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December 10, 2012

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: **Appalachian Power Company**
Docket No. ER13-___-000

Dear Secretary Bose:

Amanda Riggs Conner
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On behalf of Appalachian Power Company ("APCO "), American Electric Power Service Corporation ("AEP") herewith tenders for filing, pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Sections 35.1 and 35.13 of the Commission's Regulations, 18 C.F.R. §§ 35.1 and .13 (2012), a formula rate template under which APCO will calculate its capacity costs ("Capacity Compensation Formula Rate") under Section D. 8 of Schedule 8.1 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA").[1] Consistent with APCO's capacity obligations under the RAA, AEP proposes that APCO recover capacity costs calculated pursuant to this Capacity Compensation Formula Rate from Competitive Service Providers ("CSP" or "provider") which provide service to customers eligible for the retail choice program in Virginia. AEP respectfully requests that the Commission issue an order accepting the Capacity Compensation Formula Rate and permitting the new capacity rate to become effective on February 9, 2013. This filing consists of the following documents:

[1] AEP's right to submit a FPA Section 205 filing is consistent with the requirements of Schedule 8.1, Section D. 8 of the RAA and the Commission's order issued April 30, 2012, in Docket No. ER12-1173, *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,078 (2012) ("*2012 PJM Order*").

1. This letter of transmittal;
2. Attachment A, which is the clean version of the Tariff Record – RAA Schedule 8.1 – Appendix 2A: Appalachian Power Company Capacity Compensation Formula Rate Implementation Protocols; Appendix 2B: Appalachian Power Company Capacity Compensation Formula Rate; and Appendix 2C: Appalachian Power Company Capacity Compensation Formula Rate Workpapers;
3. Attachment B, which is the redline version of the Tariff Record – RAA Schedule 8.1 – Appendix 2A: Appalachian Power Company Capacity Compensation Formula Rate Implementation Protocols; Appendix 2B: Appalachian Power Company Capacity Compensation Formula Rate; and Appendix 2C: Appalachian Power Company Capacity Compensation Formula Rate Workpapers;
4. Attachment C, which populates the Capacity Compensation Formula Rate template with APCO Form 1 and Workpaper-based cost data for 2011 to compute the initial formula rate as of February 9, 2013;
5. Attachment D, which provides workpapers with additional detail to the Form 1 for the formula inputs;
6. Attachment E, which is an attestation as to the accuracy of the supporting cost of service data;
7. Attachment F, which provides a range of revenues that APCO would recover under the Capacity Compensation Formula Rate at hypothetical levels of service;
8. Attachment G, which provides a comparison of the rate in Attachment C to the demand rates in APCO's Virginia retail tariffs;
9. Attachment H, which is the testimony of Dr. Kelly Pearce, describing the impact to APCO of the RAA in the context of Virginia's choice program, and why the use of a formula rate is appropriate in this filing;
10. Attachment I, which is the testimony of Ms. Diane Keegan, supporting the specific calculations in the formula;
11. Attachment J, which is the testimony of Mr. David Davis, supporting weighted average depreciation rates underlying the depreciation expense input in the formula;
12. Attachment K, which is the testimony of Dr. William E. Avera supporting the requested rate of return on common equity; and
13. Attachment L, which is a copy of Section D of Schedule 8.1 of the RAA.

Pursuant to Section 35.7 of the Commission's regulations, 18 C.F.R. § 35.7 (2012), the contents of this filing are being submitted as part of an XML filing package that conforms to the Commission's instructions. PJM Interconnection, L.L.C. ("PJM") has agreed to make all filings that are required to be included in PJM's electronic tariffs in order to retain administrative control over the PJM tariffs. PJM has designated Schedule 8.1 – Appendix 2A, Schedule 8.1 –

Appendix 2B and Schedule 8.1 – Appendix 2C to the RAA for the filing of the Appalachian Power Company Capacity Compensation Formula Rate Protocols, Formula Template and Workpapers.

I. Background

The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. The basis for the capacity market design is the Reliability Pricing Model ("RPM"). The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement ("FRR") Alternative. The FRR Alternative provides a Load Serving Entity ("LSE") with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the RPM, which includes a variable resource requirement for capacity. The RAA sets forth the rules of participation in the PJM Capacity Market and also establishes capacity obligations of PJM Load Serving Entities. Section D. 8 of Schedule 8.1 of the RAA provides in relevant part:

> … In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. <u>In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Section 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable</u>, and a retail LSE may at any time exercise its rights under Section 206 of the FPA. (Emphasis supplied; a full copy of Section D is attached hereto as Attachment L.)

In 1999, the General Assembly enacted the Virginia Electric Utility Restructuring Act, which was designed to deregulate parts of the electric utility industry and introduce competition among the providers of electric generation. This was the authorizing legislation for electric choice in the state of Virginia. Virginia's Choice program provides for retail customers that choose to be served by a CSP. The program is limited to any individual customer or aggregated group of non-residential customers, with a peak demand in the previous calendar year of at least five MWs but representing less than one percent of the incumbent utility's load.[2] In addition, customers not meeting the five MW threshold may choose to be served by a CSP that provides 100% renewable energy. To date there has been no shopping in the APCO Virginia jurisdiction.

[2] The law also provides an exception to the one percent of native load limit for customers with demand of 90 MW or greater.

As discussed in Dr. Pearce's testimony, APCO currently participates in the PJM Capacity market as an FRR entity. To the extent that a Virginia CSP secures shopping load and chooses to have that load reflected in APCO's FRR Capacity Plan, the supplier would be required to compensate APCO for that capacity obligation in accordance with the above-quoted section of the RAA. Virginia has not established a compensation mechanism for FRR capacity.[3] Accordingly, pursuant to its rights under Section D. 8. of RAA Schedule 8.1, APCO now elects to establish as the basis for this compensation a cost-based method; *i.e.* the Capacity Compensation Formula Rate. On December 4, 2012, representatives of APCO met with members of the Virginia State Corporation Commission ("SCC") Staff to review the formula.

II. The Capacity Compensation Formula Rate.

In his testimony, Dr. Pearce discusses the benefit of this cost based formula rate and why it is an appropriate method to recover capacity costs from CSPs. AEP's proposed Capacity Compensation Formula Rate is designed to recover from Virginia CSPs the appropriate share of APCO's total generation revenue requirement through an annually-adjusting formula that tracks actual capacity costs. The formula rate is a fairly standard cost-of-service calculation and is consistent with formulas utilized to serve wholesale requirements customers by APCO and other AEP utilities that have been accepted and are on file with the Commission. APCO is asking the Commission to approve the formulaic equations that APCO will apply to its costs each year to determine the actual FRR capacity service charges assessed to CSPs. APCO, like all formula rate applicants, is not asking the Commission to rule on the prudence of any cost that APCO has included or will be including in the formula rate. The Commission can approve this formula rate and still address the prudence of APCO costs in the event a proper challenge is made consistent with the Formula Rate protocols.

One significant advantage of this formula rate proposed by APCO versus the typical formula rates filed with the Commission is that the Capacity Compensation Formula Rate is based on actual historical data shown on the most current FERC Form 1 submitted by APCO, and APCO is not proposing the typical two-step formula rate process, under which the utility initially charges a formula based on the previous year's costs and then reconciles this rate with the actual costs incurred during the year in an annual true-up. The FRR capacity rate will adjust each June 1 and remain in effect through the following May 31, which coincides with PJM's capacity years. Thus, for example, AEP proposes that the rate shown on Attachment C, which is based on APCO's 2011 costs, go into effect on February 9, 2013. Beginning on June 1, 2013, and running through May 31, 2014, the FRR capacity charges will reflect 2012 costs, as set out in the APCO FERC Form 1 filed in April 2013. The rate will then adjust again in June 2014 to reflect the 2013 costs, as set out in the Form 1 filed in 2014 and so on for each consecutive year. This methodology is particularly appropriate for the FRR capacity market, as it provides the Virginia CSPs with certainty as to the daily capacity charges; *i.e.*, they will not be subject to potential surcharges after the true-up calculations are performed. It also avoids the need for the

[3] Therefore, the issues that arose in *American Elec. Power Serv. Corp.*, 134 FERC ¶ 61,039 (2011), *reh'g pending*, in connection with the FRR rates that AEP proposed for Ohio are not applicable to this filing. That matter will not be affected by this filing, which establishes FRR rates for Virginia.

projection and true-up review processes. Attached to the formula are the "Formula Rate Implementation Protocols" ("Protocols") that provide the procedures under which APCO will prepare and circulate the annual updates to the formula. Among other things, the Protocols provide for APCO to post the annual update on an AEP internet site and to submit an informational filing with the Commission. CSPs will have an opportunity to review the annual update and request information relating to the inputs and to confirm that APCO correctly applied the formula.

The formula uses year-end plant balances to determine the annual net revenue requirement. The formula does not recover costs related to energy or fuel, because those are separate products that are not included within the RPM capacity obligations. Nor does the formula include transmission costs; those costs are recovered under the PJM open access transmission tariff.

The formula rate templates sponsored in Ms. Keegan's testimony consist of several pages that set out the underlying calculations that produce the $/MW-Day charge (prior to the application of losses) that will be assessed to Virginia CSPs. These pages show the source of the input data, which in most cases are FERC Form 1 data (identified as "FF1" in the formula, with page and line referenced), but in certain cases the data are derived from referenced workpapers, as provided in Attachment D.

Page 1 of the APCO Capacity Compensation Formula Rate shows the daily capacity charge, and Page 2 shows that the charge is derived by dividing the annual production fixed cost divided by APCO's share of PJM's average 5-CP for the year. This amount is then divided by 365 (or the actual number of days in the particular PJM planning year) to derive a MW-Day rate. Page 3 shows the calculation of the costs for generator step-up transformers and associated equipment. The derivation of the annual production fixed cost (consisting of return on rate base, demand related operation and maintenance ("O&M") expenses, depreciation expenses, taxes other than income taxes, income taxes, and credits relating to physical sales of capacity and energy) is shown on Page 4. Pages 5 through 19 show the calculation of the various other cost components that feed into the annual production fixed cost, including return on rate base, accumulated depreciation and accumulated deferred income taxes, general plant allocations and administrative and general expense allocations, cash working capital requirements, production-related materials and supplies, the composite cost of capital (long-term debt, preferred stock, and common stock – each of which has a separate schedule), fixed production O&M costs, depreciation, and taxes (income and production-related other than income). Except for the exclusion of CWIP from the rate base, an off system sales margin sharing percentage that mirrors the sharing provisions in Virginia retail rates, and setting the Postemployment Benefits Other than Pensions ("PBOP") expense to be recovered in the formula at a constant amount reflective of 2011 costs, the Capacity Compensation Formula Rate is virtually identical to the filing that AEP submitted in Docket No. ER12-1173, which the Commission accepted for filing in the *2012 PJM Order* at P 22.

A. Specific Formula Components

The Capacity Compensation Formula Rate does not propose any special assignments, and the derivation of the allocation factors contained in the formula rate is clearly shown in the filing and is consistent with Commission precedent. The formula rate uses the wages and salaries allocator and the plant allocator, the two standard allocation factors used in formula rates of this nature that are on file with and routinely accepted by the Commission.

As noted in the previous section, the formula rate is derived as a function of APCO's load at the time of PJM's average 5-CP usage; the result is the average daily demand cost for a MW of capacity. Because this denominator encompasses the load of those customers eligible to take service under the Virginia shopping provisions, there is no need to apply a revenue credit to this formula to reflect the load of shopping-eligible customers who chose to continue to take service from AEP. In fact, to do so would understate the average rate charged for capacity.

As demonstrated in the testimony of Mr. Davis (Attachment J), the depreciation expense reported in each year's formula will reflect the jurisdictionally weighted average of the rates that were in effect as of December 31 of that formula's FF1. Thus, the depreciation expense included in the initial capacity rate in this filing will be based on the weighted average of the rates that are in effect as of December 31, 2011, for the various APCO jurisdictions.

The Capacity Compensation Formula Rate provides for APCO's capacity revenue requirement to reflect a credit for APCO's off-system sales. The credit will be based on a 75% customer, 25% Company sharing of APCO's off system sales margin, as is done in the retail jurisdiction of Virginia. This credit will be shown on Line 6 of Page 4 of the formula and will be supported by a workpaper in Attachment D. The formula also will include costs allocated from the AEP East System Pool and third party sources for capacity purchases necessary to meet APCO's capacity requirements.

AEP proposes a rate of return on common equity ("ROE") of 10.4%. The testimony of Dr. William Avera (Attachment K) supports the reasonableness of this ROE. The testimony explains that Dr. Avera prepared the Commission's standard discounted cash flow methodology to produce a range of just and reasonable ROEs, from which Dr. Avera calculated the median (8.9%) and the midpoint (10.7%). The ROE that APCO proposes falls well below the top of the range (15.2%) and, importantly, is the same ROE that was approved by the SCC in setting APCO's Virginia retail rates, prior to inclusion of a 50 basis point adder awarded by the SCC.[4] AEP understands that the Commission's general policy is not to rely upon retail orders to establish the ROEs for wholesale rates, but in this limited case, using the same ROE is reasonable because the RAA capacity charges ultimately will be recovered from retail customers located within APCO's service territory who have the choice of being served by APCO or by a provider. As Dr. Avera discusses, there is no basis to distinguish APCO's risks in operating and maintaining FRR capacity needed by CSPs to serve shopping retail customers from the risks associated with operating and maintaining capacity needed by APCO to serve non-shopping

[4] *Final Order,* Case No. PUE-2011-00037 (Nov. 30, 2011).

retail customers. Any subsequent changes to the ROE will require prior approval of the Commission under Sections 205 or 206.

B. Cost Support

In Attachment C, AEP shows APCO's Capacity Compensation Formula Rate populated with 2011 costs derived from the FERC Form 1 filed in 2012. Supporting information is shown in the workpapers constituting Attachment D. An affidavit verifying the accuracy of the cost data is included in Attachment E. The cost-of-service data set out in Attachments C and D show the implementation of the formula rate using 2011 cost data that support the FRR charge that APCO proposes to recover beginning on February 9, 2013. The daily capacity charge that APCO proposes to recover beginning on June 1, 2013, will be based on APCO's 2012 costs derived from the Form 1 that will be filed in April 2013.

AEP is unable to provide a revenue comparison because to date, no Virginia CSP have been assessed any FRR charges. In addition, because the level of load served by Virginia CSPs will likely be dynamic, AEP is unable to state precisely how much FRR revenue APCO will recover under the Capacity Compensation Formula. However, Attachment F supported by Dr. Pearce's testimony provides a calculation showing a range of annual capacity revenues that APCO would recover from Virginia CSPs, based on 2011 cost data, assuming levels of retail shopping from one to ten percent of the total jurisdictional load. For each percentage point of load served by a CSP, the capacity revenue is about $4.7 million.

III. COMPLIANCE WITH 18 C.F.R. § 35.13

In compliance with the requirements of 18 C.F.R. § 35.13, AEP states as follows:

A. General Information – 18.C.F.R. § 35.13(b)

The documents provided with this filing include this Transmittal Letter and the documents listed on page 2 above. The persons upon whom this filing has been served are set out below in Section IV. A description of and the reasons for the rate changes proposed are discussed in this Transmittal Letter. AEP further states that there are no costs included in the cost-of-service data that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

B. Cost of Service Information

As discussed above, AEP submits herewith cost-of-service data in Attachments C and D that provide detailed information to permit the Commission to assess the reasonableness of the capacity charges under the Capacity Compensation Formula Rate. In addition, AEP provides revenue projections based on assumed levels of retail load served by Virginia CSPs (Attachment F), as well as the testimony of company witnesses Pearce, Keegan, Davis, and Avera in the previously described Attachments H through K. AEP requests waiver of those provisions in Section 35.13 that would require AEP to submit any additional cost-of-service data specified in the regulations.

C. Effective Date

APCO requests that its proposed rates be made effective on February 9, 2013, without suspension or further investigation. In the event that the Commission determines that the filing requires further investigation, APCO requests that any suspension of rates that may be ordered be for a nominal period. This would be consistent with the Commission's suspension policies, which provide for a nominal suspension unless the rate increase is "substantially excessive," which the Commission defines as being more than ten percent above the cost-justified level.[5] The purpose of this policy is to give utilities an incentive to tailor their rate filings to their costs.[6] In making this analysis, the Commission does not examine the size of the rate increase in isolation, but rather examines the amount of the increase that is excessive, by comparing the utility's rate filing to the utility's costs. Thus, in *Northeast Utilities,* a formula rate case, the Commission imposed a one-day suspension even though the filing utility requested a 115 percent rate increase.[7] The Commission followed this same approach in *Idaho Power Co.*, another formula rate case.[8]

Here, as in the *Northeast Utilities* and *Idaho Power* cases, APCO has proposed a formula rate that tracks its actual costs, so the rate is not excessive at all. In addition, since the purpose of the Commission's suspension policy is to encourage utilities to limit their rate filings to their costs, the Commission has indicated that it will give the filing utility some leeway if the rate is substantially excessive because of a judgmental factor such as ROE. Specifically, in *West Texas*, the Commission stated that "where a small deviation in a highly judgmental factor within our preliminary analysis, such as return on common equity, would constitute the difference between a one day and a five month suspension, we shall retain the administrative flexibility to take this into account."[9] The Commission will also not impose a five-month suspension where to do so would lead to "harsh and inequitable results."[10] Suspending APCO's filing in this case for five months would impose harsh and inequitable results because unlike the usual case – where the pre-existing rate reflected the filing utility's costs at the time it was established, and has simply become out of date – the pre-existing rate here was *never* based on APCO's costs at all but rather is a default rate that is intended to apply in the *absence* of the filing that APCO is making today (and is far below APCO's costs). Customers will not be harmed by a nominal suspension because to the extent the rate is determined to be excessive, any such amounts would be subject to refund. APCO submits that in the event the Commission determines that APCO's rate is excessive by more than ten percent, the Commission should exercise its discretion to not suspend the filing for more than a nominal period, in order to avoid harsh and inequitable results and in

[5] *West Texas Utilities Co.*, 18 FERC ¶ 61,189 (1982) ("*West Texas*").

[6] *Id.* at 61,375.

[7] *Northeast Utilities Service Co.*, 105 FERC ¶ 61,089 (2003).

[8] *Idaho Power Co.*, 115 FERC ¶ 61,281 (2006).

[9] *West Texas*, 18 FERC at 61,375. *See also Midwest Independent Transmission System Operator, Inc.*, 98 FERC ¶ 61,356 at 62,524 (2002); *Union Power Partners, L.P.*, 113 FERC ¶ 61,272 at 62,070 (2005) ("The Commission has broad discretion in determining the particular length of the suspension in each case.").

[10] *West Texas*, 18 FERC at 61,374.

view of the fact that any such suspension determination would be based on highly judgmental factors in view of APCO's operation under a cost-of-service formula rate.

IV. Correspondence and Service

AEP requests that any correspondence or communications with respect to this filing be sent to the following:

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PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[11] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[12] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714. In addition, the filing will be posted on APCO's website at https://www.appalachainpower.com/service/choice/. That site posts information applicable to Virginia CSPs. The Company will also serve a copy to CSPs licensed in the state as there are currently no CSPs registered with APCo to serve retail load in Virginia.

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[11] *See* 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).

[12] PJM already maintains, updates, and regularly uses e-mail lists for all PJM Members and affected state commissions.

If you have any questions concerning this filing, please do not hesitate to contact the undersigned.

Respectfully submitted,

AMERICAN ELECTRIC POWER
SERVICE CORPORATION
/s/

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Attachments

Attachment A

Revisions to Section(s) of the
PJM Reliability Assurance Agreement

(Clean Format)

Schedule 8.1 – Appendix 2A

Appalachian Power Company (APCO)

CAPACITY COMPENSATION FORMULA RATE IMPLEMENTATION PROTOCOLS

Definitions

The definitions and provisions contained in this Appendix 2A shall be applicable only to the provisions of Schedule 8.1 - Appendix 2A, unless otherwise specified.

"Capacity Rate" means the result produced by populating the Capacity Compensation Formula Rate Template with data to calculate the Fixed Resource Requirement capacity rate for load served by Virginia Competitive Service Providers ("CSPs").

"Annual Review Procedures" means the procedures pursuant to which an Interested Party may review the Annual Update and notify APCO of any specific challenges to the Annual Update.

"Annual Update" means the posting and informational filing submitted by APCO on or before May 25 of each year that sets forth the capacity rate for the subsequent Rate Year.

"Capacity Compensation Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Schedule 8.1 – Appendix 2B under Section D.8 of Schedule 8.1 of the PJM Interconnection, L.L.C. ("PJM") Reliability Assurance Agreement ("RAA").

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in APCO's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate template to be different from the result under the Formula Rate Template as calculated without such change.

"Partial Rate Year" means the period February 9, 2013 through May 31, 2013.

"Partial Rate Year Effective Date" means February 9, 2013.

"Protocols" means these Capacity Compensation Formula Rate Implementation Protocols.

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1 below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2 below.

Section 1 **Annual Updates**

a. The Capacity Rate for the Partial Rate Year shall become effective on the Partial Year Effective Date and such Capacity Rate shall not be subject to the Protocols. Beginning June 1, 2013, the Capacity Rate shall be revised in accordance with the Capacity Compensation Formula Rate Template, and the Annual Update for the Rate Year beginning on June 1, 2013, and all subsequent Rate Years, shall be fully subject to the Protocols.

b. On or before May 25 of 2013 and each year thereafter, APCO shall recalculate its Capacity Rate, producing the Annual Update for the upcoming Rate Year, and shall post such Annual Update, in both PDF and working Excel spreadsheet versions, on PJM's Internet website. In addition, APCO shall submit such Annual Update as an informational filing with FERC. APCO will also post such Annual Update on APCO's Internet website at https://www.appalachianpower.com/service/choice/.

c. The date as provided in Section 1.b shall be that Rate Year's Publication Date.

d. The Annual Update shall include a workable Excel file or files containing the data-populated Formula Rate Template as well as supporting calculations and workpapers that demonstrate and explain information not otherwise set out in APCO's FERC Form No. 1 reports.[1]

e. The Annual Update for the Rate Year:

() shall, to the extent specified in the Formula Rate Template, be based upon prudently incurred costs; the data for such prudently incurred costs will be taken from APCO's FERC Form No. 1 for the most recent calendar year, and will be based upon the books and

1 It is the intent that each input to the Formula Rate Template will be either taken directly from the FERC From No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet appurtenant to the filed Formula Rate Template, the inputs to the worksheet will meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate Template.

records of APCO (all of the foregoing data, books, and records maintained consistent with the USofA and FERC accounting policies, practices, and procedures);

(ii) shall be populated, in accordance with FERC's orders establishing generally applicable ratemaking policies and the Formula Rate Template, with the data identified above; and

(iii) shall be subject to the Annual Review Procedures set forth in these Protocols.

f. Formula Rate Inputs

(i) Stated inputs to the Formula Rate Template: rate of return on common equity; Post Employment Benefits other Than Pensions ("PBOPs"); and depreciation and amortization rates shall be stated values to be used in the Formula Rate Template until changed pursuant to an FPA Section 205 or 206 filing.

(ii) Cost of Service elements recorded in accounts not specifically provided for in the Capacity Rate: any cost, expense or other element of the cost of providing service not specifically provided for shall not be recoverable under the Formula Rate until filed for pursuant to FPA Section 205, accepted by FERC and, if otherwise required, a determination has been made by the Office of the Chief Accountant regarding the journal entries for the transaction.

(iii) The Formula Rate Template makes reference to certain pages and line numbers found in APCO's FERC Form 1 used for reporting calendar year 2011 data. From time to time, FERC may make changes in the format of the FERC Form 1, and such changes may result in certain page and line references included in Formula Rate Template being rendered inaccurate. To the extent that only formatting changes are involved and there is no substantive change, the Formula Rate Template shall be interpreted as if the page and line references contained therein are references to the pages and lines contained in the current FERC Form 1 on which can be found the data described on the pages and lines of the prior FERC Form 1.

Section 2 **<u>Annual Review Procedures</u>**

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have up to ninety (90) days after the Publication Date ("Review Period") (unless such period is extended with the written consent of APCO) to review the calculations and to notify APCO in writing of any specific challenges, including challenges related to any Material Changes, to the application of the Formula Rate in an Annual Update ("Preliminary Challenge").

b. Interested Parties shall have the right to serve reasonable information requests on APCO up to seventy-five (75) days after the Publication Date. Such information requests shall be limited to what is necessary to determine: (i) whether APCO has properly calculated the Annual Update under review (including any corrections pursuant to Section 4); (ii) whether APCO has correctly applied the Formula Rate Template; and (iii) whether the inputs to the Formula Rate Template are appropriate costs and revenue credits. Interested Persons can make information requests regarding allocation methodologies, including inter-corporate cost allocation methodologies, used to derive the inputs.

c. APCO shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Notwithstanding anything to the contrary contained in these Protocols, with respect to any information requests received by APCO up to seventy-five (75) days after the Publication Date for which APCO is unable to provide a response before the end of the Review Period, the Review Period shall be extended day-for-day until APCO's response is provided.

d. Preliminary or Formal Challenges related to Material Changes are not intended to serve as a means of pursuing other objections to the Annual Update. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update, but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such challenge affects the subsequent Annual Update.

e. In any proceeding initiated to address a Preliminary or Formal Challenge or *sua sponte* by FERC, a party or parties seeking to modify the Formula Rate Template in any respect shall bear the applicable burden under the FPA.

Section 3 **<u>Resolution of Challenges</u>**

a. If APCO and any Interested Party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period ends, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of APCO to continue efforts to resolve the Preliminary Challenge) to submit a written Formal Challenge to FERC, pursuant to 18 C.F.R. § 385.206, which shall be served on APCO by electronic service on the date of such filing ("Formal Challenge"). However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if FERC already has initiated a proceeding to consider the Annual Update.

b. Parties shall make a good faith effort to raise all issues in a Preliminary Challenge prior to filing a Formal Challenge; provided, however, that a Preliminary Challenge shall not be a prerequisite for bringing a Formal Challenge. Failure to notify APCO of an issue with respect to an Annual Update shall not preclude an Interested Party from pursuing such issue in a Preliminary Challenge or Formal Challenge.

c. All information and correspondence produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the FPA, or in any proceeding before the U.S. Court of Appeals to review a FERC decision.

d. Any response by APCO to a Formal Challenge must be submitted to FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

e. APCO shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate Template, and the applicable procedures in these Protocols, and of proving that it has properly calculated the challenged Annual Update pursuant to the Formula Rate Template, and of proving it has reasonably adopted and applied any Material Changes in that year's Annual Update.

f. . These Protocols in no way limit the rights of APCO or any Interested Party to initiate a proceeding at FERC at any time with respect to the Formula Rate Template or any Annual Update consistent with the party's full rights under the FPA, including Sections 205, 206 and 306, and FERC's regulations.

g. It is recognized that resolution of Formal Challenges concerning Material Changes may necessitate adjustments to the Formula Rate input data for the applicable Annual Update, or changes to the Formula Rate Template to ensure that the Formula Rate Template continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 4 **<u>Changes to Annual Informational Filings</u>**

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's FERC Form No. 1 report of APCO, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, or as the result of any FERC proceeding to consider a prior year's Annual Update, APCO shall promptly notify the Interested Parties, file a correction to the Annual Update with FERC as an amended informational filing describing the change(s) and the cost impact.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest as per section 35.19a of the Commission's regulations.

c. Changes Made During the Review Period. Unless otherwise agreed by APCO and the Interested Parties, a correction made under Section 4.a prior to the time determined for the filing of a Formal Challenge shall reset the performance dates under Sections 2 and 3 of these Protocols for Interested Party Annual Review, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of the Annual Review shall then be limited to the aspects of the Formula Rate Template affected by the corrections.

Schedule 8.1 – Appendix 2B
Appalachian Power Company
Capacity Compensation Formula Rate

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CAPACITY RATE
12 Months Ending 12/31/####

	RATE $/MW/Day (1)	CAPACITY MW (2)	Amount $ (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$	#	$

Note A: Rate will be applied to peak obligation demands at or adjusted to generation level (including losses).

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
DETERMINATION OF CAPACITY RATE
12 Months Ending 12/31/####

1. Capacity Daily Rates

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

$$\frac{\$}{\#\quad /365} = \$$$

Where: Annual Production Fixed Cost, P.4, L.8.

Note A: Average of demand at time of PJM five highest daily peaks. – Workpapers --WP1.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/####

		Reference	
.	GSU & Associated Investment	Note A	$
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	$
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$
5.	GSU Related Depreciation Expense	L.3 x L.4	$
6.	Station Equipment Acct. 353 Investment	Note B	$
7.	Percent (GSU to Acct. 353)	L.1 / L.6	%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$
9.	GSU & Associated Investment O&M	L.7 x L.8	$

Note A: Workpapers – WP-16
Note B: Workpapers – WP-17

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/####

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.18, Col.(2)	$
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$
3.	Depreciation Expense	P.16, L.11, Col.(2)	$
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(3)	$
5.	Income Tax	P.18, L.5, Col.(2)	$
6.	Sales for Resale (Credit)	Note A	$
7.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$

Note A: Workpapers – WP-15d

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/####

		Reference	Amount	Demand	Energy
1.	ELECTRIC PLANT		(1)	(2)	(3)
2.	Gross Plant in Service	P.6, L.4, Col.(2)-(4)	$	$	$
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)-(4)	$	$	$
4.	Net Plant in Service	L.2 - L.3	$	$	$
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	$	$	$
6.	Plant Held for Future Use (Note A)	Note A	$	$	$
7.	Subtotal - Electric Plant	L.4 - L.5 + L.6	$	$	$
	WORKING CAPITAL				
8.	Materials & Supplies				
9.	Fuel	P.9, L.2, Col.(2)-(4)	$	$	$
10.	Nonfuel	P.9, L.8, Col.(2)-(4)	$	$	$
11.	Total M & S	L.9 + L.10	$	$	$
12.	Prepayments Nonlabor (Note B)		$	$	$
13.	Prepayments Labor (Note B)		$	$	$
14.	Prepayments Total (Note B)		$	$	$
15.	Cash Working Capital	P.8, L.7, Col.(2)-(4)	$	$	$
16.	Total Rate Base	L.7 + L.11 + L.14 + L.15	$	$	$
17.	Weighted Cost of Capital	P.11, L.4, Col.(4)	%	%	%
18.	Return on Rate Base	L.16 x L.17	$	$	$

Note A: Workpapers – WP-19

Note B: Workpapers -- WP-5c Prepayments include amounts booked to Account 165. Nonlabor related prepayments allocated to the production function based on gross plant on P.6, L.7. Labor related prepayments allocated to production function based on wages and salaries on P.7, Note B.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/####

		System			PRODUCTION		
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1.	GROSS PLANT IN SERVICE (Note A)						
2.	Plant in Service (Note C)	FF1, P.204-207, L.100	$		$	$	$
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	$	$	$
4.	Total	L.2 + L.3	$		$	$	$
		Note A				%	%
5.				Col.(2), L.4	$	$	$
6.				Col.(1), L.4	$	$	$
7.			%	L.5/L.6	%	%	%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		$	FF1, P.200, L.22	$	$	$
10.	Allocated General Plant		$	Note B	$	$	$
11.	Total	L.9 + L.10			$	$	$
12.	ACCUMULATED DEFERRED TAXES (Note A)	(Note E)	$	P.6a, L.52	$	$	$

Note A: Excludes ARO amounts.
Note B: (% From P.7, Col.(3), L.29)
Note C: Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts
Note D: Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.
Note E: WP8a, WP8ai

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEIMPLATE
PRODUCTION RELATED ADIT
12 Months Ending 12/31/####

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1.	190	Excluded Items	$	$			
2.	190	100% Production (Energy)	$		$		
3.	190	100% Production (Demand)	$			$	
4.	190	Labor Related	$				$
5.	190	Total	$	$	$	$	$
6.		Production Allocation		%	%	%	%
7.		(Gross Plant or Wages/Salaries)		$	$	$	$
8.		Demand Related			$	$	$
9.		Energy Related			$	$	$
10.		Note A			Direct	Direct	B-7, Note B
11.	281	Excluded Items	$	$			
12.	281	100% Production (Energy)	$		$		
13.	281	100% Production (Demand)	$			$	
14.	281	Labor Related	$				$
15.	281	Total	$	$	$	$	$
16.		Production Allocation		%	%	%	%
17.		(Gross Plant or Wages/Salaries)		$	$	$	$
18.		Demand Related			$	$	$
19.		Energy Related			$	$	$
20.		Allocation Basis			Direct	Direct	B-7, Note B
21.	282	Excluded Items	$	$			
22.	282	100% Production (Energy)	$		$		
23.	282	100% Production (Demand)	$			$	
24.	282	Labor Related	$				$
25.	282	Total	$	$	$	$	$
26.		Production Allocation		%	%	%	%
27.		(Gross Plant or Wages/Salaries)		$	$	$	$
28.		Demand Related			$	$	$
29.		Energy Related			$	$	$
30.		Allocation Basis			Direct	Direct	B-7, Note B
31.	283	Excluded Items	$	$			
32.	283	100% Production (Energy)	$		$		
33.	283	100% Production (Demand)	$			$	
34.	283	Labor Related	$				$
35.	283	Total	$	$	$	$	$
36.	283	Production Allocation		%	%	%	%
37.		(Gross Plant or Wages/Salaries)		$	$	$	$
38.		Demand Related			$	$	$
39.		Energy Related			$	$	$
40.		Allocation Basis			Direct	B-6, L.7	B-7, Note B
41.	255	Excluded Items	$	$			
42.	255	100% Production (Energy)	$		$		
43.	255	100% Production (Demand)	$			$	
44.	255	Labor Related	$				$
45.	255	Total	$	$	$	$	$
46.	255	Production Allocation		%	%	%	%
47.		(Gross Plant or Wages/Salaries)		$	$	$	$

	Summary Production Related ADIT	Total	Demand	Energy
48.	Summary Production Related ADIT	Total	Demand	Energy
49.	P Plant (Energy Related)	$	$	$
50.	P Plant (Demand Related)	$	$	$
51.	Labor Related	$	$	$
52	Total	$	$	$

Source: Functionalized balances for Accounts 190, 281, 282, 283 and 255 from WP-8a and 8ai.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/####

	Total System (Note A)	Allocation Factor	General Plant Accounts 101 and 106 Related to Production (1) x (2)	Demand	Energy
1. GENERAL PLANT	(1)	(2)	(3)	(4)	(5)
2					
3. Land	$	Note B	$	$	$
4. General Offices	$		$	$	$
5. Total Land	$		$	$	$
6		%			
7. Structures	$	Note B	$	$	$
8. General Offices	$		$	$	$
9. Total Structures	$		$	$	$
10		%			
11. Office Equipment	$	Note B	$	$	$
12. General Offices			$	$	$
13. Total Office Equipment	$		$	$	$
14. Transportation Equipment	$	Note B	$	$	$
15. Stores Equipment	$	Note B	$	$	$
16. Tools, Shop & Garage Equipment	$	Note B	$	$	$
17. Lab Equipment	$	Note B	$	$	$
18. Communications Equipment	$	Note B	$	$	$
19. Miscellaneous Equipment & Other	$	Note B	$	$	$
20. Subtotal	$		$	$	$
21. PERCENT		Note C	%	%	%
22. Other Tangible Property					
23. Fuel Exploration	$	Note D	$		$
24. Rail Car Facility	$	Note D	$		$
25. Total Other Tangible Property	$		$	$	$
26. TOTAL GENERAL PLANT FF1, P.207	$		$	$	$
27. INTANGIBLE PLANT	$	Note B	$	$	$
28. TOTAL GENERAL AND INTANGIBLE	$		$	$	$
29. PERCENT		Note E	%	%	%
30. Total General and Intangible	$		$	$	$
31. Exclude Other Tangible (Railcar and Fuel Exploration)	$		$	$	$
32. Net General and Intangible	$		$	$	$
33. PERCENT			%	%	%

NOTE A: Workpapers -- 6c Data from Company's Books excluding ARO amounts.

NOTE B: Allocation factors based on wages and salaries in electric operations and maintenance expenses excluding administrative and general expenses:

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27 (see workpaper 9a).	$
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20. (see WP-9a)	$
c. Ratio (b / a)	%

NOTE C: L.20, Col.(3) / L.20, Col.(1)

NOTE D: Directly assigned to Production

NOTE E: L.28, Col.(3) / L.28, Col.(1)

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/####

	Reference	Amount (1)	PRODUCTION Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	$	$	$
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	$	$	$
3. Less Purchased Power	P.14, L.11	$	$	$
4. Other Production O&M	Sum (L.1 thru L.3)	$	$	$
5. Allocated A&G	P.10, L.17	$	$	$
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	$	$	$
7. O&M Cash Requirements	=45 / 360 x L.6	$	$	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/####

	SYSTEM		PRODUCTION			
	Reference	Amount	Reference	Amount	Demand	Energy
1. Material & Supplies (Note A)		(1)		(2)	(3)	(4)
2. Fuel (Note C)	FF1, P.110, L. 13,45,46 Workpapers WP-5b	$		$	$	$
3. Non-Fuel						
			100% Col.			
4. Production	Note D	$	1	$	$	$
5. Transmission		$	0	$	$	$
6. Distribution		$	0	$	$	$
7. General		$	Note B	$	$	$
8. Total	L.4 + L.5 + L.6 + L.7	$		$	$	$
9. Account 158 Allowances	Note D	$		$	$	$

Note A: Year end balance
Note B: Column (1) times % from P.7, Col.(3), L.29.
Note C: Workpapers WP-5b.
Note D: Workpapers WP-5a.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/####

				System		Production		
		Account	Reference	Amount (1)	Allocation Factor % (2)	Amount (3)	Demand (4)	Energy (5)
1.	ADMINISTRATIVE & GENERAL EXPENSE							
2.	RELATED TO WAGES AND SALARIES							
3.	A&G Salaries	920	Workpaper 10a	$				
4.	Outside Services	923	Workpaper 10a	$				
5.	Employee Pensions & Benefits	926	Workpaper 10a	$	Note F			
6.	Office Supplies	921	Workpaper 10a	$				
7.	Injuries & Damages	925	Workpaper 10a	$				
8.	Franchise Requirements	927	Workpaper 10a	$				
9.	Duplicate Charges - Cr.	929	Workpaper 10a	$				
10.	Total		Ls. 3 thru 9	$	Note A	$	$	$
11.	MISCELLANEOUS GENERAL EXPENSES	930	Workpaper 10a	$	Note A, C & D	$	$	$
12.	ADM. EXPENSE TRANSFER - CR.	922	Workpaper 10a	$	Note B	$	$	$
13.	PROPERTY INSURANCE	924	Workpaper 10a	$	Note E	$	$	$
14.	REGULATORY COMM. EXPENSES	928	Workpaper 10a	$	Note C	$	$	$
15.	RENTS	931	Workpaper 10a	$	Note B	$	$	$
16.	MAINTENANCE OF GENERAL PLANT	935	Workpaper 10a	$	Note B	$	$	$
17.	TOTAL A & G EXPENSE		L.10 thru 16	$		$	$	$

Note A: % from Note B, P.7
Note B: General Plant % from P.7, Col.(3), L.29
Note C: Workpapers WP -- 11. Excludes all items not related to wholesale service and also excludes FERC assessment of annual charges.
Note D: Excludes general advertising and company dues and memberships.
Note E: % Plant from P.6, L.7.
Note F: PBOP expense cannot be changed absent a Section 205/206 filing with the Commission.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/####

			Total Company Capitalization	Weighted Cost Ratios		Cost of Capital	Weighted Cost of Capital
		Reference	$	%	Reference	%	(2 x 3)
			(1)	(2)		(3)	(4)
1.	Long Term Debt	Note A	$	%	Note D	%	%
2.	Preferred Stock	Note B	$	%	Note E	%	%
3.	Common Stock	Note C	$	%	Note F	%	%
4.	Total	Note A	$	%			%

Note A: P.12, L.5, Col.1.

Note B: P.13a, L.6(2).

Note C: P.13b, L.5.

Note D: P.12, L.16 (2).

Note E: P.13a, L.7.

Note F: Return on equity cannot be changed absent a Section 205/206 filing with the Commission.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT
12 Months Ending 12/31/####

		Reference	Debt Balance	Interest & Cost Booked
			(1)	(2)
	12 Months Ending 12/31/2011 (Actual)			
1.	Bonds (Acc 221)	FF1, 112.18.c.	$	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	$	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	$	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	$	
5.	Total Long Term Debt Balance		$	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		$
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		$
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		$
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		$
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		$
11.	Interest on LTD Assoc Companies (portion Acc 430)	Workpaper-13, L.7		$
12.	Sub-total Costs and Expense			$
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 11, Col. (6)		$
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 15, Col. (6)		$
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		$
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			%

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/####

		(1)	(2)	(3)	(4)	(5)	(6)
				Net Includable			
	HEDGE AMT BY ISSUANCE	Total Hedge	Excludable	Hedge Amount	Unamortized	Amortization Period	
	FERC Form 1, p. 256-257 (i)	(Gain) / Loss	Amounts (Note A)	Subject to Limit	Balance	Beginning	Ending
1.	Debt Issuance #1	$	$	$	$		
2.	Debt Issuance #2	$	$	$	$		
3.	Debt Issuance #3	$	$	$	$		
4.	Total Hedge Amortization	$	$	$			
	Limit on Hedging (G)/L on Interest Rate Derivatives of LTD						
5.	Hedge (Gain) / Loss prior to Application of Recovery Limit						$
	Enter a hedge Gain as a negative value and a hedge Loss as a positive value						
6.	Total Capitalization			Page11, L.4, col.(1)		$	
7.	5 basis point Limit on (G)/L Recovery						%
8.	Amount of (G)/L Recovery Limit			L. 12 * L.13			$
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8)						$
	To be subtracted or added to actual Interest Expenses on Page 12, Line 14						

Note A: Annual amortization of net gains or net loss on interest rate derivative hedges on long term debt shall not cause the composite after-tax weighted average cost of capital to increase/decrease by more than 5 basis points. Hedge gains/losses shall be amortized over the life of the related debt issuance. The unamortized balance of the g/l shall remain in Acc 219 Other Comprehensive Income and shall not flow through the rate calculation. Hedge-related ADIT shall not flow through rate base. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this calculation and are to be recorded above.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PREFERRED STOCK
12 Months Ending 12/31/####

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	$
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 9 (f)	$
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	$
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. L.9	$
5.	Plus: Paid-in-Capital Pfd Stock	Note A		$
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	$
7.	Average Cost Rate		L.1 / L.6	%

Note A: Workpaper – WP-12b.

Note B: Preferred stock outstanding excludes pledged and Reacquired (Treasury) preferred stock.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMMON EQUITY
12 Months Ending 12/31/####

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	$
	Less:		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, col.b+c+d	$
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, col.e	$
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, col.f	$
5.	Total Balance of Common Equity	L.1-2-3-4	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/####

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	$	$	$
2. Lignite Handling	501.xx	$	$	$
3. Sale of Fly Ash (Revenue & Expense)	501.xx	$	$	$
4. Rents	507	$	$	$
5. Hydro O & M Expenses	535-545	$	$	$
6. Other Production Expenses	557	$	$	$
7. System Control of Load Dispatching	Note C	$	$	$
8. Other Steam Expenses	Note A	$	$	$
9. Combustion Turbine	Note A	$	$	$
10. Nuclear Power Expense-Other	Note A	$	$	$
11. Purchased Power	555	$	$	$
12. Total Production Expense Excluding Fuel Used In Electric Generation	Sum of L.1 – L.11	$	$	$
13. A & G Expense P.10, L.17		$	$	$
14. Generator Step Up related O&M	Note B	$	$	$
15. Total O & M		$	$	$

NOTE A: Amounts recorded in O&M Expense Accounts classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8 and 575.7

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

Line No.	Description	FERC Account No.	Energy Related	Demand Related
1	POWER PRODUCTION EXPENSES			
2	Steam Power Generation			
3	Operation supervision and engineering	500	-	xx
4	Fuel	501	xx	-
5	Steam expenses	502	-	xx
6	Steam from other sources	503	xx	-
7	Steam transferred-Cr.	504	xx	-
8	Electric expenses	505	-	xx
9	Miscellaneous steam power expenses	506	-	xx
10	Rents	507	-	xx
11	Allowances	509	xx	-
12	Maintenance supervision and engineering	510	xx	-
13	Maintenance of structures	511	-	xx
14	Maintenance of boiler plant	512	xx	-
15	Maintenance of electric plant	513	xx	-
16	Maintenance of miscellaneous steam plant	514	-	xx
17	Total steam power generation expenses			
18	Nuclear Power			
19	Operation supervision and engineering	517		xx
20	Coolants and Water	519		xx
21	Steam Expenses	520		xx
22	Steam from other sources	521		xx
23	Less: ; Steam Transferred	522		xx
24	Electric Expenses	523		xx
25	Miscellaneous Nuclear Power Expense	524		xx
26	Rents	525		xx
27	Maintenance supervision and engineering	528	xx	
28	Maintenance of structures	529		xx
29	Maintenance of Reactor Plant Equip	530	xx	
30	Maintenance of electric plant	531	xx	
31	Maintenance of Misc Nuclear Plant	532	xx	
32	Total power production expenses Nuclear			
33	Hydraulic Power Generation			
34	Operation supervision and engineering	535	-	xx
35	Water for power	536	-	xx
36	Hydraulic expenses	537	-	xx
37	Electric expenses	538	-	xx
38	Misc. hydraulic power generation expenses	539	-	xx
39	Rents	540	-	xx
40	Maintenance supervision and engineering	541	-	xx
41	Maintenance of structures	542	-	xx
42	Maintenance of reservoirs, dams and waterways	543	-	xx
43	Maintenance of electric plant	544	xx	-
44	Maintenance of miscellaneous hydraulic plant	545	-	xx
45	Total hydraulic power generation expenses			
46	Other Power Generation			
47	Operation supervision and engineering	546	-	xx

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(2 of 2)

48	Fuel	547	xx	-
49	Generation expenses	548	-	xx
50	Miscellaneous other power generation expenses	549	-	xx
51	Rents	550	-	xx
52	Maintenance supervision and engineering	551	-	xx
53	Maintenance of structures	552	-	xx
54	Maintenance of generation and electric plant	553	-	xx
55	Maintenance of misc. other power generation plant	554	-	xx
56	Total other power generation expenses			
57	Other Power Supply Expenses			
58	Purchased power	555	xx	xx
59	System control and load dispatching	556	-	xx
60	Other expenses	557	-	xx
61	Station equipment operation expense (Note A)	562	-	xx
62	Station equipment maintenance expense (Note A)	570	-	xx

Note A: Restricted to expenses related to Generator Step-up Transformers and Other Generator related expenses.
See Note D, Page 6

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED DEPRECIATION EXPENSE
12 Months Ending 12/31/####

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
1.	Steam	$	$	$
2.	Nuclear	$	$	$
3.	Hydro	$	$	$
4.	Conventional	$	$	$
5.	Pump Storage	$	$	$
6.	Other Production	$	$	$
7.	Int. Comb.	$	$	$
8.	Other	$	$	$
9.	Production Related General & Intangible Plant	$	$	$
10.	Generator Step Up Related Depreciation (Note A)	$	$	$
11.	Total Production	$	$	$

Note: Lines 1 through 8 will be Depreciation Expense reported on P.336 of the FF1 excluding the amortization of acquisition adjustments. See Workpapers WP -- 6d.

Line 9 will be total General & Intangible Plant (from P.336 of the FF1, adjusted for amortization adjustments) times ratio of Production Related General Plant to total General Plant computed on P.7, L.33, Col.(3)

Depreciation expense excludes amounts associated with ARO.

Note A: Line 10, see P.3, L.5

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RPODUCTION RELATED TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/####

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT	%	Amount
			(1)		(3)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	$	Note B	$
2	Property Related	Note A	$	Note C	$
3	Other	Note A	$	Note C	$
4	Production	Note A	$		$
5	Gross Receipts / Distribution Related	Note A	$	Note D	$
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	$		$

Note A: See Workpapers -- WP8c.

Note B: Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services shown on Worksheets WP-9a and WP-9b.

	Amount	%
(1) Total W & S (excl. A & G)	$	%
(2) Production W & S	$	%

Note C: Allocated on the basis of Gross Plant Investment from P. 6, Ln.7

Note D: Not allocated to wholesale

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/####

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.18	$	$	$
2.	Effective Income Tax Rate	P.19, L.2	%	%	%
3.	Income Tax Calculated	L.1 x L.2	$	$	$
4.	ITC Adjustment	P.19, L.13	$	$	$
5.	Income Tax	L.3 + L.4	$	$	$

Note A: Classification based on Production Plant classification of P.19, L.20 and L.21.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/####

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		%
3.	where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p as shown below.		
4.	GRCF=1 / (1 - T)		#
5.	Federal Income Tax Rate	FIT	%
6.	State Income Tax Rate (Composite)	SIT	%
7.	Percent of FIT deductible for state purposes	Note A	%
8.	Weighted Cost of Long Term Debt	WCLTD	%
9.	Weighted Average Cost of Capital	WACC	%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	$
11.	Gross Plant Allocation Factor	L.19	%
12.	Production Plant Related ITC Amortization	L.10 x L.11	$
13.	ITC Adjustment	L.12 x L.4	$
14.	<u>Gross Plant Allocator</u>		Total
15.	Gross Plant	P.6, L.6, Col.2	$
16.	Production Plant Gross	P.6, L.5, Col.2	$
17.	Demand Related Production Plant	P.6, L.5, Col.3	$
18.	Energy Related Production Plant	P.6, L.5, Col.4	$
19.	Production Plant Gross Plant Allocator	L.16 / L.15	%
20.	Production Plant - Demand Related	L.17 / L.16	%
21.	Production Plant - Energy Related	L.18 / L.16	%

Note A: Percent deductible for state purposes provided from Company's books and records.

Schedule 8.1 – Appendix 2C
Appalachian Power Company
Workpapers in Support of the Capacity Compensation Formula Rate

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 1 - Production System Peak Demand
For the Year Ending December 31, _ _ _ _

Month	Day	(EDT) Hour	Demand (MW)	Source
July	#	#	#	CBR[1]
July	#	#	#	
July	#	#	#	
July	#	#	#	
June	#	#	#	
Average Peak			#	
Average Production System Peak Demand			#	

Company's average five CP demands at time of PJM system peak.

Notes:
[1]CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 2 - Production Revenue Credits
For the Year Ending December 31, _ _ _ _

	Production			
	Total	Demand	Energy	Source [1]
	$	$	$	
Total	$	$	$	

Notes:

[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 3

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Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 4

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Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5a - Materials and Supplies
Balances as of December 31, _ _ _ _

Period	1540001 M&S Regular	1540004 M&S Exempt Material	1540006 Lime and Limestone	1540012 Urea Charge	1540013 Transportation Inventory	1540022 M&S Lime & Limestone Intrasit	1540023 M&S Urea	1540024 M&S Proj Spares	M&S Total	Source [1]
12/31/20##	$	$	$	$	$	$	$	$	$	110.48.c
								Total	$	

Period	158 Allowances	Source [1]
12/31/20##	$	110.52.c

Functionalization of Materials & Supplies

M&S December 20##[2]		
Production	$	%
Transmission	$	%
Distribution	$	%
	$	%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5b - Fuel Inventory
Balances as of December 31, _ _ _ _

Period	1510001 Fuel Stock Coal	1510002 Fuel Stock Oil	1510003 Fuel Stock Gas	1510004 Fuel Stock Coal Trans	1510019 Fuel Stock Prepays	1510020 Fuel Stock In Transit	Fuel Stock Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	110.45.c

Period	1520000 Fuel Stock Undistributed	Source [1]
12/1/20##	$	110.46.c

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5c - Prepayments
For the Year Ending December 31, _ _ _ _

Period	1650001 Prepayments Insurance	1650004 Prepayments Rents	1650005 Prepayments Employee Benefits	1650006 Prepayments Other	1650009 Prepayments Carrying Cost	1650010 Prepayments Pension Benefits	1650021/ 1650023 Prepayments Ins. & Lease	1650014 Prepayments FAS 158 Contra Asset	165000211* Prepayments Taxes	Prepayments Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	$	$	$	111.57.c

Period	Exclude [2] Rate Base	Non Labor [2] Related	Labor [2] Related
12/1/20##	$	$	$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.
1650001 - This account shall include amounts representing prepayments of insurance.
1650004 - This account shall include amounts representing prepayments of interest.
1650005 - This account shall include amounts representing prepayments of employee benefits.
1650006 - This account shall include amounts representing prepayments of other items not listed.
1650009 - This account is used for factoring the AEP-East electric accounts receivable.
1650010 - This account shall include amounts representing prepayments of pension benefits.
1650021 - This account shall include amounts representing prepayments of insurance with EIS (Energy Insurance Services).
1650023 - Track balance of prepaid lease expense for agreements that qualify as a lease under company policy and are not tracked in PowerPlant Lease Accounting system will use this account.
1650014 - This account is used to track the long term portion of the FAS 158 PBO liability (Projected Benefit Obligation) for the Qualified Pension Plan when the net plan is still prepaid. This account offsets account 1650010.
165000211 - This account shall include amounts representing prepayments of taxes.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6a - Plant in Service
Balances as of December 31, _ _ _ _

Line	Month	Production					
		Total		ARO			Excluding ARO & AFUDC
	Month	Amount	Source [1]	Amount	Source [1]		
1	12/1/20##	$	205.46.g	$	205.15,24,34.g		$
2	Total						$
		Transmission					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
3	12/1/20##	$	207.58.g	$	207.57.g		$
4	Total						$
		Distribution					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
5	12/1/20##	$	207.75.g	$	207.74.g		$
6	Total						$
		General					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
7	12/1/20##	$	207.99.g	$	207.98.g		$
8	Total						$
		Intangible					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
9	12/1/20##	$	205.5.g	$	CBR		$
10	Total						$
11	December 31, ______ Plant In Service (excluding ARO)						$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6b - Accumulated Depreciation
Balance as of December 31, _ _ _ _

RESERVE ACCT [2]	RESERVE AMOUNT	PRODUCTION	TRANSMISSION	DISTRIBUTION	GENERAL
1080005	$	$	$	$	$
1080001 ARO	$	$	$	$	$
1080001/1080011	$	$	$	$	$
1110001	$	$	$	$	$
10800013	$	$	$	$	$
	$	$	$	$	$
APCo Exc. ARO [3]	$	$	$	$	$
FERC Form 1 pg. 219	$	$	$	$	$
FERC Form 1 pg. 200	$				
Total Check	$				

Note: Data excludes Asset Retirement Obligations.

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the total balances.
[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6c - General Plant and Intangible Plant
Balances as of December 31, _ _ _ _

Description	Account	12/31/20##
INTANGIBLE PLANT (FF1 205.2-5.g)		
Organization	301	$
Franchises and Consents	302	$
Miscellaneous Intangible Plant	303	$
TOTAL INTANGIBLE PLANT		$
GENERAL PLANT (FF1 207.86-97.g)		
Land	389	$
Structures	390	$
Office Equipment	391	$
Transportation	392	$
Stores Equipment	393	$
Tools, Shop, Garage, Etc.	394	$
Laboratory Equipment	395	$
Power Operated Equipment	396	$
Communications Equipment	397	$
Miscellaneous Equipment	398	$
Fuel Exploration	399	$
TOTAL GENERAL PLANT		$
General Plant (FF1 207.86-97 g)		
Total General and Intangible Exc. ARO		$
Total General and Intangible	205.5.g, 207.99.g	$

Note: Total includes Intangible Plant.
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6d - Depreciation Expense
For the Year Ending December 31, _ _ _ _

Description	Amount	Source
Steam Production	$	FF1, 336, 2, b & d
Hydraulic Production	$	FF1, 336, 4, 5 b
Other Production Plant	$	FF1, 336, 6 b
Transmission	$	FF1, 336, 7, b
Distribution	$	FF1, 336, 8, b
General	$	FF1, 336, 10, b & d
Intangible Plant	$	FF1, 336, 1
Sub-Total	$	
ARO Dep Exp	$	FF1, 336, 12, c
Total Depr Expense	$	FF1, 336, 12, f

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 7

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Appalachian Power Company
Capacity Cost of Service Formula Rate

Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 281: *Listing of Individual Tax Differences*					
1	TOTAL ACCOUNT 281	$	$	$		
	FF1, pg.273, Ln.8					
2	ACCOUNT 282:					
3	*Listing of Individual Tax Differences*					
4	**TOTAL ACOUNT 282**	$	$	$	$	$
5	***FF1, pg. 275, Ln. 5***					
6	**Labor Related**			$	$	$
7	**Energy Related**			$	$	$
8	**ARO**			$	$	$
9	**Demand Related**			$	$	$
10	**Excluded**			$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
11	ACCOUNT 283:					
12	Listing of Individual Tax Differences					
13	TOTAL ACCOUNT 283	$	$	$	$	$
14						
15	FF1, pg. 277, Ln. 9					
16	Labor Related			$	$	$
17	Energy Related			$	$	$
18	ARO			$	$	$
19	Demand Related			$	$	$
20	Excluded			$		
21	JURISDICTIONAL AMOUNTS FUNCTIONALIZED					
22	TOTAL COMPANY AMOUNTS FUNCTIONALIZED					
23	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT					
24	NOTE: POST 1970 ACCUMULATED DEFERRED					
25	INV TAX CRED. (JDITC) IN A/C 255					
26	SEC ALLOC - ITC - 46F1 - 10%	$		$	$	$
27	HYDRO CREDIT - ITC - 46F1	$		$	$	$
28						
29	TOTAL ACCOUNT 255	$		$	$	$
30	ITC Balance Included in Ratebase	$		$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8ai - ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190
For the Year Ending December 31,
_ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN O
		PER BOOKS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 190: *Listing of Individual Tax Differences*					
1	TOTAL ACCOUNT 190 FF 1, p. 234, L. 8 Col. (c)	$	$	$	$	$
Energy Related				$	$	$
ARO				$	$	$
Labor Related				$	$	$
Demand Related				$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8b - Effective Income Tax Rate
For the Year Ending December 31, _ _ _ _'

Effective Income Tax Rate

T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			%
EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p are as shown below.			%
GRCF=1 / (1 - T)			#
Amortized Investment Tax Credit (enter negative)	FF1 P.114, Ln.19, Col.c		$
FIT		%	
SIT		%	State Income Tax Rate (Composite).
p		%	Percent of FIT deductible for state purposes (Note 2).
WCLTD		%	
WACC		%	

Development of Composite State Income Tax Rates for 2011 (Note 1)

Tennessee Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Michigan Business Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Virginia Net Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
West Virginia Net Income	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Illinois Corporation Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Total Effective State Income Tax Rate		%

Note 1: Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

Note 2: From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _

Payroll Related Other Taxes	$	Payroll
Property Related Other Taxes	$	Property
Direct Production Related	$	Production
Direct Distribution Related	$	Distribution
Other	$	Other
Not Allocated ((Gross Receipts, Commission Assessments)	$	NA
	$	

Line No.	(A) Annual Tax Expenses by Type	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference	Basis
1	**Revenue Taxes**			
2	Gross Receipts Tax			
		$	P.### ln # (i)	N/A
		$	P.### ln # (i)	N/A
		$	P.### ln # (i)	N/A
3	**Real Estate and Personal Property Taxes**			
4	Real and Personal Property - West Virginia			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
5	Real and Personal Property - Virginia			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
6	Real and Personal Property - Tennessee			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
7	Real and Personal Property - Other Jurisdictions			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
8	**Payroll Taxes**			
9	Federal Insurance Contribution (FICA)			
		$	P.### ln # (i)	Payroll
10	Federal Unemployment Tax			
		$	P.### ln # (i)	Payroll

11	State Unemployment Insurance			
		$	P.### ln # (i)	Payroll
		$	P.### ln # (i)	Payroll
		$	P.### ln # (i)	Payroll
12	**Production Taxes**			
13	State Severance Taxes			
		$	P.### ln # (i)	
14	**Miscellaneous Taxes**			
15	State Business & Occupation Tax			
		$	P.### ln # (i)	Production
		$	P.### ln # (i)	Production
		$	P.### ln # (i)	Production
16	State Public Service Commission Fees			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
17	State Franchise Taxes			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
18	State Lic/Registration Fee			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
19	Misc. State and Local Tax			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
20	Sales & Use			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
21	Federal Excise Tax			
		$	P.### ln # (i)	Production
22	Michigan Single Business Tax			
		$	P.### ln # (i)	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9a - Wages and Salaries
For the Year Ending December 31, _ _ _ _

	APCo [1]	AEPSC [2]	Total
Production:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Transmission:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Distribution:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Customer Accounts	$	$	$
Customer Service and Informational	$	$	$
Sales	$	$	$
Total Wages and Salaries Excluding A & G	$	$	$
Administrative and General			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Total O & M Payroll	$	$	$

[1] APCo Wages and Salaries from FERC Form Pg. 354.
[2] From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9b - Production Payroll Demand/Energy Allocation
For the Year Ended December 31, 2011

Account	Demand	Energy	Total	Source [1]
500	$		$	
501		$	$	
502	$		$	
505	$		$	
506	$		$	
510		$	$	
511	$		$	
512		$	$	
513		$	$	
514	$		$	
517	$		$	
519	$		$	
520	$		$	
523	$		$	
524	$		$	
528		$	$	
529	$		$	
530		$	$	
531		$	$	
532		$	$	
535	$		$	
536	$		$	
537	$		$	
538	$		$	
539	$		$	
541	$		$	
542	$		$	
543	$		$	
544		$	$	
545	$		$	
546	$		$	
547		$	$	
548	$		$	
549	$		$	
553	$		$	
554	$		$	
555	$	$	$	
556	$		$	
557	$		$	
Total	$	$	$	
Allocation Factors	%	%	%	

[1] CBR indicates that data comparable to that reported in the FERC Form 1's from the Company's Books and Records.

Appalachian Michigan Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _
Note: Source of data is FERC Form 1, page 320-323, Column b.

Production

500	Operation Supv & Engineering	$
501	Fuel	$
502	Steam Expenses	$
505	Electric Expenses	$
506	Misc. Steam Power Expense	$
507	Rents	$
509	Allowances	$
517	Operation Supv & Engineering	$
518	Fuel	$
519	Coolants and Water	$
520	Steam Expenses	$
523	Electric Expenses	$
524	Misc. Nuclear Power Expense	$
535	Operation Supv & Engineering	$
536	Water for Power	$
537	Hydraulic Expenses	$
538	Electric Expenses	$
539	Miscellaneous Hydraulic Power	$
540	Rents	$
546	Operation Supv & Engineering	$
547	Fuel	$
548	Generation Expenses	$
549	Misc. Power Generation Expense	$
	Total Operation	$
510	Maintenance Supv & Engineering	$
511	Maintenance of Structures	$
512	Maintenance of Boiler Plant	$
513	Maintenance of Electric Plant	$
514	Maintenance of Misc Plant	$
528	Maintenance Supv & Engineering	$
529	Maintenance of Structures	$
530	Maintenance of Reactor Plant	$
531	Maintenance of Electric Plant	$
532	Maintenance of Misc. Nuclear Plant	$
541	Maintenance Supv & Engineering	$
542	Maintenance of Structures	$
543	Maintenance of Reservious, Dams and Waterways	$
544	Maintenance of Electric Plant	$
545	Maintenance of Miscellaneous Hydraulic Plant	$
551	Maintenance Supv & Engineering	$
553	Maintenance of Generating & Electric Plant	$
554	Maintenance of Misc. Other Power Gen. Plant	$
	Total Maintenance	$
555	Purchased Power	$
556	System Control	$

557	Other Expense	$
	Total Other	$
	Total Production	$
Transmission		
560	Operation Supv & Engineering	$
561.1	Load Dispatch-Reliability	$
561.2	Load Dispatch-Monitor and Operate	$
561.3	Load Dispatch-Transmission Service	$
561.4	Scheduling, System Control	$
561.5	Reliability, Planning and Standards Dev.	$
561.6	Transmission Service Studies	$
561.7	Generation Interconnection Studies	$
561.8	Reliability, Planning and Standards Dev.	$
562	Station Expense	$
563	Overhead Line Expense	$
564	Underground Line Expense	$
565	Trans of Electricity by Others	$
566	Misc Transmission Expense	$
567	Rents	$
	Total Operation	$
568	Maintenance Supv & Engineering	$
569	Maintenance of Structures	$
569.1	Maintenance of Computer Hardware	$
569.2	Maintenance of Computer Software	$
569.3	Maintenance of Communication Equip	$
570	Maintenance of Station Equip	$
571	Maintenance of OH Lines	$
572	Maintenance of UG Lines	$
573	Maintenance of Misc Trans	$
	Total Maintenance	$
	Total Transmission	$
Regional Market Expense		
575.7	Market Facilitation, Monitoring and Compliance	$
Distribution		
580	Operation Supv & Engineering	$
581	Load Dispatching	$
582	Station Expense	$
583	Overhead Line Expense	$
584	Underground Line Expense	$
585	Street Lighting	$
586	Meter Expenses	$
587	Customer Installations	$
588	Misc Distribution Expense	$
589	Rents	$
	Total Operation	$
590	Maintenance Supv & Engineering	$
591	Maintenance of Structures	$

592	Maintenance of Station Equip	$
593	Maintenance of OH Lines	$
594	Maintenance of UG Lines	$
595	Maintenance of Line Trsfrs	$
596	Maintenance of Street Lights	$
597	Maintenance of Meters	$
598	Maintenance of Misc Dist Plant	$
	Total Maintenance	$
	Total Distribution	$
Customer Accounts		
901	Supervision	$
902	Meter Reading Expenses	$
903	Customer Records/Collection	$
904	Uncollectible Accounts	$
905	Misc Customer Accts Exp	$
	Total Customer Accounts	$
Customer Service and Informational		
907	Supervision	$
908	Customer Assistance	$
909	Info & Instructional Adv	$
910	Misc Cust Service & Info Expense	$
	Total Customer Service	$
Sales Expense		
911	Supervision	$
912	Selling Expenses	$
913	Advertising Expenses	$
916	Misc Sales Expense	$
	Total Sales Expense	$
Administrative and General		
920	A & G Salaries	$
921	Office Supplies & Exp	$
922	Adm Exp Trsfr - Credit	$
923	Outside Services	$
924	Property Insurance	$
925	Injuries and Damages	$
926	Employee Benefits	$
926a	Less: Actual Employee Benefits (Note A)	$
926b	Allowed Employee Benefits (Note B)	$
926	Employee Benefits	$
927	Franchise Requirements	$
928	Regulatory Commission Exp	$
929	Duplicate Charges - Credit	$
930.1	General Advertising Expense	$
930.2	Misc General Expense	$
930.2	Company Dues and Memberships	$
931	Rents	$
933	Transportation	$
	Total Operation	$

935	Maintenance of Gen Plant	$
	Total Maintenance	$
	Total Administrative & General	$
	Total O & M Expenses	$
	Total Elec O & M Exp. - FERC Form1 pg. 323, L. 198(b)	$
	Difference	$

Actual Expense - Removed from Cost of Service		
Note A:	Acct 926 (0039) PBOP Gross Cost	$
	Acct 926 (0057) PBOP Medicare Part Subsidy	$
	PBOP Amounts in Annual Informational Filing	$
Allowable Expense		
Note B:	Acct 926 (0039) PBOP Gross Cost	$
	Acct 926 (0057) PBOP Medicare Part Subsidy	$
	PBOP Amounts Recovery Allowance	$

Note B: Changing PBOP included in the formula rate will require, as applicable, a FPA Section 205 or Section 206 filing.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 11 - Regulatory Commission Expense
For the Year Ending December 31, _ _ _ _

Regulatory Commission Expense - Acct. 928 [1]	##
Retail	##
Wholesale - FERC	##

Note Excludes FERC Annual charges and amounts related to retail

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances
350, 46, d

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12a - Common Stock
For the Year Ending December 31, _ _ _ _

Month	Total Capital	Source(s)	Preferred Stock Issued	Preferred Stock Premium (Discount)	Preferred Stock G(L) on Reacq'd	Preferred Stock Source(s)*	Unapprop Sub Earnings	Source	Acc Oth Comp Income	Source	Common Equity Balance
	a		b	c	d		e		f		g=a-b-c-d-e-f
12/1/20##	$	112.16.c	$	$	$	112.3.c,6.c., 7.c.	$	112.12. c.	$	112.15. c.	$

NOTE: * Includes preferred portions of capital stock (common and preferred) accounts according to Company Books and Records below.

