscellaneous current and accrued liabilities (Schedule XIII)	147,224	71,265
243	Obligations under capital leases - Current	24,798	21,144
	Total Current and Accrued Liabilities	399,720	278,202
	DEFERRED CREDITS		
253	Other deferred credits	15,103	16,368
255	Accumulated deferred investment tax credits	902	953
	Total Deferred Credits	16,005	17,321
282	**ACCUMULATED DEFERRED INCOME TAXES**	42,750	45,887
	TOTAL LIABILITIES AND PROPRIETARY CAPITAL	$ 681,857	$ 544,299

Note: Long term debt includes $2,000,000 due within one year at December 31, 2000 and $2,000,000 at December 31, 1999 (See note 7, Schedule XIV). "Other" Other noncurrent liabilities includes amounts due within one year of $762,664 at December 31, 2000 and $849,937 at December 31, 1999.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	7,010	1,159	-	-	8,169
304 Land and Land Rights	11,489	-	-	-	11,489
305 Structures and Improvements	182,892	281	-	-	183,173
306 Leasehold Improvements	6,810	-	-	-	6,810
307 Equipment (2)	34,167	1,991	(16,617)	-	19,541
308 Office Furniture and Equipment	15,678	103	(2,576)	-	13,205
309 Automobiles, Other Vehicles and Related Garage Equipment	194	-	-	-	194
310 Aircraft and Airport Equipment	12,897	210	(13,107)	-	-
311 Other Service Company Property (3)	118,717	31,091	(23,291)	992	127,509
SUB-TOTALS	389,854	34,835	(55,591)	992	370,090
107 Non-Billable Construction Work in Progress (4)	77	26,381	-	(77)	26,381
TOTALS	$ 389,931	$ 61,216	$ (55,591)	$ 915	$ 396,471

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE II - SERVICE COMPANY PROPERTY
(In Thousands)

FOOTNOTES

(1) *Provide an explanation of those changes considered material:*

Transfers of leased property from assoicate companies (Account 311).
Capitalization of computer system (Account 107).

(2) *Subaccounts are required for each class of equipment owned. The service company shall provide a listing by subaccount of equipment additions during the year and the balance at the close of the year:*

Subaccount Description	Additions	Balance At Close Of Year
Account 307 - Equipment:		
Data Processing Equipment	$ 1,148	$ 14,286
Communications Equipment	644	3,959
Other	199	1,296
TOTALS	$ 1,991	$ 19,541

(3) *Describe Other Service Company Property:*

Account 311 includes leased assets at December 31, 2000 ($127,425,000) which have been capitalized in accordance with FASB Statement Nos. 13 and 71 and other owned assets at December 31, 2000 ($84,000).

(4) *Describe Non-Billable Construction Work in Progress:*

Capitalized Software	$ 24,353
Leasehold Improvements	155
Office Furniture	1,792
Leased Assets	81
TOTALS	$ 26,381

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE III - ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF SERVICE COMPANY PROPERTY

(In Thousands)

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	ADDITIONS	RETIREMENTS OR SALES	OTHER CHANGES (1)	BALANCE AT CLOSE OF YEAR
301 Organization	$ -	$ -	$ -	$ -	$ -
303 Miscellaneous Intangible Plant	2,977	1,705	-	-	4,682
304 Land and Land Rights	-	-	-	-	-
305 Structures and Improvements	73,961	5,425	-	-	79,386
306 Leasehold Improvements	2,991	505	-	-	3,496
307 Equipment	17,904	8,540	(16,617)	27	9,854
308 Office Furniture and Equipment	10,016	1,378	(2,567)	-	8,827
309 Automobiles, Other Vehicles and Related Garage Equipment	196	31	-	-	227
310 Aircraft and Airport Equipment	2,806	355	(3,161)	-	-
311 Other Service Company Property	49,802	24,373	(20,517)	390	54,048
TOTALS	$ 160,653	$ 42,312	$ (42,862)	$ 417	$ 160,520

(1) Provide an explanation of those changes considered material:

Account 307 represents depreciation balance for asset transferred from an affiliate company. Account 311 represents accumulated amortization on leased property transferred from associate companies.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE IV - INVESTMENTS
(In Thousands)

Instructions: Complete the following schedule concerning investments.

Under Account 124 "Other Investments", state each investment separately, with description, including the name of issuing company, number of shares or principal amount, etc.

Under Account 136, "Temporary Cash Investments", list each investment separately.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 123 - Investment in Associate Companies		
Investment in Common Stock of Subs	$ -	$ -
SUB-TOTALS	-	-
Account 124 - Other Investments		
Cash Surrender value of Life Insurance Policies		
(net of policy loans and accrued interest)	11,977	13,348
Umbrella Trust	64,755	74,267
Notes receivable Constructive Marketing Program	135	96
Other Investments 1991-1996		
COLI Tax and Interest	37,783	-
Homes related to employee relocations	110	252
Country Club Memberships	549	605
Texas Stadium Box Seats	525	459
SUB-TOTALS	115,834	89,027
Account 136 - Temporary Cash Investments	-	-
TOTALS	$ 115,834	$ 89,027

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 146 - Accounts Receivable from Associate Companieis		
Account Balances by Associate Company		
AEP Communications, Inc.	$ 41	$ 62
AEP Communications, LLC	1,020	5,101
AEP Credit, Inc.	-	233
AEP Delaware Investment Company II	3	11
AEP Energy Management, LLC	195	-
AEP Energy Services Gas Holding Company	634	660
AEP Energy Services Investments, Inc.	-	34
AEP Energy Services Limited	-	203
AEP Energy Services Ventures, Inc.	-	11
AEP Energy Services, Inc.	-	4,709
AEP Fiber Venture, LLC	-	4
AEP Generating Company	(4)	775
AEP Investments, Inc.	111	149
AEP Power Marketing, Inc.	-	1
AEP Pro Serv, Inc.	363	2,208
AEP Pushan Power, LDC	137	49
AEP Resource Services LLC	-	10
AEP Resources Australia Holdings Pty, Ltd	151	(29)
AEP Resources, Inc.	1,004	2,231
AEP Resources International, Limited	10	-
AEP Resources Limited	246	383
AEP Retail Energy, LLC	-	22
AEP System Pool	-	(10,272)
AEPR Global Investments B.V.	1	-
American Electric Power Company, Inc.	4,626	14,119
American Electric Power Service Corporation/Central South West Services, Inc	-	494
Appalachian Power Company	2,405	45,259
Appalachian Power/Ohio Power Joint Account (Amos)	13,412	15,913
Appalachian Power/Ohio Power Joint Account (Sporn)	4,234	4,310
Blackhawk Coal Company	138	17
C3 Communications, Inc.	116	142
Cardinal Operating Company	503	611

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES

(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Cedar Coal Company	(13)	16
Central and South West Corporation	4,533	10,122
Central Appalachian Coal Company	3	2
Central Coal Company	4	3
Central Ohio Coal Company	296	1,045
Central Power and Light Company	14,431	13,111
Colomet, Inc.	-	29
Columbus Southern Power Company	3,805	28,758
Conesville Coal Preparation Company	200	333
CSW Credit, Inc.	263	-
CSW Energy, Inc.	348	414
CSW Energy Services, Inc.	18	130
CSW International, Inc.	86	91
CSW Leasing, Inc.	222	281
CSW Power Marketing, Inc.	54	-
EnerShop, Inc.	29	21
Franklin Real Estate Company	-	(1)
Indiana Franklin Realty, Inc.	1	-
Indiana Michigan Power Company	13,907	40,348
Indiana Michigan Power Company/Water Transportation Division	1,941	1,738
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	1,960	2,080
Jefferson Island Storage & Hub LLC	50	12
Kentucky Power Company	4,860	9,739
Kingsport Power Company	781	1,248
LIG Chemical Company	1	-
LIG, Inc.	-	(2)
LIG Liquids Company, LLC	65	4
Louisiana Intrastate Gas Company, LLC	130	100
Ohio Power Company	2,408	32,692
Ohio Power/Cook Coal Terminal	744	660
Public Service Company of Oklahoma	5,661	7,796
SEEBOARD plc	724	1,700
Simco, Inc.	2	2
Southern Appalachian Coal Company	6	3
Southern Ohio Coal Company/Martinka	15	704

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Southern Ohio Coal Company/Meigs	1,635	2,965
Southwestern Electric Power Company	7,466	9,553
Tuscaloosa Pipeline Company	1	(1)
West Texas Utilities Company	3,312	4,458
West Virginia Power Company	1	1
Wheeling Power Company	503	1,118
Windsor Coal Company	616	1,002
TOTALS	$ 100,415	$ 259,695

ANALYSIS OF CONVENIENCE OR ACCOMMODATION PAYMENTS:	TOTAL PAYMENTS
BY COMPANY:	
AEP Communications	$ 223
AEP Energy Services, Inc.	261
AEP Resources Australia Holdings Pty, Ltd	1
Appalachian Power Company	186,575
Blackhawk Coal Company	3
C3 Communications, Inc.	249
Cedar Coal Company	21
Central and South West Corporation	(3,657)
Central Ohio Coal Company	24
Central Power and Light Company	7,473
Columbus Southern Power Company	291,065
Conesville Coal Preparation Company	3
CSW Credit	42
CSW Energy Services, Inc.	571
CSW Energy, Inc.	1,386
CSW International, Inc.	155

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE V - ACCOUNTS RECEIVABLE FROM ASSOCIATE COMPANIES
(In Thousands)

Instructions: Complete the following schedule listing accounts receivable from each associate company. Where the service company has provided accommodation or convenience payments for associate companies, a separate listing of total payments for each associate company by subaccount should be provided.

CSW Leasing, Inc.	(999)
EnerShop, Inc.	115
Indiana Michigan Power Company	106,066
Indiana Michigan Power/Water Transportation Division	209
Indiana Michigan/AEP Generating Joint Account (Rockport)	103
Kentucky Power Company	196
Kingsport Power Company	28
LIG Liquids Company, LLC	2
Louisiana Intrastate Gas Company LLC	3
Ohio Power Company	31,943
Ohio Power/Cook Coal Terminal	13
Public Service Company of Oklahoma	(4,806)
SEEBOARD	322
Southern Appalachian Power Company	1
Southern Ohio Coal Company/Meigs	63
Southern Ohio Coal Company/Martinka	19
Southwestern Electric Power Company	170
West Texas Utilities Company	(1,538)
Wheeling Power Company	46
Windsor Coal Company	17
TOTAL	$ 616,368

ANALYSIS OF CONVENIENCE OR ACCOMMODATION PAYMENTS:	TOTAL PAYMENTS
FOR:	
Interchange Power Pool & Transmission Agreements	$ 615,554
Insurance	6,413
Employee Benefit Plans	(1,795)
Membership Dues	397
Trustee Fees	1,912
Educational Programs	90
Consulting Fees	1,076
Telephone Service	181
Office Space	(9,155)
Miscellaneous	1,695
TOTAL	$ 616,368

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE VI - FUEL STOCK EXPENSES UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company. Under the section headed "Summary" listed below give an overall report of the fuel functions performed by the service company.

