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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio power company and Columbus southern Power Company.	: : : :	Case No. 10-2929-EL-UNC

DIRECT TESTIMONY OF RALPH C. SMITH
ON BEHALF OF
THE STAFF OF THE
PUBLIC UTILITIES COMMISSION OF OHIO

April 16, 2012

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I. INTRODUCTION

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

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

2. Q. What is your occupation?

A. I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

3. Q. Please describe Larkin & Associates.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous gas, electric, water and wastewater, and telephone utility cases.

4. Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 31 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

My professional career has included over 31 years in public accounting and utility regulatory consulting at Larkin & Associates and its predecessor firm. I have performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorneys general, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arkansas, Arizona, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington, DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. I have presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on many occasions. I have also presented seminars on utility accounting and ratemaking on behalf of various clients, and have taught at the Institute of Public Utilities sponsored by Michigan State University.

5. Q. What professional designations do you hold?

A. I hold the following professional designations:

Certified Public Accountant (licensed in the State of Michigan)

Attorney (licensed in the State of Michigan)

Certified Rate of Return Analyst

Certified Financial Planner™ professional

6. Q. Please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan -

Dearborn, in April 1979. I passed all parts of the C.P.A. examination on my first sitting in 1979, received my C.P.A. license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. I also have participated each year in a variety of continuing professional education required to maintain my CPA license and CFP® certificate.

Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts (SURFA)1. I have served as an arbitrator in disputes involving financial transactions as part of the National Association of Securities Dealers, Inc. (NASD) Dispute Resolution program and the Financial Industry Regulatory Authority, Inc. (FINRA). I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

7. Q. Have you prepared an appendix that contains additional information on your educational background and professional experience?

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[1] Formerly, the National Society of Rate of Return Analysts.

A. Yes. Appendix RCS-1, attached to this testimony also summarizes some of my regulatory experience and qualifications.

8. Q. On whose behalf are you appearing?

A. I am testifying on behalf of the Staff ("Staff") of the Public Utilities Commission of Ohio ("Commission" or "PUCO").

9. Q. Have you previously presented testimony before the Commission?

A. Yes. I have testified before the Commission in the following electric utility fuel adjustment cases:

- Management/Performance and Financial Audit of the Fuel and Purchased Power Rider of the Cincinnati Gas & Electric Company, (Audit 1) Case No. 05-806-EL-UNC
- Management/Performance and Financial Audit of the Fuel and Purchased Power Rider of the Duke Energy Ohio, (Audit 2) Case No. 06-1068-EL-UNC
- Management/Performance and Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company, (Audit 1) Case No. 09-0872-EL-FAC and 09-0873-EL-FAC
- Management/Performance and Financial Audits of the FAC of The Columbus Southern Power Company and The Ohio Power Company (Audit 2); Case No. 10-268-EL-FAC, Case No. 10-269-EL-FAC, Case No.

10-870-EL-FAC, Case No. 10-871-EL-FAC, Case No. 10-1286-EL-FAC, Case No. 10-1287-EL-FAC

- Management/Performance and Financial Audit of the Fuel And Purchased Power Rider of The Dayton Power and Light Company (Audit 1); Case No. 09-1012-EL-FAC

In addition, I filed testimony in Case Nos. 07-1080-GA-ATR and 07-1081-GA-ALT, involving Vectren Energy Delivery of Ohio, Inc., application for Authority to Amend its Rates and Charges for Gas Services and Related Matters.

10. Q. What is the purpose of your testimony?

A. Energy Ventures Analysis, Inc. ("EVA") and Larkin & Associates, PLLC ("Larkin") were contracted by the PUCO on March 21, 2012, to compute a capacity rate for Columbus Southern Power Company ("CSP") and Ohio Power Company ("OPCo"), collectively referred to as AEP Ohio or the Companies. The purpose of my testimony is to describe that analysis and the resultant capacity rates.

11. Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring four Exhibits identified as follows:

Exhibit RCS-1: Capacity Rate for CSP based on adjusted 2010 information and energy margins computed by Ryan Harter of EVA using the Aurora model;

Exhibit RCS-2: Capacity Rate for OPCo based on adjusted 2010 information and energy margins computed by Ryan Harter of EVA using the Aurora model; and

Exhibit RCS-3: Merged CSP and OPCo capacity rate.

12. Q. Please describe the tasks you performed related to your testimony in this case.

A. I reviewed and analyzed data and performed other procedures as necessary to obtain an understanding of the Capacity Charges being proposed by AEP Ohio. These procedures included reviewing the Company's testimony and exhibits; discussing the information contained within the Excel files supporting AEP Ohio's formula templates for CSP and OPCo populated with 2010 data[2]; discovery of AEP; reviewing AEP's responses to the data requests of the Staff and other parties; review of selected information from other PUCO dockets; and review of selected information from FERC Docket No. ER11-2183-000.

Q. What issues will you be addressing in your testimony?

A. I will be responding to AEP Ohio witness Kelly Pearce's testimony concerning the capacity rates that were developed in his Exhibits KDP-3 and KDP-4. I

[2] These Excel files relate to Exhibits KDP-3 and KDP-4 that were filed with the testimony of AEP Ohio witness Kelly Pearce on August 31, 2011.

also present a calculation of the capacity rate for the merged company in response to Dr. Pearce's Exhibit KDP-6, using the results of my calculations and information provided to me from PUCO Staff witness Ryan Harter of EVA concerning energy credits and receipts by AEP Ohio from PJM relating to the provision of ancillary services.

13. Q. Does your testimony comprehensively address all concerns that may exist with respect to OPC and CSP's Capacity Charges?

A. No. It is strictly limited to developing a capacity rate that uses as a starting point the AEP Ohio 2010 data from Dr. Pearce's Exhibits KDP-3 and KDP-4 and which reflects an offset for energy sales margins and ancillary service receipt amounts (each stated in $/MW Day) that were provided to me by Mr. Ryan Harter of EVA.

14. Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized into the following sections:

II. Summary of Conclusions and Recommendations

III. Development of Capacity Rates

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

15. Q. Please summarize your conclusions and recommendations.

A. Based on my review of the Company's testimony, on the discovery that has been conducted, on publicly available information, and on my experience in the area of regulatory accounting, policy, and revenue requirement determination, my conclusions and recommendations to date are as follows and summarized below:

- As shown on Exhibit RCS-1, Schedule A, page 1, a capacity rate for CSP based on adjusted 2010 information is $289.59 per MW day before deductions. After deducting the energy margins computed by Ryan Harter of EVA using the Aurora model and the ancillary service receipts offset provided to me by Mr. Harter, the CSP capacity rate would be $236.18 per MW day.
- As shown on Exhibit RCS-2, Schedule A, page 1, a capacity rate for OPCo based on adjusted 2010 information is $318.76 per MW day before deductions. After deducting the energy margins computed by Ryan Harter of EVA using the Aurora model and the ancillary service receipts offset provided to me by Mr. Harter, the OPCo capacity rate would be $81.08 per MW day.
- As shown on Exhibit RCS-3, a capacity rate for merged CSP and OPCo based on adjusted 2010 information is $305.48 per MW day before deductions. After deducting the energy margins computed by Ryan Harter of EVA using the Aurora model and the ancillary service receipts offset

provided to me by Mr. Harter, the merged capacity rate would be $144.58 per MW day.

III. DEVELOPMENT OF CAPACITY RATES

16. Q. Please explain how you developed the capacity rates for CSP and OPCo shown on Exhibits RCS-1 and RCS-2.

A. I started with the 2010 information used by AEP Ohio witness Dr. Kelly Pearce from the Excel files that relate to his Exhibits KDP-3 and KDP-4, and made adjustments for the following items:

1) The 11.15% return on equity used by AEP Ohio on page 11 of Exhibits KDP-3 and KDP-4 was adjusted to 10.0% for CSP and 10.3% for OPCo.
2) The overall rates of return used by AEP Ohio of 8.63% for CSP and 8.62% for OPCo on page 11 of Exhibits KDP-3 and KDP-4 were adjusted to 7.78% and 7.97% for CSP and OPCo, respectively.
3) Construction Work in Progress ("CWIP") on page 5 of Exhibits KDP-3 and KDP-4 was removed from rate base.
4) Plant Held for Future Use on page 5 of Exhibit KDP-3 was removed from rate base.
5) Cash Working Capital, calculated by AEP Ohio using a one-eighth O&M formula method, was removed from rate base on page 5 of Exhibits KDP-3 and KDP-4.

6) Prepayments were removed from rate base on page 5 of Exhibits KDP-3 and KDP-4.

7) Accumulated Deferred Income Taxes ("ADIT") on page 5 of Exhibits KDP-3 and KDP-4 were adjusted to remove various account 190 items from rate base including a federal investment tax credit "gross up" item that had been recorded on CSP's books, ADIT debit balances for IGCC revenues, net ADIT debits related to uncertain tax positions (i.e., "FIN 48" items), and ADIT items related to accrued liabilities. ADIT credit balances in account 283 related to prepayments were also removed, consistent with the removal of prepayments from rate base.

8) The Return on Rate Base on page 4, line 1, of Exhibit KDP-3 and KDP-4 respectively, was adjusted based on the return and rate base adjustments described above.

9) Operations and Maintenance ("O&M) Expense on page 4, line 2, of Exhibit KDP-3 and KDP-4, respectively, was adjusted to remove:

    a. Estimated payroll and employee benefit costs related to positions at AEP Ohio and the affiliate, AEP Service Company ("AEPSC"), that no longer exist due to the AEP corporate-wide 2010 voluntary and involuntary severance programs.

    b. Nonrecurring severance cost recorded by CSP and OPCo in 2010 related to the AEP corporate-wide 2010 voluntary and involuntary severance programs.

10) Taxes Other Than Income Taxes on page 4, line 4, of Exhibit KDP-3 and KDP-4, respectively, were adjusted to remove an estimate of the payroll tax expense recorded by CSP and OPCo in 2010 that relates to payroll for positions at AEP Ohio and AEPSC that are no longer there due to the AEP 2010 severance programs.

11) Income Tax on page 4, line 5, of Exhibit KDP-3 and KDP-4, respectively, was adjusted for the following:

a. To reflect the return used.

b. To reflect a pro forma estimated Domestic Production Activities Deduction ("DPAD") on a "separate return" basis as a reduction to income taxes related to electric generating capacity.

Return on Equity and Rate of Return

17. Q. What return on equity did you apply for CSP and OPCo?

A. I applied a 10.0% ROE for CSP and a 10.3% ROE for OPCo. Both of these are from the Commission's Opinion and Order dated December 14, 2011 in Case Nos. 11-351-EL-AIR et al, at page 5, paragraph II-A-(1)(e) and elsewhere in that other. They were part of a stipulation in the most recent CSP and OPCo electric distribution rate cases. In the CSP distribution rate case, Case No. 11-351-EL-AIR, et al, the Staff Report had recommended a cost of equity recommendation of 8.58% to 9.59%.[3] For OPCo, in Case No. 11-352-EL-AIR, et al, the corresponding recommendation for ROE in the Staff Report was 8.59% to 9.60%.[4] In lieu of preparing a specific cost of capital analysis directed to AEP Ohio's capacity costs, the 10.0% and 10.3% ROEs noted above from the December 14, 2011 Opinion and Order are being used as reasonable inputs and appear to represent a consensus stipulation position. I also note that those stipulated ROEs were higher than Staff's recommendations in the respective AEP Ohio electric distribution utility rate cases.

18. Q. What overall rate of return did you apply?

A. I applied an overall rate of return of 7.78% for CSP and 7.97% for OPCo. Both of these are from the Commission's Opinion and Order dated December 14, 2011 in Case Nos. 11-351-EL-AIR et al, at page 5, paragraph II-A-(1)(c) and (d), respectively. They were part of a stipulation in the most recent CSP and OPCo electric distribution rate cases. The parties to the stipulation in those cases specified those returns were a just and reasonable rate of return for CSP and OPCo, respectively.

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[3] Staff Report in Case Nos. 11-0351-EL-AIR et al, filed 9/15/2011, at page 16.

[4] Staff Report in Case Nos. 11-0352-EL-AIR et al, filed 9/15/2011, at page 16.

Construction Work in Progress

19. Q. What information was important concerning the circumstances under which CWIP can be included in rate base?

A. Section 4909.15 of the Ohio Revised Code provides that the Commission, in its discretion, may include a reasonable allowance for construction work in progress (CWIP) but, in no event may such allowance be made by the Commission until it has determined that the particular construction project is at least seventy-five percent complete.

Also, no allowance for CWIP shall be in rates for a period exceeding 48 months and any sums of money that the Company may have received must be given back to the customers once the property is used and useful and in service.[5]

Section 4928.143 of the Revised Code, dealing with Electric Security Plan, also provides that a reasonable allowance for CWIP for any of the electric distribution utility's cost of constructing an electric generation facility or for an environmental expenditure for any electric generation facility of the electric distribution utility can be considered, provided the cost is incurred

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5 This concept of returning any sums of money that the Company may have received during the construction period to the customers once the property has been placed into service is sometimes referred to as "mirror CWIP."

or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the CWIP allowance limitations of division (A) of section 4905.15 of the Revised Code, except the Commission may authorize an allowance upon the incurrence of the cost or occurrence of the expenditure. Additionally, the Commission must first determine in the proceeding that there is need for the facility based on resource planning. Further, no CWIP allowance shall be authorized unless the facility's construction was sourced through a competitive bid process.

20. Q. Has AEP Ohio demonstrated that the CWIP it is requesting in rate base meets the above noted criteria?

A. No. AEP Ohio has not demonstrated (1) that the CWIP it has requested is 75% complete; (2) that the concept of mirror-CWIP has been applied; (3) that the Commission has determined that there is need for each facility based on resource planning; or (4) that the facility's construction was sourced through a competitive bid process. Because these criteria have not been met, CWIP should be excluded from rate base.