Account	Description	12/1/20##
2010001	Common Stock Issued	$
	Source [1]	*112.2.c*
2040002	PS Not Subj to Mandatory Redem	$
	Source [1]	*112.3.c*
2070000	Prem on Capital Stk	$
	Source [1]	*112.6.c*
2080000	Donations Recvd from Stckhldrs	$
2100000	Gain Rsle/Cancl Req Cap Stock	$
2110000	Miscellaneous Paid-In Capital	$
		$
	Source [1]	*112.7.c*
2151000	Appropriations of Retained Earnings	$
2160001	Unapprp Retnd Erngs-Unrstrictd	$
4330000	Transferred from Income	$
4370000	Div Decl-PS Not Sub to Man Red	$
4380001	Dividends Declared	$
4390000	Adj to Retained Earnings	-
	Retained Earnings	$
	Source [1]	*112.11.c*
2161001	Unap Undist Consol Sub Erng	$
2161002	Unap Undist Nonconsol Sub Erng	-

4181001 & 002	Equity in Earnings	-
	Unapprop Sub Earnings	$
	Source[1]	*112.12.c*
2190002	OCI-Min Pen Liab FAS 158-Affil	$
2190004	OCI-Min Pen Liab FAS 158-SERP	$
2190006	OCI-Min Pen Liab FAS 158-Qual	$
2190007	OCI-Min Pen Liab FAS 158-OPEB	$
2190010	OCI-for Commodity Hedges	$
2190015	Accum OCI-Hdg-CF-Int Rate	$
2190016	Accum OCI-Hdg-CF-For Exchg	-
	Acc Oth Comp Inc	$
	Source[1]	*112.15.c*
	Total Capital	$
	Common Equity Balance	$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12b - Preferred Stock
For the Year Ending December 31, _ _ _ _

	Preferred Stock		Premium on Preferred		(Discount) on Preferred		Other Paid in Capital - Pfd		Total Outstanding	Preferred
	A		b		C		d		a+b-c+d	
Month	Acct 204	Source 1	Acct 207	Source 1	Acc 213	Source 1	Acc 208-211	Source 1		Dividends
12/1/20##	$	112.3.c	$	112.6.c	$	112.9.c	$	112.7.c	$	$
Total	$		$		$		$		$	$

Cost of Preferred Stock = Pfd Dividends/Average Pfd Outstanding Balance = %

NOTES:
(1) All data is from the monthly Balance Sheet of the Company's Books and Records (CBR).
(2) Accounts 207-213 are capital stock accounts containing both common and preferred capital. Preferred portions of these accounts are from the CBR.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13 - Outstanding Long-Term Debt
For the Year Ending December 31, _ _ _ _

Line	Period	Advances from Associated Co	FF1 Reference	Bonds	FF1 Reference	(Reacquired Bonds)	FF1 Reference	Installment Purchase Contracts	FF1 Reference	Senior Unsecured Notes	FF1 Reference	Debntr Trust Pref Secrty Insts	FF1 Reference	Total Debt Outstanding	Reference
		2230000		2210000		2220001		2240002		2240006		2240046			
		A		b		c		d		e		F		g=a+b+c+d+e+f	
1	12/1/20##	$	112.20.c.	$	112.18.c.	$	112.19.c.	$	257, col. (h)	$	257, col. (h)	$	257, col. (h)	$	FF1, 112,20,c & 112,21,c
2	12/1/20##	$		$		$		$		$		$		$	

Appalachian Power Company
Interest & Amortization on Long-Term Debt
For the Year Ending December 31, _ _ _ _

Line	Description		Acct	FF1 Ref
1	Interest	IPC	4270002	$
2	Interest	Unsecured	4270006	$
3	Interest	TPS	4270040	$
4			(FF1, P.117,L.62)	$
5	Amort Debt Disc/ Exp		Acct 428 (FF1, P.117, L.63)	$
6	Amort Loss Reacq		Acct 428.1 (FF1, P.117, L.64)	$
7	Interest*	Assoc LT	4300001 (FF1, P.117, L.67)	$
8	Amort Debt Premium		Acct 429 (FF1, P.117, L.65)	$
9	Amort Gain Reacq		Acct 429.1 (FF1, P.117, L.66)	$
10	Cost of Long Term Debt			$
11	<u>Reconcilation to FF1, 257, 33,</u>			
12	Interest on LT Debt		Line 4	$
13	Interest on Assoc LT Debt		Line 7	$

14	Total (FF1, 257, 33, i)	$
15	Amortization of Hedge Gain / Loss included in Acct 4270006 (subject to limit on Workpaper 13a)	$

*Per Company Books and Records Interest associated with LTD.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13a - Recoverable Hedge Gains/Losses
For the Year Ended December 31, _ _ _ _

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge Gain or Loss for _ _ _ _	Less Excludable Amounts (See NOTE on Line For the Year Ended December 31, _ _ _ _)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
1	Listing of Debt Issues with Hedging	$	$	$	$	11/1/20##	11/1/20##
2		$	$	$	$	12/1/20##	12/1/20##
3		$	$	$	$	11/1/20##	11/1/20##
4		$	$	$	$	12/1/20##	12/1/20##
5		$	$	$	$	11/1/20##	11/1/20##
6		$	$	$	$	12/1/20##	12/1/20##
7		$	$	$	$	11/1/20##	11/1/20##
8		$	$	$	$	12/1/20##	12/1/20##
9		$	$	$	$	11/1/20##	11/1/20##
10		$	$	$	$	12/1/20##	12/1/20##
11	Total Hedge Amortization	$	$	$			

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 14 - Non-Fuel Power Production O&M Expenses
For the Year Ending December 31, _ _ _ _

Account		December	Less Carbon Capture Expense	Total
500	Demand	$		$
502	Demand	$		$
503	Energy	$		$
504 - Cr.	Energy	$		$
505	Demand	$		$
506	Demand	$	$	$
507	Demand	$		$
509	Energy	$		$
510	Energy	$		$
511	Demand	$		$
512	Energy	$		$
513	Energy	$		$
514	Demand	$		$
517	Demand	$		$
519	Demand	$		$
520	Demand	$		$
521	Demand	$		$
522 - Cr.	Demand	$		$
523	Demand	$		$
524	Demand	$		$
525	Demand	$		$
528	Energy	$		$
529	Demand	$		$
530	Energy	$		$
531	Energy	$		$
532	Energy	$		$
535	Demand	$		$
536	Demand	$		$
537	Demand	$		$
538	Demand	$		$
539	Demand	$		$
540	Demand	$		$
541	Demand	$		$
542	Demand	$		$
543	Demand	$		$

544	Energy	$		$
545	Demand	$		$
546	Demand	$		$
548	Demand	$		$
549	Demand	$		$
550	Demand	$		$
551	Demand	$		$
552	Demand	$		$
553	Demand	$		$
554	Demand	$		$
Total		$	$	$
Demand		$	$	$
Energy		$	$	$
Total		$	$	$
Demand	%			%
Energy	%			%
Total	%			%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances
pgs. 320-323, , b

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15a

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15b

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15c - Purchased Power
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Energy ($) [1]	Other Charges [2]	Total Purchased Power Expense
12/1/20##	$	$	$	$
Total	$	$	$	$
	327, ,,j	327, , k	327,,l	327,,m

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] Excludes the deferred portion of APCo's capacity equalization payments related to environmental compliance investments FF 1, pg. 327, column (l)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15d - Off-System Sales
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Other Charges ($) [1]	Energy ($) [1]	Total
12/1/20##	$	$	$	$

Month	($) Margins [2]
12/1/20##	$

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
FF1, 311, h, j, i (Non-RQ)

[2] Margins provided by Accounting (represents 75% of system sales margins)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 16 - GSU Plant and Accumulated Depreciation Balance
For the Year Ending December 31, _______

company	major_location	asset_location	gl_account	state	utility_account	month	book_cost	allocated _reserve	net_book_value
Listing of Individual GSU Assets							$	$	$
Appalachian Power – Gen Total							$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 17 – Balance of Transmission Investment
Balance as of December _ _ _ _

fr_desc	fpa	fc_sortid	Description	Beginning_balance	additions	retirements	transfers	adjustments	ending_balance	start_month	end_month
none	353 - Station Equipment	6	Transmission Plant - Electric	$	$	$	$	$	$	1/1/20##	12/1/20##

Notes:
References to data from FERC Form 1 page(s) 206,207, Ln. 50

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 18 - Fuel Expense
For the Year Ending December 31, _ _ _ _

		Source
Fuel		
Fuel - Account 501	$	320, 5, b
Fuel - Account 518	$	320, 25, b
Fuel - Account 547	$	321, 63, b
Total Fuel	$	
Other		
Fuel Handling	$	CBR
Sale of Fly Ash (Revenue & Expense)	$	CBR

Notes:
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 19 - Plant Held for Future Use
For the Year Ending December 31, _ _ _ _

	End of Year		
	Total	Demand [1]	Energy
Production	$	$	$
Transmission	$	$	$
Distribution	$	$	$
General	$	$	$
Total	$	$	$
	FF1, 214, d		

Notes:
[1] CBR indicates that data comparable to that reported in the FERC Form 1
is from the Company's Books and Records.

Attachment B

Revisions to Section(s) of the
PJM Reliability Assurance Agreement

(Marked / Redline Format)

Schedule 8.1 – Appendix 2A

Appalachian Power Company (APCO)

CAPACITY COMPENSATION FORMULA RATE IMPLEMENTATION PROTOCOLS

Definitions

The definitions and provisions contained in this Appendix 2A shall be applicable only to the provisions of Schedule 8.1 - Appendix 2A, unless otherwise specified.

"Capacity Rate" means the result produced by populating the Capacity Compensation Formula Rate Template with data to calculate the Fixed Resource Requirement capacity rate for load served by Virginia Competitive Service Providers ("CSPs").

"Annual Review Procedures" means the procedures pursuant to which an Interested Party may review the Annual Update and notify APCO of any specific challenges to the Annual Update.

"Annual Update" means the posting and informational filing submitted by APCO on or before May 25 of each year that sets forth the capacity rate for the subsequent Rate Year.

"Capacity Compensation Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Schedule 8.1 – Appendix 2B under Section D.8 of Schedule 8.1 of the PJM Interconnection, L.L.C. ("PJM") Reliability Assurance Agreement ("RAA").

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in APCO's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate template to be different from the result under the Formula Rate Template as calculated without such change.

"Partial Rate Year" means the period February 9, 2013 through May 31, 2013.

"Partial Rate Year Effective Date" means February 9, 2013.

"Protocols" means these Capacity Compensation Formula Rate Implementation Protocols.

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1 below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2 below.

Section 1 Annual Updates

a. The Capacity Rate for the Partial Rate Year shall become effective on the Partial Year Effective Date and such Capacity Rate shall not be subject to the Protocols. Beginning June 1, 2013, the Capacity Rate shall be revised in accordance with the Capacity Compensation Formula Rate Template, and the Annual Update for the Rate Year beginning on June 1, 2013, and all subsequent Rate Years, shall be fully subject to the Protocols.

b. On or before May 25 of 2013 and each year thereafter, APCO shall recalculate its Capacity Rate, producing the Annual Update for the upcoming Rate Year, and shall post such Annual Update, in both PDF and working Excel spreadsheet versions, on PJM's Internet website. In addition, APCO shall submit such Annual Update as an informational filing with FERC. APCO will also post such Annual Update on APCO's Internet website at https://www.appalachianpower.com/service/choice/.

c. The date as provided in Section 1.b shall be that Rate Year's Publication Date.

d. The Annual Update shall include a workable Excel file or files containing the data-populated Formula Rate Template as well as supporting calculations and workpapers that demonstrate and explain information not otherwise set out in APCO's FERC Form No. 1 reports.[1]

e. The Annual Update for the Rate Year:

() shall, to the extent specified in the Formula Rate Template, be based upon prudently incurred costs; the data for such prudently incurred costs will be taken from APCO's FERC Form No. 1 for the most recent calendar year, and will be based upon the books and

1 It is the intent that each input to the Formula Rate Template will be either taken directly from the FERC From No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet appurtenant to the filed Formula Rate Template, the inputs to the worksheet will meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate Template.

records of APCO (all of the foregoing data, books, and records maintained consistent with the USofA and FERC accounting policies, practices, and procedures);

(ii) shall be populated, in accordance with FERC's orders establishing generally applicable ratemaking policies and the Formula Rate Template, with the data identified above; and

(iii) shall be subject to the Annual Review Procedures set forth in these Protocols.

f. Formula Rate Inputs

(i) Stated inputs to the Formula Rate Template: rate of return on common equity; Post Employment Benefits other Than Pensions ("PBOPs"); and depreciation and amortization rates shall be stated values to be used in the Formula Rate Template until changed pursuant to an FPA Section 205 or 206 filing.

(ii) Cost of Service elements recorded in accounts not specifically provided for in the Capacity Rate: any cost, expense or other element of the cost of providing service not specifically provided for shall not be recoverable under the Formula Rate until filed for pursuant to FPA Section 205, accepted by FERC and, if otherwise required, a determination has been made by the Office of the Chief Accountant regarding the journal entries for the transaction.

(iii) The Formula Rate Template makes reference to certain pages and line numbers found in APCO's FERC Form 1 used for reporting calendar year 2011 data. From time to time, FERC may make changes in the format of the FERC Form 1, and such changes may result in certain page and line references included in Formula Rate Template being rendered inaccurate. To the extent that only formatting changes are involved and there is no substantive change, the Formula Rate Template shall be interpreted as if the page and line references contained therein are references to the pages and lines contained in the current FERC Form 1 on which can be found the data described on the pages and lines of the prior FERC Form 1.

Section 2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have up to ninety (90) days after the Publication Date ("Review Period") (unless such period is extended with the written consent of APCO) to review the calculations and to notify APCO in writing of any specific challenges, including challenges related to any Material Changes, to the application of the Formula Rate in an Annual Update ("Preliminary Challenge").

b. Interested Parties shall have the right to serve reasonable information requests on APCO up to seventy-five (75) days after the Publication Date. Such information requests shall be limited to what is necessary to determine: (i) whether APCO has properly calculated the Annual Update under review (including any corrections pursuant to Section 4); (ii) whether APCO has correctly applied the Formula Rate Template; and (iii) whether the inputs to the Formula Rate Template are appropriate costs and revenue credits. Interested Persons can make information requests regarding allocation methodologies, including inter-corporate cost allocation methodologies, used to derive the inputs.

c. APCO shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Notwithstanding anything to the contrary contained in these Protocols, with respect to any information requests received by APCO up to seventy-five (75) days after the Publication Date for which APCO is unable to provide a response before the end of the Review Period, the Review Period shall be extended day-for-day until APCO's response is provided.

d. Preliminary or Formal Challenges related to Material Changes are not intended to serve as a means of pursuing other objections to the Annual Update. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update, but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such challenge affects the subsequent Annual Update.

e. In any proceeding initiated to address a Preliminary or Formal Challenge or *sua sponte* by FERC, a party or parties seeking to modify the Formula Rate Template in any respect shall bear the applicable burden under the FPA.

Section 3 Resolution of Challenges

a. If APCO and any Interested Party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period ends, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of APCO to continue efforts to resolve the Preliminary Challenge) to submit a written Formal Challenge to FERC, pursuant to 18 C.F.R. § 385.206, which shall be served on APCO by electronic service on the date of such filing ("Formal Challenge"). However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if FERC already has initiated a proceeding to consider the Annual Update.

b. Parties shall make a good faith effort to raise all issues in a Preliminary Challenge prior to filing a Formal Challenge; provided, however, that a Preliminary Challenge shall not be a prerequisite for bringing a Formal Challenge. Failure to notify APCO of an issue with respect to an Annual Update shall not preclude an Interested Party from pursuing such issue in a Preliminary Challenge or Formal Challenge.

c. All information and correspondence produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the FPA, or in any proceeding before the U.S. Court of Appeals to review a FERC decision.

d. Any response by APCO to a Formal Challenge must be submitted to FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

e. APCO shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate Template, and the applicable procedures in these Protocols, and of proving that it has properly calculated the challenged Annual Update pursuant to the Formula Rate Template, and of proving it has reasonably adopted and applied any Material Changes in that year's Annual Update.

f. . These Protocols in no way limit the rights of APCO or any Interested Party to initiate a proceeding at FERC at any time with respect to the Formula Rate Template or any Annual Update consistent with the party's full rights under the FPA, including Sections 205, 206 and 306, and FERC's regulations.

g. It is recognized that resolution of Formal Challenges concerning Material Changes may necessitate adjustments to the Formula Rate input data for the applicable Annual Update, or changes to the Formula Rate Template to ensure that the Formula Rate Template continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 4 Changes to Annual Informational Filings

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's FERC Form No. 1 report of APCO, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, or as the result of any FERC proceeding to consider a prior year's Annual Update, APCO shall promptly notify the Interested Parties, file a correction to the Annual Update with FERC as an amended informational filing describing the change(s) and the cost impact.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest as per section 35.19a of the Commission's regulations.

c. Changes Made During the Review Period. Unless otherwise agreed by APCO and the Interested Parties, a correction made under Section 4.a prior to the time determined for the filing of a Formal Challenge shall reset the performance dates under Sections 2 and 3 of these Protocols for Interested Party Annual Review, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of the Annual Review shall then be limited to the aspects of the Formula Rate Template affected by the corrections.

Schedule 8.1 – Appendix 2B
Appalachian Power Company
Capacity Compensation Formula Rate

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CAPACITY RATE
12 Months Ending 12/31/####

	RATE $/MW/Day (1)	CAPACITY MW (2)	Amount $ (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$	#	$

Note A: Rate will be applied to peak obligation demands at or adjusted to generation level (including losses).

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
DETERMINATION OF CAPACITY RATE
12 Months Ending 12/31/####

1. Capacity Daily Rates

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

$$\frac{\$}{\#\quad /365} = \quad \$$$

Where: Annual Production Fixed Cost, P.4, L.8.

Note A: Average of demand at time of PJM five highest daily peaks. – Workpapers --WP1.

Appendix 2
Page 3

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/####

		Reference	
.	GSU & Associated Investment	Note A	$
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	$
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$
5.	GSU Related Depreciation Expense	L.3 x L.4	$
6.	Station Equipment Acct. 353 Investment	Note B	$
7.	Percent (GSU to Acct. 353)	L.1 / L.6	%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$
9.	GSU & Associated Investment O&M	L.7 x L.8	$

Note A: Workpapers – WP-16
Note B: Workpapers – WP-17

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/####

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.18, Col.(2)	$
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$
3.	Depreciation Expense	P.16, L.11, Col.(2)	$
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(3)	$
5.	Income Tax	P.18, L.5, Col.(2)	$
6.	Sales for Resale (Credit)	Note A	$
7.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$

Note A: Workpapers – WP-15d

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/####

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)-(4)	$	$	$
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)-(4)	$	$	$
4.	Net Plant in Service	L.2 - L.3	$	$	$
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	$	$	$
6.	Plant Held for Future Use (Note A)	Note A	$	$	$
7.	Subtotal - Electric Plant	L.4 - L.5 + L.6	$	$	$
	WORKING CAPITAL				
8.	Materials & Supplies				
9.	Fuel	P.9, L.2, Col.(2)-(4)	$	$	$
10.	Nonfuel	P.9, L.8, Col.(2)-(4)	$	$	$
11.	Total M & S	L.9 + L.10	$	$	$
12.	Prepayments Nonlabor (Note B)		$	$	$
13.	Prepayments Labor (Note B)		$	$	$
14.	Prepayments Total (Note B)		$	$	$
15.	Cash Working Capital	P.8, L.7, Col.(2)-(4)	$	$	$
16.	Total Rate Base	L.7 + L.11 + L.14 + L.15	$	$	$
17.	Weighted Cost of Capital	P.11, L.4, Col.(4)	%	%	%
18.	Return on Rate Base	L.16 x L.17	$	$	$

Note A: Workpapers – WP-19

Note B: Workpapers -- WP-5c Prepayments include amounts booked to Account 165. Nonlabor related prepayments allocated to the production function based on gross plant on P.6, L.7. Labor related prepayments allocated to production function based on wages and salaries on P.7, Note B.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/####

		System			PRODUCTION		
		Reference	Amount (1)	Reference	Amount (2)	Demand (3)	Energy (4)
1.	GROSS PLANT IN SERVICE (Note A)						
2.	Plant in Service (Note C)	FF1, P.204-207, L.100	$		$	$	$
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	$	$	$
4.	Total	L.2 + L.3	$		$	$	$
		Note A				%	%
5.				Col.(2), L.4	$	$	$
6.				Col.(1), L.4	$	$	$
7.			%	L.5/L.6	%	%	%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		$	FF1, P.200, L.22	$	$	$
10.	Allocated General Plant		$	Note B	$	$	$
11.	Total	L.9 + L.10			$	$	$
12.	ACCUMULATED DEFERRED TAXES (Note A)	(Note E)	$	P.6a, L.52	$	$	$

Note A: Excludes ARO amounts.
Note B: (% From P.7, Col.(3), L.29)
Note C: Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts
Note D: Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.
Note E: WP8a, WP8ai

Appendix 2
Page 6a

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEIMPLATE
PRODUCTION RELATED ADIT
12 Months Ending 12/31/####

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1.	190	Excluded Items	$	$			
2.	190	100% Production (Energy)	$		$		
3.	190	100% Production (Demand)	$			$	
4.	190	Labor Related	$				$
5.	190	Total	$	$	$	$	$
6.		Production Allocation		%	%	%	%
7.		(Gross Plant or Wages/Salaries)		$	$	$	$
8.		Demand Related			$	$	$
9.		Energy Related			$	$	$
10.		Note A			Direct	Direct	B-7, Note B
11.	281	Excluded Items	$	$			
12.	281	100% Production (Energy)	$		$		
13.	281	100% Production (Demand)	$			$	
14.	281	Labor Related	$				$
15.	281	Total	$	$	$	$	$
16.		Production Allocation		%	%	%	%
17.		(Gross Plant or Wages/Salaries)		$	$	$	$
18.		Demand Related			$	$	$
19.		Energy Related			$	$	$
20.		Allocation Basis			Direct	Direct	B-7, Note B
21.	282	Excluded Items	$	$			
22.	282	100% Production (Energy)	$		$		
23.	282	100% Production (Demand)	$			$	
24.	282	Labor Related	$				$
25.	282	Total	$	$	$	$	$
26.		Production Allocation		%	%	%	%
27.		(Gross Plant or Wages/Salaries)		$	$	$	$
28.		Demand Related			$	$	$
29.		Energy Related			$	$	$
30.		Allocation Basis			Direct	Direct	B-7, Note B
31.	283	Excluded Items	$	$			
32.	283	100% Production (Energy)	$		$		
33.	283	100% Production (Demand)	$			$	
34.	283	Labor Related	$				$
35.	283	Total	$	$	$	$	$
36.	283	Production Allocation		%	%	%	%
37.		(Gross Plant or Wages/Salaries)		$	$	$	$
38.		Demand Related			$	$	$
39.		Energy Related			$	$	$
40.		Allocation Basis			Direct	B-6, L.7	B-7, Note B
41.	255	Excluded Items	$	$			
42.	255	100% Production (Energy)	$		$		
43.	255	100% Production (Demand)	$			$	
44.	255	Labor Related	$				$
45.	255	Total	$	$	$	$	$
46.	255	Production Allocation		%	%	%	%
47.		(Gross Plant or Wages/Salaries)		$	$	$	$

48.	Summary Production Related ADIT	Total	Demand	Energy
49.	P Plant (Energy Related)	$	$	$
50.	P Plant (Demand Related)	$	$	$
51.	Labor Related	$	$	$
52	Total	$	$	$

Source: Functionalized balances for Accounts 190, 281, 282, 283 and 255 from WP-8a and 8ai.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/####

	Total System (Note A)	Allocation Factor	General Plant Accounts 101 and 106 Related to Production (1) x (2)	Demand	Energy
1. GENERAL PLANT	(1)	(2)	(3)	(4)	(5)
2					
3. Land	$	Note B	$	$	$
4. General Offices	$		$	$	$
5. Total Land	$		$	$	$
6		%			
7. Structures	$	Note B	$	$	$
8. General Offices	$		$	$	$
9. Total Structures	$		$	$	$
10		%			
11. Office Equipment	$	Note B	$	$	$
12. General Offices			$	$	$
13. Total Office Equipment	$		$	$	$
14. Transportation Equipment	$	Note B	$	$	$
15. Stores Equipment	$	Note B	$	$	$
16. Tools, Shop & Garage Equipment	$	Note B	$	$	$
17. Lab Equipment	$	Note B	$	$	$
18. Communications Equipment	$	Note B	$	$	$
19. Miscellaneous Equipment & Other	$	Note B	$	$	$
20. Subtotal	$		$	$	$
21. PERCENT		Note C	%	%	%
22. Other Tangible Property					
23. Fuel Exploration	$	Note D	$		$
24. Rail Car Facility	$	Note D	$		$
25. Total Other Tangible Property	$		$	$	$
26. TOTAL GENERAL PLANT FF1, P.207	$		$	$	$
27. INTANGIBLE PLANT	$	Note B	$	$	$
28. TOTAL GENERAL AND INTANGIBLE	$		$	$	$
29. PERCENT		Note E	%	%	%
30. Total General and Intangible	$		$	$	$
31. Exclude Other Tangible (Railcar and Fuel Exploration)	$		$	$	$
	-		-	-	-
32. Net General and Intangible	$		$	$	$
33. PERCENT			%	%	%

NOTE A: Workpapers -- 6c Data from Company's Books excluding ARO amounts.

NOTE B: Allocation factors based on wages and salaries in electric operations and maintenance expenses excluding administrative and general expenses:

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27 (see workpaper 9a).	$
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20. (see WP-9a)	$
c. Ratio (b / a)	%

NOTE C: L.20, Col.(3) / L.20, Col.(1)

NOTE D: Directly assigned to Production

NOTE E: L.28, Col.(3) / L.28, Col.(1)

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/####

	Reference	Amount (1)	PRODUCTION Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	$	$	$
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	$	$	$
3. Less Purchased Power	P.14, L.11	$	$	$
4. Other Production O&M	Sum (L.1 thru L.3)	$	$	$
5. Allocated A&G	P.10, L.17	$	$	$
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	$	$	$
7. O&M Cash Requirements	=45 / 360 x L.6	$	$	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/####

	SYSTEM		PRODUCTION			
	Reference	Amount	Reference	Amount	Demand	Energy
1. Material & Supplies (Note A)		(1)		(2)	(3)	(4)
2. Fuel (Note C)	FF1, P.110, L. 13,45,46 Workpapers WP-5b	$		$	$	$
3. Non-Fuel						
4. Production	Note D	$	100% Col. 1	$	$	$
5. Transmission		$	0	$	$	$
6. Distribution		$	0	$	$	$
7. General		$	Note B	$	$	$
8. Total	L.4 + L.5 + L.6 + L.7	$		$	$	$
9. Account 158 Allowances	Note D	$		$	$	$

Note A: Year end balance
Note B: Column (1) times % from P.7, Col.(3), L.29.
Note C: Workpapers WP-5b.
Note D: Workpapers WP-5a.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/####

		Account	Reference	System Amount (1)	Allocation Factor % (2)	Production Amount (3)	Demand (4)	Energy (5)
1.	ADMINISTRATIVE & GENERAL EXPENSE							
2.	RELATED TO WAGES AND SALARIES							
3.	A&G Salaries	920	Workpaper 10a	$				
4.	Outside Services	923	Workpaper 10a	$				
5.	Employee Pensions & Benefits	926	Workpaper 10a	$	Note F			
6.	Office Supplies	921	Workpaper 10a	$				
7.	Injuries & Damages	925	Workpaper 10a	$				
8.	Franchise Requirements	927	Workpaper 10a	$				
9.	Duplicate Charges - Cr.	929	Workpaper 10a	$				
10.	Total		Ls. 3 thru 9	$	Note A	$	$	$
11.	MISCELLANEOUS GENERAL EXPENSES	930	Workpaper 10a	$	Note A, C & D	$	$	$
12.	ADM. EXPENSE TRANSFER - CR.	922	Workpaper 10a	$	Note B	$	$	$
13.	PROPERTY INSURANCE	924	Workpaper 10a	$	Note E	$	$	$
14.	REGULATORY COMM. EXPENSES	928	Workpaper 10a	$	Note C	$	$	$
15.	RENTS	931	Workpaper 10a	$	Note B	$	$	$
16.	MAINTENANCE OF GENERAL PLANT	935	Workpaper 10a	$	Note B	$	$	$
17.	TOTAL A & G EXPENSE		L.10 thru 16	$		$	$	$

Note A: % from Note B, P.7
Note B: General Plant % from P.7, Col.(3), L.29
Note C: Workpapers WP -- 11. Excludes all items not related to wholesale service and also excludes FERC assessment of annual charges.
Note D: Excludes general advertising and company dues and memberships.
Note E: % Plant from P.6, L.7.
Note F: PBOP expense cannot be changed absent a Section 205/206 filing with the Commission.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/####

			Total Company Capitalization	Weighted Cost Ratios		Cost of Capital	Weighted Cost of Capital
		Reference	$ (1)	% (2)	Reference	% (3)	(2 x 3) (4)
1.	Long Term Debt	Note A	$	%	Note D	%	%
2.	Preferred Stock	Note B	$	%	Note E	%	%
3.	Common Stock	Note C	$	%	Note F	%	%
4.	Total	Note A	$	%			%

Note A: P.12, L.5, Col.1.

Note B: P.13a, L.6(2).

Note C: P.13b, L.5.

Note D: P.12, L.16 (2).

Note E: P.13a, L.7.

Note F: Return on equity cannot be changed absent a Section 205/206 filing with the Commission.

Appendix 2
Page 12

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT
12 Months Ending 12/31/####

		Reference	Debt Balance	Interest & Cost Booked
			(1)	(2)
	12 Months Ending 12/31/2011 (Actual)			
1.	Bonds (Acc 221)	FF1, 112.18.c.	$	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	$	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	$	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	$	
5.	Total Long Term Debt Balance		$	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		$
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		$
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		$
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		$
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		$
11.	Interest on LTD Assoc Companies (portion Acc 430)	Workpaper-13, L.7		$
12.	Sub-total Costs and Expense			$
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 11, Col. (6)		$
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 15, Col. (6)		$
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		$
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			%

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/####

		(1)	(2)	(3)	(4)	(5)	(6)
				Net Includable			
	HEDGE AMT BY ISSUANCE	Total Hedge	Excludable	Hedge Amount	Unamortized	Amortization Period	
	FERC Form 1, p. 256-257 (i)	(Gain) / Loss	Amounts (Note A)	Subject to Limit	Balance	Beginning	Ending
1.	Debt Issuance #1	$	$	$	$		
2.	Debt Issuance #2	$	$	$	$		
3.	Debt Issuance #3	$	$	$	$		
4.	Total Hedge Amortization	$	$	$			
	Limit on Hedging (G)/L on Interest Rate Derivatives of LTD						
5.	Hedge (Gain) / Loss prior to Application of Recovery Limit						$
	Enter a hedge Gain as a negative value and a hedge Loss as a positive value						
6.	Total Capitalization			Page11, L.4, col.(1)		$	
7.	5 basis point Limit on (G)/L Recovery						%
8.	Amount of (G)/L Recovery Limit			L. 12 * L.13			$
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8)						$
	To be subtracted or added to actual Interest Expenses on Page 12, Line 14						

Note A: Annual amortization of net gains or net loss on interest rate derivative hedges on long term debt shall not cause the composite after-tax weighted average cost of capital to increase/decrease by more than 5 basis points. Hedge gains/losses shall be amortized over the life of the related debt issuance. The unamortized balance of the g/l shall remain in Acc 219 Other Comprehensive Income and shall not flow through the rate calculation. Hedge-related ADIT shall not flow through rate base. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this calculation and are to be recorded above.

Appendix 2
Page 13a

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PREFERRED STOCK
12 Months Ending 12/31/####

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	$
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 9 (f)	$
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	$
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. L.9	$
5.	Plus: Paid-in-Capital Pfd Stock	Note A		$
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	$
7.	Average Cost Rate		L.1 / L.6	%

Note A: Workpaper – WP-12b.

Note B: Preferred stock outstanding excludes pledged and Reacquired (Treasury) preferred stock.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMMON EQUITY
12 Months Ending 12/31/####

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	$
	Less:		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, col.b+c+d	$
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, col.e	$
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, col.f	$
5.	Total Balance of Common Equity	L.1-2-3-4	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/####

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	$	$	$
2. Lignite Handling	501.xx	$	$	$
3. Sale of Fly Ash (Revenue & Expense)	501.xx	$	$	$
4. Rents	507	$	$	$
5. Hydro O & M Expenses	535-545	$	$	$
6. Other Production Expenses	557	$	$	$
7. System Control of Load Dispatching	Note C	$	$	$
8. Other Steam Expenses	Note A	$	$	$
9. Combustion Turbine	Note A	$	$	$
10. Nuclear Power Expense-Other	Note A	$	$	$
11. Purchased Power	555	$	$	$
12. Total Production Expense Excluding Fuel Used In Electric Generation	Sum of L.1 – L.11	$	$	$
13. A & G Expense P.10, L.17		$	$	$
14. Generator Step Up related O&M	Note B	$	$	$
15. Total O & M		$	$	$

NOTE A: Amounts recorded in O&M Expense Accounts classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8 and 575.7

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

Line No.	Description	FERC Account No.	Energy Related	Demand Related
1	POWER PRODUCTION EXPENSES			
2	Steam Power Generation			
3	Operation supervision and engineering	500	-	xx
4	Fuel	501	xx	-
5	Steam expenses	502	-	xx
6	Steam from other sources	503	xx	-
7	Steam transferred-Cr.	504	xx	-
8	Electric expenses	505	-	xx
9	Miscellaneous steam power expenses	506	-	xx
10	Rents	507	-	xx
11	Allowances	509	xx	-
12	Maintenance supervision and engineering	510	xx	-
13	Maintenance of structures	511	-	xx
14	Maintenance of boiler plant	512	xx	-
15	Maintenance of electric plant	513	xx	-
16	Maintenance of miscellaneous steam plant	514	-	xx
17	Total steam power generation expenses			
18	Nuclear Power			
19	Operation supervision and engineering	517		xx
20	Coolants and Water	519		xx
21	Steam Expenses	520		xx
22	Steam from other sources	521		xx
23	Less: ; Steam Transferred	522		xx
24	Electric Expenses	523		xx
25	Miscellaneous Nuclear Power Expense	524		xx
26	Rents	525		xx
27	Maintenance supervision and engineering	528	xx	
28	Maintenance of structures	529		xx
29	Maintenance of Reactor Plant Equip	530	xx	
30	Maintenance of electric plant	531	xx	
31	Maintenance of Misc Nuclear Plant	532	xx	
32	Total power production expenses Nuclear			
33	Hydraulic Power Generation			
34	Operation supervision and engineering	535	-	xx
35	Water for power	536	-	xx
36	Hydraulic expenses	537	-	xx
37	Electric expenses	538	-	xx
38	Misc. hydraulic power generation expenses	539	-	xx
39	Rents	540	-	xx
40	Maintenance supervision and engineering	541	-	xx
41	Maintenance of structures	542	-	xx
42	Maintenance of reservoirs, dams and waterways	543	-	xx
43	Maintenance of electric plant	544	xx	-
44	Maintenance of miscellaneous hydraulic plant	545	-	xx
45	Total hydraulic power generation expenses			
46	Other Power Generation			
47	Operation supervision and engineering	546	-	xx

				Page 15 (con't) (2 of 2)
48	Fuel	547	xx	-
49	Generation expenses	548	-	xx
50	Miscellaneous other power generation expenses	549	-	xx
51	Rents	550	-	xx
52	Maintenance supervision and engineering	551	-	xx
53	Maintenance of structures	552	-	xx
54	Maintenance of generation and electric plant	553	-	xx
55	Maintenance of misc. other power generation plant	554	-	xx
56	Total other power generation expenses			
57	Other Power Supply Expenses			
58	Purchased power	555	xx	xx
59	System control and load dispatching	556	-	xx
60	Other expenses	557	-	xx
61	Station equipment operation expense (Note A)	562	-	xx
62	Station equipment maintenance expense (Note A)	570	-	xx

Note A: Restricted to expenses related to Generator Step-up Transformers and Other Generator related expenses.
See Note D, Page 6

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED DEPRECIATION EXPENSE
12 Months Ending 12/31/####

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
1.	Steam	$	$	$
2.	Nuclear	$	$	$
3.	Hydro	$	$	$
4.	Conventional	$	$	$
5.	Pump Storage	$	$	$
6.	Other Production	$	$	$
7.	Int. Comb.	$	$	$
8.	Other	$	$	$
9.	Production Related General & Intangible Plant	$	$	$
10.	Generator Step Up Related Depreciation (Note A)	$	$	$
11.	Total Production	$	$	$

Note: Lines 1 through 8 will be Depreciation Expense reported on P.336 of the FF1 excluding the amortization of acquisition adjustments. See Workpapers WP -- 6d.

Line 9 will be total General & Intangible Plant (from P.336 of the FF1, adjusted for amortization adjustments) times ratio of Production Related General Plant to total General Plant computed on P.7, L.33, Col.(3)

Depreciation expense excludes amounts associated with ARO.

Note A: Line 10, see P.3, L.5

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RPODUCTION RELATED TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/####

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT	%	Amount
			(1)		(3)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	$	Note B	$
2	Property Related	Note A	$	Note C	$
3	Other	Note A	$	Note C	$
4	Production	Note A	$		$
5	Gross Receipts / Distribution Related	Note A	$	Note D	$
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	$		$

Note A: See Workpapers -- WP8c.

Note B: Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services shown on Worksheets WP-9a and WP-9b.

	Amount	%
(1) Total W & S (excl. A & G)	$	%
(2) Production W & S	$	%

Note C: Allocated on the basis of Gross Plant Investment from P. 6, Ln.7

Note D: Not allocated to wholesale

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/####

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.18	$	$	$
2.	Effective Income Tax Rate	P.19, L.2	%	%	%
3.	Income Tax Calculated	L.1 x L.2	$	$	$
4.	ITC Adjustment	P.19, L.13	$	$	$
5.	Income Tax	L.3 + L.4	$	$	$

Note A: Classification based on Production Plant classification of P.19, L.20 and L.21.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/####

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		%
3.	where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p as shown below.		
4.	GRCF=1 / (1 - T)		#
5.	Federal Income Tax Rate	FIT	%
6.	State Income Tax Rate (Composite)	SIT	%
7.	Percent of FIT deductible for state purposes	Note A	%
8.	Weighted Cost of Long Term Debt	WCLTD	%
9.	Weighted Average Cost of Capital	WACC	%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	$
11.	Gross Plant Allocation Factor	L.19	%
12.	Production Plant Related ITC Amortization	L.10 x L.11	$
13.	ITC Adjustment	L.12 x L.4	$
14.	Gross Plant Allocator		Total
15.	Gross Plant	P.6, L.6, Col.2	$
16.	Production Plant Gross	P.6, L.5, Col.2	$
17.	Demand Related Production Plant	P.6, L.5, Col.3	$
18.	Energy Related Production Plant	P.6, L.5, Col.4	$
19.	Production Plant Gross Plant Allocator	L.16 / L.15	%
20.	Production Plant - Demand Related	L.17 / L.16	%
21.	Production Plant - Energy Related	L.18 / L.16	%

Note A: Percent deductible for state purposes provided from Company’s books and records.

Schedule 8.1 – Appendix 2C
Appalachian Power Company
Workpapers in Support of the Capacity Compensation Formula Rate

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 1 - Production System Peak Demand
For the Year Ending December 31, _ _ _ _

Month	Day	(EDT) Hour	Demand (MW)	Source
July	#	#	#	CBR[1]
July	#	#	#	
July	#	#	#	
July	#	#	#	
June	#	#	#	
Average Peak			#	
Average Production System Peak Demand			#	

Company's average five CP demands at time of PJM system peak.

Notes:
[1]CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 2 - Production Revenue Credits
For the Year Ending December 31, _ _ _ _

	Production			
	Total	Demand	Energy	Source [1]
	$	$	$	
Total	$	$	$	

Notes:

[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 3

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Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 4

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Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5a - Materials and Supplies
Balances as of December 31, _____

Period	1540001 M&S Regular	1540004 M&S Exempt Material	1540006 Lime and Limestone	1540012 Urea Charge	1540013 Transportation Inventory	1540022 M&S Lime & Limestone Intrasit	1540023 M&S Urea	1540024 M&S Proj Spares	M&S Total	Source[1]
12/31/20##	$	$	$	$	$	$	$	$	$	110.48.c
								Total	$	

Period	158 Allowances	Source[1]
12/31/20##	$	110.52.c

Functionalization of Materials & Supplies

M&S December 20##[2]		
Production	$	%
Transmission	$	%
Distribution	$	%
	$	%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5b - Fuel Inventory
Balances as of December 31, _ _ _ _

	1510001	1510002	1510003	1510004	1510019	1510020		
	Fuel Stock	Fuel Stock	Fuel Stock	Fuel Stock	Fuel Stock	Fuel Stock	Fuel Stock	
Period	Coal	Oil	Gas	Coal Trans	Prepays	In Transit	Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	110.45.c

	1520000	
	Fuel Stock	
Period	Undistributed	Source [1]
12/1/20##	$	110.46.c

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5c - Prepayments
For the Year Ending December 31, ______

Period	1650001 Prepayments Insurance	1650004 Prepayments Rents	1650005 Prepayments Employee Benefits	1650006 Prepayments Other	1650009 Prepayments Carrying Cost	1650010 Prepayments Pension Benefits	1650021/ 1650023 Prepayments Ins. & Lease	1650014 Prepayments FAS 158 Contra Asset	165000211* Prepayments Taxes	Prepayments Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	$	$	$	111.57.c

Period	Exclude [2] Rate Base	Non Labor [2] Related	Labor [2] Related
12/1/20##	$	$	$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.
1650001 - This account shall include amounts representing prepayments of insurance.
1650004 - This account shall include amounts representing prepayments of interest.
1650005 - This account shall include amounts representing prepayments of employee benefits.
1650006 - This account shall include amounts representing prepayments of other items not listed.
1650009 - This account is used for factoring the AEP-East electric accounts receivable.
1650010 - This account shall include amounts representing prepayments of pension benefits.
1650021 - This account shall include amounts representing prepayments of insurance with EIS (Energy Insurance Services).
1650023 - Track balance of prepaid lease expense for agreements that qualify as a lease under company policy and are not tracked in PowerPlant Lease Accounting system will use this account.
1650014 - This account is used to track the long term portion of the FAS 158 PBO liability (Projected Benefit Obligation) for the Qualified Pension Plan when the net plan is still prepaid. This account offsets account 1650010.
165000211 - This account shall include amounts representing prepayments of taxes.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6a - Plant in Service
Balances as of December 31, _____

Line	Month	Production					
		Total		ARO			Excluding ARO & AFUDC
	Month	Amount	Source [1]	Amount	Source [1]		
1	12/1/20##	$	205.46.g	$	205.15,24,34.g		$
2	Total						$
		Transmission					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
3	12/1/20##	$	207.58.g	$	207.57.g		$
4	Total						$
		Distribution					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
5	12/1/20##	$	207.75.g	$	207.74.g		$
6	Total						$
		General					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
7	12/1/20##	$	207.99.g	$	207.98.g		$
8	Total						$
		Intangible					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
9	12/1/20##	$	205.5.g	$	CBR		$
10	Total						$
11	December 31, _______ Plant In Service (excluding ARO)						$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6b - Accumulated Depreciation
Balance as of December 31, _____

RESERVE ACCT [2]	**RESERVE AMOUNT**	**PRODUCTION**	**TRANSMISSION**	**DISTRIBUTION**	**GENERAL**
1080005	$	$	$	$	$
1080001 ARO	$	$	$	$	$
1080001/1080011	$	$	$	$	$
1110001	$	$	$	$	$
10800013	$	$	$	$	$
	$	$	$	$	$
APCo Exc. ARO [3]	$	$	$	$	$
FERC Form 1 pg. 219	$	$	$	$	$
FERC Form 1 pg. 200	$				
Total Check	$				

Note: Data excludes Asset Retirement Obligations.

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the total balances.
[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6c - General Plant and Intangible Plant
Balances as of December 31, ____

Description	Account	12/31/20##
INTANGIBLE PLANT (FF1 205.2-5.g)		
Organization	301	$
Franchises and Consents	302	$
Miscellaneous Intangible Plant	303	$
TOTAL INTANGIBLE PLANT		$
GENERAL PLANT (FF1 207.86-97.g)		
Land	389	$
Structures	390	$
Office Equipment	391	$
Transportation	392	$
Stores Equipment	393	$
Tools, Shop, Garage, Etc.	394	$
Laboratory Equipment	395	$
Power Operated Equipment	396	$
Communications Equipment	397	$
Miscellaneous Equipment	398	$
Fuel Exploration	399	$
TOTAL GENERAL PLANT		$
General Plant (FF1 207.86-97 g)		
Total General and Intangible Exc. ARO		$
Total General and Intangible	205.5.g, 207.99.g	$

Note: Total includes Intangible Plant.
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6d - Depreciation Expense
For the Year Ending December 31, _ _ _ _

Description	Amount	Source
Steam Production	$	FF1, 336, 2, b & d
Hydraulic Production	$	FF1, 336, 4, 5 b
Other Production Plant	$	FF1, 336, 6 b
Transmission	$	FF1, 336, 7, b
Distribution	$	FF1, 336, 8, b
General	$	FF1, 336, 10, b & d
Intangible Plant	$	FF1, 336, 1
Sub-Total	$	
ARO Dep Exp	$	FF1, 336, 12, c
Total Depr Expense	$	FF1, 336, 12, f

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 7

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate

Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D		COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY		FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	- BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##		- GENERATION	- TRANSMISSION	- DISTRIBUTION
	ACCOUNT 281: *Listing of Individual Tax Differences*						
1	TOTAL ACCOUNT 281	$	$	-	$	-	-
	FF1, pg.273, Ln.8						
2	ACCOUNT 282: *Listing of Individual Tax*						
3	*Differences*						
4	**TOTAL ACOUNT 282**	$	$	-	$	$	$
5	***FF1, pg. 275, Ln. 5***	-	-	-	-	-	-
6	**Labor Related**	-	-	-	$	$	$
7	**Energy Related**	-	-	-	$	$	$
8	**ARO**	-	-	-	$	$	$
9	**Demand Related**				$	$	$
10	**Excluded**	-	-	-	$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _____

	COLUMN A	COLUMN B	COLUMN D		COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY		FUNCTIONALIZATION 12/31/##		
		-			-	-	-
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##		GENERATION	TRANSMISSION	DISTRIBUTION
11	ACCOUNT 283:						
12	Listing of Individual Tax Differences						
13	TOTAL ACCOUNT 283	$	$	_	$	$	$
14		-	-	-	-	-	-
15	FF1, pg. 277, Ln. 9	-	-	-	-	-	-
16	Labor Related	-	-	-	$	$	$
17	Energy Related	-	-	-	$	$	$
18	ARO	-	-	-	$	$	$
19	Demand Related				$	$	$
20	Excluded	-	-	-	$		
21	JURISDICTIONAL AMOUNTS FUNCTIONALIZED						
22	TOTAL COMPANY AMOUNTS FUNCTIONALIZED						
23	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT						
24	NOTE: POST 1970 ACCUMULATED DEFERRED						
25	INV TAX CRED. (JDITC) IN A/C 255						
26	SEC ALLOC - ITC - 46F1 - 10%	$			$	$	$
27	HYDRO CREDIT - ITC - 46F1	$			$	$	$
28							
29	TOTAL ACCOUNT 255	$	_	_	$	$	$
30	ITC Balance Included in Ratebase	$			$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8ai - ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190
For the Year Ending December 31,
_ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN O
		PER BOOKS BALANCE AS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
			BALANCE AS			
	ACCUMULATED DEFERRED FIT ITEMS	OF 12-31-##	OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 190:					
	Listing of Individual Tax Differences					
1	TOTAL ACCOUNT 190	$	$	$	$	$
	FF 1, p. 234, L. 8 Col. (c)					
	Energy Related	-	-	$	$	$
	ARO	-	-	$	$	$
	Labor Related	-	-	$	$	$
	Demand Related	-	-	$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8b - Effective Income Tax Rate
For the Year Ending December 31, _ _ _ _'

Effective Income Tax Rate

T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		%
EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		%
where WCLTD and WACC from Exhibit B-11		
and FIT, SIT & p are as shown below.		
GRCF=1 / (1 - T)		#
Amortized Investment Tax Credit (enter negative)	FF1 P.114, Ln.19, Col.c	$

FIT	%	
SIT	%	State Income Tax Rate (Composite).
p	%	Percent of FIT deductible for state purposes (Note 2).
WCLTD	%	
WACC	%	

Development of Composite State Income Tax Rates for 2011 (Note 1)

Tennessee Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Michigan Business Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Virginia Net Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
West Virginia Net Income	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Illinois Corporation Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Total Effective State Income Tax Rate		%

Note 1: Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

Note 2: From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _

Payroll Related Other Taxes	$	Payroll
Property Related Other Taxes	$	Property
Direct Production Related	$	Production
Direct Distribution Related	$	Distribution
Other	$	Other
Not Allocated ((Gross Receipts, Commission Assessments)	$	NA
	$	

Line No.	(A) Annual Tax Expenses by Type	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference	Basis
1	**Revenue Taxes**			
2	Gross Receipts Tax			
		$	P.### ln # (i)	N/A
		$	P.### ln # (i)	N/A
		$	P.### ln # (i)	N/A
3	**Real Estate and Personal Property Taxes**			
4	Real and Personal Property - West Virginia			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
5	Real and Personal Property - Virginia			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
6	Real and Personal Property - Tennessee			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
7	Real and Personal Property - Other Jurisdictions			
		$	P.### ln # (i)	Property
		$	P.### ln # (i)	Property
8	**Payroll Taxes**			
9	Federal Insurance Contribution (FICA)			
		$	P.### ln # (i)	Payroll
10	Federal Unemployment Tax			
		$	P.### ln # (i)	Payroll

11	State Unemployment Insurance			
		$	P.### ln # (i)	Payroll
		$	P.### ln # (i)	Payroll
		$	P.### ln # (i)	Payroll
12	**Production Taxes**			
13	State Severance Taxes			
		$	P.### ln # (i)	
14	**Miscellaneous Taxes**			
15	State Business & Occupation Tax			
		$	P.### ln # (i)	Production
		$	P.### ln # (i)	Production
		$	P.### ln # (i)	Production
16	State Public Service Commission Fees			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
17	State Franchise Taxes			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
18	State Lic/Registration Fee			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
19	Misc. State and Local Tax			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
20	Sales & Use			
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
		$	P.### ln # (i)	Other
21	Federal Excise Tax			
		$	P.### ln # (i)	Production
22	Michigan Single Business Tax			
		$	P.### ln # (i)	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9a - Wages and Salaries
For the Year Ending December 31, _ _ _ _

	APCo [1]	AEPSC [2]	Total
Production:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Transmission:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Distribution:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Customer Accounts	$	$	$
Customer Service and Informational	$	$	$
Sales	$	$	$
Total Wages and Salaries Excluding A & G	$	$	$
Administrative and General			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Total O & M Payroll	$	$	$

[1] APCo Wages and Salaries from FERC Form Pg. 354.

[2] From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9b - Production Payroll Demand/Energy Allocation
For the Year Ended December 31, 2011

Account	Demand	Energy	Total	Source [1]
500	$		$	
501		$	$	
502	$		$	
505	$		$	
506	$		$	
510		$	$	
511	$		$	
512		$	$	
513		$	$	
514	$		$	
517	$		$	
519	$		$	
520	$		$	
523	$		$	
524	$		$	
528		$	$	
529	$		$	
530		$	$	
531		$	$	
532		$	$	
535	$		$	
536	$		$	
537	$		$	
538	$		$	
539	$		$	
541	$		$	
542	$		$	
543	$		$	
544		$	$	
545	$		$	
546	$		$	
547		$	$	
548	$		$	
549	$		$	
553	$		$	
554	$		$	
555	$	$	$	
556	$		$	
557	$		$	
Total	$	$	$	
Allocation Factors	%	%	%	

[1] CBR indicates that data comparable to that reported in the FERC Form 1's from the Company's Books and Records.

Appalachian Michigan Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, ______
Note: Source of data is FERC Form 1, page 320-323, Column b.

Production		
500	Operation Supv & Engineering	$
501	Fuel	$
502	Steam Expenses	$
505	Electric Expenses	$
506	Misc. Steam Power Expense	$
507	Rents	$
509	Allowances	$
517	Operation Supv & Engineering	$
518	Fuel	$
519	Coolants and Water	$
520	Steam Expenses	$
523	Electric Expenses	$
524	Misc. Nuclear Power Expense	$
535	Operation Supv & Engineering	$
536	Water for Power	$
537	Hydraulic Expenses	$
538	Electric Expenses	$
539	Miscellaneous Hydraulic Power	$
540	Rents	$
546	Operation Supv & Engineering	$
547	Fuel	$
548	Generation Expenses	$
549	Misc. Power Generation Expense	$
	Total Operation	$
510	Maintenance Supv & Engineering	$
511	Maintenance of Structures	$
512	Maintenance of Boiler Plant	$
513	Maintenance of Electric Plant	$
514	Maintenance of Misc Plant	$
528	Maintenance Supv & Engineering	$
529	Maintenance of Structures	$
530	Maintenance of Reactor Plant	$
531	Maintenance of Electric Plant	$
532	Maintenance of Misc. Nuclear Plant	$
541	Maintenance Supv & Engineering	$
542	Maintenance of Structures	$
543	Maintenance of Reservious, Dams and Waterways	$
544	Maintenance of Electric Plant	$
545	Maintenance of Miscellaneous Hydraulic Plant	$
551	Maintenance Supv & Engineering	$
553	Maintenance of Generating & Electric Plant	$
554	Maintenance of Misc. Other Power Gen. Plant	$
	Total Maintenance	$
555	Purchased Power	$
556	System Control	$

557	Other Expense	$
	Total Other	$
	Total Production	$
Transmission		
560	Operation Supv & Engineering	$
561.1	Load Dispatch-Reliability	$
561.2	Load Dispatch-Monitor and Operate	$
561.3	Load Dispatch-Transmission Service	$
561.4	Scheduling, System Control	$
561.5	Reliability, Planning and Standards Dev.	$
561.6	Transmission Service Studies	$
561.7	Generation Interconnection Studies	$
561.8	Reliability, Planning and Standards Dev.	$
562	Station Expense	$
563	Overhead Line Expense	$
564	Underground Line Expense	$
565	Trans of Electricity by Others	$
566	Misc Transmission Expense	$
567	Rents	$
	Total Operation	$
568	Maintenance Supv & Engineering	$
569	Maintenance of Structures	$
569.1	Maintenance of Computer Hardware	$
569.2	Maintenance of Computer Software	$
569.3	Maintenance of Communication Equip	$
570	Maintenance of Station Equip	$
571	Maintenance of OH Lines	$
572	Maintenance of UG Lines	$
573	Maintenance of Misc Trans	$
	Total Maintenance	$
	Total Transmission	$
Regional Market Expense		
575.7	Market Facilitation, Monitoring and Compliance	$
Distribution		
580	Operation Supv & Engineering	$
581	Load Dispatching	$
582	Station Expense	$
583	Overhead Line Expense	$
584	Underground Line Expense	$
585	Street Lighting	$
586	Meter Expenses	$
587	Customer Installations	$
588	Misc Distribution Expense	$
589	Rents	$
	Total Operation	$
590	Maintenance Supv & Engineering	$
591	Maintenance of Structures	$

592	Maintenance of Station Equip	$
593	Maintenance of OH Lines	$
594	Maintenance of UG Lines	$
595	Maintenance of Line Trsfrs	$
596	Maintenance of Street Lights	$
597	Maintenance of Meters	$
598	Maintenance of Misc Dist Plant	$
	Total Maintenance	$
	Total Distribution	$
Customer Accounts		
901	Supervision	$
902	Meter Reading Expenses	$
903	Customer Records/Collection	$
904	Uncollectible Accounts	$
905	Misc Customer Accts Exp	$
	Total Customer Accounts	$
Customer Service and Informational		
907	Supervision	$
908	Customer Assistance	$
909	Info & Instructional Adv	$
910	Misc Cust Service & Info Expense	$
	Total Customer Service	$
Sales Expense		
911	Supervision	$
912	Selling Expenses	$
913	Advertising Expenses	$
916	Misc Sales Expense	$
	Total Sales Expense	$
Administrative and General		
920	A & G Salaries	$
921	Office Supplies & Exp	$
922	Adm Exp Trsfr - Credit	$
923	Outside Services	$
924	Property Insurance	$
925	Injuries and Damages	$
926	Employee Benefits	$
926a	Less: Actual Employee Benefits (Note A)	$
926b	Allowed Employee Benefits (Note B)	$
926	Employee Benefits	$
927	Franchise Requirements	$
928	Regulatory Commission Exp	$
929	Duplicate Charges - Credit	$
930.1	General Advertising Expense	$
930.2	Misc General Expense	$
930.2	Company Dues and Memberships	$
931	Rents	$
933	Transportation	$
	Total Operation	$

935	Maintenance of Gen Plant	$
	Total Maintenance	$
	Total Administrative & General	$
	Total O & M Expenses	$
	Total Elec O & M Exp. - FERC Form1 pg. 323, L. 198(b)	$
	Difference	$

Actual Expense - Removed from Cost of Service		
Note A:	Acct 926 (0039) PBOP Gross Cost	$
	Acct 926 (0057) PBOP Medicare Part Subsidy	$
	PBOP Amounts in Annual Informational Filing	$
Allowable Expense		
Note B:	Acct 926 (0039) PBOP Gross Cost	$
	Acct 926 (0057) PBOP Medicare Part Subsidy	$
	PBOP Amounts Recovery Allowance	$

Note B: Changing PBOP included in the formula rate will require, as applicable, a FPA Section 205 or Section 206 filing.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 11 - Regulatory Commission Expense
For the Year Ending December 31, _ _ _ _

Regulatory Commission Expense - Acct. 928 [1]	##
Retail	##
Wholesale - FERC	##

Note Excludes FERC Annual charges and amounts related to retail

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances
350, 46, d

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12a - Common Stock
For the Year Ending December 31, ______

Month	Total Capital	Source(s)	Preferred Stock Issued	Premium (Discount)	G(L) on Reacq'd	Source(s)*	Unapprop Sub Earnings	Source	Acc Oth Comp Income	Source	Common Equity Balance
	a		b	c	d		e		f		g=a-b-c-d-e-f
12/1/20##	$	112.16.c	$	$	$	112.3.c,6.c., 7.c.	$	112.12. c.	$	112.15. c.	$

NOTE: * Includes preferred portions of capital stock (common and preferred) accounts according to Company Books and Records below.

Account	Description		12/1/20##
2010001	Common Stock Issued		$
		Source [1]	*112.2.c*
2040002	PS Not Subj to Mandatory Redem		$
		Source [1]	*112.3.c*
2070000	Prem on Capital Stk		$
		Source [1]	*112.6.c*
2080000	Donations Recvd from Stckhldrs		$
2100000	Gain Rsle/Cancl Req Cap Stock		$
2110000	Miscellaneous Paid-In Capital		$
			$
		Source [1]	*112.7.c*
2151000	Appropriations of Retained Earnings		$
2160001	Unapprp Retnd Erngs-Unrstrictd		$
4330000	Transferred from Income		$
4370000	Div Decl-PS Not Sub to Man Red		$
4380001	Dividends Declared		$
4390000	Adj to Retained Earnings		-
	Retained Earnings		$
		Source [1]	*112.11.c*
2161001	Unap Undist Consol Sub Erng		$
2161002	Unap Undist Nonconsol Sub Erng		-

4181001 & 002	Equity in Earnings	-
	Unapprop Sub Earnings	$
	Source [1]	*112.12.c*
2190002	OCI-Min Pen Liab FAS 158-Affil	$
2190004	OCI-Min Pen Liab FAS 158-SERP	$
2190006	OCI-Min Pen Liab FAS 158-Qual	$
2190007	OCI-Min Pen Liab FAS 158-OPEB	$
2190010	OCI-for Commodity Hedges	$
2190015	Accum OCI-Hdg-CF-Int Rate	$
2190016	Accum OCI-Hdg-CF-For Exchg	-
	Acc Oth Comp Inc	$
	Source [1]	*112.15.c*
	Total Capital	$
	Common Equity Balance	$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[1] CBR indicates that data comparable to that reported in the the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12b - Preferred Stock
For the Year Ending December 31, _ _ _ _

	Preferred Stock		Premium on Preferred		(Discount) on Preferred		Other Paid in Capital - Pfd		Total Outstanding	Preferred
	A		b		C		d		a+b-c+d	_
Month	Acct 204	Source 1	Acct 207	Source 1	Acc 213	Source 1	Acc 208-211	Source 1	_	Dividends
12/1/20##	$	112.3.c	$	112.6.c	$	112.9.c	$	112.7.c	$	$
Total	$		$		$		$		$	$

Cost of Preferred Stock = Pfd Dividends/Average Pfd Outstanding Balance = ______%

NOTES:
(1) All data is from the monthly Balance Sheet of the Company's Books and Records (CBR).
(2) Accounts 207-213 are capital stock accounts containing both common and preferred capital. Preferred portions of these accounts are from the CBR.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13 - Outstanding Long-Term Debt
For the Year Ending December 31, _____

Line	Period	Advances from Associated Co	FF1 Reference	Bonds	FF1 Reference	(Reacquired Bonds)	FF1 Reference	Installment Purchase Contracts	FF1 Reference	Senior or Unsecured Notes	FF1 Reference	Debntr Trust Pref Secrty Insts	FF1 Reference	Total Debt Outstanding	Reference
		2230000		2210000		2220001		2240002		2240006		2240046			
		A		b		c		d		e		F		g=a+b+c+d+e+f	
1	12/1/20##	$	112.20.c.	$	112.18.c.	$	112.19.c.	$	257, col. (h)	$	257, col. (h)	$	257, col. (h)	$	FF1, 112,20,c & 112,21,c
2	12/1/20##	$		$		$		$		$		$		$	

Appalachian Power Company
Interest & Amortization on Long-Term Debt
For the Year Ending December 31, _____

Line	Description		Acct	FF1 Ref
1	Interest	IPC	4270002	$
2	Interest	Unsecured	4270006	$
3	Interest	TPS	4270040	$
4			(FF1, P.117,L.62)	$
5	Amort Debt Disc/ Exp		Acct 428 (FF1, P.117, L.63)	$
6	Amort Loss Reacq		Acct 428.1 (FF1, P.117, L.64)	$
7	Interest*	Assoc LT	4300001 (FF1, P.117, L.67)	$
8	Amort Debt Premium		Acct 429 (FF1, P.117, L.65)	$
9	Amort Gain Reacq		Acct 429.1 (FF1, P.117, L.66)	$
10	Cost of Long Term Debt			$
11	Reconciliation to FF1, 257, 33,			
12	Interest on LT Debt		Line 4	$
13	Interest on Assoc LT Debt		Line 7	$

14	Total (FF1, 257, 33, i)	$
15	Amortization of Hedge Gain / Loss included in Acct 4270006 (subject to limit on Workpaper 13a)	$

*Per Company Books and Records Interest associated with LTD.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13a - Recoverable Hedge Gains/Losses
For the Year Ended December 31, _ _ _ _

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge Gain or Loss for _ _ _ _	Less Excludable Amounts (See NOTE on Line For the Year Ended December 31, _ _ _ _)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
1	Listing of Debt Issues with Hedging	$	$	$	$	11/1/20##	11/1/20##
2	_	$	$	$	$	12/1/20##	12/1/20##
3	_	$	$	$	$	11/1/20##	11/1/20##
4	_	$	$	$	$	12/1/20##	12/1/20##
5	_	$	$	$	$	11/1/20##	11/1/20##
6	_	$	$	$	$	12/1/20##	12/1/20##
7	_	$	$	$	$	11/1/20##	11/1/20##
8	_	$	$	$	$	12/1/20##	12/1/20##
9	_	$	$	$	$	11/1/20##	11/1/20##
10	_	$	$	$	$	12/1/20##	12/1/20##
		_	_	_			
11	Total Hedge Amortization	$	$	$			

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 14 - Non-Fuel Power Production O&M Expenses
For the Year Ending December 31, _ _ _ _

Account		December	Less Carbon Capture Expense	Total
500	Demand	$		$
502	Demand	$		$
503	Energy	$		$
504 - Cr.	Energy	$		$
505	Demand	$		$
506	Demand	$	$	$
507	Demand	$		$
509	Energy	$		$
510	Energy	$		$
511	Demand	$		$
512	Energy	$		$
513	Energy	$		$
514	Demand	$		$
517	Demand	$		$
519	Demand	$		$
520	Demand	$		$
521	Demand	$		$
522 - Cr.	Demand	$		$
523	Demand	$		$
524	Demand	$		$
525	Demand	$		$
528	Energy	$		$
529	Demand	$		$
530	Energy	$		$
531	Energy	$		$
532	Energy	$		$
535	Demand	$		$
536	Demand	$		$
537	Demand	$		$
538	Demand	$		$
539	Demand	$		$
540	Demand	$		$
541	Demand	$		$
542	Demand	$		$
543	Demand	$		$

544	Energy	$		$
545	Demand	$		$
546	Demand	$		$
548	Demand	$		$
549	Demand	$		$
550	Demand	$		$
551	Demand	$		$
552	Demand	$		$
553	Demand	$		$
554	Demand	$		$
Total		$	$	$
Demand		$	$	$
Energy		$	$	$
Total		$	$	$
Demand	%			%
Energy	%			%
Total	%			%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances
pgs. 320-323, , b

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15a

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15b

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15c - Purchased Power
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Energy ($) [1]	Other Charges [2]	Total Purchased Power Expense
12/1/20##	$	$	$	$
Total	$	$	$	$
	327, ,,j	327, , k	327,,l	327,,m

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] Excludes the deferred portion of APCo's capacity equalization payments related to environmental compliance investments FF 1, pg. 327, column (l)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15d - Off-System Sales
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Other Charges ($) [1]	Energy ($) [1]	Total
12/1/20##	$	$	$	$

Month	($) Margins [2]
12/1/20##	$

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
FF1, 311, h, j, i (Non-RQ)

[2] Margins provided by Accounting (represents 75% of system sales margins)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 16 - GSU Plant and Accumulated Depreciation Balance
For the Year Ending December 31, _______

company	major_location	asset_location	gl_account	state	utility_account	month	book_cost	allocated _reserve	net_book_value
Listing of Individual GSU Assets							$	$	$
Appalachian Power – Gen Total							$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 17 – Balance of Transmission Investment
Balance as of December ____

fr_desc	fpa	fc_sortid	Description	Beginning_balance	additions	retirements	transfers	adjustments	ending_balance	start_month	end_month
none	353 - Station Equipment	6	Transmission Plant - Electric	$	$	$	$	$	$	1/1/20##	12/1/20##

Notes:
References to data from FERC Form 1 page(s) 206,207, Ln. 50

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 18 - Fuel Expense
For the Year Ending December 31, _ _ _ _

			Source
Fuel			
Fuel - Account 501	$		320, 5, b
Fuel - Account 518	$		320, 25, b
Fuel - Account 547	$		321, 63, b
Total Fuel	$		
Other			
Fuel Handling	$	-	CBR
Sale of Fly Ash (Revenue & Expense)	$	-	CBR

Notes:
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 19 - Plant Held for Future Use
For the Year Ending December 31, _ _ _ _

	End of Year		
	Total	Demand [1]	Energy
Production	$	$	$
Transmission	$	$	$
Distribution	$	$	$
General	$	$	$
Total	$	$	$
	FF1, 214, d		

Notes:
[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Attachment C

Populated
Capacity Compensation Formula Rate Template
with APCO Form 1 and Workpaper-based Cost Data
for 2011 to Compute the Initial Formula Rate
as of February 9, 2013

Appalachian Power Company
Formula Rate Template - Capacity Rate
12 Months Ending 12/31/2011 (actuals)

	RATE $/MW/Day (1)	CAPACITY MW (2)	Amount $ (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$478.53844	0	$0.00

Note A: Rate will be applied to peak obligation demands
at or adjusted to generation level (including losses).

DETERMINATION OF RATES APPLICABLE TO
APCO CAPACITY REQUIREMENTS
12 Months Ending 12/31/2011 (actuals)

1. Capacity Daily Rates

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

$$\frac{1{,}035{,}003{,}989}{5{,}925.6 \quad /365} = \$478.53844$$

Where: Annual Production Fixed Cost, P.4, L. 8

Note A: Average of demand at time of PJM five highest daily peaks.
Workpapers -- WP1

Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2011 (actuals)

		Reference	
1.	GSU & Associated Investment	Note A	31,219,942
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	1,942,021,775
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	1.61%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	30,417,733
5.	GSU Related Depreciation Expense	L.3 x L.4	488,995
6.	Station Equipment Acct. 353 Investment	Note B	769,009,760
7.	Percent (GSU to Acct. 353)	L.1 / L.6	4.06%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	4,385,759
9.	GSU & Associated Investment O&M	L.7 x L.8	178,051

Note A: Workpapers -- WP-16
Note B: Workpapers -- WP-17

ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2011 (actuals)

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.18, Col.(2)	$236,655,806
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$616,818,521
3.	Depreciation Expense	P.16, L.11, Col.(2)	$120,663,000
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(3)	$58,293,674
5.	Income Tax	P.18, L.5, Col.(2)	$92,281,559
6.	Sales for Resale (Credit)	Note A	$89,708,571
7.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6)	$1,035,003,989

Note A: Workpapers--WP-15d

RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2011 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)-(4)	5,309,207,934	5,249,989,715	59,218,219
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)-(4)	1,942,107,913	1,913,270,570	28,837,343
4.	Net Plant in Service	L.2 - L.3	3,367,100,021	3,336,719,145	30,380,876
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	560,063,141	424,495,238	135,567,903
6.	Plant Held for Future Use (Note A)	Note A	428,415	428,415	0
7.	Subtotal - Electric Plant	L.4 - L.5 + L.6	2,807,465,295	2,912,652,322	(105,187,027)
	WORKING CAPITAL				
8.	Materials & Supplies				
9.	Fuel	P.9, L.2, Col.(2)-(4)	143,931,036	0	143,931,036
10.	Nonfuel	P.9, L.8, Col.(2)-(4)	63,224,362	63,224,362	0
11.	Total M & S	L.9 + L.10	207,155,398	63,224,362	143,931,036
12.	Prepayments Nonlabor (Note B)		2,719,241	2,688,911	30,330
13.	Prepayments Labor (Note B)		107,053,402	68,182,018	38,871,383
14.	Prepayments Total (Note B)		109,772,642	70,870,929	38,901,714
15.	Cash Working Capital	P.8, L.7, Col.(2)-(4)	33,930,239	20,414,172	13,516,066
16.	Total Rate Base	L.7 + L.11 + L.14 + L.15	3,158,323,574	3,067,161,784	91,161,789
17.	Weighted Cost of Capital	P.11, L.4, Col.(4)	7.72%	7.72%	7.72%
18.	Return on Rate Base	L.16 x L.17	243,689,660	236,655,806	7,033,854

Note A: Workpapers -- WP-19

Note B: Workpapers -- WP-5c Prepayments include amounts booked to Account 165. Nonlabor related prepayments allocated to the production function based on gross plant on P.6, L.7. Labor related prepayments allocated to production function based on wages and salaries on P.7, Note B.