ACCOUNT DESCRIPTION	LABOR	EXPENSES	TOTAL
Account 152 - Fuel Stock Expenses Undistributed			
Associate Companies			
Appalachian Power Company	$ 318	$ 366	$ 683
Appalachian Power/Ohio Power Joint Account (Amos)	214	231	445
Appalachian Power/Ohio Power Joint Account (Sporn)	90	92	183
Cardinal Operating Company	154	160	314
Columbus Southern Power Company	275	285	560
Indiana Michigan Power Company	137	146	283
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	152	327	480
Kentucky Power Company	134	158	292
Ohio Power Company	683	711	1,393
TOTALS	$ 2,157	$ 2,476	$ 4,633

Summary: The service company provides overall management of fuel supply and transportation procurement, as well as general administration.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE VII - STORES EXPENSE UNDISTRIBUTED
(In Thousands)

Instructions: Report the amount of labor and expenses incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

ACCOUNT DESCRIPTION	LABOR	EXPENSES	TOTAL
Account 163 - Billable Stores Expense Undistributed			
Associate Companies			
AEP Communications, Inc.	$ 1	$ 1	$ 2
AEP Energy Services, Inc.	4	6	10
AEP Generating Company	62	55	117
AEP Investments, Inc.	-	1	1
AEP Pro Serv, Inc.	3	2	5
AEP Resources, Inc.	14	12	26
American Electric Power Company, Inc.	35	37	72
Appalachian Power Company	1,142	1,326	2,468
Appalachian Power/Ohio Power Joint Account (Amos)	53	70	123
Appalachian Power/Ohio Power Joint Account (Sporn))	37	48	85
C3 Communications, Inc.	1	13	14
Cardinal Operating Company	39	49	88
Central and South West Corporation	98	39	137
Central Ohio Coal Company	18	2	20
Central Power and Light Company	633	590	1,223
Columbus Southern Power Company	587	674	1,261
Conesville Coal Preparation Company	6	5	11
Cook Coal Terminal	7	3	10
CSW Credit , Inc.	1	-	1
CSW Energy, Inc.	1	11	12
CSW International, Inc.	-	1	1
ENERSHOP	-	1	1
Indiana Michigan Power Company	797	934	1,731
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	44	52	96
Indiana Michigan Power Company/Water Transportation Division	15	26	41
Kentucky Power Company	226	272	498
Kingsport Power Company	44	50	94
Louisiana Intrastate Gas Company, LLC	1	2	3
Ohio Power Company	1,224	1,421	2,645
Public Service Company of Oklahoma	406	399	805
SEEBOARD plc	4	173	177
Southern Ohio Coal Company - Meigs	106	70	176
Southwestern Electric Power Company	412	274	686
West Texas Utilities Company	194	257	451
Wheeling Power Company	29	32	61
Windsor Coal Company	42	28	70
TOTALS	$ 6,286	$ 6,936	$13,222

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE VIII - MISCELLANEOUS CURRENT AND ACCRUED ASSETS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped, showing number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 174 - Miscellaneous Current and Accrued Assets		
Reclass of year-end debit balances in liability accounts	$ 689	$ 1,676
Pension Plan	3,362	7,726
TOTALS	$ 4,051	$ 9,402

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE IX - MISCELLANEOUS DEFERRED DEBITS
(In Thousands)

Instructions: Provide detail of items in this account. Items less than $10,000 may be grouped by class showing the number of items in each class.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 186 - Miscellaneous Deferred Debits		
Regulatory Asset - Postemployment Benefits	$ 973	$ 648
Regulatory Asset - Postretirement Benefits	2,478	3,715
Regulatory Asset - Taxes	237	217
Unbilled Charges	712	172
TOTALS	$ 4,400	$ 4,752

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE X - RESEARCH, DEVELOPMENT OR DEMONSTRATION EXPENDITURES
(In Thousands)

Instructions: Provide a description of each material research, development, or demonstration project which incurred costs by the service corporation during the year.

ACCOUNT DESCRIPTION	AMOUNT
Account 188 - Billable Research, Development, or Demonstration Expenditures	
Transmission and Distribution	$ 1,109
Steam Power	513
Maintenance of Boiler Plant	13
Fuel	8
Resource Allocation Framework Project with Electric Power Research Institute	201
Wind	(170)
Solar	97
General Activities	334
TOTALS	$ 2,105

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE XI - PROPRIETARY CAPITAL
(Dollars in thousands except per share amounts)

ACCOUNT NUMBER	CLASS OF STOCK	NUMBER OF SHARES AUTHORIZED	PAR OR STATED VALUE PER SHARE	OUTSTANDING CLOSE OF PERIOD NO. OF SHARES	OUTSTANDING CLOSE OF PERIOD TOTAL AMOUNT
Account 201	**Common Stock Issued**	20,000	$ 100	13,500	$ 1,350
Account 201	**Common Stock Issued**	10,000	$ 10	10,000	100
				TOTAL	$ 1,450

Instructions: Classify amounts in each account with brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.

ACCOUNT DESCRIPTION	AMOUNT
Account 211 - Miscellaneous Paid-In Capital	
None	
Account 215 - Appropriated Retained Earnings	
None	
TOTAL	$ -

Instructions: Give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentage, amount of dividend, date declared and date paid.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	NET INCOME OR (LOSS)	DIVIDENDS PAID	BALANCE AT CLOSE OF YEAR
Account 216 - Unappropriated Retained Earnings	$ -	$ -	$ -	$ -
TOTALS	$ -	$ -	$ -	$ -

For the Year Ended December 31, 2000

SCHEDULE XII - LONG-TERM DEBT
(In Thousands)

Instructions: Advances from associate companies should be reported separately for advances on notes, and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation column. For Account 224 - Other long-term debt, provide the name of creditor company or organization, terms of the obligation, date of maturity, interest rate, and the amount authorized and outstanding.

NAME OF CREDITOR	TERM OF OBLIGATION CLASS & SERIES OF OBLIGATION	DATE OF MATURITY	INTEREST RATE	AMOUNT AUTHORIZED	BALANCE AT BEGINNING OF YEAR	ADDITIONS	DEDUCTIONS (1)	BALANCE AT CLOSE OF YEAR
Account 223 - Advances From Associate Companies		None	None	$ 1,100	$ 1,100	$ -	$ -	$ 1,100
Account 224 - Other Long-Term Debt:								
Connecticut Bank & Trust Company (as Trustee), Series E Mortgage Notes		12/15/08	9.600	70,000	50,000	-	2,000	48,000
Suntrust Bank		10/14/03	6.355	10,000	10,000	-	-	10,000
SUBTOTALS				80,000	60,000	-	2,000	58,000
TOTALS				$ 81,100	$ 61,100	$ -	$ 2,000	$ 59,100

(1) Give an explanation of deductions:
Loan Payments. See Note 7, Schedule XIV for further explanation of dates of maturity.

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 233 - Notes Payable to Associate Companies		
Central and South West Corporation	$ 90,173	$ 61,398
TOTALS	$ 90,173	$ 61,398
Account 234 - Accounts Payable to Associate Companies		
AEP Communications, LLC	$ -	$ 56
AEP Energy Services Limited	-	13
AEP Energy Services, Inc.	2,808	2,479
AEP Pro Serv Inc.	-	116
AEP Resources Australia	-	48
AEP System Pool	-	553
American Electric Power Company, Inc.	12	3,766
American Electric Power Service Corporation	329	-
Amos Plant	-	257
Appalachian Power Company	(427)	3,193
Appalachian Power/Ohio Power Joint Account (Sporn)	-	206
Cardinal Operating Company	-	150
Central and South West Corporation	1,180	-
Central Power and Light Company	-	1,247
Columbus Southern Power Company	(194)	3,187
Datapult, LLC	-	791
Franklin Real Estate Company	-	115
Indiana Michigan Power Company	1,177	22,168
Indiana Michigan Power/AEP Generating Joint Account (Rockport)	-	147
Kentucky Power Company	1,244	1,381
Kingsport Power Company	-	156
Ohio Power Company	9,873	35,421
Public Service Company of Oklahoma	-	717
Southwestern Power Company	-	827
West Texas Utilities	-	937
Wheeling Power Company	-	167
Miscellaneous - 5 items in 1999, 10 items in 2000	(9)	3
TOTALS	$ 15,993	$ 78,101

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE XIII - CURRENT AND ACCRUED LIABILITIES
(In Thousands)

Instructions: Provide balance of notes and accounts payable to each associate company. Give description and amount of miscellaneous current and accrued liabilites. Items less than $10,000 may be grouped, showing the number of items in each group.

	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 242 - Miscellaneous Current and Accrued Liabilities		
Control Cash Disbursements Accounts	$ 9,937	$ 9,248
Control Payroll Disbursement Accounts	775	1,101
Deferred Compensation Benefits	1,097	763
Employee Benefits	3,259	4,287
Incentive Pay	30,061	95,727
Real and Personal Property Taxes	212	644
Rent for Office Space at Market Square, Washington, D.C.	209	21
Rent on John E. Dolan Engineering Laboratory	835	791
Rent on Personal Property	221	-
Severance Pay	627	-
Vacation Pay	23,884	33,973
Workers' Compensation	148	669
TOTALS	$ 71,265	$ 147,224

Schedule XIV
NOTES TO FINANCIAL STATEMENTS

INSTRUCTIONS: *The space below is provided for important notes regarding the financial statements or any account thereof. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.*

1. SIGNIFICANT ACCOUNTING POLICIES:

Organization

American Electric Power Service Corporation (the Company or AEPSC) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company provides certain managerial and professional services including administrative and engineering services to the affiliated companies in the American Electric Power (AEP) System and periodically to unaffiliated companies.

Merger

On June 15, 2000, AEP Co., Inc. merged with Central and South West Corporation (CSW) so that CSW became a wholly-owned subsidiary of AEP Co., Inc. On December 31, 2000, AEP Co., Inc. combined its investment in the net assets of CSW Services, Inc., a wholly-owned service company of CSW, with its investment in AEPSC. Since the merger of AEP and CSW was accounted for as a pooling of interests, the financial statements of AEPSC give retroactive effect to the combination of AEPSC and CSW Services, Inc. as if they had always been combined.

Regulation and Basis of Accounting

As a subsidiary of AEP Co., Inc., AEPSC is subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act).

The Company's accounting conforms to the Uniform System of Accounts for Mutual and Subsidiary Service Companies prescribed by the SEC pursuant to the 1935 Act. As a cost-based rate-regulated entity, AEPSC's financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), the financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions to match expenses and revenues in cost-based rates. Regulatory assets are expected to be recovered in future periods through billings to affiliated companies and regulatory liabilities are expected to reduce future billings. The Company has reviewed all the evidence currently available and concluded that it continues to meet the requirements to apply SFAS 71. Among other things application of SFAS 71 requires that the Company's billing rates be cost-based regulated. In the event a portion of the Company's business were to no longer meet those requirements, net regulatory assets would have to be written off for that portion of the business and long-term assets would have to be tested for possible impairment.

Recognized regulatory assets and liabilities are comprised of the following:

	December 31, 2000 (in thousands)
Regulatory Assets:	
Unamortized Loss on Reacquired Debt	$3,375
Postretirement Benefits	648
Postemployment Benefits	3,715
Total Regulatory Assets	$7,738
Regulatory Liabilities:	
Deferred Amounts Due to Affiliates for Income Tax Benefits	$7,274
Deferred Investment Tax Credits	902
Total Regulatory Liabilities	$8,176

Use of Estimates

The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of management's estimates. Actual results could differ from those estimates.

Operating Revenues and Expenses

Services rendered to both affiliated and unaffiliated companies are provided at cost. The

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charges for services include no compensation for the use of equity capital, all of which is furnished by AEP Co., Inc. The costs of the services are determined on a direct charge basis to the extent practicable and on reasonable bases of proration for indirect costs.

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in billings, (that is, deferred taxes are not included in the cost of determining regulated billings for services), deferred income taxes are recorded and related regulatory assets and liabilities are established in accordance with SFAS 71.

Investment Tax Credits

Investment tax credits have been accounted for under the flow-through method unless they have been deferred in accordance with regulatory treatment. Investment tax credits that have been deferred are being amortized over the life of the related investment.

Property

Property is stated at original cost. Land, structures and structural improvements are generally subject to first mortgage liens. Depreciation is provided on a straight-line basis over the estimated useful lives of the property. The annual composite depreciation rate is 9.8%.

Investments

Investments include the cash surrender value of trust owned life insurance policies held under a grantor trust to provide funds for non-qualified deferred compensation plans sponsored by the Company.

Cash and Cash Equivalents

Cash and cash equivalents include unrestricted special deposits, working funds and temporary cash investments with original maturities of three months or less.

Debt

With SEC staff approval, gains and losses on reacquired debt are deferred and amortized over the term of the replacement debt.

Debt issuance expenses are amortized over the term of the related debt, with the amortization included in interest charges.