Plant Held for Future Use

21. Q. Please explain the adjustment to remove Plant Held for Future Use.

A. AEP Ohio proposed to include $5.366 million of Plant Held for Future Use for CSP on Exhibit KDP-3, page 5, line 6. This adjustment removes that amount from the production demand rate base for CSP.

22. Q. What items are included in AEP Ohio's request for Plant Held for Future Use?

A. AEP Ohio was requested to provide details. Its request for CSP appears to primarily relate to land and land rights for a Newbury Project, which CSP's 2010 FERC Form 1, at page 214, lists as being originally included in account 105, Plant Held for Future Use, on 12/80 and 12/87 with balances of $4,991,594 and $61,220. Nothing is listed in CSP's 2010 FERC Form 1 for a "date expected to be used in utility service" for those items.

23. Q. Why should Plant Held for Future Use be excluded from rate base?

A. Generally, Plant Held for Future Use should be excluded from utility rate base because it is not considered to be used and useful in providing utility service. Unless the utility demonstrates specific, definite plans for utilizing such property to provide utility service within a reasonable time frame, my experience has generally been that the PHFFU is excluded from utility rate base. Lacking such definite plans for utilization in the provision of utility service, the property is not used and useful for providing utility service, and the cost should therefore not be borne by ratepayers. AEP Ohio has presented no definite plans as to when it will utilize any of the Plant Held for Future Use that it is requesting be included in generation rate base. Consequently, I believe that a compelling argument can be made for the exclusion of this PHFFU from rate base, and my recommendation, therefore, is to exclude it entirely from rate base.

24. Q. Can Plant Held for Future Use be excluded from rate base?

A. Yes.

25. Q. Was Plant Held for Future Use included in AEP Ohio's rate base in the recent CSP and OPCo distribution rate cases?

A. It appears no PHFFU was included in AEP Ohio's rate base in the recent distribution rate cases. AEP Ohio's workpapers supporting its Exhibit KDP-3, page 5, references the PHFFU to Workpaper 19. That workpaper shows that CSP functionalized the $13.026 million of December 31, 2010 PHFFU that was reported in its 2010 FERC Form 1 as follows:

Production	5,366,165
Transmission	3,796,688
Distribution	3,356,603
General	506,771
Total	13,026,227

However, a review of Schedule B-1 from the Staff Report in CSP's distribution rate case, Case Nos. 11-352-EL-AIR *et al,* does not show any Plant Held for Future Use being included in CSP's distribution rate base. Similarly, the Staff report in Case Nos. 11-351-EL-AIR et al, does not show any Plant Held for Future Use being included in OPCo's distribution rate base. This would appear to be consistent with the guidance we received from Staff concerning the general policy that PHFFU is not included in utility rate base.

26. Q. Please summarize your recommendation concerning PHFFU.

A. The PHFFU that AEP Ohio included in its proposed production demand rate base for CSP should be removed for the reasons stated above. This reduces CSP's proposed rate base by $5.366 million.

Cash Working Capital

27. Q. What is Cash Working Capital?

A. Cash working capital is generally defined as the average amount of capital provided by investors in the Company, over and above the investments in plant and other specifically quantified rate base items, to bridge the gap between the time that expenditures are required to provide service and the time collections are received for the service.

28. Q. When is a Cash Working Capital allowance includable in rate base?

A. Large utilities are typically required to prepare a lead-lag study to support a Cash Working Capital allowance being includable in rate base. CSP and OPCo, individually and merged, are considered to be large utilities for supporting a Cash Working Capital allowance. Where a lead-lag study is not presented by a large utility such as CSP or OPCo, we cannot recommend a Working Capital allowance.

29. Q. Did AEP Ohio prepare a lead-lag study to support its claim for Working Capital?

A. No. AEP Ohio's claim is based on a one-eighth O&M formula. AEP Ohio did not prepare a lead-lag study.

30. Q. In general, do you agree with the use of the one-eighth formula method to determine a utility's CWC requirement?

A. No. There are several conceptual problems with the use of the one-eighth formula method, including the following:

First and most importantly, there is no evidence that the formula accurately or appropriately calculates a CWC allowance that is based on AEP Ohio's actual requirements for cash working capital. The formula always produces a positive CWC allowance, even in situations where no CWC requirement exists, and even in situations where the utility's CWC requirement is negative. Thus, the formula method is not a reliable means of deriving a CWC allowance for AEP Ohio in this proceeding.

AEP Ohio's filing has assumed a cash working capital allowance based on a one-eighth formula method, without providing any support for an assumption that AEP Ohio actually has a cash working capital requirement. The assumption underlying a one-eighth cash working capital allowance is that revenues for the service are collected, on average, 45 days after cash operating expenses are paid to produce the service. AEP Ohio has presented no reliable evidence that it has a net cash working capital requirement of 45 days (1/8th of 365 days = 45 days).

Included in AEP Ohio's operating expenses are charges from affiliates, such as charges from AEP Service Company. Providing for a cash working capital allowance based on affiliate charges would essentially amount to giving AEP Ohio a return on affiliate expenses. That would seem to be contradictory to the provision by the affiliated service company of services at cost.

AEP Ohio's proposed allowance also fails to consider the lag in the payment of current income tax expense. In a legitimate lead-lag study, there would need to be recognition of the lag in income tax payments, which are required to be made quarterly. Because AEP Ohio has failed to prove that it has a cash working capital requirement, a zero allowance should be used.

In the absence of a reliable lead-lag study, the presumption should be that there is a zero CWC requirement, and the CWC allowance should be set at zero. Setting the CWC allowance at zero thus places the burden of establishing and supporting with competent evidence any request for a positive CWC allowance where it belongs, on the utility that is requesting the allowance. Setting the CWC allowance presumptively at zero for determining a utility's revenue requirement thus also places the burden of establishing the amount of a negative CWC amount on the party advocating the use of a negative CWC allowance for ratemaking purposes.

31. Q. Have you removed AEP Ohio's Cash Working Capital request from rate base?

A. Yes. Based on the above-noted information and conceptual concerns regarding the use of a formula method (rather than a properly prepared lead-lag study), the Working Capital request by AEP Ohio has been removed from rate base.

Prepayments

32. Q. What Prepayments has AEP Ohio included in rate base?

A. AEP Ohio has included in generation demand rate base two items of prepayments: (1) non-labor prepayments of $4.488 million for CSP and

$2.045 million for OPCo and (2) labor related prepayments consisting of prepaid pensions of $37.952 million for CSP and $73.653 million for OPCo.

33. Q. Should the prepayments be included in rate base?

A. No. Without a properly prepared lead-lag study no prepayments should be included in rate base.

34. Q. How does the ratemaking treatment you have applied for Working Capital and Prepaid Pensions compare with the recommendations in the Staff Reports in CSP and OPCo's last distribution rate cases?

A. In the Staff Reports in CSP's and OPCo's last distribution rate cases, Case Nos. 11-351-EL-AIR and 11-352-EL-AIR et al, Staff removed Working Capital including the 13-month balances requested by AEP Ohio for materials and supplies, uncollectibles and prepayments, but Staff increased rate base to recognize a prepaid pension asset. To determine AEP Ohio's capacity rates, I have removed the one-eighth formula based Company request for Cash Working Capital and have removed prepayments including the prepaid pension asset. I have not removed the Company's requested balance for materials and supplies related to generation capacity (i.e., the demand portion of generation).

35. Q. Please explain the additional concerns relating to the AEP Ohio proposed pension asset that caused you to remove it in determining a rate for AEP Ohio's capacity.

A. The pension asset is being removed because (1) AEP Ohio has failed to demonstrate that has a net prepaid pension asset, and information reported in the 2010 FERC Form 1 concerning pension funding status suggest there is a net liability; (2) pension funding levels are the result of discretionary AEP management decisions concerning the funding of defined benefit pensions, and (3) pension expense would typically be included in the determination of cash working capital in a lead lag study.

36. Q. How has AEP Ohio failed to demonstrate that it has a prepaid pension asset related to the provision of generation capacity?

A. Page 123.32 of the CSP and OPCo FERC Form 1 for 2010 shows that funded status of the defined benefit pension plans. For CSP, the FERC Form 1 reports pension plan benefit obligations of $349.8 million at December 31, 2010 and pension plan assets of $277.3 million, for a net underfunded status at December 31, 2010 of $72.5 million. The FERC Form 1 on page 123.32 also shows this net amount of $72.5 million as a long-term liability.

For OPCo, the FERC Form 1 reports pension plan benefit obligations of $629.9 million at December 31, 2010 and pension plan assets of $518.7 million, for a net underfunded status at December 31, 2010 of $111.2 million. OPCo's 2010 FERC Form 1 on page 123.33 also shows this net amount of $111.2 million as a long-term liability.

The defined benefit pension plans for CSP and OPCo, as reported in the 2010 FERC Form 1 on pages 123.32 and 123.33, thus show pension plan obligations in excess of pension assets, and show a net long-term pension liability for both companies. The reporting of a significant long-term pension liability at December 31, 2010 for each company contradicts the Companies' proposal to include a pension asset amount in rate base.

37. Q. Could the inclusion in generation capacity rate base of AEP Ohio's proposed pension asset provide a disincentive for making reasonable reforms to the Company's pension plans?

A. I believe that it could. Factors such as worker mobility, the ERISA and other compliance and reporting requirements, and the increased costs of defined benefit pension plans in recent years have hastened their decline, and there is a discernible trend away from such plans. Providing what essentially would amount to a guaranteed return on a pension asset could deter the Company from making reforms to its pension plans that would reduce cost, as many companies are doing.

38. Q. What evidence do you have that indicates a trend away from defined benefit plans?

A. In March 2009, the U.S. Government Accountability Office issued a report (GAO-09-291, dated March 30, 2009)[6], which concluded that:

> **The number of private defined benefit (DB) pension plans**, an important source of retirement income for millions of Americans, **has declined substantially over the past two decades. For example, about 92,000 single-employer DB plans existed in 1990, compared to just under 29,000 single-employer plans today.** Although this decline has been concentrated among smaller plans, **there is a widespread concern that large DB plans covering many participants have modified, reduced, or otherwise frozen plan benefits in recent years.** GAO was asked to examine (1) what changes employers have made to their pension and benefit offerings, including to their defined contribution (DC) plans and health offerings over the last 10 years or so, and (2) what changes employers might make with respect to their pensions in the future, and how these changes might be influenced by changes in pension law and other factors. To gather information about overall changes in pension and health benefit offerings, GAO asked 94 of the nation's largest DB plan sponsors to participate in a survey; 44 of these sponsors responded. These respondents represent about one-quarter of the total liabilities in the nation's single-employer insured DB plan system as of 2004. The survey was largely completed prior to the current financial market difficulties of late 2008.
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> GAO's survey of the largest sponsors of DB pension plans revealed that **respondents have made a number of revisions to their retirement benefit offerings over the last 10 years or so. Generally speaking, they have changed benefit formulas; converted to hybrid plans (such plans are legally DB plans, but they contain certain features that resemble**

6 A copy of the complete GAO study can be obtained online at: http://www.gao.gov/new.items/d09291.pdf

DC plans); or frozen some of their plans. Eighty-one percent of responding sponsors reported that they modified the formula for computing benefits for one or more of their DB plans. Among all plans reported by respondents, 28 percent of these (or 47 of 169) plans were under a plan freeze--an amendment to the plan to limit some or all future pension accruals for some or all plan participants. The vast majority of respondents (90 percent, or 38 of 42 respondents) reported on their 401(k)-type DC plans. Regarding these DC plans, a majority of respondents reported either an increase or no change to the employer or employee contribution rates, with roughly equal responses to both categories. About 67 percent of (or 28 of 42) responding firms plan to implement or have already implemented an automatic enrollment feature to one or more of their DC plans. With respect to health care offerings, all of the (42) responding firms offered health care to their current workers. Eighty percent (or 33 of 41 respondents) offered a retiree health care plan to at least some current workers, although 20 percent of (or 8 of 41) respondents reported that retiree health benefits were to be fully paid by retirees. Further, 46 percent of (or 19 of 41) responding firms reported that it is no longer offered to employees hired after a certain date. At the time of the survey, most sponsors reported no plans to revise plan formulas, freeze or terminate plans, or convert to hybrid plans before 2012. When asked about the influence of recent legislation or changes to the rules for pension accounting and reporting, responding firms generally indicated these were not significant factors in their benefit decisions. Finally, a minority of sponsors said they would consider forming a new DB plan. Those sponsors that would consider forming a new plan might do so if there were reduced unpredictability or volatility in DB plan funding requirements and greater scope in accounting for DB plans on corporate balance sheets. **The survey results suggest that the long-time stability of larger DB plans is now vulnerable to the broader trends of eroding retirement security. The current market turmoil appears likely to exacerbate this trend.**

As illustrative examples, I am also aware that the following utilities have closed, frozen, significantly modified or discontinued their defined benefit pension plans:

- PacifiCorp / Rocky Mountain Power – In 2007, the company froze the final average pay formula for non-union employees and will make future accruals under a cash balance formula. Employees hired on or after 1/1/08 do not participate in the retirement plan. In 2008: (1) the company also froze the final average pay formula within the retirement plans and ceased future accruals for Local 659 union employees and Local S1978 union employees;

and (2) the company froze the final average pay formula within the retirement plan and ceased future accruals for Local 125 union employees hired prior to 1/1/06 and over a certain age. Effective 1/1/09, non-union employees were permitted to choose to continue receiving pay credits under the cash balance formula approach within the retirement plan or receive the credits as additional fixed contribution within the 401(k) plan during a limited election period.