PRODUCTION-RELATED
ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/2011 (actuals)

		System			PRODUCTION		
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1.	GROSS PLANT IN SERVICE (Note A)						
2.	Plant in Service (Note C)	FF1, P.204-207, L.100	10,196,284,012		5,146,118,503	5,146,118,503	0
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	163,089,431	103,871,212	59,218,219
4.	Total	L.2 + L.3	10,196,284,012		5,309,207,934	5,249,989,715	59,218,219
		Note A				99%	1%
5.				Col.(2), L.4	5,309,207,934	5,249,989,715	59,218,219
6.				Col.(1), L.4	10,196,284,012	10,196,284,012	10,196,284,012
7.			100.00%	L.5/L.6	52.07%	51.49%	0.58%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		3,471,796,797	FF1, P.200, L.22	1,862,688,675	1,862,688,675	0
10.	Allocated General Plant		144,823,959	Note B	79,419,238	50,581,895	28,837,343
11.	Total	L.9 + L.10			1,942,107,913	1,913,270,570	28,837,343
12.	ACCUMULATED DEFERRED TAXES (Note A)	Note E	1,346,731,900	P.6a, L. 52	560,063,141	424,495,238	135,567,903

Note A: Excludes ARO amounts.
Note B: (% From P.7, Col.(3), L.29)
Note C: Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts
Note D: Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.
Note E: WP--8a, WP--8ai

PRODUCTION-RELATED ADIT
12 Months Ending 12/31/2011 (actuals)

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1	190	Excluded Items	-	-			
2	190	100% Production (Energy)	73,799,755		73,799,755		
3	190	100% Production (Demand)	307,110,496			307,110,496	
4	190	Labor Related	-				-
5	190	Total	380,910,251	-	73,799,755	307,110,496	-
6		Production Allocation		0.00%	100.00%	100.00%	100.00%
7		(Gross Plant or Wages/Salaries)		-	73,799,755	307,110,496	-
8		Demand Related			-	307,110,496	-
9		Energy Related			73,799,755	-	-
10		Note A			Direct	Direct	B-7, Note B
11	281	Excluded Items		-			
12	281	100% Production (Energy)			-		
13	281	100% Production (Demand)	(158,523,703)			(158,523,703)	
14	281	Labor Related	-				-
15	281	Total	(158,523,703)	-	-	(158,523,703)	-
16		Production Allocation		0.00%	100.00%	100.00%	54.84%
17		(Gross Plant or Wages/Salaries)		-	-	(158,523,703)	-
18		Demand Related			-	(158,523,703)	-
19		Energy Related			-	-	-
20		Allocation Basis			Direct	Direct	B-7, Note B
21	282	Excluded Items	(675,746,866)	(675,746,866)			
22	282	100% Production (Energy)	3,497		3,497		
23	282	100% Production (Demand)	(463,442,009)			(463,442,009)	
24	282	Labor Related	52,646				52,646
25	282	Total	(1,139,132,733)	(675,746,866)	3,497	(463,442,009)	52,646
26		Production Allocation		0.00%	100.00%	100.00%	100.00%
27		(Gross Plant or Wages/Salaries)		-	3,497	(463,442,009)	52,646
28		Demand Related			-	(463,442,009)	33,530
29		Energy Related			3,497	-	19,116
30		Allocation Basis			Direct	Direct	B-7, Note B
31	283	Excluded Items	(110,921,893)	(110,921,893)			
32	283	100% Production (Energy)	(193,229,825)		(193,229,825)		
33	283	100% Production (Demand)	(81,327,460)			(81,327,460)	
34	283	Labor Related	(44,506,538)				(44,506,538)
35	283	Total	(429,985,716)	(110,921,893)	(193,229,825)	(81,327,460)	(44,506,538)
36	283	Production Allocation		0.00%	100.00%	100.00%	100.00%
37		(Gross Plant or Wages/Salaries)		-	(193,229,825)	(81,327,460)	(44,506,538)
38		Demand Related			-	(81,327,460)	(28,346,092)
39		Energy Related			(193,229,825)	0	(16,160,446)
40		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
41	255	Excluded Items	-	-			
42	255	100% Production (Energy)	-		-		
43	255	100% Production (Demand)	-			-	
44	255	Labor Related	-				-
45	255	Total	-	-	-	-	-
46	255	Production Allocation		0.00%	100.00%	100.00%	100.00%
47		(Gross Plant or Wages/Salaries)		-	-	-	-
						Direct	

	Summary Production Related ADIT	Total	Demand	Energy
48	Summary Production Related ADIT	Total	Demand	Energy
49	P Plant (Energy Related)	(119,426,573)	-	(119,426,573)
50	P Plant (Demand Related)	(396,182,676)	(396,182,676)	0
51	Labor Related	(44,453,892)	(28,312,562)	(16,141,330)
52	Total	(560,063,141)	(424,495,238)	(135,567,903)

Source: Functionalized balances for Accounts 190, 281, 282, 283 and 255 from WP-8a and 8ai.

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2011 (actuals)

General Plant Accounts 101 and 106

1. GENERAL PLANT	Total System (Note A) (1)	Allocation Factor (2)	Related to Production (1) x (2) (3)	Demand (4)	Energy (5)
2.					
3. Land	14,937,188	Note B	8,191,325	5,217,032	2,974,292
4. General Offices	0		0	0	0
5. Total Land	14,937,188		8,191,325	5,217,032	2,974,292
6.					
7. Structures	107,343,774	Note B	58,865,679	37,491,390	21,374,289
8. General Offices	0		0	0	0
9. Total Structures	107,343,774		58,865,679	37,491,390	21,374,289
10.					
11. Office Equipment	6,233,701	Note B	3,418,466	2,177,212	1,241,254
12. General Offices	0		0	0	0
13. Total Office Equipment	6,233,701		3,418,466	2,177,212	1,241,254
14. Transportation Equipment	445	Note B	244	155	89
15. Stores Equipment	1,222,779	Note B	670,553	427,074	243,480
16. Tools, Shop & Garage Equipment	20,325,300	Note B	11,146,083	7,098,910	4,047,173
17. Lab Equipment	2,723,359	Note B	1,493,448	951,173	542,275
18. Communication Equipment	30,689,756	Note B	16,829,791	10,718,848	6,110,943
19. Miscellaneous Equip & Other	4,674,199	Note B	2,563,259	1,632,533	930,726
20. Subtotal	188,150,501		103,178,849	65,714,326	37,464,523
21. PERCENT		Note C	54.84%	34.93%	19.91%
22. Other Tangible Property					
23. Fuel Exploration	0	Note D	0		0
24. Rail Car Facility	0	Note D	0		0
25. Total Other Tangible Property	0		0	0	0
26. TOTAL GENERAL PLANT FF1, P.207	188,150,501		103,178,849	65,714,326	37,464,523
27. INTANGIBLE PLANT	109,249,193	Note B	59,910,582	38,156,885	21,753,697
28. TOTAL GENERAL AND INTANGIBLE	297,399,694		163,089,431	103,871,212	59,218,219
29. PERCENT		Note E	54.84%	34.93%	19.91%
30. Total General and Intangible	297,399,694		163,089,431	103,871,212	59,218,219
31. Exclude Other Tangible (Railcar and Fuel Exploration)	0		0	0	0
32. Net General and Intangible	297,399,694		163,089,431	103,871,212	59,218,219
33. PERCENT			54.84%	34.93%	19.91%

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2011 (actuals)

NOTE A: Workpapers -- 6c - Data from Company's Books excluding ARO amounts.
NOTE B: Allocation factors based on wages and salaries in electric operations and maintenance expenses excluding administrative and general expenses:

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27 (see workpaper 9a).	132,000,539
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20. (see WP-9a)	72,387,071
c. Ratio (b / a)	54.838%

NOTE C: L.20, Col.(3) / L.20, Col.(1)
NOTE D: Directly assigned to Production
NOTE E: L.28, Col.(3) / L.28, Col.(1)

PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/2011 (actuals)

	Reference	Amount (1)	PRODUCTION Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	1,419,506,121	574,805,302	844,700,819
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	(28,453,900)	0	(28,453,900)
3. Less Purchased Power	P.14, L.11	(1,183,049,516)	(453,327,093)	(729,722,423)
4. Other Production O&M	Sum (L.1 thru L.3)	208,002,705	121,478,209	86,524,496
5. Allocated A&G	P.10, L.17	63,439,203	41,835,168	21,604,035
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	271,441,908	163,313,377	108,128,531
7. O&M Cash Requirements	=45 / 360 x L.6	33,930,239	20,414,172	13,516,066

PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/2011 (actuals)

	SYSTEM		PRODUCTION			
	Reference	Amount	Reference	Amount	Demand	Energy
1. Material & Supplies (Note A)		(1)		(2)	(3)	(4)
2. Fuel (Note C)	FF1, P.110, L. 13,45,46 Workpapers WP-5b	143,931,036		143,931,036	0	143,931,036
3. Non-Fuel						
4. Production	Note D	63,224,362	100% Col. 1	63,224,362	63,224,362	0
5. Transmission		12,666,173	0	0	0	0
6. Distribution		14,699,618	0	0	0	0
7. General		0	Note B	0	0	0
8. Total	L.4 + L.5 + L.6 + L.7	90,590,153		63,224,362	63,224,362	0
9. Account 158 Allowances	Note D	26,614,549		26,614,549	0	26,614,549

Note A: Year end balance.

Note B: Column (1) times % from P.7, Col.(3), L.29.
Note C: Workpapers WP-5b
Note D: Workpapers WP-5a

PRODUCTION-RELATED
ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/2011 (actuals)

				System		Production		
		Account	Reference	Amount (1)	Allocation Factor % (2)	Amount (3)	Demand (4)	Energy (5)
1.	ADMINISTRATIVE & GENERAL EXPENSE							
2.	RELATED TO WAGES AND SALARIES							
3.	A&G Salaries	920	Workpapers 10-a	32,268,084				
4.	Outside Services	923	Workpapers 10-a	28,646,471				
5.	Employee Pensions & Benefits	926	Workpapers 10-a	26,385,423	Note F			
6.	Office Supplies	921	Workpapers 10-a	5,165,177				
7.	Injuries & Damages	925	Workpapers 10-a	9,360,136				
8.	Franchise Requirements	927	Workpapers 10-a	0				
9.	Duplicate Charges - Cr.	929	Workpapers 10-a	(138,507)				
10.	Total		Ls. 3 thru 9	101,686,784	Note A	55,763,473	35,515,603	20,247,870
11.	MISCELLANEOUS GENERAL EXPENSES	930	Workpapers 10-a	6,501,717	Note A & D	3,565,442	2,270,820	1,294,622
12.	ADM. EXPENSE TRANSFER - CR.	922	Workpapers 10-a	(6,535,860)	Note B	(3,584,165)	(2,282,745)	(1,301,420)
13.	PROPERTY INSURANCE	924	Workpapers 10-a	4,800,287	Note E	2,499,511	2,471,632	27,879
14.	REGULATORY COMM. EXPENSES	928	Workpapers 10-a	2,739,774	Note C	1,518,064	1,518,064	0
15.	RENTS	931	Workpapers 10-a	1,089,443	Note B	597,434	380,504	216,930
16.	MAINTENANCE OF GENERAL PLANT	935	Workpapers 10-a	5,615,484	Note B	3,079,445	1,961,290	1,118,155
17.	TOTAL A & G EXPENSE		L.10 thru 16	115,897,629		63,439,203	41,835,168	21,604,035

Note A: % from Note B, P.7
Note B: General Plant % from P.7, Col.(3), L.29
Note C: Workpapers WP -- 11 Excluding all items not related to wholesale service and also excludes FERC assessment of annual charges.
Note D: Excludes general advertising and company dues and memberships.
Note E: % Plant from P.6, L.7.
Note F: PBOP expense cannot be changed absent a Section 205/206 filing with the Commission.

COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2011 (actuals)

		Reference	Total Company Capitalization $ (1)	Weighted Cost Ratios % (2)	Reference	Cost of Capital % (3)	Weighted Cost of Capital (2 x 3) (4)
1.	Long Term Debt	Note A	3,734,408,392	55.51%	Note D	5.56%	3.09%
2.	Preferred Stock	Note B	0	0.00%	Note E	0.00%	0.00%
3.	Common Stock	Note C	2,993,346,798	44.49%	Note F	10.40%	4.63%
4.	Total	Note A	6,727,755,190	100.00%			7.72%

Note A: P.12, L.5, Col.1.

Note B: P.13a, L.6(2).

Note C: P.13b, L.5.

Note D: P.12, L.16 (2).

Note E: P.13a, L.7.

Note F: Return on equity cannot be changed absent a Section 205/206 filing with the Commission.

LONG TERM DEBT
12 Months Ending 12/31/2011 (actuals)

		Reference	Debt Balance (1)	Interest & Cost Booked (2)
	12 Months Ending 12/31/2011 (Actual)			
1.	Bonds (Acc 221)	FF1, 112.18.c.	0	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	0	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	0	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	3,734,408,392	
5.	Total Long Term Debt Balance		3,734,408,392	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		202,991,579
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		3,686,430
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		1,113,482
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		0
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		0
11.	Interest on LTD Assoc Companies (portion Acc 430)	Workpapers --13, L.7		0
12.	Sub-total Costs and Expense			207,791,491
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 11, Col. (6)		1,815,730
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 15, Col. (6)		1,815,730
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		207,791,491
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			5.56%

LONG TERM DEBT
Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/2011 (actuals)

Appendix 2
Page 12a

		(1)	(2)	(3)	(4)	(5)	(6)
	HEDGE AMT BY ISSUANCE FERC Form 1, p. 256-257 (i)	Total Hedge (Gain) / Loss	Excludable Amounts (Note A)	Net Includable Hedge Amount Subject to Limit	Unamortized Balance	Amortization Period Beginning	Ending
1.	Senior Unsecured Notes - Series I	764,169		764,169	1,974,104	Jan-05	Feb-15
2.	Senior Unsecured Notes - Series K	1,336,324		1,336,324	4,565,775	Jun-05	Jun-17
3.	Senior Unsecured Notes - Series M	(91,093)		(91,093)	(0)	Apr-06	Apr-11
4.	Senior Unsecured Notes - Series O	96,458		96,458	60,287	Aug-07	Aug-12
5.	Senior Unsecured Notes - Series L	(238,880)		(238,880)	(895,798)	Sep-05	Oct-35
6.	Senior Unsecured Notes - Series H	37,068		37,068	790,884	May-03	May-33
7.	Senior Unsecured Notes - Series N	(194,198)		(194,198)	(4,709,312)	Apr-06	Apr-36
8.	Senior Unsecured Notes - Series Q	159,672	-	159,672	4,184,715	Mar-08	Apr-38
9.	Senior Unsecured Notes - Series S	826,212	-	826,212	2,807,343	May-10	May-15
	Senior Unsecured Notes - Series T	(880,003)		(880,003)	10,434,320	Mar-11	Mar-21
10.	Total Hedge Amortization	1,815,730	-	1,815,730			

	<u>Limit on Hedging (G)/L on Interest Rate Derivatives of LTD</u>			
11.	Hedge (Gain) / Loss prior to Application of Recovery Limit			1,815,730
	Enter a hedge Gain as a negative value and a hedge Loss as a positive value			
12.	Total Capitalization	Page 11, L.4, col.(1)	6,727,755,190	
13.	5 basis point Limit on (G)/L Recovery			0.0005
14.	Amount of (G)/L Recovery Limit	L. 12 * L. 13		3,363,878
15.	Hedge (Gain) / Loss Recovery (Lesser of Line 11 or Line 14)			1,815,730
	To be subtracted or added to actual Interest Expenses on Page 12, Line 14			

Note A: Annual amortization of net gains or net loss on interest rate derivative hedges on long term debt shall not cause the composite after-tax weighted average cost of captial to increase/decrease by more than 5 basis points. Hedge gains/losses shall be amortized over the life of the related debt issuance. The unamortized balance of the g/l shall remain in Acc 219 Other Comprehensive Income and shall not flow through the rate calculation. Hedge-related ADIT shall not flow through rate base. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this calculation and are to be recorded above.

PREFERRED STOCK
12 Months Ending 12/31/2011 (actuals)

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	731,661
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 9 (f)	0
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	0
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. L.9	0
5.	Plus: Paid-in-Capital Pfd Stock	Note A		0
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	0
7.	Average Cost Rate		L.1 / L.6	0.00%

Note A: Workpaper -- WP-12b.

Note B: Preferred stock outstanding excludes pledged and Reacquired (Treasury) preferred stock.

B-13b
COMMON EQUITY
12 Months Ending 12/31/2011 (actuals)

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	2,936,414,454
	<u>Less:</u>		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, col.b+c+d	0
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, col.e	1,610,810
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, col.f	(58,543,154)
5.	Total Balance of Common Equity	L.1-2-3-4	2,993,346,798

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2011 (actuals)

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	28,533,129		28,533,129
2. Lignite Handling	501.xx	0		0
3. Sale of Fly Ash (Revenue & Expense)	501.xx	(79,229)		(79,229)
4. Rents	507	0		
5. Hydro O & M Expenses	535-545	0		
6. Other Production Expenses	557	10,735,312	10,735,312	
7. System Control of Load Dispatching	Note C	13,862,268	13,862,268	
8. Other Steam Expenses	Note A	183,405,125	96,880,629	86,524,496
9. Combustion Turbine	Note A	0		0
10. Nuclear Power Expense-Other	Note A	0		
11. Purchased Power	555	1,183,049,516	453,327,093	729,722,423
12. Total Production Expense Excluding Fuel Used In Electric Generation	Sum L.1-L. 11	1,419,506,121	574,805,302	844,700,819
13. A & G Expense P.10, L.17		63,439,203	41,835,168	21,604,035
14. Generator Step Up related O&M	Note B	178,051	178,051	0
15. Total O & M		1,483,123,375	616,818,521	866,304,854

NOTE A: Amounts recorded in O&M Expense Accounts classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8 and 575.7

Line No.	Description	FERC Account No.	Energy Related	Demand Related
1	POWER PRODUCTION EXPENSES			
2	Steam Power Generation			
3	Operation supervision and engineering	500	-	xx
4	Fuel	501	xx	-
5	Steam expenses	502	-	xx
6	Steam from other sources	503	xx	-
7	Steam transferred-Cr.	504	xx	-
8	Electric expenses	505	-	xx
9	Miscellaneous steam power expenses	506	-	xx
10	Rents	507	-	xx
11	Allowances	509	xx	-
12	Maintenance supervision and engineering	510	xx	-
13	Maintenance of structures	511	-	xx
14	Maintenance of boiler plant	512	xx	-
15	Maintenance of electric plant	513	xx	-
16	Maintenance of miscellaneous steam plant	514	-	xx
17	Total steam power generation expenses			
18	Nuclear Power			
19	Operation supervision and engineering	517		xx
20	Coolants and Water	519		xx
21	Steam Expenses	520		xx
22	Steam from other sources	521		xx
23	Less: ; Steam Transferred	522		xx
24	Electric Expenses	523		xx
25	Miscellaneous Nuclear Power Expense	524		xx
26	Rents	525		xx
27	Maintenance supervision and engineering	528	xx	
28	Maintenance of structures	529		xx
29	Maintenance of Reactor Plant Equip	530	xx	
30	Maintenance of electric plant	531	xx	
31	Maintenance of Misc Nuclear Plant	532	xx	
32	Total power production expenses Nuclear			
33	Hydraulic Power Generation			
34	Operation supervision and engineering	535	-	xx
35	Water for power	536	-	xx
36	Hydraulic expenses	537	-	xx
37	Electric expenses	538	-	xx
38	Misc. hydraulic power generation expenses	539	-	xx
39	Rents	540	-	xx
40	Maintenance supervision and engineering	541	-	xx
41	Maintenance of structures	542	-	xx
42	Maintenance of reservoirs, dams and waterways	543	-	xx
43	Maintenance of electric plant	544	xx	-
44	Maintenance of miscellaneous hydraulic plant	545	-	xx
45	Total hydraulic power generation expenses			
46	Other Power Generation			
47	Operation supervision and engineering	546	-	xx
48	Fuel	547	xx	-
49	Generation expenses	548	-	xx
50	Miscellaneous other power generation expenses	549	-	xx
51	Rents	550	-	xx
52	Maintenance supervision and engineering	551	-	xx
53	Maintenance of structures	552	-	xx
54	Maintenance of generation and electric plant	553	-	xx
55	Maintenance of misc. other power generation plant	554	-	xx

56	Total other power generation expenses			
57	Other Power Supply Expenses			
58	Purchased power	555	xx	xx
59	System control and load dispatching	556	-	xx
60	Other expenses	557	-	xx
61	Station equipment operation expense (Note A)	562	-	xx
62	Station equipment maintenance expense (Note A)	570	-	xx

Note A: Restricted to expenses related to Generator Step-up Transformers and Other Generator related expenses.
See Note D, Page 6

PRODUCTION-RELATED DEPRECIATION EXPENSE
12 Months Ending 12/31/2011 (actuals)

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
1.	Steam	107,522,154	107,522,154	0
2.	Nuclear	0	0	0
3.	Hydro	3,278,807	3,278,807	0
4.	Conventional	0	0	0
5.	Pump Storage	0	0	0
6.	Other Production	0	0	0
7.	Int. Comb.	0	0	0
8.	Other	3,149,573	3,149,573	0
9.	Production Related General & Intangible Plant	9,771,546	6,223,471	3,548,075
10.	Generator Step Up Related Depreciation (Note A)	488,995	488,995	0
11.	Total Production	124,211,076	120,663,000	3,548,075

Note: Lines 1 through 8 will be Depreciation Expense reported on P.336 of the FF1 excluding the amortization of acquisition adjustments - Workpapers WP -- 6d.

Line 9 will be total General & Intangible Plant (from P.336 of the FF1, adjusted for amortization adjustments) times ratio of Production Related General Plant to total General Plant computed on P.7, L.33, Col.(3)

Depreciation expense excludes amounts associated with ARO.

Note A: Line 10, see P.3, L.5

PRODUCTION RELATED
TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/2011 (actuals)

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT	%	Amount
			(1)		(3)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	7,791,618	Note B	4,272,804
2	Property Related	Note A	47,956,035	Note C	24,970,721
3	Other	Note A	16,061,710	Note C	8,363,337
4	Production	Note A	20,686,812		20,686,812
5	Gross Receipts / Distribution Related	Note A	13,530,158	Note D	0
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	106,026,333		58,293,674

Note A: Workpapers -- WP8c.

Note B: Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services shown on Worksheets WP-9a and WP-9b.

	Amount	%
(1) Total W & S (excl. A & G)	132,000,539	100.00%
(2) Production W & S	72,387,071	54.84%

Note C: Allocated on the basis of Gross Plant Investment from Page 6, Ln.7

Note D: Not allocated to wholesale

PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2011 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.18	243,689,660	236,655,806	7,033,854
2.	Effective Income Tax Rate	P.19, L.2	39.2471%	39.2471%	39.2471%
3.	Income Tax Calculated	L.1 x L.2	95,641,212	92,880,626	2,760,586
4.	ITC Adjustment	P.19, L.13	(605,824)	(599,067)	(6,757)
5.	Income Tax	L.3 + L.4	95,035,388	92,281,559	2,753,829

Note A: Classification based on Production Plant classification of P.19, L.20 and L.21.

COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/2011 (actuals)

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.56%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.25%
3.	where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p as shown below.		
4.	GRCF=1 / (1 - T)		1.6544
5.	Federal Income Tax Rate	FIT	35.0000%
6.	State Income Tax Rate (Composite)	SIT	7.0100%
7.	Percent of FIT deductible for state purposes	Note A	0.0000%
8.	Weighted Cost of Long Term Debt	WCLTD	3.089%
9.	Weighted Average Cost of Capital	WACC	7.716%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	(703,248)
11.	Gross Plant Allocation Factor	L.19	52.070%
12.	Production Plant Related ITC Amortization	L. 10 X L. 11	(366,181)
13.	ITC Adjustment	L.12 x L.4	(605,824)
14.	<u>Gross Plant Allocator</u>		Total
15.	Gross Plant	P.6, L.6, Col.2	10,196,284,012
16.	Production Plant Gross	P.6, L.5, Col.2	5,309,207,934
17.	Demand Related Production Plant	P.6, L.5, Col.3	5,249,989,715
18.	Energy Related Production Plant	P.6, L.5, Col.4	59,218,219
19.	Production Plant Gross Plant Allocator	L.16 / L.15	52.070%
20.	Production Plant - Demand Related	L.17 / L.16	98.885%
21.	Production Plant - Energy Related	L.18 / L.16	1.115%

Note A: Percent deductible for state purposes provided from Company's books and records.

Attachment D

Workpapers
with Additional Detail to the
Form 1 for the Formula Inputs

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 1 - Production System Peak Demand
For the Year Ended December 31, 2011

Month	Day	(EDT) Hour	Demand (MW)	Source [1]
July	22	1500	6,179.0	CBR
July	21	1700	6,133.0	
July	20	1700	6,028.0	
July	19	1700	5,499.0	
June	8	1700	5,789.0	
Average Peak			5,925.6	
Average Production System Peak Demand			5,925.6	

Company's average five CP demands at time of PJM system peak.

Notes:
[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 2 - Production Revenue Credits
For the Year Ended December 31, 2011

	Production			
	Total	Demand	Energy	Source [1]
	0	0	0	
Total	0	0	0	

Notes:

[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 3

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Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 4

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Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5a - Materials and Supplies
Balances as of December 31, 2011

Period	1540001 M&S Regular	1540004 M&S Exempt Material	1540006 Lime and Limestone	1540012 Urea Charge	1540013 Transportation Inventory	1540022 M&S Lime & Limestone Intrasit	1540023 M&S Urea	1540024 M&S Proj Spares	M&S Total	Source[1]
Dec-11	76,471,153	420,072	2,397,164	1,155,503	586,755	90,669	9,361,253	107,583	90,590,152	110.48.c
								Total	90,590,152	

Period	158 Allowances	Source[1]
Dec-11	26,614,549	110.52.c

Functionalization of Materials & Supplies

M&S December 2011[2]		
Production	63,224,362	69.79%
Transmission	12,666,173	13.98%
Distribution	14,699,618	16.23%
	90,590,153	100.00%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Power Company
Capacity Cost of Service Formula Rate
Workpaper 5b - Fuel Inventory
For the Year Ended December 31, 2011

Period	1510001 Fuel Stock Coal	1510002 Fuel Stock Oil	1510003 Fuel Stock Gas	1510004 Fuel Stock Coal Trans	1510019 Fuel Stock Prepays	1510020 Fuel Stock In Transit	Fuel Stock Total	Source [1]
Dec-11	124,871,789	8,045,570	385,391	-	5,364	5,358,644	138,666,758	110.45.c

Total 138,666,758

Period	1520000 Fuel Stock Undistributed	Source [1]
Dec-11	5,264,278	110.46.c

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5c - Prepayments
For the Year Ended December 31, 2011

Period	1650001 Prepayments Insurance	1650004 Prepayments Interest	1650005 Prepayments Employee Benefits	1650006 Prepayments Other	1650009 Prepayments Carrying Cost	1650010 Prepayments Pension Benefits	1650021/1650023 Prepayments Ins. & Lease	1650014 Prepayments FAS 158 Contra Asset	165000211 Prepayments Taxes	Prepayments Total	Source [1]
Dec-11	1,935,794	27,220	-	23,404	49,321	195,215,893	1,549,536	(195,215,893)	1,637,001	5,222,276	111.57.c

Period	Exclude Rate Base [2]	Non Labor Related [2]	Labor Related [2]
Dec-11	(195,215,893)	5,222,276	195,215,893

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.
1650001 - This account shall include amounts representing prepayments of insurance.
1650004 - This account shall include amounts representing prepayments of interest.
1650005 - This account shall include amounts representing prepayments of employee benefits.
1650006 - This account shall include amounts representing prepayments of other items not listed.
1650009 - This account is used for factoring the AEP-East electric accounts receivable.
1650010 - This account shall include amounts representing prepayments of pension benefits.
1650021 - This account shall include amounts representing prepayments of insurance with EIS (Energy Insurance Services).
1650023 - Track balance of prepaid lease expense for agreements that qualify as a lease under company policy and are not tracked in PowerPlant Lease Accounting system will use this account.
1650014 - This account is used to track the long term portion of the FAS 158 PBO liability (Projected Benefit Obligation) for the Qualified Pension Plan when the net plan is still prepaid. This account offsets account 1650010.
165000211 - This account shall include amounts representing prepayments of taxes.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6a - Plant in Service
For the Year Ended December 31, 2011

Line	Month	Production Total Amount	Production Total Source [1]	Production ARO Amount	Production ARO Source [1]	Excluding ARO
1	Dec-11	5,182,826,934	205.46.g	67,928,373	205.15,24,34.g	5,114,898,561
2	Total					5,114,898,561

Line	Month	Transmission Total Amount	Transmission Total Source [1]	Transmission ARO Amount	Transmission ARO Source [1]	Excluding ARO
3	Dec-11	1,942,021,775	207.58.g	-	207.57.g	1,942,021,775
4	Total					1,942,021,775

Line	Month	Distribution Total Amount	Distribution Total Source [1]	Distribution ARO Amount	Distribution ARO Source [1]	Excluding ARO
5	Dec-11	2,841,967,051	207.75.g	3,069	207.74.g	2,841,963,982
6	Total					2,841,963,982

Line	Month	General Total Amount	General Total Source [1]	General ARO Amount	General ARO Source [1]	Excluding ARO
7	Dec-11	188,962,248	207.99.g	811,747	207.98.g	188,150,501
8	Total					188,150,501

Line	Month	Intangible Total Amount	Intangible Total Source [1]	Intangible ARO Amount	Intangible ARO Source [1]	Excluding ARO
9	Dec-11	109,249,193	205.5.g	-	CBR	109,249,193
10	Total					109,249,193

11	12 Months December 31, 2011 Plant In Service (excluding ARO)	10,196,284,012

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6b - Accumulated Depreciation
For the Year Ending December 31, 2011

RESERVE ACCT[2]		RESERVE AMOUNT		PRODUCTION		TRANSMISSION		DISTRIBUTION		GENERAL
1080005	$	(9,917,680.76)		(4,842,013.85)		(2,603,579.46)		(2,285,166.69)		(186,920.76)
1080001 ARO	$	26,302,626.74		26,034,076.48				1,447.88		267,102.38
1080001/1080011	$	3,399,450,989.07		1,857,757,736.98		610,184,069.34		868,761,791.54		62,747,391.21
1110001	$	82,263,488.66		-						82,263,488.66
10800013	$	-		-						-
	$	3,498,099,423.71	$	1,878,949,799.61	$	607,580,489.88	$	866,478,072.73	$	145,091,061.49
APCo Exc. ARO [3]		3,471,796,796.97		1,852,915,723.13		607,580,489.88		866,476,624.85		144,823,959.11
FERC Form 1 pg. 219	$	3,415,835,935		1,878,949,799		607,580,490		866,478,073		62,827,573
FERC Form 1 pg. 200	$	82,263,489								
Total Check	$	3,498,099,424								

Note: Data excludes Asset Retirement Obligations.

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the beginning and ending total balances.
[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6c - General Plant and Intangible Plant
For the Year Ended December 31, 2011

Description	Account	31-Dec-11
Intangible Plant (FF1, 205.2-5 g)		
Organization	301	133,394
Franchises and Consents	302	8,908,849
Miscellaneous Intangible Plant	303	100,206,950
TOTAL INTANGIBLE PLANT		109,249,193
Land	389	14,937,188
Structures	390	107,343,774
Office Equipment	391	6,233,701
Transportation	392	445
Stores Equipment	393	1,222,779
Tools, Shop, Garage, Etc.	394	20,324,479
Laboratory Equipment	395	2,723,359
Power Operated Equipment	396	821
Communications Equipment	397	30,689,756
Miscellaneous Equipment	398	6,199,872
Other Tangible Property	399	(1,525,673)
TOTAL GENERAL PLANT		188,150,501
General Plant (FF1 207.86-97 g)		
Total General and Intangible Exc. ARO		297,399,694
Total General and Intangible	205.5.g, 207.99.g	298,211,441

Note: Total includes Intangible Plant.
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6d - Depreciation Expense
For the Year Ended December 31, 2011

Description	Amount	Source
Steam Production	107,522,154	FF1, 336, 2, b & d
Hydraulic Production	3,278,807	FF1, 336, 4, 5 b
Other Production Plant	3,149,573	FF1, 336, 6 b
Transmission	30,417,733	FF1, 336, 7, b
Distribution	89,436,440	FF1, 336, 8, b
General	2,637,864	FF1, 336, 10, b & d
Intangible Plant	15,180,917	FF1, 336, 1, d
Sub-Total	251,623,488	
ARO Dep Exp	12,340,608	FF1, 336, 12, c
Total Depr Expense	263,964,096	FF1, 336, 12, f

Appalachian Power Power Company
Capacity Cost of Service Formula Rate
Workpaper 7

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APPALACHIAN POWER COMPANY
SPECIFIED DEFERRED CREDITS
PERIOD ENDED DECEMBER 31, 2011
Workpaper 8a

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	APPLICABLE/NON-UTILI	FUNCTIONALIZATION 12/31/11		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-11	BALANCE AS OF 12-31-11	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 281:					
1	TX AMORT POLLUTION CONT EQPT	158,523,703		158,523,703	0	0
2		0		0	0	0
3		0		0	0	0
4				0	0	0
5	NON-UTILITY DEFERRED FIT	0	0			
6	SFAS 109 FLOW-THRU 281.3	0	0			
7	SFAS 109 EXCESS DFIT 281.4	0	0			
8						
9	TOTAL ACCOUNT 281	158,523,703	0	158,523,703	0	0
10	FF 1, pg. 273, Ln. 8					
11						
12	ACCOUNT 282:					
13						
14	BOOK VS. TAX DEPRECIATION	852,581,429		245,281,670	244,313,460	362,986,299
15	FERC ORDER 144 CATCH UP	105,851		0	39,544	66,307
16	CAPD INTEREST-SECTION 481(a)-CHANGE IN	2,646,108		828,121	1,116,879	701,109
17	RELOCATION CST-SECTION 481(a)-CHANGE II	495,493		0	0	495,493
18	PJM INTEGRATION-SEC 481(a)-INTANG-DFD L	327,560		0	327,560	0
19	R & D DEDUCTION - SECTION 174	6,750,937		6,414,213	0	336,724
20	BK PLANT IN SERVICE - SFAS 143 - ARO	11,717,407		11,253,354	(200)	464,253
21	MNTR CARBON CAPTURE - SFAS 143 - ARO	4,452,527		4,452,527	0	0
22	DFIT GENERATION PLANT	32,712,442		32,712,442	0	0
23	GAIN/LOSS ON ACRS/MACRS PROPERTY	69,994,536		17,207,446	7,441,274	45,345,816
24	GAIN/LOSS ON ACRS/MACRS BK/TX UNIT PRC	(9,680,038)		(9,680,038)	0	0
25	ABFUDC	1,405,706		1,391,538	5,292	8,876
26	ABFUDC - TRANSMISSION	1,201,782		0	1,201,782	0
27	ABFUDC - GENERAL	25,921		0	9,408	16,513
28	ABFUDC - DISTRIBUTION	2,741		0	0	2,741
29	TXS CAPD	72,891		0	27,230	45,661
30	PENS CAPD	14,596		0	5,452	9,144
31	SEC 481 PENS/OPEB ADJUSTMENT	(38,011)		(52,646)	5,124	9,510
32	SAV PLAN CAPD	20,051		0	7,491	12,560
33	PERCENT REPAIR ALLOWANCE	24,057,018		15,405,992	2,905,831	5,745,195
34	BOOK/TAX UNIT OF PROPERTY ADJ	55,035,440		55,035,440	0	0
35	BK/TAX UNIT OF PROPERTY ADJ-SEC 481 AD.	98,160,350		98,160,350	0	0
36	CAPITALIZED RELOCATION COSTS	2,139,959		0	286,110	1,853,848
37	EXTRAORDINARY LOSS ON DISP OF PROP	78,817		0	0	78,817
38	DEFD TAX GAIN - FIBER OPTIC LINE	1,923		0	1,923	0
39	AMORT PERPETUAL TERM ELECT PLT	137		137	0	0
40	CAPITALIZED LEASES - A/C 1011 ASSETS	253,968		51,787	17,010	185,171
41	GAIN ON DEFERRED DEBT	135,710		0	50,699	85,011
42	REMOVAL COSTS	2,294,593		2,294,593	0	0
43	REMOVAL COSTS - ARO-MTNR CARBON CAP	(64,317)		(64,317)	0	0
44	REMOVAL COSTS REV - SFAS 143 - ARO	(798,376)		(798,376)	0	0
45	TAX WRITE OFF MINE DEVEL COSTS	(316,319)		(316,319)	0	0
46	BK DEPLETION -- NUEAST	312,822		312,822	0	0
47	2007 IRS AUDIT ADJUSTMENTS - A/C 282	(1,661,681)		(1,661,681)	0	0
48	NON-UTILITY DEFERRED FIT	0	0			
49	SFAS 109 FLOW-THRU 282.3	177,249,764	(177,249,764)			
50	SFAS 109 EXCESS DFIT 282.4	(2,317,278)	2,317,278			
51						
52	**TOTAL ACOUNT 282**	1,329,372,460	(174,932,486)	478,229,055	257,761,869	418,449,050
53	***FF1, pg. 275, Ln. 5***					
	Labor Related			(52,646)	372,857	76,875
54	**Energy Related**			(3,497)	0	0
	ARO			14,843,189	(200)	464,253
	Demand Related			463,442,009	257,389,212	417,907,922
	Excluded			675,746,866		
55	ACCOUNT 283:					
56						
57	SW - UNDER RECOVERY FUEL COST	122,103,306		122,103,306	0	0
58	SV - UNDER RECOVERY FUEL COST	14,386,634		14,386,634	0	0
59	WV -ENEC UNDER RECOVERY BANK	110,315		110,315	0	0
60	DEFD EQUITY CARRY CHGS - WV-ENEC	(2,450,304)		(2,450,304)	0	0
61	WV UNRECOV FUEL POOL CAPACITY IMPACT	(3,013,103)		(3,013,103)	0	0
62	PROPERTY TAX - NEW METHOD - BOOK	4,354,053		131,376	1,246,190	2,976,488
63	MTM BK GAIN - A/L - TAX DEFL	16,886,843		16,886,843	0	0
64	MARK & SPREAD-DEFL-283-A/L	213,026		213,026	0	0
65	ACCRUED BK PENSION EXPENSE	59,784,587		25,517,432	2,823,577	31,443,578
66	ACCRUED BK PENSION COSTS - SFAS 158	(106,870,113)		(42,243,811)	(6,925,762)	(57,700,540)
67	DEFD RTO EXPS & CARRYING CHARGES	1,592,464		0	1,592,464	0
68	DEFD ENVIRON COMP COSTS & CARRYING C	19,411,774		19,411,774	0	0
69	DEFD SYS RELIABILITY COSTS & CARRYING (	635,174		0	122,536	512,639
70	DEFD EQUITY CARRY CHRGS-RELIABILITY C/	(120,837)		0	(59,853)	(60,984)
71	DEFD STORM DAMAGE	14,542,044		0	0	14,542,044
72	RATE CASE DEFD CHGS	(0)		(0)	(0)	0
73	BOOK > TAX BASIS - EMA - A/C 283	17,554,090		17,554,090	0	0
74	DEFD TX GAIN-INTERCO SALE-EMA	(61,618)		(61,618)	0	0
75	DEFD TAX GAIN - EPA AUCTION	0		0	0	0
76	BK DEFL - MACSS COSTS	1,218,390		0	0	1,218,390
77	TRANSITION REGULATORY ASSETS	(1)		0	0	(1)
78	REG ASSET - SFAS 143 - ARO	3,683,424		3,683,424	0	0
79	REG ASSET - SFAS 158 - PENSIONS	106,870,113		42,243,811	6,925,762	57,700,540
80	REG ASSET - SFAS 158 - SERP	75,233		(130)	0	75,363
81	REG ASSET - SFAS 158 - OPEB	19,867,311		8,394,826	1,360,123	10,112,362
82	REG ASSET - UNDERRECOVERY-VIRGINIA T-I	6,843,662		0	6,843,662	0
83	REG ASSET - MOUNTAINEER CARBON CAPTU	250,708		250,708	0	0
84	REG ASSET - DEFERRED RPS COSTS	1,020,129		1,020,129	0	0
85	REG ASSET - CARRYING CHARGES-WV ENEC	8,920,699		8,920,699	0	0
86	TAX DEFL - NON-DEPRECIABLES	274		274	0	0
87	REG ASSET-DEFD SEVERENCE COSTS	4,387,830		2,431,445	307,235	1,649,150
88	REG ASSET-TRANS AGREEMENT PHASE-IN-W	673,751		673,751	0	0
89	REG ASSET-DEFD VA WIND REPLACEMENT C	2,781,301		2,781,301	0	0
90	REG ASSET-NET CCS FEED STUDY COSTS	467,203		467,203	0	0
91	REG ASSET-DEFERRED VA RPS INCREM COS	2,199,468		2,199,468	0	0
92	REG ASSET-DEFERRED VA WIND NON-INCRE	9,565,935		9,565,935	0	0
93	REG ASSET-DEFD VA SOFTWARE LICENSING	323,229		122,827	0	200,402
94	BOOK LEASES CAPITALIZED FOR TAX	3,249,165		2,699,691	82,212	467,261
95	CAPITALIZED SOFTWARE COSTS - BOOK	9,218,899		4,375,962	1,374,943	3,467,994
96	LOSS ON REACQUIRED DEBT	4,757,345		2,446,354	784,842	1,526,149
97	DEFD SFAS 106 BOOK COSTS	5,281		0	733	4,548
98	REG ASSET - ACCRUED SFAS 112	7,925,608		3,664,176	792,533	3,468,898
99	STATE NOL CURRENT BENEFIT	20,817,601		20,817,601	0	0
100	NON-UTILITY DEFERRED FIT	(3,296,424)	3,296,424			
101	SFAS 109 FLOW-THRU 283.3	184,636,493	(184,636,493)			
102	SFAS 109 EXCESS DFIT 283.4	0	0			
103	ADIT FED - HEDGE-INTEREST RATE 2830015	5,620,654	(5,620,654)			
104	ADIT FED - HEDGE-FOREIGN EXC 2830016	57,113	(57,113)			
105	SFAS 133 ADIT FED - SFAS 133 NONAFFIL 283	150,925	(150,925)			
106						
107		561,349,654	(187,168,762)	285,305,416	17,271,195	71,604,281
108						
109						
110	DEFD STATE INCOME TAXES	59,488,247		37,441,831	9,327,000	12,719,416
111	SFAS 109 - DEFD STATE INCOME TAXES	237,853,069	(237,853,069)			
112						
113	TOTAL ACCOUNT 283	858,690,970	(425,021,831)	322,747,247	26,598,195	84,323,697
114						
	FF1, pg. 277, Ln. 9					
	Labor Related			44,506,538	6,659,143	50,422,296
	Energy Related			193,229,825	0	0
	ARO			3,683,424	0	0
	Demand Related			81,327,460	19,939,052	33,901,401
115	**Excluded**			110,921,893		
116	JURISDICTIONAL AMOUNTS FUNCTIONALIZED					

APPALACHIAN POWER COMPANY
SPECIFIED DEFERRED CREDITS
APPALACHIAN POWER COMPANY
SPECIFIED DEFERRED CREDITS
PERIOD ENDED DECEMBER 31, 2011
Workpaper 8a

117						
118	TOTAL COMPANY AMOUNTS FUNCTIONALIZED					
119						
120	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT					
121						
122	NOTE: POST 1970 ACCUMULATED DEFERRED					
123	INV TAX CRED. (JDITC) IN A/C 255					
124	SEC ALLOC - ITC - 46F1 - 10%	3,230,614		1,451,542	915,869	863,203
125	HYDRO CREDIT - ITC - 46F1	435,000		435,000	0	0
126						
127	TOTAL ACCOUNT 255	3,665,614	0	1,886,542	915,869	863,203
	ITC Balance Included in Ratebase	3,665,614		1,886,542	915,869	863,203

APPALACHIAN POWER COMPANY
ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190
PERIOD ENDED DECEMBER 31, 2011
Workpaper 8ai

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	\PPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/11		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-11	BALANCE AS OF 12-31-11	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 190:					
1	NOL & TAX CREDIT C/F - DEF TAX ASSET	72,066,659		60,052,234	828,099	11,186,326
2	BOOK VS. TAX DEPRECIATION	20,489		0	20,489	0
3	INT EXP CAPITALIZED FOR TAX	74,803,166		57,481,106	12,431,897	4,890,162
4	CIAC-BOOK RECEIPTS	(670,845)		0	0	(670,845)
5	CIAC-BOOK RECEIPTS - DISTR - SV	7,340,573		0	259,495	7,081,079
6	CIAC-BOOK RECEIPTS - TRANS	781,204		0	781,204	0
7	CIAC-BOOK RECEIPTS - DISTR - SW	2,893,022		0	31,559	2,861,463
8	CIAC - MUSSER ACQUISITION	13,387		0	0	13,387
9	SW - OVER RECOVERY FUEL COSTS	0		0	0	0
10	SV - OVER RECOVERY FUEL COSTS	0		0	0	0
11	PROVS POSS REV REFDS	2,605,919		8,201	2,597,718	(0)
12	SALE/LEASE - GRUNDY	641		0	0	641
13	MTM BK LOSS - A/L - TAX DEFL	0		0	0	0
14	MARK & SPREAD-DEFL-190-A/L	309,743		309,743	0	0
15	PROV WORKERS COMP	140,107		84,092	6,271	49,743
16	SUPPLEMENTAL EXECUTIVE RETIRE PLAN	(94,709)		139	0	(94,848)
17	ACCD SUP EXEC RETIR PLAN COSTS-SFAS	75,233		(130)	0	75,363
18	ACCRD BK SUP. SAVINGS PLAN EXP	158,660		158,660	(0)	(0)
19	EMPLOYER SAVINGS PLAN MATCH	(0)		0	0	(0)
20	ACCRUED PSI PLAN EXP	161,656		85,582	0	76,075
21	BK PROV UNCOLL ACCTS	1,508,567		(369,869)	916,563	961,872
22	PROV - TRADING CREDIT RISK - A/L	618,212		618,212	0	0
23	PROV - FAS 157 - A/L	(87,288)		(87,288)	0	0
24	ACCRD COMPANYWIDE INCENTV PLAN	1,811,176		1,309,276	28,812	473,088
25	ACCRUED ENVIRONMENTAL LIAB-CURREN	12,950		0	0	12,950
26	ACCRUED BOOK VACATION PAY	3,425,580		1,504,974	247,786	1,672,820
27	ACCRUED MGMT INCENTIVE BONUS	166,885		166,885	0	0
28	ACCRUED BK SEVERANCE BENEFITS	32,026		0	0	32,026
29	ACCRUED INTEREST EXPENSE - STATE	(1)		(0)	(0)	(0)
30	ACCRUED INTEREST-LONG-TERM - FIN 48	(643,939)		(658,313)	6,700	7,674
31	ACCRUED INTEREST-SHORT-TERM - FIN 48	83,457		63,061	2,250	18,147
32	ACCRUED STATE INCOME TAX EXPENSE	49,457		0	(240,349)	289,806
33	BK DFL RAIL TRANS REV/EXP	(177,579)		(177,579)	0	0
34	ACCRUED RTO CARRYING CHARGES	2		0	2	0
35	DEFD EQUITY CARRYING CHRGS-ENVIRON	(0)		(0)	0	0
36	FEDERAL MITIGATION PROGRAMS	2,356,384		2,356,384	0	0
37	STATE MITIGATION PROGRAMS	993,364		993,364	0	0
38	DEFD REV-EPRI/MNTR CARBON CAPTURE-(	288,628		288,628	0	0
39	DEFD REV-EPRI/MNTR CARBON CAPTURE-I	1,053,218		1,053,218	0	0
40	DEFD BK CONTRACT REVENUE	616,213		0	616,213	0
41	DEFD STORM DAMAGES	0		0	0	0
42	FK BK WRITE-OFF BLUE RIDGE EASE	13,422		13,422	0	0
43	FR BK WRITE-OFF BLUE RIDGE EASE	15,660		15,660	0	0
44	SV BK WRITE-OFF BLUE RIDGE EASE	99,325		99,325	0	0
45	CV BK WRITE-OFF BLUE RIDGE EASE	6,218		6,218	0	0
46	DEFD TX LOSS-INTERCO SALE-EMA	368,904		368,904	0	0
47	DEFD BOOK GAIN - EPA AUCTION	0		0	0	0
48	ADVANCE RENTAL INC (CUR MO)	477,875		0	0	477,875
49	DEFERRED BOOK RENTS	708,978		0	708,978	0
50	REG - LIAB - UNREAL MTM GAIN - DEFL	5,458,851		5,458,851	0	0
51	REG ASSET/LIAB-CENTURY ALUMINUM	(4,483,739)		0	0	(4,483,739)
52	CAPITALIZED SOFTWARE COSTS - TAX	2,898		1,867	5	1,026
53	CAPITALIZED ADVERTISING EXP - TAX	1,562,326		0	1,562,326	0
54	ACCRD SFAS 106 PST RETIRE EXP	14,072,158		5,938,390	917,463	7,216,305
55	SFAS 106 PST RETIRE EXP - NON-DEDUCT (	9,134,490		4,405,243	468,396	4,260,851
56	ACCRD OPEB COSTS - SFAS 158	19,867,311		8,394,826	1,360,122	10,112,362
57	ACCRD SFAS 112 EMPLOY BEN	7,953,480		3,692,048	792,533	3,468,898
58	ACCRD BOOK ARO EXPENSE-SFAS 143	25,558,504		25,220,161	6,014	332,329
59	SFAS 106 - MEDICARE SUBSIDY-NORM-(PP/	(6,159,368)		(2,625,240)	(373,730)	(3,160,399)
60	ACCRD BK ARO EXP-MTNR CARBON CAPTU	14,606,137		14,606,137	0	0
61	ACCRUED BK REMOVAL COST - ACRS	68,062,912		6,965,666	21,899,997	39,197,249
62	FIN 48 - DEFD STATE INCOME TAXES	(247,087)		(199,132)	(11,405)	(36,550)
63	DEFD STATE INCOME TAXES	26,665,311		18,949,066	3,264,450	4,451,796
64	ACCRD SIT/FRANCHISE TAX RESERVE	(783,321)		(593,236)	0	(190,085)
65	ACCRUED SALES & USE TAX RESERVE	190,085		0	0	190,085
66	ACCRD SIT TX RES-LNG-TERM-FIN 48	(780,607)		(773,580)	(137)	(6,889)
67	ACCRD SIT TX RES-SHORT-TERM-FIN 48	199,213		157,285	10,169	31,759
68	SFAS 109 - DEFD SIT LIABILITY	0		0	0	0
69	1985-1987 IRS AUDIT SETTLEMENT	0		0	0	0
70	1991-1996 IRS AUDIT SETTLEMENT	89,808		0	0	89,808
71	1997-2003 IRS AUDIT SETTLEMENT	1,557,472		0	0	1,557,472
72	2007 IRS AUDIT ADJUSTMENTS - A/C 190	670,845		0	0	670,845
73	IRS CAPITALIZATION ADJUSTMENT	2,777,305		2,801,716	0	(24,412)
74	AMT CREDIT DEFERRED	15,842,087		15,166,563	521,584	153,940
75						

APPALACHIAN POWER COMPANY
APPALACHIAN POWER COMPANY
ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190
PERIOD ENDED DECEMBER 31, 2011
Workpaper 8ai

76	NON-UTILITY DEFERRED FIT	9,286,802	(9,286,802)			
77	SFAS 109 FLOW-THRU 190.3	84,149,405	(84,149,405)			
78	SFAS 109 EXCESS DFIT 190.4	1,247,765	(1,247,765)			
79	SFAS 133 ADIT FED - SFAS NONAFFIL 19000	855,471	(855,471)			
80	ADIT FED - PENSION OCI NAF 1900009	20,678,221	(20,678,221)			
81	ADIT FED - HEDGE-INTEREST RATE 190001	5,040,941	(5,040,941)			
82	ADIT FED - HEDGE-FOREIGN EXC 1900016	85,423	(85,423)			
83	DEFERRED SIT 1901002	73,799,755	(73,799,755)	73,799,755	0	0
84						
85	TOTAL ACCOUNT 190	571,363,451	(195,143,782)	307,110,496	49,661,475	93,247,452
	FF1, pg. 234, Ln. 8					
	Labor Related			23,116,613	3,447,658	24,183,310
	Energy Related			6,490,842	616,213	0
	ARO			39,826,298	6,014	332,329
	Demand Related			237,676,743	45,591,590	68,731,814
	Excluded			142,570,585		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8b - Effective Income Tax Rate
For the Year Ended December 31, 2011

Effective Income Tax Rate

T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.56%
EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p are as shown below.		39.25%
GRCF=1 / (1 - T)		1.6544
Amortized Investment Tax Credit (enter negative)	FF1 P.114, Ln.19, Col.c	(703,248)

FIT	35.0000%	
SIT	7.0100%	State Income Tax Rate (Composite).
p	0.0000%	Percent of FIT deductible for state purposes (Note 2).
WCLTD	3.09%	
WACC	7.72%	

Development of Composite State Income Tax Rates for 2011 (Note 1)

Tennessee Income Tax	6.5000%	
Apportionment Factor - Note 2	1.8550%	
Effective State Income Tax Rate		0.12000%
Michigan Business Income Tax	6.0400%	
Apportionment Factor - Note 2	0.5100%	
Effective State Income Tax Rate		0.03000%
Virginia Net Income Tax	6.0000%	
Apportionment Factor - Note 2	42.0700%	
Effective State Income Tax Rate		2.52000%
West Virginia Net Income	8.5000%	
Apportionment Factor - Note 2	48.7300%	
Effective State Income Tax Rate		4.14000%
Illinois Corporation Income Tax	9.5000%	
Apportionment Factor - Note 2	2.1100%	
Effective State Income Tax Rate		0.2000%
Total Effective State Income Tax Rate		7.0100%

Note 2: Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

Note 2: From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ended December 31, 2011

Payroll Related Other Taxes	7,791,618	Payroll
Property Related Other Taxes	47,956,035	Property
Direct Production Related	20,686,812	Production
Direct Distribution Related	-	Distribution
Other	16,061,710	Other
Not Allocated ((Gross Receipts, Commi	13,530,158	NA
	106,026,333	

Line No.	(A) Annual Tax Expenses by Type	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference	Basis
1	**Revenue Taxes**			
2	Gross Receipts Tax			
		12,386,942	P.263.1 ln 7 (i)	N/A
		(2,121)	P.263.1 ln 34 (i)	N/A
		1,145,337	P.263.1 ln 35 (i)	N/A
3	**Real Estate and Personal Property Taxes**			
4	Real and Personal Property - West Virginia			
		16,194,137	P.263 ln 34 (i)	Property
		16,424,566	P.263 ln 35 (i)	Property
		40	P.263 ln 37 (i)	Property
		(26,626)	P.263 ln 38 (i)	Property
		150,377	P.263 ln 39 (i)	Property
		150,006	P.263 ln 40 (i)	Property
		(2,532)	P.263.1 ln 2 (i)	Property
		(1,416)	P.263.1 ln 3 (i)	Property
5	Real and Personal Property - Virginia			
		360	P.263.2 ln 19 (i)	Property
		299,472	P.263.2 ln 20 (i)	Property
		13,615,562	P.263.2 ln 21 (i)	Property
		5,596	P.263.2 ln 23 (i)	Property
		27,362	P.263.2 ln 24 (i)	Property
		(44,836)	P.263.2 ln 25 (i)	Property
		(192,269)	P.263.2 ln 26 (i)	Property
		467,432	P.263.2 ln 27 (i)	Property
6	Real and Personal Property - Tennessee			
		9,229	P.263.3 ln 7 (i)	Property
		864,750	P.263.3 ln 8 (i)	Property
7	Real and Personal Property - Other Jurisdictions			
		13,936	P.263.1 ln 37 (i)	Property
		889	P.263.4 ln 5 (i)	Property
8	**Payroll Taxes**			
9	Federal Insurance Contribution (FICA)			
		7,528,200	P.263 ln 6 (i)	Payroll
10	Federal Unemployment Tax			

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ended December 31, 2011

		78,130	P.263 ln 9 (i)	Payroll
11	State Unemployment Insurance			
		125,236	P.263.1 ln 22 (i)	Payroll
		59,865	P.263.2 ln 34 (i)	Payroll
		187	P.263.3 ln 20 (i)	Payroll
12	**Production Taxes**			
13	State Severance Taxes			
		-		
14	**Miscellaneous Taxes**			
15	State Business & Occupation Tax			
		135,797	P.263 ln 21 (i)	Production
		20,315,008	P.263 ln 22 (i)	Production
		219,800	P.263 ln 23 (i)	Production
16	State Public Service Commission Fees			
		1,809,638	P.263 ln 26 (i)	Other
		2,834,753	P.263 ln 27 (i)	Other
17	State Franchise Taxes			
		(819,174)	P.263.1 ln 25 (i)	Other
		(14,244)	P.263.1 ln 28 (i)	Other
		126,487	P.263.1 ln 29 (i)	Other
		2,452,830	P.263.2 ln 8 (i)	Other
		9,562,000	P.263.2 ln 9 (i)	Other
		140,000	P.263.3 ln 4 (i)	Other
		60	P.263.3 ln 33 (i)	Other
18	State Lic/Registration Fee			
		1,700	P.263.2 ln 11 (i)	Other
		22	P.263.3 ln 12 (i)	Other
		115	P.263.1 ln 13 (i)	Other
19	Misc. State and Local Tax			
		520	P.263.1 ln 11 (i)	Other
		70	P.263.4 ln 23 (i)	Other
		100	P.263.3 ln 24 (i)	Other
20	Sales & Use			
		1,595	P.263 ln 30 (i)	Other
		9,767	P.263 ln 31(i)	Other
		(38,600)	P.263 ln 32(i)	Other
		(7,766)	P.263.2 ln 14 (i)	Other
		1,837	P.263.2 ln 15 (i)	Other
21	Federal Excise Tax			
		16,207	P.263 ln 14 (i)	Production
22	Michigan Single Business Tax			
		-		
23	Total Taxes by Allocable Basis	106,026,333		
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))			

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9a - Wages and Salaries
For the Year Ended December 31, 2011

	APCo[1]	AEPSC[2]	Total
Production:			
Operation	25,938,364	13,654,513	39,592,877
Maintenance	26,716,619	6,077,575	32,794,194
Total	52,654,983	19,732,088	72,387,071
Transmission:			
Operation	1,215,100	3,846,842	5,061,942
Maintenance	2,521,971	1,137,804	3,659,775
Total	3,737,071	4,984,646	8,721,717
Distribution:			
Operation	6,395,799	2,054,906	8,450,705
Maintenance	24,396,872	290,735	24,687,607
Total	30,792,671	2,345,641	33,138,312
Customer Accounts	6,618,102	9,010,150	15,628,252
Customer Service and Informational	1,709,902	415,285	2,125,187
Sales	0	0	0
Total Wages and Salaries Excluding A & G	**95,512,729**	**36,487,810**	**132,000,539**
Administrative and General			
Operation	1,015,762	36,839,002	37,854,764
Maintenance	2,100,849	88,422	2,189,271
Total	3,116,611	36,927,424	40,044,035
Total O & M Payroll	98,629,340	73,415,234	172,044,574

[1] Wages and Salaries from FERC Form Pg. 354.
[2] From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9b - Production Payroll Demand/Energy Allocation
For the Year Ended December 31, 2011

Account	Demand	Energy	Total	Source [1]
500	9,178,418		9,178,418	
501		1,189,259	1,189,259	
502	14,086,003		14,086,003	
505	1,264,293		1,264,293	
506	4,837,742		4,837,742	
510		4,318,955	4,318,955	
511	1,386,002		1,386,002	
512		14,237,708	14,237,708	
513		4,754,010	4,754,010	
514	5,646,319		5,646,319	
517	0		0	
519	0		0	
520	0		0	
523	0		0	
524	0		0	
528		-	0	
529	0		0	
530		-	0	
531		-	0	
532		-	0	
535	745,508		745,508	
536	0		0	
537	642,438		642,438	
538	116,539		116,539	
539	769,268		769,268	
541	242,566		242,566	
542	99,237		99,237	
543	200,612		200,612	
544		1,629,861	1,629,861	
545	106,370		106,370	
546	203,396		203,396	
547		78,829	78,829	
548	193,014		193,014	
549	27,289		27,289	
553	170,897		170,897	
554	1,657		1,657	
555	84,336	75,322	159,658	
556	635,607		635,607	
557	5,465,616		5,465,616	
Total	46,103,127	26,283,944	72,387,071	
Allocation Factors	0.6368972595	0.3631027405	1.0000000000	

[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Michigan Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, 2011
Note: Source of data is FERC Form 1, page 320-323, Column b.

Production

500	Operation Supv & Engineering	14,377,362
501	Fuel	727,837,686
502	Steam Expenses	45,697,606
505	Electric Expenses	1,625,112
506	Misc. Steam Power Expense	35,821,343
507	Rents	45,663
509	Allowances	(288,021)
517	Operation Supv & Engineering	0
518	Fuel	0
519	Coolants and Water	0
520	Steam Expenses	0
523	Electric Expenses	0
524	Misc. Nuclear Power Expense	0
535	Operation Supv & Engineering	1,319,015
536	Water for Power	29,991
537	Hydraulic Expenses	987,455
538	Electric Expenses	125,801
539	Miscellaneous Hydraulic Power	2,010,720
540	Rents	300,820
546	Operation Supv & Engineering	150,606
547	Fuel	1,745,302
548	Generation Expenses	245,157
549	Misc. Power Generation Expense	54,507
	Total Operation	832,086,125
510	Maintenance Supv & Engineering	5,465,596
511	Maintenance of Structures	7,310,602
512	Maintenance of Boiler Plant	61,223,435
513	Maintenance of Electric Plant	15,615,956
514	Maintenance of Misc Plant	9,970,334
528	Maintenance Supv & Engineering	0
529	Maintenance of Structures	0
530	Maintenance of Reactor Plant	0
531	Maintenance of Electric Plant	0
532	Maintenance of Misc. Nuclear Plant	0
541	Maintenance Supv & Engineering	306,769
542	Maintenance of Structures	431,662
543	Maintenance of Reservious, Dams and Waterways	1,856,624
544	Maintenance of Electric Plant	4,507,530
545	Maintenance of Miscellaneous Hydraulic Plant	883,053
551	Maintenance Supv & Engineering	197
553	Maintenance of Generating & Electric Plant	815,908
554	Maintenance of Misc. Other Power Gen. Plant	(2,406)
	Total Maintenance	108,385,260
555	Purchased Power	1,183,049,516
556	System Control	1,087,081
557	Other Expense	10,735,312
	Total Other	1,194,871,909
	Total Production	2,135,343,294

Appalachian Michigan Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, 2011
Note: Source of data is FERC Form 1, page 320-323, Column b.

Transmission		
560	Operation Supv & Engineering	2,779,303
561.1	Load Dispatch-Reliability	23,952
561.2	Load Dispatch-Monitor and Operate	3,283,510
561.3	Load Dispatch-Transmission Service	3
561.4	Scheduling, System Control	5,609,726
561.5	Reliability, Planning and Standards Dev.	452,276
561.6	Transmission Service Studies	0
561.7	Generation Interconnection Studies	0
561.8	Reliability, Planning and Standards Dev.	1,291,538
562	Station Expense	1,205,197
563	Overhead Line Expense	681,941
564	Underground Line Expense	0
565	Trans of Electricity by Others	16,296,116
566	Misc Transmission Expense	471,007
567	Rents	102,665
	Total Operation	32,197,234
568	Maintenance Supv & Engineering	632,769
569	Maintenance of Structures	104,847
569.1	Mainteneance of Computer Hardware	228,099
569.2	Maintenance of Computer Software	873,958
569.3	Maintenance of Communication Equip	645,403
570	Maintenance of Station Equip	3,180,562
571	Maintenance of OH Lines	7,550,063
572	Maintenance of UG Lines	0
573	Maintenance of Misc Trans	69,242
	Total Maintenance	13,284,943
	Total Transmission	45,482,177
Regional Market Expense		
575.7	Market Facilitation, Monitoring and Compliance	5,873,923
Distribution		
580	Operation Supv & Engineering	6,589,547
581	Load Dispatching	899,613
582	Station Expense	972,388
583	Overhead Line Expense	644,967
584	Underground Line Expense	1,300,437
585	Street Lighting	124,359
586	Meter Expenses	38,157
587	Customer Installations	1,059,626
588	Misc Distribution Expense	6,865,599
589	Rents	2,143,779
	Total Operation	20,638,472

Appalachian Michigan Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, 2011
Note: Source of data is FERC Form 1, page 320-323, Column b.

590	Maintenance Supv & Engineering	144,772
591	Maintenance of Structures	110,950
592	Maintenance of Station Equip	3,387,392
593	Maintenance of OH Lines	56,930,992
594	Maintenance of UG Lines	1,318,832
595	Maintenance of Line Trsfrs	2,129,144
596	Maintenance of Street Lights	415,879
597	Maintenance of Meters	314,001
598	Maintenance of Misc Dist Plant	4,964,658
	Total Maintenance	69,716,620
	Total Distribution	90,355,092
Customer Accounts		
901	Supervision	1,171,818
902	Meter Reading Expenses	4,076,241
903	Customer Records/Collection	28,641,441
904	Uncollectible Accounts	6,088,304
905	Misc Customer Accts Exp	146,685
	Total Customer Accounts	40,124,489
Customer Service and Informational		
907	Supervision	839,059
908	Customer Assistance	3,168,794
909	Info & Instructional Adv	10,215
910	Misc Cust Service & Info Expense	752
	Total Customer Service	4,018,820
Sales Expense		
911	Supervision	71
912	Selling Expenses	7
913	Advertising Expenses	0
916	Misc Sales Expense	0
	Total Sales Expense	78

Appalachian Michigan Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, 2011
Note: Source of data is FERC Form 1, page 320-323, Column b.

Administrative and General		
920	A & G Salaries	32,268,084
921	Office Supplies & Exp	5,165,177
922	Adm Exp Trsfr - Credit	(6,535,860)
923	Outside Services	28,646,471
924	Property Insurance	4,800,287
925	Injuries and Damages	9,360,136
926	Employee Benefits	26,385,423
926a	Less: Actual Employee Benefits (Note A)	(6,222,780)
926b	Allowed Employee Benefits (Note B)	6,222,780
926	Employee Benefits	26,385,423
927	Franchise Requirements	0
928	Regulatory Commission Exp	2,739,774
929	Duplicate Charges - Credit	(138,507)
930.1	General Advertising Expense	2,235,006
930.2	Misc General Expense	6,501,717
930.2	Company Dues and Memberships	454,691
931	Rents	1,089,443
933	Transportation	0
	Total Operation	112,971,842
935	Maintenance of Gen Plant	5,615,484
	Total Maintenance	5,615,484
	Total Administrative & General	118,587,326
	Total O & M Expenses	2,439,785,199
	Total Elec O & M Exp. - FERC Form1 pg. 323, L. 198(b)	2,439,785,199
	Difference	0

Actual Expense - Removed from Cost of Service		
Note A:	Acct 926 (0039) PBOP Gross Cost	10,806,289
	Acct 926 (0057) PBOP Medicare Part Subsidy	(4,583,509)
	PBOP Amounts in Annual Informational Filing	6,222,780
Allowable Expense		
Note B:	Acct 926 (0039) PBOP Gross Cost	10,806,289
	Acct 926 (0057) PBOP Medicare Part Subsidy	(4,583,509)
	PBOP Amounts in Annual Informational Filing	6,222,780

Note B: Changing PBOP included in the formula rate will require, as applicable, a FPA Section 205 or Section 206 filing.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 11 - Regulatory Commission Expense
For the Year Ended December 31, 2011

Regulatory Commission Expense - Acct. 928 [1]	2,739,774
Retail	1,221,710
Wholesale - FERC	1,518,064

Note: Excludes FERC annual charges and amounts related to retail.

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances
350, 46, d

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12a - Common Stock
For the Year Ending December 31, 2011

Month	Total Capital	Source(s)	Preferred Stock Issued	Preferred Stock Premium (Discount)	Preferred Stock G(L) on Reacq'd	Preferred Stock Source(s)*	Unapprop Sub Earnings	Source	Acc Oth Comp Income	Source	Common Equity Balance
	a		b	c	d		e		f		g=a-b-c-d-e-f
Dec-11	2,936,414,454	112.16.c	0	0	0	112.3.c,6.c.,7.c.	1,610,810	112.12.c.	(58,543,154)	112.15.c.	2,993,346,798

NOTE: * Includes preferred portions of capital stock (common and preferred) accounts according to Company Books and Records below.