Comprehensive Income

There were no material differences between net income and comprehensive income.

2. COMMITMENTS AND CONTINGENCIES:

The Company is involved in a number of legal proceedings and claims. While management is unable to predict the outcome of litigation, any potential liability which may result there from would be recoverable from affiliated companies.

On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against the AEP System companies in their suit against the United States over deductibility of interest claimed in their consolidated federal income tax return related to a corporate owned life insurance (COLI) program. The suite was filed to resolve the IRS assertion that interest deductions for the COLI program should not be allowed. In 1998 and 1999 AEPSC paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in Investments on the balance sheet pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, expenses increased by $38 million which

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were billed to the affiliated companies. The appeal of this decision is planned.

3. BENEFIT PLANS:

The Company participates in the AEP System qualified pension plan, a defined benefit plan which covers all employees. Net pension credits for the year ended December 31, 2000 were $5.7 million.

Postretirement Benefits Other Than Pensions are provided for retired employees for medical and death benefits under an AEP System plan. The Company's annual accrued costs were $18 million in 2000.

A defined contribution employee savings plan required that the Company make contributions to this plan totaling $10.8 million in 2000.

4. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT:

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value because of the short-term maturities of these instruments. At December 31, 2000 the fair value of long-term debt, excluding advances from Parent Company, was $70 million based on quoted market prices for similar issues and the current interest rates offered for debt of the same remaining maturities. The carrying amount for long-term debt, excluding advances from Parent Company, was $58 million at December 31, 2000.

The Company is subject to market risk as a result of changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has fixed and variable interest rates with terms from one day to nine years at December 31, 2000. A near term change in interest rates should not materially affect results of operations or financial position since the Company would not expect to liquidate its entire debt portfolio in a one year holding period.

5. INCOME TAXES:

The details of income taxes as reported are as follows:

	Year Ended December 31, 2000 (in thousands)
Current (net)	$ 70,526
Deferred (net)	(18,485)
Deferred Investment Tax Credits (net)	(51)
Total Income Taxes As Reported	$ 51,990

The following is a reconciliation of the difference between the amount of income taxes computed by multiplying book income before income taxes by the federal statutory tax rate, and the amount of income taxes reported.

	Year Ended December 31, 2000 (in thousands)
Net Income	-
Income Taxes	$ 51,990
Pre-Tax Income	$ 51,990
Income Tax on Pre-Tax Income at Statutory Rate (35%)	$ 18,197
Increase (Decrease) in Income Tax Resulting from the Following Items:	
Corporate Owned Life Insurance	29,560
State Income Taxes	2,700
Other	1,533
Total Income Taxes as Reported	$ 51,990
Effective Income Tax Rate	N.M.

Schedule XIV
NOTES TO FINANCIAL STATEMENTS

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The following tables show the elements of the net deferred tax asset and the significant temporary differences:

	December 31, 2000 (in thousands)
Deferred Tax Assets	$ 73,105
Deferred Tax Liabilities	(42,750)
Net Deferred Tax Assets	$ 30,355

Property Related Temporary Differences	$(36,652)
Accrued Pension Expense	8,283
Accrued Vacation Pay	7,978
Deferred and Accrued Compensation	20,785
Amounts Due to Affiliates For Future Income Taxes	2,239
All Other (net)	27,722
Net Deferred Tax Assets	$ 30,355

The Company joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses utilized to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1999 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

6. LEASES:

Leases of structures, improvements, office furniture and miscellaneous equipment are for periods of up to 30 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

The components of lease rental costs are as follows:

	Year Ended December 31, 2000 (in thousands)
Lease Payments on Operating Leases	$ 8,419
Amortization of Capital Leases	27,402
Interest on Capital Leases	6,748
Total Lease Rental Costs	$42,569

Property under capital leases and related obligations recorded on the Balance Sheets are as follows:

	December 31, 2000 (in thousands)
Property Under Capital Leases:	
Structures and Improvements	$ 11,754
Office Furniture and Miscellaneous Equipment	115,671
Total Property Under Capital Leases	127,425
Accumulated Amortization	53,982
Net Property Under Capital Leases	$ 73,443
Obligations Under Capital Leases*:	
Noncurrent Liability	$48,645
Liability Due Within One Year	24,798
Total Obligations Under Capital leases	$73,443

* Represents the present value of future minimum lease payments.

Property under operating leases and related obligations are not included in the Balance Sheets.

Future minimum lease payments for capital leases consisted of the following at December 31, 2000:

	Capital Leases (in thousands)
2001	$29,352
2002	21,792
2003	14,052
2004	6,940
2005	3,137
Later Years	16,027
Total Future Minimum Lease Rentals	91,300
Less Estimated Interest Element	17,857
Estimated Present Value of Future Minimum Lease Rentals	$73,443

Future minimum lease payments for noncancellable operating leases were not material at December 31, 2000.

Schedule XIV
NOTES TO FINANCIAL STATEMENTS

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7. LONG-TERM DEBT:

Long-term debt was outstanding as follows:

	Interest Rate	December 31, 2000 (in thousands)
Notes Payable to Banks:		
Due October 2003	6.355%	$10,000
Mortgage Notes:		
Series E (a)	9.60%	48,000
Advances from Parent Company	(b)	1,100
		59,100
Less Portion Due Within One Year		2,000
Total		$57,100

(a) Due in annual installments of $2,000,000 until 2007 and the balance in December 2008.
(b) The advances from parent company are non-interest bearing and have no due date.

Long-term debt outstanding at December 31, 2000 is payable as follows:

	Principal Amount (in thousands)
2001	$ 2,000
2002	2,000
2003	12,000
2004	2,000
2005	2,000
Later Years	39,100
Total	$59,100

8. SEGMENT INFORMATION:

The Company has one reportable segment. The Company provides certain managerial and professional services including administrative and engineering services. For the year ended December 31, 2000, all of the Company's revenues are derived from managerial and professional services including administrative and engineering services in the United States.

9. MERGER AND ACQUISITIONS COSTS:

The cost of services performed by AEPSC related to mergers and acquisitions are charged to AEP Co., Inc., or its regulated affiliates, or nonregulated affiliates as appropriate. Such costs would be charged to AEP's regulated utilities only if the merger or acquisition pertained to them. Merger costs of AEP Co., Inc. with CSW that were allowed to be recovered from rate-payers were recorded on the electric utility affiliates' books.

10. SHORT-TERM DEBT BORROWINGS

In June 2000 the AEP System established a Money Pool to coordinate short-term borrowings for certain subsidiaries, primarily the domestic electric utility operating companies. The operation of the Money Pool is designed to match on a daily basis the available cash and borrowing requirements of the participants, thereby minimizing the need for short-term borrowings from external sources and increasing the interest income for participants with available cash. Participants with excess cash loan funds to the Money Pool reducing the amount of external funds AEP needs to borrow to meet the short-term cash requirements of other participants whose short-term cash requirements are met through advances from the Money Pool. AEP borrows the funds on a daily basis, when necessary, to meet the net cash requirements of the Money Pool participants. A weighted average daily interest rate which is calculated based on the outstanding short-term debt borrowings made by AEP is applied to each Money Pool participant's daily outstanding investment or debt position to determine interest income or interest expense. The Money Pool participants include interest income in nonoperating income and interest expense in interest charges. As a result of becoming a Money Pool participant, AEPSC retired its short-term debt. At December 31, 2000 AEPSC is a net borrower from the Money Pool and reports its debt position as Advances from Affiliates on the balance sheet.

AEPSC incurred interest expense for amounts borrowed from the AEP money pool for 2000 of $4,748,000.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SCHEDULE XV - COMPARATIVE INCOME STATEMENT
(In Thousands)

ACCOUNT	DESCRIPTION	CURRENT YEAR	PRIOR YEAR
	INCOME		
456	Other electric revenues	$ 138	$ 218
457	Services rendered to associate companies	1,200,660	866,171
458	Services rendered to non associate companies	4,381	2,203
419	Interest income - other	96	157
421	Miscellaneous income or loss	4,660	592
447	Impact studies	322	245
	TOTAL INCOME	1,210,257	869,586
	EXPENSES		
500-559	Power production	184,585	25,469
560-579	Transmission	22,329	6,451
580-599	Distribution	28,647	9,170
901-903	Customer accounts expense	111,402	34,447
905	Miscellaneous customer accounts	907	275
906-917	Customer service & information	26,998	7,188
920	Salaries and wages	322,187	392,663
921	Office supplies and expenses	67,327	63,270
922	Administrative expense transferred - credit	(164,947)	(48,992)
923	Outside services employed	90,681	135,677
924	Property insurance	227	177
925	Injuries and damages	8,527	1,334
926	Employee pensions and benefits	74,505	62,433
928	Regulatory commission expense	12,634	1,747
930.1	General advertising expenses	3,034	4,607
930.2	Miscellaneous general expenses	17,865	13,033
931	Rents	71,198	51,055
935	Maintenance of structures and equipment	14,269	9,754
403-405	Depreciation and amortization expense	18,115	14,931
408	Taxes other than income taxes	34,353	30,007
409	Income taxes	70,819	15,576
410	Provision for deferred income taxes	35,148	14,642
411	Provision for deferred income taxes - credit	(53,683)	(29,181)
416	Expense - sports lighting	1,883	3
417	Administrative - business venture	1,456	1,299
426.1	Donations	1,949	2,161
426.3 - 426.5	Other deductions	3,613	4,971
427	Interest on long-term debt	5,853	6,266
428	Amortization of debt discount and expense	427	-
430	Interest on debt to associate companies	7,095	4,704
431	Other interest expense	12,501	1,479
	TOTAL EXPENSE - INCOME STATEMENT	1,031,904	836,616
	COST OF SERVICE - BALANCE SHEET		
107	Construction work in progress	128,957	19,172
108	Retirement work in progress	4,905	71
120	Nuclear fuel	1	-
151	Fuel stock	1,978	-
152	Fuel stock expense undistributed	4,425	-
163	Stores expense undistributed	12,151	3,607
165	Prepayments	-	(478)
182	Regulatory Assets	1,863	-
183	Preliminary survey and investigation charges	747	787
184	Clearing accounts	2,687	1,241
186	Miscellaneous deferred debits	18,650	8,536
188	Research, development, or demonstration expenses	1,989	34
	TOTAL COST OF SERVICE - BALANCE SHEET	178,353	32,970
	NET INCOME OR (LOSS)	$ -	$ -

Notes:
All accounts on this schedule reflect amounts as booked by the service company.
Prior to 2000, the Balance Sheet accounts only include amounts billable to former CSW system companies.