- American Water Works Company, Inc. – The company closed the defined benefit pension plan to all non-union employees hired on or after 1/1/06, and froze the accrued benefits under the defined benefit plan for union employees hired on or after 1/1/01.
- Aqua America, Inc. Employees hired after April 1, 2003 do not participate in the Company's defined benefit pension plans.
- Verizon – As of 6/30/06, Verizon management employees no longer earn pension benefits under the defined benefit plan.
- Shenandoah Telecommunications Company – The defined benefit pension plan was frozen as of 1/31/07; the company also announced its intent to settle benefits earned under the plan and terminate the plan.
- Cincinnati Bell – Effective 3/28/09, the company froze pay-related pension credits under the defined benefit pension plan for managers and non-union employees who were accruing benefits under such plan, were under the age of 50, and were not eligible for the 2007 early retirement option.

Additionally, United Illuminating Company, Vermont Electric Cooperative (union employees), Connecticut Natural Gas, Southern Connecticut Gas, and Northeast Utilities no longer offer defined benefit pension plans to new hires or only allow for a cash balance plan for new hires.

39. Q. Does management have a wide latitude in determining how and when to fund defined benefit pension plans?

A. Yes. There is frequently a very large range between the minimum funding required under ERISA and the maximum annual funding, which is typically limited by the maximum tax-deductible funding contribution limitations under the Internal Revenue Code.

40. Q. **Over the long-term, would increased funding of a defined benefit pension plan be expected to result in lower future net periodic pension cost, other things being equal?**

A. Yes. The additional funds contributed into the pension trust would earn a return and the earned return would reduce future pension expense, other things being equal.

41. Q. **How does CSP's and OPCo's 2010 pension expense compare with 2009?**

A. Page 123.39 from CSP's and OPCo's FERC Form 1 for 2010 shows the net periodic pension cost recognized as expense for 2009 and 2010. For CSP, the defined benefit pension expense increased from $1.788 million in 2009 to $3.939 million in 2010, an increase of $2.151 million or 120%. For OPCo, the defined benefit pension expense increased from $1.788 million in 2009 to $3.939 million in 2010, an increase of $3.538 million or 67%, as summarized below:

Net Periodic Pension Cost Recognized As Expense ($000)		
Year	CSP	OPCo
2010	3,939	8,804
2009	1,788	5,266
Increase $	2,151	3,538
Increase %	120%	67%
Source: FERC Form 1, page 123.39		

The increased 2010 defined benefit pension expense for CSP and OPCo have not been adjusted by Staff in determining AEP Ohio's revenue requirement for generating capacity.

42. Q. Are the considerations with respect to the appropriateness of including of a pension asset in utility rate base perhaps different for determining a capacity rate in the current case, than they might be for determining rates for electric distribution utility service?

A. Yes. The situation with AEP Ohio's distribution function and its generation function in this respect are somewhat different in the aspect of whether potential future reductions to pension cost that could occur from increased pension funding would inure to ratepayers. In the current case, capacity rates are being developed for AEP Ohio that will be in place for a relatively short time, i.e., until AEP Ohio's generation is market priced. This is a different situation from AEP Ohio's provision of distribution service, which has been and is expected to continue to be based on cost-based regulation. Thus, the ratepayers paying the rates established in the current case, i.e., the CRES providers, may not benefit over the long term from future reductions in AEP Ohio's pension cost. Thus, including a pension asset in rate base for purposes of establishing a capacity rate would not be appropriate.

43. Q. How is pension expense typically reflected in a lead-lag study?

A. Pension expense associated with defined benefit pension plans and other types of retirement plans is typically reflected in a lead-lag study by applying a calculated payment lag to the amount of related pension expense that is included in the utility's operating expenses. In the current case, AEP Ohio has not presented a lead-lag study. The lack of a lead-lag study to properly measure a working capital requirement in total and specifically as it relates to pension expense, is thus another reason for rejecting inclusion of a pension asset in CSP's or OPCo's rate base in the current case for purposes of determining a capacity rate.

44. Q. In another recent rate case, involving an AEP affiliated utility in another jurisdiction, have you also recommended a reasonable alternative concerning the ratemaking treatment of a utility's claimed pension asset?

A. Yes. In a recent rate case involving Appalachian Power Company (APCO) in Virginia State Corporation Commission Case No. PUE-2011-00037 I had noted that statements in AEP's board minutes revealed that recent decisions by AEP management to provide for prefunding of future pension obligations in 2010 was to be financed by AEP with a relatively low cost source of capital; thus the pension asset presented in APCO's rate case should not receive a return at APCO's overall cost of capital. In that Virginia rate case, APCO had included a lead-lag study to determine the allowance for cash working capital, and pension expense was included in the expenses that were addressed in the lead-lag study. APCO's detailed lead-lag study included a provision for cash working capital related to the net payment lag for labor costs, including pension and other employee benefits. In that case, I had recommended, in addition to removing the prepaid pension from rate base, making a corresponding adjustment to provide interest on the average prepaid pension balance, net of related ADIT, at the commercial paper interest rate. The allowance of financing costs on the net prepaid pension asset at the commercial paper rate addressed a source of financing for the prepaid pension asset.[7] The additional offsetting adjustment was intended to address concerns with respect to the relationship between pension expense in rate base and operating expenses, and to protect ratepayers from having their base rates for APCO's electric service increased unnecessarily as a result of the AEP

[7] The interest expense related to imputing the debt-based financing would then be included above-the-line as a utility operating expense for ratemaking purposes.

management decision to pre-fund future pension obligations. I also have noted that a similar regulatory treatment of applying a debt-based return on pension asset amounts had been applied by the Illinois Commerce Commission in a series of rate cases involving Commonwealth Edison Company ("ComEd").

45. Q. How have you treated the Accumulated Deferred Income Taxes related to the CSP and OPCo pension assets?

A. The Accumulated Deferred Income Taxes related to the CSP and OPCo pension assets have also been removed from AEP Ohio's proposed generation demand rate base for CSP and OPCo, as described below.

Accumulated Deferred Income Taxes

46. Q. How did AEP Ohio determine its rate base offset for ADIT?

A. AEP Ohio started with the components of its recorded balances of ADIT at December 31, 2010 and allocated them to the generation (demand) function.

47. Q. What adjustments have you made for ADIT?

A. The adjustments I have made for ADIT are shown on Schedule B-1 of Exhibit RCS-1 for CSP and Exhibit RCS-2 for OPCo.

48. Q. Please explain those adjustments.

A. Referring to Exhibit RCS-1, Schedule B-1, line 1, CSP had increased rate base for $5.228 million of ADIT in account 190 for a "gross up" related to federal investment tax credits ("ITC"). For ratemaking purposes, ITC is being amortized as a reduction to federal income tax expense. Amortizing ITC as a reduction to income tax expense is one of the methods provided for the normalization of ITC in the Internal Revenue Code and Treasury Regulations. When that method is selected, there is no rate base impact of the deferred ITC. An alternative method of reflecting ITC for ratemaking purposes that is also permitted by the tax code involves deducting ITC from rate base, and not reflecting an impact on income tax expense. Because CSP has chosen to reduce income taxes for the ITC amortization, there is no basis for either adding or deducting the ITC from rate base. CSP has provided no valid basis for adding the deferred ITC to jurisdictional rate base. Additionally, when the debit balance that CSP has recorded in Account 190 for the ITC is amortized, that amortization would reduce income tax expense; however, CSP has not reflected that additional reduction to income tax expense for this additional amortization of the ITC item it recorded in Account 190 in its proposed income tax expense. Removal of the Deferred ITC in account 190 that CSP had proposed to include in rate base reduces the Company's proposed production demand jurisdictional rate base by $5.229 million.

49. Q. Please discuss the removal of the ADIT debit balance in Account 190 for "IGCC Revenues."

A. As shown on Exhibits RCS-1 and RCS-2, Schedule B-1, line 2, CSP and OPCo proposed to increase production demand rate base by $4.324 million and $4.160 million, respectively, for ADIT in account 190 for "IGCC Revenues." CSP and OPCo have not identified an IGCC power plant that is in service and providing capacity. Page 123.21 of CSP's and OPCo's respective 2010 FERC Form 1 reports state that CSP and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of cost recovery exists. The ADIT debit balance in account 190 is not related to a plant that is in service. Additionally, none of the revenue that CSP and OPCo collected for pre-construction costs of an IGCC plant has been reflected in their determinations of the revenue requirement for capacity in the current case. Consequently, the ADIT debit balance for the "IGCC Plant" should be removed from production demand rate base, as shown on Schedule B-1, line 2, of Exhibits RCS-1 and RCS-2.

50. Q. Please discuss the removal of the net "FIN 48" items from account 190 ADIT.

A. Both CSP and OPCo included net debit balances in account 190 ADIT for "FIN 48" items that relate to uncertain tax positions. Those items should be removed from rate base, consistent with accounting guidance provided by FERC and for other reasons discussed below. Removal of the FIN 48 items from account 190 ADIT reduces CSP's production demand rate base by $275,544 as shown on Exhibit RCS-1, Schedule B-1, line 3, and reduces OPCo's production demand rate base by $1.772 million as shown on Exhibit RCS-2, Schedule B-1, line 3. Detail of each company's account 190 FIN 48 items is presented on Schedule B-1, lines 9-13.

51. Q. What is a "FIN 48" amount?

A. The FIN 48 liability represents the difference between the Company's position taken on the tax return versus the identification of "uncertain" tax positions as required for financial statement reporting.[8] FIN 48 recognizes that differences in the interpretation of tax law exist (i.e. legislation and statutes, legislative intent, regulations, rulings and case law), and seeks to eliminate any uncertain tax benefit from the financial statements until the uncertainty associated with the position has been removed. An uncertainty may be removed by either (1) review of the technical merits of the position

[8] Financial Accounting Standards Interpretation No. 48 ("FIN 48") has subsequently been codified in the Accounting Standards Codification ("ASC") as part of ASC 740 Income Taxes.

by the relevant taxing authority, (2) expiration of the statute of limitations or (3) law change.

52. Q. Has FERC provided guidance on accounting and financial reporting for uncertainty in income taxes?

A. Yes. On May 25, 2007, in Docket No. AI07-2-000, FERC provided guidance on accounting for uncertainty in income taxes. That FERC regulatory accounting guidance on uncertain taxes is attached in CUB Exhibit 1.3. The FERC guidance provides as follows:

> Under existing Commission requirements, entities measure and recognize current and deferred tax liabilities (and assets) based on the positions taken or expected to be taken in a filed tax return and recognize uncertainties regarding those positions by recording a separate liability for the potential future payment of taxes when the criteria for recognition of a liability contained in FASB Statement No. 5, *Accounting for Contingencies*, are met, generally as part of the accrual for current payment of income tax. Where uncertainties exist with respect to tax positions involving temporary differences, the amounts recorded in the accounts established for accumulated deferred income taxes are based on the positions taken in the tax returns filed or expected to be filed. [Temporary difference as used here means a difference between the tax basis of an asset or liability as reflected or expected to be reflected in a tax return and its reported amount in the financial statements.] Recognition of a separate liability for any uncertainty related to temporary differences is therefore not necessary because the entity has already recorded a deferred tax liability for the item or would be entitled to record a deferred tax asset for the item if a separate liability for the uncertainty was recognized.
>
> This practice results in the accumulated deferred income tax accounts reflecting an accurate measurement of the cash

> available to the entity as a result of temporary differences. This is an important measurement objective of the Commission Uniform Systems of Account because accumulated deferred income tax balances, which are significant in amount for most Commission jurisdictional entities, reduce the base on which cost-based, rate-regulated entities are permitted to earn a return. **FIN 48, which does not permit a liability for uncertain tax positions related to temporary differences to be classified as a deferred tax liability, frustrates this important measurement objective.** Therefore, entities should continue to recognize deferred income taxes for Commission accounting and reporting purposes based on the difference between positions taken in tax returns filed or expected to be filed and amounts reported in the financial statements. Also, consistent with the direction provided in Docket No. AI93-5 regarding the implementation of FASB Statement No. 109, **public utilities and licensees, natural gas companies and centralized service companies should not remove from accumulated deferred income taxes and reclassify as a current liability the amount of deferred income taxes payable within 12 months of the balance sheet date.**

(Emphasis supplied.)

53. Q. Are you familiar with how another electric utility owned by AEP has applied the FERC guidance?

A. Yes, I am aware of a response by Indiana Michigan Power Company ("IMPC") to data request SDI 4-7 in its current electric utility rate case in Indiana, IURC Cause No. 44075. Parts c and d of that request and the related responses state as follows:

> c. How has the Company treated FIN 48 amounts for purposes of its rate case filing? Please explain fully and provide references to where such treatment is reflected in the Company's filing.

> Response: For purposes of the Company's filing, the FIN-48 ADIT balances have not been taken into consideration. The Company adheres to the guidance pursuant to FERC Docket No. AI07-2-000 which summarizes the accounting for uncertain tax positions. The accounting for uncertain tax positions represents accruals and recordation's of income taxes which will be ultimately resolved at a future unspecified time. Therefore, in the Company's rate filing, there are no amounts related to uncertain tax positions in rate base or income tax expense.
>
> d. Has the Company attempted to not reflect any tax savings related to repairs deductions or any other tax deductions taken on an income tax return because of uncertainty?
>
> Response: No.
>
> (Emphasis supplied.)

In summary, that utility (which is also part of American Electric Power Company) has interpreted the FERC guidance on uncertain income tax positions to require that tax savings related to deductions taken on income tax returns should be reflected for ratemaking purposes and the FIN 48 ADIT balances are not to be taken into consideration for ratemaking purposes. CSP and OPCo are also AEP-owned electric utilities and should thus be similarly following the FERC guidance for uncertain income taxes. Following the FERC guidance for uncertain tax positions as IMPC has done is a good general practice, and should also be applied for AEP Ohio in the current case.