Account	Description	Dec-11
2010001	Common Stock Issued	260,457,768
	Source [1]	*112.2.c*
2040002	PS Not Subj to Mandatory Redem	-
	Source [1]	*112.3.c*
2070000	Prem on Capital Stk	-
	Source [1]	*112.6.c*
2080000	Donations Recvd from Stckhldrs	1,571,109,974
2100000	Gain Rsle/Cancl Req Cap Stock	433
2110000	Miscellaneous Paid-In Capital	2,642,015
		1,573,752,422
	Source [1]	*112.7.c*
2151000	Appropriations of Retained Earnings	9,892,243
2160001	Unapprp Retnd Erngs-Unrstrictd	1,122,277,367
4330000	Transferred from Income	162,726,004
4370000	Div Decl-PS Not Sub to Man Red	(731,661)
4380001	Dividends Declared	(135,000,000)
4390000	Adj to Retained Earnings	(27,345)
	Retained Earnings	1,159,136,608
	Source [1]	*112.11.c*
2161001	Unap Undist Consol Sub Erng	1,578,710
2161002	Unap Undist Nonconsol Sub Erng	-
4181001 & 002	Equity in Earnings	32,100
	Unapprop Sub Earnings	1,610,810
	Source [1]	*112.12.c*
2190002	OCI-Min Pen Liab FAS 158-Affil	(19,856,320)
2190004	OCI-Min Pen Liab FAS 158-SERP	-
2190006	OCI-Min Pen Liab FAS 158-Qual	-
2190007	OCI-Min Pen Liab FAS 158-OPEB	(38,402,411)
2190010	OCI-for Commodity Hedges	(1,308,461)
2190015	Accum OCI-Hdg-CF-Int Rate	1,076,613
2190016	Accum OCI-Hdg-CF-For Exchg	(52,575)
	Acc Oth Comp Inc	(58,543,154)
	Source [1]	*112.15.c*
	Total Capital	2,936,414,454
	Common Equity Balance	2,993,346,798

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12b - Preferred Stock
For the Year Ending December 31, 2011

	Preferred Stock		Premium on Preferred		(Discount) on Preferred		Other Paid in Capital - Pfd		Total Outstanding	Preferred
	a		b		c		d		a+b-c+d	
Month	Acct 204	Source 1	Acct 207	Source 1	Acc 213	Source 1	Acc 208-211	Source 1		Dividends
Dec-11	0	112.3.c	0	112.6.c	0	112.9.c	0	112.7.c	0	731,661
Total	0		0		0		0		0	731,661

Cost of Preferred Stock = Pfd Dividends/Average Pfd Outstanding Balance = 0.00%

NOTES:
(1) All data is from the monthly Balance Sheet of the Company's Books and Records (CBR).
(2) Accounts 207-213 are capital stock accounts containing both common and preferred capital. Preferred portions of these accounts are from the CBR.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13 - Outstanding Long-Term Debt
For the Year Ending December 31, 2011

Line	Period	Advances from Associated Co	FF1 Reference	Bonds	FF1 Reference	(Reacquired Bonds)	FF1 Reference	Installment Purchase	FF1 Reference	Senior Unsecured Notes	FF1 Reference	Debntr Trust Pref Secrty Insts	FF1 Reference	Total Debt Outstanding	Reference
		2230000		2210000		2220001		2240002		2240006		2240046			
		a		b		c		d		e		f		g=a+b+c+d+e+f	
1	Dec-11	0	112.20.c.	0	112.18.c.	0	112.19.c.	0	257, col. (h)	3,734,408,392	257, col. (h)	0	257, col. (h)	3,734,408,392	FF1, 112,20,c & 112,21,c
2	Dec-11	0		0		0		0		3,734,408,392		0		3,734,408,392	

Appalachian Power Company
Interest & Amortization on Long-Term Debt
For the Year Ending December 31, 2011

Line	Description		Acct	FF1 Ref
1	Interest	IPC	4270002	16,456,438
2	Interest	Unsecured	4270006	186,220,587
3	Interest	IPC	4270202	314,554
4			(FF1, P.117,L.62)	202,991,579
5	Amort Debt Disc/ Exp		Acct 428 (FF1, P.117, L.63)	3,686,430
6	Amort Loss Reacq		Acct 428.1 (FF1, P.117, L.64)	1,113,482
7	Interest*	Assoc LT	4300001 (FF1, P.117, L.67)	-
8	Amort Debt Premium		Acct 429 (FF1, P.117, L.65)	-
9	Amort Gain Reacq		Acct 429.1 (FF1, P.117, L.66)	-
10	Cost of Long Term Debt			207,791,491
11	Reconcilation to FF1, 257, 33, i			
12	Interest on LT Debt		Line 4	202,991,579
13	Interest on Assoc LT Debt		Line 7	-
14	Total (FF1, 257, 33, i)			202,991,579
15	Amortization of Hedge Gain / Loss included in Acct 4270006 (subject to limit on B-13)			1,815,730

*Per Company Books and Recrods interest associated with LTD.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13a - Recoverable Hedge Gains/Losses
For the Year Ended December 31, 2011

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge Gain or Loss for 2011	Less Excludable Amounts (See NOTE on Line For the Year Ended December 31, 2011)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
1	Senior Unsecured Notes - Series I	764,169		764,169	1,974,104	Jan-05	Feb-15
2	Senior Unsecured Notes - Series K	1,336,324		1,336,324	4,565,775	Jun-05	Jun-17
3	Senior Unsecured Notes - Series M	(91,093)		(91,093)	(0)	Apr-06	Apr-11
4	Senior Unsecured Notes - Series O	96,458		96,458	60,287	Aug-07	Aug-12
5	Senior Unsecured Notes - Series L	(238,880)		(238,880)	(895,798)	Sep-05	Oct-35
6	Senior Unsecured Notes - Series H	37,068		37,068	790,884	May-03	May-33
7	Senior Unsecured Notes - Series N	(194,198)		(194,198)	(4,709,312)	Apr-06	Apr-36
8	Senior Unsecured Notes - Series Q	159,672	-	159,672	4,184,715	Mar-08	Apr-38
9	Senior Unsecured Notes - Series S	826,212	-	826,212	2,807,343	May-10	May-15
10	Senior Unsecured Notes - Series T	(880,003)		(880,003)	10,434,320	Mar-11	Mar-21
11	Total Hedge Amortization	1,815,730	-	1,815,730			

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 14 - Non-Fuel Power Production O&M Expenses
For the Year Ending December 31, 2011

Account		December	Less Carbon Capture Expense	Total
500	Demand	14,377,362		14,377,362
502	Demand	45,697,606		45,697,606
503	Energy	0		0
504 - Cr.	Energy	0		0
505	Demand	1,625,112		1,625,112
506	Demand	35,821,343	27,483,272	8,338,071
507	Demand	45,663		45,663
509	Energy	(288,021)		(288,021)
510	Energy	5,465,596		5,465,596
511	Demand	7,310,602		7,310,602
512	Energy	61,223,435		61,223,435
513	Energy	15,615,956		15,615,956
514	Demand	9,970,334		9,970,334
517	Demand	0		0
519	Demand	0		0
520	Demand	0		0
521	Demand	0		0
522 - Cr.	Demand	0		0
523	Demand	0		0
524	Demand	0		0
525	Demand	0		0
528	Energy	0		0
529	Demand	0		0
530	Energy	0		0
531	Energy	0		0
532	Energy	0		0
535	Demand	1,319,015		1,319,015
536	Demand	29,991		29,991
537	Demand	987,455		987,455
538	Demand	125,801		125,801
539	Demand	2,010,720		2,010,720
540	Demand	300,820		300,820
541	Demand	306,769		306,769
542	Demand	431,662		431,662
543	Demand	1,856,624		1,856,624
544	Energy	4,507,530		4,507,530
545	Demand	883,053		883,053
546	Demand	150,606		150,606
548	Demand	245,157		245,157
549	Demand	54,507		54,507
550	Demand	0		0
551	Demand	197		197
552	Demand	0		0
553	Demand	815,908		815,908
554	Demand	(2,406)		(2,406)
Total		210,888,397	27,483,272	183,405,125
Demand		124,363,901	27,483,272	96,880,629
Energy		86,524,496	0	86,524,496
Total		210,888,397	27,483,272	183,405,125
Demand	%			52.823%
Energy	%			47.177%
Total	%			100.000%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances
pgs. 320-323, , b

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15a

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Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15b

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Appalachian Power Company
Capactiy Cost of Service Formula Rate
Workpaper 15c - Purchased Power
For the Year Ended December 31, 2011

Month	Demand ($) [1]	Energy ($) [1]	Other Charges [2]	Total Purchased Power Expense
Dec-11	427,450,782	729,722,423	25,876,311	1,183,049,516
Total	427,450,782	729,722,423		1,183,049,516
	327, ,,j	327, , k	327,,l	327,,m

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] Excludes the deferred portion of APCo's capacity equalization payments related to environmental compliance investments FF 1, pg. 327, column (l)

Appalachian Power Company
Capactiy Cost of Service Formula Rate
Workpaper 15d - Off-System Sales
For the Year Ended December 31, 2011

Month	Demand ($) [1]	Other Charges ($) [1]	Energy ($) [1]	Total
Dec-11	23,607,274	0	554,440,668	578,047,942

Month	($) Margins [2]
Dec-11	89,708,571

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
F1, 311, h, j, i (Non-RQ)

[2] margins provided by Accounting (represents 75% of system sales margins)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 16 - GSU Plant and Accumulated Depreciation Balance
For the Year Ended December 31, 2011

	company	asset_location	gl_account	state	utility_account	month	book_cost	allocated_reserve	net_book_value
Appalac	Clinch River Generating Plant	Clinch River Generating Plant : APCo : 0770	1010001 Plant In Service	VA	35300 - Station E	12/2011	809,439.53	435,217.73	374,221.80
Appalac	John E Amos Generating Plant, AP/OP	John E. Amos Generating Plant Unit No. 3 : 02:0743 / 07:8600	1010001 Plant In Service	WV	35200 - Structure	12/2011	24,415.85	11,082.79	13,333.06
Appalac	John E Amos Generating Plant, AP/OP	John E. Amos Generating Plant Unit No. 3 : 02:0743 / 07:8600	1010001 Plant In Service	WV	35300 - Station E	12/2011	3,953,007.42	1,226,522.32	2,726,485.10
Appalac	John E Amos Generating Plant, AP/OP	John E. Amos Generating Plant Unit Nos. 1,2 : APCo : 0740	1010001 Plant In Service	WV	35200 - Structure	12/2011	61,600.00	39,269.75	22,330.25
Appalac	John E Amos Generating Plant, AP/OP	John E. Amos Generating Plant Unit Nos. 1,2 : APCo : 0740	1010001 Plant In Service	WV	35300 - Station E	12/2011	11,953,306.70	3,295,506.51	8,657,800.19
Appalac	Kanawha River Generating Plant	Kanawha River Generating Plant : APCo : 0720	1010001 Plant In Service	WV	35200 - Structure	12/2011	51,793.82	21,202.67	30,591.15
Appalac	Kanawha River Generating Plant	Kanawha River Generating Plant : APCo : 0720	1010001 Plant In Service	WV	35300 - Station E	12/2011	1,154,018.84	428,764.00	725,254.84
Appalac	Niagara Hydro Plant	Niagara Hydro Plant : APCo : 0650	1010001 Plant In Service	VA	35200 - Structure	12/2011	1,579.00	862.67	716.33
Appalac	Niagara Hydro Plant	Niagara Hydro Plant : APCo : 0650	1010001 Plant In Service	VA	35300 - Station E	12/2011	374,454.12	35,447.48	339,006.64
Appalac	Philip Sporn Generating Plant	Philip Sporn Generating Plant Units 1 - 4 : APCo : 0750 / OPCo : 7500	1010001 Plant In Service	WV	35200 - Structure	12/2011	21,114.30	10,957.06	10,157.24
Appalac	Philip Sporn Generating Plant	Philip Sporn Generating Plant Units 1 - 4 : APCo : 0750 / OPCo : 7500	1010001 Plant In Service	WV	35300 - Station E	12/2011	1,056,836.74	480,140.29	576,696.45
Appalac	Smith Mt Pumped Storage Hydro Plant	Smith Mountain Pumped Storage Hydro Plant : APCo : 0550	1010001 Plant In Service	VA	35300 - Station E	12/2011	6,650.76	72.66	6,578.10
Appalac	Transmission Subs =<69KV-VA, APCo	Byllesby 69KV Substation : APCo : 0631	1010001 Plant In Service	VA	35300 - Station E	12/2011	132,441.00	73,697.01	58,743.99
Appalac	Transmission Subs =<69KV-VA, APCo	Reusens 34.5KV Substation : APCo : 0681	1010001 Plant In Service	VA	35300 - Station E	12/2011	58,521.00	37,285.51	21,235.49
Appalac	Transmission Subs =<69KV-WV, APCo	Belle 46KV Substation : APCo : 3205	1010001 Plant In Service	WV	35300 - Station E	12/2011	107,576.00	31,435.53	76,140.47
Appalac	Transmission Subs =<69KV-WV, APCo	London Hydro 46KV Substation : APCo : 0521	1010001 Plant In Service	WV	35300 - Station E	12/2011	366,061.00	141,553.80	224,507.20
Appalac	Transmission Subs =<69KV-WV, APCo	Marmet Hydro 46KV Substation : APCo : 0511	1010001 Plant In Service	WV	35300 - Station E	12/2011	25,751.00	16,406.74	9,344.26
Appalac	Transmission Subs =<69KV-WV, APCo	Winfield Hydro 69KV Substation : APCo : 0531	1010001 Plant In Service	WV	35300 - Station E	12/2011	1,959,926.26	221,657.29	1,738,268.97
Appalac	Transmission Subs 138KV-VA, APCo	Claytor 138KV Substation : APCo : 0621	1010001 Plant In Service	VA	35300 - Station E	12/2011	673,990.00	202,506.87	471,483.13
Appalac	Transmission Subs 138KV-VA, APCo	Clinch River 138KV Substation : APCo : 0771	1010001 Plant In Service	VA	35200 - Structure	12/2011	46,746.00	29,166.56	17,579.44
Appalac	Transmission Subs 138KV-VA, APCo	Glen Lyn 138KV Substation : APCo : 0782	1010001 Plant In Service	VA	35200 - Structure	12/2011	8,638.11	4,457.61	4,180.50
Appalac	Transmission Subs 138KV-VA, APCo	Glen Lyn 138KV Substation : APCo : 0782	1010001 Plant In Service	VA	35300 - Station E	12/2011	1,322,858.17	686,750.72	636,107.45
Appalac	Transmission Subs 138KV-VA, APCo	Leesville 138KV Substation : APCo : 0691	1010001 Plant In Service	VA	35300 - Station E	12/2011	193,579.48	121,191.70	72,387.78
Appalac	Transmission Subs 138KV-VA, APCo	Smith Mountain 138KV Substation : APCo : 0551	1010001 Plant In Service	VA	35300 - Station E	12/2011	1,721,558.88	539,022.02	1,182,536.86
Appalac	Transmission Subs 138KV-WV, APCo	Cabin Creek 138KV/46KV Substation : APCo : 3005	1010001 Plant In Service	WV	35300 - Station E	12/2011	107,576.00	27,817.27	79,758.73
Appalac	Transmission Subs 765KV-WV, APCo	Mountaineer Plant 765KV Substation : APCo : 0711	1010001 Plant In Service	WV	35200 - Structure	12/2011	84,966.37	44,551.67	40,414.70
Appalac	Transmission Subs 765KV-WV, APCo	Mountaineer Plant 765KV Substation : APCo : 0711	1010001 Plant In Service	WV	35300 - Station E	12/2011	4,941,535.98	1,610,405.61	3,331,130.37
Appalachian Power - Gen Total							31,219,942.33	9,772,951.84	21,446,990.49

Appalachian Power Company
Workpaper 17-Balance of Transmission Investment
Capacity Cost of Service Formula Rate
Balance as of December 2011

fr_desc	fpa	fc_sortid	description	beginning_balance	additions	retirements	transfers	adjustments	ending_balance	start_month	end_month
none	353 - Station Equipment	6	Transmission Plant - Electric	733,270,790	43,599,135	6,504,358	(1,355,807)	-	769,009,760	1/1/11	12/1/11

Notes:
References to data from FERC Form 1 page(s) 206,207, Ln. 50

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 18 - Fuel Expense
For the Year Ending December 31, 2011

		Source
Fuel		
Fuel - Account 501	727,837,686	320, 5, b
Fuel - Account 518	0	320, 25, b
Fuel - Account 547	1,745,302	321, 63, b
Total Fuel	729,582,988	
Other		
Fuel Handling	28,533,129	CBR
Sale of Fly Ash (Revenue & Expense)	(79,229)	CBR

Notes:
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 19 - Plant Held for Future Use
For the Year Ending December 31, 2011

	End of Year		
	Total	Demand [1]	Energy
Production	428,415	428,415	0
Transmission	1,947,017	1,947,017	0
Distribution	3,473,337	3,473,337	0
General	0	0	0
Total	5,848,769	5,848,769	0
	FF1, 214, d		

Notes:
[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Attachment E

Attestation as to the
Accuracy of the Supporting Cost of Service Data

Attachment E

Attestation

I, Julie A. Sloat, Vice President of Regulatory Case Management, being duly sworn, state that the cost support prepared for this filing is true, accurate and correct to the best of my knowledge, information, and belief.

Julie A. Sloat

SUBSCRIBED AND SWORN TO BEFORE ME,

this 10th day of December, 2012.

Notary Public

My Commission expires: May 11th, 2016

NOTARIAL SEAL STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Recorded in
Franklin County
My Comm. Exp. 5/11/16

Attachment F

Range of Revenues APCO would recover
under the Capacity Compensation Formula Rate
at Hypothetical Levels of Service

Appalachian Power Company
Virginia Jurisdiction Capacity Rate Filing at FERC
Estimated FRR Capacity Rate Revenues Under Hypothetical Levels of Shopping

	(A)	(B)	(C) = (A) * (B)	(D) = (C) * 365	(E)	(F) = (D) * (E)
					FRR Capacity Rate	
Line #	Proportion of Total VA Demand Served by CSPs	VA Jurisdictional 5/CP Avg MW Demand (1)	5/CP Avg MW Demand at Assumed Shopping Levels	Annual Shopping MW/Day	Rate MW/Day(2)	Annual Revenue Requirement
1	1%	2,692.2	26.9	9,827	$ 478.54	$ 4,702,385
2	2%	2,692.2	53.8	19,653	$ 478.54	$ 9,404,770
3	3%	2,692.2	80.8	29,480	$ 478.54	$ 14,107,155
4	4%	2,692.2	107.7	39,306	$ 478.54	$ 18,809,540
5	5%	2,692.2	134.6	49,133	$ 478.54	$ 23,511,925
6	6%	2,692.2	161.5	58,959	$ 478.54	$ 28,214,310
7	7%	2,692.2	188.5	68,786	$ 478.54	$ 32,916,695
8	8%	2,692.2	215.4	78,612	$ 478.54	$ 37,619,080
9	9%	2,692.2	242.3	88,439	$ 478.54	$ 42,321,465
10	10%	2,692.2	269.2	98,266	$ 478.54	$ 47,023,850

Notes

(1) Average of the 2011 5/CPs in the formula, times jurisdictional allocation of APCo Firm Load to VA.Retail Jurisdiction (45.434% allocation).

Avg of 5/CP	5,925.6
VA/Total APCo Firm Demand (3)	45.434%
VA Portion of 5/CP avg	2,692.2

(2) $MW/Day Rate per Attachment A.

(3) This represents the VA firm demand as a portion of APCo's total firm demand per the demand and energy study filed in APCo's most recent Virginia base ratecase.

Attachment G

Comparison of the Rate to the
Demand Rates in APCO's Virginia Retail Tariffs

Appalachian Power Company
Virginia Jurisdiction
Comparison of Formula Rate vs. Retail LPS Capacity Rate Based on 5CP Determinants

Line				
I.	*Formula Calculation*			
1	Demand Revenue Requirement (Attachment A, pg. 4, Ln. 7)		$	1,035,003,989
2	APCO Demand @ PJM 5 CP (MWs)			5,925.6
3	MW-Year Revenue	Ln 1/Ln 2	$	174,667
4	Days in Planning Year			365
5	MW-Day	Ln 3/Ln 4	$	478.54
6	MW-Month	Ln 3/12	$	14,555.54
7	**kW-Month**	Ln 6/1000	**$**	**14.56**
II.	*LPS Tariff Production Demand (1)*			
8	LPS Demand Revenue Requirement			$114,976,411
9	Less: Secondary Service Demand Revenue Requirement			$10,282,935
10	Demand Revenue Requirement for LPS Customers at Primary, Subtransmission or Transmission			$104,693,476
11	Primary kW			287,514
12	Subtransmission kW			210,642
13	Transmission kW			70,110
14	PJM 5 CP (kW)			568,267
15	kW-Year Revenue	Ln 10/ Ln 14	$	184.23
16	kW-Day	Ln 15/ Ln 4	$	0.50
17	**kW-Month**	Ln 16 * 30	**$**	**15.14**

Note (1): Based on settlement rate design in Va SCC Case No. PUE2011-00037
and metered load research average PJM 5 CP's filed in that case TYE 12/31/2010.

Attachment H

Testimony of Dr. Kelly Pearce

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company, Inc.	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF
KELLY D. PEARCE
ON BEHALF OF
APPALACHIAN POWER COMPANY

December 10, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company, Inc.	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF
KELLY D. PEARCE
ON BEHALF OF
APPALACHAIN POWER COMPANY

<u>PERSONAL BACKGROUND</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelly D. Pearce. My business address is 155 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation ("AEPSC") as Director-Contracts and Analysis.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mechanical Engineering from Oklahoma State University in 1984. I received Master of Science and Doctor of Philosophy degrees in Nuclear Engineering from the University of Michigan in 1986 and 1991 respectively. I received a Master of Science in Industrial Administration degree from Carnegie Mellon University in 1994.

From 1986 to 1988 I worked for a subsidiary of Olin Corporation. From 1991 to 1996 I worked for the United States Department of Energy within the Office of

Fossil Energy. My responsibilities included serving as a Contracting Officer's Representative in the oversight and administration of government-funded research of advanced generation and environmental remediation technologies and projects. I also supported strategic studies for the deployment and commercialization of these technologies as well as administration and support of Government research and development solicitations. I was promoted twice during this time.

In 1996 I joined AEPSC as a Rate Consultant I. In 2001, I was promoted to Senior Regulatory Consultant. My responsibilities included preparation of class cost-of-service studies and rate design for AEP operating companies and the preparation of special contracts and regulated pricing for retail customers. In 2003 I transferred to Commercial Operations as Manager of Cost Recovery Analysis. In 2007 I was promoted to Director of Commercial Analysis. During this period, I was responsible for analyzing the financial impacts of Commercial Operations-related activities. I also supported settlement of AEP's generation pooling agreements among the operating companies.

In 2010 I transferred to Regulatory Services in my current position of Director-Contracts and Analysis. My group is responsible for performing financial analyses concerning AEP's generation resources and load obligations, various settlement support for AEP's power pools and regulatory support in areas that relate to commercial operations. In addition, my group is responsible for AEP's formula rate contracts.

I am a registered Professional Engineer in Ohio and West Virginia.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony to the Virginia State Corporation Commission ("VSCC") in Case Numbers PUE-2001-00011 and PUE-2011-00034 and submitted testimony and testified before the VSCC in Case No. PUE-2001-00306.

I have also submitted testimony and testified before the Indiana Utility Regulatory Commission in Cause No. 43992 and before the Public Utilities Commission of Ohio on behalf of Ohio Power Company ("OPCo") and its precedent sister company, Columbus Southern Power Company[1] in Case No. 11-346-EL-SSO, et al, and Case No. 10-2929-EL-UNC. My testimony in these proceedings was on behalf of operating companies that are affiliates of APCO.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to introduce and support the adoption of the capacity formula rate proposed by APCO. This formula rate would be utilized to compensate APCO for capacity that is used by Competitive Service Providers ("CSPs") in Virginia to serve former APCO customers in cases where the CSPs choose not to provide their own capacity.

Please see the testimony of APCO witness Diane Keegan for a discussion about the computational aspects of the formula itself.

ATTACHMENTS

[1] On January 1, 2012, Ohio Power Company and Columbus Southern Power Company were merged, with Ohio Power Company the surviving entity.

Q. ARE YOU SPONSORING ANY ATTACHMENTS IN THIS PROCEEDING?

A. Yes, I am sponsoring the following Attachments or sections of Attachments included in this filing:

Attachment A: a clean version of Tariff Record – RAA Schedule 8.1 – Appendix 2A: Appalachian Power Company Formula Rate Implementation Protocols;

Attachment B: a redline version of Tariff Record – RAA Schedule 8.1 – Appendix 2A: Appalachian Power Company Formula Rate Implementation Protocols;

Attachment F: An example of capacity revenues under the formula based on assumed participation in the Choice program of 1% up to 10% of the cumulative load of Virginia firm requirements customers. This attachment is based on the MW-day rate provided on page 1 of Attachment C as supported in Ms. Keegan's testimony;

Attachment G: A comparison of the rate produced by the formula based on 2011 FERC Form 1 ("FFI") information with the tariff demand rate for retail large power service customers on a comparable basis.

In addition to Appendix 2A, APCO is providing in Attachments A & B, respectively, clean and redline copies of Appendix 2B the blank formula template and Appendix 2C, the blank template of the supporting workpapers. These specific documents are included in the filing as Tariff Record R.A.A Schedule 8.1, Appendices 2B and 2C. Ms. Keegan will support Appendices 2B and 2C.

Q. WERE THESE ATTACHMENTS AND TARIFF RECORDS PREPARED UNDER YOUR SUPERVISION AND DIRECTION?

A. Yes.

APPLICABLE MARKET AND CAPACITY OBLIGATION

Q. WHAT IS THE RATIONALE FOR THE FORMULA RATES PROPOSED?

A. Under the PJM Reliability Assurance Agreement ("RAA"), Schedule D, Section 8, APCO elected, along with other AEP Operating Companies, to utilize the Fixed Resource Requirement ("FRR") option to provide or "self-supply" capacity to meet its Load Serving Entity ("LSE") obligations rather than acquire this capacity through the PJM RPM market. Since APCO is self-supplying its own generation resources to satisfy these load obligations, the costs to provide this capacity is the actual embedded capacity cost of APCO's generation.

Q. UNDER THE FRR OPTION HOW LONG IS THE COMMITMENT TO PROVIDE CAPACITY TO CSPS?

A. In accordance with PJM rules APCO must make this commitment three years in advance. The Company is then fully committed and locked-in to providing the capacity resources needed for all of the loads that are contained in the forecasted load requirement, plus the additional capacity necessary to satisfy the required Installed Reserve Margin ("IRM").

Q. HOW DOES RETAIL CHOICE IMPACT THIS PROCESS?

A. At the time the Company completed its portion of the AEP PJM FRR capacity plan, it included its entire forecasted retail load within the AEP Zone, which was then used to determine the capacity obligation. Subsequently, if CSPs sign up any of this APCO load, the CSPs are required and obligated to reimburse the Company for its capacity costs that has already been committed to serve this load during the PJM Planning Year (“PY”) that is for the 12-month period from June to May.

Q. IS THERE ANY EXCEPTION THAT ALLOWS APCO TO REDUCE ITS CAPACITY OBLIGATION TO ACCOUNT FOR LOADS SERVED BY CSPS?

A. Yes, there is one exception. If a CSP notifies APCO prior to the submittal of its capacity plan for a future planning year (three years hence) that the CSP will supply its own generation capacity for that PY, then APCO will reduce its own capacity resources by an equivalent amount for that year. Because retail choice is just starting in Virginia in that customers have not yet begun shopping, CSPs will be able to elect this option for loads they anticipate signing up for the applicable planning year three years hence (i.e., PY June 2016- May 2017). In the meantime, APCO will be obliged to service that load per the terms of the RAA.

Q. SINCE CSPS DID NOT AVAIL THEMSELVES OF THIS OPTION, HOW WILL THE CAPACITY OBLIGATION OF THE SWITCHING CUSTOMERS BE MET?

A. By the Company’s generation resources. Since CSPs have thus far chosen not to self-supply, then APCO is *required* to commit the capacity necessary to serve all customer loads, *including loads to be committed to a CSP for future periods*. In short, in this situation, shopping customers’ capacity obligations will continue to be met by the capacity resources of APCO.

Q. HOW IS APCO IMPACTED BY THIS RESULT?

A. APCO will continue to maintain and provide the capacity resources for shopping customers, but will no longer receive these customers' generation revenues.

Q. IS THERE ANY COMPENSATION MADE TO APCO FOR THIS CAPACITY COMMITMENT?

A. Yes. Under RAA Schedule 8.1, Section D-8, in the absence of a State Compensation Mechanism ("SCM"), an FRR entity will be compensated by the LSE at the capacity price in the unconstrained portions of the PJM region, as determined in accordance with Attachment DD in the PJM Tariff.

Q. DOES AN FRR ENTITY HAVE ANY OTHER OPTIONS TO DETERMINE THE PRICE CHARGED FOR CAPACITY?

A. Yes. Under Attachment DD, the FRR entity is permitted to make a Section 205 filing with the FERC for approval of compensation based on a rate that reflects the FRR entity's cost or other just and reasonable basis. The Virginia State Corporation Commission has not established a SCM, so by virtue of this application APCO is requesting FERC approval to implement a cost-based capacity mechanism.

Q. WILL THESE COST-BASED PAYMENTS PROVIDE AN APPROPRIATE LEVEL OF COMPENSATION?

A. Yes. The formula described by Ms. Keegan will create a rate based on APCO's most recent cost structure, capital structure and net investment prior to the current planning year. The resultant rate will provide fair and appropriate compensation for use of the Company's capacity.

<u>FORMULA RATE DESCRIPTION</u>

Q. PLEASE GENERALLY DESCRIBE THE DEVELOPMENT OF THE FRR-BASED REIMBURSEMENT RATES PROPOSED BY APCO.

A. APCO utilized a formula rate approach for this capacity that is based upon the average cost of serving APCO's LSE obligation load – both the load served directly by APCO or by a CSP – on a dollar per MegaWatt-day basis. By CSPs paying a rate that is based upon average costs, they are neither subsidizing nor being subsidized by APCO.

Q. WHAT ARE SOME OF THE ADVANTAGES OF THE FORMULA RATE APPROACH?

A. Formula rates are currently utilized in many states by AEP for other wholesale customer sales. As previously stated, the formula rates use an average allocation of cost between the parties based on common cost allocation mechanisms.

Second, the formula rate approach provides a high degree of transparency. The Company's annual FF1 report is the primary source document for the formula template and supporting work papers. The transparency of the data facilitates review and verification of the resulting rate for CSPs using APCO's capacity. What is approved as the rate is the formula itself. Following approval, the rate is simply updated using the next year's accounting information. As a result, updating the rate becomes a straightforward, fairly mechanical process and the updates are readily available for regulatory review. Under the Company's proposal, rates will be known prior to the beginning of a given PJM PY.

Q. HOW ARE THE FRR CHARGES UPDATED UNDER THE TEMPLATE?

A. Under the proposed protocols, the Company will utilize a given year's FF1 annual report shortly after it is available to update the capacity rates that will be available for the subsequent PJM PY. For example, once the 2012 FF1 becomes available, currently required by FERC in April 2013, APCO will update the capacity rate and have it available no later than May 25, 2013. This is the rate that will be in effect for the PJM PY 2013/2014 that runs from June 1, 2013 through May 31, 2014. The same process will be used for each subsequent year as long as such rates are in effect.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes it does.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Appalachian Power Company, Inc. **Docket No. ER13-____-000**

AFFIDAVIT OF KELLY D. PEARCE

Kelly D. Pearce, being first duly sworn, deposes and says that he is the Kelly D. Pearce referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

Kelly D. Pearce

Kelly D. Pearce

Subscribed and sworn to before me this 4th day of December, 2012.

Ellen A McAninch

Notary Public

Commission Expires on: May 11th, 2016

NOTARIAL SEAL STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Recorded in
Franklin County
My Comm. Exp. 5/11/16

Attachment I

Testimony of Ms. Diane Keegan

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF
DIANE KEEGAN
ON BEHALF OF
APPALACHIAN POWER COMPANY

December 10, 2012

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Appalachian Power Company	**Docket No. ER13-____-000**

**DIRECT TESTIMONY OF
DIANE KEEGAN ON BEHALF OF
APPALACHIAN POWER COMPANY**

<u>PERSONAL BACKGROUND</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Supervisor, Formula Rates-East, by American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Appalachian Power Company (APCo or Company).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a B.A. in Marketing, Business Management and Accounting and a Master of Business Administration from Franklin University. I also completed the EEI Electric Rate Advanced Course.

I began my professional career in 1989 as an Engineering Technician in AEPSC's Regulated Pricing and Analysis Department. In 1995 I became a Rate Analyst in the Rate Department for Columbus Southern Power Company, an AEP operating company. In 1996 I returned to AEPSC and worked in the Rate Department until 2000 when I was promoted to Senior Business Analyst, Energy Delivery & Customer Relations, where I was responsible for technical support and system specifications for customer billing for all of the AEP System's eleven operating companies. In 2001 I joined AEPSC Regulatory Services as Regulatory Consultant I, Transmission and Interconnection Services, where I was responsible for transmission cost of service and wholesale contracts. In 2003, I returned to Regulated Pricing and Analysis and held the position of Principal Regulatory Consultant where I was responsible for preparation of class cost of service studies, functional cost of service studies, rate design for the AEP System operating companies, and special contracts and pricing for retail and wholesale customers until I took my current position as Supervisor of Formula Rates. In this position I am responsible for the implementation and preparation of all of AEP's East wholesale formula rates for both transmission and generation. I am also responsible for implementation and preparation of any AEP East capacity formula rates approved by this Commission.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony on behalf of Indiana Michigan Power Company (I&M) before the Michigan Regulatory Commission in Case No. U-16180. I submitted testimony on behalf of I&M before the Indiana Utility Regulatory Commission in Cause No. 43306. I also submitted testimony for the Company before the Virginia State Corporation Commission in Case No. PUE-2006-00065 and the Federal Energy Regulatory Commission in Docket No. ER08-1521.

<u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe and support the capacity formula rate proposed by APCo in determining the price paid by Competitive Service Providers (“CSPs”) who serve eligible customers under the state of Virginia’s retail Choice program.

As discussed in the testimony of APCO witness Kelly D. Pearce, APCO has elected to be designated as a Fixed Resource Requirement (“FRR”) entity under PJM’s Reliability Assurance Agreement (“RAA”), Section 8-D; this formula rate would determine the price at which APCO would be compensated for FRR capacity that is used to serve former APCO customers in Virginia in cases where the CSPs choose not to provide their own capacity.

As will be shown in my testimony, the current calculations are based upon 2011 Federal Energy Regulatory Commission (“FERC”) Form 1(“FF1”) information for APCO (set out in APCO’s FF1 filed in 2012), along with additional information from the books and records of the Company.

<u>ATTACHMENTS</u>

Q. ARE YOU SPONSORING ANY ATTACHMENTS IN THIS PROCEEDING?

A. Yes, I am sponsoring the following Attachments included in this filing:

Attachment C: Formula Template for APCO populated with 2011 data.

Attachment D: Formula Template Supporting Workpapers for the APCO template populated with 2011 data.

In addition to these attachments, APCO is providing, as Attachments A & B respectively, clean and redline copies of the Formula Rate Protocols, the blank formula template, and the blank template of the supporting workpapers. These specific documents are included in the filing as Tariff Record R.A.A Schedule 8.1, Appendices 2A, 2B and 2C, respectively. I will be supporting Appendices 2B and 2C. Dr. Pearce will be supporting Appendix 2A.

Q. WERE THESE ATTACHMENTS AND TARIFF RECORDS PREPARED BY YOU OR UNDER YOUR SUPERVISION AND DIRECTION?

A. Yes.

FORMULA RATE DESCRIPTION

Q. PLEASE GENERALLY DESCRIBE THE DEVELOPMENT OF THE FRR-BASED REIMBURSEMENT RATES PROPOSED BY APCO.

A. The formula rate template selected for this rate development is modeled after the template that was accepted for filing by this Commission in Docket No. ER12-1173-000 on behalf of Indiana Michigan Power Company ("I&M"), which was modeled after the template included in a settlement that was approved by the FERC to derive the capacity charges applied to wholesale sales made by Southwestern Electric Power Company ("SWEPCo"), an APCO-affiliated operating company, to the Cities of Minden, Louisiana and Prescott, Arkansas.

Q. PLEASE DESCRIBE THE CAPACITY PORTION OF THE RATE IN DETAIL.

A. The blank or unpopulated formula rate template is provided as Tariff Record R.A.A. Schedule 8.1, Appendix 2B in this application. The formula utilizes common cost allocation principles that are used to compute an average per unit cost that includes the cost of capital on assets and actual expenses incurred. The final daily charge calculation that would be used to compute the individual CSPs' bills, based on their applicable daily obligation peak load, is shown on Attachment C, page 1 of the formula.[1] Throughout the formula the specific references for the inputs are clearly shown. The FF1 annual reports are utilized heavily throughout these templates for source data. In certain instances, additional detail is obtained from the Company's books and records, such as the income statements. To facilitate review of the completed formula the Company will also provide, with each annual update, supporting workpapers to supplement the development of input amounts when they cannot be directly sourced from the FERC Form 1. A blank template of these workpapers is shown in Tariff Record R.A.A. Schedule 8.1, Appendix 2C.

Q. ARE THERE ANY ITEMS IN PARTICULAR TO NOTE?

A. Yes. As shown on page 4, line 6 of Attachment C, the annual production costs are reduced for 75% of the margins on APCo's off-system sales. As a result, CSPs will get a benefit from those off-system sales.

Q. PLEASE DISCUSS THE KEY ASPECTS OF THE TEMPLATES.

A. Below I address three key aspects of the templates:

- the peaks used to determine the capacity rates,
- the Return on Equity ("ROE"), and
- the use of end-of-year account balances

Q. PLEASE DESCRIBE HOW PEAK DEMAND IS DETERMINED.

---

[1] This cost-based rate excludes zonal scaling factors and forecast pool requirements adjustments that are applied to rates under RPM pricing.

A. As noted on page 2 of Attachment C, the denominator is based on the average APCO peak demands that are coincident with the PJM five highest daily summer peak demands. This is appropriate in order to be consistent with the demands that will be used to charge CSPs today through the PJM settlement process.

Q. PLEASE DESCRIBE THE ROE THAT IS INCLUDED IN THE TEMPLATE.

A. APCO proposes to use a fixed ROE of 10.4% to be consistent with the base ROE accepted in APCO's most recent Virginia base case, Case No PUE 2010-00037. APCO witness Dr. William E. Avera supports the use of this ROE in his testimony. Unlike the other formula inputs that will be updated annually, APCO proposes that the ROE remain fixed for the term that this rate is applicable, absent any appropriate regulatory filing or filings to modify the ROE.

Q. PLEASE DESCRIBE WHY APCO HAS CHOSEN TO USE HISTORICAL COST DATA WITHOUT A SUBSEQUENT RECONCILIATION.

A. The capacity formula rates that are based on costs and revenues that are later subject to true-up are reconciled for other wholesale customers between the rates charged and revenues collected during a period and the actual costs incurred by the seller during that same period, computed after the fact. This is performed by collecting or crediting the difference between these revenues and actual costs in a subsequent period, commonly referred to as a "true-up." This is appropriate for the other wholesale customers so that no under- or over-collection occurs and the seller ultimately collects the precise costs incurred to serve these customers. However, the formula rates for other wholesale customers are generally applied under long-term contracts.

Because it would be impractical and administratively burdensome for CSPs to be subject to such true-up obligations, especially because they can enter and leave the market at will and are likely to have load that is changing over the period due to customer switching, APCO is not proposing a formula rate with a true-up or reconciliation process. This results in a benefit to CSPs since it removes a source of uncertainty regarding their capacity rate over the period.

In other words, as an example, the 2011 FF1 actual accounting data will be used to determine the capacity rate charged to CSPs for the PJM PY 2012/2013 with no subsequent reconciliation or true-up. This will provide rate certainty for CSPs during the planning year. However, since there is no true-up, the lag between the historic costs and actual costs for the rate-effective period should be minimized as much as practical. Consequently, APCO proposes to utilize only the end-of-year rate base balances for the formula calculations rather than average annual values from the historic period. The end-of-year rate base balances will be closer to the rate base in effect during the applicable PJM PY than an average rate base, which uses more dated balances. Even this end-of-year balance may potentially understate the average rate base for the PJM PY in which these capacity rates are in effect.

Q. DOES THE FORMULA RATE TEMPLATE INCLUDE CWIP COSTS?

A. No, CWIP balances are not being included in rate base in the formula rate template.

PROPOSED CAPACITY RATES

Q. PLEASE PROVIDE THE CAPACITY COMPENSATION RATES PROPOSED BY THE COMPANY.

A. The formula rate template and supporting workpapers shown in Attachments C and D have been populated with information from the 2011 APCO's FF1. As seen on page 1, Attachment C, the capacity compensation rate will be $478.54/MW-day for the PJM PY 2012/2013. If approved by the Commission, the APCO rate will be computed each spring as previously described for the subsequent PJM PY. The first applicable update would occur using 2012 FF1 information for the PJM PY that begins June 1, 2013.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company, Inc. **Docket No. ER13-____-000**

AFFIDAVIT OF DIANE KEEGAN

Diane Keegan, being first duly sworn, deposes and says that she is the Diane Keegan referred to in the foregoing testimony, that she has read such testimony and is familiar with the contents thereof and that the answers therein are true and correct to the best of her knowledge, information, and belief.

Diane Keegan

Diane Keegan

Subscribed and sworn to before me this 3rd day of December, 2012.

Ellen A. McAninch

Notary Public

Commission Expires on: May 11th, 2016

NOTARIAL SEAL STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Recorded in
Franklin County
My Comm. Exp. 5/11/16

Attachment J

Testimony of Mr. David Davis

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF DAVID A. DAVIS
ON BEHALF OF
APPALACHIAN POWER COMPANY

December 10, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF
DAVID A. DAVIS
ON BEHALF OF
APPALACHIAN POWER COMPANY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David A. Davis. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My position is Manager - Property Accounting Policy & Research for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP").

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. My responsibilities include providing the AEP electric operating subsidiaries with accounting support for regulatory filings, including the preparation of depreciation studies and testimony. I also monitor regulatory proceedings and legislation for accounting implications and assist in determining the appropriate regulatory accounting treatment.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.

A. I received a Master's Degree in Business Administration from the University of Dayton in 1988. I also have a Bachelor's Degree in Business Administration with a major in accounting from Ohio University that I received in 1976. I am a Certified Public Accountant (inactive) in the state of Ohio. In 1980, I was employed by Columbus Southern Power Company ("CSP"), one of the AEP operating companies, as an accountant. I have held various positions in the Accounting Department including special studies, reports and lease accounting. From 1984 to 1985, I was employed by Columbia Gas System Service Corporation as a staff auditor where my responsibilities included financial and procedural audits of the Columbia Gas Distribution Companies and other subsidiary companies. From 1986 to present, I have been employed by AEP at the AEPSC, CSP or Ohio Power Company. At AEP, I have held several positions including Supervisor of Consolidation Accounting, Manager/Supervisor of Property Accounting (for 16 years) and my current position of Manager - Property Accounting Policy & Research.

Q. HAVE YOU PRESENTED EXPERT TESTIMONY IN RATE AND DEPRECIATION PROCEEDINGS BEFORE ANY REGULATORY AUTHORITY?

A. Yes. In 2007, I prepared a depreciation study and testimony and testified before the Oklahoma Corporation Commission ("OCC") on behalf of Public Service Company of Oklahoma ("PSO") concerning depreciation in Cause No. PUD 200600285. Also, in 2007 I prepared a depreciation study that was provided to the Louisiana Public Service Commission in Docket No. U23327, Subdocket A on behalf of Southwestern Electric Power Company ("SWEPCO") for its generation assets. In 2008, I prepared an updated depreciation study and testimony for PSO and testified before the OCC in Cause No. PUD 200800144. In 2009, I prepared a depreciation study for SWEPCO that was filed with the Arkansas Public Service Commission in Docket No. 09-008-U. Also, in 2009, I prepared a depreciation study for SWEPCO that was filed with the Public Utility Commission of Texas ("PUC") in Docket No. 37364. In 2010, I submitted an updated depreciation study and testimony for PSO in Cause No. 201000050 to the OCC. In February 2011, I filed a depreciation study including testimony with the Public Utilities Commission of Ohio on behalf of CSP and Ohio Power Company (Case Numbers 11-351-EL-AIR and 11-352-EL-AIR). In June 2011, I prepared an updated depreciation study that was provided to the Louisiana Public Service Commission in Docket No. U23327, Subdocket F on behalf of SWEPCO for its generation assets. In July 2011, I filed a depreciation study and testimony in Michigan with the Michigan Public Service Commission in Case No. U-16801 for Indiana Michigan Power Company. In September 2011, I filed a depreciation study and testimony in Indiana with the Indiana Utility Regulatory Commission in Cause No. 44075 for Indiana Michigan Power Company. In July 2012, I filed a depreciation study and testimony in Texas with the Public Utility Commission of Texas in PUC Docket No. 40443 for SWEPCO. In August 2012, I filed depreciation testimony with exhibits with the Federal Energy Regulatory Commission ("FERC") for Transource Missouri in Docket No. ER12-2554-000 (Transource Missouri is a jointly owned subsidiary of AEP and Great Plains Energy).

Q. HAVE YOU HAD ANY FORMAL TRAINING RELATING TO DEPRECIATION AND UTILITY ACCOUNTING?

A. Yes. I am currently vice-president of the Society of Depreciation Professionals ("SDP") and have completed training offered by the SDP that included Depreciation Basics, Life and Net Salvage Analysis, and Preparing and Defending a Depreciation Study. These training classes included an introduction to plant and depreciation accounting, data requirements and collection, depreciation models, life cycle analysis, current regulatory issues, actuarial life analysis, net salvage analysis and simulation life analysis.

In addition, I am a member of the American Institute of Certified Public Accountants and have attended and participated in numerous Edison Electric Institute Property Accounting and Valuation meetings. I also traveled to Tirana, Albania in 2010 with the USAID program to provide a presentation to Albanian utility personnel regarding "Depreciation for a Regulated Utility".

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss how book depreciation rates are calculated for Appalachian Power Company ("APCO") and to show how book depreciation amounts from the FERC Form No. 1 were used in the formula rate calculations. I also discuss amortization expense and how APCO calculates these amounts.

Q. WHAT EXHIBITS ARE YOUR SPONSORING IN YOUR TESTIMONY?

A. In my testimony I am sponsoring the following exhibits:

EXHIBIT AEP-301: Summary of APCO's Weighted Jurisdictional Depreciation Rates;

EXHIBIT AEP-302: Order in Case No. 05-1278-E-PC-PW-42T Supporting WV Jurisdictional Depreciation Rates;

EXHIBIT AEP-303: Summary of WV Jurisdictional Rates accepted in in Case No. 05-1278-E-PC-PW-42T;

EXHIBIT AEP-304: VA Jurisdictional Depreciation Study from 2006;

EXHIBIT AEP-305: VA SCC Order in Case No. PUE-2006-00065 Approving Current Depreciation Rates;

EXHIBIT AEP-306: APCO Monthly Depreciation Expense by Function;

EXHIBIT AEP 307: Supporting Calculation of July 2011 Depreciation Expense for Steam Plant Shown on EXHIBIT AEP-306 and supported by rates in EXHIBIT AEP-301;

EXHIBIT AEP-308: Summary of Jurisdictional Allocation Factors in EXHIIBIT AEP-301 as filed in WV Case No. 10-0699-E-42T; and

EXHIBIT AEP-309: Amortization of Intangible Plant.

III. DEFINITION OF DEPRECIATION

Q. **PLEASE EXPLAIN THE DEFINITION OF DEPRECIATION AS USED IN PREPARING YOUR TESTIMONY.**

A. The definition of depreciation that I used in preparing my testimony is the same that is used by FERC and the National Association of Regulatory Utility Commissioners. That definition is:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant.

IV. DEPRECIATION OVERVIEW

Q. HOW DOES APCO CALCULATE ITS BOOK DEPRECIATION EXPENSE?

A. APCO uses a straight line method to calculate its book depreciation expense, where the service value of the plant is charged to depreciation expense through equal annual charges over its service life. (A change in plant value or a new estimate of depreciation parameters would result in a change in depreciation expense for any depreciation method, including straight line.) The straight line method used by APCO includes employing a broad group procedure along with a remaining life technique.

The broad group procedure considers all units of plant within a particular depreciation category (usually a plant account or sub-account) to be one group. The broad group procedure is widely used and produces relatively stable depreciation rates from year to year.

The remaining life technique (used with the broad group procedure) recovers the un-depreciated original cost less future net salvage over the remaining life of the property. With this technique, gross plant less accumulated depreciation is used as the numerator and the remaining life is used as the denominator in calculating depreciation expense and the depreciation rate.

Q. ARE THERE OTHER FACTORS TO CONSIDER WHEN CALCULATING BOOK DEPRECIATION RATES TO APPLY TO APCO'S PLANT IN SERVICE BALANCES?

A. Yes. APCO is a multi-jurisdictional company with approval of depreciation rates subject to the Virginia State Corporation Commission ("VSCC"), the Public Service Commission of West Virginia ("WVPSC") and FERC. Since most of APCO's property (other than distribution property) benefits all of its jurisdictions, book depreciation expense is calculated using jurisdictionally weighted average depreciation rates. For example, if for APCO Mountaineer Plant account 312 (boiler plant equipment) the Virginia jurisdiction was 40% of the total, West Virginia was 50% and FERC was 10%, and each of the individual jurisdictional depreciation rates were 3%, 8% and 9%, respectively, the weighted average jurisdictional depreciation rate would be 6.1% (40% times 3% plus 50% times 8% plus 10% times 9%). See EXHIBIT AEP-301 which provides the calculation of APCO's weighted average jurisdictional depreciation rates based on rates in effect during April to December 2011 (Note that the April update to the weighted average depreciation rates consisted of a change in allocation factors only and that depreciation rates did not change in 2011).

Q. WHEN WERE APCO'S CURRENT DEPRECIATION RATES APPROVED BY THE VSCC, WVPSC AND FERC?

A. APCO's current depreciation rates were approved by the WVPSC in April 2006 via a settlement in Case No. 05-1278-E-PC-PW-42T. See EXHIBIT AEP-302 which provides a copy of the order (EXHIBIT F in the order sets out the approved functional depreciation rates). The approved depreciation rates were not filed as part of a depreciation study in the West Virginia case; however, APCO provided these depreciation rates (see EXHIBIT AEP-303) during settlement discussions and they were adopted as a component of the settlement. The depreciation parameters for the West Virginia depreciation rates were developed in a depreciation study filed in Virginia and this depreciation study report is included here as EXHIBIT AEP-304.

APCO's Virginia depreciation rates used to calculate 2011 depreciation expense were approved by the VSCC in May 2007 in an order in Case No. PUE 2006-00065. See EXHIBIT AEP-305 which provides a copy of the order. (As noted above, the depreciation study report for the Virginia case is included here as EXHIBIT AEP-304.) Note that APCO's Virginia depreciation rates were updated by a November 30, 2011 order in Case No. PUE 2011-00037. These new Virginia rates were effective beginning in February 2012.

APCO's current FERC depreciation rates were approved by FERC in March 1990 in Docket Nos. ER90-132 and ER90-133.

Q. WHAT ARE THE JURISDICTIONAL ALLOCATION FACTORS USED IN CALCULATING THE WEIGHTED AVERAGE RATE FOR EACH PLANT ACCOUNT?

A. The jurisdictional allocator used to calculate the weighted average depreciation rates for Production plant is based on a demand allocator. The weighted average allocator for General plant is based on a payroll allocator. The specific demand and payroll allocators used in EXHIBIT AEP-301 are shown on EXHIBIT AEP-308. These were developed for WV Case No. 10-0699-E-42T and provided to me by AEP's Regulatory Pricing group.

Q. HOW OFTEN ARE THE DEPRECIATION RATES UPDATED?

A. Depreciation rates are changed whenever new depreciation studies are provided in a rate proceeding and the applicable state or federal commissions approves the new rates. The jurisdictional allocation factors developed for that rate proceeding will be used in developing the updated weighted average depreciation rates (these factors are updated at the same time as each general rate filing). Jurisdictional allocation factors are based on each jurisdiction's contribution to the peak coincident with the overall APCO peak. Once the jurisdictional rates have been established, they will remain in effect until changed in a subsequent rate case.

Q. ARE THE JURISDICTIONAL DEPRECIATION RATES USED TO CALCULATE DEPRECIATION EXPENSE USED IN THE CALCULATION OF FERC FORMULA RATES?

A. Yes. The amount in the formula is sourced from the FERC Form 1, which reflects the book expense based on the weighted average of the jurisdictional rates for each functional property class. Monthly depreciation expense is calculated by applying each annual rate (see EXHIBIT AEP-301) to the prior month's gross plant balance for each plant account and dividing the result by twelve to determine the monthly functional expense. The cumulative sum of January through December monthly amounts then becomes the annual expense found in the FERC Form 1. See EXHIBIT AEP-306 which shows the 2011 monthly depreciation expense for APCO by function (note that the total year to date depreciation expense for 2011 ties to page 336 of the 2011 FERC Form 1, line 12, column b). See EXHIBIT AEP-307 for a calculation of July 2011's steam production depreciation expense using the depreciation rates from EXHIBIT AEP-301.

Q. WHAT ARE APCO'S INTANGIBLE PLANT AMORTIZATION RATES?

A. APCO's intangible amortization rates are included on EXHIBIT AEP-309, which also details the amount of amortization expense charged by month for 2011. Amortization is generally determined on a straight line basis where the cost to be amortized is divided by a number of periods (life of capital software, license period, lease period, etc.).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company, Inc. **Docket No. ER13-____-000**

AFFIDAVIT OF DAVID A. DAVIS

David A. Davis, being first duly sworn, deposes and says that he is the David A. Davis referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

David A. Davis

David A. Davis

Subscribed and sworn to before me this 30th day of November, 2012.

Ellen A. McAninch

Notary Public

Commission Expires on: May 11, 2016

NOTARIAL SEAL STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Recorded in
Franklin County
My Comm. Exp. 5/11/16

APPALACHIAN POWER COMPANY
CALCULATION OF TOTAL COMPANY
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
EFFECTIVE AS OF 4/1/2011

Update for Change in allocation factors from WV Case No. 10-0699-E-42T.
Order Dated March 30, 2011

		VIRGINIA			WEST VIRGINIA			FERC WHOLESALE			FERC KINGSPORT			TOTAL COMPANY
		(1)			(2)			(3)			(4)			
STEAM PRODUCTION PLANT	*PLANT ACCT.*	*VA SCC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*PSC OF WV APPROVED RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
Mountaineer Plant														
	311.0	1.47%	0.475096	0.70%	1.67%	0.427991	0.71%	3.01%	0.034710	0.10%	3.01%	0.062203	0.19%	1.70%
	312.0	1.80%	0.475096	0.86%	2.01%	0.427991	0.86%	3.01%	0.034710	0.10%	3.01%	0.062203	0.19%	2.01%
	314.0	1.68%	0.475096	0.80%	1.92%	0.427991	0.82%	3.01%	0.034710	0.10%	3.01%	0.062203	0.19%	1.91%
	315.0	1.44%	0.475096	0.68%	1.65%	0.427991	0.71%	3.01%	0.034710	0.10%	3.01%	0.062203	0.19%	1.68%
	316.0	1.65%	0.475096	0.78%	1.87%	0.427991	0.80%	3.01%	0.034710	0.10%	3.01%	0.062203	0.19%	1.87%
Kanawha River Plant														
	311.0	0.45%	0.475096	0.21%	0.35%	0.427991	0.15%	4.56%	0.034710	0.16%	4.56%	0.062203	0.28%	0.80%
	312.0	1.49%	0.475096	0.71%	1.40%	0.427991	0.60%	4.56%	0.034710	0.16%	4.56%	0.062203	0.28%	1.75%
	314.0	1.12%	0.475096	0.53%	1.02%	0.427991	0.44%	4.56%	0.034710	0.16%	4.56%	0.062203	0.28%	1.41%
	315.0	0.92%	0.475096	0.44%	0.82%	0.427991	0.35%	4.56%	0.034710	0.16%	4.56%	0.062203	0.28%	1.23%
	316.0	2.17%	0.475096	1.03%	2.09%	0.427991	0.89%	4.56%	0.034710	0.16%	4.56%	0.062203	0.28%	2.36%
Amos Plant - Units 1 & 2														
	311.0	1.49%	0.475096	0.71%	2.12%	0.427991	0.91%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	1.93%
	312.0	2.79%	0.475096	1.33%	3.20%	0.427991	1.37%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	3.01%
	314.0	2.17%	0.475096	1.03%	2.77%	0.427991	1.19%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	2.53%
	315.0	1.86%	0.475096	0.88%	2.43%	0.427991	1.04%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	2.23%
	316.0	1.82%	0.475096	0.86%	2.44%	0.427991	1.04%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	2.21%
Amos Plant - Unit 3														
	311.0	1.46%	0.475096	0.69%	2.06%	0.427991	0.88%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	1.88%
	312.0	2.35%	0.475096	1.12%	2.83%	0.427991	1.21%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	2.64%
	314.0	2.21%	0.475096	1.05%	2.76%	0.427991	1.18%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	2.54%
	315.0	1.67%	0.475096	0.79%	2.24%	0.427991	0.96%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	2.06%
	316.0	2.40%	0.475096	1.14%	2.84%	0.427991	1.21%	3.18%	0.034710	0.11%	3.18%	0.062203	0.20%	2.66%
Sporn Plant														
	311.0	0.33%	0.475096	0.16%	0.22%	0.427991	0.09%	5.67%	0.034710	0.20%	5.67%	0.062203	0.35%	0.80%
	312.0	2.02%	0.475096	0.96%	1.92%	0.427991	0.82%	5.67%	0.034710	0.20%	5.67%	0.062203	0.35%	2.33%
	314.0	1.09%	0.475096	0.52%	0.98%	0.427991	0.42%	5.67%	0.034710	0.20%	5.67%	0.062203	0.35%	1.49%
	315.0	1.08%	0.475096	0.51%	0.97%	0.427991	0.42%	5.67%	0.034710	0.20%	5.67%	0.062203	0.35%	1.48%
	316.0	1.28%	0.475096	0.61%	1.18%	0.427991	0.50%	5.67%	0.034710	0.20%	5.67%	0.062203	0.35%	1.66%
Clinch River Plant														
	311.0	2.58%	0.475096	1.23%	2.58%	0.427991	1.10%	3.60%	0.034710	0.12%	3.60%	0.062203	0.22%	2.67%
	312.0	3.26%	0.475096	1.55%	3.26%	0.427991	1.39%	3.60%	0.034710	0.12%	3.60%	0.062203	0.22%	3.28%
	314.0	2.66%	0.475096	1.26%	2.67%	0.427991	1.14%	3.60%	0.034710	0.12%	3.60%	0.062203	0.22%	2.74%
	315.0	2.32%	0.475096	1.10%	2.32%	0.427991	0.99%	3.60%	0.034710	0.12%	3.60%	0.062203	0.22%	2.43%
	316.0	3.05%	0.475096	1.45%	3.05%	0.427991	1.31%	3.60%	0.034710	0.12%	3.60%	0.062203	0.22%	3.10%
Glen Lyn Plant #5														
	311.0	5.07%	0.475096	2.41%	4.06%	0.427991	1.74%	5.01%	0.034710	0.17%	5.01%	0.062203	0.31%	4.63%
	312.0	5.89%	0.475096	2.80%	4.92%	0.427991	2.11%	5.01%	0.034710	0.17%	5.01%	0.062203	0.31%	5.39%
	314.0	6.45%	0.475096	3.06%	5.53%	0.427991	2.37%	5.01%	0.034710	0.17%	5.01%	0.062203	0.31%	5.91%
	315.0	6.09%	0.475096	2.89%	5.17%	0.427991	2.21%	5.01%	0.034710	0.17%	5.01%	0.062203	0.31%	5.58%
	316.0	10.95%	0.475096	5.20%	10.47%	0.427991	4.48%	5.01%	0.034710	0.17%	5.01%	0.062203	0.31%	10.16%
Glen Lyn Plant #6 and Common														
	311.0	3.25%	0.475096	1.54%	3.14%	0.427991	1.35%	4.33%	0.034710	0.15%	4.33%	0.062203	0.27%	3.31%
	312.0	4.41%	0.475096	2.10%	4.31%	0.427991	1.84%	4.33%	0.034710	0.15%	4.33%	0.062203	0.27%	4.36%
	314.0	3.74%	0.475096	1.78%	3.63%	0.427991	1.55%	4.33%	0.034710	0.15%	4.33%	0.062203	0.27%	3.75%
	315.0	3.50%	0.475096	1.66%	3.39%	0.427991	1.45%	4.33%	0.034710	0.15%	4.33%	0.062203	0.27%	3.53%
	316.0	4.70%	0.475096	2.23%	4.61%	0.427991	1.97%	4.33%	0.034710	0.15%	4.33%	0.062203	0.27%	4.62%

APPALACHIAN POWER COMPANY
CALCULATION OF TOTAL COMPANY
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
EFFECTIVE AS OF 4/1/2011

Update for Change in allocation factors from WV Case No. 10-0699-E-42T.
Order Dated March 30, 2011

		VIRGINIA			**WEST VIRGINIA**			**FERC WHOLESALE**			**FERC KINGSPORT**			**TOTAL COMPANY**
	PLANT ACCT.	*(1) VA SCC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*(2) PSC OF WV APPROVED RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*(3) FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*(4) FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
Putnam Coal Terminal														
	311.0	1.12%	0.475096	0.53%	3.03%	0.427991	1.30%	3.04%	0.034710	0.11%	3.04%	0.062203	0.19%	2.13%
	312.0	1.29%	0.475096	0.61%	2.96%	0.427991	1.27%	3.04%	0.034710	0.11%	3.04%	0.062203	0.19%	2.18%
	315.0	1.30%	0.475096	0.62%	2.90%	0.427991	1.24%	3.04%	0.034710	0.11%	3.04%	0.062203	0.19%	2.16%
	316.0	1.38%	0.475096	0.66%	3.10%	0.427991	1.33%	3.04%	0.034710	0.11%	3.04%	0.062203	0.19%	2.29%
Central Plant Maintenance		2.00%	0.475096	0.95%	2.07%	0.427991	0.89%	2.50%	0.034710	0.09%	2.50%	0.062203	0.16%	2.09%
Central Machine Shop		2.01%	0.475096	0.95%	2.10%	0.427991	0.90%	2.50%	0.034710	0.09%	2.50%	0.062203	0.16%	2.10%
Little Broad Run - Mountaineer		1.64%	0.475096	0.78%	1.76%	0.427991	0.75%	1.58%	0.034710	0.05%	1.58%	0.062203	0.10%	1.68%
Little Broad Run - Sporn		1.64%	0.475096	0.78%	1.76%	0.427991	0.75%	5.67%	0.034710	0.20%	5.67%	0.062203	0.35%	2.08%
HYDRAULIC PRODUCTION PLANT														
Claytor														
	331.0	1.21%	0.475096	0.57%	1.28%	0.427991	0.55%	1.58%	0.034710	0.05%	1.58%	0.062203	0.10%	1.27%
	332.0	0.78%	0.475096	0.37%	0.87%	0.427991	0.37%	1.58%	0.034710	0.05%	1.58%	0.062203	0.10%	0.89%
	333.0	0.61%	0.475096	0.29%	0.72%	0.427991	0.31%	1.58%	0.034710	0.05%	1.58%	0.062203	0.10%	0.75%
	334.0	1.71%	0.475096	0.81%	1.78%	0.427991	0.76%	1.58%	0.034710	0.05%	1.58%	0.062203	0.10%	1.72%
	335.0	2.14%	0.475096	1.02%	2.18%	0.427991	0.93%	1.58%	0.034710	0.05%	1.58%	0.062203	0.10%	2.10%
	336.0	0.44%	0.475096	0.21%	0.55%	0.427991	0.23%	1.58%	0.034710	0.05%	1.58%	0.062203	0.10%	0.59%
Byllesby														
	331.0	2.97%	0.475096	1.41%	1.09%	0.427991	0.47%	1.83%	0.034710	0.06%	1.83%	0.062203	0.11%	2.05%
	332.0	3.35%	0.475096	1.59%	3.08%	0.427991	1.32%	1.83%	0.034710	0.06%	1.83%	0.062203	0.11%	3.08%
	333.0	3.12%	0.475096	1.48%	3.98%	0.427991	1.70%	1.83%	0.034710	0.06%	1.83%	0.062203	0.11%	3.35%
	334.0	3.06%	0.475096	1.45%	2.21%	0.427991	0.95%	1.83%	0.034710	0.06%	1.83%	0.062203	0.11%	2.57%
	335.0	4.39%	0.475096	2.09%	1.86%	0.427991	0.80%	1.83%	0.034710	0.06%	1.83%	0.062203	0.11%	3.06%
Buck														
	331.0	1.92%	0.475096	0.91%	1.08%	0.427991	0.46%	1.78%	0.034710	0.06%	1.78%	0.062203	0.11%	1.54%
	332.0	3.06%	0.475096	1.45%	2.57%	0.427991	1.10%	1.78%	0.034710	0.06%	1.78%	0.062203	0.11%	2.72%
	333.0	2.65%	0.475096	1.26%	4.87%	0.427991	2.08%	1.78%	0.034710	0.06%	1.78%	0.062203	0.11%	3.51%
	334.0	4.08%	0.475096	1.94%	2.99%	0.427991	1.28%	1.78%	0.034710	0.06%	1.78%	0.062203	0.11%	3.39%
	335.0	2.63%	0.475096	1.25%	1.94%	0.427991	0.83%	1.78%	0.034710	0.06%	1.78%	0.062203	0.11%	2.25%
	336.0	1.60%	0.475096	0.76%	1.05%	0.427991	0.45%	1.78%	0.034710	0.06%	1.78%	0.062203	0.11%	1.38%
Niagara														
	331.0	2.88%	0.475096	1.37%	1.34%	0.427991	0.57%	1.63%	0.034710	0.06%	1.63%	0.062203	0.10%	2.10%
	332.0	4.06%	0.475096	1.93%	2.16%	0.427991	0.92%	1.63%	0.034710	0.06%	1.63%	0.062203	0.10%	3.01%
	333.0	3.85%	0.475096	1.83%	4.43%	0.427991	1.90%	1.63%	0.034710	0.06%	1.63%	0.062203	0.10%	3.89%
	334.0	3.82%	0.475096	1.81%	2.02%	0.427991	0.86%	1.63%	0.034710	0.06%	1.63%	0.062203	0.10%	2.83%
	335.0	4.19%	0.475096	1.99%	3.42%	0.427991	1.46%	1.63%	0.034710	0.06%	1.63%	0.062203	0.10%	3.61%
Reusens														
	331.0	3.56%	0.475096	1.69%	0.77%	0.427991	0.33%	1.74%	0.034710	0.06%	1.74%	0.062203	0.11%	2.19%
	332.0	4.37%	0.475096	2.08%	1.27%	0.427991	0.54%	1.74%	0.034710	0.06%	1.74%	0.062203	0.11%	2.79%
	333.0	3.69%	0.475096	1.75%	2.24%	0.427991	0.96%	1.74%	0.034710	0.06%	1.74%	0.062203	0.11%	2.88%
	334.0	3.84%	0.475096	1.82%	1.19%	0.427991	0.51%	1.74%	0.034710	0.06%	1.74%	0.062203	0.11%	2.50%
	335.0	3.80%	0.475096	1.81%	3.04%	0.427991	1.30%	1.74%	0.034710	0.06%	1.74%	0.062203	0.11%	3.28%
Leesville														
	331.0	0.80%	0.475096	0.38%	0.86%	0.427991	0.37%	1.72%	0.034710	0.06%	1.72%	0.062203	0.11%	0.92%
	332.0	1.30%	0.475096	0.62%	1.34%	0.427991	0.58%	1.72%	0.034710	0.06%	1.72%	0.062203	0.11%	1.37%
	333.0	0.85%	0.475096	0.40%	0.91%	0.427991	0.39%	1.72%	0.034710	0.06%	1.72%	0.062203	0.11%	0.96%
	334.0	1.08%	0.475096	0.51%	1.14%	0.427991	0.49%	1.72%	0.034710	0.06%	1.72%	0.062203	0.11%	1.17%
	335.0	1.44%	0.475096	0.68%	1.49%	0.427991	0.64%	1.72%	0.034710	0.06%	1.72%	0.062203	0.11%	1.49%
	336.0	0.79%	0.475096	0.38%	0.85%	0.427991	0.36%	1.72%	0.034710	0.06%	1.72%	0.062203	0.11%	0.91%

APPALACHIAN POWER COMPANY
CALCULATION OF TOTAL COMPANY
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
EFFECTIVE AS OF 4/1/2011

Update for Change in allocation factors from WV Case No. 10-0699-E-42T.
Order Dated March 30, 2011

		VIRGINIA			WEST VIRGINIA			FERC WHOLESALE			FERC KINGSPORT			TOTAL COMPANY
	PLANT ACCT.	(1) VA SCC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(2) PSC OF WV APPROVED RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(3) FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(4) FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
London														
	331.0	1.75%	0.475096	0.83%	1.75%	0.427991	0.75%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.74%
	332.0	1.54%	0.475096	0.73%	1.54%	0.427991	0.66%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.55%
	333.0	1.52%	0.475096	0.72%	1.52%	0.427991	0.65%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.53%
	334.0	2.17%	0.475096	1.03%	2.17%	0.427991	0.93%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	2.12%
	335.0	2.20%	0.475096	1.05%	2.20%	0.427991	0.94%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	2.15%
	336.0	1.43%	0.475096	0.68%	1.43%	0.427991	0.61%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.45%
Marmet														
	331.0	1.69%	0.475096	0.80%	1.69%	0.427991	0.73%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.69%
	332.0	1.62%	0.475096	0.77%	1.62%	0.427991	0.69%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.62%
	333.0	1.54%	0.475096	0.73%	1.54%	0.427991	0.66%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.55%
	334.0	2.22%	0.475096	1.05%	2.22%	0.427991	0.95%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	2.16%
	335.0	2.23%	0.475096	1.06%	2.23%	0.427991	0.95%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	2.17%
	336.0	1.48%	0.475096	0.70%	1.48%	0.427991	0.63%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.49%
Winfield														
	331.0	1.61%	0.475096	0.77%	1.61%	0.427991	0.69%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.62%
	332.0	1.62%	0.475096	0.77%	1.62%	0.427991	0.69%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.62%
	333.0	1.24%	0.475096	0.59%	1.24%	0.427991	0.53%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.28%
	334.0	1.49%	0.475096	0.71%	1.49%	0.427991	0.64%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.51%
	335.0	2.00%	0.475096	0.95%	2.00%	0.427991	0.86%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	1.97%
	336.0	2.22%	0.475096	1.05%	2.22%	0.427991	0.95%	1.65%	0.034710	0.06%	1.65%	0.062203	0.10%	2.16%
Smith Mountain														
	331.0	0.96%	0.475096	0.46%	1.04%	0.427991	0.45%	2.21%	0.034710	0.08%	2.21%	0.062203	0.14%	1.13%
	332.0	0.86%	0.475096	0.41%	0.95%	0.427991	0.41%	2.21%	0.034710	0.08%	2.21%	0.062203	0.14%	1.04%
	333.0	1.37%	0.475096	0.65%	1.44%	0.427991	0.62%	2.21%	0.034710	0.08%	2.21%	0.062203	0.14%	1.49%
	334.0	1.49%	0.475096	0.71%	1.57%	0.427991	0.67%	2.21%	0.034710	0.08%	2.21%	0.062203	0.14%	1.60%
	335.0	1.47%	0.475096	0.70%	1.54%	0.427991	0.66%	2.21%	0.034710	0.08%	2.21%	0.062203	0.14%	1.58%
	336.0	0.85%	0.475096	0.40%	0.94%	0.427991	0.40%	2.21%	0.034710	0.08%	2.21%	0.062203	0.14%	1.02%
OTHER PRODUCTION PLANT														
Ceredo														
	341.0	1.22%	0.475096	0.58%	1.22%	0.427991	0.52%	1.22%	0.034710	0.04%	1.22%	0.062203	0.08%	1.22%
	344.0	1.60%	0.475096	0.76%	1.60%	0.427991	0.68%	1.60%	0.034710	0.06%	1.60%	0.062203	0.10%	1.60%
	345.0	1.22%	0.475096	0.58%	1.22%	0.427991	0.52%	1.22%	0.034710	0.04%	1.22%	0.062203	0.08%	1.22%
	346.0	1.22%	0.475096	0.58%	1.22%	0.427991	0.52%	1.22%	0.034710	0.04%	1.22%	0.062203	0.08%	1.22%
GENERAL PLANT														
	390.0	1.35%	0.508653	0.69%	1.42%	0.434436	0.62%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	1.51%
	391.0	2.48%	0.508653	1.26%	2.57%	0.434436	1.12%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	2.58%
	392.0	0.82%	0.508653	0.42%	1.15%	0.434436	0.50%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	1.12%
	393.0	1.28%	0.508653	0.65%	1.34%	0.434436	0.58%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	1.43%
	394.0	2.11%	0.508653	1.07%	2.14%	0.434436	0.93%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	2.20%
	395.0	1.21%	0.508653	0.62%	1.39%	0.434436	0.60%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	1.42%
	396.0	0.30%	0.508653	0.15%	0.76%	0.434436	0.33%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	0.68%
	397.0	3.09%	0.508653	1.57%	3.19%	0.434436	1.39%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	3.16%
	398.0	1.91%	0.508653	0.97%	2.03%	0.434436	0.88%	3.43%	0.020300	0.07%	3.43%	0.036611	0.13%	2.05%

(1) As approved in VA Case No. PUE 2006-00065 on May 15, 2007.
Depreciation rates were made effective on January 1, 2006.

(2) Approved by PSC of WV Order dated July 26, 2006 in
Case No. 05-1278-E-PC-PW-42T effective July 1, 2006.

(3) Approved by FERC March 2, 1990 in Docket ER90-132

(4) Approved by FERC March 2, 1990 in Docket ER90-133

(5) Allocation Factors updated for a change in factors from
WV Case No. 10-0699-E-42T, order dated March 30, 2011

**PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
CHARLESTON**

CASE NO. 05-1278-E-PC-PW-42T

**APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY**

Joint Application for Rate Increases on Notice with Proposed Effective Dates and Changes in Tariff Provisions, Pursuant to W.Va. Code, §24-2-4a, *inter alia*, for Reactivation and Modification of Expanded Net Energy Cost Mechanism, for Disposition of ENEC Over-recovery Balance, for Implementation of System Reliability Tracker Mechanism, and for Waiver of Provisions of the Commission's Rules.