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For the Year Ended December 31, 2000

ANALYSIS OF BILLING - ASSOCIATE COMPANIES - ACCOUNT 457
(In Thousands)

NAME OF ASSOCIATE COMPANY	DIRECT COSTS CHARGED 457.1	INDIRECT COSTS CHARGED 457.2	COMPENSATION FOR USE OF CAPITAL 457.3	TOTAL AMOUNT BILLED
AEP Communications, Inc.	$ 155	$ 20	$ 2	$ 177
AEP Communications, LLC	10,217	1,760	12	11,989
AEP Credit, Inc.	582	174	2	758
AEP Delaware Investment Company II	7	1	-	8
AEP Energy Management, LLC	265	31	-	296
AEP Energy Services Gas Holding Company	22	3	1	26
AEP Energy Services, Inc.	26,134	1,940	41	28,115
AEP Energy Services Limited	929	120	-	1,049
AEP Energy Services Ventures, Inc.	11	-	-	11
AEP Fiber Venture, LLC	121	14	-	135
AEP Generating Company	2,543	192	8	2,743
AEP Investments, Inc.	734	123	-	857
AEP Power Marketing, Inc.	28	2	-	30
AEP Pro Serv, Inc.	8,482	1,264	6	9,752
AEP Pushan Power, LDC	633	77	-	710
AEP Resources Australia Holdings Pty, Ltd	17	3	-	20
AEP Resources Australia Pty., Ltd.	2	-	-	2
AEP Resources International, Limited	21	3	-	24
AEP Resources Limited	115	20	-	135
AEP Resources Project Management Company, Ltd	4	-	-	4
AEP Resources, Inc.	10,609	1,487	15	12,111
AEP Resources Services LLC	8	1	-	9
AEP Retail Energy, LLC	134	19	-	153
AEP System Pool	20,292	2,572	-	22,864
American Electric Power Company, Inc.	35,565	5,084	74	40,723
Appalachian Power Company	149,251	17,603	427	167,281
Appalachian Power/Ohio Power Joint Account (Amos)	15,327	1,690	43	17,060
Appalachian Power/Ohio Power Joint Account (Sporn)	3,490	465	23	3,978
Blackhawk Coal Company	19	17	-	36
C3 Communications, Inc.	1,027	193	17	1,237
Cardinal Operating Company	4,583	548	24	5,155
Cedar Coal Company	46	4	-	50
Central and South West Corporation	102,644	7,906	574	111,124
Central Appalachian Coal Company	1	-	-	1
Central Coal Company	3	1	-	4
Central Ohio Coal Company	2,239	214	6	2,459
Central Power and Light Company	89,838	15,486	1,045	106,369
Colomet, Inc.	48	8	-	56
Columbus Southern Power Company	86,796	10,337	251	97,384
Conesville Coal Preparation Company	680	110	2	792
CSW Credit, Inc.	571	82	11	664
CSW Energy, Inc.	2,306	467	23	2,796
CSW Energy Services, Inc.	601	91	5	697
CSW International, Inc.	594	128	7	729
CSW Leasing, Inc.	46	10	-	56
EnerShop Inc.	104	27	3	134
Franklin Real Estate Company	122	10	-	132
Indiana Franklin Reality, Inc.	13	1	-	14
Indiana Michigan Power Company	116,502	12,303	290	129,095
Indiana Michigan Power/Water Transportation	1,458	197	3	1,658
Indiana Michigan/AEP Generating Joint Account (Rockport)	6,122	855	23	7,000
Jefferson Island Storage & Hub LLC	179	16	-	195
Kentucky Power Company	32,094	3,799	93	35,986
Kingsport Power Company	3,948	529	14	4,491
LIG Chemical Company	2	1	-	3
LIG Liquids Company LLC	138	14	-	152
LIG Pipeline Company	3	1	-	4
LIG, Inc.	1	-	-	1
Louisiana Intrastate Gas Company, LLC	188	19	-	207
Ohio Power Company	155,220	17,647	434	173,301
Ohio Power/Cook Coal Terminal	636	81	2	719
Public Service Company of Oklahoma	52,180	8,964	551	61,695
SEEBOARD	7,350	1,276	46	8,672
Simco, Inc.	2	-	-	2
Southern Appalachian Coal Company	3	1	-	4
Southern Ohio Coal Company - Martinka	687	2	-	689
Southern Ohio Coal Company - Meigs	6,906	763	17	7,686
Southwestern Electric Power Company	64,670	11,414	685	76,769
Tuscaloosa Pipeline Company	2	-	-	2
West Texas Utilites Company	28,813	5,355	319	34,487
Wheeling Power Company	4,120	542	14	4,676
Windsor Coal Company	2,725	307	6	3,038
Unbilled Revenues	(781)	-	-	(781)
TOTALS	$ 1,061,147	$ 134,394	$ 5,119	$ 1,200,660

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

ANALYSIS OF BILLING - NONASSOCIATE COMPANIES - ACCOUNT 458
(In Thousands)

NAME OF NONASSOCIATE COMPANY	DIRECT COST CHARGED 458.1	INDIRECT COST CHARGED 458.2	COMPENSATION FOR USE OF CAPITAL 458.3	TOTAL COST	EXCESS OR DEFICIENCY 458.4	TOTAL AMOUNT BILLED
Associated Electric Cooperative	$ 2	$ -	$ -	$ 2	$ -	$ 2
Cartonajes Estrella	69	-	-	69	-	69
Casino Magic	1	-	-	1	-	1
CG&E/Zimmer Services Agreement	2	-	-	2	-	2
Cinergy	7	1	-	8	-	8
City of Collinsville	8	-	-	8	-	8
City of Minden	29	-	-	29	-	29
East Central Area Reliability	1,173	166	-	1,339	-	1,339
Electric Power Research Institute	15	-	-	15	-	15
Geothermal Heat Pump Consortium	(7)	-	-	(7)	-	(7)
Harrah's Casino	27	-	-	27	-	27
Indiana Kentucky Electric Corporation	1,457	56	-	1,513	-	1,513
Ohio Valley Electric Company	1,053	181	-	1,234	-	1,234
Sabine Mining Company	-	-	-	-	3	3
Sistemas De Energia	56	-	-	56	-	56
Whit	-	-	-	-	1	1
Others	57	9	-	66	15	81
TOTALS	$ 3,949	$ 413	$ -	$ 4,362	$ 19	$ 4,381

Instruction: Provide a brief description of the services rendered to each nonassociate company:
Engineering, Computer and Environmental Laboratory services.

SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES
(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - INCOME STATEMENT										
456	Other electric revenues	$(138)	$--	$ (138)	$ -	$ -	$ -	$ (138)	-	$ (138)
421	Miscellaneous income or loss	(4,573)	(87)	(4,660)	-	-	-	(4,573)	(87)	(4,660)
447	Impact studies	(322)	-	(322)	-	-	-	(322)	-	(322)
458	Services rendered to non associate companies	(19)	-	(19)	19	-	19	-	-	-
500-559	Power production	171,821	12,223	184,044	426	115	541	172,247	12,338	184,585
560-579	Transmission	19,133	2,803	21,936	393	-	393	19,526	2,803	22,329
580-599	Distribution	23,361	5,253	28,614	33	-	33	23,394	5,253	28,647
901-903	Customer accounts expense	100,183	11,216	111,399	3	-	3	100,186	11,216	111,402
905	Customer assistance	841	66	907	-	-	-	841	66	907
906-917	Customer service & information	24,233	2,765	26,998	-	-	-	24,233	2,765	26,998
920	Salaries and wages	285,807	34,821	320,628	1,442	117	1,559	287,249	34,938	322,187
921	Office supplies and expenses	57,309	9,608	66,917	396	14	410	57,705	9,622	67,327
922	Administrative expense transferred - credit	(164,334)	(613)	(164,947)	-	-	-	(164,334)	(613)	(164,947)
923	Outside service employed	82,623	8,136	90,759	(114)	36	(78)	82,509	8,172	90,681
924	Property insurance	214	13	227	-	-	-	214	13	227
925	Injuries and damages	8,066	456	8,522	5	-	5	8,071	456	8,527
926	Employee pensions and benefits	72,357	2,010	74,367	133	5	138	72,490	2,015	74,505
928	Regulatory commission expense	11,583	1,051	12,634	-	-	-	11,583	1,051	12,634
930 1	General advertising expense	2,919	115	3,034	-	-	-	2,919	115	3,034
930 2	Miscellaneous general expense	17,029	834	17,863	2	-	2	17,031	834	17,865
931	Rents	55,840	15,283	71,123	-	75	75	55,840	15,358	71,198
935	Maintenance of structures and equipment	12,909	1,363	14,272	-	(3)	(3)	12,909	1,360	14,269
403-405	Depreciation and amortization expense	15,877	2,220	18,097	-	18	18	15,877	2,238	18,115
408	Taxes other than income taxes	32,058	2,284	34,342	-	11	11	32,058	2,295	34,353
409	Income taxes	68,746	1,115	69,861	958	-	958	69,704	1,115	70,819
410	Provision for deferred income taxes	35,816	(668)	35,148	-	-	-	35,816	(668)	35,148
411	Provision for deferred income taxes - credit	(53,747)	154	(53,593)	(90)	-	(90)	(53,837)	154	(53,683)
416	Sports lighting	1,772	111	1,883	-	-	-	1,772	111	1,883
417	Administrative - business venture	984	301	1,285	171	-	171	1,155	301	1,456
419	Interest income - other	(95)	(1)	(96)	-	-	-	(95)	(1)	(96)
426.1	Donations	1,853	96	1,949	-	-	-	1,853	96	1,949
426 3-426 5	Other deductions	3,354	259	3,613	-	-	-	3,354	259	3,613
427	Interest on long-term debt	3,294	2,536	5,830	-	23	23	3,294	2,559	5,853
428	Amortization of debt discount and expense	226	199	425	-	2	2	226	201	427
430	Interest on debt to associate companies	4,245	2,850	7,095	-	-	-	4,245	2,850	7,095
431	Other interest expense	12,176	135	12,311	190	-	190	12,366	135	12,501
TOTAL COST OF SERVICE - INCOME STATEMENT		903,401	118,907	1,022,308	3,967	413	4,380	907,368	119,320	1,026,688

SCHEDULE XVI - ANALYSIS OF CHARGES FOR SERVICE - ASSOCIATE AND NONASSOCIATE COMPANIES
(In Thousands)

Instruction: Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

		ASSOCIATE COMPANY CHARGES			NONASSOCIATE COMPANY CHARGES			TOTAL CHARGES FOR SERVICE		
ACCOUNT	DESCRIPTION OF ITEMS	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL	DIRECT COST	INDIRECT COST	TOTAL
COST OF SERVICE - BALANCE SHEET										
107	Construction work in progress	117,666	11,290	128,956	1	-	1	117,667	11,290	128,957
108	Retirement work in progress	4,682	223	4,905	-	-	-	4,682	223	4,905
120	Nuclear fuel	1	-	1	-	-	-	1	-	1
151	Fuel stock	1,661	317	1,978	-	-	-	1,661	317	1,978
152	Fuel stock expense undistributed	4,145	280	4,425	-	-	-	4,145	280	4,425
163	Stores expense undistributed	10,901	1,250	12,151	-	-	-	10,901	1,250	12,151
182	Regulatory assets	1,856	7	1,863	-	-	-	1,856	7	1,863
183	Preliminary survey & investigation charges	616	131	747	-	-	-	616	131	747
184	Clearing accounts	2,492	195	2,687	-	-	-	2,492	195	2,687
186	Miscellaneous deferred debits	17,151	1,499	18,650	-	-	-	17,151	1,499	18,650
188	Research, development, or demonstration expense	1,782	207	1,989	-	-	-	1,782	207	1,989
TOTAL COST OF SERVICE - BALANCE SHEET		162,953	15,399	178,352	1	-	1	162,954	15,399	178,353
TOTAL COST OF SERVICE		$ 1,066,354	$ 134,306	$ 1,200,660	$ 3,968	$ 413	$ 4,381	$ 1,070,322	$ 134,719	$ 1,205,041

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For the Year Ended December 31, 2000

SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

			DEPARTMENT OR SERVICE FUNCTION							
ACCOUNT	DESCRIPTION OF ITEMS	TOTAL AMOUNT	OVERHEAD	ACCOUNTING	ACCOUNTING & FIN. SVCS.	AEP PROSERV	AUDIT SERVICES	CORPORATE COMMUN.	CORPORATE DEVELOP.	CORPORATE PLAN & BUDG.
456	Other Electric Revenues	$ (138)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
419	Interest Income - Other	(96)	-	(1)	-	-	-	-	-	-
421	Miscellaneous Income or Loss	(4,660)	(44)	(4,411)	-	-	-	-	-	-
447	Impact Studies	(322)	-	-	-	-	-	-	-	-
500-559	Power Production	184,585	2,053	93	14	480	65	32	109	1,122
560-579	Transmission	22,329	939	199	-	-	19	-	51	6
580-599	Distribution	28,647	2,526	610	-	-	30	41	74	-
901-903	Customer Accounts Expense	111,402	3,273	8,829	-	-	5	1	30	243
905	Misc. Customer Accounts/Customer Assistance	907	34	-	-	-	-	40	-	-
906-917	Customer Service & Information	26,998	844	991	-	15	-	1,835	27	48
920	Salaries and Wages	322,187	11,955	29,986	125	225	5,556	7,798	19,242	8,105
921	Office Supplies and Expenses	67,327	7,704	1,989	2	3	523	2,122	2,474	770
922	Administrative Expense Transferred - Credit	(164,947)	1	(196,815)	8	8	234	260	1,311	229
923	Outside Service Employed	90,681	8,016	2,542	-	-	214	1,397	1,659	562
924	Property Insurance	227	11	(1)	-	-	-	-	-	-
925	Injuries and Damages	8,527	178	507	-	-	8	12	27	11
926	Employee Pensions and Benefits	74,505	1,237	15,225	2	-	261	321	919	344
928	Regulatory Commission Expense	12,634	7	967	-	-	20	50	37	751
930.1	General Advertising Expense	3,034	17	-	-	1	-	2,965	-	-
930.2	Miscellaneous General Expense	17,865	258	7,066	-	-	14	307	467	172
931	Rents	71,198	17,545	1,426	-	-	75	208	151	61
935	Maintenance of Structures and Equipment	14,269	2,124	77	-	-	4	3	12	34
403-405	Depreciation and Amortization Expense	18,115	11,505	4,417	-	-	-	-	-	-
408	Taxes Other than Income Taxes	34,353	1,987	11,475	5	2	188	266	571	249
409	Income Taxes	70,819	1,329	302	-	-	-	-	-	-
410	Provision for Deferred Income Taxes	35,148	3,664	(1,834)	-	-	-	-	-	-
411	Provision for Deferred Income Taxes - Credit	(53,683)	(5,577)	1,402	-	-	-	-	-	-
417	Administrative - Business Venture	1,456	25	-	-	275	-	-	-	-
416	Cost and Expense of Merchandising	1,883	43	983	-	-	11	-	52	-
426.1	Donations	1,949	74	4	-	-	2	384	-	-
426.3-426.5	Other Deductions	3,613	37	223	-	113	-	146	18	2
427	Interest on Long Term Debt	5,853	2,385	177	-	-	-	-	-	-
428	Amortization on Long Term Debt	427	201	-	-	-	-	-	-	-
430	Interest On Debt To Associate Companies	7,095	26	6,126	-	-	-	-	-	-
431	Other Interest Expense	12,501	7	201	-	-	-	-	-	-
107	Construction Work in Progress	128,957	4,219	1,132	4	83	6	153	490	721
108	Retirement Work in Progress	4,905	41	171	-	14	-	8	7	22
120	Nuclear Fuel	1	-	-	-	-	-	-	-	-
151	Fuel Stock	1,978	176	138	-	-	8	-	-	-
152	Fuel Stock Expense Undistributed	4,425	126	332	-	-	-	7	7	21
163	Stores Expense Undistributed	12,151	472	(134)	-	-	1	14	14	41
182	Regulatory Assets	1,863	4	39	-	-	-	7	7	25
183	Preliminary Survey & Investigation Charges	747	-	1	-	-	-	-	-	-
184	Clearing Accounts	2,687	(8)	(17)	10	-	-	6	6	13
186	Miscellaneous Deferred Debits	18,650	781	(510)	-	-	1	49	279	607
188	Research, Development, or Demonstration Exp.	1,989	112	(11)	-	-	-	4	6	10
	TOTAL COST OF SERVICE	$ 1,205,041	$ 80,307	$ (106,104)	$ 170	$ 1,219	$ 7,245	$ 18,436	$ 28,047	$ 14,169

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION								
ACCOUNT	DESCRIPTION OF ITEMS	CORPORATE SUPPLY CHAIN	CUSTOMER & COMM. SVCS.	ENERGY DEL. SUPPORT	ENERGY DISTRIBUTION	ENERGY SERVICES	ENGINEERING SERVICES	ENVIRON. AFFAIRS	ENVIRON. SERVICES	EXECUTIVE GROUP
456	Other Electric Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (138)
419	Interest Income - Other	-	-	-	-	-	-	-	-	-
421	Miscellaneous Income or Loss	-	(1)	5	(1)	-	(1)	-	-	(1)
447	Impact Studies	-	-	-	(111)	-	-	-	-	-
500-559	Power Production	67	8	75	208	95,976	8,590	-	9,516	11,113
560-579	Transmission	3	30	1,454	1,903	7	58	-	632	6,333
580-599	Distribution	5	1,235	3,196	11,637	1	2	-	1,169	709
901-903	Customer Accounts Expense	23	78,113	20	610	24	-	-	-	58
905	Misc. Customer Accounts/Customer Assistance	-	555	6	22	-	-	-	-	246
906-917	Customer Service & Information	-	17,450	7	-	31	2	-	1	2,681
920	Salaries and Wages	2,789	4,531	6,989	3,482	18,834	4,625	260	2,462	67,281
921	Office Supplies and Expenses	347	2,836	6,388	786	2,181	700	18	509	3,669
922	Administrative Expense Transferred - Credit	496	6,050	2,334	4,133	495	2,068	-	992	1,323
923	Outside Service Employed	26	528	974	243	437	(385)	-	(58)	3,187
924	Property Insurance	-	-	-	-	-	-	-	-	-
925	Injuries and Damages	12	98	61	366	41	51	-	15	130
926	Employee Pensions and Benefits	373	2,930	983	964	2,178	1,258	-	384	876
928	Regulatory Commission Expense	-	1,915	41	290	126	-	-	10	140
930.1	General Advertising Expense	-	3	1	-	-	-	-	-	-
930.2	Miscellaneous General Expense	150	614	716	1,131	72	17	-	57	572
931	Rents	566	3,766	2,254	235	711	126	-	170	1,297
935	Maintenance of Structures and Equipment	-	95	4,724	1	2	99	-	-	86
403-405	Depreciation and Amortization Expense	-	-	-	-	-	-	-	-	-
408	Taxes Other than Income Taxes	277	2,477	769	591	1,327	1,057	7	322	642
409	Income Taxes	-	-	-	-	-	-	-	-	-
410	Provision for Deferred Income Taxes	-	-	-	-	-	-	-	-	-
411	Provision for Deferred Income Taxes - Credit	-	-	-	-	-	-	-	-	-
417	Administrative - Business Venture	-	-	-	1	452	-	-	119	-
416	Cost and Expense of Merchandising	-	448	-	2	-	-	-	-	1
426.1	Donations	-	2	-	8	10	-	-	-	1,207
426.3-426.5	Other Deductions	4	41	5	2	20	10	-	184	722
427	Interest on Long Term Debt	-	-	-	-	-	-	-	-	-
428	Amortization on Long Term Debt	-	-	-	-	-	-	-	-	-
430	Interest On Debt To Associate Companies	-	-	-	-	-	-	-	-	-
431	Other Interest Expense	-	-	-	-	-	-	-	-	-
107	Construction Work in Progress	1,860	3,508	3,632	10,221	1,035	13,023	-	183	14,009
108	Retirement Work in Progress	96	18	84	97	35	346	-	32	81
120	Nuclear Fuel	-	-	-	-	-	-	-	-	-
151	Fuel Stock	-	-	-	-	36	220	-	70	-
152	Fuel Stock Expense Undistributed	94	17	82	67	1,114	797	-	88	79
163	Stores Expense Undistributed	5,630	33	171	351	65	541	-	5	643
182	Regulatory Assets	87	23	76	64	31	260	-	2	87
183	Preliminary Survey & Investigation Charges	-	-	-	-	-	-	-	-	-
184	Clearing Accounts	173	14	57	300	15	106	-	6	50
186	Miscellaneous Deferred Debits	239	242	516	323	80	655	-	5	1,381
188	Research, Development, or Demonstration Exp.	47	8	257	140	17	321	-	84	238
		$ 13,364	$ 127,587	$ 35,877	$ 38,066	$ 125,353	$ 34,546	$ 285	$ 16,959	$ 118,702

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION									
ACCOUNT	DESCRIPTION OF ITEMS	FOSSIL & HYDRO OPER.	GENERAL SERVICES	GOVERNMENTAL AFFAIRS	HUMAN RESOURCES	INFORMATION TECHNOLOGY	LEGAL	MAINT SVCS & REG SVC ORG	MAJOR PROJECTS	MARKET & BUS. DEV.	MINING OPERATIONS
456	Other Electric Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
419	Interest Income - Other	-	-	-	-	-	-	-	-	-	-
421	Miscellaneous Income or Loss	-	(2)	-	(1)	(2)	-	(3)	-	-	-
447	Impact Studies	-	-	-	-	-	-	-	-	-	-
500-559	Power Production	9,650	61	-	530	4,917	58	28,937	211	398	3,610
560-579	Transmission	5	1	-	7	633	-	114	21	44	1
580-599	Distribution	-	-	-	54	7,104	-	2	-	-	1
901-903	Customer Accounts Expense	-	11,843	-	37	7,786	9	-	-	-	-
905	Misc. Customer Accounts/Customer Assistance	-	-	-	-	4	-	1	-	-	-
906-917	Customer Service & Information	3	7	-	85	2,285	1	-	-	-	1
920	Salaries and Wages	1,593	9,664	81	23,520	49,085	9,969	2,166	1,035	84	2,904
921	Office Supplies and Expenses	162	5,566	3	7,045	12,870	1,265	774	180	14	307
922	Administrative Expense Transferred - Credit	585	1,192	-	2,068	4,121	424	707	48	18	111
923	Outside Service Employed	(53)	6,521	-	2,559	35,071	8,969	364	30	-	929
924	Property Insurance	-	37	-	-	-	-	-	-	-	-
925	Injuries and Damages	20	23	-	4,334	111	15	99	-	-	40
926	Employee Pensions and Benefits	381	493	-	36,694	3,102	358	2,529	-	-	239
928	Regulatory Commission Expense	220	13	-	76	1,067	13	62	-	-	160
930.1	General Advertising Expense	-	-	-	44	-	1	-	-	-	-
930.2	Miscellaneous General Expense	69	417	-	1,132	812	1,611	1	-	-	44
931	Rents	7	9,052	-	1,524	28,770	214	828	(4)	(1)	24
935	Maintenance of Structures and Equipment	1	1,145	-	645	5,046	141	24	-	-	-
403-405	Depreciation and Amortization Expense	-	2,188	-	-	-	-	5	-	-	-
408	Taxes Other than Income Taxes	295	2,501	4	1,260	2,768	288	2,701	89	12	137
409	Income Taxes	-	-	-	-	-	-	-	-	-	-
410	Provision for Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-
411	Provision for Deferred Income Taxes - Credit	-	-	-	-	-	-	-	-	-	-
417	Administrative - Business Venture	-	-	-	-	17	-	437	-	-	130
416	Cost and Expense of Merchandising	-	352	-	-	(9)	-	-	-	-	-
426.1	Donations	-	5	-	143	3	10	3	-	-	86
426.3-426.5	Other Deductions	4	5	193	154	12	36	13	-	1	11
427	Interest on Long Term Debt	-	2,670	-	-	-	-	-	-	-	-
428	Amortization on Long Term Debt	-	226	-	-	-	-	-	-	-	-
430	Interest On Debt To Associate Companies	-	-	-	-	-	-	-	-	-	-
431	Other Interest Expense	-	-	-	-	-	-	-	-	-	-
107	Construction Work in Progress	1,177	500	-	718	34,209	527	16,061	997	1	1,034
108	Retirement Work in Progress	41	12	-	10	518	4	2,782	83	-	14
120	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
151	Fuel Stock	-	-	-	-	103	-	1	-	-	1,226
152	Fuel Stock Expense Undistributed	117	11	-	10	505	4	360	-	1	228
163	Stores Expense Undistributed	1,932	32	-	21	979	8	598	1	-	26
182	Regulatory Assets	24	10	-	10	471	4	288	-	-	12
183	Preliminary Survey & Investigation Charges	-	-	-	-	-	-	-	-	-	-
184	Clearing Accounts	39	1,065	-	7	325	2	174	-	-	51
186	Miscellaneous Deferred Debits	75	629	-	3,634	2,263	1,426	1,024	44	20	912
188	Research, Development, or Demonstration Exp.	13	7	-	5	296	18	188	-	-	6
		$ 16,360	$ 56,246	$ 281	$ 86,325	$ 205,242	$ 25,375	$ 61,240	$ 2,735	$ 592	$ 12,244

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SCHEDULE XVII - SCHEDULE OF EXPENSE DISTRIBUTION BY DEPARTMENT OR SERVICE FUNCTION
(In Thousands)

Instruction: Indicate each department or service function. (See Instruction 01-3 General Structure of Accounting System: Uniform System of Accounts).