54. Q. Please describe the adjustment for FIN 48

A. As shown on Exhibits RCS-1 and RCS-2, Schedule B-1, line 3, this adjustment removes the net ADIT items related to FIN 48 from rate base.

55. Q. Please continue with your explanation of the ADIT adjustments.

A. ADIT in account 190 related to other asset or liability balances that are not reflected in rate base is removed on Exhibits RCS-1 and RCS-2, Schedule B-1, line 4, for CSP and OPCo, respectively. This decreases CSP's production demand rate base by $1.362 million and increases OPCo's by $1.884 million. Each of the "labor-related" ADIT balances in account 190 listed on Exhibit RCS-1, Schedule B-1, lines 14-22 and on Exhibit RCS-2, Schedule B-1, lines 14-23, are being removed. Each of these items apparently relates to other balance sheet accounts that are not being reflected in the determination of rate base. For example, there are apparently liability balances related to vacation pay, incentive compensation and other postretirement benefits (SFAS 106). Based on the matching principle, if the related ADIT debit balances are included in rate base, then the accrued liabilities and operating reserves giving rise to those deferred taxes should be deducted from rate base. However, those related liability balances or reserves are not being deducted from rate base. Consequently, the related ADIT balances in Account 190 for CSP and OPCo are being removed to reflect proper matching of related items.

56. Q. Has AEP indicated that it would be providing additional information for some of those items?

A. Yes. In particular, it is unusual to have a large credit balance for ADIT in account 190 for a reserve for workers compensation or SFAS 112 postemployment benefits, as OPCo had at December 31, 2010.[9] Those balances may be indicative of unusual activity in 2010 for OPCo.

57. Q. Please explain the adjustment to remove the ADIT in account 283 related to the pension asset.

A. CSP and OPCo recorded ADIT in account 283 related to a pension asset. Because the pension asset is being excluded from production demand rate base, as explained above, the ADIT credits that relate to the pension asset should also be removed, consistent with the matching principle. As shown on Exhibits RCS-1 and RCS-2, Schedule B-1, line 5, removal of the ADIT for prepaid pension increase CSP's production demand rate base by $1.362 million and OPCo's by $1.883 million. These ADIT amounts related to the pension asset are credit balances and had decreased AEP Ohio's proposed rate base. On a net basis, AEP Ohio's proposal to include a prepaid pension asset in rate base increased rate base by the net amount of the prepaid pension asset, less the related ADIT. The pension asset and the

[9] See, e.g., Exhibit RCS-2, Schedule B-1, lines 14 and 22, respectively.

directly related ADIT should receive the same ratemaking treatment, i.e., both should be excluded from rate base, based on the matching principle.

58. Q. How does the "CCD Bill" item relate to the pension asset that AEP Ohio included in generation capacity rate base?

A. That is presently unclear. AEP Ohio was requested to provide additional information concerning the item on Exhibit RCS-1, Schedule B-1, line 28, with respect to item 620C, the CCD Bill ADIT for prepaid pensions. The CCD Bill refers to billings from joint owners.

59. Q. Please explain the adjustment to ADIT for item 906D, SFAS 106 postretirement benefits, nondeductible contribution.

A. As shown on Exhibits RCS-1 and RCS-2, Schedule B-1, line 6, this ADIT debit-balance item that CSP and OPCo included in account 283 is also being removed from production demand rate base. This item appears to be similar in concept to the ADIT items for various benefit items that were removed from account 190. The debit-balance ADIT presumably relates to a deferred credit or liability account that is not being recognized in the determination of rate base. Consequently, the related ADIT should also be removed.

60. Q. What is the net result of the ADIT adjustments on CSP's and OPCo's capacity rate base?

A. The ADIT adjustments reduce CSP's production demand rate base by $7.848 million as shown on Exhibit RCS-1, Schedule B-1, and increases OPCo's production demand rate base by $8.480 million, as shown on Exhibit RCS-2, Schedule B-1.

Operating and Maintenance Expense

61. Q. Have you made any adjustments to Operating and Maintenance Expense?

A. Yes. As shown on Exhibits RCS-1 and RCS-2, Schedule C, the following adjustments have been made to O&M Expense:

1) To remove payroll and benefits for eliminated positions; and

2) To remove 2010 severance expense.

Each of those adjustments is explained below.

Payroll and Benefits for Eliminated Positions

62. Q. Why is there a need to adjust AEP Ohio's 2010 data to remove payroll and benefit costs associated with positions that were eliminated in the 2010 severance programs?

A. AEP Ohio's unadjusted 2010 data includes the payroll, benefit and payroll tax expense for positions that have been eliminated as a result of AEP's 2010 voluntary and involuntary severance programs. Because the rates in this proceeding are to be applied prospectively, AEP Ohio's expenses should not include labor costs for personnel that were there in early 2010 but who, as a result of the 2010 severance programs, are no longer with the Company. Consequently, there is a need to adjust AEP Ohio's 2010 information to remove the costs related to the significant number of positions that were permanently eliminated as a result of the 2010 severance programs.

63. Q. Has AEP Ohio provided work force information for CSP, OPCo and the AEP Service Company?

A. Yes. In response to PUCO Staff Set 1 INT-01-011, Attachment 1 provided work force information for CSP, OPCO and AEPSC. That information shows that significant work force reductions occurred after May 2010:

Headcount Before and After 2010 Severance

Date	AEPSC	CSP	OPCo	
10-Jan	6,169	1,256	2,389	
10-Feb	6,134	1,244	2,386	
10-Mar	6,116	1,233	2,383	
10-Apr	6,088	1,227	2,375	
10-May	6,101	1,222	2,372	Severance
10-Jun	5,510	1,054	2,081	
10-Jul	5,479	1,049	2,071	
10-Aug	5,246	1,055	2,083	
10-Sep	5,208	1,047	2,081	
10-Oct	5,197	1,054	2,094	
10-Nov	5,179	1,062	2,103	
10-Dec	5,171	1,062	2,104	
11-Jan	5,138	1,056	2,098	
11-Feb	5,146	1,057	2,096	
11-Mar	5,152	1,058	2,103	
11-Apr	5,148	1,059	2,105	
11-May	5,156	1,055	2,101	
11-Jun	5,182	1,059	2,111	
11-Jul	5,170	1,055	2,125	
11-Aug	5,146	1,054	2,124	
11-Sep	5,094	1,055	2,106	
11-Oct	5,072	1,054	2,104	
11-Nov	5,064	1,054	2,099	
11-Dec	5,068	1,055	2,106	

The following tables compare the average work force for January through May 2010, with the average work force subsequently in 2010 and with the average work force in 2011:

Average			
Jan-May 2010	6,122	1,236	2,381
Remainder of 2010	5,284	1,055	2,088
2011	5,128	1,056	2,107

Estimated net severed positions			
Jan-May 2010 versus remainder of 2010:			
Count	837	182	293
Percent	14%	15%	12%
Jan-May 2010 versus average 2011			
Count	994	180	275
Percent	16.2%	14.6%	11.5%

The information on work force levels summarized above reinforces that using unadjusted 2010 payroll and benefit expenses would not be representative of ongoing conditions since AEP's work force, including the work force at CSP, OPCo and AEP Service Company has been significantly reduced from the levels that existed in early 2010.

64. Q. What amount of payroll and benefit costs have you removed from AEP Ohio's 2010 O&M Expense allocated to the generation function?

A. As shown on Exhibit RCS-1, Schedule C-1, for CSP an amount of $6.022 million is removed for direct payroll expense reductions for CSP allocated to the generation demand function, and $0.495 million for reductions in expense to various employee benefits that were directly impacted by the work force reduction. Additionally, $3.533 million is removed for payroll for AEP Service Company employee payroll charged to CSP and allocated to CSP's generation demand function, and approximately $290,000 for AEP Service Company employee benefits. The total reduction in payroll and benefits allocated to CSP's generation function is $10.340 million. Similarly, as shown on Exhibit RCS-2, Schedule C-1, for OPCo, an amount of $15.734 million is removed for direct payroll expense reductions for OPCo allocated to the generation demand function, and $1.136 million for reductions in expense to various employee benefits that were directly impacted by the work force reduction. Additionally, $7.323 million is removed for payroll for AEP Service Company employee payroll charged to OPCo allocated to OPCo's generation demand function, and approximately $529,000 for AEP Service Company employee benefits. The total reduction in payroll and benefits allocated to OPCo's generation function is $24.722 million.

AEP 2010 Severance Program Cost

65. Q. Please explain why the 2010 severance program cost should be removed from 2010 O&M Expense.

A. The 2010 severance cost should be removed from 2010 O&M Expense because rates for AEP Ohio's generating capacity are being established prospectively and this was a significant non-recurring cost that was recorded in 2010.

66. Q. Should the severance cost be amortized?

A. Perhaps, but the amortization should have commenced when the savings began, and there is no demonstrated need for a prospective amortization of 2010 severance cost in the current case to determine a revenue requirement for AEP Ohio's capacity. AEP began to realize cost savings due to the reduced salaries as soon as employees accepted the voluntary retirement offer and/or were involuntarily terminated in mid-2010. Amortization of the costs to achieve that savings should have commenced as soon as the savings from the reduced work force and reduced AEPSC charges commenced. AEP Ohio has not demonstrated that there is any net amount of remaining costs to achieve that has not already been absorbed by related savings experienced by AEP through June 1, 2012, the approximate effective date of new rates in this proceeding. Consequently, there is no need for a prospective amortization of 2010 severance costs in establishing AEP Ohio's revenue requirement for capacity rates that would be applied prospectively from June 1, 2012. Severance costs recorded by CSP and OPCo in 2010, including AEPSC charges to these utilities, should therefore be removed in determining a revenue requirement for AEP Ohio's capacity.

67. Q. When did AEP and its subsidiaries begin to realize savings from the severance program?

A. AEP and its subsidiaries including AEPSC and APCO implemented a work force reduction program in 2010, and the related payroll savings commenced around June 2010. One of the primary purposes of this work force reduction was to manage AEP's earnings in view of changing economic conditions. AEP's Securities and Exchange Commission ("SEC") form 10-Q for the quarterly period ending June 30, 2011, for example, describes that cost reduction initiative at page 79 as follows:

> In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.
>
> We recorded a charge for $293 million to Other Operation expense during the second quarter of 2010 primarily related to severance benefits as the result of the headcount reduction initiatives.

AEP's SEC Form 10-K for the year ending December 31, 2010 contains similar statements at page 403, and also states that:

> Management recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. Management does not expect additional costs to be incurred related to this initiative.

AEP began to realize cost savings due to the reduced salaries and benefits as soon as employees accepted the voluntary retirement offer and/or were involuntarily terminated in mid-2010.

68. Q. How has the regulatory commission in Virginia addressed amortization of severance costs associated with the AEP 2010 severance program?

A. In its Final Order dated November 30, 2011, in Case No. PUE-2011-00037, an Appalachian Power Company ("APCo") application for the review of rates, the Virginia State Corporation Commission addressed the AEP severance program cost at pages 16-17 as follows (footnotes omitted):

> In 2010, AEP implemented cost reduction initiatives associated primarily with workforce reductions. The final

> cost of the workforce reduction was $299 million at a total AEP level. The Company's "share of those costs was approximately $26.7 million, of which $16.7 million of such costs was directly related to [APCo's] workforce reductions and approximately $10 million of such costs was for the Company's share of [American Electric Power Service Corporation's ('ASPSC')] workforce reductions." We reject the Company's request to defer and amortize the costs of the workforce reduction program over four years beginning with the effective date of the rates provided in this case, which would "cause customers to pay the full amount of the workforce reduction costs over that period of time."
>
> We find that it is reasonable – for regulatory accounting purposes in this case – to match the specific costs of this severance program with the specific savings related thereto. We deny the Company's proposal to evaluate earnings to determine whether these 2010 costs should be deferred, amortized, and collected in full from ratepayers in the future. Rather, we conclude that it is appropriate for the amortization of the costs of this program to commence with – and to track – the realization of the savings related thereto in a manner that effectuates the matching of costs and savings. Moreover, this finding provides the Company with a reasonable opportunity to recover its severance costs.
>
> In this regard, based on the evidence presented, we find that the savings realized from this cost reduction initiative exceed the costs therefore prior to the start of the rate year in this case. As a result, these severance costs will be completely amortized before the beginning of the rate year, and, thus, no such costs shall be included in rates prospectively. …

69. Q. Was that the same AEP 2010 severance program that also impacted CSP and OPCo in 2010?

A. Yes.

70. Q. The Virginia Order you quoted above referred to an "effective date" of the rates provided in that case. To what specific date or dates does that pertain?

A. In Virginia Case No. PUE-2011-00037, APCo had proposed to defer and amortize severance cost for itself and for AEPSC charges, commencing with December 1, 2012, the date when APCO's application had initially assumed new rates from that proceeding would become effective.[10]

71. Q. Have you evaluated the amortization period of severance cost for CSP and OPCo similarly to the method described in that Virginia APCo order?

A. Yes. As shown on Exhibit RCS-1, Schedule C-2, for CSP, total annual payroll savings of approximately $34.536 million would provide for amortization of the total severance cost of $32.213 million over a period of approximately 11 months. Thus, commencing with June 2010, the amortization of severance costs for CSP would be effectively completed in approximately May or June of 2011, roughly one year prior to the June 1, 2012 effective date for the CSP capacity rates being established in the current proceeding. Thus, there is no basis for a prospective amortization

[10] Due to various delays encountered in processing that case, expectations about the rate effective date were adjusted accordingly such that the rate year was subsequently expected to commence on or about February 1, 2012.

of CSP's severance cost to be included in operating expenses in the current case.