JOINT STIPULATION AND AGREEMENT FOR SETTLEMENT

Pursuant to *W. Va. Code* 24-1-9(f) and Rule 13.4 of Title 150, Series 1, *Rules of Practice and Procedure*, the following parties to this proceeding (hereinafter "the Stipulating Parties"), Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (collectively "the Companies"), the Staff of the Public Service Commission of West Virginia ("the Staff"), the Consumer Advocate Division of the Public Service Commission of West Virginia ("the CAD"), E.I. du Pont de Nemours and Company, Huntington Alloys Corporation, Bayer Crop Science/Bayer Material Science, PPG Industries, Inc., Union Carbide Corporation, and Steel of West Virginia, Inc. ("SWVA, Inc.") referred to collectively as West Virginia Energy Users Group ("WVEUG"), Century Aluminum of West Virginia, Inc. ("Century"), The Kroger Co. ("Kroger"), the Huntington Sanitary Board and South Putnam Public Service District (collectively "Huntington/South Putnam"), and the West Virginia Community Action

Partnership ("WVCAP"), join in this Joint Stipulation and Agreement for Settlement ("this Agreement"), and request that the Public Service Commission of West Virginia ("the Commission") approve and adopt it, in its entirety and without modification, as the full and final resolution of the instant proceeding. In support of this Agreement, the Stipulating Parties make the following representations:

Procedural History

1. On August 26, 2005 the Companies filed their Joint Application to reinstate the Expanded Net Energy Cost ("ENEC") proceedings, increase base rates and make changes in classifications, charges, rules and regulations, and other tariff provisions. The Joint Application was supported by seven volumes, including Rule 42 data, workpapers, ENEC data, proposed tariffs, a class cost of service study, and a report on emerging and state-of-the-art concepts.

2. On September 13, 2005 the Commission issued an Order which, among other things, suspended the use of the rates and charges stated in the Companies' revised tariff sheets until June 23, 2006. By order of January 27, 2006 the Commission, in response to a motion filed by the Companies, extended the suspension period until July 28, 2006, but authorized deferred accounting for ENEC to commence July 1, 2006.

3. At various dates various entities filed petitions to intervene, which were granted by the Commission. Intervenors Concept Mining, Inc. and the West Virginia State Building and Construction Trades Council, AFL-CIO later withdrew from this proceeding. The South Bluefield Neighborhood Association intervened but did not offer testimony, participate in any of the settlement meetings, or appear at the April 18, 2006 hearing in this matter.

4. On September 26, 2005 the Companies filed the direct testimony and exhibits of Dana E. Waldo, Terry R. Eads, Paul R. Moul, John M. McManus, Stephen D. Baker, Jeffrey B. Bartsch, Alan D. Bragg, Jeffrey L. Brubaker, Steven H. Ferguson, Chris Potter, Oliver J. Sever, O. Patrick Taylor, and Philip A. Wright.

5. The Companies provided public notice in substantial compliance with the Commission's directions.

6. In the course of the discovery phase of this proceeding, numerous requests for information were filed by various parties and responded to by the parties to whom they were addressed.

7. On January 18, 2006 the Companies filed the supplemental direct testimony and exhibits of Terry R. Eads, Steven H. Ferguson, and Chris Potter, and a revised Volume IV containing revised ENEC data.

8. On March 8, 2006 the Staff filed the direct testimony and exhibits of James W. Ellars, Michael L. Fletcher, Steven M. Kaz, Robert R. McDonald, Edwin L. Oxley, David L. Pauley, and Thomas D. Sprinkle, as well as Staff Rule 42 Reports for APCo and WPCo; the CAD filed the direct testimony and exhibits of Byron L. Harris, Emily Medine, Randall Short, and Ralph Smith; WVEUG filed the direct testimony and exhibits of Stephen J. Baron, Richard A. Baudino, Timothy R. Duke and Richard Piotrowski; Century Aluminum filed the direct testimony and exhibits of Gerald J. Kitchen and Ronald Thompson; WVCAP filed the direct testimony and exhibits of Dwight Coburn; The Kroger Co. filed the direct testimony and exhibits of Kevin C. Higgins; West Virginia Building and Construction Trades Council, AFL-CIO filed the direct testimony and exhibits of George L. Donkin; and the Huntington Sanitary Board

and South Putnam Public Service District filed the direct testimony of Jack D. Gaines, J. Bruce Fox, and Michael McNulty.

9. On April 7, 2006 the Companies filed the rebuttal testimony and exhibits of Dana E. Waldo, Terry R. Eads, Paul R. Moul, Stephen D. Baker, Steven H. Ferguson, Jeffrey L. Brubaker, Jeffrey B. Bartsch, James I. Warren, Philip J. Nelson, O. Patrick Taylor, Alan D. Bragg, and Chris Potter.

10. On April 7, 2006 the Staff filed the amended direct testimony and exhibits and rebuttal testimony of Robert R. McDonald and the amended direct testimony and exhibits of Thomas D. Sprinkle; the CAD filed the rebuttal testimony and exhibits of Byron L. Harris and Ralph C. Smith; WVEUG filed the rebuttal testimony and exhibits of Stephen J. Baron; Century Aluminum filed the rebuttal testimony and exhibits of Gerald J. Kitchen; the Huntington Sanitary Board and South Putnam Public Service District filed the rebuttal testimony and exhibits of Jack D. Gaines.

11. On April 14, 2006 the Companies filed the additional rebuttal testimony of Chris Potter.

12. For some weeks prior to hearing, the Stipulating Parties engaged in settlement discussions concerning all aspects of the instant proceeding, and have now reached agreement on a comprehensive series of proposals to recommend to the Commission as a fair and just settlement of the issues in this proceeding.

13. At a hearing held on April 18, 2006 the Stipulating Parties represented to the Commission that a settlement in principle had been reached among those parties. The Commission directed the Stipulating Parties to provide it with a written and executed

settlement agreement memorializing the settlement by 9:30 a.m. April 21, 2006. The Commission admitted into the record all of the testimony and exhibits specified above.

14. Except as set forth in paragraph 15 below, the Stipulating Parties agree that the substantive elements of the proposed settlement, which are hereby submitted for the Commission's approval, resolve all of the issues in this proceeding, and are set forth in particular below and in the exhibits attached hereto.

15. Although the Stipulating Parties have reached agreement on most of the substantive elements presented in the case, there remain two related issues in contention among the parties which will have to be resolved by the Commission. This first issue involves one aspect of the Special Rate Mechanism for Century Aluminum set forth in paragraph 37 below. As explained in paragraph 37d, there is the possibility that at the end of experimental rate program for Century in 2009, there may be a deficit (an under-recovery) which will be spread to other customers in future rate proceedings. The second issue is the treatment of the ENEC Bank discussed in paragraphs 19 to 24 below. As part of the consideration for the Special Rate Mechanism, Century has given up any claim for a portion of the ENEC Bank. If the Special Rate Mechanism, including the recovery of any deficit, is not approved, Century will reassert its claim for a portion of the ENEC Bank. Set forth below are the positions of the respective parties on these issues.

a. Staff. Staff has agreed to all terms and conditions of the Joint Stipulation and Agreement for Settlement except for the condition in the Special Rate Mechanism for Century Aluminum whereby any deficit that remains at the end of the experimental rate mechanism time period will be recorded by APCo as a regulatory asset and flowed back to all other ratepayers. Staff is willing to defer any argument concerning the deficit until the end of the experimental rate period, and if a deficit in fact exists at that time, advance its arguments to the Commission regarding the proper treatment of such deficit.

b. The Companies. APCo and WPCo support approval of the Special Rate Mechanism for Century Aluminum, but do not support the special rate mechanism without the provision objected to by the Staff, which is an integral element of the negotiated special rate mechanism. The Companies ask the Commission to resolve here and now any issues about the experimental rate program and to approve it or disapprove it without deferring any critical issues for resolution at a later date.

c. Century Aluminum. If the Commission does not approve this experimental rate program in all its particulars, including providing APCo recovery of any deficit, and thereby APCo does not enter into a special contract with Century Aluminum, then Century withdraws its support for the remainder of this settlement and reasserts its claim to the ENEC Bank.

d. WVEUG. WVEUG supports approval of the Special Rate Mechanism for Century Aluminum. However, if the Special Rate Mechanism is disapproved and Century reasserts its claim for a portion of the ENEC Bank, WVEUG asserts that the allocation of the ENEC Bank set forth in Exhibit C continues to be reasonable and should be approved as part of this settlement.

e. The Kroger Co. The Kroger Co. takes the same position as WVEUG.

f. CAD. Within the context of the overall settlement, the CAD supports approval of the Special Rate Mechanism for Century Aluminum. However, if the Special Rate Mechanism is disapproved and Century reasserts its claim for a portion of the ENEC Bank, CAD asserts that Century has no legitimate claim on the ENEC Bank.

Accordingly, the ENEC Bank should continue to be allocated as set forth in Exhibit C hereto.

g. Huntington Sanitary Board and South Putnam Public Service District. These parties take the same position as the CAD.

h. Accordingly, the Stipulating Parties ask that the Commission render a specific decision on the issues outlined above. The Stipulating Parties stand ready to offer oral argument, witnesses and/or written briefs on these issues at the direction of the Commission.

16. **Expanded Net Energy Cost** The Stipulating Parties agree that the Expanded Net Energy Cost ("ENEC") mechanism should be reinstituted for the Companies, with new ENEC rates established in this proceeding, and annual ENEC proceedings to resume in 2007.

17. The Stipulating Parties agree to the following ENEC rates:

a. Consistent with the Commission's January 27, 2006 Order in this proceeding, the Stipulating Parties acknowledge that the Companies will commence deferred accounting for revenues and costs included in the ENEC on July 1, 2006 and agree that the ENEC rates to be used for such deferred accounting for each tariff class on July 1, 2006, shall be those set forth in Company Exhibit No. 1, Revised Volume IV, Revised Section 2, Attachment 1, which is attached hereto as Exhibit A and incorporated herein.

b. The Stipulating Parties agree that, beginning July 28, 2006, the ENEC rates for each tariff class shall be those set forth in Company Exhibit No. 1, Revised Volume IV, Revised Section 1, Attachment 1, which is attached hereto as

Exhibit B and incorporated herein. Those ENEC rates will stay in effect until July 1, 2007, or further order of the Commission, and are projected to produce additional annual revenues of $56.01 million.

18. The Stipulating Parties agree to the following elements and procedures to govern further ENEC proceedings.

a. The Companies will make their next ENEC filing by March 1, 2007, and then will make new ENEC filings by March 1st of each year thereafter.

b. In the ENEC filing of March 1, 2007:

i. the actual cost review period shall be July 1, 2006, through December 31, 2006; and

ii. the forecast period shall be July 1, 2007, through June 30, 2008.

c. In subsequent annual ENEC proceedings the actual cost review period shall be the immediately preceding calendar year, and the forecast period shall be the twelve months from July 1st of the year in which the proceeding is initiated through June 30th of the following year.

ENEC Over-Recovery Balance

19. The Stipulating Parties agree that the accumulated ENEC over-recovery balance ("the Bank") being held by APCo, and to be fed back to customers pursuant to this Agreement, is $51,207,683, plus simple interest on the principal balance as per the Commission's November 10, 2005 Order. That simple interest has been accrued since November, 2005 and will continue to be accrued on the declining principal balance until the entire balance has been fed back to customers.

20. The allocation of the Bank among customer classes and customers shall be in accordance with the proposal of WVEUG, which is attached hereto as Exhibit C and incorporated herein by reference.

21. Beginning July 28, 2006, the Companies shall implement negative surcharges by customer class, for all classes and customers receiving a portion of the Bank, designed to feed back one-third of the principal balance of the Bank to said customer classes and customers over the following eleven (11) months. Pursuant to the following paragraph, certain customers may elect an accelerated feedback of their portion of the Bank.

22. The Kroger Co., Huntington Sanitary Board, South Putnam Public Service District, and/or the members of WVEUG may request alternative feedback mechanism(s) designed to enable them to realize an accelerated feedback of their shares of the Bank. On condition that no alternative mechanism enables an electing customer to receive more than the shares of the Bank, plus interest up to the date of payout, which it would have received under the standard mechanism provided for in the preceding paragraph, the Companies are willing, after Commission approval of this Agreement, to negotiate reasonable mechanisms for accelerated feedback, subject to legal constraints and practical limitations.

23. In consideration of the Special Rate Mechanism discussed below, Century shall not be entitled to any share in the principal balance of the Bank or any interest accrued thereon.

24. The timing and particulars of the feed back of the residual balance of the Bank, plus interest, remaining after compliance with the preceding paragraphs of this

section, shall be as determined and directed by the Commission in the next ENEC proceeding filed by the Companies.

Recovery of Expenditures Related to the 765 kV Line and Scrubbers

25. APCo is currently engaged in the following extraordinary construction projects: (1) the Wyoming-Jacksons Ferry 765 kV Transmission Line; and (2) the retrofit of flue-gas desulfurization units ("scrubbers") on the Mountaineer generating plant and Units 1, 2 and 3 of the John Amos generating plant (collectively referred to as "the projects").

26. The Stipulating Parties adopt, with certain modifications, the CAD's proposal for rate increments in future ENEC proceedings. The Wyoming-Jacksons Ferry 765 kV line is to be provided electric plant in service ("EPIS") treatment at a 10.5% return on equity based on the construction work in progress ("CWIP") balance as of December 31, 2005, including projected depreciation, taxes and other fixed operating expense. The Wyoming-Jacksons Ferry line and each of APCo's planned scrubber projects will be afforded EPIS treatment at a 10.5% return on equity in succeeding ENEC proceedings after a given project has been placed in service, provided the project is in service no later than March 1st of the year the ENEC factor becomes effective. EPIS treatment will include the recovery of estimated fixed costs.

27. The Stipulating Parties agree that the Companies should be allowed to recover the construction expenditures and other costs related to the projects during the construction phase and, after the projects are classified as EPIS, in the following manner:

a. APCo shall accrue AFUDC on construction expenditures for each project, based on a 10.5% ROE. In each ENEC proceeding APCo shall be allowed to recover a return and associated taxes ("Return") on all CWIP expenditures along with accrued AFUDC made in connection with the projects through the end of the ENEC review period, December 31st of each year. Rates recovering such return ("construction surcharges") shall go into effect on July 1st of the next succeeding year as part of the ENEC.

b. The return on such CWIP and EPIS shall be based on:

i. the amount of equity, long term debt, short term debt and preferred stock in APCo's capital structure based on a thirteen month average as of December 31st of each year;

ii. a rate of return on equity capital of 10.5%, and a return on other capital (long term debt, short term debt and preferred stock) at the thirteen month average cost of such other capital component as of December 31st of each year.

c. CWIP balances earning a CWIP allowance would not be subject to the accrual of AFUDC. CWIP balances in excess of amounts earning a CWIP allowance shall continue to be subject to the accrual of AFUDC during the construction period. In addition to a return on CWIP existing at December 31st of each year, all projects that are transferred to EPIS by March 1st of the succeeding year, shall also be allowed to recover depreciation, property taxes and other fixed costs associated with such EPIS to be incurred over the next succeeding ENEC recovery period.

d. In succeeding ENEC proceedings, projects previously transferred to EPIS shall be allowed to recover a Return on EPIS balances net of accumulated depreciation as of December 31st of each year, along with depreciation, property taxes and other fixed costs.

e. The Stipulating Parties agree that the Companies shall be allowed to recover in rates effective July 28, 2006, a total of $23.21 million associated with CWIP expenditures on the projects as of December 31, 2005. The Stipulating Parties also agree that the $23.21 million allowance includes recovery of depreciation, property taxes and other fixed costs associated with the Wyoming-Jacksons Ferry 765 kV transmission line.

f. Construction surcharges and EPIS surcharges shall be established as part of the Companies' annual ENEC proceedings, but the costs and revenues associated with these construction surcharges and EPIS surcharges shall not be subject to deferred accounting for regulatory purposes. The Stipulating Parties acknowledge that the construction and EPIS surcharges established in this case are calculated for the various customer classes based on the twelve coincident peak (12 CP) demand allocator.

Base Rates

28. The Stipulating Parties agree that effective July 28, 2006, the Companies' current base rates shall be reduced by $18,433,000 on an annual basis, based on a return on equity of 10.5%. Exhibit D, attached hereto and incorporated herein, is a cost of service showing the derivation of the Companies' stipulated base rate revenue requirement. Although no Stipulating Party agrees with each and every item in the attached cost of service, all parties agree that the overall cost of service is reasonable, and should be adopted by the Commission.

29. The base rates provided for in this Agreement reflect the recovery of the amortization of the Asset Retirement Obligation ("ARO") as proposed by the Companies in this case.

30. The rate changes with respect to base rate decreases, the feedback of the Bank, ENEC increases, and the 2006 construction surcharges shall be allocated among the customer classes as shown on Exhibit E attached hereto and incorporated herein.

Reliability Expenditures

31. The Companies shall collectively expend an average of $18,660,000 annually in each calendar year, 2007, 2008, and 2009, for measures designed to maintain and enhance reliability of service (i.e. right-of-way vegetation management and asset management activities). This annual sum constitutes an addition of $4.782 million over 2004 test year levels.

32. The Stipulating Parties agree that if APCo fails to earn a rate of return on common equity ("ROE") of at least 10.5% on a per books West Virginia retail jurisdictional basis during any of the calendar years, 2007, 2008, or 2009, APCo shall be entitled to defer an amount for T&D reliability expenditures sufficient to enable its ROE to equal 10.5%, up to a collective maximum annual deferral of $4.782 million. At its election, APCo shall be allowed to obtain appropriate recovery of any such deferrals in succeeding ENEC or base rate case(s) following such deferrals.

33. If the Companies intend to include in a case the issue of recovery of any deferral referred to in the preceding paragraph, the Companies will give prior notice to the other Stipulating Parties along with a calculation showing the derivation of the deferral. The other Stipulating Parties shall be free to take whatever position they deem appropriate concerning the appropriate amount of such recovery based on the ROE earned by APCo, the proper calculation of ROE, and the sums expended on T&D reliability measures.

34. The Companies recognize that it is their responsibility, as it is the responsibility of all public utilities in this State, under W Va. Code §24-3-1, to provide a reasonable level of reliable electric service to their customers. Nothing in this Agreement is intended to (1) relieve or limit the Companies' obligation to expend the funds needed to discharge this responsibility or (2) absolve the Companies of their legal duty as set forth in W. Va. Code §24-3-1.

Depreciation Rates

35. Effective July 1, 2006, APCo's West Virginia depreciation rates shall be modified in accordance with the schedule of depreciation rates attached hereto as Exhibit F and incorporated herein by reference.

36. Notwithstanding the provisions of this Agreement by which the Stipulating Parties agree to changes in the Companies' depreciation rates as a significant element of the Settlement, the Staff wishes to make clear that its agreement is due to the unique circumstances of this case. The Staff holds firm to its position that depreciation rate issues should not be part of any application filing in a base rate case, but should be addressed by a separate filing made pursuant to Rule 20 of the Commission's Rules of Practice and Procedure.

Special Rate Mechanism for Century Aluminum

37. The Stipulating Parties agree that Century provides important contributions to the economy of West Virginia in terms of good-paying industrial jobs, tax revenues, and other factors. In light of those contributions, the electric-energy-intensiveness of Century's operations, and the competitiveness of Century's industry, the Stipulating Parties agree that it is appropriate to undertake an experiment in devising and

applying a special rate mechanism to Century that is linked to the commodity price of aluminum and that compensates the Companies' ratepayers for the risks which the experiment poses for them. If approved by the Commission, the special rate mechanism experiment shall be implemented August 1, 2006 and shall operate as follows:

a. Century currently pays a rate equivalent to $27.16 per Mwh (the "current rate"). Subject to subpart c hereof, on and after August 1, 2006, Century shall pay each month to APCo the lower of the cost-based rate applicable to Century resulting from this or any future rate proceeding, or the current rate plus a surcharge based on the simple average daily price of aluminum for the month as quoted on the London Metal Exchange and as published by Reuters ("the LME price"). These surcharges are set forth in Exhibit G attached hereto and incorporated herein.

b. Each month the current price plus the surcharge will be greater than or less than the total rate responsibility allocated to Century. ("the otherwise applicable rate"). Century and APCo will keep a running cumulative balance of these monthly surpluses and deficits ("the Century Bank"). If in any month APCo does not receive adequate revenue under the experimental rate mechanism, including any payments from the Century Bank, equivalent to that which would be due from the otherwise applicable rate, APCo will be authorized to record a regulatory asset in the amount of such under-recovery for future recovery from the Companies' customers, as a part of its ENEC, at the conclusion of the experiment, pursuant to subpart d hereof. Century shall maintain a monthly accounting record of the Century Bank, subject to audit by the Companies and the Public Service Commission, showing the monthly and cumulative surplus or deficit.

c. As security for the Companies and other ratepayers, a portion of the monthly payments based on the current rate plus the applicable surcharge will be retained by APCo, up to $1,000,000, and will be paid by Century in months when the current price plus the applicable surcharge exceeds the otherwise applicable rate. That amount will be considered part of the Century Bank, although held by APCo as a regulatory liability to be credited to customers in accordance with subpart d hereof. At Century's option, the $1,000,000 amount can be paid to APCo in equal monthly payments during the first year of the experimental rate program. APCo will accrue interest on the amount collected under this subpart at the Commission's approved interest rate on deposits.

d. The experimental rate program will be reviewed by the Commission during the 2009 ENEC proceeding. If the experimental rate program is extended, any existing Century Bank balance will roll forward into the new plan. If the experimental rate program is terminated, Century will have no further obligations to pay or rights to receive payments under this program. If the program is terminated, the Companies will reflect any regulatory asset and/or regulatory liability as a net charge or credit to all customers, excluding Century, in the next ENEC proceeding.

e. If the Commission approves this experimental rate program in all its particulars, Century and APCo will negotiate a detailed contract to implement this experimental rate program and will file such contract with the Commission under Rule 39 of the Commission's Rules. If the Commission does not approve this experimental rate program in all its particulars, APCo shall have no obligation to provide service to Century other than at its otherwise applicable rate.

RS Rate Design

38. The increase allocated to the residential (RS) class shall be recovered from the usage blocks in that rate class. There will be no increase in the customer charge and no imposition of a separate minimum bill.

LGS Rate Design

39. The Stipulating Parties agree to modify the demand/energy split for the LGS rate schedule to reflect a demand charge at 80% of full cost. The base rate revenue reduction applicable to the LGS class shall be applied 80% to energy and 20% to demand. Customer migrations between MGS and LGS shall not be permitted until the next rate case, except in the case of material changes in load which result in a dramatic change in a customer's usage characteristics. However, the Companies agree that the accounts of Huntington/South Putnam and the water and sewer utilities that have supported the participation of Huntington/South Putnam in this proceeding (which are listed on Exhibit H attached hereto and incorporated herein) will have been placed on the appropriate MGS or LGS rate schedule for which they qualify prior to July 28, 2006.

Low-Income Weatherization Projects

40. For the next three years, the Companies shall make a collective annual contribution of $250,000 to the West Virginia Governor's Office of Economic Opportunity to be administered for WVCAP, to be used for low-income residential weatherization projects. The scheduling of the payments and the usage of the funds shall be arranged between the Companies and OEO weatherization staff on behalf of WVCAP.

Terms and Conditions of Service
<u>and Requested Rule Waivers</u>

41. The Companies have withdrawn their requests for a partial waiver of Electric Rule 4.2.1.a, for a grant of flexibility and discretion to require additional security deposits of non-residential customers, for the institution of fixed non-refundable charges for temporary service, and for a tariff modification concerning customer liability.

42. The Stipulating Parties agree that the Companies should be granted partial waivers of Electric Rules 4.8.1.a.F and 4.8.1.a H to enable them to defer non-emergency reconnections of service from times of darkness to times of daylight and authorize their field personnel to decline to accept cash payments to forestall disconnections of service for non-payment.

43. The Companies shall be authorized to impose a 1% delayed payment charge ("DPC") on a current bill owed by customers served under Rate Schedules R.S. and R.S. – T.O.D. if not paid "by the next scheduled read date." The DPC may be assessed only once on a given current bill. Before this new DPC is implemented, the Companies shall be required to give notice by bill message or bill insert to at least the customer classes affected, in two successive billing months, of the basic facts about the new DPC. The Companies shall change the proposed language in their tariffs about the point at which an account becomes subject to a DPC assessment for balances not paid "by the next bill preparation date" to "by the next scheduled read date." The approval and implementation of this new DPC shall have no effect on the DPCs already in operation under other rate schedules of the Companies.

Base Rate Case Filing Commitment

44. The Companies commit to filing a base rate case, predicated on a 2009 test year, by no later than the second quarter of 2010.

General Matters

45. The Stipulating Parties agree to waive their right to conduct in this proceeding any examination of the witnesses of any other party to this Agreement, except that the parties may ask clarifying questions concerning this Agreement.

46. This Agreement is entered into subject to the acceptance and approval of the Commission. It results from a review of any and all filings in this proceeding, the Stipulating Parties' prefiled testimony and exhibits, and extensive discovery and discussion. It reflects substantial compromises by the Stipulating Parties and the withdrawal of their respective positions asserted in this case, and is being proposed to expedite and simplify the resolution of this proceeding and other outstanding matters. It is made without any admission or prejudice to any positions which any party might adopt during subsequent litigation. The Stipulating Parties adopt this Agreement as being in the public interest, without adopting any of the compromise positions set forth herein as ratemaking principles applicable to future ENEC proceedings, Rule 42 proceedings, or other regulatory proceedings, except as expressly provided herein. The Stipulating Parties acknowledge that it is the Commission's prerogative to accept, reject, or modify any stipulation. However, in the event that this Agreement is rejected or modified by the Commission, it is expressly understood by the Stipulating Parties that they are not bound to accept this Agreement as modified or rejected, and may avail themselves of whatever

rights are available to them under law and the Commission's Rules of Practice and Procedure.

WHEREFORE, the Stipulating Parties (except the Staff with regard to the one element identified in Paragraph 15) on the basis of all the foregoing, respectfully request that the Commission make appropriate Findings of Fact and Conclusions of Law adopting and approving the Joint Stipulation and Agreement for Settlement in its entirety, including specifically Exhibits A through H.

Respectfully submitted this 24th day of April, 2006.

Respectfully Submitted

APPALACHIAN POWER COMPANY and WHEELING POWER COMPANY

By: ______________________

STAFF OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By: ______________________

CONSUMER ADVOCATE DIVISION OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By: ______________________

WEST VIRGINIA ENERGY USERS GROUP

By: ______________________________

CENTURY ALUMINUM OF WEST VIRGINIA, INC.

By: ______________________________

THE KROGER CO.

By: ______________________________

HUNTINGTON SANITARY BOARD AND SOUTH PUTNAM PUBLIC SERVICE DISTRICT

By: ______________________________

WEST VIRGINIA COMMUNITY ACTION PARTNERSHIP

By: ______________________________

{R0129314.1}

EXHIBIT A

Revised Section 2: Actual Period Ended December 31, 2004

ENEC Rates

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
EXPANDED NET ENERGY COST (ENEC) RATES
TWELVE MONTHS ENDED 12/31/2004
INCLUDES DATA CORRECTIONS

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
RS		1.612	
RS -TOD / RS-LM-TOD			
	ON-PEAK	1.617	
	OFF-PEAK	1.106	
SWS		1.619	
SGS		1.526	
SGS - LM-TOD			
	ON-PEAK	1.526	
	OFF-PEAK	1.169	
SS	-SEC	1.107	1.342
	-PRI	1.076	1.303
	-AF	1.539	
MGS	-SEC	1.107	1.159
	-PRI	1.077	1.125
	-SUBTRAN	1.057	1.095
	-TRANS	1.041	1.077
	-AF	1.541	
GS-TOD			
ON-PEAK	-SEC	1.864	
OFF-PEAK	-SEC	1.256	
ON-PEAK	- PRI	2.040	
OFF-PEAK	-PRI	1.318	
LGS	-SEC	1.106	1.660
	-PRI	1.076	1.612
	-SUBT	1.057	1.570
	-TRANS	1.041	1.544
LCP	-SEC	1.106	1.597
	- PRI	1.076	1.550
	- SUBT	1.057	1.511
	- TRANS	1.040	1.486
IP	-SEC	1.105	1.884
	- PRI	1.075	1.829
	- SUBT	1.057	1.782
	- TRANS		
	All Other	1.040	1.752
	SPECIAL CONTRACT I	1.040	1.752
	SPECIAL CONTRACT G	1.040	1.769
	SPECIAL CONTRACT H	1.040	2.212
OL		1.105	
SL		1.105	

SPECIAL CONTRACT A			
	FIRM POWER	1.040	1.752
	INTERRUPTIBLE DEMAND		1.162
	P1	1.040	
	P2	1.040	
	P2.5	1.040	
	P3	1.040	
	P4	1.040	
SPECIAL CONTRACT B			
	138 KV SERVICE		
	CAPACITY CHARGE		0.913
	P1	1.040	
	P2	1.040	
	P2.5	1.040	
	P3	1.040	
	P4	1.040	
	46 KV SERVICE		
	P1	1.055	
	P2	1.055	
	P2.5	1.055	
	P3	1.055	
	P4	1.055	
SPECIAL CONTRACT C			
	P1	1.096	
	P2	1.275	
	P3	12.752	
	P4	7.555	
SPECIAL CONTRACT D			
	FIRM POWER	1.054	1.777
	ON-PEAK DEMAND		0.644
	OFF-PEAK DEMAND EXCESS		0.118
	SHOULD. PEAK DEM. EXCESS		0.379
	INTERR. ENERGY	1.040	
SPECIAL CONTRACT E			
	-SEC		
	ON-PEAK	1.653	
	OFF-PEAK	1.385	
	SHOULDER PEAK	1.447	
	-PRI		
	ON-PEAK	1.674	
	OFF-PEAK	1.333	
	SHOULDER PEAK	1.418	
SPECIAL CONTRACT F			
	FIRM POWER	1.057	2.048
	BACK-UP POWER	1.057	0.205
	MAINTENANCE	1.094	

FLOODWALL ENEC Factor for floodwall accounts is the energy component of the appropriate general service tariff for which the customer would qualify.

EXHIBIT B

Revised Section 1

Attachment 1
Page 1 of 3

Revised Section 1: Proposed Period Ending December 31, 2006

ENEC Rates

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
PROPOSED EXPANDED NET ENERGY COST (ENEC) RATES
2006 ENEC FACTOR
INCLUDES DATA CORRECTION & INCLUDES CEREDO

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
RS		1.932	
RS -TOD / RS-LM-TOD			
	ON-PEAK	1.938	
	OFF-PEAK	1.407	
SWS		1.943	
SGS		1.846	
SGS - LM-TOD			
	ON-PEAK	1.846	
	OFF-PEAK	1.473	
SS	-SEC	1.408	1.387
	-PRI	1.369	1.347
	-AF	1.853	
MGS	-SEC	1.408	1.198
	-PRI	1.370	1.162
	-SUBTRAN	1.345	1.132
	-TRANS	1.325	1.113
	-AF	1.856	
GS-TOD			
ON-PEAK	-SEC	2.339	
OFF-PEAK	-SEC	1.406	
ON-PEAK	- PRI	2.554	
OFF-PEAK	-PRI	1.367	
LGS	-SEC	1.407	1.715
	-PRI	1.369	1.665
	-SUBT	1.345	1.622
	-TRANS	1.325	1.595
LCP	-SEC	1.407	1.649
	- PRI	1.369	1.601
	- SUBT	1.345	1.560
	- TRANS	1.323	1.534
IP	-SEC	1.406	1.948
	- PRI	1.368	1.890
	- SUBT	1.344	1.842
	- TRANS		
	All Other	1.323	1.811
SPECIAL CONTRACT I		1.323	1.811
SPECIAL CONTRACT G		1.323	1.834
SPECIAL CONTRACT H		1.324	2.269
OL		1.406	
SL		1.406	

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
PROPOSED EXPANDED NET ENERGY COST (ENEC) RATES
2006 ENEC FACTOR
INCLUDES DATA CORRECTION & INCLUDES CEREDO

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
SPECIAL CONTRACT A			
	FIRM POWER	1.323	1.811
	INTERRUPTIBLE DEMAND		1.852
	P1	1.323	
	P2	1.323	
	P2.5	1.323	
	P3	1.323	
	P4	1.323	
SPECIAL CONTRACT B			
	138 KV SERVICE		
	CAPACITY CHARGE		0.945
	P1	1.323	
	P2	1.323	
	P2.5	1.323	
	P3	1.323	
	P4	1.323	
	46 KV SERVICE		
	P1	1.343	
	P2	1.343	
	P2.5	1.343	
	P3	1.343	
	P4	1.343	
SPECIAL CONTRACT C			
	P1	1.383	
	P2	1.621	
	P3	16.208	
	P4	11.716	
SPECIAL CONTRACT D			
	FIRM POWER	1.3410	1.837
	ON-PEAK DEMAND		0.659
	SHOULD. PEAK DEM.		0.391
	OFF-PEAK DEMAND		0.121
	INTERR. ENERGY	1.3230	
SPECIAL CONTRACT E			
	-SEC		
	ON-PEAK	1.987	
	OFF-PEAK	1.665	
	SHOULDER PEAK	1.740	
	-PRI		
	ON-PEAK	2.001	
	OFF-PEAK	1.593	
	SHOULDER PEAK	1.695	
SPECIAL CONTRACT F			
	FIRM POWER	1.344	2.120
	BACK-UP POWER	1.344	0.212
	MAINTENANCE	1.382	

FLOODWALL ENEC Factor for floodwall accounts is the energy component of the appropriate general service tariff for which the customer would qualify.

EXHIBIT C

Baron Exhibit__(SJB-1R)
(Modified per Stipulation)

Appalachian Power Company
WVEUG Proposal to
Distribute ENEC Overrecovery
Case No. 05-1 278-E-PC-PW4ZT

Tariff	Voltage	WVEUG Settlement (total bank balance)	WVEUG Settlement (1st year 1/3rd feedback)
RS		27,899,511	9,299,837
SWS		269,845	89,948
SGS		1,222,031	407,344
SS	Sec.	803,504	267,835
SS	Pri.	46,266	15,422
SS	Ath. Field	10,983	3,661
		860,752	286,917
MGS	Sec.	3,252,179	1,084,060
MGS	Pri.	364,330	121,443
MGS	Subtr.	21,653	7,218
MGS	Trans.	-	-
MGS	Ath. Field	6,011	2,004
		3,644,173	1,214,724
GS-LMTOD	Sec-pea k	35,890	11,963
GS-LMTOD	Sec-off	19,089	6,363
GS-LMTOD	Pri -peak	22,663	7,554
GS-LMTOD	Pri- off	8,443	2,814
		86,086	28,695
LGS	Sec.	3,236,546	1,078,849
LGS	Pri.	493,058	164,353
LGS	Subtr.	12,999	4,333
LGS	Trans.	-	-
		3,742,603	1,247,534
LCP	Sec.	250,008	83,336
LCP	Pri.	1,407,623	469,208
LCP	Subtr.	2,411,049	803,683
LCP	Trans.	723,990	241,330
		4,792,671	1,597,557
IP	Sec.	201,991	67,330
IP	Pri.	2,262,228	754,076
IP	Subtr.	2,043,526	681,175
IP	Trans.	1,251,161	417,054
		5,758,907	1,919,636
SPECIAL A		-	-
SPECIAL B		437,195	145,732
SPECIAL C		4,244	1,415
SPECIAL D		418,383	139,461
SPECIAL E		9,996	3,332
SPECIAL F		78,987	26,329
SPECIAL G		1,217,003	405,668
SPECIAL H		-	-
SPECIAL I		552,492	184,164
OL		137,008	45,669
SL		76,093	25,364
TOTAL		51,207,981	17,069,327

EXHIBIT D

Exhibit ________

Appalachian Power Company and Wheeling Power Company
Case No. 05-1278-E-PC-PW-42T
Revenue Requirement Calculation for Settlement

	Settlement
Weighted Cost of Capital	7.601%
Return on Equity	10.50%
Rate Base	1,657,541,508
Return on Rate Base	125,996,586
Federal Taxes	31,499,147
State Taxes	11,969,676
Operation & Maintenance Expense	727,297,676
Depreciation Expense	79,833,661
Taxes Other Than Income	53,803,432
Total Expenses	904,403,591
Revenue Requirement	1,030,400,177
Going Level Revenues	1,048,473,441
Subtotal	(18,073,264)
Additional Uncollectibles	(65,064)
Additonal B&O	(291,702)
Revenue Increase/(Decrease)	(18,430,030)

EXHIBIT E

Appalachian Power Company
Revenue Changes by Tariff Class
Case No. 05-1278-E-PC-PW-42T

Tariff	Base Rate Decrease	ENEC Increase	Construction Surcharge	Net Revenue Change	ENEC Bank Amortization	Net Impact
RS	$2,422,695	$18,735,076	$9,321,136	$30,478,907	($9,299,837)	$21,179,070
SWS	($49,693)	$284,837	$141,870	$377,015	($89,948)	$287,066
SGS	($313,432)	$794,042	$328,594	$809,203	($407,344)	$401,860
SS	($202,033)	$1,068,225	$513,713	$1,379,905	($286,917)	$1,092,988
MGS	($4,769,035)	$4,649,496	$2,168,946	$2,049,407	($1,243,420)	$805,987
LGS	($3,846,810)	$4,846,586	$1,921,120	$2,920,896	($1,247,534)	$1,673,362
LCP	($4,361,852)	$6,185,894	$2,461,890	$4,285,933	($1,597,557)	$2,688,376
IP	($3,826,607)	$7,613,388	$2,655,841	$6,442,622	($1,919,636)	$4,522,986
SPECIAL A	($8,117)	$136,538	$24,304	$152,725	$0	$152,725
SPECIAL B	($203,009)	$596,431	$190,164	$583,586	($145,732)	$437,854
SPECIAL C	($8,105)	$6,739	$256	($1,110)	($1,415)	($2,525)
SPECIAL D	($392,810)	$594,700	$139,778	$341,668	($139,461)	$202,207
SPECIAL E	$94	$11,929	$4,482	$16,505	($3,332)	$13,173
SPECIAL F	($40,547)	$107,780	$35,765	$102,998	($26,329)	$76,669
SPECIAL G	($508,467)	$1,205,428	$354,502	$1,051,463	($405,668)	$645,796
SPECIAL H	($1,125,428)	$8,121,578	$2,705,226	$9,701,376	$0	$9,701,376
SPECIAL I	($431,249)	$742,623	$242,311	$553,685	($184,164)	$369,521
				$0		
OL	($560,767)	$222,218	$0	($338,549)	($45,669)	($384,218)
SL	($204,858)	$87,575	$0	($117,283)	($25,364)	($142,647)
TOTAL	($18,430,000)	$56,011,083	$23,209,899	$60,790,982	($17,069,327)	$43,721,655

EXHIBIT F

Exhibit No ______

Appalachian Power Company
Depreciation Rates
Case No. 05-1278-E-PC-PW-42T

	Current Rates	New Rates
Steam Production		
Mountaineer	2.64%	1.93%
Amos	2.79%	2.98%
Kanawha River	3.88%	1.19%
Sporn	4.86%	1.53%
Clinch River	3.48%	3.00%
Glyn Lyn 5	0.92%	4.99%
Glyn Lyn 6	3.71%	4.00%
Hydro Production		
Claytor	2.71%	1.17%
Byllesby	2.90%	2.89%
Buck	3.21%	2.95%
Niagara	2.31%	2.41%
Ruesens	1.69%	1.64%
Leesville	2.51%	1.21%
London	1.65%	1.85%
Marmet	1.65%	1.91%
Winfield	1.65%	1.76%
Smith Mountain	3.39%	1.29%
Other Production		
Central Maintenance	4.02%	2.07%
Central Machine	4.02%	2.10%
Little Broad Run	4.02%	1.76%
Transmission Plant	2.21%	1.63%
Distribution Plant	3.20%	3.37%
General Plant	3.14%	1.80%

EXHIBIT G

SCHEDULE B
CENTURY ALUMINUM OF WEST VIRGINIA, INC.
MAXIMUM MONTHLY SURCHARGE [(1)]

MONTHLY LME PRICE [(2)]	MAXIMUM MONTHLY SURCHARGE [(3)]
$2200/tonne or less ($0.998/lb or less)	Zero
$2300/tonne ($1.043/lb)	1.87 mills/kWh
$2400/tonne ($1.089/lb)	3.73 mills/kWh
$2500/tonne ($1.134/lb)	5.56 mills/kWh
$2600/tonne ($1.179/lb)	7.43 mills/kWh
$2700/tonne ($1.225/lb)	9.30 mills/kWh
$2800/tonne ($1.270/lb)	11.16 mills/kWh
$2900/tonne ($1.315/lb)	12.99 mills/kWh
$3000/tonne ($1.361/lb)	14.86 mills/kWh

(1) The **Maximum Monthly Surcharge** shall remain in effect for the full term of this agreement, unless modified by Century Aluminum and approved by the PSC of West Virginia.

(2) The **LME PRICE** shall be defined as the daily cash settlement for high grade aluminum, as quoted on the London Metal Exchange (as published by Reuters). The monthly LME Price shall be the simple average of the daily prices.

(3) For LME prices not shown, the **Maximum Monthly Surcharge** may be interpolated between the points.

EXHIBIT H

PUBLICLY-OWNED SEWER AND WATER UTILITIES SUPPORTING INTERVENTION OF SOUTH PUTNAM PSD AND HUNTINGTON SANITARY BOARD THROUGH CONTRIBUTIONS UNDERWRITING EXPERT WITNESS AND ATTORNEY FEES

Bluewell Public Service District

Chelyan Public Service District

Culloden Public Service District

Fayetteville, Town of

Hodgesville Public Service District/
Tennerton Public Service District

Hurricane Water & Sanitary Board

Lavalette Public Service District

Logan County Public Service District

Oakvale Road Public Service District

Pea Ridge Public Service District

West Hamlin, Town of

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	STEAM PRODUCTION PLANT											
	MOUNTAINEER			2040								
311.0	Structures & Improvements	94,162,401	FCST.		1.06	99,812,145	40,360,427	46,607,678	53,204,467	33.85	1,571,772	1.67%
312.0	Boiler Plant Equipment	517,306,950	FCST.		1.13	584,556,854	219,955,014	254,001,090	330,555,763	31.76	10,407,927	2.01%
314.0	Turbogenerator Units	88,101,139	FCST.		1.14	100,435,298	41,606,473	48,046,595	52,388,703	31.05	1,687,237	1.92%
315.0	Accessory Electrical Equipment	65,084,612	FCST.		1.07	69,640,535	29,370,139	33,916,241	35,724,294	33.25	1,074,415	1.65%
316.0	Misc. Power Plant Equip.	15,391,998	FCST.		1.11	17,085,118	6,777,673	7,826,766	9,258,352	32.18	287,705	1.87%
	Total	780,047,100				871,529,950	338,069,726	390,398,370	481,131,580		15,029,055	1.93%
	KANAWHA RIVER			2018								
311.0	Structures & Improvements	17,350,476	FCST.		1.01	17,523,981	12,988,577	16,773,231	750,750	12.41	60,496	0.35%
312.0	Boiler Plant Equipment	93,526,135	FCST.		1.03	96,331,919	62,315,936	80,473,755	15,858,164	12.14	1,306,274	1.40%
314.0	Turbogenerator Units	32,501,320	FCST.		1.04	33,801,373	23,085,600	29,812,357	3,989,016	12.05	331,039	1.02%
315.0	Accessory Electrical Equipment	8,396,631	FCST.		1.02	8,564,564	5,972,933	7,713,346	851,218	12.34	68,980	0.82%
316.0	Misc. Power Plant Equip.	4,877,087	FCST.		1.03	5,023,400	2,928,170	3,781,390	1,242,010	12.20	101,804	2.09%
	Total	156,651,649				161,245,236	107,291,216	138,554,077	22,691,159		1,868,593	1.19%
	AMOS			UNIT 1&2 2032 UNIT 3 2033								
311.0	Structures & Improvements - Units 1,2	31,257,107	FCST.		1.05	32,819,962	17,165,428	15,500,440	17,319,523	26.11	663,329	2.12%
311.0	Structures & Improvements - Unit 3	20,706,443	FCST.		1.05	21,741,765	11,271,073	10,177,817	11,563,948	27.08	427,029	2.06%
312.0	Boiler Plant Equipment - Units 1,2	593,072,413	FCST.		1.10	652,379,654	199,570,686	180,213,007	472,166,648	24.89	18,970,134	3.20%
312.0	Boiler Plant Equipment - Unit 3	161,596,564	FCST.		1.10	177,756,220	66,507,429	60,056,434	117,699,786	25.76	4,569,091	2.83%
314.0	Turbogenerator Units - Units 1,2	91,058,126	FCST.		1.12	101,985,101	44,625,810	40,297,258	61,687,843	24.46	2,521,989	2.77%
314.0	Turbogenerator Units - Unit 3	23,535,111	FCST.		1.12	26,359,324	10,994,182	9,927,784	16,431,541	25.31	649,211	2.76%
315.0	Accessory Electrical Equipment-Units 1,2	36,563,945	FCST.		1.07	39,123,421	17,986,271	16,241,664	22,881,757	25.76	888,267	2.43%
315.0	Accessory Electrical Equipment-Unit 3	9,159,965	FCST.		1.06	9,709,563	4,687,440	4,232,774	5,476,789	26.71	205,046	2.24%
316.0	Misc. Power Plant Equip. - Units 1,2	3,600,018	FCST.		1.08	3,888,019	1,861,346	1,680,802	2,207,218	25.13	87,832	2.44%
316.0	Misc. Power Plant Equip. - Unit 3	13,053,976	FCST.		1.08	14,098,294	4,932,995	4,454,511	9,643,783	26.03	370,487	2.84%
	Total	983,603,668				1,079,861,325	379,602,660	342,782,490	737,078,835		29,352,416	2.98%
	SPORN			2018								
311.0	Structures & Improvements	12,169,979	FCST.		1.05	12,778,478	9,196,348	12,451,298	327,180	12.41	26,364	0.22%
312.0	Boiler Plant Equipment	78,626,019	FCST.		1.06	83,343,580	48,015,680	65,010,320	18,333,261	12.14	1,510,153	1.92%
314.0	Turbogenerator Units	18,048,132	FCST.		1.07	19,311,501	12,693,083	17,185,665	2,125,836	12.05	176,418	0.98%
315.0	Accessory Electrical Equipment	6,570,200	FCST.		1.05	6,898,710	4,513,446	6,110,932	787,778	12.34	63,839	0.97%
316.0	Misc. Power Plant Equip.	3,155,274	FCST.		1.07	3,376,143	2,159,335	2,923,609	452,535	12.20	37,093	1.18%
	Total	118,569,604				125,708,413	76,577,892	103,681,823	22,026,590		1,813,868	1.53%

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
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ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	CLINCH RIVER			2021								
311.0	Structures & Improvements	34,770,730	FCST.		1.01	35,118,437	21,549,549	21,337,359	13,781,079	15.37	896,622	2.58%
312.0	Boiler Plant Equipment	160,791,813	FCST.		1.04	167,223,486	89,824,380	88,939,913	78,283,572	14.95	5,236,359	3.26%
314.0	Turbogenerator Units	56,450,106	FCST.		1.05	59,272,611	37,374,592	37,006,579	22,266,033	14.80	1,504,462	2.67%
315.0	Accessory Electrical Equipment	11,548,753	FCST.		1.02	11,779,728	7,777,927	7,701,341	4,078,387	15.25	267,435	2.32%
316.0	Misc. Power Plant Equip.	5,037,599	FCST.		1.03	5,188,727	2,905,079	2,876,474	2,312,253	15.03	153,843	3.05%
	Total	268,599,001				278,582,989	159,431,527	157,861,665	120,721,324		8,058,721	3.00%
	GLEN LYN UNIT 5			2012								
311.0	Structures & Improvements	3,203,253	FCST.		1.01	3,235,286	2,448,029	2,392,111	843,175	6.48	130,120	4.06%
312.0	Boiler Plant Equipment	22,595,346	FCST.		1.02	23,047,253	16,305,826	15,933,364	7,113,888	6.40	1,111,545	4.92%
314.0	Turbogenerator Units	6,466,012	FCST.		1.02	6,595,332	4,416,243	4,315,366	2,279,966	6.38	357,361	5.53%
315.0	Accessory Electrical Equipment	2,141,252	FCST.		1.01	2,162,665	1,481,826	1,447,978	714,687	6.46	110,633	5.17%
316.0	Misc. Power Plant Equip.	133,832	FCST.		1.02	136,509	47,626	46,538	89,971	6.42	14,014	10.47%
	Total	34,539,695				35,177,044	24,699,550	24,135,357	11,041,687		1,723,673	4.99%
	GLEN LYN UNIT 6			2015								
311.0	Structures & Improvements	12,235,833	FCST.		1.01	12,358,191	9,198,427	8,724,224	3,633,967	9.45	384,547	3.14%
312.0	Boiler Plant Equipment	65,674,477	FCST.		1.03	67,644,711	43,604,185	41,356,277	26,288,434	9.29	2,829,756	4.31%
314.0	Turbogenerator Units	20,940,304	FCST.		1.03	21,568,513	15,332,810	14,542,364	7,026,149	9.24	760,406	3.63%
315.0	Accessory Electrical Equipment	5,888,751	FCST.		1.02	6,006,526	4,351,918	4,127,565	1,878,961	9.41	199,677	3.39%
316.0	Misc. Power Plant Equip.	3,078,101	FCST.		1.03	3,170,444	1,948,925	1,848,453	1,321,991	9.32	141,845	4.61%
	Total	107,817,466				110,748,386	74,436,265	70,598,884	40,149,502		4,316,230	4.00%
	OTHER											
788.0	Centralized Maintenence	85,770	FCST.	2040	1.00	85,770	26,239	25,546	60,224	33.85	1,779	2.07%
748.0	Central Machine Shop	9,394,028	FCST.	2040	1.00	9,394,028	3,135,233	3,052,448	6,341,580	32.18	197,066	2.10%
714.0	Little Broad Run Ash Disposal	1,185,159	FCST.	2040	1.00	1,185,159	537,856	523,654	661,505	31.76	20,828	1.76%
	Total	10,664,957				10,664,957	3,699,328	3,601,648	7,063,309		219,673	2.06%
	Total Steam Production Plant	2,460,493,140				2,673,518,299	1,163,808,164	1,231,614,314	1,441,903,985		62,382,229	2.54%
HYDRAULIC PRODUCTION PLANT - CONVENTIONAL												
	CLAYTOR			2041								
331.0	Structures & Improvements	1,857,385	FCST.		1.07	1,987,402	915,377	1,163,207	824,195	34.56	23,848	1.28%
332.0	Reservoirs, Dams & Waterways	9,649,464	FCST.		1.07	10,324,926	5,816,242	7,390,939	2,933,988	34.93	83,996	0.87%
333.0	Waterwheels, Turbines & Gen.	2,033,553	FCST.		1.07	2,175,902	1,325,395	1,684,234	491,668	33.67	14,603	0.72%
334.0	Accessory Electrical Equip.	2,777,547	FCST.		1.07	2,971,975	1,130,881	1,437,057	1,534,918	31.03	49,466	1.78%
335.0	Misc. Power Plant Equip.	1,941,693	FCST.		1.07	2,077,612	521,847	663,133	1,414,479	33.42	42,324	2.18%
336.0	Roads, Railroads & Bridges	31,799	FCST.		1.07	34,025	21,906	27,837	6,188	35.50	174	0.55%
	Total	18,291,441				19,571,842	9,731,648	12,366,407	7,205,435		214,411	1.17%

APPALACHIAN POWER COMPANY
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BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
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ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	BYLLESBY			2024								
331.0	Structures & Improvements	818,261	FCST.		1.07	875,539	560,925	416,163	459,376	18.24	8,919	1.09%
332.0	Reservoirs, Dams & Waterways	4,121,283	FCST.		1.07	4,409,773	2,435,649	1,807,063	2,602,710	18.35	126,936	3.08%
333.0	Waterwheels, Turbines & Gen.	1,778,552	FCST.		1.07	1,903,051	1,172,201	869,682	1,033,368	18.00	70,786	3.98%
334.0	Accessory Electrical Equip.	963,627	FCST.		1.07	1,031,081	677,503	502,655	528,426	17.29	21,296	2.21%
335.0	Misc. Power Plant Equip.	604,218	FCST.		1.07	646,513	221,194	164,109	482,404	17.94	11,238	1.86%
	Total	8,285,941				8,865,957	5,067,472	3,759,671	5,106,286		239,176	2.89%
	BUCK			2024								
331.0	Structures & Improvements	313,749	FCST.		1.07	335,711	253,019	215,436	120,275	18.24	3,388	1.08%
332.0	Reservoirs, Dams & Waterways	4,853,563	FCST.		1.07	5,193,312	2,769,679	2,358,272	2,835,040	18.35	124,737	2.57%
333.0	Waterwheels, Turbines & Gen.	1,258,750	FCST.		1.07	1,346,863	837,009	712,680	634,183	18.00	61,301	4.87%
334.0	Accessory Electrical Equip.	2,492,373	FCST.		1.07	2,666,839	1,017,710	866,540	1,800,299	17.29	74,522	2.99%
335.0	Misc. Power Plant Equip.	111,858	FCST.		1.07	119,688	75,113	63,956	55,732	17.94	2,170	1.94%
336.0	Roads, Railroads & Bridges	3,437	FCST.		1.07	3,678	2,981	2,538	1,140	18.50	36	1.05%
	Total	9,033,730				9,666,091	4,955,511	4,219,422	5,446,669		266,154	2.95%
	NIAGARA			2024								
331.0	Structures & Improvements	196,124	FCST.		1.07	209,853	155,819	104,151	105,702	18.24	2,628	1.34%
332.0	Reservoirs, Dams & Waterways	4,906,269	FCST.		1.07	5,249,708	2,328,782	1,556,576	3,693,132	18.35	105,975	2.16%
333.0	Waterwheels, Turbines & Gen.	626,066	FCST.		1.07	669,891	343,998	229,931	439,960	18.00	27,735	4.43%
334.0	Accessory Electrical Equip.	196,432	FCST.		1.07	210,182	117,524	78,554	131,628	17.29	3,968	2.02%
335.0	Misc. Power Plant Equip.	218,800	FCST.		1.07	234,116	101,706	67,981	166,135	17.94	7,483	3.42%
	Total	6,143,691				6,573,749	3,047,829	2,037,193	4,536,556		147,789	2.41%
	RUESENS			2024								
331.0	Structures & Improvements	473,944	FCST.		1.07	507,120	267,610	199,578	307,542	18.24	3,649	0.77%
332.0	Reservoirs, Dams & Waterways	1,587,411	FCST.		1.07	1,698,530	570,480	425,452	1,273,078	18.35	20,160	1.27%
333.0	Waterwheels, Turbines & Gen.	1,652,343	FCST.		1.07	1,768,007	902,044	672,725	1,095,282	18.00	37,012	2.24%
334.0	Accessory Electrical Equip.	890,140	FCST.		1.07	952,450	485,011	361,711	590,739	17.29	10,593	1.19%
335.0	Misc. Power Plant Equip.	305,931	FCST.		1.07	327,346	159,414	118,887	208,459	17.94	9,300	3.04%
	Total	4,909,769				5,253,453	2,384,559	1,778,353	3,475,100		80,715	1.64%
	LEESVILLE			2040								
331.0	Structures & Improvements	2,136,795	FCST.		1.07	2,286,371	1,251,422	1,665,992	620,379	33.61	18,458	0.86%
332.0	Reservoirs, Dams & Waterways	10,439,935	FCST.		1.07	11,170,730	4,809,932	6,403,361	4,767,369	33.96	140,382	1.34%
333.0	Waterwheels, Turbines & Gen.	3,038,483	FCST.		1.07	3,251,177	1,762,965	2,346,998	904,179	32.77	27,592	0.91%
334.0	Accessory Electrical Equip.	579,557	FCST.		1.07	620,126	315,545	420,078	200,048	30.28	6,607	1.14%
335.0	Misc. Power Plant Equip.	1,173,274	FCST.		1.07	1,255,403	516,824	688,037	567,366	32.54	17,436	1.49%
336.0	Roads, Railroads & Bridges	80,790	FCST.		1.07	86,445	47,116	62,725	23,720	34.50	688	0.85%
	Total	17,448,834				18,670,252	8,703,804	11,587,191	7,083,061		211,162	1.21%

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	LONDON			2044								
331.0	Structures & Improvements	544,668	FCST.		1.07	582,795	239,093	227,158	355,637	37.39	9,512	1.75%
332.0	Reservoirs, Dams & Waterways	679,103	FCST.		1.07	726,640	348,163	330,784	395,856	37.83	10,464	1.54%
333.0	Waterwheels, Turbines & Gen.	1,243,977	FCST.		1.07	1,331,055	679,509	645,590	685,465	36.35	18,857	1.52%
334.0	Accessory Electrical Equip.	1,806,433	FCST.		1.07	1,932,883	664,894	631,705	1,301,178	33.24	39,145	2.17%
335.0	Misc. Power Plant Equip.	401,986	FCST.		1.07	430,125	117,125	111,279	318,846	36.05	8,845	2.20%
336.0	Roads, Railroads & Bridges	48,853	FCST.		1.07	52,273	26,662	25,331	26,942	38.50	700	1.43%
	Total	4,725,020				5,055,771	2,075,446	1,971,847	3,083,924		87,522	1.85%
	MARMET			2044								
331.0	Structures & Improvements	598,323	FCST.		1.07	640,206	286,888	261,247	378,959	37.39	10,135	1.69%
332.0	Reservoirs, Dams & Waterways	708,044	FCST.		1.07	757,607	356,652	324,775	432,832	37.83	11,441	1.62%
333.0	Waterwheels, Turbines & Gen.	1,114,921	FCST.		1.07	1,192,965	626,112	570,152	622,814	36.35	17,134	1.54%
334.0	Accessory Electrical Equip.	2,072,679	FCST.		1.07	2,217,767	758,282	690,508	1,527,258	33.24	45,946	2.22%
335.0	Misc. Power Plant Equip.	443,556	FCST.		1.07	474,605	129,933	118,320	356,285	36.05	9,883	2.23%
336.0	Roads, Railroads & Bridges	1,275	FCST.		1.07	1,364	701	638	726	38.50	19	1.48%
	Total	4,938,798				5,284,514	2,158,568	1,965,640	3,318,874		94,559	1.91%
	WINFIELD			2044								
331.0	Structures & Improvements	457,134	FCST.		1.07	489,133	213,535	213,768	275,366	37.39	7,365	1.61%
332.0	Reservoirs, Dams & Waterways	1,287,289	FCST.		1.07	1,377,399	587,779	588,419	788,980	37.83	20,856	1.62%
333.0	Waterwheels, Turbines & Gen.	934,699	FCST.		1.07	1,000,128	579,746	580,378	419,750	36.35	11,547	1.24%
334.0	Accessory Electrical Equip.	84,392	FCST.		1.07	90,299	48,384	48,437	41,863	33.24	1,259	1.49%
335.0	Misc. Power Plant Equip.	3,028,933	FCST.		1.07	3,240,958	1,055,464	1,056,614	2,184,344	36.05	60,592	2.00%
336.0	Roads, Railroads & Bridges	23,567	FCST.		1.07	25,217	5,075	5,081	20,136	38.50	523	2.22%
	Total	5,816,014				6,223,135	2,489,983	2,492,696	3,730,439		102,143	1.76%
	Total Hydraulic Production - Conventional	79,593,238				85,164,765	40,614,820	42,178,420	42,986,345		1,443,631	1.81%
HYDRAULIC PRODUCTION PLANT - PUMPED STORAGE												
	SMITH MOUNTAIN			2040								
331.0	Structures & Improvements	12,079,151	FCST.		1.07	12,924,692	6,326,896	8,685,105	4,239,587	33.61	126,141	1.04%
332.0	Reservoirs, Dams & Waterways	24,730,954	FCST.		1.07	26,462,121	13,449,471	18,462,460	7,999,661	33.96	235,561	0.95%
333.0	Waterwheels, Turbines & Gen.	56,457,401	FCST.		1.07	60,409,419	24,540,300	33,687,147	26,722,273	32.77	815,449	1.44%
334.0	Accessory Electrical Equip.	7,270,041	FCST.		1.07	7,778,944	3,153,130	4,328,389	3,450,555	30.28	113,955	1.57%
335.0	Misc. Power Plant Equip.	4,470,378	FCST.		1.07	4,783,304	1,852,619	2,543,141	2,240,163	32.54	68,843	1.54%
336.0	Roads, Railroads & Bridges	1,052,133	FCST.		1.07	1,125,782	572,513	785,904	339,878	34.50	9,852	0.94%
	Total Pumped Storage	106,060,058				113,484,262	49,894,929	68,492,145	44,992,117		1,369,801	1.29%
	Total Hydraulic Production	185,653,296				198,649,027	90,509,749	110,670,565	87,978,462		2,813,432	1.52%

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
TRANSMISSION PLANT												
352.0	Structures & Improvements	43,114,120	55 R3.0	N.A.	1.00	43,114,120	15,197,213	19,268,856	23,845,264	35.61	669,623	1.55%
353.0	Station Equipment	538,487,127	35 R2.0	N.A.	0.85	457,714,058	193,736,912	245,642,982	212,071,076	20.19	10,503,768	1.95%
354.0	Towers & Fixtures	230,212,337	87 R2.5	N.A.	1.10	253,233,571	67,077,432	85,048,844	168,184,727	63.96	2,629,530	1.14%
355.0	Poles & Fixtures	98,737,201	37 L2.0	N.A.	1.15	113,547,781	32,751,846	41,526,733	72,021,048	26.33	2,735,323	2.77%
356.0	OH Conductor & Devices	283,492,453	80 R2.5	N.A.	0.90	255,143,208	69,590,864	88,235,676	166,907,532	58.18	2,868,813	1.01%
357.0	Underground Conduit	255,431	55 S2.0	N.A.	1.00	255,431	139,080	176,342	79,089	25.05	3,157	1.24%
358.0	Underground Conductor	3,671,406	25 L3.0	N.A.	1.00	3,671,406	1,588,000	2,013,458	1,657,948	14.19	116,839	3.18%
	Total Transmission Plant	1,197,970,075				1,126,679,575	380,081,347	481,912,891	644,766,684		19,527,053	1.63%
DISTRIBUTION PLANT (WEST VIRGINIA)												
361.0	Structures & Improvements	12,769,337	43 R4.0	N.A.	1.00	12,769,337	4,700,965	5,214,764	7,554,573	27.17	278,048	2.18%
362.0	Station Equipment	88,168,409	37 R1.0	N.A.	0.85	74,943,148	21,083,048	23,387,351	51,555,797	26.59	1,938,917	2.20%
364.0	Poles, Towers, & Fixtures	236,073,582	30 R1.5	N.A.	1.55	365,914,052	117,202,052	130,011,825	235,902,228	20.39	11,569,506	4.90%
365.0	Overhead Conductor & Devices	182,080,409	43 L0.0	N.A.	0.85	154,768,348	26,816,293	29,747,220	125,021,128	35.55	3,516,769	1.93%
366.0	Underground Conduit	25,050,422	47 S6.0	N.A.	1.00	25,050,422	7,111,627	7,888,903	17,161,519	33.66	509,849	2.04%
367.0	Underground Conductor	44,620,493	52 R0.5	N.A.	1.00	44,620,493	6,148,481	6,820,488	37,800,005	44.83	843,185	1.89%
368.0	Line Transformers	170,926,200	32 R0.5	N.A.	1.10	188,018,820	49,083,168	54,447,786	133,571,034	23.65	5,647,824	3.30%
369.0	Services	100,346,183	36 R0.5	N.A.	1.13	113,391,187	23,588,768	26,166,937	87,224,249	28.51	3,059,426	3.05%
370.0	Meters	41,450,459	25 S6.0	N.A.	1.10	45,595,505	17,342,458	19,237,928	26,357,577	15.49	1,701,587	4.11%
371.0	Installations on Custs. Prem.	23,266,459	11 S6.0	N.A.	1.08	25,127,776	11,291,126	12,525,206	12,602,569	6.06	2,079,632	8.94%
373.0	Street Lighting & Signal Sys.	6,910,400	21 S6.0	N.A.	0.95	6,564,880	3,244,937	3,599,597	2,965,283	10.62	279,217	4.04%
	Total Distribution Plant (West Virginia)	931,662,353			11.61	1,056,763,967	287,612,923	319,048,005	737,715,962		31,423,960	3.37%
GENERAL PLANT												
390.0	Structures & Improvements	97,515,978	38 R3.0	N.A.	0.72	70,211,504	24,276,548	35,900,071	34,311,433	24.86	1,380,186	1.42%
391.0	Office Furniture & Equipment	5,195,551	30 L3.0	N.A.	0.95	4,935,773	1,399,392	2,069,416	2,866,358	21.49	133,381	2.57%
392.0	Transportation Equipment	16,942	27 S6.0	N.A.	0.95	16,095	9,401	13,902	2,193	11.23	195	1.15%
393.0	Stores Equipment	838,300	55 R4.0	N.A.	1.00	838,300	296,468	438,416	399,884	35.55	11,249	1.34%
394.0	Tools Shop & Garage Equipment	11,190,608	43 R0.5	N.A.	1.00	11,190,608	1,621,623	2,398,050	8,792,558	36.77	239,123	2.14%
395.0	Laboratory Equipment	2,516,760	37 S2.0	N.A.	1.00	2,516,760	1,266,309	1,872,613	644,147	18.38	35,046	1.39%
396.0	Power Operated Equipment	3,662	25 L2.0	N.A.	1.00	3,662	2,303	3,406	256	9.27	28	0.76%
397.0	Communication Equipment	21,536,031	24 R0.5	N.A.	0.95	20,459,229	5,882,076	8,698,393	11,760,837	17.10	687,768	3.19%
398.0	Miscellaneous Equipment	2,383,390	35 S6.0	N.A.	1.00	2,383,390	900,768	1,332,052	1,051,338	21.77	48,293	2.03%
	Total General Plant	141,197,222				112,555,322	35,654,888	52,726,319	59,829,003		2,535,268	1.80%

APPALACHIAN POWER COMPANY

DEPRECIATION STUDY REPORT

OF

ELECTRIC PLANT IN SERVICE

AT DECEMBER 31, 2005

CONTENTS

INTRODUCTION

This report presents the results of a depreciation study of Appalachian Power Company's (APCO) depreciable electric utility plant in service at December 31, 2005. The study was prepared by James E. Henderson, Senior Staff Accountant at American Electric Power Service Corporation (AEPSC). The purpose of this depreciation study was to develop appropriate annual depreciation accrual rates for each of the primary plant accounts that comprise the functional groups for which APCO computes its annual depreciation expense.

The recommended depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in this Study is the same as that used by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."
>
> "Service value means the difference between original cost and the net

salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant." (FERC Accounting and Reporting Requirements for Public Utilities and Licensees, ¶15.001.)

Section I of this report contains Schedule I, which shows the recommended depreciation accrual rates by primary plant accounts and composited to functional plant classifications and Schedule II, that shows a comparison of the current mortality characteristics that were used to compute the recommended depreciation rates and the mortality characteristics used to determine the existing depreciation rates and accruals for the Transmission, Distribution and General Plant Functions. A comparison of APCO's current functional group composite depreciation rates and accruals to the recommended functional group rates and accruals follows:

Annual Rates and Accruals
($000)
Total Company

	Existing		Recommended		Increase
Functional Group	Rate %	Amount	Rate %	Amount	(Decrease)
Steam Production	3.84	95,726,298	2.30	57,323,936	(38,402,362)
Hydraulic Production	2.99	5,542,344	1.46	2,703,241	(2,839,103)
Other Production	2.86	2,277,298	3.28	2,840,909	363,611
Transmission Plant	2.19	26,235,545	1.63	19,508,062	(6,727,483)
Distribution Plant	3.31	69,517,785	3.35	70,383,558	1,610,765
General Plant	3.24	4,574,790	1.72	2,432,222	(2,142,568)
Total	3.29	$204,074,060	2.50	$155,191,928	$(48,882,132)

Based on Depreciable Plant In Service as of December 31, 2005, I am recommending a decrease in annual depreciation expense of $48,882,132 or 0.79% in the annual composite rate. The depreciation rate changes are necessary because of changes (both increases and decreases) in the average service lives and the gross salvage and gross cost of removal estimates that were used to calculate APCO's current depreciation rates.

Section II of this report contains an explanation of the methods and procedures used in this study. Examples of computations discussed in Section II appear in Appendix A.

SECTION I

SCHEDULES

SCHEDULES

SCHEDULE	SUBJECT
I	Determination of Recommended Annual Depreciation Rates and Accruals by Primary Plant Account
II	Comparison of Mortality Characteristics for Transmission, Distribution and General Plant

SCHEDULE I

Schedule I shows the determination of the recommended annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number.
Column II	-	Account title.
Column III	-	Original Cost at December 31, 2004
Column IV	-	Average Life and (Iowa) Curve Type.
Column V	-	Terminal Retirement Date for accounts utilizing Life-Span Analysis
Column VI	-	Net Salvage Ratio.
Column VII	-	Total to be Recovered (Column III) * (Column IV).
Column VIII	-	Calculated Depreciation Requirement.
Column IX	-	Allocated Accumulated Depreciation – APCO's Accounting group accumulated depreciation (book reserve) spread to each account on the basis of the Calculated Depreciation Requirement shown in Column VIII.
Column X	-	Remaining to be Recovered (Column VII - Column IX).
Column XI	-	Average Remaining Life.
Column XII	-	Recommended Annual Accrual Amount.
Column XIII	-	Recommend Annual Accrual Percent or Depreciation Rate (Column XII/Column III).