		DEPARTMENT OR SERVICE FUNCTION							
ACCOUNT	DESCRIPTION OF ITEMS	NUCLEAR	OPERATIONS & TECH SVCS	PLANNING & BUS. DEV.	PUBLIC POLICY	RISK MGMT.	TAX	TRANSMISSION	TREASURY
456	Other Electric Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
419	Interest Income - Other	-	-	-	-	-	(18)	-	(77)
421	Miscellaneous Income or Loss	-	-	-	-	-	-	(1)	(197)
447	Impact Studies	-	-	-	-	-	-	(211)	-
500-559	Power Production	3,078	2,807	35	-	85	-	123	564
560-579	Transmission	-	1	6	37	-	2	9,823	-
580-599	Distribution	-	-	9	-	-	-	242	-
901-903	Customer Accounts Expense	-	-	6	-	-	-	32	460
905	Misc. Customer Accounts/Customer Assistance	-	-	-	-	-	-	(1)	-
906-917	Customer Service & Information	-	2	670	-	-	12	-	-
920	Salaries and Wages	82	505	10,885	116	621	4,576	2,383	8,673
921	Office Supplies and Expenses	23	144	1,640	954	42	292	662	2,363
922	Administrative Expense Transferred - Credit	5	179	222	-	-	230	1,640	376
923	Outside Service Employed	(3)	17	15,033	-	45	2,010	(77)	(76)
924	Property Insurance	-	-	-	-	3	-	-	177
925	Injuries and Damages	1	5	7	-	1	5	159	2,190
926	Employee Pensions and Benefits	38	169	182	-	-	154	1,455	456
928	Regulatory Commission Expense	-	-	6,187	-	-	144	112	226
930.1	General Advertising Expense	-	-	-	-	-	-	-	2
930.2	Miscellaneous General Expense	25	47	163	-	-	22	1,140	769
931	Rents	11	619	438	-	(2)	135	908	84
935	Maintenance of Structures and Equipment	-	-	1	-	-	-	1	4
403-405	Depreciation and Amortization Expense	-	-	-	-	-	-	-	-
408	Taxes Other than Income Taxes	20	114	144	3	28	266	1,276	235
409	Income Taxes	-	-	-	-	-	69,188	-	-
410	Provision for Deferred Income Taxes	-	-	-	-	-	33,318	-	-
411	Provision for Deferred Income Taxes - Credit	-	-	-	-	-	(49,508)	-	-
417	Administrative - Business Venture	-	-	-	-	-	-	-	-
416	Cost and Expense of Merchandising	-	-	-	-	-	-	-	-
426.1	Donations	-	-	7	-	-	-	1	-
426.3-426.5	Other Deductions	2	6	1,622	-	-	4	22	1
427	Interest on Long Term Debt	-	-	-	-	-	-	-	621
428	Amortization on Long Term Debt	-	-	-	-	-	-	-	-
430	Interest On Debt To Associate Companies	-	-	-	-	-	-	-	943
431	Other Interest Expense	-	-	-	-	-	11,471	-	822
107	Construction Work in Progress	-	546	2,567	-	12	30	16,255	44
108	Retirement Work in Progress	-	7	97	-	-	1	282	2
120	Nuclear Fuel	1	-	-	-	-	-	-	-
151	Fuel Stock	-	-	-	-	-	-	-	-
152	Fuel Stock Expense Undistributed	-	7	95	-	1	-	252	3
163	Stores Expense Undistributed	-	14	183	-	-	2	505	3
182	Regulatory Assets	-	7	88	-	-	1	235	1
183	Preliminary Survey & Investigation Charges	-	-	-	-	-	-	746	-
184	Clearing Accounts	-	3	49	-	-	3	229	9
186	Miscellaneous Deferred Debits	-	56	1,821	-	-	5	1,452	641
188	Research, Development, or Demonstration Exp.	-	3	47	-	-	-	173	-
		$ 3,283	$ 5,258	$ 42,204	$ 1,110	$ 836	$ 72,345	$ 39,818	$ 19,319

DEPARTMENTAL ANALYSIS OF SALARIES
(In Thousands except Number of Personnel)

NAME OF DEPARTMENT *Indicate each department or service function.*	DEPARTMENTAL SALARY EXPENSE INCLUDED IN AMOUNTS BILLED TO: TOTAL AMOUNT	PARENT COMPANY	OTHER ASSOCIATES	NON ASSOCIATES	NUMBER OF PERSONNEL END OF YEAR
Service Groups (Overheads)	$ 10,758	$ -	$ 10,361	$ 397	-
Accounting	23,264	8,807	14,455	2	396
Accounting & Financial Services	93	13	80	-	6
AEP ProServ	505	13	492	-	2
Audit Services	4,246	374	3,872	-	43
Corporate Communications	5,362	409	4,953	-	66
Corporate Development	14,518	1,747	12,769	2	134
Corporate Planning & Budgeting	8,392	653	7,735	4	83
Corporate Supply Chain	5,974	196	5,778	-	59
Customer & Community Services	50,416	883	49,533	-	1,434
Energy Delivery Support	13,881	447	13,432	2	156
Energy Distribution	18,426	572	17,832	22	180
Energy Services	43,668	337	43,244	87	333
Engineering Services	16,750	114	16,364	272	299
Environmental Affairs	172	-	172	-	9
Environmental Services	8,451	284	8,132	35	106
Executive Group	75,895	1,948	73,506	441	206
Fossil & Hydro Operations	8,616	396	8,205	15	107
General Services	7,264	562	6,702	-	205
Governmental Affairs	117	-	117	-	17
Human Resources	19,984	2,818	17,157	9	364
Information Technology	48,918	4,338	44,580	-	826
Legal	7,551	678	6,867	6	87
Maintenance Services & Regional Service Organization	38,066	530	37,465	71	681
Major Projects	1,707	92	1,367	248	89
Marketing & Business Development	410	9	267	134	15
Mining Operations	6,034	63	5,971	-	36
Nuclear	483	12	471		1
Operations & Technical Services	2,183	120	2,056	7	10
Planning & Business Development	8,770	1,313	7,457	-	111
Public Policy	94	-	94	-	5
Risk Management	606	2	540	64	38
Tax	3,204	50	3,154	-	50
Transmission	21,603	604	20,947	52	402
Treasury	7,362	430	6,929	3	47
TOTALS	$ 483,743	$ 28,814	$ 453,056	$ 1,873	6,603

These amounts include charges to accounts throughout the Income Statement, including billable Balance Sheet accounts. Therefore, these amounts cannot be identified in total with any particular line on Schedule XV, but are distributed among various lines.

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
A & A Transfer	Consulting Services	$ 133
ABB Power T & D Co Inc.	Consulting Services	169
Abby Lane/Dana Temporaries Inc.	Temporary Office and Accounting Services	356
ABS Consulting Inc.	Consulting Services	399
Accountemps	Temporary Office and Accounting Services	296
Accounting Principles	Temporary Office and Accounting Services	212
Active Development	Consulting Services	300
Adecco Employment Services Inc.	Temporary Office and Accounting Services	123
Advanced Programming Resources	Consulting Services	297
Aerotek Inc.	Temporary Office and Accounting Services	268
Al Stalter and Associates	Consulting Services	539
Allen's Floors Systems	Maintenance Services	108
Analysis Group Economics	Consulting Services	1,131
Analysts International Corporation	Consulting Services	1,061
Andersen Consulting LP	Consulting Services	776
Applied Performance Technologies	Consulting Services	239
ASAP Software Express Inc.	Software License	2,024
Aspect Telecommunications Corporation	Telecommunications Services	1,442
Aurther Andersen	Auditing Services	1,156
Authoria, Inc.	Software License	421
AYCO Company, LP	Financial Services	595
Banctec Service Corporation	Software License	210
Bank of Oklahoma	Banking Services	851
Barcus Co. Inc.	Utility Center Operating	101
Barlow & Hardtner, LLC	Legal Services	216
Bell & Howell Co.	Software Maintenance	134
BMC Receivables Corporation No. 3	Consulting Services	109
BMC Software Distribution Inc.	Software License	3,192
Bracewell & Patterson	Legal Services	1,013
Bradford, T. C. Consulting	Consulting Services	176
Brothers & Company	Consulting Services	225
Broyles & Pratt	Legal Services	108
Burr Wolff LP	Financial Services	116
Butlers Janitorial	Carpet Cleaning Services	147
Buypay Traveler Express Co. Inc.	Wire Service	1,131
Cambridge Energy	Research & Development	119
Candle Corporation	Software License	528
Cap Gemini America	Consulting Services	440
CDI Corporation	Design Services	120
Cedant Mortgage	Mortgage Services	129
Centra Software Inc.	Software License	118
Christy & Viener	Legal Services	1,328
CIT Financial USA, Inc.	Software License	374
City of McAllen	Consulting Services	337
Clark, Thomas & Winters	Legal Services	464
Climate Control Council	Consulting Services	100
Communications Network Inc.	Consulting Services	135
Compaq Computer Corporation	Computer Support	149
Complete Business Solutions Inc.	Consulting Services	659
Computer Associates Inc.	Software License	2,995
Computer Project Resources Inc.	Consulting Services	190
Compuware Corporation	Software License	792
Consultants of Dallas	Consulting Services	156

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

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FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Computer Associates Inc.	Software License	2,995
Computer Project Resources Inc.	Consulting Services	190
Compuware Corporation	Software License	792
Consultants of Dallas	Consulting Services	156
A. C. Coy Company	Consulting Services	210
Craig Stevens C.	Consulting Services	213
Credit Bureau Services	Credit Information Services	197
Crowe Chizek	Software License	142
Data Dynamics, Inc.	Consulting Services	1,455
Database Consultants, Inc.	Consulting Services	177
DAVOX Corporation	Consulting Services	517
Dell Computer Corporation	Computer Support	4,745
Deloitte & Touche LLP	Auditing & Consulting Services	2,580
Dewey Ballentine LLP	Legal Services	173
Digital Equipment Corporation	Consulting Services	190
Dispatch Consumer Services Inc.	Printing Services	137
Doerner, Sauders, Daniel, and Anderson	Legal Services	209
Dorsey, R & Co. Inc.	Consulting Services	193
Dowling, Nancy Lenthe Ph.D.	Consulting Services	120
Economists Incorporated	Consulting Services	414
Edison Electric Institute	Consulting Services	186
Electric Power Research Institute	Research Services	6,800
EMC Corporation	Computer Support	804
Energy Crossroads	Consulting Services	110
ENTEX	PC Workstation Support	974
EPRI Solutions	Research & Development	152
Equifax Credit Information Service	Credit Information Services	721
Equiserve	Transfer Agent	147
Everest Data Research Inc.	Consulting Services	612
Financo Inc.	Consulting Services	192
Paul J. Ford & Co.	Consulting Services	189
Franklin Computer Services Group Inc.	Consulting Services	128
Frontway Network Solutions	Network & eBusiness Services	334
Gartner Group Inc.	Industry Information Services	277
Graves, Dougherty, Hearon & Moody	Legal Services	365
Grosh Consulting	Consulting Services	472
Hewitt Associates	Consulting Services	669
Hewlett-Packard Co.	Computer Support	159
Hogan & Harston LLP	Legal Services	151
Howard Systems	Consulting Services	202
Hunton & Williams	Legal Services	204
Hyperion Software Corporation	Software License	358
Idea Integration	Consulting Services	162
Imprimis Group Inc.	Temporary Office and Accounting Services	498
Indecon Inc.	Consulting Services	1,203
Indus International	Consulting Services	145
Information Builders Inc.	Software Maintenance	385
Information Consultants	Consulting Services	212
Infosystems Corporation	Consulting Services	173