Similarly, as shown on Exhibit RCS-2, Schedule C-2, for OPCO, total annual payroll savings of approximately $49.258 million would provide for amortization of the total severance cost of $52.661 million over a period of approximately 13 months. Thus, commencing with June 2010, the amortization of severance costs for OPCO would be effectively completed in approximately July 2011, roughly ten months prior to the June 1, 2012 effective date for the OPCO capacity rates being established in the current proceeding. Thus, there is no basis for a prospective amortization of OPCO's severance cost to be included in operating expenses in the current case.

72. Q. What amount of severance costs have you removed from AEP Ohio's 2010 O&M Expense allocated to the generation demand (i.e., capacity) function?

A. As shown on Exhibit RCS-1, Schedule C-2, an amount of $9.852 million of severance cost for CSP and allocated AEP Service Company severance costs allocated to CSP's generation demand function has been removed. Similarly, as shown on Exhibit RCS-1, Schedule C-2, an amount of $29.152 million of severance cost for OPCO and allocated AEP Service

Company severance costs allocated to OPCO's generation demand function has been removed.

Income Tax Expense

73. Q. How has AEP Ohio proposed to provide for income tax expense in its capacity rates?

A. AEP Ohio proposes to calculate income tax expense based on an assumption that its requested equity return represents taxable income. AEP Ohio has calculated its proposed income tax expense by applying an income tax rate "gross up" factor to its requested return. The AEP Ohio calculations of income taxes are reproduced for CSP and OPCo, respectively, on Exhibits RCS-1 and RCS-2, Schedule E, lines 1-5.

74. Q. What adjustments have you made to AEP Ohio's calculation?

A. I have revised the return amount to correspond with the rate base and cost of capital being used. I have also reflected a pro forma adjustment for a Domestic Production Activities Deduction on a "separate return" basis. As shown on Exhibit RCS-1, Schedule E, this produces an allowance for income taxes for CSP of $36.907 million (without the DPAD), for a reduction of $8.984 million from CSP's requested amount of $45.891 million. The tax effect of the "separate return" based DPAD calculation reduces that by \$3.379 million, for a total reduction to CSP's requested income taxes of \$12.363 million.

Similarly, a s shown on Exhibit RCS-2, Schedule E, this produces an allowance for income taxes for OPCO of \$108.811 million (without the DPAD), for a reduction of \$14.529 million from OPCO's requested amount of \$123.340 million. The tax effect of the "separate return" based DPAD calculation reduces that by \$0.879 million, for a total reduction to OPCO's requested income taxes of \$15.409 million.

Domestic Production Activities Deduction

75. Q. What is the §199 deduction for Domestic Production Activities?

A. Section 199 of the Internal Revenue Code provides for a special deduction for Domestic Production Activities. This is known as the §199 Deduction or the Domestic Production Activities Deduction (or DPAD). Because AEP Ohio has its own generation supply, such activities are considered domestic production activities, and thus AEP Ohio are eligible for the DPAD deduction for their generation operations if they have positive taxable income and meet the other requirements for claiming the deduction. For purposes of determining its capacity revenue requirement, AEP Ohio has taxable income, and otherwise meets the requirements of qualifying for a DPAD on a "separate return" basis. Thus for purposes of determining a revenue requirement for AEP Ohio's generating capacity, the result should reflect the reduction to current federal income tax expense for the §199 deduction, computed on a "separate return" basis.

76. Q. Does AEP Ohio participate in a consolidated federal income tax return?

A. Yes. AEP Ohio participates in the AEP corporate consolidated corporate federal income tax return. However, for purposes of determine a rate for AEP Ohio's generation capacity, the Company's federal income tax expense is based on an assumption of a "separate return" (i.e., all impacts of the consolidated income tax are ignored for ratemaking purposes). Consequently, for ratemaking purposes it is appropriate to compute the impact on current federal income tax expense for the Company's generation function on a separate return basis, including the §199 deduction. AEP Ohio's federal income tax expense is being determined on a "separate return" basis in the current case. For its income tax calculation for ratemaking purposes, AEP Ohio has assumed that it has federal taxable income and has requested a positive amount of federal income tax expense which is included in its proposed revenue requirement for generation capacity. The Company's generation revenue requirement calculation assumes that the generation function has positive federal taxable income. It also appears from other information that both CSP and OPCo would have qualified for a DPAD for 2010 based on their "separate return" information.

77. Q. Did AEP Ohio include a calculation of the §199 deduction impact in its revenue requirement for generation capacity?

A. No. Nowhere in the AEP Ohio revenue requirement calculation for capacity is the impact of a pro forma §199 deduction accounted for.

78. Q. On what form is the §199 deduction calculated?

A. The §199 deduction for Domestic Production Activities is computed on IRS form 8903. The DPAD that is computed on form 8903 appears on the front page of the corporate federal income tax return (form 1120) on line 25. It is an additional deduction that is beyond the operating expenses recorded by the utility on its books and the other tax deductions.

79. Q. Please address the Section 199 deduction, as it relates to the interplay between a "separate return" based calculation for income taxes and the impact of participating in a consolidated federal income tax return in another recent utility rate case?

A. Where a utility participates in a consolidated federal income tax return with other affiliates, the Section 199 deduction amount that is allocated to a utility as result of participating in the consolidated tax return can be lower than the Section 199 deduction when computed on a "stand alone" basis for the utility. Because of other impacts on the consolidated return, the amount of the allocated DPAD can be lower than if it had been computed on a separate standalone tax return basis.

AEP Ohio's proposed revenue requirement for generating capacity and its computation of income tax expense for purposes of determining capacity rates in the current proceeding is essentially based on the assumption that CSP and OPCo each file a separate standalone tax return for all income and deductions. The §199 Deduction related to AEP Ohio's generation revenue requirement should therefore, also reflect the §199 deduction computed on separate return basis. In other words, for ratemaking purposes all components of the income tax expense should be computed on a standalone separate tax return basis, including the §199 Deduction, as a matter of conceptual and computational consistency. The principle is that it would not be appropriate to randomly quantify certain components of an income tax expense computation on a standalone basis and other components on a consolidated basis. By omitting a DPAD for CSP and OPCo, the Company is applying a consolidated tax return concept, whereas for all other aspects of the income tax calculations, a "separate return" concept is being applied. The inconsistency in the application of the "separate return" concept causes AEP Ohio's income tax request to be overstated.

80. Q. Would that principle of consistent application of the "separate return" concept also apply to AEP Ohio for determining the revenue requirement for its generating capacity?

A. Yes. The principle that it is not appropriate to randomly quantify certain components of an income tax expense computation on a standalone basis and other components on a consolidated basis would apply to AEP Ohio in the current case. For purposes of determining a revenue requirement and cost rate for capacity, AEP Ohio has computed its federal income tax expense for ratemaking purposes on a "separate return" basis. They have essentially based their request for income tax expense at proposed rates upon the current taxable income represented by the return on equity (grossed up for income taxes), and have reduced that only for ITC amortization, but not for other deductions, such as the DPAD, that CSP or OPCo would claim on a "separate return" basis. Nor have the companies reflected any benefit from participating in the AEP consolidated federal income tax return in their proposed income tax calculations. AEP Ohio has not reflected the §199 deduction that CSP and OPCo would be eligible for on a separate return basis. Consistent ratemaking treatment would thus require the §199 deduction to be reflected for ratemaking purposes by preparing a pro forma calculation that is consistent with the "separate return" concept that is being used for ratemaking purposes.

81. Q. Has AEP Ohio provided calculations of the §199 deduction/DPAD for CSP and OPCo on a "separate return" basis for 2010?

A. Yes. AEP Ohio provided that information in response to PUCO Staff Set 1, INT-01-025, in CONFIDENTIAL Attachment 1.

82. Q. Have you prepared a pro forma §199 deduction/DPAD for CSP and OPCo on a "separate return" basis?

A. Yes. For purposes of determining the generation capacity revenue requirement, I prepared a calculation of the §199 deduction and the related reduction to current income tax expense on a separate return basis for CSP and OPCo. The calculations are shown on Exhibit RCS-1 and RCS-2, Schedule E, for each company.

83. Q. Please explain that calculation.

A. Once it is determined that the entity has qualifying domestic production activities, which CSP and OPCo each do for their electric generation operations, there are three factors that limit the amount of deduction for domestic production activities: (1) Qualified Production Activities Income; (2) Taxable Income; and (3) W-2 wages. As shown on Schedule E of Exhibits RCS-1 and RCS-2, for CSP's and OPCo's generation operations, respectively, I have computed a pro forma §199 deduction on a separate return basis that takes into consideration each of these three factors. The tax effect of the pro forma §199 deduction thus reduces income tax expense for CSP by \$3.379 million as shown on Exhibit RCS-1, Schedule E. Similarly, the tax effect of the DPAD reduces income tax expense for OPCo by \$0.879 million, as shown on Exhibit RCS-2, Schedule E.

Payroll Tax Expense

84. Q. Have you reflected an adjustment for Taxes Other Than Income Taxes?

A. Yes. As shown on Exhibits RCS-1 and RCS-2, Schedule F, for CSP and OPCo, respectively, the reduction in 2010 payroll expense related to the lower work force after the AEP severance program, also reduces Payroll Tax Expense. To estimate the reduction to Payroll Tax Expense, I applied the combined FICA and Medicare rate of 7.65% to the reduction to Payroll Expense allocated to production demand. As shown on Exhibit RCS-1, Schedule F, this reduces Taxes Other Than Income Taxes allocated to CSP's generation demand function by \$0.731 million. Similarly, as shown on Exhibit RCS-2, Schedule F, this reduces Taxes Other Than Income Taxes allocated to OPCo's generation demand function by \$1.764 million.

Capacity Equalization Revenue

85. Q. How has AEP Ohio reflected the Capacity Equalization Revenue received in 2010 by CSP and OPCo?

A. During 2010, both CSP and OPCo received significant amounts of Capacity Equalization Revenue from other members of the AEP East Pool, primarily from Appalachian Power Company. AEP Ohio has reflected the Capacity Equalization Revenue received in 2010 by CSP and OPCo as a dollar-for-dollar offset against their capacity revenue requirement. The Capacity Equalization Revenues received in 2010 by CSP and OPCo are included on Exhibits KDP-3 and KDP-4, respectively, at page 4, line 6, in the Sales for Resale Revenue, which AEP Ohio subtracted in determining its proposed revenue requirement for capacity on line 8, which is labeled there as the Annual Production Fixed Cost.

For CSP, Exhibit KDP-3, at page 4, line 6, shows an amount of $30,785,441. That amount agrees with the $30,785,441 demand charges amount on page 311.8 of CSP's 2010 FERC Form 1.

For OPCo, Exhibit KDP-4, at page 4, line 6, shows an amount of $459,510,726. That amount agrees with the $459,510,726 demand charges amount on page 311.6 of OPCo's 2010 FERC Form 1.

86. Q. Are you satisfied with AEP Ohio's reflection of the Capacity Equalization Revenue?

A. Yes. The payments that AEP Ohio receives from the other members in the AEP East Pool for capacity equalization are payments for capacity. It is therefore necessary and appropriate to deduct such amounts in arriving at the capacity revenue requirement of AEP Ohio that remains, i.e., that is <u>not</u> being covered by payments from the other members in the AEP East Pool.

Ancillary Services Revenue

87. Q. What amounts of Ancillary Services Revenue has AEP Ohio used?

A. As shown on Exhibits KDP-3 and KDP-4, page 4, line 7, AEP Ohio used $29,070 for CSP and $34,520 for OPCo, respectively, for Ancillary Services Revenue.

88. Q. What is the source of that Ancillary Services Revenue?

A. The source of those amounts of Ancillary Services Revenue is described in the OPCo's FERC Form 1 for 2010 at page 450.1, as a footnote for Schedule page 310.1, line no. 5, as: "Carolina Power and Light transmission services from a grandfathered agreement. Activity reflects both the base rate and Ancillary 1 base dollars." AEP advised us that the grandfathered Carolina Power and Light agreement is also the source for the CSP Ancillary Services Revenue.

89. Q. Do those amounts appear to account for all of the receipts for providing Ancillary Services that AEP Ohio receives from PJM?

A. No, it does not. AEP Ohio receives payments from PJM when AEP Ohio is called upon to provide a variety of Ancillary Services.

90. Q. How much did CSP and OPCo receive from PJM in 2010 and 2011 for the provision of Ancillary Services?

A. That information was requested by Staff from AEP Ohio and has been analyzed and addressed, as described below, by Staff witness Ryan Harter.

Energy Sales Margin and Ancillary Services Receipts

91. Q. What was your source for the Energy Sales Margins and Ancillary Services Receipts shown on Exhibits RCS-1 and RCS-2, Schedule A?

A. That information was provided to me by Ryan Harter of EVA. Mr. Harter is also appearing as a Staff witness in this matter.

92. Q. How have you reflected the energy sales margin and ancillary services eceipts?

A. I have reflected those items, as provided to me by Mr. Harter, as deductions to the calculated rate for capacity. This is shown for CSP and OPCo, respectively, on Exhibits RCS-1 and RCS-2, Schedule A, page 1, lines 3 and 4.

93. Q. How would you propose to address additional information provided by AEP Ohio?

A. Rather than hold up the filing of testimony pending receipt of some additional information from AEP Ohio, I have determined that it is preferable that my testimony should be filed prior to the start of the hearing. Additional information provided by AEP Ohio after finalization of my testimony will therefore be evaluated as received. If it is determined to materially affect the results, updates can be provided prior to or concurrent with oral testimony at the hearing.