SCHEDULE II

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	STEAM PRODUCTION PLANT											
	MOUNTAINEER			2040								
311.0	Structures & Improvements	94,162,401	FCST.		1.06	99,812,145	40,360,427	52,962,050	46,850,095	33.85	1,384,050	1.47%
312.0	Boiler Plant Equipment	517,306,950	FCST.		1.13	584,556,854	219,955,014	288,630,950	295,925,904	31.76	9,317,566	1.80%
314.0	Turbogenerator Units	88,101,139	FCST.		1.14	100,435,298	41,606,473	54,597,145	45,838,153	31.05	1,476,259	1.68%
315.0	Accessory Electrical Equipment	65,084,612	FCST.		1.07	69,640,535	29,370,139	38,540,295	31,100,240	33.25	935,346	1.44%
316.0	Misc. Power Plant Equip.	15,391,998	FCST.		1.11	17,085,118	6,777,673	8,893,847	8,191,271	32.18	254,545	1.65%
	Total	780,047,100				871,529,950	338,069,726	443,624,286	427,905,664		13,367,776	1.71%
	KANAWHA RIVER			2018								
311.0	Structures & Improvements	17,350,476	FCST.		1.01	17,523,981	12,988,577	16,559,914	964,066	12.41	77,685	0.45%
312.0	Boiler Plant Equipment	93,526,135	FCST.		1.03	96,331,919	62,315,936	79,450,317	16,881,602	12.14	1,390,577	1.49%
314.0	Turbogenerator Units	32,501,320	FCST.		1.04	33,801,373	23,085,600	29,433,213	4,368,159	12.05	362,503	1.12%
315.0	Accessory Electrical Equipment	8,396,631	FCST.		1.02	8,564,564	5,972,933	7,615,250	949,314	12.34	76,930	0.92%
316.0	Misc. Power Plant Equip.	4,877,087	FCST.		1.03	5,023,400	2,928,170	3,733,299	1,290,100	12.20	105,746	2.17%
	Total	156,651,649				161,245,236	107,291,216	136,791,994	24,453,242		2,013,440	1.29%
	AMOS			UNIT 1&2 2032 UNIT 3 2033								
311.0	Structures & Improvements - Units 1,2	31,257,107	FCST.		1.05	32,819,962	17,165,428	20,631,404	12,188,558	26.11	466,816	1.49%
311.0	Structures & Improvements - Unit 3	20,706,443	FCST.		1.05	21,741,765	11,271,073	13,546,884	8,194,881	27.08	302,617	1.46%
312.0	Boiler Plant Equipment - Units 1,2	593,072,413	FCST.		1.10	652,379,654	199,570,686	239,867,219	412,512,435	24.89	16,573,420	2.79%
312.0	Boiler Plant Equipment - Unit 3	161,596,564	FCST.		1.10	177,756,220	66,507,429	79,936,349	97,819,871	25.76	3,797,355	2.35%
314.0	Turbogenerator Units - Units 1,2	91,058,126	FCST.		1.12	101,985,101	44,625,810	53,636,479	48,348,622	24.46	1,976,640	2.17%
314.0	Turbogenerator Units - Unit 3	23,535,111	FCST.		1.12	26,359,324	10,994,182	13,214,084	13,145,240	25.31	519,369	2.21%
315.0	Accessory Electrical Equipment-Units 1,2	36,563,945	FCST.		1.07	39,123,421	17,986,271	21,617,989	17,505,433	25.76	679,559	1.86%
315.0	Accessory Electrical Equipment-Unit 3	9,159,965	FCST.		1.06	9,709,563	4,687,440	5,633,910	4,075,653	26.71	152,589	1.67%
316.0	Misc. Power Plant Equip. - Units 1,2	3,600,018	FCST.		1.08	3,888,019	1,861,346	2,237,182	1,650,838	25.13	65,692	1.82%
316.0	Misc. Power Plant Equip. - Unit 3	13,053,976	FCST.		1.08	14,098,294	4,932,995	5,929,046	8,169,248	26.03	313,840	2.40%
	Total	983,603,668				1,079,861,325	379,602,660	456,250,546	623,610,779		24,847,898	2.53%
	SPORN			2018								
311.0	Structures & Improvements	12,169,979	FCST.		1.05	12,778,478	9,196,348	12,277,309	501,169	12.41	40,384	0.33%
312.0	Boiler Plant Equipment	78,626,019	FCST.		1.06	83,343,580	48,015,680	64,101,897	19,241,683	12.14	1,584,982	2.02%
314.0	Turbogenerator Units	18,048,132	FCST.		1.07	19,311,501	12,693,083	16,945,521	2,365,980	12.05	196,347	1.09%
315.0	Accessory Electrical Equipment	6,570,200	FCST.		1.05	6,898,710	4,513,446	6,025,541	873,169	12.34	70,759	1.08%
316.0	Misc. Power Plant Equip.	3,155,274	FCST.		1.07	3,376,143	2,159,335	2,882,756	493,388	12.20	40,442	1.28%
	Total	118,569,604				125,708,413	76,577,892	102,233,024	23,475,389		1,932,914	1.63%
	CLINCH RIVER			2021								
311.0	Structures & Improvements	34,770,730	FCST.		1.01	35,118,437	21,549,549	21,338,944	13,779,494	15.37	896,519	2.58%
312.0	Boiler Plant Equipment	160,791,813	FCST.		1.04	167,223,486	89,824,380	88,946,520	78,276,966	14.95	5,235,917	3.26%
314.0	Turbogenerator Units	56,450,106	FCST.		1.05	59,272,611	37,374,592	37,009,327	22,263,284	14.80	1,504,276	2.66%
315.0	Accessory Electrical Equipment	11,548,753	FCST.		1.02	11,779,728	7,777,927	7,701,913	4,077,815	15.25	267,398	2.32%
316.0	Misc. Power Plant Equip.	5,037,599	FCST.		1.03	5,188,727	2,905,079	2,876,687	2,312,040	15.03	153,828	3.05%
	Total	268,599,001				278,582,989	159,431,527	157,873,391	120,709,598		8,057,938	3.00%

SCHEDULE II

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	GLEN LYN UNIT 5			2012								
311.0	Structures & Improvements	3,203,253	FCST.		1.01	3,235,286	2,448,029	2,182,133	1,053,153	6.48	162,524	5.07%
312.0	Boiler Plant Equipment	22,595,346	FCST.		1.02	23,047,253	16,305,826	14,534,745	8,512,508	6.40	1,330,079	5.89%
314.0	Turbogenerator Units	6,466,012	FCST.		1.02	6,595,332	4,416,243	3,936,566	2,658,766	6.38	416,734	6.44%
315.0	Accessory Electrical Equipment	2,141,252	FCST.		1.01	2,162,665	1,481,826	1,320,875	841,789	6.46	130,308	6.09%
316.0	Misc. Power Plant Equip.	133,832	FCST.		1.02	136,509	47,626	42,453	94,056	6.42	14,650	10.95%
	Total	34,539,695				35,177,044	24,699,550	22,016,773	13,160,271		2,054,296	5.95%
	GLEN LYN UNIT 6			2015								
311.0	Structures & Improvements	12,235,833	FCST.		1.01	12,358,191	9,198,427	8,594,966	3,763,225	9.45	398,225	3.25%
312.0	Boiler Plant Equipment	65,674,477	FCST.		1.03	67,644,711	43,604,185	40,743,542	26,901,169	9.29	2,895,712	4.41%
314.0	Turbogenerator Units	20,940,304	FCST.		1.03	21,568,513	15,332,810	14,326,905	7,241,609	9.24	783,724	3.74%
315.0	Accessory Electrical Equipment	5,888,751	FCST.		1.02	6,006,526	4,351,918	4,066,411	1,940,115	9.41	206,176	3.50%
316.0	Misc. Power Plant Equip.	3,078,101	FCST.		1.03	3,170,444	1,948,925	1,821,066	1,349,378	9.32	144,783	4.70%
	Total	107,817,466				110,748,386	74,436,265	69,552,891	41,195,495		4,428,620	4.11%
	PUTNAM COAL TERMINAL			2040								
311.0	Structures & Improvements	3,282,844	FCST.		1.10	3,611,128	1,664,064	2,369,032	1,242,096	33.85	36,694	1.12%
312.0	Boiler Plant Equipment	24,853,652	FCST.		1.10	27,339,017	12,065,716	17,177,264	10,161,753	31.76	319,954	1.29%
315.0	Accessory Electrical Equipment	3,482,907	FCST.		1.10	3,831,198	1,634,486	2,326,924	1,504,274	33.25	45,241	1.30%
316.0	Misc. Power Plant Equip.	644,476	FCST.		1.10	708,924	297,579	423,646	285,278	32.18	8,865	1.38%
	Total	32,263,879				35,490,267	15,661,845	22,296,866	13,193,401		410,755	1.27%
	OTHER											
788.0	Centralized Maintenence	85,770	FCST.	2040	1.00	85,770	26,239	27,682	58,088	33.85	1,716	2.00%
748.0	Central Machine Shop	9,394,028	FCST.	2040	1.00	9,394,028	3,135,233	3,307,706	6,086,322	32.18	189,134	2.01%
714.0	Little Broad Run Ash Disposal	1,185,159	FCST.	2040	1.00	1,185,159	537,856	567,444	617,715	31.76	19,449	1.64%
	Total	10,664,957				10,664,957	3,699,328	3,902,833	6,762,124		210,299	1.97%
	Total Steam Production Plant	2,492,757,019				2,709,008,566	1,179,470,009	1,414,542,604	1,294,465,962		57,323,936	2.30%

SCHEDULE II

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	HYDRAULIC PRODUCTION PLANT - CONVENTIONAL											
	CLAYTOR			2041								
331.0	Structures & Improvements	1,857,385	FCST.		1.07	1,987,402	915,377	1,213,469	773,933	34.56	22,394	1.21%
332.0	Reservoirs, Dams & Waterways	9,649,484	FCST.		1.07	10,324,926	5,816,242	7,710,299	2,614,627	34.93	74,853	0.78%
333.0	Waterwheels, Turbines & Gen.	2,033,553	FCST.		1.07	2,175,902	1,325,395	1,757,009	418,892	33.67	12,441	0.61%
334.0	Accessory Electrical Equip.	2,777,547	FCST.		1.07	2,971,975	1,130,881	1,499,152	1,472,823	31.03	47,464	1.71%
335.0	Misc. Power Plant Equip.	1,941,693	FCST.		1.07	2,077,612	521,847	691,786	1,385,825	33.42	41,467	2.14%
336.0	Roads, Railroads & Bridges	31,799	FCST.		1.07	34,025	21,906	29,040	4,985	35.50	140	0.44%
	Total	18,291,441				19,571,842	9,731,848	12,900,756	6,671,086		198,760	1.09%
	BYLLESBY			2024								
331.0	Structures & Improvements	818,261	FCST.		1.07	875,539	560,925	431,949	443,590	18.24	8,919	1.09%
332.0	Reservoirs, Dams & Waterways	4,121,283	FCST.		1.07	4,409,773	2,435,649	1,875,611	2,534,162	18.35	126,936	3.08%
333.0	Waterwheels, Turbines & Gen.	1,778,552	FCST.		1.07	1,903,051	1,172,201	902,672	1,000,378	18.00	70,786	3.98%
334.0	Accessory Electrical Equip.	963,627	FCST.		1.07	1,031,081	677,503	521,722	509,359	17.29	21,296	2.21%
335.0	Misc. Power Plant Equip.	604,218	FCST.		1.07	646,513	221,194	170,334	476,179	17.94	11,238	1.86%
	Total	8,285,941				8,865,957	5,067,472	3,902,288	4,963,669		239,176	2.89%
	BUCK			2024								
331.0	Structures & Improvements	313,749	FCST.		1.07	335,711	253,019	225,727	109,985	18.24	3,388	1.08%
332.0	Reservoirs, Dams & Waterways	4,853,563	FCST.		1.07	5,193,312	2,769,679	2,470,925	2,722,387	18.35	124,737	2.57%
333.0	Waterwheels, Turbines & Gen.	1,258,750	FCST.		1.07	1,346,863	837,009	746,724	600,138	18.00	61,301	4.87%
334.0	Accessory Electrical Equip.	2,492,373	FCST.		1.07	2,666,839	1,017,710	907,934	1,758,905	17.29	74,522	2.99%
335.0	Misc. Power Plant Equip.	111,858	FCST.		1.07	119,688	75,113	67,011	52,677	17.94	2,170	1.94%
336.0	Roads, Railroads & Bridges	3,437	FCST.		1.07	3,678	2,981	2,659	1,018	18.50	36	1.05%
	Total	9,033,730				9,666,091	4,955,511	4,420,981	5,245,110		266,154	2.95%
	NIAGARA			2024								
331.0	Structures & Improvements	196,124	FCST.		1.07	209,853	155,819	106,684	103,169	18.24	2,628	1.34%
332.0	Reservoirs, Dams & Waterways	4,906,269	FCST.		1.07	5,249,708	2,328,782	1,594,435	3,655,273	18.35	105,975	2.16%
333.0	Waterwheels, Turbines & Gen.	626,066	FCST.		1.07	669,891	343,998	235,523	434,367	18.00	27,735	4.43%
334.0	Accessory Electrical Equip.	196,432	FCST.		1.07	210,182	117,524	80,465	129,718	17.29	3,968	2.02%
335.0	Misc. Power Plant Equip.	218,800	FCST.		1.07	234,116	101,706	69,635	164,481	17.94	7,483	3.42%
	Total	6,143,691				6,573,749	3,047,829	2,086,741	4,487,008		147,789	2.41%
	RUESENS			2024								
331.0	Structures & Improvements	473,944	FCST.		1.07	507,120	267,610	199,187	307,933	18.24	3,649	0.77%
332.0	Reservoirs, Dams & Waterways	1,587,411	FCST.		1.07	1,698,530	570,480	424,620	1,273,910	18.35	20,160	1.27%
333.0	Waterwheels, Turbines & Gen.	1,652,343	FCST.		1.07	1,768,007	902,044	671,409	1,096,598	18.00	37,012	2.24%
334.0	Accessory Electrical Equip.	890,140	FCST.		1.07	952,450	485,011	361,003	591,446	17.29	10,593	1.19%
335.0	Misc. Power Plant Equip.	305,931	FCST.		1.07	327,346	159,414	118,655	208,691	17.94	9,300	3.04%
	Total	4,909,769				5,253,453	2,384,559	1,774,875	3,478,578		80,715	1.64%

SCHEDULE II

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
	LEESVILLE			2040								
331.0	Structures & Improvements	2,136,795	FCST.		1.07	2,286,371	1,251,422	1,708,763	577,608	33.61	17,186	0.80%
332.0	Reservoirs, Dams & Waterways	10,439,935	FCST.		1.07	11,170,730	4,809,932	6,567,754	4,602,976	33.96	135,541	1.30%
333.0	Waterwheels, Turbines & Gen.	3,038,483	FCST.		1.07	3,251,177	1,762,965	2,407,252	843,924	32.77	25,753	0.85%
334.0	Accessory Electrical Equip.	579,557	FCST.		1.07	620,126	315,545	430,863	189,263	30.28	6,250	1.08%
335.0	Misc. Power Plant Equip.	1,173,274	FCST.		1.07	1,255,403	516,824	705,701	549,702	32.54	16,893	1.44%
336.0	Roads, Railroads & Bridges	80,790	FCST.		1.07	86,445	47,116	64,335	22,110	34.50	641	0.79%
	Total	17,448,834				18,670,252	8,703,804	11,884,668	6,785,584		202,264	1.16%
	LONDON			2044								
331.0	Structures & Improvements	544,668	FCST.		1.07	582,795	239,093	227,158	355,636	37.39	9,512	1.75%
332.0	Reservoirs, Dams & Waterways	679,103	FCST.		1.07	726,640	348,163	330,784	395,856	37.83	10,464	1.54%
333.0	Waterwheels, Turbines & Gen.	1,243,977	FCST.		1.07	1,331,055	679,509	645,590	685,465	36.35	18,857	1.52%
334.0	Accessory Electrical Equip.	1,806,433	FCST.		1.07	1,932,883	664,894	631,705	1,301,178	33.24	39,145	2.17%
335.0	Misc. Power Plant Equip.	401,986	FCST.		1.07	430,125	117,125	111,279	318,846	36.05	8,845	2.20%
336.0	Roads, Railroads & Bridges	48,853	FCST.		1.07	52,273	26,662	25,331	26,942	38.50	700	1.43%
	Total	4,725,020				5,055,771	2,075,446	1,971,847	3,083,924		87,522	1.85%
	MARMET			2044								
331.0	Structures & Improvements	598,323	FCST.		1.07	640,206	286,888	261,247	378,959	37.39	10,135	1.69%
332.0	Reservoirs, Dams & Waterways	708,044	FCST.		1.07	757,607	356,652	324,775	432,832	37.83	11,441	1.62%
333.0	Waterwheels, Turbines & Gen.	1,114,921	FCST.		1.07	1,192,965	626,112	570,152	622,814	36.35	17,134	1.54%
334.0	Accessory Electrical Equip.	2,072,679	FCST.		1.07	2,217,767	758,282	690,508	1,527,258	33.24	45,946	2.22%
335.0	Misc. Power Plant Equip.	443,556	FCST.		1.07	474,605	129,933	118,320	356,285	36.05	9,883	2.23%
336.0	Roads, Railroads & Bridges	1,275	FCST.		1.07	1,364	701	638	726	38.50	19	1.48%
	Total	4,938,798				5,284,514	2,158,568	1,965,640	3,318,874		94,559	1.91%
	WINFIELD			2044								
331.0	Structures & Improvements	457,134	FCST.		1.07	489,133	213,535	213,768	275,366	37.39	7,365	1.61%
332.0	Reservoirs, Dams & Waterways	1,287,289	FCST.		1.07	1,377,399	587,779	588,419	788,980	37.83	20,856	1.62%
333.0	Waterwheels, Turbines & Gen.	934,699	FCST.		1.07	1,000,128	579,746	580,378	419,750	36.35	11,547	1.24%
334.0	Accessory Electrical Equip.	84,392	FCST.		1.07	90,299	48,384	48,437	41,863	33.24	1,259	1.49%
335.0	Misc. Power Plant Equip.	3,028,933	FCST.		1.07	3,240,958	1,055,464	1,056,614	2,184,344	36.05	60,592	2.00%
336.0	Roads, Railroads & Bridges	23,567	FCST.		1.07	25,217	5,075	5,081	20,136	38.50	523	2.22%
	Total	5,816,014				6,223,135	2,489,983	2,492,696	3,730,439		102,143	1.76%
	Total Hydraulic Production - Conventional	79,593,238				85,164,765	40,614,820	43,400,492	41,764,273		1,419,082	1.78%
	HYDRAULIC PRODUCTION PLANT - PUMPED STORAGE											
	SMITH MOUNTAIN			2040								
331.0	Structures & Improvements	12,079,151	FCST.		1.07	12,924,692	6,326,896	9,043,751	3,880,941	33.61	115,470	0.96%
332.0	Reservoirs, Dams & Waterways	24,730,954	FCST.		1.07	26,462,121	13,449,471	19,224,856	7,237,265	33.96	213,111	0.86%
333.0	Waterwheels, Turbines & Gen.	56,457,401	FCST.		1.07	60,409,419	24,540,300	35,078,238	25,331,182	32.77	772,999	1.37%
334.0	Accessory Electrical Equip.	7,270,041	FCST.		1.07	7,778,944	3,153,130	4,507,127	3,271,817	30.28	108,052	1.49%
335.0	Misc. Power Plant Equip.	4,470,378	FCST.		1.07	4,783,304	1,852,619	2,648,159	2,135,146	32.54	65,616	1.47%
336.0	Roads, Railroads & Bridges	1,052,133	FCST.		1.07	1,125,782	572,513	818,358	307,424	34.50	8,911	0.85%
	Total Pumped Storage	106,060,058				113,484,262	49,894,929	71,320,488	42,163,774		1,284,159	1.21%
	Total Hydraulic Production	185,653,296				198,649,027	90,509,749	114,720,980	83,928,047		2,703,241	

SCHEDULE II

APPALACHIAN POWER COMPANY
CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE & CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL ACCRUAL AMOUNT (XII)	RECOMMENDED ANNUAL ACCRUAL PERCENT (XIII)
OTHER PRODUCTION PLANT												
	CEREDO			2041								
341.0	Structures & Improvements	711,244	FCST.		1.01	718,356	80,815	0	718,356	35.5	20,235	2.85%
344.0	Generators	75,537,304	FCST.		1.09	82,335,662	9,986,805	0	82,335,662	32.6	2,525,634	3.34%
345.0	Accessory Electrical Equip	10,227,917	FCST.		1.01	10,330,196	1,162,147	0	10,330,196	35.5	290,991	2.85%
346.0	Misc. Power Plant Equip.	142,330	FCST.		1.01	143,753	16,172	0	143,753	35.5	4,049	2.85%
	Total	86,618,795				93,527,967	11,245,940	0	93,527,967		2,840,910	3.28%

SCHEDULE I

APPALACHIAN POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
	TRANSMISSION PLANT											
352.0	Structures & Improvements	43,114,120	55 R3.0	N.A.	1.00	43,114,120	15,197,213	19,290,032	23,824,088	35.61	669,028	1.55%
353.0	Station Equipment	538,487,127	35 R2.0	N.A.	0.85	457,714,058	193,736,912	245,912,937	211,801,121	20.19	10,490,397	1.95%
354.0	Towers & Fixtures	230,212,337	87 R2.5	N.A.	1.10	253,233,571	67,077,432	85,142,310	168,091,260	63.96	2,628,068	1.14%
355.0	Poles & Fixtures	98,737,201	37 L2.0	N.A.	1.15	113,547,781	32,751,846	41,572,370	71,975,411	26.33	2,733,589	2.77%
356.0	OH Conductor & Devices	283,492,453	80 R2.5	N.A.	0.90	255,143,208	69,590,864	88,332,644	166,810,563	58.18	2,867,146	1.01%
357.0	Underground Conduit	255,431	55 S2.0	N.A.	1.00	255,431	139,080	176,536	78,895	25.05	3,149	1.23%
358.0	Underground Conductor	3,671,406	25 L3.0	N.A.	1.00	3,671,406	1,588,000	2,015,670	1,655,736	14.19	116,683	3.18%
	Total Transmission Plant	1,197,970,075				1,126,679,575	380,081,347	482,442,501	644,237,074		19,508,062	1.63%
	DISTRIBUTION PLANT (VIRGINIA)											
361.0	Structures & Improvements	14,114,815	43 R4.0	N.A.	1.00	14,114,815	5,196,296	5,444,339	8,670,476	27.17	319,119	2.26%
362.0	Station Equipment	119,406,060	37 R1.0	N.A.	0.85	101,495,151	28,552,672	29,915,619	71,579,532	26.59	2,691,972	2.25%
364.0	Poles, Towers, & Fixtures	250,814,740	30 R1.5	N.A.	1.55	388,762,847	124,520,508	130,464,431	258,298,416	20.39	12,667,897	5.05%
365.0	Overhead Conductor & Devices	204,027,955	43 L0.0	N.A.	0.85	173,423,762	30,048,667	31,483,025	141,940,737	35.55	3,992,707	1.96%
366.0	Underground Conduit	33,346,884	47 S6.0	N.A.	1.00	33,346,884	9,466,930	9,918,829	23,428,055	33.66	696,021	2.09%
367.0	Underground Conductor	98,941,215	52 R0.5	N.A.	1.00	98,941,215	13,633,605	14,284,398	84,656,817	44.83	1,888,397	1.91%
368.0	Line Transformers	231,116,620	32 R0.5	N.A.	1.10	254,228,282	66,367,448	69,535,464	184,692,818	23.65	7,809,421	3.38%
369.0	Services	121,503,239	36 R0.5	N.A.	1.13	137,298,660	28,562,240	29,925,644	107,373,016	28.51	3,766,153	3.10%
370.0	Meters	60,121,032	25 S6.0	N.A.	1.10	66,133,135	25,154,039	26,354,754	39,778,381	15.49	2,568,004	4.27%
371.0	Installations on Custs. Prem.	21,071,370	11 S6.0	N.A.	1.08	22,757,080	10,225,858	10,713,984	12,043,095	6.06	1,987,309	9.43%
372.0	Leased Property on Cust. Prem.	771	25 L3.0	N.A.	1.00	771	390	409	362	12.36	29	3.80%
373.0	Street Lighting & Signal Sys.	13,261,901	21 S6.0	N.A.	0.95	12,598,806	6,227,429	6,524,692	6,074,114	10.62	571,950	4.31%
	Total Distribution Plant (Virginia)	1,167,726,602				1,303,101,408	347,956,082	364,565,589	938,535,819		38,958,980	3.34%
	DISTRIBUTION PLANT (WEST VIRGINIA)											
361.0	Structures & Improvements	12,769,337	43 R4.0	N.A.	1.00	12,769,337	4,700,965	5,214,764	7,554,573	27.17	278,048	2.18%
362.0	Station Equipment	88,168,409	37 R1.0	N.A.	0.85	74,943,148	21,083,048	23,387,351	51,555,796	26.59	1,938,917	2.20%
364.0	Poles, Towers, & Fixtures	236,073,582	30 R1.5	N.A.	1.55	365,914,052	117,202,052	130,011,825	235,902,227	20.39	11,569,506	4.90%
365.0	Overhead Conductor & Devices	182,080,409	43 L0.0	N.A.	0.85	154,768,348	26,816,293	29,747,220	125,021,128	35.55	3,516,769	1.93%
366.0	Underground Conduit	25,050,422	47 S6.0	N.A.	1.00	25,050,422	7,111,627	7,888,903	17,161,519	33.66	509,849	2.04%
367.0	Underground Conductor	44,620,493	52 R0.5	N.A.	1.00	44,620,493	6,148,481	6,820,488	37,800,005	44.83	843,185	1.89%
368.0	Line Transformers	170,926,200	32 R0.5	N.A.	1.10	188,018,820	49,083,168	54,447,786	133,571,034	23.65	5,647,824	3.30%
369.0	Services	100,346,183	36 R0.5	N.A.	1.13	113,391,187	23,588,768	26,166,938	87,224,249	28.51	3,059,426	3.05%
370.0	Meters	41,450,459	25 S6.0	N.A.	1.10	45,595,505	17,342,458	19,237,928	26,357,577	15.49	1,701,587	4.11%
371.0	Installations on Custs. Prem.	23,266,459	11 S6.0	N.A.	1.08	25,127,776	11,291,126	12,525,206	12,602,569	6.06	2,079,632	8.94%
373.0	Street Lighting & Signal Sys.	6,910,400	21 S6.0	N.A.	0.95	6,564,880	3,244,937	3,599,597	2,965,283	10.62	279,217	4.04%
	Total Distribution Plant (West Virginia)	931,662,353				1,056,763,967	287,612,923	319,048,007	737,715,960		31,423,960	3.37%

SCHEDULE I

APPALACHIAN POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2005
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/05 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
DISTRIBUTION PLANT (TENNESSEE)												
370.0	Meters	47,141	25 S6.0	N.A.	1.10	51,855	19,723	42,281	9,574	15.49	618	1.31%
	Total Distribution Plant (Tennessee)	47,141				51,855	19,723	42,281	9,574		618	1.31%
	Total Distribution Plant	2,099,436,096				2,359,917,229	635,588,728	683,655,877	1,676,261,352		70,383,558	3.35%
GENERAL PLANT												
390.0	Structures & Improvements	97,515,978	38 R3.0	N.A.	0.72	70,211,504	24,276,548	37,514,604	32,696,900	24.86	1,315,241	1.35%
391.0	Office Furniture & Equipment	5,195,551	30 L3.0	N.A.	0.95	4,935,773	1,399,392	2,162,484	2,773,290	21.49	129,050	2.48%
392.0	Transportation Equipment	16,942	27 S6.0	N.A.	0.95	16,095	9,401	14,527	1,568	11.23	140	0.82%
393.0	Stores Equipment	838,300	55 R4.0	N.A.	1.00	838,300	296,468	458,133	380,167	35.55	10,694	1.28%
394.0	Tools Shop & Garage Equipment	11,190,608	43 R0.5	N.A.	1.00	11,190,608	1,621,623	2,505,898	8,684,710	36.77	236,190	2.11%
395.0	Laboratory Equipment	2,516,760	37 S2.0	N.A.	1.00	2,516,760	1,266,309	1,956,830	559,930	18.38	30,464	1.21%
396.0	Power Operated Equipment	3,662	25 L2.0	N.A.	1.00	3,662	2,303	3,559	103	9.27	11	0.30%
397.0	Communication Equipment	21,536,031	24 R0.5	N.A.	0.95	20,459,229	5,882,076	9,089,585	11,369,644	17.10	664,891	3.09%
398.0	Miscellaneous Equipment	2,383,390	35 S6.0	N.A.	1.00	2,383,390	900,768	1,391,959	991,431	21.77	45,541	1.91%
	Total General Plant	141,197,222				112,555,322	35,654,888	55,097,578	57,457,744		2,432,222	1.72%
	Total Depreciable Electric Plant	6,203,632,503				6,600,337,686	2,332,550,881	2,750,459,540	3,849,878,146		155,191,929	

SCHEDULE II

APPALACHIAN POWER COMPANY
ANNUAL VIRGINIA DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON TOTAL COMPANY PLANT IN SERVICE AT DECEMBER 31, 2005
REVISED 03/30/06

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/05 (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
PRODUCTION PLANT							
	Steam Production						
	Mountaineer						
311	Structures & Improvements	94,162,401	3.32%	3,126,192	1.47%	1,384,050	(1,742,142)
312	Boiler Plant Equipment	517,306,950	3.32%	17,174,591	1.80%	9,317,566	(7,857,024)
314	Turbogenerator Units	88,101,139	3.32%	2,924,958	1.68%	1,476,269	(1,448,689)
315	Accessory Electrical Equipment	65,084,612	3.32%	2,160,809	1.44%	935,346	(1,225,464)
316	Misc. Power Plant Equipment	15,391,998	3.23%	497,162	1.65%	254,545	(242,616)
	Total Mountaineer	780,047,100	3.32%	25,883,711	1.71%	13,367,776	(12,515,935)
	Kanawha River						
311	Structures & Improvements	17,350,476	3.91%	678,404	0.45%	77,685	(600,719)
312	Boiler Plant Equipment	93,526,135	3.91%	3,656,872	1.49%	1,390,577	(2,266,295)
314	Turbogenerator Units	32,501,320	3.91%	1,270,802	1.12%	362,503	(908,299)
315	Accessory Electrical Equipment	8,396,631	3.91%	328,308	0.92%	76,930	(251,378)
316	Misc. Power Plant Equipment	4,877,087	3.91%	190,694	2.17%	105,746	(84,948)
	Total Kanawha River	156,651,649	3.91%	6,125,079	1.29%	2,013,440	(4,111,639)
	Amos						
311	Structures & Improvements	51,963,550	4.35%	2,260,414	1.48%	769,433	(1,490,981)
312	Boiler Plant Equipment	754,668,977	4.35%	32,828,100	2.70%	20,370,776	(12,457,325)
314	Turbogenerator Units	114,593,237	4.35%	4,984,806	2.18%	2,496,010	(2,488,796)
315	Accessory Electrical Equipment	45,723,910	4.35%	1,988,990	1.82%	832,148	(1,156,842)
316	Misc. Power Plant Equipment	16,653,994	4.35%	724,449	2.28%	379,532	(344,917)
	Total Amos	983,603,668	4.35%	42,786,760	2.53%	24,847,898	(17,938,862)
	Sporn						
311	Structures & Improvements	12,169,979	4.90%	596,329	0.33%	40,384	(555,945)
312	Boiler Plant Equipment	78,626,019	4.90%	3,852,675	2.02%	1,584,982	(2,267,693)
314	Turbogenerator Units	18,048,132	4.90%	884,358	1.09%	196,347	(688,012)
315	Accessory Electrical Equipment	6,570,200	4.90%	321,940	1.08%	70,759	(251,181)
316	Misc. Power Plant Equipment	3,155,274	4.90%	154,608	1.28%	40,442	(114,167)
	Total Sporn	118,569,604	4.90%	5,809,911	1.63%	1,932,914	(3,876,996)
	Clinch River						
311	Structures & Improvements	34,770,730	3.50%	1,216,976	2.58%	896,519	(320,457)
312	Boiler Plant Equipment	160,791,813	3.50%	5,627,713	3.26%	5,235,917	(391,796)
314	Turbogenerator Units	56,450,106	3.50%	1,975,754	2.66%	1,504,276	(471,478)
315	Accessory Electrical Equipment	11,548,753	3.50%	404,206	2.32%	267,398	(136,809)
316	Misc. Power Plant Equipment	5,037,599	3.50%	176,316	3.05%	153,828	(22,488)
	Total Clinch River	268,599,001	3.50%	9,400,965	3.00%	8,057,938	(1,343,027)
	Glen Lyn 5						
311	Structures & Improvements	3,203,253	0.92%	29,470	5.07%	162,524	133,054
312	Boiler Plant Equipment	22,595,346	0.92%	207,877	5.89%	1,330,079	1,122,202
314	Turbogenerator Units	6,466,012	0.92%	59,487	6.44%	416,734	357,247
315	Accessory Electrical Equipment	2,141,252	0.92%	19,700	6.09%	130,308	110,608
316	Misc. Power Plant Equipment	133,832	0.92%	1,231	10.95%	14,650	13,419
	Total Glen Lyn 5	34,539,695	0.92%	317,765	5.95%	2,054,296	1,736,530

SCHEDULE II

APPALACHIAN POWER COMPANY
ANNUAL VIRGINIA DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON TOTAL COMPANY PLANT IN SERVICE AT DECEMBER 31, 2005
REVISED 03/30/06

ACCOUNT NO. (1)	TITLE (2)	ORIGINAL COST AT 12/31/05 (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
	Glen Lyn 6						
311	Structures & Improvements	12,235,833	3.73%	456,397	3.25%	398,225	(58,172)
312	Boiler Plant Equipment	65,674,477	3.73%	2,449,658	4.41%	2,895,712	446,054
314	Turbogenerator Units	20,940,304	3.73%	781,073	3.74%	783,724	2,651
315	Accessory Electrical Equipment	5,888,751	3.73%	219,650	3.50%	206,176	(13,475)
316	Misc. Power Plant Equipment	3,078,101	3.73%	114,813	4.70%	144,783	29,970
	Total Glen Lyn 6	107,817,466	3.73%	4,021,591	4.11%	4,428,620	407,029
	Putnam Coal Terminal						
311	Structures & Improvements	3,282,844	2.95%	96,844	1.12%	36,694	(60,150)
312	Boiler Plant Equipment	24,853,652	2.95%	733,183	1.29%	319,954	(413,228)
315	Accessory Electrical Equipment	3,482,907	2.95%	102,746	1.30%	45,241	(57,504)
316	Misc. Power Plant Equipment	644,476	2.95%	19,012	1.38%	8,865	(10,147)
	Total Putnam Coal Terminal	32,263,879	2.95%	951,784	1.27%	410,755	(541,029)
	Other						
788	Centralized Maintenance	85,770	4.02%	3,448	2.00%	1,716	(1,732)
848	Central Machine Shop	9,394,028	4.02%	377,640	2.01%	189,134	(188,506)
316	Little Broad Run Ash Disposal	1,185,159	4.02%	47,643	1.64%	19,449	(28,194)
	Total Other	10,664,957	4.02%	428,731	1.97%	210,299	(218,432)
	Total Steam Production	2,492,757,019	3.84%	95,726,298	2.30%	57,323,936	(38,402,361)
	Hydraulic Production						
	Claytor						
331	Structures & Improvements	1,857,385	2.72%	50,521	1.21%	22,394	(28,127)
332	Reservoirs, Dams & Waterways	9,649,464	2.72%	262,465	0.78%	74,853	(187,612)
333	Waterwheels, Turbines & Generators	2,033,553	2.72%	55,313	0.61%	12,441	(42,872)
334	Accessory Electrical Equipment	2,777,547	2.72%	75,549	1.71%	47,464	(28,085)
335	Misc. Power Plant Equipment	1,941,693	2.72%	52,814	2.14%	41,467	(11,347)
336	Roads, Railroads, Bridges	31,799	2.72%	865	0.44%	140	(725)
	Total Claytor	18,291,441	2.72%	497,527	1.09%	198,760	(298,767)
	Byllesby						
331	Structures & Improvements	818,261	2.91%	23,811	1.09%	8,919	(14,892)
332	Reservoirs, Dams & Waterways	4,121,283	2.91%	119,929	3.08%	126,936	7,006
333	Waterwheels, Turbines & Generators	1,778,552	2.91%	51,756	3.98%	70,786	19,031
334	Accessory Electrical Equipment	963,627	2.91%	28,042	2.21%	21,296	(6,745)
335	Misc. Power Plant Equipment	604,218	2.91%	17,583	1.86%	11,238	(6,344)
	Total Byllesby	8,285,941	2.91%	241,121	2.89%	239,176	(1,945)

SCHEDULE II

APPALACHIAN POWER COMPANY
ANNUAL VIRGINIA DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON TOTAL COMPANY PLANT IN SERVICE AT DECEMBER 31, 2005
REVISED 03/30/06

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/05 (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
	Buck						
331	Structures & Improvements	313,749	3.21%	10,071	1.08%	3,388	(6,683)
332	Reservoirs, Dams & Waterways	4,853,563	3.21%	155,799	2.57%	124,737	(31,063)
333	Waterwheels, Turbines & Generators	1,258,750	3.21%	40,406	4.87%	61,301	20,895
334	Accessory Electrical Equipment	2,492,373	3.21%	80,005	2.99%	74,522	(5,483)
335	Misc. Power Plant Equipment	111,858	3.21%	3,591	1.94%	2,170	(1,421)
336	Roads, Railroads, Bridges	3,437	3.21%	110	1.05%	36	(74)
	Total Buck	9,033,730	3.21%	289,983	2.95%	266,154	(23,828)
	Niagara						
331	Structures & Improvements	196,124	2.31%	4,530	1.34%	2,628	(1,902)
332	Reservoirs, Dams & Waterways	4,906,269	2.31%	113,335	2.16%	105,975	(7,359)
333	Waterwheels, Turbines & Generators	626,066	2.31%	14,462	4.43%	27,735	13,273
334	Accessory Electrical Equipment	196,432	2.31%	4,538	2.02%	3,968	(570)
335	Misc. Power Plant Equipment	218,800	2.31%	5,054	3.42%	7,483	2,429
	Total Niagara	6,143,691	2.31%	141,919	2.41%	147,789	5,870
	Reusens						
331	Structures & Improvements	473,944	1.69%	8,010	0.77%	3,649	(4,360)
332	Reservoirs, Dams & Waterways	1,587,411	1.69%	26,827	1.27%	20,160	(6,667)
333	Waterwheels, Turbines & Generators	1,652,343	1.69%	27,925	2.24%	37,012	9,088
334	Accessory Electrical Equipment	890,140	1.69%	15,043	1.19%	10,593	(4,451)
335	Misc. Power Plant Equipment	305,931	1.69%	5,170	3.04%	9,300	4,130
	Total Reusens	4,909,769	1.69%	82,975	1.64%	80,715	(2,260)
	Leesville						
331	Structures & Improvements	2,136,795	2.51%	53,634	0.80%	17,186	(36,448)
332	Reservoirs, Dams & Waterways	10,439,935	2.51%	262,042	1.30%	135,541	(126,501)
333	Waterwheels, Turbines & Generators	3,038,483	2.51%	76,266	0.85%	25,753	(50,513)
334	Accessory Electrical Equipment	579,557	2.51%	14,547	1.08%	6,250	(8,296)
335	Misc. Power Plant Equipment	1,173,274	2.51%	29,449	1.44%	16,893	(12,556)
336	Roads, Railroads, Bridges	80,790	2.51%	2,028	0.79%	641	(1,387)
	Total Leesville	17,448,834	2.51%	437,966	1.16%	202,264	(235,702)
	London						
331	Structures & Improvements	544,668	1.65%	8,987	1.75%	9,512	525
332	Reservoirs, Dams & Waterways	679,103	1.65%	11,205	1.54%	10,464	(741)
333	Waterwheels, Turbines & Generators	1,243,977	1.65%	20,526	1.52%	18,857	(1,668)
334	Accessory Electrical Equipment	1,806,433	1.65%	29,806	2.17%	39,145	9,339
335	Misc. Power Plant Equipment	401,986	1.65%	6,633	2.20%	8,845	2,212
336	Roads, Railroads, Bridges	48,853	1.65%	806	1.43%	700	(106)
	Total London	4,725,020	1.65%	77,963	1.85%	87,522	9,559
	Marmet						
331	Structures & Improvements	598,323	1.65%	9,872	1.69%	10,135	263
332	Reservoirs, Dams & Waterways	708,044	1.65%	11,683	1.62%	11,441	(241)
333	Waterwheels, Turbines & Generators	1,114,921	1.65%	18,396	1.54%	17,134	(1,262)
334	Accessory Electrical Equipment	2,072,679	1.65%	34,199	2.22%	45,946	11,747
335	Misc. Power Plant Equipment	443,556	1.65%	7,319	2.23%	9,883	2,564
336	Roads, Railroads, Bridges	1,275	1.65%	21	1.48%	19	(2)
	Total Marmet	4,938,798	1.65%	81,490	1.91%	94,559	13,069
	Winfield						
331	Structures & Improvements	457,134	1.65%	7,543	1.61%	7,365	(178)
332	Reservoirs, Dams & Waterways	1,287,289	1.65%	21,240	1.62%	20,856	(384)

SCHEDULE II

APPALACHIAN POWER COMPANY
ANNUAL VIRGINIA DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON TOTAL COMPANY PLANT IN SERVICE AT DECEMBER 31, 2005
REVISED 03/30/06

ACCOUNT NO. (1)	TITLE (2)	ORIGINAL COST AT 12/31/05 (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
333	Waterwheels, Turbines & Generators	934,699	1.65%	15,423	1.24%	11,547	(3,875)
334	Accessory Electrical Equipment	84,392	1.65%	1,392	1.49%	1,259	(133)
335	Misc. Power Plant Equipment	3,028,933	1.65%	49,977	2.00%	60,592	10,615
336	Roads, Railroads, Bridges	23,567	1.65%	389	2.22%	523	134
	Total Winfield	5,816,014	1.65%	95,964	1.76%	102,143	6,178
	Smith Mountain						
331	Structures & Improvements	12,079,151	3.39%	409,483	0.96%	115,470	(294,013)
332	Reservoirs, Dams & Waterways	24,730,954	3.39%	838,379	0.86%	213,111	(625,268)
333	Waterwheels, Turbines & Generators	56,457,401	3.39%	1,913,906	1.37%	772,999	(1,140,907)
334	Accessory Electrical Equipment	7,270,041	3.39%	246,454	1.49%	108,052	(138,402)
335	Misc. Power Plant Equipment	4,470,378	3.39%	151,546	1.47%	65,616	(85,930)
336	Roads, Railroads, Bridges	1,052,133	3.39%	35,667	0.85%	8,911	(26,756)
	Total Smith Mountain	106,060,058	3.39%	3,595,436	1.21%	1,284,159	(2,311,277)
	Total Hydraulic Production	185,653,296	2.99%	5,542,344	1.46%	2,703,241	(2,839,103)
	Other Production						
	Ceredo						
341	Structures & Improvements	711,244	2.86%	20,342	2.85%	20,235	(107)
344	Generators	75,537,304	2.86%	2,160,367	3.34%	2,525,634	365,267
345	Accessory Electrical Equipment	10,227,917	2.86%	292,518	2.85%	290,991	(1,527)
346	Misc. Power Plant Equipment	142,330	2.86%	4,071	2.84%	4,049	(22)
	Total Ceredo	86,618,795	2.86%	2,477,298	3.28%	2,840,909	363,611
	Total Other Production	86,618,795	2.86%	2,477,298	3.28%	2,840,909	363,611
TRANSMISSION PLANT							
352.0	Structures & Improvements	43,114,120	2.19%	944,199	1.55%	669,028	(275,171)
353.0	Station Equipment	538,487,127	2.19%	11,792,868	1.95%	10,490,397	(1,302,471)
354.0	Towers & Fixtures	230,212,337	2.19%	5,041,650	1.14%	2,628,068	(2,413,582)
355.0	Poles & Fixtures	98,737,201	2.19%	2,162,345	2.77%	2,733,589	571,244
356.0	OH Cond. & Devices	283,492,453	2.19%	6,208,485	1.01%	2,867,146	(3,341,339)
357.0	Underground Conduit	255,431	2.19%	5,594	1.23%	3,149	(2,445)
358.0	Underground Conductor	3,671,406	2.19%	80,404	3.18%	116,683	36,279
	Total Transmission Plant	1,197,970,075	2.19%	26,235,545	1.63%	19,508,060	(6,727,485)
DISTRIBUTION PLANT							
	Virginia						
361.0	Structures & Improvements	14,114,815	3.40%	479,904	2.26%	319,119	(160,785)
362.0	Station Equipment	119,406,060	3.40%	4,059,806	2.25%	2,691,972	(1,367,834)
364.0	Poles, Towers, & Fixtures	250,814,740	3.40%	8,527,701	5.05%	12,667,897	4,140,196
365.0	Overhead Conductor & Devices	204,027,955	3.40%	6,936,950	1.96%	3,992,707	(2,944,243)
366.0	Underground Conduit	33,346,884	3.40%	1,133,794	2.09%	696,021	(437,773)
367.0	Underground Conductor	98,941,215	3.40%	3,364,001	1.91%	1,888,397	(1,475,604)
368.0	Line Transformers	231,116,620	3.40%	7,857,965	3.38%	7,809,421	(48,544)
369.0	Services	121,503,239	3.40%	4,131,110	3.10%	3,766,153	(364,957)
370.0	Meters	60,121,032	3.40%	2,044,115	4.27%	2,568,004	523,889
371.0	Installations on Custs. Premises	21,071,370	3.40%	716,427	9.43%	1,987,309	1,270,882
372.0	Leased Property on Cust. Premises	771	3.40%	26	3.76%	29	3
373.0	Street Lighting & Signal Sys.	13,261,901	3.40%	450,905	4.31%	571,950	121,045
	Total Distribution Plant Virginia	1,167,726,602	3.40%	39,702,704	3.34%	38,958,979	(743,725)
	West Virginia						
361.0	Structures & Improvements	12,769,337	3.20%	408,619	2.18%	278,048	(130,571)
362.0	Station Equipment	88,168,409	3.20%	2,821,389	2.20%	1,938,917	(882,472)
364.0	Poles, Towers, & Fixtures	236,073,582	3.20%	7,554,355	4.90%	11,569,506	4,015,151

APPALACHIAN POWER COMPANY — SCHEDULE II

ANNUAL VIRGINIA DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD

BASED ON TOTAL COMPANY PLANT IN SERVICE AT DECEMBER 31, 2005

REVISED 03/30/06

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/05 (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
365.0	Overhead Conductor & Devices	182,080,409	3.20%	5,826,573	1.93%	3,516,769	(2,309,804)
366.0	Underground Conduit	25,050,422	3.20%	801,614	2.04%	509,849	(291,765)
367.0	Underground Conductor	44,620,493	3.20%	1,427,856	1.89%	843,185	(584,671)
368.0	Line Transformers	170,926,200	3.20%	5,469,638	3.30%	5,647,824	178,186
369.0	Services	100,346,183	3.20%	3,211,078	3.05%	3,059,426	(151,652)
370.0	Meters	41,450,459	3.20%	1,326,415	4.11%	1,701,587	375,172
371.0	Installations on Custs. Premises	23,266,459	3.20%	744,527	8.94%	2,079,632	1,335,105
373.0	Street Lighting & Signal Sys.	6,910,400	3.20%	221,133	4.04%	279,217	58,084
	Total Distribution Plant - West Virgini	931,662,353	3.20%	29,813,195	3.37%	31,423,960	1,610,765
	Tennessee						
370.0	Meters	47,141	4.00%	1,886	1.31%	618	(1,268)
	Total Distribution Plant	2,099,436,096	3.31%	69,517,785	3.35%	70,383,557	865,772
	GENERAL PLANT						
390.0	Structures & Improvements	97,515,978	3.24%	3,159,518	1.35%	1,315,241	(1,844,277)
391.0	Office Furniture & Equipment	5,195,551	3.24%	168,336	2.48%	129,050	(39,286)
392.0	Transportation Equipment	16,942	3.24%	549	0.83%	140	(409)
393.0	Stores Equipment	838,300	3.24%	27,161	1.28%	10,694	(16,467)
394.0	Tools Shop & Garage Equipment	11,190,608	3.24%	362,576	2.11%	236,190	(126,386)
395.0	Laboratory Equipment	2,516,760	3.24%	81,543	1.21%	30,464	(51,079)
396.0	Power Operated Equipment	3,662	3.24%	119	0.30%	11	(108)
397.0	Communication Equipment	21,536,031	3.24%	697,767	3.09%	664,891	(32,876)
398.0	Miscellaneous Equipment	2,383,390	3.24%	77,222	1.91%	45,541	(31,681)
	Total General Plant	141,197,222	3.24%	4,574,790	1.72%	2,432,222	(2,142,568)
	Total Depreciable Plant	6,203,632,503	3.29%	204,074,060	2.50%	155,191,926	(48,882,134)

APPALACHIAN POWER COMPANY **SCHEDULE II**
COMPARISON OF MORTALITY CHARACTERISTICS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Existing Rates			Study Rates				
		Average Service Life (Years)	Iowa Curve	Net Salvage Factor	Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor
TRANSMISSION PLANT									
352.0	Structures & Improvements	55	R3.0	-5%	55	R3.0	5%	5%	0%
353.0	Station Equipment	35	R2.0	5%	35	R2.0	40%	25%	15%
354.0	Towers & Fixtures	60	R4.0	-5%	87	R2.5	25%	35%	-10%
355.0	Poles & Fixtures	45	L3.0	-10%	37	L2.0	5%	20%	-15%
356.0	OH Cond. & Devices	60	R5.0	0%	80	R2.5	15%	5%	10%
357.0	Underground Conduit	60	R4.0	0%	55	S2.0	0%	0%	0%
358.0	Underground Conductor and Devices	35	S2.0	5%	25	L3.0	0%	0%	0%
DISTRIBUTION PLANT									
361.0	Structures & Improvements	35	R3.0	-5%	43	R4.0	5%	5%	0%
362.0	Station Equipment	25	S0.0	30%	37	R1.0	40%	25%	15%
364.0	Poles, Towers, & Fixtures	30	L1.0	-20%	30	R1.5	5%	60%	-55%
365.0	Overhead Conductor & Devices	40	L0.5	0%	43	L0.0	40%	25%	15%
366.0	Underground Conduit	60	R4.0	0%	47	S6.0	0%	0%	0%
367.0	Underground Conductor	30	S2.0	5%	52	R0.5	0%	0%	0%
368.0	Line Transformers	30	R1.0	5%	32	R0.5	25%	35%	-10%
369.0	Services	20	S6.0	-20%	36	R0.5	2%	15%	-13%
370.0	Meters	25	R3.0	0%	25	S6.0	10%	20%	-10%
371.0	Installations on Custs. Prem.	11	L0.0	10%	11	S6.0	2%	10%	-8%
372.0	Leased Property on Cust Prem.	25	L3.0	0%	25	L3.0	0%	0%	0%
373.0	Street Lighting & Signal Sys.	18	R3.0	0%	21	S6.0	10%	5%	5%
GENERAL PLANT									
390.0	Structures & Improvements	40	R3.0	-15%	38	R3.0	30%	2%	28%
391.0	Office Furniture & Equipment	35	L0.0	2%	30	L3.0	5%	0%	5%
392.0	Transportation Equipment	35	L2.0	0%	27	S6.0	5%	0%	5%
393.0	Stores Equipment	55	R2.5	0%	55	R4.0	0%	0%	0%
394.0	Tools Shop & Garage Equipment	45	L1.5	0%	43	R0.5	0%	0%	0%
395.0	Laboratory Equipment	45	R2.0	0%	37	S2.0	0%	0%	0%
396.0	Power Operated Equipment	25	L2.0	10%	25	L2.0	0%	0%	0%
397.0	Communication Equipment	20	L3.0	-10%	24	R0.5	5%	0%	5%
398.0	Miscellaneous Equipment	35	L0.0	0%	35	S6.0	0%	0%	0%

SECTION II

DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

SECTION II

DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

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DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in this report was considered on a group plan. Under the group plan, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Determination of Annual Depreciation Rates

By the Average Remaining Life Method

APCO's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less the accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

$$\text{Annual Depreciation Expense} = \frac{\text{(Orig. Cost) (Net Salvage Ratio) - Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Methods of Life Analysis

Depending upon the type of property and the nature of the data available from the property accounting records, one of three life analyses was used to arrive at the historically realized mortality characteristics and service lives of the depreciable plant investments. These methods are identified and described as follows:

Life Span Analysis

The life span analysis was employed for Production Plant. APCO's investment in production plant includes steam, hydraulic and other generating plants. The life-span method of analysis is particularly suited to specific location property, such as a generating plant, where all of the surviving investments are likely to be retired in total at a future date.

The key elements in the life span analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements. An example of the interim retirement for Account 311, Structures and Improvements, is shown in the Appendix on Page A-1.

The age of the surviving investments was obtained from APCO's property accounting records. American Electric Power Service Corporation provided the retirement dates used in the life-span analysis for Steam Production Plant. For Hydraulic Production plants, the retirement dates were based on the FERC license expiration dates for the plants.

A discussion of the life analyses for Steam, Hydraulic and Other Production Plants follows:

Steam Production Plant

APCO's depreciable investments in Steam Production Plant consist of the following units:

Plant	Unit	Rating	Commercial Operating Date
Mountaineer	1	1,300 MW	1980
Kanawha River	1	200 MW	1953
Kanawha River	2	200 MW	1953
Amos	1	800 MW	1971
Amos	2	800 MW	1972
Amos	3*	1,3000 MW	1972
Sporn	1	150 MW	1950
Sporn	3	150 MW	1951
Clinch River	1	235 MW	1958
Clinch River	2	235MW	1958
Clinch River	3	235MW	1961

Plant	Unit	Rating	Commercial Operating Date
Glen Lyn	5	95 MW	1944
Glen Lyn	6	240 MW	1957

APCO owns 33.3% of this unit

American Electric Power Service Corporation evaluated each of the generating units and determined the following retirement dates for the units:

Plant	Unit	Retirement Date
Mountaineer	1	2040
Kanawha River	1	2018
Kanawha River	2	2018
Amos	1	2032
Amos	2	2032
Amos	3	2033
Sporn	1	2018
Sporn	3	2018
Clinch River	1	2021
Plant	Unit	Retirement Date
Clinch River	2	2021
Clinch River	3	2021
Glen Lyn	5	2012
Glen Lyn	6	2015

Hydraulic Production Plant

APCO's investment in Hydraulic Production plant consists of the following plants:

Plant	Capacity	First Unit's Commercial Operating Date	FERC License Expiration
Buck	8.5 MW	1912	2024
Niagara	2.4 MW	1906	2024
Reusens	12.5 MW	1903	2024
Leesville	50 MW	1964	2040
London	14.4 MW	1935	2044
Marmet	14.4 MW	1935	2044
Winfield	14.8 MW	1938	2044
Smith Mountain	586 MW	1965	2040

Other Production Plant

APCO's investment in this Other Production Plant consists of the Ceredo Generating Station that APCO acquired from subsidiary of Reliant Energy. This generating plant is a natural-gas, simple-cycle power plant with a nominal generating capacity of 505 megawatts. AEP's Pro Serv Subsidiary designed and built the plant for Columbia Energy. It was completed and began commercial operation in 2001. APCO intends to operate this plant as peaking generation designed for use only when the demand for electricity is high.

Actuarial Analysis

This method of analyzing past experience represents the application to industrial property of statistical procedures developed in the life insurance field for investigating human mortality. It is distinguished from other methods of life estimation by the requirement that it is necessary to know the age of the property at the time of its retirement and the age of survivors, or plant remaining in service; that is, the installation date must be known for each particular retirement and for each particular survivor.

The application of this method involves the statistical procedure known as the "annual rate method" of analysis. This procedure relates the retirements during each age interval to the exposures at the beginning of that interval, the ratio of these being the annual retirement ratio. Subtracting each retirement ratio from unity yields a sequence of annual survival ratios from which a survivor curve can be determined. This is accomplished by the consecutive multiplication of the survivor ratios. The length of this curve depends primarily upon the age of the oldest property. Normally, if the period of years from the inception of the account to the time of the study is short in relation to the expected maximum life of the property, an incomplete or stub survivor curve results.

While there are a number of acceptable methods of smoothing and extending this stub survivor curve in order to compute the area under it from which the average life is determined, the well-known Iowa Type Curve Method was used in this study.

By this procedure, instead of mathematically smoothing and projecting the stub survivor curve to determine the average life of the group, it was assumed that the stub curve would have the same mortality characteristics as the type curve selected. The selection of the appropriate type curve and average life is accomplished by plotting the stub curve, superimposing on it Iowa curves of the various types and average lives drawn to the same scale, and then determining which Iowa type curve and average life best matches the stub.

An example of the calculations involved in the Actuarial Method of Life Analysis is shown in the Appendix on Pages A-2 through A-4 for Account 353.0-Transmission Station Equipment. Pages A-2, A-3 and A-4 show the computation of the actual survivor curve for the experience band 1966 - 2005, inclusive based on historical data obtained from APCO's property records. The actual survivor curve for the 1966- 2005 period is plotted and matched on Page A-5, as explained above. This method was used for the following accounts:

352.0 Transmission Structures & Improvements
353.0 Transmission Station Equipment
361.0 Distribution Structures & Improvements
362.0 Distribution Station Equipment
390.0 General Structures & Improvements

Simulated Plant Record Analysis

The "Simulated Plant Record" (SPR) method designates a class of statistical techniques that provide an estimate of the age distribution, mortality dispersion and average service life of property accounts whose recorded history provides no indication of the age of the property units when retired from service. For each such account, the available property records usually reveal only the annual gross additions, annual retirements and balances with no indication of the age of either plant retirements or annual plant balances. For this study, the "Balances method" of analysis was used.

The SPR Balances Method is a trial and error procedure that attempts to duplicate the annual balance of a plant account by distributing the actual annual gross additions over time according to an assumed mortality distribution. Specifically, the dollars remaining in service at any date are estimated by multiplying each year's additions by the successive proportion surviving at each age as given by the assumed survivor characteristics. For a given year, the balance indicated is the accumulation of survivors from all vintages and this is compared with the actual book balance. This process is repeated for a different survivor curves and average life combinations until a pattern is discovered which produces a series of "simulated balances" most nearly equaling the actual balances shown in a company's books.

This determination is based on the distribution producing the minimum sum of squared differences between the simulated balance and the actual balances over a test period of years.

The iterative nature of the simulated methods makes them ideally suited for computerized analysis. For each analysis of a given property account, the computer program provides a single page summary containing the results of each analysis indicating the "best fit" based on criteria selected by the user.

The results of such an analysis by the Balance Method is shown for Account 364 – Distribution Poles, Towers and Fixtures on page A-6 in the Appendix. In the case of the Balances Method each curve type tested is shown along with the average service life that produced the minimum sum of squared differences from the actual balances. The analysis also shows the value of the Index of Variation of the difference that is calculated according to the following equation for the Balances Method:

$$\text{Index of Variation} = (1000)\ \frac{\text{Sum of Squared Differences}}{\text{Number of Test Years}} \Big/ \frac{\text{Average Actual}}{\text{Balance}}$$

The lower the value of the Index the better the agreement with the actual data.

The SPR Method of Life Analysis was utilized for the following accounts:

354.0 Transmission Towers & Fixtures

355.0 Transmission Poles & Fixtures

356.0 OH Conductor & Devices

357.0 Underground Conduit

358.0 Underground Conductor

364.0 Distribution Poles, Towers & Fixtures

365.0 Distribution OH Conductor & Devices

366.0 Underground Conduit

367.0 Underground Conductor & Devices

368.0 Distribution Line Transformers

369.0 Distribution Services

370.0 Distribution Meters

371.0 Installation on Customers Premises

373.0 Street Lighting & Signal Systems

391.0 Office Furniture & Equipment

392.0 Transportation Equipment

394.0 Tools, Shop & Garage Equipment

395.0 Laboratory Equipment

397.0 Communication Equipment

398.0 Miscellaneous Equipment

4. Final Selection of Average Life and Curve Type

The final selection of average life and curve type for each depreciable plant account analyzed by the Actuarial and SPR Methods was primarily based on the results of the mortality analyses of past retirement history.

5. Net Salvage

The net salvage percentages used in this report are expressed as percent of original cost and are based primarily on the Company's experience combined with the experienced judgment of the analyst. APCO maintains salvage and removal costs at the functional plant level, rather than by primary plant accounts. To aid in the selection of net salvage percentages, a review was made of the Company's experience for each plant function with respect to salvage and removal costs for the period 1954-2005. A sample of the type of salvage analysis made appears in Appendix A on Pages A-7 through A-12 for the Distribution Plant function. The salvage program analyzes historical experience on an annual basis, on the cumulative history basis and for 10 year moving averages to get the historical gross salvage, gross cost of removal and net salvage. In order to determine gross salvage, gross removal and net salvage percentages for the individual plant accounts, the original cost retirements were detailed by account for the period 1996 through 2005 and, based on judgment, gross salvage and cost of removal percentages were selected for each account. The salvage and removal percentages for each account were then netted to determine a net salvage percentage for each account.

The net salvage percents were converted to net salvage ratios and appear in Column VI on Schedule I and were used to determine the total amount to be recovered through depreciation. The same net salvage was also reflected in the determination of the calculated depreciation requirement, which was used to allocate the accumulated depreciation at the functional group to the accounts comprising each group.

The net salvage ratios shown in Column VI on Schedule I in Section I of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as .80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

6. <u>Net Salvage for Steam Production Plant</u>

While the analysis described above was used to determine the net salvage applicable to interim retirements for steam production plant, the most significant net salvage realization for generating plants occurs at the end of their life. Therefore, to assist in establishing the net salvage applicable to APCO's steam generating plant, APCO had Brandenburg Industrial Service Company (Brandenburg) perpare conceptual demolition cost estimates for each of the steam production plants and for the Ceredo plant. The cost estimates to demolish the plants are based on current (2005) price levels. The estimates of demolition costs were incorporated into the net salvage ratios for Steam Production Plant. APCO's currently approved depreciation rates for steam production also included demolition cost estimates.

Effects of Statement of Financial Accounting Standards No. 143 (SFAS 143), Financial Accounting Standards Board (FASB) Interpretation No. 47 (FIN47) and Federal Energy Regulatory Commission (FERC) Order 631 on Net Salvage

The Financial Accounting Standards Board (FASB) issued SFAS 143, Accounting for Asset Retirement Obligations, in June 2001. SFAS 143 became effective January 1, 2003 for companies whose fiscal year ends on December 31. SFAS 143 is a financial accounting requirement that deals with the identification, measurement and recording of legal liabilities associated with asset retirement. SFAS 143 was designed to standardize the way that different companies and different industries account for cost of removal when there is a legal asset retirement obligation. SFAS 143 was not intended to address the appropriate ratemaking treatment for regulated utilities.

The FASB issued FIN 47 in March 2005 to interpret the application of SFAS143. FIN 47 clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated.

As stated in APCO's financial statements, APCO has identified, but not recognized, asset retirement obligations related to electric transmission and distribution as a result of the nature of certain easements on property on which APCO has assets. Generally these easements are perpetual and require only the retirement and removal of transmission and distribution assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements as APCO plans to use the facilities indefinitely. APCO has established ARO's for ash ponds at the generating plants and for the removal and disposal of asbestos in general buildings and generating plants.

SFAS 143 did not directly change the accounting requirements for rate-regulated companies for removal costs that are not a legal retirement obligation. The Security and Exchange Commission (SEC) has interpreted SFAS 143 to require that cost of removal that is not a legal obligation should not be recognized under Generally Accepted Accounting Principles (GAAP) by unregulated entities. Statement of Financial Accounting Standards No. 71 (SFAS 71) provides that any such amounts that are recovered in rates by regulated enterprises would be classified as regulatory liabilities for SEC reporting purposes.

The (FERC) issued Order 631 on April 9, 2003. Order 631 added new balance sheet and income statement accounts to be used for recording legal Asset Retirement Obligations. In addition, Order 631 revised definitions and, the general and plant instructions contained in the FERC Uniform System of Accounts.

FERC also specifically addressed accounting for cost of removal that does not constitute a legal obligation in Section III, paragraph 36 of Order 631 as follows:

> As proposed in the NOPR, the rule applies to legal obligations associated with the retirement of tangible long-lived assets. Under existing requirements of the Uniform System of Accounts removal costs that are not asset retirement obligations are included as a component of the depreciation expense and recorded in accumulated depreciation. The Commission notes that certain jurisdictional entities may have been receiving specific allowances for cost of removal for non-legal retirement obligations as a specific component in their rates approved by their regulators. The Commission did not propose any changes to its existing accounting requirements for cost of removal for non-legal retirement obligations. Accordingly, jurisdictional entities are accounting for such costs consistent with

the requirements of the Uniform System of Accounts under Part 101 for public utilities and licensees, Part 201 for natural gas companies and Part 352 for oil pipeline companies.

APCO's current book depreciation study rate recommendations comply with the accounting requirements of SFAS 143, FIN 47 and FERC Order 631 for Transmission, Distribution and General Plant. The study splits the amount of net salvage into a gross removal component and a gross salvage component. Thus, for SEC financial reporting purposes, the amount of removal costs included in depreciation rates and accruals can readily be determined and reclassified to a regulatory liability account.

SFAS 143 prohibits non-rate regulated businesses from accruing for non-specific legal retirement obligations through depreciation accruals. However, for purpose of APCO's current rate filing, I was advised by legal counsel that the Virginia SCC rate filing requirements required all of APCO's electric plant to be treated as if it were still fully regulated by the Virginia SCC. Therefore I included removal costs in the depreciation rates that I developed for APCO's non-rate regulated generation property.

7. Calculation of Depreciation Requirement at December 31, 2005

The accumulated depreciation by functional group was allocated to individual plant accounts based on the calculation of a depreciation requirement (theoretical reserve) for each plant account using the average service life, curve type and net salvage amount recommended in this study. An example of the calculation of the depreciation requirement at December 31, 2005, for Account 364 – Distribution Poles, Towers and Fixtures, is shown on Pages A-13 through A-15 in Appendix A.

That sample printout is explained in detail as follows:

Column I - Age of each year's installation at December 31, 2005, based on the conventional procedure that all property installed in any year is assumed to be installed at the mid-point of that year.

Column II - Year of installation of the surviving dollars shown in Column III.

Column III - The original cost at December 31, 2005, by year installed, as supplied directly from Company records.

Column IV - The Average Remaining Life of each vintage of Original Cost at the various ages indicated in Column I.

Column V - Depreciation Reserve Ratio based on the Life and Dispersion (Iowa Curve) shown in Column IV heading.

Column VI - Theoretical Reserve is the product of Column III times Column V for each year.

The effect of any estimated net salvage, as indicated on Page A-14, is provided by adjusting the subtotal rather than having each vintage of original cost appearing in Column III reflect such salvage.

The average Remaining Life, also shown, is the result of the weighing of the dollars of each age.

8. Study Results

The average service life, retirement dispersion pattern and net salvage pattern used to calculate each primary plant account rate are shown on Schedule 2. The mortality characteristics and net salvage values for the current rates are also shown. The changes to the mortality characteristics follow the trends shown by the historical retirement experience. The gross salvage and gross cost of removal percentages were largely based on the history of the account for the period 1996-2005.

Steam Production Plant

The projected operating lives for the Amos and Mountaineer Plants were increased from 40 years in the prior depreciation study to 60 years. This represents the Company's current operating plans for these units. The current conceptual demolition cost estimates prepared by Brandenburg Company total $154 million. This is about 30% less than the demolition cost estimates that were reflected in the Company's 1990 study. The combination of the increase in operating lives for the Amos and Mountaineer plants and the reduction in demolition costs were the main factors that caused the reduction in depreciation rates for Steam Production Plant.

Hydraulic Production Plant

The FERC operating licenses for many of the Company's hydro plants have either been renewed or are in the process of being renewed. The depreciation study rates reflect both the actual and planned license renewals. This resulted in the decrease in depreciation rates for the Hydraulic Production Plant.

. Other Production Plant

The Ceredo generating plant did not exist at the time of the Company's last depreciation study. The recommended change in depreciation rates reflects changes made as a result of refining the original depreciation estimate for the plant.

Transmission Plant

The average remaining life of the transmission plant group increased from 34.8 years to 38.6 years. The estimated net salvage for the transmission plant function has moved from 0% to 6% positive. As a result of the increased remaining life and increased positive net salvage, the comparison of the actual accumulated depreciation to the calculated depreciation reserve requirement indicates an excess of $102.4 million. The change in remaining life reduced the annual accrual by $1.8 million; the increased positive net salvage reduced the accrual by $1.2 million and the amortization of the difference between the calculated and actual accumulated depreciation reduced the accrual by $3.7 million.

Distribution Plant

The average remaining life of the distribution plant group increased from 22.79 years to 26.77 years. The estimated net salvage for the distribution plant function has changed from negative 2% to negative 12%. The increase in remaining life and the increased negative net salvage results in a calculated accumulated depreciation in excess of the actual book accumulated depreciation of $48.1 million. The increase in remaining life decreased the annual accrual by $9.23 million and the amortization of the difference between the calculated accumulated depreciation and the actual accumulated depreciation reduced the annual accrual by $2.3 million. The offsetting increase in negative net salvage increased the annual accrual by $12.4 million.

General Plant

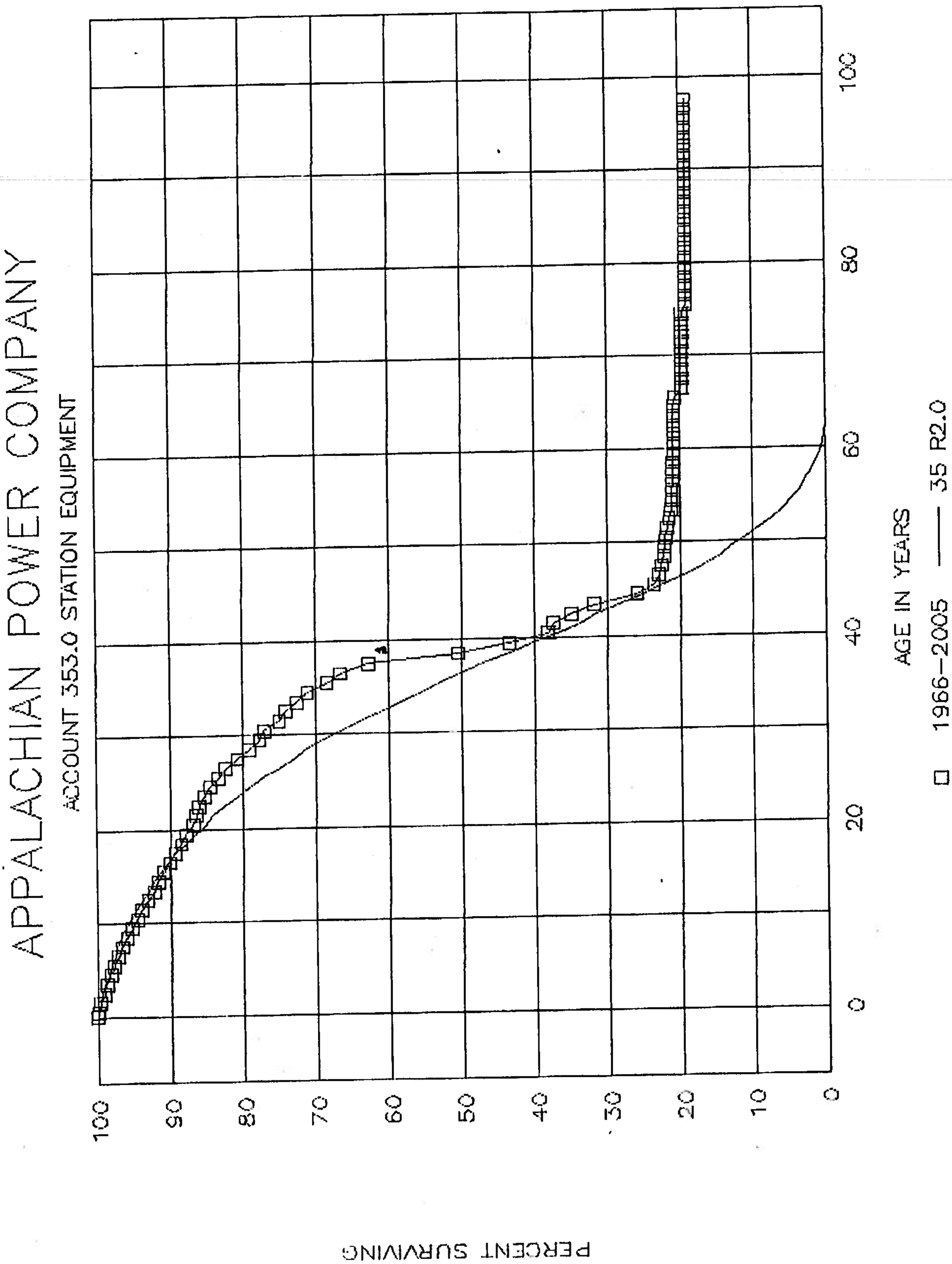
The average remaining life for the general plant group decreased from 27.82 years to 24.39 years. The estimated net salvage increased from a negative 12% to a positive 20%. The decrease in remaining life increased the annual accrual by $.4 million. The increase in positive net salvage decreased the annual accrual by $1.7 million. The calculated accumulated depreciation exceeds the actual accumulated depreciation by $20.4 million. The amortization of this difference decreased the annual accrual by $.8 million.