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Jean Simpson	Temporary Office and Accounting Services	212
Jenkens & Gilchrist	Consulting Services	149
Jeter, John A.	Consulting Services	117
Jones, Day, Reavis & Pogue	Legal Services	2,057
Kelly Services, Inc.	Temporary Office and Accounting Services	1,678
A. F. Kelly	Training Services	114
Key Personnel	Temporary Office and Accounting Services	1,598
Kforce.Com	Temporary Office and Accounting Services	461
Kleberg Law Firm	Legal Services	156
L3Comm	Consulting Services	123
LaSalle Partners	Facilities Management	3,924
Leapnet Inc.	Consulting Services	161
Lee, Hecht, & Harrison	Consulting Services	983
Linesoft Inc.	Software License	962
Logica Inc.	Consulting Services	4,475
Logical Resources Inc.	Research Services	260
Lotus Development Corporation	Software Support	218
Love Envelopes	Form Printing Services	571
M3I Systems Inc.	Consulting Services	231
Maloney, Gerald P.	Consulting Services	143
Management Applications Consulting Inc.	Consulting Services	115
Manifest Solutions Corporation	Consulting Services	164
Market Strategies Inc.	Consulting Services	960
Maxim Group	Consulting Services	1,161
Maximation Inc.	Consulting Services	326
Mercer Management Consulting Inc.	Consulting Services	1,087
Mercer, William M.	Consulting Services	403
Meta Group Inc.	Consulting Services	190
Microsoft Corporation	Software License	125
Milbank, Tweed, and Hadley, & McCoy	Legal Services	1,987
Mills James Productions	Merger Uplink	100
Moody's Investment Services	Security Analysis and Rating Services	201
Morgan Guaranty Trust Co.	Financial Services	500
Morris, Nicholas	Legal Services	604
MTI Corporation	Computer Maintenance	107
National City Bank	Financial Services	185
National Theater Company	Consulting Services	235
Neenan, Bernard & Associates	Consulting Services	123
New River Electrical Corporation	Electrical Maintenance	182
Novient Inc.	eServices Fees & Maintenance	284
Odyssey Consulting Services Inc.	Consulting Services	562
Ohio State University	Consulting Services	113
Oklahoma Press Services Inc.	Form Printing Services	310
Onesource Facility Management	Maintenance Services	171
Origin Technology In Business	Consulting Services	536
OSI Outsourcing Services Inc.	Call Handling Service	1,225
P V S International Inc.	Consulting Services	143
Paros Business Partners Inc.	Consulting Services	409
Peoplesoft USA, Inc.	Software Services and Licenses	1,267
PMI Inc.	Training Services	115
Porter, Wright, Morris & Arthur	Legal Services	116
Powerplan Consultants Inc.	Consulting Services	142
Pratt & Grant	Consulting Services	2,601

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For the Year Ended December 31, 2000

OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100,000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Pricewaterhousecoopers LLP	Consulting Services	5,049
Productivity Point International	Consulting Services	886
Professional Network Services	Consulting Services	117
Progressive Marketing, Inc.	Printing Services	141
Proquire LLC	Consulting Services	123
Protec Group Inc.	Consulting Services	707
Protocol Communications	Telecommunications Services	640
Provide Technologies	Consulting Services	534
Quick Solutions Inc.	Consulting Services	865
Rapidigm	Consulting Services	1,716
Ray & Berndtson Inc.	Legal Services	134
Remedy Corporation	Computer Support	1,494
Renaissance Worldwide IT	Consulting Services	1,105
Resource Data International Inc.	Training Services	111
Reynolds & Reynolds	Consulting Services	490
Rice, Scott	Consulting Services	415
RKS Research & Consulting	Consulting Services	105
Roland Technical Services	Consulting Services	460
S4 Netquest	Training Services	157
SAGA Software, Inc.	Consulting Services	388
Sarcom Inc.	Consulting Services	322
Schramm Computer Services	Consulting Services	105
Scott Madden & Associates	Organizational Design Support	131
Search Engines	Temporary Office and Accounting Services	185
Shell Services International Inc.	Consulting Services	336
Sidley & Austin	Legal Services	2,070
Simpson Thacher & Bartlett	Legal Services	474
Sinuflite Training	Aviation Training Services	114
Skipping Stone Inc.	Consulting Services	180
Small World Systems Inc.	Software License	146
Sodexho Marriott Services	Catering	379
Software Support Group	Consulting Services	374
Southwestern Bell	Telecommunications Services	109
Spherion Corporation	Consulting Services	159
SPR Systems & Programming Inc.	Consulting Services	128
Staff Tek	Temporary Office and Accounting Services	237
Standard & Poor's	Security Analysis and Rating Services	109
Steptoe & Johnson LLP	Legal Services	1,379
Sterling Commerce Interchange	Software License	113
Sterling Software Inc.	Software License	130
Stone, Pigman, Walther, Wittman & Hitchenson LLP	Legal Services	218
Stonehenge Partnership	Legal Services	283
Summit Construction	Consulting Services	140
Sun Technical Systems	Consulting Services	382
Sungard CCS	Consulting Services	180
Superior Technical Research	Consulting Services	109
Swafford Consulting Inc.	Consulting Services	172
Taratec Corporation	Consulting Services	180
Taylor, Porter, Brooks & Phill	Legal Services	112
Techlaw Inc.	Legal Services	234
Techmate Inc.	Consulting Services	236
Techrite Copy Services	Office Equipment Services	218
Teksystems	Consulting Services	204

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OUTSIDE SERVICES EMPLOYED
(In Thousands)

Instructions: Provide a breakdown of outside services employed. If the aggregate amount paid to any one payee and included within one category is less than $100.000, only the aggregate number and amount of all such payments included within the subaccount need be shown. Provide a brief description of the service rendered by each vendor listed.

FROM WHOM PURCHASED	SERVICE PROVIDED	AMOUNT
Tesseract	Payroll Benefits Maintenance	103
Thomas Glover Associates Inc.	Consulting Services	148
Thomas, Michael Inc.	Recruiting	117
TQS Research Inc.	Research & Development	107
Training Solutions Group	Training Services	113
Trammell Crow Company	Office Building Security	351
Tulsa Office Solutions	Office Equipment Services	290
Twenty First Century	Consulting Services	255
Twinwood International	Legal Services	106
TXU Electric	Consulting Services	108
Ubics Inc.	Consulting Services	467
Ultimate Business Systems	Computer Services	140
Unisys Corporation	Consulting Services	964
Usertech	Consulting Services	287
Utilities International	Consulting Services	1,141
Utility Data Resources	Consulting Services	435
Varo Engineers, Ltd.	Engineering Services	162
Vinson & Elkins LLP	Legal Services	3,437
Wagstaff, Alvis. Stubleman, Seamster, and Longrace LLP	Legal Services	286
White, Coffey, Galt, and Fite	Legal Services	349
Wilkinson, Carmody & Gillman	Legal Services	597
Willow Wood Lawn Care	Lawn Services	136
Wilson Consulting	Consulting Services	304
Others (2,601 under $100,000)	Various Services	23,333
TOTAL		$ 158,219

These amounts include charges to accounts throughout the Income Statement, including billable Balance Sheet accounts. Therefore, these amounts cannot be identified in total with any particular line on Schedule XV, but are distributed among various lines.

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For the Year Ended December 31, 2000

EMPLOYEE PENSIONS AND BENEFITS - ACCOUNT 926
(In Thousands)

Instructions: Provide a listing of each pension plan and benefit program provided by the service company. Such listing should be limited to $25,000.

DESCRIPTION	AMOUNT
Medical	$ 29,807
Deferred Compensation Benefits	1,165
Other Postretirement Benefits	9,851
Savings Plan	10,691
Supplemental Pension Plan	3,564
Retirement Plan	(6,938)
Long-Term Disability	2,418
Group Life Insurance	6,629
Accidental Death and Disability	65
Dental Insurance	1,528
Employee Educational Assistance	690
Training Administration Expense	1,499
Employee Benefit - Corporate Owned Life Insurance	1,723
Post Employment Benefits	10,619
Employee Awards and Events Program	526
Other Executive Benefits	163
Miscellaneous	505
TOTAL	$ 74,505

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

GENERAL ADVERTISING EXPENSES - ACCOUNT 930.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.1, "General Advertising Expenses", classifying the items according to the nature of the advertising and as defined in the account definition. If a particular class includes an amount in excess of $3,000 applicable to a single payee, show separately the name of the payee and the aggregate amount applicable thereto.

DESCRIPTION	NAME OF PAYEE	AMOUNT
General Advertising	Aboutbusiness	$ 4
	Acadian Concessions	5
	AT&T Media Services	5
	Brothers & Company	5
	CenturyTel Center	8
	Corpus Christi Caller Times	42
	Elite Home & Lifestyle, Inc.	6
	Golden Banner Press	25
	Inventiva	125
	J L Media, Inc	312
	Journal Record	4
	KJRH 2 Tulsa	3
	KTAB - TV	8
	KTBS, Inc.	20
	Longdon Publishing	22
	MC Media, L.L.C.	10
	Meek's Lithograph Company	20
	Morehead Dotts & Associates	18
	National Yellow Pages Direct	668
	New York Financial Writers, Assn.	3
	Oklahoma Press Services, Inc.	86
	Our Texas Magazine	11
	Outdoor Placement of Texas	78
	Pabst Creative Communications	50
	Progressive Marketing, Inc.	199
	Reed-Poland Associates	6
	San Angelo Standard Times	4
	Shreveport Baseball, Inc.	4
	Southwestern Bell	13
	Team Azteca	45
	Tulsa Drillers	5
	United Way of Costal Bend	4
	Verzion Southwest	6
	Others (180)	122
	SUB-TOTAL	1,946
Recruiting and Employment Advertising	Indepth Profile Inc.	7
	JWG Associates	12

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

GENERAL ADVERTISING EXPENSES - ACCOUNT 930.1

(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.1, "General Advertising Expenses", classifying the items according to the nature of the advertising and as defined in the account definition. If a particular class includes an amount in excess of $3,000 applicable to a single payee, show separately the name of the payee and the aggregate amount applicable thereto.

DESCRIPTION	NAME OF PAYEE	AMOUNT
	Katherine Polen & Associates	4
	Nationwide Advertising Services	8
	World Publishing Company	5
	Others (22)	7
	SUB-TOTAL	43
Public Relations	Ark-La-Tex Hockey Club, L.L.C.	4
	Brothers & Company	40
	CenturyTel Center	15
	Dallas Mavericks	29
	HMS Partners of Ohio, Ltd.	525
	Inventiva	166
	J L Media, Inc,	38
	Langdon Publishing	4
	Morehead Dotts & Associates	25
	Oklahoma Today	6
	Our Texas Magazine	18
	Pabst Creative Communications	28
	Premiums and Promotions, Inc.	27
	Rio Grande Valley White Wings	3
	Tulsa Drillers	5
	University of Tulsa	10
	Others (146)	102
	SUB-TOTAL	1,045
	TOTAL	$ 3,034

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For the Year Ended December 31, 2000

MISCELLANEOUS GENERAL EXPENSES - ACCOUNT 930.2
(In Thousands)

Instructions: Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Payments and expenses permitted by Section 321(b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441 (b)(2)) shall be separately classified.

DESCRIPTION	AMOUNT
Membership Fees and Dues	$ 7,313
Salaries, Salary Related Expenses and Overheads	2,327
Directors' Fees and Expenses	55
Cook Plant contract settlement	113
Relocation Expenses	6,785
Directors' Fees and Expenses	228
Trustee, Registrar, and Transfer Agent Fees	477
Annual Report Expenses	172
Corporate Financial Rating Fees	259
Miscellaneous	136
TOTAL	$ 17,865

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For the Year Ended December 31, 2000

RENTS - ACCOUNT 931
(In Thousands)

Instructions: Provide a listing of the amount included in Account 931, "Rents", classifying such expenses by major groupings of property, as defined in the account definition of the Uniform System of Accounts.