94. Q. Does this conclude your testimony?

A. Yes. However, I reserve the right to submit supplemental testimony as described herein, as new information subsequently becomes available or in response to positions taken by other parties.

II. PROOF OF SERVICE

I hereby certify that a true copy of the foregoing **Direct Testimony of Ralph C. Smith** submitted on behalf of the Staff of the Public Utilities Commission of Ohio, was served by electronic mail, upon the following Parties of Record, this 16th day of April, 2012.

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Exhibit RCS-1
Schedules for Determining Capacity Cost
For Columbus Southern Power Company
Case No. 10-2929-EL-UNC

Schedule	Description	No. of Pages	Confi-dential	Exhibit Page No.
	Revenue Requirement Summary Schedules			
A	Calculation of Capacity Cost	3	No	2-4
B	Adjusted Production Capacity Rate Base	2	No	5-6
B-1	Accumulated Deferred Income Taxes	1	No	7
C	Adjusted Operating and Maintence Expense	1	No	8
C-1	Payroll and Benefits for Severed Employees	1	No	9
C-2	Severance Cost Recorded in 2010	1	No	10
D	Capital Structure and Cost Rates	1	No	11
E	Income Tax Expense	1	No*	12
F	Taxes Other Than Income Taxes - Payroll Tax Expense for Severed Employees	1	No	13
	Total Pages (including Contents page)	13		

*In an email dated 4-16-2012, AEP counsel agreed to public disclosure of OPCo and CSP related DPAD amounts that the Companies had previously designated as being confidential.

COLUMBUS SOUTHERN POWER COMPANY
CAPACITY (FIXED) CHARGE CALCULATION
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-1
Schedule A
Page 1

		RATE $/MW/Day (1)	Loss Factor (2)	Final FRR Rate (1) x (2) (Note A) (3)
	Capacity Daily Charge:			
	Per AEP Ohio:			
1	Amount	$316.78211	1.034126	$327.59
	Per Staff:			
2	Amount	$280.03688	1.034126	$289.59
3	Less Energy Sales Margin			($46.75)
4	Less Ancillary Service Revenue for CSP's Generation			($6.66)
5	Capacity Daily Charge			$236.18

Notes and Source

Line 1: Exhibit KDP-3, page 1
Line 2: Exhibit RCS-1, Schedule A, page 2
Line 3&4: Amounts are sponsored by PUCO Staff witness Ryan Harter
Line 5: Sum of Lines 2 through 4

Note A: Final Rate that will be applied to CRES providers demand that will be metered at or adjusted to transmission level.

Case No. 10-2929-EL-UNC
Page 2 of 13

COLUMBUS SOUTHERN POWER COMPANY
DETERMINATION OF RATES APPLICABLE TC
OPC'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(OPC 5 CP Demand/365)}}$$

Per AEP Ohio:

1 $$\frac{\$477{,}093{,}822}{4{,}126.2 \quad /365} = \$316.78211$$

2 Per Staff:

$$\frac{\$421{,}753{,}189}{4{,}126.2 \quad /365} = \$280.03688$$

Notes and Source

Line 1:	Exhibit KDP-3, page 2
Line 2:	Exhibit RCS-2, Schedule A, page 3

COLUMBUS SOUTHERN POWER COMPANY
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

	Description	Per AEP Ohio PRODUCTION Amount (A)	Staff Adjustments (B)	Staff Adjusted (C)
1.	Return on Rate Base	$129,071,540	($22,054,089)	$107,017,451
2.	Operation & Maintenance Expense	$217,843,953	($20,192,408)	$197,651,545
3.	Depreciation Expense	$59,590,261		$59,590,261
4.	Taxes Other Than Income Taxes	$55,511,568	($730,942)	$54,780,626
5.	Income Tax	$45,891,012	($8,983,714)	$36,907,298
5a.	Income Tax - Separate Return FIT Savings from DPAD		($3,379,481)	($3,379,481)
6.	Sales for Resale	($30,785,441)		($30,785,441)
7.	Ancillary Service Revenue	($29,070)		($29,070)
8.	Annual Production Fixed Cost	$477,093,822	($55,340,634)	$421,753,189

Notes and Source

Col.A:	Exhibit KDP-4, page 4	
Col.B:		
Line 1:	Schedule B	
Line 2:	Schedule C	
Line 4:	Schedule F	
Line 5:	Schedule E	
	Income Taxes without DPAD	$36,907,298
	Federal Income Tax Savings from Separate Return DPAD	($3,379,481)
	Income Taxes with DPAD	$33,527,817

COLUMBUS SOUTHERN POWER COMPANY
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-1
Schedule B
Page 1

		Per AEP Demand	Staff Adjustments	Staff Adjusted
1.	ELECTRIC PLANT	(A)	(B)	(C)
2.	Gross Plant in Service	$2,787,065,908	$0	$2,787,065,908
3.	Less: Accumulated Depreciation	($1,080,899,054)	$0	($1,080,899,054)
4.	Net Plant in Service	$1,706,166,853	$0	$1,706,166,853
5.	Less: Accumulated Deferred Taxes	($352,760,604)	($7,847,689)	($360,608,292)
6.	Plant Held for Future Use	$5,366,165	($5,366,165)	$0
7.	Pollution Control CWIP	$22,821,421	($22,821,421)	$0
8.	Non-Pollution Control CWIP (50%)	$27,563,093	($27,563,093)	$0
9.	Subtotal - Electric Plant	$1,409,156,928	($63,598,367)	$1,345,558,561
10.	WORKING CAPITAL			
11.	Materials & Supplies			
12.	Fuel	$0	$0	$0
13.	Nonfuel	$30,166,105	$0	$30,166,105
14.	Total M & S	$30,166,105	$0	$30,166,105
15a.	Prepayments Nonlabor	$4,488,336	($4,488,336)	$0
15b.	Prepayments Labor	$37,951,915	($37,951,915)	$0
15c	Prepayments Total	$42,440,251	($42,440,251)	$0
16.	Cash Working Capital	$13,931,878	($13,931,878)	$0
17.	Total Rate Base	$1,495,695,162	($119,970,496)	$1,375,724,666
18.	Weighted Cost of Capital	8.63%		7.78%
19.	Return on Rate Base	$129,071,540	($22,054,089)	$107,017,451

Notes and Source

Col.A: Exhibit KDP-3, page 5
Col.B: Page 2
Line 18: Schedule D

COLUMBUS SOUTHERN POWER COMPANY
PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Rate Base Adjustments

Exhibit RCS-1
Schedule B
Page 2

		Remove CWIP	Remove Cash Working Capital	Remove Prepayments	Adjust ADIT	Plant Held For Future Use	Total Staff Adjustments
1.	ELECTRIC PLANT						
2.	Gross Plant in Service						$0
3.	Less: Accumulated Depreciation						$0
4.	Net Plant in Service						
5.	Less: Accumulated Deferred Taxes				($7,847,689)		($7,847,689)
6.	Plant Held for Future Use					($5,366,165)	($5,366,165)
7.	Pollution Control CWIP	($22,821,421)					($22,821,421)
8.	Non-Pollution Control CWIP	($27,563,093)					($27,563,093)
9.	Subtotal - Electric Plant						
10.	WORKING CAPITAL						
11.	Materials & Supplies						
12.	Fuel						$0
13.	Nonfuel						$0
14.	Total M & S						
15a.	Prepayments Nonlabor			($4,488,336)			($4,488,336)
15b.	Prepayments Labor			($37,951,915)			($37,951,915)
15c	Prepayments Total						
16.	Cash Working Capital		($13,931,878)				($13,931,878)
17.	Total Rate Base	($50,384,513)	($13,931,878)	($42,440,251)	($7,847,689)	($5,366,165)	($119,970,496)

COLUMBUS SOUTHERN POWER COMPANY
ACCUMULATED DEFERRED INCOME TAXES
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-1
B-1
Page 1

	Description	Generation	Production Demand	Staff Adjustment
	Account 190			
1	SEC ALLOC - ITC - GENERATION PLANT	5,228,899	5,228,899	(5,228,899)
2	IGCC REVENUES	4,324,004	4,324,004	(4,324,004)
3	Net FIN 48 Items	275,544	275,544	(275,544)
4	ADIT items related to accrued benefit		1,362,266	(1,362,266)
	Account 283			
5	ADIT related to Prepaid Pension:		(3,627,511)	3,627,511
6	906D SFAS 106 PST RETIRE EXP - NON-DEDUCT CONT		284,486	(284,486)
7	Net Adjustment to Production Demand ADI'		7,847,689	(7,847,689)

Notes and Source
Col.A, Account 190, items: AEP Ohio response to IEU-1-102 Attachment FRR WP 2010 CSP, WP8ε

Line 3: FIN 48 items				
8		ACCRUED INTEREST - L/T - FIN 48	167,153	
9		ACCRUED INTEREST - S/T - FIN 48	(627,789)	
10		ACCRD SIT TX RESERVE - L/T - FIN 48	67,960	
11		ACCRD SIT TX RESERVE - SHRT - FIN 48	734,944	
12		DEFD STATE INCOME TAXES - FIN 48	(66,724)	
13		Total	275,544	
Line 4:	ADIT items related to accrued benefit			
14		PROV WORKER'S COMP	501,675	
15		SUPPLEMENTAL EXECUTIVE RETIRE PLAN	310	
16		ACCRUED PSI PLAN EXP	13,717	
17		ACCRD COMPANYWIDE INCENTV PLAN	597,481	
18		ACCRUED BOOK VACATION PAY	819,581	
19		CCD BILL-DFRD RETIRE BENEFITS-DFL	1,667,411	
20		ACCRD SFAS 106 PST RETIRE EXP	1,738,481	
21		ACCRD SFAS 112 EMPLOY BEN	1,041,436	
22		SFAS 106-MEDICARE SUBSIDY-NORM-(PPACA)	(1,457,725)	
23		Labor Relatec	4,922,369	
24		Production Allocatior	38.4564%	KDP-3, B6a
25		Demand Allocatior	71.9647%	KDP-3, B6a
26		Production Demanc	1,362,266	
Line 5:	ADIT related to Prepaid Pension:			
27	605B	ACCRUED BK PENSION EXPENSE	(9,924,515)	
28	620C	CCD BILL - PREPAID PENSIONS - DEFERRAL	(3,183,023)	
29		Related to Prepaid Pension:	(13,107,538)	
30		Production Allocatior	38.4564%	KDP-3, B6a
31		Demand Allocatior	71.9647%	KDP-3, B6a
32		Production Demanc	(3,627,511)	
Line 6:	906D	SFAS 106 PST RETIRE EXP - NON-DEDUCT CONT	1,027,954	
33		Production Allocatior	38.4564%	KDP-3, B6a
34		Demand Allocatior	71.9647%	KDP-3, B6a
35		Production Demanc	284,486	

COLUMBUS SOUTHERN POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-1
Schedule C
Page 1

	Description	Staff Adjustments	Reference
1	Payroll and Benefits Recorded in 2010 for Severed Employees	$ (10,339,924)	Schedule C-1
2	Severance Cost Recorded in 2010 for 2010 Voluntary and Involuntary Severance Programs	$ (9,852,484)	Schedule C-2
3	Adjutments to Production O&M Expense	$ (20,192,408)	

COLUMBUS SOUTHERN POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Payroll and Employee Benefits for Severed Employees

Exhibit RCS-1
Schedule C-1
Page 1

		Staff Adjustments		
	Description	Payroll	Employee Benefits	Payroll & Benefits
		(A)	(B)	(C)
	Payroll and Benefits Recorded in 2010 for Severed Employees			
1	CSP Employees	$ (6,021,901)	$ (494,824)	$ (6,516,725)
2	AEP Service Company Employees Charged to CSP	$ (3,532,898)	$ (290,301)	$ (3,823,199)
3	Total	$ (9,554,799)	$ (785,125)	$ (10,339,924)

Notes and Source

Col.A:

Line 1: See Staff Set 1 INT-01-017, Attachment 1 and related detail provided by AEP Ohio in Excel

	Total		Production Demand
Direct Severance CSP	(19,323,036)		(6,021,901)

Line 2: Staff Set 1 INT-01-019(a), Attachment and related detail provided by AEP Ohio in Excel

	Total	Production	Production Demand
AEPSC Reduction in Payroll Charged to CSP	(15,212,584)	(4,064,726)	(3,532,898)
Total CSP Direct and AEPSC Allocated Payroll Savings	(34,535,620)		

Col.B: Estimated Benefit Costs Saved by Severance:

Line 1: CSP Employees

Account		Savings Amount		
9260004	Group Life Insurance Premiums	(22,063)		
9260005	Group Medical Ins Premiums	(1,278,459)		
9260007	Group L-T Disability Ins Prem	(22,483)		
9260009	Group Dental Insurance Prem	(51,829)		
9260027	Savings Plan Contributions	(88,821)		
9260051	Frg Ben Loading - Grp Ins	109,335		
9260052	Frg Ben Loading - Savings	95,007		
Net Amount		(1,259,313)		
Allocation			63.7080%	61.6770%
Allocated Amount			(802,283)	(494,824)

Line 2: Estimated based on proportion of benefits to payroll for CSP Direct employees

COLUMBUS SOUTHERN POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Severance Cost Recorded in 2010

Exhibit RCS-1
Schedule C-2
Page 1

	Description	Total Amount (A)	Production (B)	Production Demand (C)	Staff Adjustments (D)
	Severance Cost Recorded in 2010				
1	Ohio Power Direct	$21,083,541	$6,499,321	$6,394,054	$ (6,394,054)
2	AEP Service Company Charged to OPCo	$11,129,180	$3,974,397	$3,458,430	$ (3,458,430)
3	Total	$32,212,721	$10,473,719	$9,852,484	$ (9,852,484)