APPENDIX A

APPALACHIAN POWER COMPANY
CALCULATION OF INTERIM RETIREMENT RATIOS
STEAM PRODUCTION PLANT
ACCOUNT 311.0 STRUCTURES & IMPROVEMENTS

YEAR	ADDITIONS	RETIREMENTS	BALANCE	AVERAGE BALANCE	RETIREMENT RATIO
1944			2,838,839	N. A.	N. A.
1945	15,083	11,876	2,842,026	2,840,433	0.0042
1946	350	985	2,841,391	2,841,709	0.0003
1947	3,740	41	2,845,090	2,843,241	0.0000
1948	3,590	1,104	2,847,576	2,846,333	0.0004
1949	6,641	0	2,854,217	2,850,897	0.0000
1950	5,496,850	0	8,351,067	5,602,642	0.0000
1951	0	22,184	8,328,883	8,339,975	0.0027
1952	216,378	0	8,545,261	8,437,072	0.0000
1953	9,647,807	6,273	18,186,795	13,366,028	0.0005
1954	399,751	2,581	18,583,965	18,385,380	0.0001
1955	108,825	80,668	18,612,122	18,598,044	0.0043
1956	36,720	8,877	18,639,965	18,626,044	0.0005
1957	4,460,081	6,490	23,093,558	20,866,761	0.0003
1958	9,243,129	5,626	32,331,059	27,712,308	0.0002
1959	667,737	5,152	32,993,844	32,662,352	0.0002
1960	92,615	26,902	33,059,357	33,026,501	0.0008
1961	3,084,871	18,128	36,126,100	34,592,729	0.0005
1962	194,864	20,578	36,300,386	36,213,243	0.0006
1963	82,223	4,951	36,377,658	36,339,022	0.0001
1964	58,001	26,931	36,408,728	36,393,193	0.0007
1965	23,493	18,323	36,413,898	36,411,313	0.0005
1966	34,610	11,206	36,437,302	36,425,600	0.0003
1967	34,673	30,457	36,441,518	36,439,410	0.0008
1968	6,282	4,874	36,442,906	36,442,212	0.0001
1969	274,551	5,258	36,712,199	36,577,553	0.0001
1970	67,805	15,394	36,764,410	36,738,305	0.0004
1971	17,098,918	218	53,863,110	45,313,760	0.0000
1972	11,233,934	19,087	65,077,977	59,470,544	0.0003
1973	9,237,448	1,354	74,314,071	69,696,024	0.0000
1974	3,189,136	42,803	77,460,403	75,887,237	0.0006
1975	2,028,990	7,576	79,481,817	78,471,110	0.0001
1976	458,356	398,391	79,541,782	79,511,800	0.0050
1977	135,885	31,590	79,646,077	79,593,930	0.0004
1978	7,985,887	102,652	87,529,312	83,587,695	0.0012
1979	2,130,732	28,754	89,631,290	88,580,301	0.0003
1980	82,499,958	54,669	172,076,579	130,853,935	0.0004
1981	2,458,368	12,140	174,522,805	173,299,692	0.0001
1982	2,966,173	5,183	177,483,795	176,003,300	0.0000
1983	1,087,764	22,937	178,548,622	178,016,209	0.0001
1984	1,097,802	4,883	179,641,561	179,095,092	0.0000
1985	3,779,175	101,834	183,319,102	181,480,332	0.0006
1986	463,961	132,500	183,650,583	183,484,833	0.0007
1987	927,094	73,059	184,504,598	184,077,581	0.0004
1988	1,721,425	26,598	186,199,425	185,352,012	0.0001
1989	675,660	26,464	186,848,621	186,524,023	0.0001
1990	485,175	78,642	187,255,154	187,051,888	0.0004
1991	699,378	102,744	187,851,788	187,553,471	0.0005
1992	2,580,203	425,034	190,006,957	188,929,373	0.0022
1993	10,796,909	423,598	200,380,268	195,193,613	0.0022
1994	1,244,293	346,091	201,278,470	200,829,369	0.0017
1995	2,744,243	376,402	203,646,311	202,462,391	0.0019
1996	4,406,219	637,447	207,415,083	205,530,697	0.0031
1997	3,895,202	832,979	210,477,308	208,946,195	0.0040
1998	1,977,893	357,592	212,097,607	211,287,457	0.0017
1999	3,001,642	151,212	214,948,037	213,522,822	0.0007
2000	529,971	65,704	215,412,304	215,180,171	0.0003
2001	3,784,586	875,694	218,321,196	216,866,750	0.0040
2002	175,010	143,475	218,352,731	218,336,964	0.0007
2003	3,629,112	833,872	221,147,971	219,750,351	0.0038
2004	3,565,999	379,627	224,334,343	222,741,157	0.0017
2005	6,365,103	1,474,610	229,224,836	226,779,589	0.0065
TOTAL 1945-2005	235,318,031	8,932,034	6,434,872,951	6,321,679,952	0.0649

AVERAGE INTERIM RATE $\frac{0.0649}{61}$ 0.0011


APPALACHIAN POWER COMPANY
ACCOUNT 353.0 STATION EQUIPMENT
PERCENT SURVIVING
AGE IN YEARS
0
20
40
60
80
100
10
30
50
70
90
1966–2005
35 R2.0

DELOITTE HASKINS & SELLS DEPRECIATION SYSTEM - DSACT03 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2005 PAGE 1

****APPALACHIAN POWER COMPANY**** 2-19-2006

ACCOUNT NO.: 35300000

1966 THRU 2005 BAND ANALYSIS SURVIVOR REPORT

AGE	RETIREMENTS	EXPOSURES	ANNUAL % SURVIVORS	CUMULATIVE % SURVIVORS
0.50	1292435.	609502793.	99.79	99.79
1.50	1108404.	599223017.	99.82	99.60
2.50	3170995.	584211305.	99.46	99.06
3.50	2035989.	567377505.	99.64	98.71
4.50	3068719.	557005033.	99.45	98.16
5.50	2494802.	528374203.	99.53	97.70
6.50	2938540.	512415779.	99.43	97.14
7.50	2878717.	496513920.	99.42	96.58
8.50	3211612.	474106374.	99.32	95.92
9.50	3522987.	460848015.	99.24	95.19
10.50	3274365.	447618920.	99.27	94.49
11.50	2865740.	435800044.	99.34	93.87
12.50	3640888.	417548007.	99.13	93.05
13.50	3966507.	399536028.	99.01	92.13
14.50	2099283.	374544966.	99.44	91.61
15.50	2747028.	349116551.	99.21	90.89
16.50	3121642.	342166667.	99.09	90.06
17.50	2761828.	328922646.	99.16	89.31
18.50	3064638.	318214668.	99.04	88.45
19.50	2325146.	311948738.	99.25	87.79
20.50	3164896.	305318624.	98.96	86.88
21.50	1787288.	289812598.	99.38	86.34
22.50	1152611.	264526142.	99.56	85.96
23.50	2131679.	258920847.	99.18	85.26
24.50	2028547.	249877363.	99.19	84.57
25.50	3218729.	212808601.	98.49	83.29
26.50	2019754.	177686169.	98.86	82.34
27.50	3189134.	161530052.	98.03	80.71
28.50	2832421.	139537474.	97.97	79.08
29.50	2297171.	132612303.	98.27	77.71
30.50	979984.	125701751.	99.22	77.10
31.50	3291868.	119917123.	97.25	74.98
32.50	1203680.	108984576.	98.90	74.16
33.50	1868102.	91100113.	97.95	72.63
34.50	1706781.	84765012.	97.99	71.17
35.50	2541326.	67603387.	96.24	68.50

DELOITTE HASKINS & SELLS DEPRECIATION SYSTEM - DSACT03 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2005 PAGE 2

****APPALACHIAN POWER COMPANY**** 2-19-2006

ACCOUNT NO.: 35300000

1966 THRU 2005 BAND ANALYSIS SURVIVOR REPORT

AGE	RETIREMENTS	EXPOSURES	ANNUAL % SURVIVORS	CUMULATIVE % SURVIVORS
36.50	1467472.	53921582.	97.28	66.63
37.50	508270.	8928688.	94.31	62.84
38.50	1606768.	8199676.	80.40	50.53
39.50	804663.	5761332.	86.03	43.47
40.50	616957.	4929347.	87.48	38.03
41.50	77404.	3940979.	98.04	37.28
42.50	255952.	3859676.	93.37	34.81
43.50	320339.	3544608.	90.96	31.66
44.50	587788.	3224007.	81.77	25.89
45.50	226896.	2588798.	91.24	23.62
46.50	62908.	2114194.	97.02	22.92
47.50	30266.	2049970.	98.52	22.58
48.50	32197.	1832968.	98.24	22.18
49.50	5285.	1798376.	99.71	22.12
50.50	7620.	1420550.	99.46	22.00
51.50	13733.	1275195.	98.92	21.76
52.50	13580.	1203925.	98.87	21.52
53.50	16085.	1057392.	98.48	21.19
54.50	2100.	1027137.	99.80	21.15
55.50	1933.	952802.	99.80	21.10
56.50	7156.	869026.	99.18	20.93
57.50	1.	850190.	100.00	20.93
58.50	0.	807979.	100.00	20.93
59.50	970.	806556.	99.88	20.90
60.50	0.	804226.	100.00	20.90
61.50	1.	803522.	100.00	20.90
62.50	0.	803019.	100.00	20.90
63.50	0.	802419.	100.00	20.90
64.50	2620.	802167.	99.67	20.84
65.50	10707.	795356.	98.65	20.56
66.50	32095.	784617.	95.91	19.72
67.50	0.	752491.	100.00	19.72
68.50	0.	742348.	100.00	19.72
69.50	0.	741387.	100.00	19.72
70.50	270.	741387.	99.96	19.71
71.50	0.	740235.	100.00	19.71

DELOITTE HASKINS & SELLS DEPRECIATION SYSTEM - DSACT03 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2005 PAGE 3

****APPALACHIAN POWER COMPANY**** 2-19-2006

ACCOUNT NO.: 35300000

1966 THRU 2005 BAND ANALYSIS SURVIVOR REPORT

AGE	RETIREMENTS	EXPOSURES	ANNUAL % SURVIVORS	CUMULATIVE % SURVIVORS
72.50	0.	350498.	100.00	19.71
73.50	0.	350498.	100.00	19.71
74.50	459.	350498.	99.87	19.68
75.50	11115.	350039.	96.82	19.06
76.50	0.	5757.	100.00	19.06
77.50	0.	5757.	100.00	19.06
78.50	0.	5757.	100.00	19.06
79.50	0.	5757.	100.00	19.06
80.50	0.	5757.	100.00	19.06
81.50	0.	5757.	100.00	19.06
82.50	0.	5757.	100.00	19.06
83.50	0.	5757.	100.00	19.06
84.50	0.	5757.	100.00	19.06
85.50	0.	5757.	100.00	19.06
86.50	0.	5757.	100.00	19.06
87.50	0.	5757.	100.00	19.06
88.50	0.	5757.	100.00	19.06
89.50	0.	5757.	100.00	19.06
90.50	0.	5757.	100.00	19.06
91.50	0.	5757.	100.00	19.06
92.50	0.	5757.	100.00	19.06
93.50	0.	5757.	100.00	19.06
94.50	0.	5757.	100.00	19.06
95.50	0.	5757.	100.00	19.06
96.50	0.	5757.	100.00	19.06
97.50	0.	5757.	100.00	19.06

TOTAL 97727846.

REALIZED LIFE = 46.18 YEARS

DELOITTE HASKINS & SELLS — DEPRECIATION SYSTEM - DSSIMBAL02 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2005 — 2-18-2006

**** APPALACHIAN POWER COMPANY ****

SIMULATED PLANT BALANCE METHOD OF LIFE ANALYSIS FOR ACCOUNT 36400000

USING BALANCES PERIOD EQUAL TO LAST 40 YEARS

AVERAGE LIFE AT WHICH BOOK BALS EQUAL SIMULATED BALS AT END OF										MORT	INDEX OF VARIATION FOR ANALYSIS OF DATA ENDING IN									
1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	DISP	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
34.6	34.6	34.6	34.7	34.8	35.0	35.2	35.4	35.7	36.1	SC	-202	-194	-183	-180	-174	-176	-191	221	254	288
31.8	31.8	31.8	31.9	32.0	32.1	32.3	32.6	32.8	33.1	S-.5	225	215	202	195	186	184	195	222	354	289
29.8	29.8	29.8	29.9	29.9	30.0	30.1	30.3	30.5	30.7	S0	253	244	228	216	204	197	202	225	255	290
28.8	28.7	28.0	28.8	28.8	28.9	29.0	29.2	29.4	29.6	S0.5	277	269	252	237	223	212	212	227	252	284
27.9	27.8	27.8	27.8	27.9	27.9	28.0	28.1	28.3	28.5	S1	305	297	280	262	246	232	227	236	256	285
27.2	27.2	27.2	27.2	27.2	27.2	27.3	27.4	27.6	27.8	S1.5	332	325	307	288	270	254	245	248	262	286
26.7	26.6	26.6	26.6	26.6	26.6	26.7	26.8	26.9	27.1	S2	361	354	337	316	298	280	267	265	273	293
25.9	25.9	25.8	25.8	25.8	25.8	25.9	25.9	26.1	26.2	S3	411	406	389	366	347	327	309	300	300	311
25.4	25.3	25.3	25.2	25.2	25.2	25.2	25.3	25.4	25.6	S4	462	459	442	419	399	376	355	341	335	339
25.2	25.1	25.0	24.9	24.9	24.9	24.9	25.0	25.1	25.2	S5	496	495	478	455	434	410	387	370	362	363
25.0	24.9	24.8	24.8	24.7	24.7	24.7	24.8	24.9	25.1	S6	517	515	499	475	454	430	406	388	378	379
34.7	34.6	34.7	34.7	34.8	34.9	35.1	35.4	35.6	36.0	L0	223	217	204	196	187	185	196	224	257	293
32.4	32.3	32.4	32.4	32.5	32.6	32.8	33.0	33.2	33.5	L0.5	240	233	219	208	197	192	200	224	256	292
30.5	30.4	30.4	30.5	30.5	30.6	30.7	30.9	31.1	31.4	L1	260	253	238	224	211	203	207	227	256	292
29.3	29.2	29.2	29.3	29.3	29.4	29.5	29.6	29.8	30.0	L1.5	288	280	264	248	233	222	220	235	259	291
28.2	28.1	28.1	28.2	28.2	28.2	28.3	28.4	28.6	28.8	L2	317	310	293	275	258	244	238	246	266	294
26.8	26.7	26.7	26.7	26.7	26.7	26.8	26.9	27.0	27.2	L3	372	366	349	328	309	290	277	275	284	303
25.8	25.7	25.7	25.7	25.6	25.6	25.7	25.8	25.9	26.0	L4	429	425	407	384	364	343	325	314	313	323
25.4	25.3	25.2	25.2	25.1	25.1	25.2	25.2	25.3	25.5	L5	474	471	454	430	409	387	365	350	344	348
32.0	32.0	32.1	32.2	32.3	32.4	32.6	32.8	33.1	33.4	R0.5	221	211	198	192	184	182	194	220	251	284
30.1	30.1	30.1	30.2	30.2	30.3	30.5	30.6	30.8	31.1	R1	249	237	222	211	199	193	198	-218	246	277
28.9	28.9	28.9	29.0	29.0	29.1	29.2	29.3	29.5	29.7	R1.5	277	266	249	234	219	208	207	220	-240	-268
27.9	27.8	27.8	27.9	27.9	27.9	28.0	28.2	28.3	28.5	R2	309	299	281	263	246	232	225	231	246	270
27.1	27.1	27.1	27.1	27.1	27.1	27.2	27.3	27.5	27.6	R2.5	340	332	314	294	277	260	248	248	258	277
26.5	26.4	26.4	26.4	26.4	26.4	26.5	26.5	26.7	26.8	R3	375	369	352	330	312	293	278	272	276	291
25.7	25.6	25.6	25.6	25.5	25.5	25.6	25.7	25.8	25.9	R4	432	428	411	389	369	349	329	317	314	321
25.3	25.1	25.1	25.0	25.0	25.0	25.0	25.1	25.2	25.3	R5	485	483	467	443	423	400	377	361	353	354

THE INDEX OF VARIATION IS MULTIPLIED BY 10 TO OBTAIN A HIGHER LEVEL OF RANKING PRECISION

APPALACHIAN POWER COMPANY
Distribution Plant Net Salvage

14-Mar-06

Year	361	362	364	365	366	367	368	369	370	371	373	Total	Removal %	Weighted (000)
	Retirements													
1996	76,530	2,651,372	5,810,152	4,009,491	25,608	528,686	7,392,311	901,199	1,548,808	1,124,232	297,560	24,365,949	-16	-389,855
1997	23,233	1,413,045	4,181,534	3,100,840	52,365	314,864	6,830,283	887,176	2,128,629	1,188,444	321,465	20,441,878	-13	-265,744
1998	89,056	1,271,149	2,184,063	1,364,779	185	-64,101	2,393,997	2,111,008	1,155,703	1,117,678	225,322	11,848,839	-35	-414,709
1999	30,134	953,230	3,304,346	2,171,651	66,868	285,976	5,456,373	1,325,442	3,412,116	910,477	240,581	18,157,194	-1	-18,157
2000	40,799	1,098,009	7,942,407	5,207,782	143,434	361,791	7,111,932	1,452,811	3,068,215	1,713,288	331,182	28,471,650	-5	-142,358
2001	25,044	1,022,972	4,910,794	6,967,079	233,381	475,756	6,367,032	1,430,650	2,048,920	1,582,040	325,162	25,388,830	-5	-126,944
2002	9,101	1,017,329	3,274,141	4,156,897	55,353	176,624	5,452,162	2,217,009	2,026,676	1,190,049	232,544	19,807,885	-1	-19,808
2003	65,560	1,940,050	2,560,741	4,840,308	37,253	308,629	5,362,246	6,977,855	1,506,501	1,527,319	312,731	25,439,193	-39	-992,129
2004	1	1,037,338	3,905,283	5,420,556	6,098	306,405	5,458,133	7,406,664	2,738,796	721,482	602,964	27,603,720	-19	-524,471
2005	7,609	1,950,815	3,831,342	5,909,080	3,681	387,618	6,109,275	5,022,742	20,671,356	1,443,316	251,262	45,588,096	1	45,588
TOTAL	367,067	14,355,309	41,904,803	43,148,463	624,226	3,082,248	57,933,744	29,732,556	40,305,720	12,518,325	2,843,213	247,113,234	-12	-2,848,588

EVALUATION BASED ON 1996 -2005 ACTUAL

	361	362	364	365	366	367	368	369	370	371	373	Total
Total Retmts	367,067	14,355,309	41,904,803	43,148,463	624,226	3,082,248	57,933,744	29,732,556	40,305,720	12,518,325	2,843,213	246,815,674
Net Salvage %	0	15	-55	15	0	0	-10	-13	-10	-8	5	-12
Net Salvage $	0	2,153,296	-23,047,642	6,472,269	0	0	-5,793,374	-3,865,232	-4,030,572	-1,001,466	142,161	-28,970,560

14-Mar-06

APPALACHIAN POWER COMPANY
Distribution Plant Salvage Test

Year	Retirements 361	362	364	365	366	367	368	369	370	371	373	Total	Salvage %	Weighted (000)
1996	76,530	2,651,372	5,810,152	4,009,491	25,608	528,686	7,392,311	901,199	1,548,808	1,124,232	297,560	24,365,949	24%	5,848
1997	23,233	1,413,045	4,181,534	3,100,840	52,365	314,864	6,830,283	887,176	2,128,629	1,188,444	321,465	20,441,878	30%	6,133
1998	89,056	1,271,149	2,184,063	1,364,779	185	-64,101	2,393,997	2,111,008	1,155,703	1,117,678	225,322	11,848,839	32%	3,792
1999	30,134	953,230	3,304,346	2,171,661	66,868	285,976	5,456,373	1,325,442	3,412,116	910,477	240,581	18,157,194	10%	1,816
2000	40,799	1,098,009	7,942,407	5,207,782	143,434	361,791	7,111,932	1,452,811	3,068,215	1,713,288	331,182	28,471,650	22%	6,264
2001	25,044	1,022,972	4,910,794	6,967,079	233,381	475,756	6,367,032	1,430,650	2,048,920	1,582,040	325,162	25,388,830	37%	9,394
2002	9,101	1,017,329	3,274,141	4,156,897	55,353	176,624	5,452,162	2,217,009	2,026,676	1,190,049	232,544	19,807,885	33%	6,537
2003	65,560	1,940,050	2,560,741	4,840,308	37,253	308,629	5,362,246	6,977,855	1,506,501	1,527,319	312,731	25,439,193	1%	254
2004	1	1,037,338	3,905,283	5,420,556	6,098	306,405	5,458,133	7,406,664	2,738,796	721,482	602,964	27,603,720	11%	3,036
2005	7,609	1,950,815	3,831,342	5,909,080	3,681	387,618	6,109,275	5,022,742	20,671,356	1,443,316	251,262	45,588,096	2%	912
TOTAL	367,067	14,355,309	41,904,803	43,148,463	624,226	3,082,248	57,933,744	29,732,556	40,305,720	12,518,325	3,140,773	247,113,234	18%	43,985

EVALUATION BASED ON 1996 -2005 ACTUAL

	361	362	364	365	366	367	368	369	370	371	373	Total
Total Retrnts	367,067	14,355,309	41,904,803	43,148,463	624,226	3,082,248	57,933,744	29,732,556	40,305,720	12,518,325	3,140,773	247,113,234
Gross Salvage, %	5	40	5	40	0	0	25	2	10	2	10	18
Gross Salvage $	18,353	5,742,124	2,095,240	17,259,385	0	0	14,483,436	594,651	4,030,572	250,367	314,077	44,788,205

APPALACHIAN POWER COMPANY
Distribution Plant Removal Test

14-Mar-06

	Retirements													
Year	361	362	364	365	366	367	368	369	370	371	373	Total	Removal %	Weighted (000)
1996	76,530	2,651,372	5,810,152	4,009,491	25,608	528,686	7,392,311	901,199	1,548,808	1,124,232	297,560	24,365,949	40%	9,746
1997	23,233	1,413,045	4,181,534	3,100,840	52,365	314,864	6,830,283	887,176	2,128,629	1,188,444	321,465	20,441,878	43%	8,790
1998	89,056	1,271,149	2,184,063	1,364,779	185	-64,101	2,393,997	2,111,008	1,155,703	1,117,678	225,322	11,848,839	67%	7,939
1999	30,134	953,230	3,304,346	2,171,651	66,868	285,976	5,456,373	1,325,442	3,412,116	910,477	240,581	18,157,194	11%	1,997
2000	40,799	1,098,009	7,942,407	5,207,782	143,434	361,791	7,111,932	1,452,811	3,068,215	1,713,288	331,182	28,471,650	27%	7,687
2001	25,044	1,022,972	4,910,794	6,967,079	233,381	475,756	6,367,032	1,430,650	2,048,920	1,582,040	325,162	25,388,830	41%	10,409
2002	9,101	1,017,329	3,274,141	4,156,897	55,353	176,624	5,452,162	2,217,009	2,026,676	1,190,049	232,544	19,807,885	34%	6,735
2003	65,560	1,940,050	2,560,741	4,840,308	37,253	308,629	5,362,246	6,977,855	1,506,501	1,527,319	312,731	25,439,193	40%	10,176
2004	1	1,037,338	3,905,283	5,420,556	6,098	306,405	5,458,133	7,406,664	2,738,796	721,482	602,964	27,603,720	31%	8,557
2005	7,609	1,950,815	3,831,342	5,909,080	3,681	387,618	6,109,275	5,022,742	20,671,356	1,443,316	251,262	45,588,096	1%	456
TOTAL	367,067	14,355,309	41,904,803	43,148,463	624,226	3,082,248	57,933,744	29,732,556	40,305,720	12,518,325	3,140,773	247,113,234	29%	72,493

EVALUATION BASED ON 1996 -2005 ACTUAL

	361	362	364	365	366	367	368	369	370	371	373	Total
Total Retmts	367,067	14,355,309	41,904,803	43,148,463	624,226	3,082,248	57,933,744	29,732,556	40,305,720	12,518,325	3,140,773	247,113,234
Gross Removal %	5	25	60	25	0	0	35	15	20	10	5	30
Gross Removal $	18,353	3,588,827	25,142,882	10,787,116	0	0	20,276,810	4,459,883	8,061,144	1,251,833	157,039	73,743,887

DELOITTE HASKINS & SELLS

DEPRECIATION SYSTEM - DSALVG01 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2005

2-24-2006

**** APPALACHIAN POWER COMPANY ****

ACCOUNT NO.: 10860000

DISTRIBUTION

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1954	0.	2360914.	0.	0.%	1132398.	48.%	408282.	17.%	31.%	31.%
1955	0.	2397639.	0.	0.%	1196243.	50.%	524521.	22.%	28.%	28.%
1956	0.	4128237.	0.	0.%	2360339.	57.%	644116.	16.%	42.%	42.%
1957	0.	3407162.	0.	0.%	1772435.	52.%	858114.	25.%	27.%	27.%
1958	0.	2758059.	0.	0.%	1052822.	38.%	756075.	27.%	11.%	11.%
1959	0.	2322094.	0.	0.%	927874.	40.%	834464.	36.%	4.%	4.%
1960	0.	2609506.	0.	0.%	951705.	36.%	771617.	30.%	7.%	7.%
1961	0.	2591444.	0.	0.%	948019.	37.%	734433.	28.%	8.%	8.%
1962	0.	2513474.	0.	0.%	929678.	37.%	739858.	29.%	8.%	8.%
1963	0.	3087801.	0.	0.%	1188074.	38.%	817686.	26.%	12.%	12.%
1964	0.	3191696.	0.	0.%	1141615.	36.%	823696.	26.%	10.%	10.%
1965	0.	3239755.	0.	0.%	1184065.	37.%	941636.	29.%	7.%	7.%
1966	0.	4764343.	0.	0.%	1981104.	42.%	1183235.	25.%	17.%	17.%
1967	0.	4922912.	0.	0.%	1989633.	40.%	1436356.	29.%	11.%	11.%
1968	0.	5116641.	0.	0.%	1834311.	36.%	1615940.	32.%	4.%	4.%
1969	0.	6854382.	0.	0.%	2510165.	37.%	1777783.	26.%	11.%	11.%
1970	0.	6219812.	0.	0.%	2496009.	40.%	1940363.	31.%	9.%	9.%
1971	0.	5469240.	0.	0.%	2510269.	46.%	1734212.	32.%	14.%	14.%
1972	0.	6077356.	0.	0.%	3836449.	63.%	2242165.	37.%	26.%	26.%
1973	0.	6717655.	0.	0.%	3226668.	48.%	2260077.	34.%	14.%	14.%
1974	0.	7587365.	0.	0.%	4078616.	54.%	2391440.	32.%	22.%	22.%
1975	0.	5266860.	0.	0.%	1886571.	36.%	1671518.	32.%	4.%	4.%
1976	0.	5165738.	0.	0.%	3057988.	59.%	2169119.	42.%	17.%	17.%
1977	0.	6565704.	0.	0.%	3474793.	53.%	2419469.	37.%	16.%	16.%
1978	0.	7244272.	0.	0.%	3760670.	52.%	2773530.	38.%	14.%	14.%
1979	0.	6572320.	0.	0.%	3638495.	55.%	2997732.	46.%	10.%	10.%
1980	0.	8374943.	0.	0.%	5515222.	66.%	3645978.	44.%	22.%	22.%
1981	0.	8547227.	0.	0.%	4932960.	58.%	3792812.	44.%	13.%	13.%
1982	0.	7942696.	0.	0.%	3958773.	50.%	4341805.	55.%	-5.%	-5.%
1983	0.	8641435.	0.	0.%	4499940.	52.%	3945599.	46.%	6.%	6.%
1984	0.	9733678.	0.	0.%	4800438.	49.%	4317725.	44.%	5.%	5.%
1985	0.	1831429.	0.	0.%	1639173.	90.%	2070330.	113.%	-24.%	-24.%
1986	0.	10650595.	0.	0.%	4134045.	39.%	5184410.	49.%	-10.%	-10.%
1987	0.	15288347.	0.	0.%	7618558.	50.%	5330728.	35.%	15.%	15.%
1988	0.	12006124.	0.	0.%	2082239.	17.%	6720763.	56.%	-39.%	-39.%
1989	0.	16361356.	0.	0.%	6306950.	39.%	6383307.	39.%	0.%	0.%
1990	0.	18188768.	0.	0.%	5150062.	28.%	7777236.	43.%	-14.%	-14.%
1991	0.	15964463.	0.	0.%	3960664.	25.%	8320391.	52.%	-27.%	-27.%
1992	0.	25036118.	0.	0.%	4925017.	20.%	9089135.	36.%	-17.%	-17.%
1993	0.	22937869.	0.	0.%	4166003.	18.%	9198057.	40.%	-22.%	-22.%
1994	0.	19728096.	0.	0.%	4668837.	24.%	10161229.	52.%	-28.%	-28.%
1995	0.	32729359.	0.	0.%	6992700.	21.%	10842237.	33.%	-12.%	-12.%

DELOITTE HASKINS & SELLS

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2-24-2006

**** APPALACHIAN POWER COMPANY ****

ACCOUNT NO.: 10060000

DISTRIBUTION

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1996	0.	24310600.	0.	0.%	5785985.	24.%	9618862.	40.%	-16.%	-16.%
1997	0.	21597923.	0.	0.%	6466288.	30.%	9360683.	43.%	-13.%	-13.%
1998	0.	8179171.	0.	0.%	2630662.	32.%	5459659.	67.%	-35.%	-35.%
1999	0.	18152317.	0.	0.%	1757838.	10.%	1977329.	11.%	-1.%	-1.%
2000	0.	28477922.	0.	0.%	6302681.	22.%	7716373.	27.%	-5.%	-5.%
2001	0.	25388478.	0.	0.%	9331953.	37.%	10512679.	41.%	-5.%	-5.%
2002	0.	20233919.	0.	0.%	6603674.	33.%	6815323.	34.%	-1.%	-1.%
2003	0.	25873297.	0.	0.%	309172.	1.%	10436123.	40.%	-39.%	-39.%
2004	0.	27455349.	0.	0.%	3071573.	11.%	8375014.	31.%	-19.%	-19.%
2005	0.	45613998.	0.	0.%	761734.	2.%	368073.	1.%	1.%	1.%
	0.	598397858.	0.	0.%	173440229.	29.%	209237297.	35.%	-6.%	-6.%

ROLLING BAND

1954-1963	0.	28176130.	0.	0.%	12459587.	44.%	7089166.	25.%	19.%	19.%
1955-1964	0.	29007112.	0.	0.%	12468804.	43.%	7504580.	26.%	17.%	17.%
1956-1965	0.	29849228.	0.	0.%	12456626.	42.%	7921695.	27.%	15.%	15.%
1957-1966	0.	30485334.	0.	0.%	12077391.	40.%	8460814.	28.%	12.%	12.%
1958-1967	0.	32001084.	0.	0.%	12294589.	38.%	9039056.	28.%	10.%	10.%
1959-1968	0.	34359666.	0.	0.%	13076078.	38.%	9898921.	29.%	9.%	9.%
1960-1969	0.	38891954.	0.	0.%	14658369.	38.%	10842240.	28.%	10.%	10.%
1961-1970	0.	42502260.	0.	0.%	16202753.	38.%	12010986.	28.%	10.%	10.%
1962-1971	0.	45380056.	0.	0.%	17765003.	39.%	13010765.	29.%	10.%	10.%
1963-1972	0.	48943938.	0.	0.%	20671774.	42.%	14513072.	30.%	13.%	13.%
1964-1973	0.	52573792.	0.	0.%	22710368.	43.%	15955463.	30.%	13.%	13.%
1965-1974	0.	56969461.	0.	0.%	25647369.	45.%	17523207.	31.%	14.%	14.%
1966-1975	0.	58996566.	0.	0.%	26349875.	45.%	18253089.	31.%	14.%	14.%
1967-1976	0.	59397961.	0.	0.%	27426759.	46.%	19238973.	32.%	14.%	14.%
1968-1977	0.	61040753.	0.	0.%	28911919.	47.%	20222086.	33.%	14.%	14.%
1969-1978	0.	63168384.	0.	0.%	30838278.	49.%	21379676.	34.%	15.%	15.%
1970-1979	0.	62886322.	0.	0.%	31966608.	51.%	22599625.	36.%	15.%	15.%
1971-1980	0.	65041453.	0.	0.%	34985741.	54.%	24305240.	37.%	16.%	16.%
1972-1981	0.	68119440.	0.	0.%	37400432.	55.%	26363840.	39.%	16.%	16.%
1973-1982	0.	69984780.	0.	0.%	37530756.	54.%	28463480.	41.%	13.%	13.%
1974-1983	0.	71908560.	0.	0.%	38804028.	54.%	30149002.	42.%	12.%	12.%
1975-1984	0.	74054873.	0.	0.%	39525850.	53.%	32075287.	43.%	10.%	10.%
1976-1985	0.	70619442.	0.	0.%	39278452.	56.%	32474099.	46.%	10.%	10.%
1977-1986	0.	76104299.	0.	0.%	40354509.	53.%	35489390.	47.%	6.%	6.%
1978-1987	0.	84826942.	0.	0.%	44498274.	52.%	38400649.	45.%	7.%	7.%
1979-1988	0.	89588794.	0.	0.%	42819843.	48.%	42347882.	47.%	1.%	1.%

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STUDY AS OF DECEMBER 31, 2005

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**** APPALACHIAN POWER COMPANY ****

ACCOUNT NO.: 10860000

DISTRIBUTION

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1980-1989	0.	99377830.	0.	0.%	45488298.	46.%	45733457.	46.%	0.%	0.%
1981-1990	0.	109191655.	0.	0.%	45123138.	41.%	49864715.	46.%	-4.%	-4.%
1982-1991	0.	116608891.	0.	0.%	44150842.	38.%	54400294.	47.%	-9.%	-9.%
1983-1992	0.	133702313.	0.	0.%	45117086.	34.%	59147624.	44.%	-10.%	-10.%
1984-1993	0.	147998747.	0.	0.%	44783149.	30.%	64400082.	44.%	-13.%	-13.%
1985-1994	0.	157993165.	0.	0.%	44651548.	28.%	70243586.	44.%	-16.%	-16.%
1986-1995	0.	188891095.	0.	0.%	50005075.	26.%	79015493.	42.%	-15.%	-15.%
1987-1996	0.	202551100.	0.	0.%	51657015.	26.%	83449945.	41.%	-16.%	-16.%
1988-1997	0.	208860676.	0.	0.%	50504745.	24.%	87479900.	42.%	-18.%	-18.%
1989-1998	0.	205033723.	0.	0.%	51053168.	25.%	86218796.	42.%	-17.%	-17.%
1990-1999	0.	206824684.	0.	0.%	46504056.	22.%	81812818.	40.%	-17.%	-17.%
1991-2000	0.	217113838.	0.	0.%	47656675.	22.%	81751955.	38.%	-16.%	-16.%
1992-2001	0.	226537853.	0.	0.%	53027964.	23.%	83936243.	37.%	-14.%	-14.%
1993-2002	0.	221735654.	0.	0.%	54706621.	25.%	81662431.	37.%	-12.%	-12.%
1994-2003	0.	224671082.	0.	0.%	50849790.	23.%	82900497.	37.%	-14.%	-14.%
1995-2004	0.	232398335.	0.	0.%	49252526.	21.%	81114282.	35.%	-14.%	-14.%
1996-2005	0.	245282974.	0.	0.%	43021560.	18.%	70640118.	29.%	-11.%	-11.%

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STUDY AS OF DECEMBER 31, 2005   PAGE 1

**** APPALACHIAN POWER COMPANY ****   3-15-2006

AVERAGE LIFE GROUP METHOD THEORETICAL RESERVE
ACCOUNT 36400000

AGE	VINTAGE YEAR	SURVIVING BALANCE 12/31/2005	REMAINING LIFE ASL CURVE 30.0 R1.5	RESERVE RATIO	THEORETICAL RESERVE
0.5	2005	15478787.	29.5889	0.01370	212110.
1.5	2004	13563194.	28.7713	0.04096	555505.
2.5	2003	14643309.	27.9614	0.06795	995081.
3.5	2002	18041990.	27.1591	0.09470	1708492.
4.5	2001	23774316.	26.3647	0.12118	2880900.
5.5	2000	25809096.	25.5781	0.14740	3804211.
6.5	1999	29030852.	24.7993	0.17336	5032719.
7.5	1998	13398380.	24.0284	0.19905	2666972.
8.5	1997	22934573.	23.2656	0.22448	5148382.
9.5	1996	26835953.	22.5107	0.24964	6699391.
10.5	1995	29579680.	21.7642	0.27453	8120411.
11.5	1994	28076227.	21.0264	0.29912	8398166.
12.5	1993	24034162.	20.2978	0.32341	7772809.
13.5	1992	21190788.	19.5791	0.34736	7360927.
14.5	1991	17697796.	18.8707	0.37098	6565458.
15.5	1990	16084546.	18.1734	0.39422	6340851.
16.5	1989	13503116.	17.4877	0.41708	5631826.
17.5	1988	13122151.	16.8143	0.43952	5767493.
18.5	1987	12965935.	16.1537	0.46154	5984346.
19.5	1986	13037792.	15.5066	0.48311	6298749.
20.5	1985	9621718.	14.8735	0.50422	4851441.
21.5	1984	8668618.	14.2549	0.52484	4549609.
22.5	1983	8102604.	13.6514	0.54495	4415541.
23.5	1982	9773101.	13.0635	0.56455	5517418.
24.5	1981	8190145.	12.4915	0.58362	4779896.
25.5	1980	7983047.	11.9360	0.60213	4806866.
26.5	1979	6378453.	11.3973	0.62009	3955223.
27.5	1978	5812302.	10.8757	0.63748	3705210.
28.5	1977	4650176.	10.3714	0.65429	3042547.
29.5	1976	3627394.	9.8846	0.67051	2432213.
30.5	1975	2332468.	9.4154	0.68615	1600432.
31.5	1974	3556446.	8.9636	0.70121	2493831.
32.5	1973	2854380.	8.5291	0.71570	2042867.

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STUDY AS OF DECEMBER 31, 2005 PAGE 2

**** APPALACHIAN POWER COMPANY **** 3-15-2006

AVERAGE LIFE GROUP METHOD THEORETICAL RESERVE
ACCOUNT 36400000

AGE	VINTAGE YEAR	SURVIVING BALANCE 12/31/2005	REMAINING LIFE ASL CURVE 30.0 R1.5	RESERVE RATIO	THEORETICAL RESERVE
33.5	1972	2161265.	8.1117	0.72961	1576881.
34.5	1971	1738140.	7.7108	0.74297	1291390.
35.5	1970	1663303.	7.3258	0.75581	1257134.
36.5	1969	955686.	6.9559	0.76814	734097.
37.5	1968	1106461.	6.6001	0.78000	863037.
38.5	1967	925216.	6.2574	0.79142	732235.
39.5	1966	761095.	5.9265	0.80245	610740.
40.5	1965	591949.	5.6064	0.81312	481326.
41.5	1964	450824.	5.2956	0.82348	371244.
42.5	1963	348880.	4.9932	0.83356	290812.
43.5	1962	289490.	4.6983	0.84339	244153.
44.5	1961	388411.	4.4105	0.85298	331308.
45.5	1960	201718.	4.1297	0.86234	173950.
46.5	1959	186527.	3.8565	0.87145	162549.
47.5	1958	178489.	3.5910	0.88027	157119.
48.5	1957	152716.	3.3363	0.88879	135732.
49.5	1956	122031.	3.0911	0.89696	109457.
50.5	1955	79195.	2.8562	0.90479	71655.
51.5	1954	58402.	2.6294	0.91235	53283.
52.5	1953	47038.	2.4050	0.91983	43267.
53.5	1952	33182.	2.1713	0.92762	30780.
54.5	1951	32346.	1.9103	0.93632	30286.
55.5	1950	28789.	1.6051	0.94650	27249.
56.5	1949	19664.	1.2638	0.95787	18836.
57.5	1948	11533.	0.9074	0.96975	11184.
58.5	1947	2479.	0.5000	0.98333	2438.
		406888324.			155950035.
			NET SALVAGE VALUE(%)		-55.
			RESERVE AFTER SALVAGE		241722560.
			REMAINING LIFE (YRS)		20.39

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, MAY 15, 2007

APPLICATION OF

APPALACHIAN POWER COMPANY

CASE NO. PUE-2006-00065

For an increase in electric rates

FINAL ORDER

On May 4, 2006, Appalachian Power Company ("Appalachian," "APCo," or "Company") filed with the State Corporation Commission ("Commission") an application, pursuant to § 56-582 C of the Code of Virginia ("Code") and the Commission's Rules Governing Utility Rate Increase Applications and Annual Informational Filings, 20 VAC 5-200-30, for an increase in electric rates. Appalachian requests an annual increase in base revenues of $225.8 million and proposes a $27.3 million credit to its fuel factor, resulting in an overall increase of $198.5 million in charges to its customers.

On May 30, 2006, the Commission issued an Order for Notice and Hearing and Suspending Rates that directed the Company to provide public notice of its application, established a procedural schedule, and assigned this matter to a Hearing Examiner to conduct further proceedings. The Commission suspended Appalachian's proposed rate increase for a period of 150 days from the date the application was filed, the maximum period permitted under § 56-238 of the Code. As a result, the Company's proposed rates, charges, and terms and conditions of service were permitted by law to take effect for service rendered on and after October 2, 2006, on an interim basis subject to refund with interest.

The Commission's Staff ("Staff") and the following parties participated in this proceeding pursuant to the Commission's Rules of Practice and Procedure and the aforementioned Order for

Notice and Hearing and Suspending Rates: The Kroger Co. ("Kroger"); Old Dominion Committee for Fair Utility Rates ("Old Dominion Committee"); VML/VACO APCo Steering Committee ("Steering Committee"); Wal-Mart Stores East, LP ("Wal-Mart"); Steel Dynamics, Inc. – Roanoke Bar Division ("Steel Dynamics"); Michel King, *pro se*; and Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel").

Public hearings were held in this matter on November 7 and December 6-13, 2006. The following counsel appeared at one or more of the hearings: Anthony Gambardella, Esquire, Charles E. Bayless, Esquire, Guy T. Tripp, III, Esquire, and Jason T. Jacoby, Esquire, on behalf of APCo; Kurt J. Boehm, Esquire, on behalf of Kroger; Edward L. Petrini, Esquire, on behalf of the Old Dominion Committee; Howard W. Dobbins, Esquire, and Robert D. Perrow, Esquire, on behalf of the Steering Committee; Kristine E. Nelson, Esquire, and Scott DeBroff, Esquire, on behalf of Wal-Mart; Damon E. Xenopoulos, Esquire, and Shaun C. Mohler, Esquire, on behalf of Steel Dynamics; Michel King, *pro se*; C. Meade Browder, Jr., Esquire, Ashley C. Beuttel, Esquire, and D. Mathias Roussy, Jr., Esquire, on behalf of Consumer Counsel; and William H. Chambliss, Esquire, Arlen K. Bolstad, Esquire, and Katharine A. Hart, Esquire, on behalf of the Commission's Staff. Eight public witnesses testified at the hearings.[1]

On February 5, 2007, the following participants filed post-hearing briefs: Appalachian; Kroger; Old Dominion Committee; Steering Committee; Wal-Mart; Steel Dynamics; Michel King, *pro se*; Consumer Counsel; and Staff.

On March 28, 2007, Hearing Examiner Alexander F. Skirpan, Jr., entered a Report that explained the procedural history of this case, summarized the record, analyzed the evidence and issues in this proceeding, and made certain findings and recommendations. The Hearing

[1] Report of Alexander F. Skirpan, Jr., Hearing Examiner, dated March 28, 2007 ("Hearing Examiner's Report"), at 3-4, 26-29.

Examiner "recommended that the Commission increase APCo's base rates by approximately $75.876 million and credit the Company's fuel factor by about $45.254 million, which produces an overall net increase of approximately $30.621 million."[2] The Hearing Examiner's Report included the following findings and recommendations:

> (1) The use of a test year ending December 31, 2005, is proper in this proceeding;
>
> (2) APCo's test year operating revenues, after all adjustments, are $1,021,679,803;
>
> (3) APCo's test year operating revenue deductions, after all adjustments, are $918,029,934;
>
> (4) APCo's test year net operating income and adjusted net operating income, after all adjustments are $103,649,869 and $102,223,519, respectively;
>
> (5) APCo's current rates produce a return on adjusted rate base of 5.06% and a return on equity of 4.40%;
>
> (6) APCo's current cost of equity is within a range of 9.6% - 10.6%, and the Company's rates should be established based on the 10.1% midpoint of the return on equity range;
>
> (7) APCo's overall cost of capital, using the midpoint of the return on equity range and the capital structure as adjusted by Staff, is 7.40%;
>
> (8) APCo's adjusted test year rate base is $2,021,702,421;
>
> (9) APCo's application requesting additional gross annual base revenues of $225,847,296, and a credit to its fuel factor of $27,290,378, or a net annual increase in revenues of $198,556,918, is unjust and unreasonable because it will generate a return on rate base greater than 7.40%;
>
> (10) APCo requires $75,875,512 in additional annual base rate revenues to earn its overall cost of capital;
>
> (11) APCo should retain fifty percent of its [off-system sales ('OSS')] margins in base rates and include fifty percent of its OSS margins in its fuel

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[2] *Id.* at 1.

factor. APCo's shareholders will be entitled to a ten percent sharing of OSS margins included in the fuel factor;

(12) Due to the proposed change in treatment of OSS margins, APCo requires $75,875,512 in additional gross annual base rate revenues, and a credit to its fuel factor of $45,254,245, or a net increase in annual revenues of $30,621,267;

(13) APCo and Staff's proposed revenue allocation methodology is just and reasonable;

(14) APCo should file permanent rates designed to produce the additional revenues found reasonable using the revenue apportionment methodology proposed by APCo and Staff;

(15) APCo should be required to refund, with interest, all revenues collected under its interim rates in excess of the amounts found just and reasonable herein;

(16) APCo should continue to include the cost of environmental compliance investments in the fixed cost of its generation facilities for cost allocation purposes;

(17) APCo should continue to allocate the cost of OSS margins included in base rates based upon demand;

(18) APCo should design its [Large General Service] rates to maintain current load factor crossover points, and to move rate components closer to cost of service;

(19) APCo should continue its surcharge for sales and use taxes;

(20) APCo should implement its proposed changes to terms and conditions, subject to the revisions proposed by Staff regarding the time period for recovery of billing errors and revisions agreed to by the Company regarding discontinuation of service without notice, and denial and discontinuance of service; and

(21) APCo should be directed to file a new Chapter 4 application for approval of its service company agreement with [American Electric Power Service Corporation ('AEP Service')] within thirty days of the final order in this case.[3]

[3] *Id.* at 68-70.

On or before April 18, 2007, the following participants filed comments on the Hearing Examiner's Report: Appalachian; Kroger; Old Dominion Committee; Steering Committee; Wal-Mart; Michel King, *pro se*; Consumer Counsel; and Staff. On April 30, 2007, Steel Dynamics filed a Motion for Leave to File and Reply, seeking authority to file a reply to APCo's comments on the Hearing Examiner's Report. On May 2, 2007, the Company filed a response in opposition to Steel Dynamics' Motion for Leave to File and Reply. On May 10, 2007, Consumer Counsel filed a response, noting that Consumer Counsel does not oppose Steel Dynamics' motion provided that such does not delay entry of a final order in this case.

NOW THE COMMISSION, having considered the record, the pleadings, the Hearing Examiner's Report, and the applicable law, is of the opinion and finds as follows. We deny Steel Dynamics' Motion for Leave to File and Reply, having not found good cause to grant leave for the filing of a reply under 5 VAC 5-10-120 C of the Commission's Rules of Practice and Procedure. As set forth below, we adopt in part and modify in part the findings and recommendations in the Hearing Examiner's Report. Our findings herein result in an overall net rate increase of approximately $24.0 million. We find that APCo's requested net increase of $198.5 million does not result in just and reasonable rates.

Code of Virginia

The Hearing Examiner explained that "APCo seeks to increase its base rates pursuant to Virginia Code § 56-582 C, which permits the Company to:"

> petition the Commission, during the period January 1, 2004, through June 30, 2007, for approval of a one-time change in its rates, and if the capped rates are continued after July 1, 2007, such incumbent electric utility may at any time after July 1, 2007, petition the Commission for approval of a one-time change in its rates. . . . Any petition for changes to capped rates filed pursuant to

> this subsection shall be governed by the provisions of Chapter 10 (§ 56-232 et seq.) of this title.[4]

Section 56-582 C explicitly adopts Chapter 10 of Title 56 as the legal standard by which this case is to be decided. As further noted by the Hearing Examiner, "[u]nder Chapter 10, § 56-234 establishes the duty of a public utility to furnish service at 'reasonable and just rates . . . [and] to charge uniformly . . . all persons, corporations or municipal corporations using such service under like conditions.' Similarly, § 56-235 grants the Commission the power to fix 'just and reasonable' rates. Just and reasonable rates are defined in § 56-235.2 A as follows:"

> Any rate . . . shall be considered to be just and reasonable only if: (1) the public utility has demonstrated that such rates . . . in the aggregate provide revenues not in excess of the aggregate actual costs incurred by the public utility in serving customers within the jurisdiction of the Commission, subject to such normalization for nonrecurring costs and adjustments for known future increases in costs as the Commission may deem reasonable, and a fair return on the public utility's rate base used to serve those jurisdictional customers; (1a) the investor-owned public electric utility has demonstrated that no part of such rates . . . includes costs for advertisement, except for advertisements either required by law or rule or regulation, or for advertisements which solely promote the public interest, conservation or more efficient use of energy; and (2) the public utility has demonstrated that such rates . . . contain reasonable classifications of customers. Notwithstanding § 56-234, the Commission may approve, either in the context of or apart from a rate proceeding after notice to all affected parties and hearing, special rates . . . to individual customers or classes of customers where it finds such measures are in the public interest. . . . In determining costs of service, the Commission may use the test year method of estimating revenue needs, but shall not consider any adjustments or expenses that are speculative or cannot be predicted with reasonable certainty. In any Commission order establishing a fair and reasonable rate of return for an investor-owned . . . electric public utility, the Commission shall set forth the findings of fact and conclusions of law upon which such order is based.[5]

[4] *Id.* at 29 (quoting Va. Code § 56-582 C).

[5] *Id.* at 29-30 (quoting Va. Code §§ 56-234, -235, and -235.2 A).

Our discussion herein will follow the structure set forth in the Hearing Examiner's Report. We will first address revenue requirement, and then cost allocation and rate design. Finally, we will rule on Appalachian's new arguments, presented for the first time in its comments on the Hearing Examiner's Report, that: (1) this proceeding must conform to recently enacted changes in Virginia law; and (2) APCo's customers should wait a minimum of six months before receiving any of the refunds required by this Final Order.

Revenue Requirement

The Hearing Examiner separated the revenue requirement issues into four categories: (1) adjustment cut-off date; (2) OSS margins; (3) cost of capital; and (4) other revenue requirement issues. The Company approximated the revenue requirement impact, as to the differences between itself and Staff, of these issues as follows: (1) adjustment cut-off date – \$71.8 million; (2) OSS margins – \$79.6 million; (3) cost of capital – \$26.9 million; and (4) other revenue requirement issues – \$7.5 million.[6]

<u>Adjustment Cut-Off Date</u>

As noted above, the applicable Virginia statute states that the revenue requirement determination herein is "subject to ... adjustments for known future increases in costs as the Commission may deem reasonable" and that "[i]n determining costs of service, the Commission ... shall not consider any adjustments or expenses that are speculative or cannot be predicted with reasonable certainty."[7] In addition, the Company states that the Commission's "instructions for Schedule 17 [of APCo's application] provide [as follows:]"

[6] *Id.* at 30.

[7] Va. Code § 56-235.2 A.

> 'Each adjustment shall be numbered sequentially and listed under the appropriate description category (Operating Revenues, Interest Expense, Common Equity Capital, etc.). Ratemaking adjustments shall reflect no more than the initial *rate year level of revenues, expenses, rate base and capital....* Detailed workpapers substantiating each adjustment shall be provided in Schedule 21.'[8]

The test year[9] in this case, as chosen by APCo, is calendar year 2005. The rate year[10] is October 2006 through September 2007. The Staff, Consumer Counsel, the Old Dominion Committee, and the Steering Committee updated the test year based on actual data through June 30, 2006. In contrast, the Company explains that it "updated some, but not all, costs through the end of [the] 'rate year' in accordance with Schedule 17 of the Commission's Rate Case Rules [and] introduced detailed evidence of certain actual costs incurred after June 30, 2006 and through September 30, 2006, as well as firm commitments to incur further costs through September 30, 2007."[11]

The Hearing Examiner found "that revenue requirements in this case should be based upon audited results through June 30, 2006, as proposed by Staff, Consumer Counsel, the Old Dominion Committee, and the Steering Committee."[12] The Hearing Examiner stated that "[u]nder § 56-235.2 and the long history of its application by the Commission, the emphasis has been on the test year and actual costs. Audits and verification of revenues, expenses, and investments are basic to cost of service regulation and are designed to subject an applicant's

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[8] Appalachian's April 18, 2007 Comments at 30 (quoting the instructions for Schedule 17 of the Commission's Rules Governing Utility Rate Increase Applications and Annual Informational Filings (20 VAC 5-200-30) (emphasis in original)).

[9] *See, e.g.,* Va. Code § 56-235.2 A ("In determining costs of service, the Commission may use the test year method of estimating revenue needs....").

[10] The rate year represents the first year that the new rates will be in effect.

[11] Appalachian's April 18, 2007 Comments at 23.

[12] Hearing Examiner's Report at 33.

operation to scrutiny to provide the Commission with the information necessary to determine just and reasonable rates."[13]

Appalachian objects to this recommendation "because it conflicts with the plain language of Va. Code § 56-235.2 A, ignores the Commission's Schedule 17 in its Rate Case Rules, is based on faulty analysis, and ignores uncontroverted relevant evidence in this case."[14] On brief, the Company presents a list of eight "Commission rate decisions approving updating cost adjustments such as those presented by the Company in this case."[15] According to the Company, in the eight cases it cites the Commission permitted rate base updates for periods ranging from seven months to 18 months after the end of the test year. In the instant case, APCo requests adjustments for certain actual costs incurred up to nine months after the test year, and for other projected cost increases spanning 21 months beyond the test year.

In addition, APCo asserts that the "Hearing Examiner has misapplied the plain language of [the] statute," in that the language of § 56-235.2 A "shows clearly that there is no requirement that adjustments be based on Staff s 'audited results' of only actual costs."[16] The Company states that the "statute provides specifically for adjustments for 'future increases in costs' which could not be subject to such an audit. Similarly the same statute prohibits adjustments for expenses that 'cannot be predicted with reasonable certainty.' 'Predicted' expenses by definition cannot be 'actual.' Thus the plain language of the statute shows that adjustments are not limited to Staff's 'actual audited' costs."[17] Appalachian argues that the "fact that costs incurred after June 30, 2006

[13] *Id.* at 32.

[14] Appalachian's April 18, 2007 Comments at 23-24.

[15] *Id.* at 37-41.

[16] *Id.* at 24.

[17] *Id.* at 24-25.

were not audited, which is beyond the control of the Company, is no justification under the statute for ignoring those costs in the determination of a revenue requirement in this case. The statute does not require an audit, and the Rate Case Rules do not require an audit. The Company's witnesses who verified the actual expenditures after June 30, 2006 were available for cross-examination. ... The Company has done all it can to verify those expenditures for inclusion in the revenue requirement, and they should be so included."[18] Appalachian concludes that "§ 56-235.2 A requires that [the Hearing Examiner] engage in such an analysis and evaluation to reach a conclusion as to the reasonableness of those costs. Because he failed to do so, the Commission must now engage in that analysis and evaluation based on the evidence regarding those costs that are in evidence in this case."[19]

Upon review of the record, we adopt the Hearing Examiner's recommendation on this issue. We have considered the post-June 2006 adjustments proposed by the Company. We must evaluate these adjustments in terms of establishing just and reasonable rates under the statute, which requires a "demonstrat[ion] that such rates ... in the aggregate provide revenues not in excess of the aggregate actual costs incurred by the public utility in serving customers...."[20] We do not find that APCo's post-June 2006 adjustments are reasonable and will result in just and reasonable rates. APCo has not demonstrated that its aggregate rates will not provide revenues in excess of its aggregate costs if the Commission includes the post-June 2006 adjustments proposed by the Company. Appalachian also has not established that these selective adjustments, for both actual and projected costs, should not be offset by other post-June 2006

[18] *Id.* at 25.

[19] *Id.* at 26.

[20] Va. Code § 56-235.2 A.

adjustments for increased revenues or decreased costs that have occurred or that can be predicted to occur with reasonable certainty. In addition, we find that APCo's projections, some of which were prepared in the fall of 2005[21] and some of which extend 21 months beyond the test year, are speculative.

Appalachian is correct that the Virginia statute does not mandate, as a precondition to reasonableness, that other parties have a chance to audit and to verify every proposed adjustment. The ability of participants in the case to audit and to verify such adjustments, however, is one means to help establish that the adjustments selected by the Company are reasonable and that such adjustments need not be offset by updating other costs and revenues. Indeed, the Hearing Examiner gives the following example: "[I]n adjusting the test year for a significant increase in vegetation management, it is unclear whether test year sales have been adjusted to reflect a reduction in outages, or other maintenance expenses, materials and supply inventories, or other equipment adjusted to reflect the savings that may be realized from a more aggressive vegetation management program."[22] Appalachian has not shown that its post-June 2006 adjustments to actual 2005 test year results will produce just and reasonable rates that properly align those adjustments with its other costs and revenues.

Finally, we reject the Company's assertion that Schedule 17 somehow requires approval of adjustments proposed through the end of the rate year. Appalachian states that the Commission's Rate Case Rules "require[] utilities to file rate year information on Schedule 17" and further notes that the instructions for Schedule 17 limit ratemaking adjustments to "no more

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[21] *See* Consumer Counsel's April 18, 2007 Comments at 3 n.7.

[22] Hearing Examiner's Report at 33.

than the initial rate year level of revenues, expenses, rate base and capital."[23] Schedule 17 is part of the Commission's Rules Governing Utility Rate Increase Applications and Annual Informational Filings (20 VAC 5-200-30) and, thus, reflects a filing requirement for rate increase applications. These rules permit, but do not mandate, the use of rate year adjustments. The Commission in no manner violates its own rules if adjustments proposed by the Company in Schedule 17 are not approved for ratemaking purposes.

OSS Margins

The Hearing Examiner stated that "[t]here are three issues related to OSS margins: (i) the level of OSS margins that should be considered in this proceeding, (ii) whether OSS margins should remain as a reduction to base rates or become part of the fuel factor or other tracking mechanism, and (iii) whether there should be a sharing of OSS margins between customers and shareholders."[24]

We reject APCo's estimated level of OSS margins. As found by the Hearing Examiner, "APCo has failed to prove that its estimated rate year level of OSS margins is reasonably certain and has failed to show that its actual OSS margins through June 2006, are unreasonably high."[25] We find that the level of OSS margins should reflect actual margins earned through June 30, 2006 and adopt the Hearing Examiner's finding "that Staff's adjusted OSS margins of $100.6 million for the twelve months ended June 2006, should be used in determining revenue requirements in this proceeding."[26]

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[23] Appalachian's April 18, 2007 Comments at 30-33.

[24] Hearing Examiner's Report at 36.

[25] *Id.*

[26] *Id.* at 37.

We also acknowledge, as noted by the Hearing Examiner, that ratepayers would receive a larger credit, and thus benefit, if we accepted rate year adjustments for OSS margins beyond June 2006. For example, "actual OSS margins for the twelve months ended September 2006, were more than $26 million higher, on a total APCo basis, or more than 11.6% higher than actual margins for the twelve months ended June 2006."[27] However, as we did above with other proposed adjustments, we again find that it is reasonable to limit test year adjustments to the use of actual, verifiable data through June 30, 2006 to establish the level of OSS margins. Similarly, we reject APCo's $68.2 million estimate for rate year OSS margins, which is "35% lower than jurisdictional margins earned for the twelve months ended September 2006 ($103.9 million)"[28] and "fails to meet the test of being reasonably certain."[29]

We also find that it is reasonable to continue the Commission's existing policy and credit 100% of OSS margins to customers. As argued by the Old Dominion Committee, Appalachian's "fixed costs for OSS sales and trading activities would be included in its revenue requirement, including the costs of AEP's Commercial Operations Department, which consists of capital investment and operating expenses necessary to engage in such sales and trading activities. Similarly, Appalachian's revenue requirement includes its share of the costs of generation and transmission facilities needed to generate and deliver energy subject to the OSS sales and trading activities."[30] We conclude that continuing to reflect 100% of APCo's adjusted test year OSS margins in rates remains consistent with the fact that customers have paid, and continue to pay, the fixed costs incurred to provide the infrastructure used to produce such margins.

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[27] *Id.* at 36.

[28] Consumer Counsel's April 18, 2007 Comments at 6 n.15.

[29] Hearing Examiner's Report at 39.

We further conclude that margin sharing is not required as an additional incentive for Appalachian to maximize OSS margins. As a public utility, APCo: (1) has a public service obligation to optimize use of its generation assets; and (2) is fairly compensated for its share of the costs and risks of producing the margins.[31] We agree with the Old Dominion Committee that "[s]uch 'extra' compensation is not needed to compensate Appalachian for doing what is has agreed to do by virtue of its acceptance of its monopoly franchise."[32] We also note that, under the Commission's prior treatment of OSS margins, "from 2000 to 2005, [the Company's] shareholders retained approximately $180 million in OSS margins otherwise allocable to APCo's Virginia-jurisdictional operations."[33]

We reject the argument that the volatility of OSS margins necessitates different treatment from what we find herein. Although OSS margins may fluctuate on a month-to-month basis, the amount of OSS margins reflected in rates is not based on any one month of data, but rather an adjusted test year. In this regard, the evidence in this case shows that the Company's OSS margins – based on a rolling 12-month average – have not been volatile, but have steadily trended upward since December 2004.[34]

Finally, we find that the level of adjusted test year OSS margins found reasonable herein (*i.e.*, $100.6 million) shall be credited to customers through a separate OSS Margin Rider. We also find that it is reasonable to allocate OSS margins to customer classes based 50% on demand

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[30] Old Dominion Committee's April 18, 2007 Comments at 13-14.

[31] *See, e.g., id.* at 18; Lamm, Exh. 65 at 5.

[32] Old Dominion Committee's April 18, 2007 Comments at 18.

[33] Hearing Examiner's Report at 40.

[34] *See* Lamm, Exh. 66.

and 50% on energy.[35] The Company's temporary system sales rider, which APCo placed in effect on an interim basis and subject to refund during this case, shall terminate upon the effective date of the rates approved in this Final Order, at which time the separate OSS Margin Rider shall become effective.[36]

Cost of Capital

We find that the cost of capital in this case should be based on Staff's *capital structure* as adjusted through June 2006, and a *cost of equity* range of 9.6% to 10.6%, using 10.0% to calculate APCo's revenue requirement.

Capital Structure

The Hearing Examiner explains that "there are two contested issues regarding capital structure. The first pertains to the use of APCo's projected capital structure of September 2007, or Staff's actual capital structure of June 2006. The second issue concerns whether equity should be adjusted to remove undistributed subsidiary earnings."[37]

We find that "Staff's proposed use of a capital structure [as adjusted through] ... historic June 2006 is reasonable and consistent with the use of a rate base as of the same date. Generally, the cost of financing such a rate base reflects the actual capital employed as of that date."[38] In

[35] The participants in this case provide evidence and arguments supporting various OSS margin allocations. Some of the proposals allocate on the basis of demand and some on energy, and some are dependent upon whether OSS margins are collected through fuel factor or base rate calculations. We have established, however, a separate OSS Margin Rider, and we find that a combined demand and energy allocation results in just and reasonable rates for all customer classes.

[36] Accordingly, Appalachian also shall recalculate, using the level of adjusted test year OSS margins (*i.e.,* $100.6 million) and the methodology for allocating OSS margins for customer classes (50% on demand and 50% on energy) found reasonable herein, each customer's share of the approved OSS margins between the date interim rates took effect subject to refund and the effective date of the OSS Margin Rider approved in this case. Appalachian shall credit to customers the resulting increased credit in accordance with the refund requirements set forth in this Final Order.

[37] Hearing Examiner's Report at 43.

[38] *Id.*

addition, "Staff maintained that the Commission has a long history of precedent in the use of an actual capital structure rather than a projected capital structure."[39] We disagree with the Company's assertion that Staff's proposed capital structure "is contrary to the weight of the evidence."[40] Although we find that APCo's proposed capital structure is not reasonable, the Commission does not need to make such finding prior to adopting a June 2006 capital structure. For example, as explained by the Hearing Examiner, "in *Central Tel. Co. of Va. v. Corp. Comm'n.*,[41] the Commission's decision to use the capital structure of the parent of the local utility was upheld, without a finding of unreasonableness of the actual capital structure of the local utility, which was used in the utility's prior case."[42]

Steel Dynamics "proposed an adjustment to the level of equity reflected in the capital structure to remove undistributed subsidiary earnings," which would "reduce the revenue requirement for the Company by approximately $1 million."[43] We agree with the Hearing Examiner that such adjustment is not necessary; the "average cost of capital is an average of all capital, regardless of whether it is used for financing assets devoted to providing utility service or other non-utility assets."[44]

Cost of Equity

The Hearing Examiner explained that the "return on equity recommendations of the experts that testified in this case are as follows: Company witness Moul – 11.0% to 12.0%,

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[39] *Id.*

[40] Appalachian's April 18, 2007 Comments at 23.

[41] 219 Va. 863 (1979).

[42] Hearing Examiner's Report at 43-44.

[43] *Id.* at 42.

[44] *Id.* at 44.

using the midpoint of 11.5%; Staff witness Maddox – 9.4% to 10.4%, using the low end of 9.4%; and Consumer Counsel witness Parcell – 9.5% to 9.75%, with emphasis on the low end. Each of the witnesses based his recommendation on the results of [Discounted Cash Flow ('DCF'), Capital Asset Pricing Model ('CAPM')], and risk premium or comparable earnings models."[45]

We agree with the Hearing Examiner that Mr. Moul's comparable earnings should be given little weight in this proceeding. The Hearing Examiner stated that "I am unconvinced that the risks of the entities chosen by Mr. Moul are comparable to APCo, and I question the selection criteria, especially the use of Value Line's timeliness rank."[46] Mr. Moul's comparable earnings approach attempted "to compare APCo to International Speedway, the Washington Post, and Tootsie Roll Industries."[47]

Mr. Moul's alternative DCF, which is driven by high and low extremes of DCF calculations for a proxy group of companies, also includes Exelon. The Hearing Examiner agreed with Staff "that Exelon is not a good proxy for APCo because it has divested its generation assets and has been involved in proposed mergers."[48] The inclusion of Exelon "increases the upper end of Mr. Moul's zone of reasonableness from 11.19% to 15.08%;" whereas, "[e]xcluding Exelon, Mr. Moul's alternative DCF produces results of about 9.785%."[49]

We also reject APCo's proposed adjustments for (1) leverage (where market value exceeds book value), and (2) flotation costs (for issuance of stock). The Company argued that the "need for the [leverage] adjustment arises because common equity must be sold in the market

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[45] *Id.*

[46] *Id.* at 47.

[47] *Id.*

[48] *Id.*

[49] *Id.*

at a market price while rate making in this case will proceed on the book value of the common equity. This difference means that investors' risk expectations are governed by a capital structure with an equity ratio based on the market price of the stock. ... Investment decisions are made in the market based on the financial risk reflected in market capitalization ratios. If a different set of capitalization ratios are used to set the authorized return on equity, that return does not comport with the risk expectations of investors."[50]

The Hearing Examiner's rejection of the leverage adjustment properly included the following analysis:

> As Mr. Parcell shows in his attached schedules, market value has exceeded book value on utility stocks for many years. If, as Mr. Moul argues, such differences cause distortions in DCF and CAPM results used in the ratesetting process, these distortions should be measurable in some way. Mr. Maddox expressed this sentiment during the hearing:
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>> The [leverage] adjustment, I believe, is unnecessary because the book value is what is used for ratemaking purposes. If, as Mr. Moul would contend, that was insufficient, that investors were not being afforded a reasonable return on that book value, one would expect that they would drive down the prices of those stocks.
>
> Furthermore, Mr. Moul's adjustment of *beta*, as reported by Value Line, for his own *beta*, adjusted for leverage, takes his CAPM approach out of the realm of investor expectations. In other words, as Mr. Parcell testified, investors do not have access to leveraged *betas*.[51]

The Hearing Examiner rejected the flotation adjustment because "neither Mr. Moul, nor any other APCo witness, attempted to establish actual costs incurred by the Company in regards to the issuance of common stock. Based on my understanding of the Commission's established

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[50] Appalachian's April 18, 2007 Comments at 15.

[51] Hearing Examiner's Report at 45-46 (citations omitted) (emphasis in original).

policy of permitting flotation costs only where, and to the extent, a utility actually incurs a cost to issue common stock, I find that no flotation adjustment should be made to the cost of equity for such costs in this case."[52] Appalachian responds that the "evidence in this case shows that the Company's parent incurs flotation costs to issue common stock...[, that] APCo's parent has continuing flotation costs...[, and that if] the Commission intends its policy to require evidence of an impending common stock issuance, the policy should be changed."[53] The Hearing Examiner's understanding of the Commission's established policy is correct. No flotation adjustment shall be allowed under the facts of this case.

In addition, as discussed by Staff, "significant biases ... remain embodied in Mr. Moul's analysis," such as (1) his "inappropriate use of projected interest rates that boost his risk premium recommendation," and (2) "the upward bias in Mr. Moul's DCF analysis because his growth rate primarily emphasized projected earnings per share growth rates and ignored other projected rates of growth for dividends, book value, and retained earnings to estimate a long-term sustainable growth rate assumed by the DCF model and reflected in the rates developed by the other witnesses."[54]

We find that a cost of equity ranging from 9.6% to 10.6%, using 10.0% to calculate revenue requirement, results in a fair and reasonable return. Although the Hearing Examiner recommends using the midpoint of this range (*i.e.*, 10.1%) to calculate revenue requirement, we conclude that there is sufficient evidence to utilize a cost of equity that is ten basis points below the midpoint. Staff and Consumer Counsel proposed using the low end of the cost of equity

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[52] *Id.* at 46.