TYPE OF PROPERTY	AMOUNT
Office Space	$ 26,050
Offsite Storage Space	37
Computer Timesharing	89
Computer Software	4,720
Computer Equipment	32,736
Office Equipment	1,902
Telecommunications Equipment	3,188
Miscellaneous	2,476
TOTAL	$ 71,198

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For the Year Ended December 31, 2000

TAXES OTHER THAN INCOME TAXES - ACCOUNT 408
(In Thousands)

Instructions: Provide an analysis of Account 408 "Taxes Other Than Income Taxes". Separate the analysis into two groups: (1) other than U.S. Government taxes, and (2) U.S. Government taxes. Specify each of the various kinds of taxes and show the amounts thereof. Provide a subtotal for each class of tax.

DESCRIPTION	AMOUNT
Taxes Other Than U.S. Government Taxes	
State Unemployment Taxes	$ 547
Property, Franchise, Ad Valorem and Other Taxes	3,880
SUB-TOTAL	4,427
U.S. Government Taxes	
Social Security Taxes	29,524
Federal Unemployment Taxes	402
SUB-TOTAL	29,926
TOTAL	$ 34,353

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For the Year Ended December 31, 2000

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
2000 Salute to the House-Commerce Committee	Community	$ 25
African American Businessmen's, Assoc.	Community	10
American Legislative Exchange	Community	3
American Society of Mechanical Engineers	Educational	25
Associate of Graduates, United States Air Force Academy	Educational	5
Austin Lyric Opera	Community	5
Balletmet	Community	6
Boy Scouts of America	Community	6
Boys and Girls Clubs of America	Community	5
Brookings Institution	Community	10
Campaign for Advancement of Manufacturing, Inc.	Community	15
Center of Science and Industry	Community	39
Champion of the Children Fund	Community	5
Child Care Group	Community	6
Children's Hospital Foundation	Community	29
Circle Ten Council Boy Scouts	Community	10
College Fund/United Negro College Fund	Educational	14
Columbus Academy	Educational	3
Columbus Association for Performing Arts	Community	10
Columbus Metropolitan Club	Community	3
Columbus Museum of Art	Community	5
Columbus Symphony Orchestra	Community	25
Columbus Technology Leadership	Community	25
Columbus Zoo	Community	12
Cornell University	Educational	4
Council for Ethics	Community	5
Cowboy Artist of America	Community	8
Crystal Charity	Community	5
Dallas Arboretum	Community	25
Dallas Area Interfaith	Community	3
Dallas Citizens Council	Community	3
Dallas Museum of Art	Community	5
Dallas Opera	Community	10
Dallas Symphony Association, Inc.	Community	15
Decorative Arts Center of Ohio	Community	30
Directions for Youth	Community	5
Energy Research Center	Community	6
Family Gateway	Community	5

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Financial Accounting Foundation	Educational	3
Forging New Links	Community	3
Fort Bend CASA	Community	6
Franklin University	Educational	4
Goodwill Rehabilitation	Community	5
Governor's Business Association	Community	5
Grandview Heights High School	Educational	10
Greater Dallas Chamber of Commerce	Community	36
Habitat for Humanity	Community	16
I Know I Can	Educational	7
Illinois Institute of Technology	Educational	3
Lancaster Country Club	Community	4
Lancaster Festival Inc.	Community	4
Lancaster/Fairfield Bicentennial	Community	5
Leadership Texas	Educational	10
Leukemia Society	Community	9
Links Inc.	Community	5
Management Improvement Committee	Community	5
National Academy of Engineering	Educational	5
National Governors Association	Community	12
National Press Foundation	Community	3
Nature Conservancy	Community	10
Nature Conservatory of Texas	Community	6
Ohio Academy of Science	Educational	4
Ohio Award for Excellence	Community	7
Ohio Chamber of Commerce	Community	5
Ohio Chamber of Commerce Manufacturers	Community	10
Ohio Dominican College	Educational	7
Ohio Energy Project	Community	35
Ohio Foundation of Independent Colleges	Educational	28
Ohio Legislative Black Caucus Foundation	Community	3
Ohio River Valley Water Sanitation Commission	Community	15
Ohio State University	Educational	101
Opera Columbus	Community	8
Resources for the Future	Community	25
Salesmanship Club	Community	28
Salvation Army Inc.	Community	20
Science & Mathematics Network	Educational	5

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For the Year Ended December 31, 2000

DONATIONS - ACCOUNT 426.1
(In Thousands)

Instructions: Provide a listing of the amount included in Account 426.1, "Donations", classifying such expenses by its purpose. The aggregate number and amount of all items of less than $3,000 may be shown in lieu of details.

NAME OF RECIPIENT	PURPOSE OF DONATION	AMOUNT
Simon Kenton Council	Community	61
Southeast Community Business & Education	Community	10
St Jude Hospital	Community	3
STM Wireless - Provinir School - Bolivia	Educational	7
Texas Business and Education Association	Educational	5
Texas Council of Economic Development	Community	5
Texas Tech University	Educational	20
United Way of Franklin County	Community	327
United Way of Metropolitan Dallas, Inc.	Community	50
University of Texas	Educational	20
University of Texas at Austin	Educational	20
Utilitree Carbon Company	Community	20
Utility Business Association	Community	5
Utility Business Education Coalition	Educational	30
Virginia Polytechnic Institute	Educational	15
Virginia Tech Foundation Inc.	Educational	8
Volunteer Center of Dallas	Community	3
Washington University Institute	Educational	15
Wilds	Community	6
Winter Power Meeting 2001 - Institute of Electrical Engineers	Educational	10
Women's Auxiliary to Children	Community	3
YMCA of Metropolitan Dallas	Community	15
Young Men's Christian Association	Community	10
Employees and Others (Salaries, salary related expenses, overheads and other expenses)	Various	83
Others (178)		291
TOTAL		$ 1,949

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

OTHER DEDUCTIONS - ACCOUNTS 426.3 - 426.5
(In Thousands)

Instructions: Provide a listing of the amount included in Accounts 426.3 through 426.5, "Other Deductions", classifying such expenses according to their nature.

DESCRIPTION	NAME OF PAYEE	AMOUNT
Expenditures for Certain Civic, Political & Related Activities	Company employee and administrative costs for civic, political and related activities	$ 2,326
Other Miscellaneous Deductions	Various	1,287
TOTAL		$ 3,613

SCHEDULE XVIII - NOTES TO STATEMENT OF INCOME

Instructions: The space below is provided for important notes regarding the statement of income or any account thereof. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.

See Notes to Financial Statements on Page 19.

ORGANIZATION CHART

Chairman, Chief Executive Officer & President

- Vice Chairman
- Corporate Development
- Legal, Policy & Corporate Communications
  - Legal
  - Corporate Communications
  - Governmental Affairs
  - Environmental Affairs
  - Public Policy
- Nuclear
- Shared Services
  - General Services
  - Human Resources
  - Information Technology
  - Corporate Supply Chain
- Finance & Analysis
  - Accounting
  - Corporate Planning & Budgeting
  - Treasury
  - Audit Services (NOTE)
  - Tax
  - Risk Management
- Energy Delivery
  - Transmission
  - Energy Distribution
  - Energy Delivery Support
  - Planning & Business Development
  - Customer & Community Services
- Wholesale
  - Energy Services
  - Operations & Technical Services
  - Fossil & Hydro Operations
  - Mining Operations
  - AEP ProServ
    - Marketing & Business Development
    - Maintenance Services & Regional Service Organization
    - Major Projects
    - Engineering Services
    - Environmental Services
    - Accounting & Financial Services

NOTE: Internal Audits Reports to the Audit Committee of the Board of Directors of American Electric Power Company, Inc. and administratively to the Executive Vice President - Finance & Analysis

METHODS OF ALLOCATION

Service Billings

1 Number of Bank Accounts
2 Number of Call Center Telephones
3 Number of Cell Phones/Pagers
4 Number of Checks Printed
5 Number of Customer Information System Customer Mailings
6 Number of Commercial Customers (Ultimate)
7 Number of Credit Cards
8 Number of Electric Retail Customers (Ultimate)
9 Number of Employees
10 Number of Generating Plant Employees
11 Number of General Ledger Transactions
12 Number of Help Desk Calls
13 Number of Industrial Customers (Ultimate)
14 Number of Job Cost Accounting Transactions
15 Number of Non-UMWA Employees
16 Number of Phone Center Calls
17 Number of Purchase Orders Written
18 Number of Radios (Base/Mobile/Handheld)
19 Number of Railcars
20 Number of Remittance Items
21 Number of Remote Terminal Units
22 Number of Rented Water Heaters
23 Number of Residential Customers (Ultimate)
24 Number of Routers
25 Number of Servers
26 Number of Stores Transactions
27 Number of Telephones
28 Number of Transmission Pole Miles
29 Number of Transtext Customers
30 Number of Travel Transactions
31 Number of Vehicles
32 Number of Vendor Invoice Payments
33 Number of Workstations
34 Active Owned or Leased Communication Channels
35 Avg. Peak Load for past Three Years
36 Coal Company Combination
37 AEPSC past 3 Months Total Bill Dollars
38 AEPSC Prior Month Total Bill Dollars
39 Direct
40 Equal Share Ratio
41 Fossil Plant Combination
42 Functional Department's Past 3 Months Total Bill Dollars
43 KWH Sales (Ultimate Customers)
44 Level of Construction - Distribution
45 Level of Construction - Production
46 Level of Construction - Transmission
47 Level of Construction - Total
48 MW Generating Capability
49 MWH's Generation
50 Current Year Budgeted Salary Dollars
51 Past 3 Mo. MMBTU's Burned (All Fuel Types)
52 Past 3 Mo. MMBTU's Burned (Coal Only)
53 Past 3 Mo. MMBTU's Burned (Gas Type Only)

METHODS OF ALLOCATION

54	Past 3 Mo. MMBTU's Burned (Oil Type Only)
55	Past 3 Mo. MMBTU's Burned (Solid Fuels Only)
56	Peak Load / Avg. No. Cust / KWH Sales Combination
57	Tons of Fuel Acquired
58	Total Assets
59	Total Assets less Nuclear Plant
60	AEPSC Annual Costs Billed (Less Interest And/or Income Taxes as Applicable)
61	Total Fixed Assets
62	Total Gross Revenue
63	Total Gross Utility Plant (Including CWIP)
64	Total Peak Load (Prior Year)

Convenience Billings

Specific Identification Ratio
(based on known and pertinent factors)
Asset Ratio
Expense Budget Ratio
Contribution Ratio
Equal Share Ratio
Gross Annual Payroll Dollars Ratio
Coal Production Ratio
Kilowatt Hours Sales (KWH) Ratio
Number of Employees Ratio
Number of Customers Ratio
Number of Vehicles Ratio

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For the Year Ended December 31, 2000

ANNUAL STATEMENT OF COMPENSATION FOR USE OF CAPITAL BILLED

The following annual statement was supplied to each associate company in support of the amount of compensation for use of capital billed during 2000:

In accordance with Instruction 01-12 of the Securities and Exchange Commission's Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies, American Electric Power Service Corporation submits the following information on the billing of interest on borrowed funds to associated companies for the year 2000:

A. Amount of interest billed to associate companies is contained on page 21, Analysis of Billing.

B. The basis for billing of interest to the associated companies is based on the Service Company's prior year Attribution Basis "AEPSC Annual Cost Billed ."

ANNUAL REPORT OF American Electric Power Service Corporation

For the Year Ended December 31, 2000

SIGNATURE CLAUSE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935 and the rules and regulations of the Securities and Exchange Commission issued thereunder, the undersigned company has duly caused this report to be signed on its behalf by the undersigned officer thereunto duly authorized.

American Electric Power Service Corporation
(Name of Reporting Company)

G E Laurey
(Signature of Signing Officer)

G. E. Laurey Assistant Controller Regulated Accounting
(Printed Name and Title of Signing Officer)

Date: April 24, 2001