Notes and Source

Col.A: AEP Ohio's response to Staff informal information requests 9 and 9, respectively
Col.B&C: AEP Ohio's response to Staff informal follow up Excel file workpapers containing jurisdictionalization

4	Severance Costs	32,212,721	Line 3
5	Payroll Savings	(34,535,620)	Schedule C-1
6	Approximate amortization period in years	0.93	
7	Approximate amortization period in months	11	

Exhibit RCS-1
Schedule D

COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

		Reference	Total Company Capitalization $ (1)	Weighted Cost Ratios % (2)	Cost of Capital % (3)	Weighted Cost of Capital (2 x 3) (4)
	I. Per AEP Ohio					
1.	Long Term Debt	Note A	1,442,745,000	48.44%	5.95%	2.88%
2.	Preferred Stock	Note B	0	0.00%	0.00%	0.00%
3.	Common Stock	Note C	1,535,416,257	51.56%	11.15%	5.75%
4.	Total		2,978,161,257	100.00%		8.63%
	II. Per Staff					
5	Long Term Debt	Note A	1,442,745,000	49.36%	5.50%	2.71%
6	Preferred Stock	Note B	0	0.00%	0.00%	0.00%
7	Common Stock	Note C	1,480,405,000	50.64%	10.00%	5.06%
8	Total		2,923,150,000	100.00%		7.78%

Notes and Source

Lines 1-4: Exhibit KDP-3, page 11

Lines 5-8: Capital Structure and Cost Rates except ROE:
Staff Report, page 126, Schedule D1 in Case No. 11-351-EL-AIR
Return on Equity and Overall Rate of Return:
Commission's 12/14/2011 Order in 11-351-EL-AIR et al
Page 12 findings of fact 12 and 13; also page 13 conclusion of law 13
Also, page 5, paragraphs II-A(1)(c) and (e)

Exhibit RCS-1
Schedule E
Page 1

PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

	Description	Tax Rate	Demand (A)	Without Pro Forma DPAD (B)
	I. Per AEP Ohio			
1.	Return on Rate Base		$129,071,540	
2.	Effective Income Tax Rate		36.8399%	
3.	Income Tax Calculated		$47,549,797	
4.	ITC Adjustment		($1,658,786)	
5.	Income Tax		$45,891,012	
	II. Per Staff	Tax Rate	With DPAD	Without DPAD
6	Return on Rate Base		$107,017,451	$107,017,451
7	Income Taxes (line 20)	36.0372%	$38,566,084	$38,566,084
8	Pro forma Interest		($37,282,138)	($37,282,138)
9	Taxable Income		$108,301,397	$108,301,397
10	State Income Tax	0.9384%	$1,016,300	1,016,300
11	Federal Taxable Income Before §199 Deduction		$107,285,097	$107,285,097
12	Federal Income Tax	35.0000%	$37,549,784	$37,549,784
13	Pro forma §199 DPAD Reduction to FIT		($3,379,481)	
14	Investment Tax Credit Amortization		($1,658,786)	(1,658,786)
15	Adjusted Federal Income Taxes		$32,511,517	$35,890,998
16	Total State and Federal Income Taxes		$33,527,817	$36,907,298
	III. Adjustment to AEP Ohio Proposed Income Tax Expense			
17	Income Tax per Staff		$33,527,817	36,907,298
18	Income Tax per AEP Ohio		$45,891,012	45,891,012
19	Adjustment to AEP Ohio Proposed Income Tax Expense		($12,363,194)	($8,983,713)
20	State and Federal Income Taxes Before ITC Amortization and DPAD		L10 + L12	$38,566,084

Notes and Source
Lines 1-5: Exhibit KDP-4, page 18, column 2, Demand
Line 6: Exhibit RCS-2, Schedule B
Line 7, income tax "gross up" rate: derived (for informational purposes only) by dividing line 7 / line 6 (without DPAD column)
Line 8: Pro forma Interest

21	Adjusted Production Rate Base		$1,375,724,666
22	Weighted Cost of Debt		2.71%
23	Pro Forma Interest		$37,282,138

Line 10, tax rate: Exhibit KDP-4, page 19, line 6
Line 12, tax rate: Exhibit KDP-4, page 19, line 5
Line 13: Pro forma "Separate Return" Domestic Production Activities Deduction

24	I. Qualified Production Activities Income	Note A	**	$240,268,493	**	
25	II. Taxable Income	Line 11		$107,285,097		
26	III. Estimated W-2 Wages (Generation)	Note A	**	35,252,627	**	
26a	Payroll Adjustment			(6,021,901)		Schedule C-1
26b	Adjusted W-2 Wages (Generation)		**	29,230,726	**	
27	9% of QPAI	9%	**	$21,624,164	**	
28	9% of Taxable Income	9%		$9,655,659		
29	50% of W-2 Wages (Generation - Adjusted)	50%	**	14,615,363	**	
30	Smaller of Limitations		**	$9,655,659	**	
31	Reduction to Current Federal Income Tax Expense					
32	Qualified Production Activities Deduction			$9,655,659		
33	Federal Income Tax Rate			35.0000%		
34	Adjustment (Reduction) to Current Federal Income Tax Expense			$3,379,481		

Line 14: Exhibit KDP-4, page 18, column 2, Demand, line 4
Note A: PUCO Staff Set 1 INT-01-025, CONFIDENTIAL Attachment 1

In an email received on 4-16-2012, AEP counsel indicated that:
If they confine the numbers in their testimony to OP and CSP numbers off the schedule we would not require that to be treated as confidential. No total company or other companies should be disclosed w/o confidential treatment.
Based on this clarification, the numbers shown on this schedule do not require confidential treatment.

COLUMBUS SOUTHERN POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Payroll Tax Expense Recorded in 2010 for Severed Employees

Exhibit RCS-1
Schedule F
Page 1

	Description	Staff Adjustments	Reference
	Payroll Recorded in 2010 for Severed Employees		
1	CSP Employees	$ (6,021,901)	Schedule C-1
2	AEP Service Company Employees	$ (3,532,898)	Schedule C-1
3	Total Payroll Expense for Production	$ (9,554,799)	
4	Payroll Tax Rate	7.65%	
5	Payroll Tax Expense Recorded in 2010 for Severed Employees	$ (730,942)	

Notes and Source

Line 4: Employer's Medicare (1.45%) and FICA (6.20%) rate for 2010

Appendix RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments
Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)

Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, Inc. (Arizona CC)
E-01773A-09-0496	Arizona Electric Power Cooperative, Inc. (Arizona CC)

R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
08-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-11049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)

Exhibit RCS-2
Schedules for Determining Capacity Cost
For Ohio Power Company
Case No. 10-2929-EL-UNC

Schedule	Description	No. of Pages	Confi-dential	Exhibit Page No.
	Revenue Requirement Summary Schedules			
A	Calculation of Capacity Cost	3	No	2-4
B	Adjusted Production Capacity Rate Base	2	No	5-6
B-1	Accumulated Deferred Income Taxes	1	No	7
C	Adjusted Operating and Maintenance Expense	1	No	8
C-1	Payroll and Benefits for Severed Employees	1	No	9
C-2	Severance Cost Recorded in 2010	1	No	10
D	Capital Structure and Cost Rates	1	No	11
E	Income Tax Expense	1	No*	12
F	Taxes Other Than Income Taxes - Payroll Tax Expense for Severed Employees	1	No	13
	Total Pages (including Contents page)	13		

*In an email dated 4-16-2012, AEP counsel agreed to public disclosure of OPCo and CSP related DPAD amounts that the Companies had previously designated as being confidential.

OHIO POWER COMPANY
CAPACITY (FIXED) CHARGE CALCULATION
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

		RATE $/MW/Day (1)	Loss Factor (2)	Final FRR Rate (1) x (2) (Note A) (3)
	Capacity Daily Charge:			
	Per AEP Ohio:			
1	Amount	$366.71683	1.034126	$379.23
	Per Staff:			
2	Amount	$308.24394	1.034126	$318.76
3	Less Energy Sales Margin			($231.02)
4	Less Ancillary Service Revenue for OPCo's Generation			($6.66)
5	Capacity Daily Charge			$81.08

Notes and Source

Line 1: Exhibit KDP-4, page 1
Line 2: Exhibit RCS-2, Schedule
Lines 3&4: Amounts are sponsored by PUCO Staff witness Ryan Harter
Line 5: Sum of Lines 2 through 4

Note A: Final Rate that will be applied to CRES providers demand that will be metered at or adjusted to transmission level.

OHIO POWER COMPANY
DETERMINATION OF RATES APPLICABLE TO
OPC'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(OPC 5 CP Demand/365)}}$$

Per AEP Ohio:

1 $$\frac{\$660{,}504{,}310}{4{,}934.6 \quad /365} = \$366.71683$$

2 Per Staff:

$$\frac{\$555{,}187{,}093}{4{,}934.6 \quad /365} = \$308.24394$$

Notes and Source

Line 1: Exhibit KDP-4, page 2
Line 2: Exhibit RCS-2, Schedule A, page 3

OHIO POWER COMPANY
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-2
Schedule A
Page 3

	Description	Per AEP Ohio PRODUCTION Demand Amount (A)	Staff Adjustments (B)	Staff Adjusted (C)
1.	Return on Rate Base	$311,327,830	($34,269,930)	$277,057,900
2.	Operation & Maintenance Expense	$338,656,260	($53,874,662)	$284,781,598
3.	Depreciation Expense	$256,957,852		$256,957,852
4.	Taxes Other Than Income Taxes	$89,767,677	($1,763,866)	$88,003,811
5.	Income Tax	$123,339,938	($14,529,407)	$108,810,531
5a.	Income Tax - Separate Return FIT Savings from DPAD		($879,352)	($879,352)
6.	Sales for Resale	($459,510,726)		($459,510,726)
7.	Ancillary Service Revenue	($34,520)		($34,520)
8.	Annual Production Fixed Cost	$660,504,310	($105,317,216)	$555,187,093

Notes and Source

Col.A: Exhibit KDP-4, page 4
Col.B:
Line 1: Schedule B
Line 2: Schedule C
Line 4: Schedule F
Line 5: Schedule E:

Income Taxes without DPAD	$108,810,531
Federal Income Tax Savings from Separate Return DPAD	($879,352)
Income Taxes with DPAD	$107,931,179

OHIO POWER COMPANY
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-2
Schedule B
Page 1

		Per AEP Demand (A)	Staff Adjustments (B)	Staff Adjusted (C)
1.	ELECTRIC PLANT			
2.	Gross Plant in Service	$6,912,623,064	$0	$6,912,623,064
3.	Less: Accumulated Depreciation	($2,616,814,774)	$0	($2,616,814,774)
4.	Net Plant in Service	$4,295,808,290	$0	$4,295,808,290
5.	Less: Accumulated Deferred Taxes	($914,813,350)	$8,479,895	($906,333,455)
6.	Plant Held for Future Use	$0	$0	$0
7.	Pollution Control CWIP	$10,860,321	($10,860,321)	$0
8.	Non-Pollution Control CWIP	$21,859,033	($21,859,033)	$0
9.	Subtotal - Electric Plant	$3,413,714,294	($24,239,458)	$3,389,474,836
10.	WORKING CAPITAL			
11.	Materials & Supplies			
12.	Fuel	$0	$0	$0
13.	Nonfuel	$86,030,030	$0	$86,030,030
14.	Total M & S	$86,030,030	$0	$86,030,030
15a.	Prepayments Nonlabor	$2,045,295	($2,045,295)	$0
15b.	Prepayments Labor	$73,652,528	($73,652,528)	$0
15c	Prepayments Total	$75,697,823	($75,697,823)	$0
16.	Cash Working Capital	$34,871,445	($34,871,445)	$0
17.	Total Rate Base	$3,610,313,592	($134,808,727)	$3,475,504,866
18.	Weighted Cost of Capital	8.62%		7.97%
19.	Return on Rate Base	$311,327,830	($34,269,930)	$277,057,900

OHIO POWER COMPANY
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Rate Base Adjustments

		Remove CWIP	Remove Cash Working Capital	Remove Prepayments	Adjust ADIT	Total Staff Adjustments
1.	ELECTRIC PLANT					
2.	Gross Plant in Service					$0
3.	Less: Accumulated Depreciation					$0
4.	Net Plant in Service					
5.	Less: Accumulated Deferred Taxes				$8,479,895	$8,479,895
6.	Plant Held for Future Use					
7.	Pollution Control CWIP	($10,860,321)				($10,860,321)
8.	Non-Pollution Control CWIP	($21,859,033)				($21,859,033)
9.	Subtotal - Electric Plant					
10.	WORKING CAPITAL					
11.	Materials & Supplies					
12.	Fuel					$0
13.	Nonfuel					$0
14.	Total M & S					
15a.	Prepayments Nonlabor			($2,045,295)		($2,045,295)
15b.	Prepayments Labor			($73,652,528)		($73,652,528)
15c	Prepayments Total					
16.	Cash Working Capital		($34,871,445)			($34,871,445)
17.	Total Rate Base	($32,719,353)	($34,871,445)	($75,697,823)	$8,479,895	($134,808,727)

OHIO POWER COMPANY
ACCUMULATED DEFERRED INCOME TAXES
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-2
B-1
Page 1

	Description	Generation	Production Demand	Staff Adjustment
	Account 190			
1	SEC ALLOC - ITC - GENERATION PLANT	0	0	0
2	IGCC REVENUES	4,159,997	4,159,997	(4,159,997)
3	Net FIN 48 Items	1,771,951	1,771,951	(1,771,951)
4	ADIT items related to accrued benefits		(1,883,556)	1,883,556
	Account 283			
5	ADIT related to Prepaid Pensions		(13,705,181)	13,705,181
6	906D SFAS 106 PST RETIRE EXP - NON-DEDUCT CONT		1,176,894	(1,176,894)
7	Net Adjustment to Production Demand ADIT		(8,479,895)	8,479,895

Notes and Source

Col.A, Account 190, items: AEP Ohio response to IEU-1-102 Attachment FRR WP 2010 OPCo, WP8ai

Line 3: FIN 48 items:				
8		ACCRUED INTEREST - L/T - FIN 48	(102,439)	
9		ACCRUED INTEREST - S/T - FIN 48	1,297,962	
10		ACCRD SIT TX RESERVE - L/T - FIN 48	77,558	
11		ACCRD SIT TX RESERVE - SHRT - FIN 48	908,445	
12		DEFD STATE INCOME TAXES - FIN 48	(409,574)	
13		Total	1,771,951	
Line 4:	ADIT items related to accrued benefits			
14		PROV WORKER'S COMP	(8,701,037)	Note A
15		SUPPLEMENTAL EXECUTIVE RETIRE PLAN	72,508	
16		ACCRUED BK SUP SAVINGS PLAN EXP	122,630	
17		ACCRUED PSI PLAN EXP	80,562	
18		ACCRD COMPANYWIDE INCENTV PLAN	1,379,747	
19		ACCRUED BOOK VACATION PAY	1,709,874	
20		ACCRUED BOOK SEVERANCE BENEFITS	410,271	
21		ACCRD SFAS 106 PST RETIRE EXP	10,332,900	
22		ACCRD SFAS 112 EMPLOY BEN	(2,947,554)	Note A
23		SFAS 106-MEDICARE SUBSIDY-NORM-(PPACA)	(4,793,631)	
24		Labor Related	(2,333,729)	
25		Production Allocation	63.7077%	KDP-4, B6a
26		Demand Allocation	61.6768%	KDP-4, B6a
27		Production Demand	(1,883,556)	
Line 5:	ADIT related to Prepaid Pensions			
28	605B	ACCRUED BK PENSION EXPENSE	(34,879,541)	
29	620C	CCD BILL - PREPAID PENSIONS - DEFERRAL	0	
30		Related to Prepaid Pensions	(34,879,541)	
31		Production Allocation	63.7077%	KDP-4, B6a
32		Demand Allocation	61.6768%	KDP-4, B6a
33		Production Demand	(13,705,181)	
Line 6:	906D	SFAS 106 PST RETIRE EXP - NON-DEDUCT CONT	2,995,184	
34		Production Allocation	63.7077%	KDP-4, B6a
35		Demand Allocation	61.6768%	KDP-4, B6a
36		Production Demand	1,176,894	

Note A: AEP Ohio has been requested to provide additional informaiton about these items and why they have debit balances at 12/31/2010

OHIO POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-2
Schedule C
Page 1

	Description	Staff Adjustments	Reference
1	Payroll and Benefits Recorded in 2010 for Severed Employees	$ (24,722,363)	Schedule C-1
2	Severance Cost Recorded in 2010 for 2010 Voluntary and Involuntary Severance Programs	$ (29,152,299)	Schedule C-2
3	Adjutments to Production O&M Expense	$ (53,874,662)	

OHIO POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Payroll and Employee Benefits for Severed Employees

Exhibit RCS-2
Schedule C-1
Page 1

		Staff Adjustments		
	Description	Payroll	Employee Benefits	Payroll & Benefits
		(A)	(B)	(C)
	Payroll and Benefits Recorded in 2010 for Severed Employees			
1	Ohio Power Employees	$ (15,733,634)	$(1,136,354)	$ (16,869,988)
2	AEP Service Company Employees Charged to OPCo	$ (7,323,443)	$ (528,932)	$ (7,852,375)
3	Total	$ (23,057,077)	$(1,665,286)	$ (24,722,363)

Notes and Source

Col.A:

Line 1: Staff Set 1 INT-01-017, Attachment 1 and related detail provided by AEP Ohio in Excel

	Total		Production Demand
Direct Severance Ohio Power	(30,019,624)		(15,733,634)

Line 2: Staff Set 1 INT-01-019(b), Attachment and related detail provided by AEP Ohio in Excel

	Total	Production	Production Demand
AEPSC Reduction in Payroll Charged to OPCo	(19,238,763)	(8,364,740)	(7,323,443)
Total OPCo Direct and AEPSC Allocated Payroll Savings	(49,258,387)		

Col.B: Estimated Benefit Costs Saved by Severance:

Line 1: Ohio Power Employees

Account Description		Amount	
926000‹ Group Life Insurance Premiums		(74,296)	
926000‡ Group Medical Ins Premiums		(2,579,905)	
926000˜ Group L-T Disability Ins Prem		(44,072)	
926000‡ Group Dental Insurance Prem		(81,107)	
926002˜ Savings Plan Contributions		(234,432)	
926005' Frg Ben Loading - Grp Ins		35,514	
926005: Frg Ben Loading - Savings		86,310	
Net Amount		(2,891,989)	(2,891,989)
Production Allocation	Exh KPD-4 Pg 7 Note B	63.7080%	(1,842,428)
Demand Allocation	W/P 9b	61.6770%	(1,136,354)

Line 2: Estimated based on proportion of benefits to payroll for CSP Direct employees

OHIO POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Severance Cost Recorded in 2010

Exhibit RCS-2
Schedule C-2
Page 1

	Description	Total Amount (A)	Production (B)	Production Demand (C)	Staff Adjustments (D)
	Severance Cost Recorded in 2010				
1	Ohio Power Direct	$33,013,131	$20,434,525	$20,156,165	$ (20,156,165)
2	AEP Service Company Charged to OPCo	$19,647,661	$10,708,408	$8,996,134	$ (8,996,134)
3	Total	$52,660,792	$31,142,933	$29,152,299	$ (29,152,299)

Notes and Source

Col.A: AEP Ohio's response to Staff informal information requests 8 and 10, respectively
Col.B: AEP Ohio's response to Staff informal follow up Excel file workpapers containing jurisdictionalization

Severance Costs	52,660,792	Line 3
Payroll Savings	(49,258,387)	Schedule C-1
Approximate amortization period in years	1.07	
Approximate amortization period in months	13	

OHIO POWER COMPANY
COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

Exhibit RCS-2
Schedule D

		Reference	Total Company Capitalization $ (1)	Weighted Cost Ratios % (2)	Cost of Capital % (3)	Weighted Cost of Capital (2 x 3) (4)
	I. Per AEP Ohio					
1.	Long Term Debt	Note A	2,734,580,000	45.49%	5.65%	2.57%
2.	Preferred Stock	Note B	18,902,783	0.31%	3.87%	0.01%
3.	Common Stock	Note C	3,258,446,556	54.20%	11.15%	6.04%
4.	Total		6,011,929,339	100.00%		8.62%
	II. Per Staff					
5	Long Term Debt	Note A	2,734,580,000	45.93%	5.27%	2.42%
6	Preferred Stock	Note B	16,626,000	0.28%	3.87%	0.01%
7	Common Stock	Note C	3,202,486,000	53.79%	10.30%	5.54%
8	Total		5,953,692,000	100.00%		7.97%

Notes and Source

Lines 1-4: Exhibit KDP-4, page 11

Lines 5-8: Capital Structure and Cost Rates except ROE:

Staff Report, page 124, Schedule D1 in Case No. 11-352-EL-AIR

Return on Equity and Overall Rate of Return:

Commission's 12/14/2011 Order in 11-351-EL-AIR et al

Page 12 findings of fact 12 and 13; also page 13 conclusion of law 13

Also, page 5, paragraphs II-A(1)(d) and (e)

Exhibit RCS-2
Schedule E
Page 1

PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)

	Description		Demand	Without Pro Forma DPAD
			(A)	(B)
	I. Per AEP Ohio			
1.	Return on Rate Base		$311,327,830	
2.	Effective Income Tax Rate		39.7482%	
3.	Income Tax Calculated		$123,747,110	
4.	ITC Adjustment		($407,172)	
5.	Income Tax		$123,339,938	
	II. Per Staff	Tax Rate	With DPAD	Without DPAD
6	Return on Rate Base		$277,057,900	$277,057,900
7	Income Taxes (line 20)	39.4205%	$109,217,699	$109,217,699
8	Pro forma Interest		($84,107,218)	($84,107,218)
9	Taxable Income		$302,168,381	$302,168,381
10	State Income Tax	1.7610%	$5,321,185	5,321,185
11	Federal Taxable Income Before §199 Deduction		$296,847,196	$296,847,196
12	Federal Income Tax	35.0000%	$103,896,518	$103,896,518
13	Pro forma §199 DPAD Reduction to FIT		($879,352)	
14	Investment Tax Credit Amortization		($407,172)	(407,172)
15	Adjusted Federal Income Taxes		$102,609,994	$103,489,346
16	Total State and Federal Income Taxes		$107,931,179	$108,810,531
	III. Adjustment to AEP Ohio Proposed Income Tax Expense			
17	Income Tax per Staff		$107,931,179	108,810,531
18	Income Tax per AEP Ohio		$123,339,938	123,339,938
19	Adjustment to AEP Ohio Proposed Income Tax Expense		($15,408,759)	($14,529,407)
20	State and Federal Income Taxes Before ITC Amortization and DPAD		L10 + L12	$109,217,703

Notes and Source

Lines 1-5: Exhibit KDP-4, page 18, column 2, Demand
Line 6: Exhibit RCS-2, Schedule B
Line 7, income tax "gross up" rate: derived (for informational purposes only) by dividing line 7 / line 6 (without DPAD columr
Line 8: Pro forma Interest

21	Adjusted Production Rate Base	$3,475,504,866
22	Weighted Cost of Debt	2.42%
23	Pro Forma Interest	$84,107,218

Line 10, tax rate: Exhibit KDP-4, page 19, line 6
Line 12, tax rate: Exhibit KDP-4, page 19, line 5
Line 13: Pro forma "Separate Return" Domestic Production Activities Deduction

24	I. Qualified Production Activities Income	Note A	**	$27,915,939	**
25	II. Taxable Income	Line 11		$296,847,196	
26	III. Estimated W-2 Wages	Note A	**	103,087,392	**
27	9% of QPAI	9%	**	$2,512,435	**
28	9% of Taxable Income	9%		$26,716,248	
29	50% of W-2 Wages	50%	**	51,543,696	**
30	Smaller of Limitation Items (lines 27 through 29)		**	$2,512,435	**
31	Reduction to Current Federal Income Tax Expense				
32	Qualified Production Activities Deduction			$2,512,435	
33	Federal Income Tax Rate			35.0000%	
34	Adjustment (Reduction) to Current Federal Income Tax Expense			$879,352	

Line 14: Exhibit KDP-4, page 18, column 2, Demand, line 4
Note A: PUCO Staff Set 1 INT-01-025, CONFIDENTIAL Attachment 1

In an email received on 4-16-2012, AEP counsel indicated that:
If they confine the numbers in their testimony to OP and CSP numbers off the schedule we would not require that to be treated as confidential. No total company or other companies should be disclosed w/o confidential treatment.
Based on this clarification, the numbers shown on this schedule do not require confidential treatment.

OHIO POWER COMPANY
PRODUCTION OPERATING AND MAINTENANCE EXPENSE
12 Months Ending 12/31/2010 (actuals with Staff Adjustments)
Payroll Tax Expense Recorded in 2010 for Severed Employees

Exhibit RCS-2
Schedule F
Page 1

	Description	Staff Adjustments	Reference
	Payroll Recorded in 2010 for Severed Employees		
1	Ohio Power Employees	$ (15,733,634)	Schedule C-1
2	AEP Service Company Employees	$ (7,323,443)	Schedule C-1
3	Total Payroll Expense for Production	$ (23,057,077)	
4	Payroll Tax Rate	7.65%	
5	Payroll Tax Expense Recorded in 2010 for Severed Employees	$ (1,763,866)	

Notes and Source

Line 4: Employer's Medicare (1.45%) and FICA (6.20%) rate for 2010

Merged CSP and OPCo Capacity Charge
Energy Credit Applicable to Capacity Rate Effective 6/2/2012

I. Merged CSP and OPCo Capacity Daily Rate

$$\text{\$/MW-day} = \frac{\text{(Annual Production Fixed Cost of CSP + OPCo)}}{\text{(CSP+OPCo 5 CP Demandx365) (Note A)}}$$

Exhibit RCS-1, Sch A, page 3 — Exhibit RCS-2, Sch A, page 3

$$\text{\$/MW-day} = \frac{\$421{,}753{,}189 \quad\quad \$555{,}187{,}093}{4{,}126.2 \quad + \quad 4{,}934.6} \;/\; 365$$

$$\text{\$/MW-day} = \frac{\$976{,}940{,}282}{9{,}060.8} \;/\; 365 = \$295.40$$

Note A: Average of demand at time of PJM five highest daily peaks.

Final FRR Rate =	RATE $/MW/Day	x	LOSS FACTOR		
Final FRR Rate =	$295.40	x	1.034126	=	**$305.48**

II. Merged CSP and OPCo Capacity Daily Rate WITH Energy Credit and Ancillary Services Receipts

AEP-Ohio Resulting Merged Capacity Rate

Final Rate =	Capacity Rate	-	Energy Credit and Ancillary Service Receipts (a)		
$/MW-Day =	$305.48	-	$160.90	=	**$144.58**

Note a: Merged Energy Credit and Ancillary Service Revenue provided from PUCO Staff witness Ryan Harter

Energy Credit	$154.24
Ancillary Services	$6.66
Combined	$160.90