[53] Appalachian's April 18, 2007 Comments at 18.

[54] Staff's April 18, 2007 Comments at 5-6.

range due to the reduced risks inuring to the Company as a result of § 56-582 B (vi) of the Code, which provides Appalachian dollar-for-dollar recovery of certain environmental and reliability costs. The Hearing Examiner found "that the record in this case is too undeveloped to support recommending a lower return on equity based on" the requirements of § 56-582 B (vi) of the Code.[55] We find, however, that the record is sufficiently developed by Consumer Counsel and Staff to justify a ten basis point reduction from the midpoint to reflect the reduced risks resulting from the Company's dollar-for-dollar recovery of certain environmental and reliability costs. In addition, we find credible the testimony of Consumer Counsel witness Parcell and Staff witness Maddox and conclude that the midpoint of their proposed ranges (9.63% and 9.9%, respectively) fall within the zone of reasonableness in this case and, thus, further support using 10.0% for revenue requirement purposes.

Other Revenue Requirement Issues

Customer Growth

We find that "the customer growth adjustment should be based on actual, audited customer growth through June 30, 2006" and, thus, reject Appalachian's request to reflect estimated customer growth through March 2007.[56]

Depreciation

We find that depreciation expense should be based on "Staff's revised depreciation-related adjustments and recommendations" that, among other things, apply the Company's new

[55] Hearing Examiner's Report at 48.

[56] *Id.*

depreciation rates to the June 30, 2006 plant in service "balances as proposed by Staff and Consumer Counsel."[57]

Working Capital

Appalachian did not file a lead/lag study to support its need for working capital. The Hearing Examiner found "that prepayments other than prepaid pensions should be excluded from rate base as APCo has decided against filing a lead/lag study to support a need for working capital."[58] The Hearing Examiner treated prepaid pensions different from other prepayments, "because prepaid pensions are directly tied to reducing operating expenses," and, thus, he "agree[d] with the Company that such prepayments should be included in rate base."[59]

In response, the Company disagreed with part of the Hearing Examiner's findings, arguing that "[b]ased on the evidence of record, the Commission should include *all* prepayments in APCo's rate base."[60] Appalachian asserted that a lead/lag study is not necessary to include prepayments in rate base, noting "that fuel and other materials and supplies inventory, which are akin to prepayments, have historically been included in working capital without a lead/lag study."[61]

Staff also disagreed with part of the Hearing Examiner's findings, arguing that the prepaid pension asset should not be included as a separate rate base item. Staff asserted that "[t]he Company, having chosen not to put its true cash working capital requirements at issue through development and filing of a lead/lag study in this case, should not be rewarded with a

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[57] *Id.*

[58] *Id.* at 49.

[59] *Id.*

[60] Appalachian's April 18, 2007 Comments at 46 (emphasis added).

[61] *Id.*

higher than necessary revenue requirement through the separation of particular items from that study that tend in its favor."[62] Consumer Counsel, Old Dominion Committee, and Steel Dynamics also assert that prepaid pensions should be excluded from rate base.[63]

The Company did not include a lead/lag study, which would have enabled a full look at necessary cash working capital. We find that it is reasonable to exclude prepayments, which represent only part of the cash working capital analysis, from rate base. The Company also has not established that it is reasonable to include *all* prepayments absent a complete lead/lag study addressing other items that may work to reduce rate base. We also agree with the Hearing Examiner that "because prepaid pensions are directly tied to reducing operating expenses, ... such prepayments should be included in rate base."[64]

Obsolete Inventory

We find as follows: (1) Appalachian "has provided sufficient explanation for the usefulness of its inactive and zero usage [materials and supplies ('M&S')] inventory;"
(2) Consumer Counsel's proposed adjustment to exclude "inactive or zero usage [M&S] inventory as not being used and useful in the provision of service to customers" is denied;
(3) "the write-off of obsolete inventory is related to maintaining adequate inventories to respond to unplanned service interruptions and therefore should be reflected in operating expenses;" and
(4) "the test year may include an abnormally high level of obsolete inventory write-off and should be normalized" as recommended by the Hearing Examiner.[65]

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[62] Staff's April 18, 2007 Comments at 2.

[63] Hearing Examiner's Report at 49.

[64] *Id.*

[65] Hearing Examiner's Report at 50-51.

Reorganization Expense

We reject Steel Dynamic's proposed adjustment to eliminate reorganization expense. We find that "that test year severance expenses are not non-recurring. In addition, Staff's adjustment to normalized AEP Service expenses based on actual costs through June 2006, appears to address this issue."[66]

Remodeling Expense

We reject Consumer Counsel's proposed adjustment to normalize test year remodeling expenses based on the three-year average of 2003 through 2005. We find that "the upward trend in actual costs indicates that an adjustment to normalize the test year is unwarranted."[67]

Rate Case Expense

We reject Consumer Counsel's proposed adjustment to limit rate case expense to an annual amount of $109,447, which was derived by normalizing the average cost of Appalachian's four previous base rate cases over three years. We find that "[c]onsidering the age of the Company's four previous base rate cases, ... the methodology proposed by [Consumer Counsel] provides no assurance that it would produce a reasonable level of rate case expense."[68]

Amortization of Generation-Related Regulatory Assets and Tax Adjustments

Appalachian adjusted its amortization period for generation-related regulatory assets in existence at the start of the capped rate period to correspond to such period. Staff contended that the new amortization periods for these assets replaced Commission-approved amortization periods and were never approved by the Commission. We agree with the Company and the

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[66] *Id.* at 51.

[67] *Id.* at 52.

[68] *Id.*

Hearing Examiner that "the proper amortization period for these assets is through the expiration of capped rates."[69]

Gains on Discretionary Sales of Emissions

The Company "excluded all of the gains it received on discretionary sales of emission allowances from its revenue requirement and proposed that any such gains be credited to the Company's environmental and reliability surcharge mechanism," whereas Staff "adjusted the test year to reflect the actual audited gains of about $7.3 million for the twelve months ended June 2006."[70] We "find nothing in the record that indicates the level of gains included in Staff's adjustments is unrepresentative or unusual" and "find that Staff's proposed adjustment for gains on the discretionary sales of emissions should be adopted."[71] Thus, we reject the Company's argument that the "evidence contradicts the Hearing Examiner's finding that the level of gains included in Staff's adjustments will be representative of on-going levels."[72]

PJM Administrative Fees

We adopt "Staff's proposed adjustment for PJM administrative fees, to reflect an additional $350,000."[73]

Public Relations and Membership Dues Expense

We reject Consumer Counsel's request to eliminate $216,978 of public relations expenses, $90,662 for EEI dues, and $79,203 in membership dues expenses for other organizations unrelated to reliability.[74]

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[69] *Id.* at 53.

[70] *Id.*

[71] *Id.*

[72] Appalachian's April 18, 2007 Comments at 46.

[73] Hearing Examiner's Report at 53.

AEP Service Expense

Staff "adjusted AEP Service Expense to reflect actual expenses for the six months ended June 2006," and this adjustment "reduces test year AEP Service Expense by approximately $1.8 million."[75] Consumer Counsel recommended exclusions totaling about $1.0 million related to public relations services, membership dues, advertising, and corporate communications. We agree with the Hearing Examiner that "Staff's adjustment provides a reasonable level of AEP Service Expense and should be adopted."[76]

Vehicle Fuel Expense

The Company "adjusted its vehicle fuel expense to reflect an increase from its test year level cost of $2.45 per gallon to $3.00 per gallon. APCo supported the use of $3.00 per gallon based on contentions that vehicle fuel prices have been and will continue to be subject to volatility, and because rates set in this case may be in effect for an extended period of time."[77] We reject the Hearing Examiner's recommendation and find that the Company's request to increase the test year cost of gasoline to $3.00 per gallon is reasonable.[78]

Charitable Donations

We find, as did the Hearing Examiner, "that Staff's proposed normalization of charitable donations produces a reasonable result and should be adopted."[79] The Company, Staff, and Consumer Counsel normalized APCo's $3.9 million donation to the American Electric Power

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[74] *Id.* at 53-54.

[75] *Id.* at 54.

[76] *Id.*

[77] *Id.*

[78] *Id.* at 55.

[79] *Id.*

("AEP") Foundation during the test year by removing two-thirds of this amount. For the remainder of the test year charitable contributions, Staff's proposed normalization adjustment based on a four-year average is reasonable.

In addition, although "Consumer Counsel pointed out that the Commission has a policy of permitting investor-owned utilities to include only fifty percent of charitable donations in revenue requirements to recognize that shareholders receive the primary benefits of such contributions[,] APCo requested that all of its charitable contributions should be reflected in rates 'given the importance of APCo's involvement in the communities in which it provides service.'"[80] The Hearing Examiner, however, found that APCo has failed to provide sufficient reasons or provide an argument for a change in circumstances that would support a change in the Commission's long-standing ratemaking treatment of charitable contributions. We likewise "agree with Staff and Consumer Counsel that fifty percent of the normalized charitable contributions should be included in the determination of the Company's revenue requirement."[81]

MLR

Staff utilized actual data through June 2006 to calculate APCo's Member Load Ratio ("MLR"). We agree with the Hearing Examiner that "Staff's MLR should be used in this case."[82]

West Virginia State Income Tax Apportionment Factors

Appalachian treats West Virginia state income taxes as the Commission has done in prior APCo cases. Staff, however, treats this issue in accordance with more recent Commission precedent as applied to the natural gas industry. As explained by the Hearing Examiner:

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[80] *Id.* at 55 (citation omitted).

[81] *Id.* at 55.

[82] *Id.* at 56.

> Consistent with the Commission's historic treatment of West Virginia state income taxes for ratemaking purposes, the Company used APCo's stand-alone West Virginia state apportionment factor for calculating the appropriate level of West Virginia corporate net income tax. Staff, consistent with the Commission's order in *VNG* used the income apportionment factors from the income tax returns actually filed by APCo in Tennessee, Ohio, West Virginia, and Virginia to develop the effective state income tax rates to be applied to Virginia jurisdictional taxable income.[83]

The Company "calculated that applying stand-alone apportionment factors to APCo stand-alone taxable income produces a West Virginia state income tax expense of $3,381,158."[84] In contrast, Staff applied a consolidated apportionment factor to APCo's stand-alone taxable income, which results in an expense of $824,845. The Hearing Examiner found that, based on the precedent in *VNG*, Staff's methodology should be used in this case. This resulted in the Hearing Examiner using "a 3.16% effective state income tax rate in the gross revenue conversion factor to calculate his recommended rate increase."[85]

Appalachian responds that "the use of the West Virginia consolidated state apportionment factor in this case would be contrary to the methodology used in APCo's previous rate filings [and] would grossly understate the impact of APCo's participation in the West Virginia consolidated income tax return...."[86] The Company concludes that "[t]o properly determine the Company's revenue requirement, an effective state income tax rate of 5.783%, which is based upon the West Virginia stand-alone apportionment factor ... should be used to determine the

[83] *Id.* at 56 (citing *Virginia Natural Gas, Inc., For Investigation of Justness and Reasonableness of Current Rates, Charges, and Terms and Conditions of Service in Compliance with Prior Commission Order*, Case No. PUE-2005-00062, Final Order (July 24, 2006) ("*VNG*")).

[84] Hearing Examiner's Report at 56.

[85] Appalachian's April 18, 2007 Comments at 44.

[86] *Id.* at 42.

gross revenue conversion factor in this case."[87] We adopt the Hearing Examiner's recommendation on this issue, which is consistent with our recent precedent in *VNG*.

State Income Tax Expense

The Hearing Examiner excluded deferred fuel-related tax adjustments from the calculation of state income tax expense "because deferred fuel may be positive or negative."[88] The Hearing Examiner did not conclude that the same deferred fuel-related tax adjustment is likely to be recurring on an annual basis. We adopt the Hearing Examiner's recommendation.

Tax Effect of AEP Debt

The Company opposed adjustments to income tax expense made by Staff, Consumer Counsel, and the Old Dominion Committee, which reflected "tax savings available to AEP in the form of interest deductions associated with AEP debt that supports its investment in APCo."[89] The Hearing Examiner adopted such adjustments, finding "that the proposed parent company debt adjustment to income tax expense properly allocates a tax benefit received by AEP, to APCo and is consistent with well-accepted Commission practice."[90]

The Hearing Examiner further explained his finding as follows:

> I agree with [Staff and Consumer Counsel] that each asset is supported by the underlying capital structure. This is why APCo's revenue requirement is determined by multiplying rate base, *i.e.*, the total assets employed by the Company to provide service to customers, by the overall cost of capital. Assignments of specific capital sources to specific assets is both impractical and fails to reflect the realities of capital formation.

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[87] *Id.* at 44.

[88] Hearing Examiner's Report at 57.

[89] *Id.*

[90] *Id.* at 58.

> In addition, as pointed out in briefs filed by Staff, Consumer Counsel, and the Old Dominion Committee, the adjustment to reflect tax savings associated with parent company debts is well-established and has been upheld by the Virginia Supreme Court.[91]

Appalachian responds that its "evidence shows that in this instance the cited general principal does not apply."[92] The Company asserts that the "positions of the Staff, [Consumer Counsel, and Old Dominion Committee] do not comport with the reality of the transactions. The funds in question were lent to the Company by its parent, and no equity infusions were made. ... The capital in question is proven to be debt not equity, and the Company proposes to treat it as debt rather than equity for purposes of calculating its tax expense."[93]

We adopt the Hearing Examiner's recommendation. We also find, contrary to APCo's assertion, that it is reasonable to treat the financing at issue herein as equity.

Interest on Customer Deposits

We agree with the Hearing Examiner that adjustments should be made to interest on customer deposits to reflect the most current interest rate.

Transmission Line and Generating Plant Investment

Michel King "argued for the exclusion of investments and costs related to the construction of the Wyoming-Jackson's Ferry transmission line or the Ceredo generating plant, based on the Company's failure to offer adequate support for the prudence of these investments

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[91] *Id.* at 57-58 (citing *GTE South Incorporated v. AT&T Communications of Virginia, Inc.*, 259 Va. 338 (2000); *Application of GTE South Inc.*, Case No. PUC-1995-00019, 1997 S.C.C. Ann. Rep. 216; *Application of Virginia-American Water Co., For a General Increase in Rates*, Case No. PUE-1995-00003, 1997 S.C.C. Ann. Rep. 333; *Commonwealth of Virginia ex rel. David W. Desmond v. United Water Virginia, Inc.*, Case No. PUE-1997-00544, 1999 S.C.C. Ann. Rep. 389; and *Application of Virginia-American Water Company, For a General Increase in Rates*, Case No. PUE-2003-00539, 2004 S.C.C. Ann. Rep. 395).

[92] Appalachian's April 18, 2007 Comments at 44.

[93] *Id.* at 45.

and because APCo failed to respond appropriately to related interrogatories."[94] The Hearing Examiner rejected this request, finding that "the record of this case contains no evidence to suggest that the Wyoming-Jackson's Ferry transmission line and the Ceredo generating plants are not used and useful in providing service to customers or are otherwise tainted by imprudence of any kind."[95]

Mr. King responded that the "Hearing Examiner erred: a) in assigning a burden of proof regarding the prudency of these investments to Mr. King rather than to APCo; and b) in proceeding upon the theory that a capital project that is 'used and useful' and not 'otherwise tainted by imprudence' meets the various requirements §§ 56-234.3, 56-235.1 and 56-235.3."[96] Mr. King asserts that "[i]t is an established matter of law that the burden of proof in rate cases regarding the prudency of a utility's expenses rests with the utility, not with Staff or respondents."[97] Mr. King quotes the following Commission precedent: "'Va. Code § 56-235.3 imposes on the Company the burden of showing its proposed rate changes to be just and reasonable [and t]hat burden extends to each item of expense.'"[98] In addition, Mr. King contends that the "criteria specifically called out in the relevant statutes (§§ 56-235.1, 56-235.3 and 56-234.3) regarding whether a utility expense is eligible for rate base recovery are that such an expense be 'just', 'reasonable', 'proper', 'efficient', and 'reasonably calculated to promote the maximum effective conservation and use of energy and capital resources.'"[99]

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[94] Hearing Examiner's Report at 58.

[95] *Id.*

[96] Michel King's April 18, 2007 Comments at 2.

[97] *Id.* (citing *Central Tele. Co. v. State Corp. Comm'n*, 219 Va. 863 (1979)).

[98] *Id.* at 3 (quoting *Commonwealth Gas Svcs., Inc.*, Case No. PUE-1986-00031, 88 P.U.R. 4th 533).

[99] *Id.* at 8.

We find that the expenses for the Wyoming-Jackson's Ferry transmission line and the Ceredo generating plant were prudent and satisfy the statutory standards referenced by Mr. King. We note, however, that Mr. King's concerns in this matter are not baseless. There is minimal evidence in the record supporting the prudency of these expenditures. Mr. King states that the Hearing Examiner declared during the hearing that "'it's very clear to me that there hasn't been a prudency review done in this case.'"[100] Mr. King is correct that it is within the Commission's discretion to deny recovery of these costs. We find, nonetheless, that there is sufficient evidence for us to conclude that these expenditures satisfy Virginia statutory requirements. For example, the transmission line in question was previously approved by this Commission,[101] has been constructed in accordance therewith, and, as noted by Mr. King, is currently in service.[102] Although the Company did not provide specific documentation as sought by Mr. King on the expenses related to the Ceredo generating plant, we find credible APCo's assertions, as alluded to by Mr. King, that prior to incurring the generating plant costs the Company "justif[ied] these expenses as less costly than various other alternatives considered, including various conservation programs, energy efficiency programs, demand response programs, expanded use of existing Time-of-Day metering programs, etc."[103]

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[100] *Id.* at 6 (quoting Hearing Examiner, Tr. 801-802).

[101] *Application of Appalachian Power Co.*, Case No. PUE-1997-00766, 2001 S.C.C. Ann. Rep. 366, Order Granting Authority to Construct Transmission Facilities (May 31, 2001).

[102] Michel King's April 18, 2007 Comments at 5.

[103] *Id.* at 6. Although Mr. King asserts that APCo failed to provide requested information, Mr. King did not seek to compel production of information during the discovery period in this case. As explained by the Hearing Examiner in response to Mr. King's argument, after the discovery phase of the case, that APCo failed to respond appropriately to interrogatories, "[t]he remedy for unresponsive answers to interrogatories is to file a motion to compel." Hearing Examiner's Report at 58.

We reaffirm the Commission's expectation, however, that in future proceedings the Company produce sufficient evidence to carry its burden on the prudence of all expenditures, not just the ones discussed by Mr. King herein or raised by a party in a subsequent case; this includes but is not limited to items such as PJM Administrative Fees, public relations expenses, advertising, and generating plant investments.

Jurisdictional Cost Allocation

The Company proposed a six coincident peak ("6-CP") demand allocation methodology to assign generation and transmission-related demand responsibility to each of the jurisdictions that the Company serves.[104] Appalachian "supported use of the 6-CP methodology on the basis that such a methodology recognizes the Company's dual peaking nature and that different AEP-East System companies peak at different times of the year."[105] In contrast, Staff, Consumer Counsel, and the Steering Committee requested continued use of a twelve coincident peak ("12-CP") methodology for jurisdictional cost allocation purposes.[106]

The Hearing Examiner stated "that consistency in jurisdictional cost allocation methodologies to avoid double recovery of costs is the primary concern in choosing between the 12-CP and 6-CP methodologies" and found "that APCo should continue to allocate costs to its Virginia jurisdiction pursuant to the 12-CP methodology."[107] The Hearing Examiner explained that both Staff and Consumer Counsel "pointed out that the 12-CP methodology is used in the Company's other jurisdictions, including West Virginia and FERC, and that use of a 6-CP

[104] The 6-CP methodology allocates costs based on the demand that occurred at the Company's six highest monthly peaks in demand.

[105] Hearing Examiner's Report at 59.

[106] The 12-CP methodology allocates costs based on the demand that occurred at each of the Company's 12 monthly peaks in demand.

[107] *Id.*

methodology may result in a double recovery of costs. Indeed, both calculated that APCo's proposed 6-CP methodology allocates a higher level of cost to the Virginia jurisdiction than the 12-CP methodology."[108] We adopt the Hearing Examiner's recommendation.

Cost Allocation and Rate Design

The Hearing Examiner separated the cost allocation and rate design issues into three categories: (1) class cost of service; (2) revenue apportionment; and (3) rate design.

Class Cost of Service

Class Demand Allocation Factor

The Company uses a 6-CP demand allocator for its class cost of service study, which the Commission has approved in prior cases. Consumer Counsel opposed the continued use of a 6-CP methodology, arguing that it shifts costs to residential customers and that using 12-CP more reasonably recognizes that power production facilities are needed to serve peak demands throughout the year. Staff, the Old Dominion Committee, and Wal-Mart supported the continued use of 6-CP for this purpose.

The Old Dominion Committee explained that using 12-CP overlooks the fact that APCo's peaks are driven primarily by the three winter and summer months and that such peaks are pronounced when compared to other peaks. We adopt the Hearing Examiner's finding "that APCo should continue to utilize a 6-CP demand allocator for its class cost of service study in this proceeding."[109]

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[108] *Id.*

[109] *Id.* at 61.

Allocation of Environmental Investment Costs

The Hearing Examiner rejected Consumer Counsel's request to allocate the Company's incremental environmental compliance investment costs on the basis of a 50% demand - 50% energy allocation factor. Rather, the Hearing Examiner "agree[d] with the Company and the Old Dominion Committee that environmental compliance investment costs become part of APCo's generating facilities and should be allocated to customer classes [based on demand] as any other fixed generation asset."[110] We adopt the Hearing Examiner's finding.

Allocation of Distribution Costs

Wal-Mart states that APCo uses only demand allocators, as opposed to both demand and customer allocators, in allocating certain distribution plant costs. Wal-Mart's "primary recommendation in this case was to have the Commission require APCo to file, in its next rate case, its [class cost of service study] allocating the distribution costs related to Accounts 364 through 368 utilizing a demand and customer cost component."[111] Wal-Mart explains that these plant accounts are "sometimes referred to as 'distribution line costs'" and include investments "such as poles, towers and fixtures, overhead conductors and devices, underground conduit, underground conductors and devices and line transformers."[112] Wal-Mart "would expect that at least 30% of these costs would be allocated on a customer component and, at the most, 70% on a demand component. This would tend to increase the cost of service to those customer classes that have a larger number of customers who utilize distribution lines."[113]

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[110] *Id.*

[111] Wal-Mart's April 17, 2007 Comments at 5.

[112] *Id.* at 4.

[113] *Id.* at 5.

We find that, in the Company's next rate case, the Commission and case participants should have an opportunity to evaluate the allocation of Accounts 364 through 368 using demand and customer allocators. Accordingly, in its next rate case, APCo shall file a class cost of service study using demand allocators as approved herein and also shall file a class cost of service study using both demand and customer allocators for Accounts 364 through 368 as requested by Wal-Mart.

Revenue Apportionment

The Hearing Examiner recommended that the revenue increase approved in this case be apportioned among customer classes based on the methodology proposed by APCo and explained that "[t]here is general agreement among APCo, Staff, Consumer Counsel, and Wal-Mart that the apportionment of the proposed rate increase among customer classes should follow the Company's proposed apportionment methodology that will move each class toward parity based on the relative rate of return for each class."[114] The Company's methodology was opposed by Kroger and the Old Dominion Committee. In addition, Wal-Mart stated that "APCo's proposed revenue allocation does not result in bringing rates close to cost of service" and "that if the Commission determined less of an increase than APCo's requested amount, [Wal-Mart] recommended that any reduction be first allocated to those customer classes whose rates are above their cost of service and then to all classes based on rate base."[115]

Kroger asserts that, under APCo's approach, "among the subsidy-paying classes, the customer classes that deserve the smallest rate increases would actually receive the largest rate increases, and vice versa [and that this] approach turns cost-based ratemaking on its head and is

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[114] Hearing Examiner's Report at 64.

[115] Wal-Mart's April 17, 2007 Comments at 6-7.

inherently unreasonable."[116] Rather, "for the subsidy-paying classes [Small General Service ('SGS'), Medium General Service ('MGS'), Large General Service ('LGS'), and Large Power Service ('LPS')], Kroger recommends that each class receive a rate increase equal to its cost-of-service based-increase plus an approximately equal percentage additional increase in order to fund the Residential subsidy."[117] Kroger states that it proposes "rationale and equitable" rate increases of MGS – 1.80%, LGS – 5.96%, and LPS – 9.71%, whereas the Hearing Examiner proposes increases of MGS – 8.02%, LGS – 7.76%, and LPS – 7.52%.[118]

The Old Dominion Committee states that although the Hearing Examiner does not adopt its recommended approach, "based on the revenue deficiency recommended in the Report, the results of [the Hearing Examiner's] recommended approach to inter-class revenue apportionment are similar to those that would be achieved pursuant to the approach recommended by [the Old Dominion Committee]."[119] The Old Dominion Committee asserts that the Hearing Examiner's "recommended approach would move such rate classes halfway toward 'parity' based on the rate of return for each class relative to the average rate of return."[120] The Old Dominion Committee further states that the Hearing Examiner "appropriately rejects the new methodology proposed by Kroger, which ... would have dramatically and unfairly increased the subsidies paid by the large industrial customers in order, in essence, to *maintain* the subsidy paid to the residential class."[121]

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[116] Kroger's April 18, 2007 Comments at 2.

[117] *Id.* at 3.

[118] *Id.* at 4.

[119] Old Dominion Committee's April 18, 2007 Comments at 39.

[120] *Id.* at 38.

[121] *Id.* at 38-39 (emphasis in original).

We adopt the Hearing Examiner's recommended revenue apportionment, which we find reasonably moves customer classes toward parity and results in just and reasonable rates for all rate classes.

Rate Design

We adopt the Hearing Examiner's recommended rate design. The Hearing Examiner noted that the rate design issues "were resolved by the end of the hearings," except for the matters discussed below.[122]

LGS Rate Design

The Hearing Examiner explained that, according to Kroger: (1) "APCo's proposed rate design for LGS has demand charges below LGS demand cost of service and proposed LGS energy charges above LGS energy cost of service;" and, thus, (2) "the Company's proposal will cause higher load factor LGS customers to subsidize lower load factor LGS customers."[123] Appalachian agreed with Kroger, in theory, but opposed Kroger's request to design LGS rates to reflect demand and energy cost of service. As stated by the Hearing Examiner, APCo "testified that Kroger's proposal will cause the MGS-LGS Secondary load factor crossover point to move from 39% to 43%, which will cause the following problems: (i) customers with load factors around the crossover point would be adversely affected as they were forced to migrate to another rate schedule while high-load factor customers would be benefited; (ii) the migration of customers would change the cost characteristics of the MGS and LGS classes, thereby rendering Kroger's cost-based rates incorrect; and (iii) the Company could experience revenue erosion."[124]

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[122] Hearing Examiner's Report at 64-65.

[123] *Id.* at 65.

[124] *Id.* at 66.

The Hearing Examiner "agree[d] with APCo that it should design MGS and LGS rates to maintain the currently proposed load factor crossover points" and further found that "APCo should be directed to utilize any reductions in the revenue requirement apportioned to LGS to design rates to move closer to cost of service, while maintaining current crossover points."[125] In response, "Kroger recommends adoption of the Report's directive to utilize any reduction in the revenue requirement apportioned to move the LGS demand charge closer to cost-of-service, but recommends that the Commission reject the arbitrary and unduly burdensome requirement that the crossover point between classes cannot change."[126] We find that the Hearing Examiner's recommended rate design, which moves intra-class LGS rates closer to cost of service while maintaining the current cross-over points, appropriately balances the interests of all LGS customers and results in just and reasonable rates for both high and low load factor customers within the rate class.

Sales and Use Tax Surcharge

The Company "currently recovers incremental sales and use tax through a surcharge that became effective September 1, 2004" and "argued that the 2004 Act of the General Assembly that instituted the sales and use surcharge, mandates the existing surcharge and its true-up mechanism."[127] Staff, however, "recommended that the sales and use surcharge be rolled into base rates" and "argued that such treatment is consistent with the elimination of the sales and use

[125] *Id.*

[126] Kroger's April 18, 2007 Comments at 5.

[127] Hearing Examiner's Report at 66.

surcharge for Roanoke Gas Company, Craig-Botetourt Electric Cooperative, and Columbia Gas of Virginia, Inc."[128]

The Hearing Examiner noted that "2004 Va. Acts Sp. Sess. I, ch. 3, cl.5[129] provides as follows:"

> That notwithstanding any provision of law to the contrary, including § 56-582 of the Code of Virginia, any public utility that is, as a result of the provisions of this act, subject to a sales and use tax on tangible personal property purchased or leased for use or consumption by such utility in the rendition of its public service is hereby authorized to recover from each customer that customer's pro rata share of the public utility's actual expense therefore by means of a *sales and use tax surcharge*. The surcharge shall be subject to *annual review and verification* by the State Corporation Commission in the year subsequent to the surcharge, based on data provided in an annual information filing or other information provided to the State Corporation Commission by such utility; however, such review and verification shall *neither constitute a rate case nor be the subject of a rate case*. If the State Corporation Commission determines that the amount of the surcharge differed from the actual sales and use tax incurred as a result of the provisions of this act, a surcharge adjustment shall be applied in the following year. Any excess in the surcharge shall be refunded to ratepayers as a deduction against the surcharge to be imposed in that subsequent year. Any shortfall in the surcharge shall be recovered through an increase in the surcharge to be imposed in that subsequent year. A surcharge that is allocated on a proportionate basis or according to the allocation factors in the utility's most recent State Corporation Commission-approved cost allocation study shall be presumed valid.[130]

The Hearing Examiner agreed with APCo, finding as follows: "Based on my reading of the above act of the General Assembly, I find that the surcharge and the subsequent annual review

[128] *Id.*

[129] *See* Editor's note to § 58.1-609.3.

[130] Hearing Examiner's Report at 66-67 (emphasis added).

and adjustments, if necessary, are required. Moreover, the act explicitly states that the surcharge is not to be the subject of a rate case."[131]

In response, Staff asserts "that while the Act does state that, 'the surcharge shall be subject to annual review and verification ... however, such review and verification shall neither constitute a rate case nor be the subject of a rate case,' this language specifically refers only to the review and verification process that can otherwise give rise to a surcharge true-up adjustment. Rolling the surcharge into base rates, when otherwise permitted by the Act, is simply not prohibited by this language."[132] Staff states that APCo "should be directed to cease billing the surcharge, be permitted to collect or refund any under- or over-recovery position as of the date of interim rates in the instant proceeding, and be directed to refund any surcharge billed after that date."[133]

We find that it is reasonable for APCo to continue to recover incremental sales and use taxes through a surcharge in the manner explicitly permitted by the above statute.

Terms and Conditions

We adopt the terms and conditions recommended by the Hearing Examiner, which include but are not limited to the following contested matters: (1) with regard to billing errors, customers will receive refunds for any overbillings made during the prior thirty-six months, and the Company will collect from customers any underbillings made during the prior twelve months; and (2) under the "Denial of Service" provision and the "Discontinuance of Service With Notice" provision of the "DENIAL OR DISCONTINUANCE OF SERVICE" section of the

[131] *Id.* at 67.

[132] Staff's April 18, 2007 Comments at 3 (footnote omitted).

[133] *Id.*

tariff, APCo will include language to state that service can be denied for prior indebtedness by a previous customer provided that the current applicant or customer occupied the premises at the time the prior indebtedness occurred and the previous customer continues to be an owner or bona fide lessee of the premises.[134]

Affiliates Act Approval

The Hearing Examiner noted that Staff "recommended that 'the Commission direct APCo to file a new Chapter 4 application for approval of its service company agreement with [AEP Service] within 30 days of the Final Order in this case.'"[135] The Hearing Examiner adopted Staff's recommendation.[136] In response, APCo asserts that "[t]here is no reason for such a filing" and that "none is given in the [Hearing Examiner's] Report."[137] APCo also explains that the "Company does not object to working with the Staff to identify any specific concerns with its affiliates agreements and to address them as necessary. The Commission, however, should neither endorse an unsupported implication that there are such specific concerns nor require an affiliate filing without any reason."[138]

Staff witness Carr testified "that the Commission's Order approving the current service agreement between APCo and [AEP Service] is six years old."[139] Mr. Carr further explained as follows:

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[134] Hearing Examiner's Report at 68.

[135] *Id.* at 16-17.

[136] *Id.* at 70.

[137] Appalachian's April 18, 2007 Comments at 47.

[138] *Id.*

[139] Carr, Exh. 54 at 15.

> Since that time, APCo and the energy industry in general have experienced dramatic changes, including the collapse of Enron and the rapid growth of the PJM regional transmission organization. In addition, Staff notes that the current service agreement contains numerous references to the Public Utility Holding Company Act of 1935, which has been repealed, and does not incorporate any of the changes caused by the enactment of the Energy Policy Act of 2005. Finally, Staff notes that the current service agreement includes an 'Other Services' clause, which could be construed to allow APCo and [AEP Service] to add or delete corporate services provided under the service agreement without separate Commission approval. The Commission has consistently denied approval of such open-ended clauses in recent service company orders. Taken together, these factors suggest than an update to the service agreement and to the Commission's regulatory approval is in order.[140]

We adopt Staff's and the Hearing Examiner's recommendation. Appalachian shall file a new Chapter 4 application for approval of its service company agreement with AEP Service within 30 days of the Final Order in this case.

Legislation Enacted in the 2007 Session of the Virginia General Assembly

The Company notes that on "April 4, 2007 the General Assembly approved the Governor's Amendment in the Nature of a Substitute for Senate Bill 1416 and House Bill 3068."[141] Appalachian asserts that this proceeding is governed, in part, by this recently passed legislation. For example, the Company contends that this new legislation must inform our analysis regarding OSS margins, cost of equity, and income tax apportionment. If Appalachian is correct, we acknowledge that application of the new statute to the current proceeding would result in a rate increase that can be estimated to be approximately $47.65 million more than the rate increase we otherwise approve herein.

[140] *Id.* (footnote omitted).

[141] Appalachian's April 18, 2007 Comments at 8.

We would not typically address a statute that has yet to take effect; however, since Appalachian has asserted that the new statute applies, at least in part, to this case, we are compelled to address APCo's assertions in this opinion.

The Constitution of Virginia provides that bills passed by the General Assembly and signed by the Governor shall become effective the following July 1, unless enacted as emergency legislation.[142] Furthermore, it is a standard rule of statutory construction in Virginia that legislation applies prospectively absent an express provision to the contrary.[143] Accordingly, and as further discussed below, we reject APCo's claims that our findings in the instant case must be modified as a result of the recently enacted statute.

<u>OSS Margins</u>

Appalachian asserts that this new statute "adds a new § 56-249.6.D.1 to the fuel factor statute" and "will take effect July 1, 2007 (Va. Const., Art. IV, §13), so beginning July 1, 2007 OSS margins must be used as provided in § 56-249.6.D.1."[144] APCo states that new § 56-249.6.D.1 provides as follows:

> 1. Energy revenues associated with off-system sales of power shall be credited against fuel factor expenses in an amount equal to the total incremental fuel factor costs incurred in the production and delivery of such sales. In addition, 75 percent of the total

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[142] Va. Const. Art. IV, § 13 ("All laws enacted at a regular session, including laws which are enacted by reason of actions taken during the reconvened session following a regular session, but excluding a general appropriation law, shall take effect on the first day of July following the adjournment of the session of the General Assembly at which it has been enacted; ... unless in the case of an emergency (which emergency shall be expressed in the body of the bill) the General Assembly shall specify an earlier date by a vote of four-fifths of the members voting in each house....").

[143] *See, e.g., Washington v. Commonwealth of Virginia*, 216 Va. 185, 193, 217 S.E.2d 815, 823 (1975) ("The general rule is that statutes are prospective in the absence of an express provision by the legislature. Thus when a statute is amended while an action is pending, the rights of the parties are to be decided in accordance with the law in effect when the action was begun, unless the amended statute shows a clear intention to vary such rights." (citing *Burton v. Seifert Plastic Relief Co.,* 108 Va. 338, 350-51, 61 S.E. 933, 938 (1908)).

[144] Appalachian's April 18, 2007 Comments at 8-9.

> annual margins from off-system sales shall be credited against fuel factor expenses; however, the Commission, upon application and after notice and opportunity for hearing, may require that a smaller percentage of such margins be so credited if it finds by clear and convincing evidence that such requirement is in the public interest. The remaining margins from off-system sales shall not be considered in the biennial reviews of electric utilities conducted pursuant to § 56-585.1. In the event such margins result in a net loss to the electric utility, (i) no charges shall be applied to fuel factor expenses and (ii) any such net losses shall not be considered in the biennial reviews of electric utilities conducted pursuant to § 56-585.1. For purposes of this subsection, 'margins from off-system sales' shall mean the total revenues received from off-system sales transactions less the total incremental costs incurred....[145]

APCo concludes that: (a) the new statute "will control the use of OSS margins beginning July 1, 2007, so the conflicting recommendation in the Hearing Examiner's report *must be rejected*;" (b) the "statutory 75% OSS margin sharing should be applied to the period October 2, 2006 through December 31, 2007 via a revised Temporary Sales Rider and 'trued-up' to actual OSS margins for that period as part of the Company's 2008 fuel factor proceeding;" (c) "[i]n annual fuel factor cases the Commission should use estimated annual OSS margins, as well as fuel costs, with later 'true-up' to actual amounts, not previously realized OSS margins which would create a gap in OSS credits to customers prior to December 31, 2007;" and (d) "[u]se of the revised Rider as described in [(b)] above makes unnecessary any revision of the current fuel factor as of July 1, 2007."[146]

We reject APCo's arguments. The new statute does not become effective until July 1, 2007. In addition, APCo's quote, above, of the new statute omits the language that immediately precedes new § 56-249.6.D.1. Specifically, § 56-249.6 D begins with this phrase: "D. In

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[145] *Id.*.

[146] *Id.* at 15 (emphasis added).

proceedings under subsections A and C:". The instant case is not a proceeding under subsections A and C of § 56-249.6; rather, Appalachian initiated this rate case pursuant to § 56-582 C of the Code. We agree with the legal analysis provided by the Attorney General, who in addition to serving as Consumer Counsel is the chief legal officer of the Commonwealth: "This [new] legislation does not become effective until July 1, 2007, and thus has no bearing on the question and does not in any way bind the Commission in this case. Moreover, the measures prescribed in this legislation apply only to 'proceedings under subsections A and C' of Virginia Code § 56-249.6. The new law does not apply to Appalachian's off-system sales margins until the Company's next fuel factor proceeding following the legislation's July 1, 2007, effective date."[147]

Likewise, we reject Appalachian's assertion that the new statute dictates the form of any rider established to credit OSS margins to customers. As explained above, we have established a separate OSS Margin Rider based on the law and facts applicable to this proceeding. The manner in which that OSS Margin Rider is, or is not, impacted in any subsequent case under the new law will be determined in that subsequent case.

As argued by APCo, however, we acknowledge that application of the new statute to this case would significantly increase the Company's revenue requirement. For example, under the OSS margin treatment found reasonable in this case by the Commission, customers receive a credit of $100.6 million. In contrast, under the Company's interpretation of the new statute, which Appalachian asserts should govern this case, customers would receive a credit of 75% of $100.6 million, or $75.5 million. Thus, if we applied the new statute to the current proceeding – as and in the manner requested by APCo – the Company's customers would see their rates increased by an additional $25.1 million over the rates approved herein.

[147] Consumer Counsel's April 18, 2007 Comments at 5 n.12.

Cost of Equity

APCo also points to newly enacted SB 1416 and HB 3068 to support its proposed cost of equity. Appalachian states that the new legislation, in part, directs as follows:

> In such proceedings the Commission shall determine fair rates of return on common equity applicable to the generation and distribution services of the utility. In so doing, the Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility, nor shall the Commission set such return more than 300 basis points higher than such average. 2007 Va. Acts c. 933, § 56-585.1 A.[148]

The Company asserts that: (1) the "new law will create a floor on return on equity that is likely to be higher than the return recommended in the [Hearing Examiner's] Report;" (2) the Hearing Examiner's recommendation "does not adequately reflect ... the intent of the new statutory provisions;" and (3) "[w]hile the record in this case does not contain an express analysis of return on equity calculations under the new legislation, there is evidence that the reported returns in other states to which the new statute refers will likely be in the range recommended by [Appalachian witness] Moul of 11% to 12%."[149]

We have no factual basis to disagree with Appalachian's conclusion regarding the likely results of the new statute, if it were applied to this case. Indeed, a sample calculation of the average returns on common equity derived from reports filed with the Securities and Exchange Commission ("SEC"), for the three-year period 2004-2006, of potential peer utilities as reflected

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148 Appalachian's April 18, 2007 Comments at 21.

149 *Id.* at 21-22.

in the new statute is 11.55%.[150] If the two utilities with the lowest return and the two utilities with the highest return are removed as reflected in § 56-585.1 A 2 b of the new law, the resulting return is 11.88%. These results are consistent with Appalachian's assertion that the peer utilities referenced in the new statute support Mr. Moul's recommended return of 11% to 12%. Thus, if we applied the midpoint of Mr. Moul's recommended range of return (*i.e.*, 11.5%) in this proceeding – as opposed to 10.0% as found reasonable herein – APCo's customers would see their rates increased by an additional $19.95 million over the rates approved in this case.[151]

For the reasons discussed above, however, Appalachian is incorrect that the new statute should inform this case. As explained above, based on the record developed in this proceeding, we find that a cost of equity ranging from 9.6% to 10.6%, using 10.0% to calculate revenue requirement, results in a fair and reasonable return for both the Company and its customers.

West Virginia State Income Tax Apportionment Factors

We adopted, above, Staff's and the Hearing Examiner's recommendation to use the income apportionment factors from the income tax returns actually filed by APCo in Tennessee, Ohio, West Virginia, and Virginia to develop the effective state income tax rates to be applied to Virginia jurisdictional taxable income. The Company, however, explains that SB 1416 and HB 3068 recently codified APCo's position "on this issue by amending § 56-235.2 A of the Code of Virginia. That section will now provide in pertinent part ... that APCo's 'apportioned state

[150] The following peer utilities were used for this example, with common equity returns based on reports filed with the SEC: Monongahela Power Company (5.87%); Entergy Mississippi, Inc. (9.59%); Tampa Electric Company (10.24%); Cleco Power (10.87%); FP&L Company (11.31%); Gulf Power (12.00%); Progress Energy Florida, Inc. (12.14%); Alabama Power (13.18%); Georgia Power (13.44%); Mississippi Power (13.71%); and Progress Energy Carolinas, Inc. (14.67%). The peer utilities, calculations, and comparisons in this Final Order do not represent findings of fact but are for illustrative purposes in addressing Appalachian's assertions and do not serve as precedent for implementation of any part of the new statute.

[151] This revenue requirement increase is estimated as follows: $831,142,082 (Common Equity Capital, Hearing Examiner's Report at Attachment 1, Line 28) x 1.5% (increased return on equity, 11.5% minus 10.0%) ÷ 0.624876 (Revenue Conversion Factor for taxes and accounts receivable factoring) = $19,951,368.

income tax costs shall be calculated according to the applicable statutory rate, as if the utility had not filed a consolidated return with its affiliates....'"[152] Appalachian states that "[a]lthough this new statute is not effective until July 1, 2007, its legislative intent is clear. The statute rejects the Hearing Examiner's recommendation to use a consolidated state apportionment factor."[153]

If we agreed to APCo's request, customers would see their rates increased by an additional $2.6 million over the rates approved in this case.[154] We are not bound, however, by a statute that is not yet in effect.

Rates and Refunds

Finally, the Company argues that: (1) its customers should continue to be charged APCo's higher rates currently in effect, which we have found unjust and unreasonable, for a *minimum* of two more months after the date of this Final Order; and (2) its customers should wait a *minimum* of six months before receiving any credits or refunds owed to them by APCo.

Specifically, the Company "requests that it be given a minimum of sixty (60) days from the date of a Final Order to prepare a compliance cost-of-service and to file rates designed to produce the revenue found reasonable by the Commission."[155] In addition, "[d]ue to the expected volume of calculations and the complexity of rebilling the unbundled rates, the Company requests that it be given a minimum of one hundred twenty (120) days from the date the Commission approves its compliance tariff to complete any customer refunds ordered by the Commission."[156]

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[152] Appalachian's April 18, 2007 Comments at 43 (emphasis omitted).

[153] *Id.*

[154] *Id.*

[155] *Id.* at 48.

[156] *Id.* at 49.

Appalachian's request in this matter is entirely unjustified. The Company's customers have endured three rate increases over the past year, which include paying significantly higher rates as a result of APCo's request in this case. Now that the Commission has rejected a large portion of Appalachian's most recent rate hike, the Company seeks to prolong this episode another six months – at a minimum. We find that such request is not just and reasonable and not in the public interest, and, indeed, that APCo's customers deserve better treatment than the Company wishes to impose upon them. We will require that the Company charge new rates, in accordance with the findings made herein, for bills rendered on and after thirty (30) days from the date of this Final Order, and that the Company effectuate refunds (with interest computed as set forth below) within ninety (90) days from the date of this Final Order.[157]

Accordingly, IT IS HEREBY ORDERED THAT:

(1) The findings and recommendations of the March 28, 2007 Hearing Examiner's Report are adopted in part and modified in part as set forth herein.

(2) Appalachian shall forthwith file revised tariffs and terms and conditions of service with the Commission's Division of Energy Regulation, in accordance with the findings made herein, for bills rendered on and after thirty (30) days from the date of this Final Order.

(3) Appalachian shall recalculate, using the rates and charges approved herein, each bill it rendered that used, in whole or in part, the rates and charges that took effect under bond and

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[157] This is consistent with prior Commission cases in which new rates and refunds (with interest computed using the average prime rate) were required to be implemented within a 90-day window. *See, e.g., Application of Appalachian Power Co. for an expedited increase in base rates*, Case No. PUE-1994-00063, 1996 S.C.C. Ann. Rep. 255, 257, Final Order (May 24, 1996) (requiring refunds on or before July 26, 1996); *Application of Appalachian Power Co. for an alternative regulatory plan*, Case No. PUE-1996-00301, 1999 S.C.C. Ann. Rep. 367, 368, Final Order (Feb. 18, 1999) (requiring revised tariffs to be filed by March 1, 1999 and refunds to be made by May 18, 1999); *Application of Washington Gas Light Co.*, Case No. PUE-2003-00603, 2004 S.C.C. Ann. Rep. 411, 413, Final Order (Sept. 27, 2004) (requiring new rates to be implemented "commencing with the October 2004 monthly billing cycle" and refunds to be made "within 90 days of the issuance of this Final Order"); *Application of Atmos Energy Corporation for an increase in rates*, Case No. PUE-2003-00507, S.C.C. Ann. Rep. 322, 323 (Jan. 7, 2005) (requiring refunds "within ninety (90) days of the entry of this Order").

subject to refund on and after October 2, 2006 and, where application of the new rates results in a reduced bill, refund the difference with interest as set out below within ninety (90) days of the issuance of this Final Order.

(4) Interest upon the ordered refunds shall be computed from the date payments of monthly bills were due to the date each refund is made at the average prime rate for each calendar quarter, compounded quarterly. The average prime rate for each calendar quarter shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the prime rate values published in the Federal Reserve Bulletin or in the Federal Reserve's Selected Interest Rates (Statistical Release H.15) for the three months of the preceding calendar quarter.

(5) The refunds ordered herein may be credited to current customers' accounts (each refund category shall be shown separately on each customer's bill). Refunds to former customers shall be made by check mailed to the last known address of such customers when the refund amount is $1 or more. Appalachian may offset the credit or refund to the extent of any undisputed outstanding balance for the current or former customer. No offset shall be permitted against any disputed portion of an outstanding balance. Appalachian may retain refunds to former customers when such refund is less than $1. Appalachian shall maintain a record of former customers for which the refund is less than $1, and such refunds shall be promptly made upon request. All unclaimed refunds shall be subject to § 55-210.6:2 of the Code of Virginia.

(6) On or before September 30, 2007, Appalachian shall deliver to the Divisions of Public Utility Accounting and Energy Regulation a report showing that all refunds have been made pursuant to this Final Order, detailing the costs of the refunds and the accounts charged.

(7) Appalachian shall bear all costs incurred in effecting the refund ordered herein.

(8) Steel Dynamics' Motion for Leave to File and Reply is denied.

(9) The Company is ordered to comply with the directives set forth in this Final Order.

(10) This case is dismissed.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to: the attached service list.

A True Copy
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Clerk of the
State Corporation Commission

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Appalachian Power Company
Depreciation and Amortization Expense by Month by Function
For the Year Ended December 31, 2011

Depreciation Expense Account 403

Function	Jan 2011	Feb 2011	Mar 2011	Apr 2011	May 2011	Jun 2011	Jul 2011	Aug 2011	Sep 2011	Oct 2011	Nov 2011	Dec 2011	Year to Date
1 - Steam Generation Plant	$8,900,995	$9,649,945	$9,414,795	$9,751,021	$8,582,845	$9,113,169	$9,105,782	$9,301,677	$9,325,169	$9,170,005	$9,672,637	$5,534,114	$107,522,153
2 - Hydro Generation Plant	$271,192	$271,640	$271,723	$272,851	$272,955	$272,954	$273,799	$273,967	$273,986	$274,002	$274,796	$274,942	$3,278,807
3 - Other Generation Plant	$262,424	$262,447	$262,447	$262,447	$262,462	$262,462	$262,462	$262,464	$262,484	$262,484	$262,492	$262,498	$3,149,573
4 - Transmission Plant	$2,470,573	$2,491,657	$2,502,877	$2,508,751	$2,515,912	$2,527,894	$2,535,434	$2,539,533	$2,554,233	$2,553,456	$2,556,089	$2,661,323	$30,417,733
5 - Distribution Plant	$7,374,606	$7,361,733	$7,398,092	$7,390,481	$7,404,710	$7,453,187	$7,442,160	$7,479,308	$7,533,763	$7,514,052	$7,534,413	$7,549,934	$89,436,440
6 - General Plant	$206,048	$204,147	$207,676	$208,192	$208,206	$208,716	$208,917	$209,800	$216,248	$209,318	$209,789	$210,228	$2,507,284
Grand Total	**$19,485,838**	**$20,241,569**	**$20,057,609**	**$20,393,743**	**$19,247,089**	**$19,838,382**	**$19,828,554**	**$20,066,750**	**$20,165,883**	**$19,983,317**	**$20,510,216**	**$16,493,040**	**$236,311,991**

Note: Total year to date depreciation expense shown above ties to FERC Form 1 page 336, line 12, column b.

Amortization Expense Account 404

Function	Jan 2011	Feb 2011	Mar 2011	Apr 2011	May 2011	Jun 2011	Jul 2011	Aug 2011	Sep 2011	Oct 2011	Nov 2011	Dec 2011	Year to Date
General Plant	$9,799	$9,981	$9,981	$10,357	$10,697	$12,111	$10,946	$10,946	$11,440	$11,440	$11,440	$11,440	$130,580
Intangible Plant	$1,200,309	$1,205,974	$1,212,243	$1,224,030	$1,233,745	$1,240,274	$1,253,586	$1,291,709	$1,674,285	$1,326,530	$1,082,504	$1,235,727	$15,180,917
Total	**$1,210,109**	**$1,215,956**	**$1,222,224**	**$1,234,387**	**$1,244,442**	**$1,252,384**	**$1,264,532**	**$1,302,655**	**$1,685,725**	**$1,337,971**	**$1,093,945**	**$1,247,167**	**$15,311,497**

Note: Total year to date amortization expense shown above ties to FERC Form 1 page 336, line 12, column d.

Appalachian Power Company
Steam Production Depreciation Expense
For the Month of July 2011

Depr Group	Plant/Unit	Date	Depreciation Rate	Steam Production Depreciation Base	July 2011 Depreciation Expense
APCo 101/6 311 Amos U1&2	Amos U1&2	Jul-11	1.93%	$38,171,894.73	$61,393.13
APCo 101/6 312 Amos U1&2	Amos U1&2	Jul-11	3.01%	$1,285,383,748.21	$3,224,170.90
APCo 101/6 314 Amos U1&2	Amos U1&2	Jul-11	2.53%	$115,487,360.09	$243,485.85
APCo 101/6 315 Amos U1&2	Amos U1&2	Jul-11	2.23%	$38,709,587.86	$71,935.32
APCo 101/6 315 Amos U3	Amos U1&2	Jul-11	2.06%	$9,523,355.38	$16,348.43
APCo 101/6 316 Amos U1&2	Amos U1&2	Jul-11	2.21%	$10,081,947.16	$18,567.58
	Amos U1&2 Total			**$1,497,357,893.43**	**$3,635,901.21**
APCo 101/6 311 Amos U3	Amos U3	Jul-11	1.88%	$39,402,441.25	$61,730.49
APCo 101/6 312 Amos U3	Amos U3	Jul-11	2.64%	$624,378,037.15	$1,373,631.68
APCo 101/6 314 Amos U3	Amos U3	Jul-11	2.54%	$31,048,882.73	$65,720.13
APCo 101/6 316 Amos U3	Amos U3	Jul-11	2.66%	$12,039,141.74	$26,686.76
	Amos U3 Total			**$706,868,502.87**	**$1,527,769.06**
APCo 101/6 311 Clinch River	Clinch River	Jul-11	2.67%	$42,907,741.03	$95,469.72
APCo 101/6 312 Clinch River	Clinch River	Jul-11	3.28%	$258,555,192.24	$706,717.52
APCo 101/6 314 Clinch River	Clinch River	Jul-11	2.74%	$59,703,379.34	$136,322.72
APCo 101/6 315 Clinch River	Clinch River	Jul-11	2.43%	$13,379,274.32	$27,093.03
APCo 101/6 316 Clinch River	Clinch River	Jul-11	3.10%	$7,084,476.39	$18,301.57
	Clinch River Total			**$381,630,063.32**	**$983,904.56**
APCo 101/6 311 Glen Lyn U5	Glen Lyn U5	Jul-11	4.63%	$3,203,525.93	$12,360.27
APCo 101/6 312 Glen Lyn U5	Glen Lyn U5	Jul-11	5.39%	$25,402,959.55	$114,101.63
APCo 101/6 314 Glen Lyn U5	Glen Lyn U5	Jul-11	5.91%	$6,576,229.85	$32,387.93
APCo 101/6 315 Glen Lyn U5	Glen Lyn U5	Jul-11	5.58%	$2,182,271.91	$10,147.56
APCo 101/6 316 Glen Lyn U5	Glen Lyn U5	Jul-11	10.16%	$220,080.41	$1,863.35
	Glen Lyn U5 Total			**$37,585,067.65**	**$170,860.74**
APCo 101/6 311 Glen Lyn U6	Glen Lyn U6	Jul-11	3.31%	$12,873,331.76	$35,508.94
APCo 101/6 312 Glen Lyn U6	Glen Lyn U6	Jul-11	4.36%	$71,629,579.96	$260,254.14
APCo 101/6 314 Glen Lyn U6	Glen Lyn U6	Jul-11	3.75%	$21,813,456.05	$68,167.05
APCo 101/6 315 Glen Lyn U6	Glen Lyn U6	Jul-11	3.53%	$6,109,943.43	$17,973.42
APCo 101/6 316 Glen Lyn U6	Glen Lyn U6	Jul-11	4.62%	$4,357,946.18	$16,778.09
	Glen Lyn U6 Total			**$116,784,257.38**	**$398,681.64**
APCo 101/6 311 Kanawha River	Kanawha River	Jul-11	0.80%	$18,304,378.00	$12,202.92
APCo 101/6 312 Kanawha River	Kanawha River	Jul-11	1.75%	$122,364,247.80	$178,447.86
APCo 101/6 314 Kanawha River	Kanawha River	Jul-11	1.41%	$33,751,620.26	$39,658.15
APCo 101/6 315 Kanawha River	Kanawha River	Jul-11	1.23%	$9,035,989.63	$9,261.89
APCo 101/6 316 Kanawha River	Kanawha River	Jul-11	2.36%	$6,289,305.16	$12,368.97
	Kanawha River Total			**$189,745,540.85**	**$251,939.79**
APCo 101/6 311 Mountaineer	Mountaineer	Jul-11	1.70%	$141,392,002.74	$200,305.34
APCo 101/6 312 Mountaineer	Mountaineer	Jul-11	2.01%	$1,118,119,454.91	$1,872,850.08
APCo 101/6 314 Mountaineer	Mountaineer	Jul-11	1.91%	$104,560,072.57	$166,424.79
APCo 101/6 315 Mountaineer	Mountaineer	Jul-11	1.68%	$66,651,788.32	$93,312.50
APCo 101/6 316 Mountaineer	Mountaineer	Jul-11	1.87%	$18,950,375.07	$29,531.00
	Mountaineer Total			**$1,449,673,693.61**	**$2,362,423.71**
APCo 101/6 311 Putnam Coal	Putnam Coal Terminal	Jul-11	2.13%	$3,282,843.91	$5,827.04
APCo 101/6 312 Putnam Coal	Putnam Coal Terminal	Jul-11	2.18%	$24,034,129.95	$43,662.01
APCo 101/6 315 Putnam Coal	Putnam Coal Terminal	Jul-11	2.16%	$3,530,795.14	$6,355.43
APCo 101/6 316 Putnam Coal	Putnam Coal Terminal	Jul-11	2.29%	$644,475.28	$1,229.88
	Putnam Coal Terminal Total			**$31,492,244.28**	**$57,074.36**
APCo 101/6 311 Sporn Plant	Sporn Plant	Jul-11	0.80%	$12,904,984.24	$8,603.32
APCo 101/6 312 Sporn Plant	Sporn Plant	Jul-11	2.33%	$89,483,027.73	$173,746.21
APCo 101/6 314 Sporn Plant	Sporn Plant	Jul-11	1.49%	$20,914,776.62	$25,969.18
APCo 101/6 315 Sporn Plant	Sporn Plant	Jul-11	1.48%	$7,196,115.19	$8,875.21
APCo 101/6 316 Sporn Plant	Sporn Plant	Jul-11	1.66%	$4,038,486.14	$5,586.57
	Sporn Plant Total			**$134,537,389.92**	**$222,780.49**
APCo 101/6 311-316 Cen Plnt Maint	Central Plant Maint	Jul-11	2.09%	$85,770.00	$149.38
	Central Plant Maint Total			**$85,770.00**	**$149.38**
APCo 101/6 311-316 Centrl Mach Shop	Central Machine Shop	Jul-11	2.10%	$13,324,810.65	$23,318.42
	Central Machine Shop Total			**$13,324,810.65**	**$23,318.42**
APCo 101/6 311-316 Little Broad Mtn	Little Broad Run	Jul-11	1.68%	$31,780,601.61	$44,492.84
APCo 101/6 311-316 Little Broad Spn	Little Broad Run	Jul-11	2.08%	$2,112,361.77	$3,661.43
	Little Broad Run Total			**$33,892,963.38**	**$48,154.27**
	Grand Total Steam Production			**$4,592,978,197.34**	**$9,682,957.63**
	July Adjustments (see below)				($577,175.26)
	July Total Steam Production				**$9,105,782.37**

Monthly Depreciation Expense (July 2011, above) equals Depreciation Base times Depreciation Rate divided by 12. July Total Steam Production above ties to Exhibit DAD-2 depreciation expense for Steam Production Plant for July.

<u>July Adjustments</u>

Deferred Environmental Depreciation (pursuant to Section 56-585.1.A.5e of the Code of Virginia) - deferral of depreciation on environmental projects that have not been recovered through Virginia base rates	($483,543.00)
Depreciation Billed to Associated Companies for joint use of Amos Simulator, Central Plant Maintenance and Central Machine Shop Facilities	($94,476.10)
Miscellaneous Adjustment	843.84
TOTAL	**($577,175.26)**

APPALACHIAN POWER COMPANY
Statement E - Apportionment Factors
Test Year Ending December, 31, 2009
AS FILED IN WV CASE NO. 10-0699-E-42T

ALLOCATION FACTORS USED EXHIBIT AEP-101

	State Jurisdiction		FERC Jurisdiction		Other Virginia Jurisdictions		
	West Virginia	Virginia	Kingsport	Sales for Resale	Public Authority	Common Wealth Va.	Street Lighting
Demand-Production	**0.427991**	**0.456204**	**0.062203**	**0.034711**	**0.015090**	**0.003703**	**0.000099**
Demand-Transmission	0.427991	0.456204	0.062203	0.034711	0.015090	0.003703	0.000099
Energy	0.430567	0.447174	0.063261	0.034766	0.019467	0.003901	0.000864
Related Distribution Plant	0.437221	0.534953	0.000019	0.000000	0.017695	0.004342	0.005770
Related General Plant	0.434435	0.486805	0.036610	0.020301	0.016020	0.003731	0.002097
Total Gross Plant	0.431743	0.479320	0.043279	0.024143	0.015809	0.003884	0.001822
Total Net Plant	0.432845	0.480582	0.041556	0.023182	0.015928	0.003911	0.001995
Depreciation & Amortization Expense	0.423593	0.496424	0.037224	0.020730	0.015822	0.003884	0.002322
Payroll	**0.434435**	**0.486805**	**0.036610**	**0.020301**	**0.016020**	**0.003731**	**0.002097**
Number of Customers	0.458332	0.534994	0.000001	0.000006	0.005228	0.001344	0.000095
Operating Revenues (Va. Only)	0.000000	0.947755	0.000000	0.000000	0.041424	0.007964	0.002858
Operating Revenues (WVa. Only)	0.828880	0.000000	0.108912	0.062208	0.000000	0.000000	0.000000
Total Transmission Plant	0.427991	0.456204	0.062203	0.034711	0.015090	0.003703	0.000099
RTO Deferred Asset	0.443381	0.472609	0.064440	0.000000	0.015633	0.003836	0.000102
AFUDC- Demand Reallocation	0.815369	0.960236	0.118503	0.066128	0.031762	0.007794	0.000208
AFUDC- General Plant Reallocation	0.879422	0.957046	0.077567	0.043011	0.031496	0.007335	0.004123
AFUDC- Dist. Plant Reallocation	0.999956	0.950587	0.000044	0.000000	0.031443	0.007716	0.010254
B&O Tax Demand Allocator	0.422591	0.460503	0.062794	0.035041	0.015234	0.003738	0.000100

		West Virginia	**Kingsport**	**Sales for Resale**	**Total Non-VA**
Demand-Production	□	0.427991	0.062203	0.034711	0.524904 □
Demand - Non-Virginia	**□ / □ =**	**0.815369**	0.475096		

Summary of VA Allocators

Production Demand	
VA Retail	0.456204
Public Authorities	0.015090
Commonwealth	0.003703
Street Lighting	0.000099
Total VA Allocators	**0.475096**

<= Ties to VA Production Demand Allocator in Production Plant Accounts on Exhibit AEP-101, pgs 1-3.

Payroll	
VA Retail	0.486805
Public Authorities	0.016020
Commonwealth	0.003731
Street Lighting	0.002097
Total VA Allocators	**0.508653**

<= Ties to VA Payroll Allocator in General Plant Section on Exhibit AEP-101, page 3.

APPALACHIAN POWER COMPANY
AMORTIZATION EXPENSE BY MONTH
FOR THE YEAR ENDED DECEMBER 31, 2011

Function	Jan 2011	Feb 2011	Mar 2011	Apr 2011	May 2011	Jun 2011	Jul 2011	Aug 2011	Sep 2011	Oct 2011	Nov 2011	Dec 2011	Year to Date
General Plant	$9,799.27	$9,981.09	$9,981.09	$10,357.25	$10,696.85	$12,110.94	$10,946.00	$10,946.00	$11,440.30	$11,440.31	$11,440.30	$11,440.30	$130,579.70
Intangible Plant	$1,200,309.39	$1,205,974.49	$1,212,243.19	$1,224,029.74	$1,233,745.04	$1,240,273.52	$1,253,586.14	$1,291,709.39	$1,674,284.54	$1,326,530.21	$1,082,504.27	$1,235,726.90	$15,180,916.82
Total	$1,210,108.66	$1,215,955.58	$1,222,224.28	$1,234,386.99	$1,244,441.89	$1,252,384.46	$1,264,532.14	$1,302,655.39	$1,685,724.84	$1,337,970.52	$1,093,944.57	$1,247,167.20	$15,311,496.52

APPALACHIAN POWER COMPANY
AMORTIZATION EXPENSE AND CALCULATION OF AMORTIZATION RATES
USING DECEMBER 31, 2011 EXPENSE AMOUNTS

Description	Plant Acct	Expense Acct	Func Class	Date	End Plant Balance	December 2011 Depreciation Expense	Calculated Annual Amortization Rate	Comments
Buck Franchise	302	4040001	Intangible Plant	Dec 2011	$248,321.00	$599.01	2.89%	Hydro License Fee
Byllesby Franchise	302	4040001	Intangible Plant	Dec 2011	$400,843.00	$1,131.26	3.39%	Hydro License Fee
Claytor Franchise	302	4040001	Intangible Plant	Dec 2011	$130,000.00	$179.38	1.66%	Hydro License Fee
Leesville Franchise	302	4040001	Intangible Plant	Dec 2011	$27,603.00	$0.14	0.01%	Hydro License Fee
Niagara Franchise	302	4040001	Intangible Plant	Dec 2011	$219,066.00	$609.00	3.34%	Hydro License Fee
Non-Depr Distr	302	4040001	Intangible Plant	Dec 2011	$72,502.61	$0.00	0.00%	Not Amortized
Reusens Franchise	302	4040001	Intangible Plant	Dec 2011	$232,281.00	$646.70	3.34%	Hydro License Fee
Smith Mtn License	302	4040001	Intangible Plant	Dec 2011	$7,578,232.16	$21,058.65	3.33%	Hydro License Fee
	302 Total				**$8,908,848.77**	**$24,224.14**		
Cap Soft EAS Distr	303	4040001	Intangible Plant	Dec 2011	$4,075,673.70	$0.00	0.00%	Fully Amortized
Cap Soft EAS Prod	303	4040001	Intangible Plant	Dec 2011	$3,173,921.55	$0.00	0.00%	Fully Amortized
Cap Soft EAS Transm	303	4040001	Intangible Plant	Dec 2011	$718,792.69	$0.00	0.00%	Fully Amortized
Cap Software Distr	303	4040001	Intangible Plant	Dec 2011	$29,286,505.83	$386,326.22	15.83%	Capital Software
Cap Software Prod	303	4040001	Intangible Plant	Dec 2011	$35,785,452.82	$570,000.89	19.11%	Capital Software
Cap Software Transm	303	4040001	Intangible Plant	Dec 2011	$12,137,186.80	$193,665.33	19.15%	Capital Software
Claytor Project	303	4040001	Intangible Plant	Dec 2011	$701,798.00	$898.07	1.54%	Hydro
Glenwood Sub	303	4040001	Intangible Plant	Dec 2011	$352,229.00	$0.00	0.00%	Fully Amortized
gridSMART Cap Softw	303	4040001	Intangible Plant	Dec 2011	$583,844.93	$9,163.19	18.83%	Capital Software
MACSS	303	4040001	Intangible Plant	Dec 2011	$11,389,284.00	$45,819.49	4.83%	Capital Software
MACSS VA CMWTH	303	4040001	Intangible Plant	Dec 2011	$98,634.00	$400.74	4.88%	Capital Software
Non-Depr Prod	303	4040001	Intangible Plant	Dec 2011	$31,932.70	$0.00	0.00%	Fully Amortized
Skimmer Station	303	4040001	Intangible Plant	Dec 2011	$1,840,763.00	$5,228.83	3.41%	Distribution Substation
Sporn Potable Water	303	4040001	Intangible Plant	Dec 2011	$30,930.55	$0.00	0.00%	Fully Amortized
	303 Total				**$100,206,949.57**	**$1,211,502.76**		
Abingdon Serv Bldg	390	4040001	General Plant	Dec 2011	$307,378.19	$0.00	0.00%	Fully Amortized
Central Mach Shop	390	4040001	General Plant	Dec 2011	$2,020,710.83	$0.00	0.00%	Fully Amortized
Clintwood Bldg	390	4040001	General Plant	Dec 2011	$7,559.00	$0.00	0.00%	Fully Amortized
Grundy Office Bldg	390	4040001	General Plant	Dec 2011	$45,566.00	$0.00	0.00%	Fully Amortized
Leases Amrtzed Distr	390	4040001	General Plant	Dec 2011	$182,056.58	$0.00	0.00%	Fully Amortized
Pearisburg Bldg	390	4040001	General Plant	Dec 2011	$23,783.00	$0.00	0.00%	Fully Amortized
Rainelle Off Bldg	390	4040001	General Plant	Dec 2011	$31,030.00	$0.00	0.00%	Fully Amortized
Richmond Ofc Bldg	390	4040001	General Plant	Dec 2011	$10,525.92	$89.97	10.26%	Leasehold Improvements
Roanoke Serv Bldg	390	4040001	General Plant	Dec 2011	$674,104.54	$11,350.33	20.21%	Leasehold Improvements
Stuart Office Bldg	390	4040001	General Plant	Dec 2011	$9,127.00	$0.00	0.00%	Fully Amortized
	390 Total				**$3,311,841.06**	**$11,440.30**		
	Grand Total				**$112,427,639.40**	**$1,247,167.20**		

Note: Account 302 Hydro License Fees are amortized over the term of the license. Account 303 Capital Software is generally amortized over a 5 year period which equates to a 20% rate applied to the prior month balance (the above calculation was rounded and based on the December monthly rate calculation). Account 390 above includes only owned improvements to general buildings that are leased by the Company and these amortization rates are determined by the lease term.

Attachment K

Testimony of Dr. William E. Avera

Exhibit AEP-400

THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF
WILLIAM E. AVERA

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AEP-404	“br + sv” Growth Rate – National Group
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AEP-410	Expected Earnings Approach

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company	**Docket No. ER13-____-000**

DIRECT TESTIMONY OF
WILLIAM E. AVERA

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Qualifications

Q. WHAT ARE YOUR QUALIFICATIONS?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the United States Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit No. AEP-401.

B. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide support for the 10.4% rate of return on equity ("ROE") requested by Appalachian Power Company ("APCO" or "the Company") in connection with the cost-based formula rate at issue in this proceeding. It is my understanding that the formula rate will be used to calculate the capacity charge under the Reliability Assurance Agreement ("RAA") among Load Serving Entities in the PJM region, which will apply to Alternative Electric Suppliers ("AES") that serve retail load under Virginia's retail choice program. APCO's 10.4% requested ROE is identical to that recently accepted by the Virginia State Corporation Commission ("SCC") in an order approving a settlement of APCO's retail rates.[1] My evaluation considered FERC's

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[1] *Order Approving Settlement*, Case No. U-16801 (Feb. 15, 2012)

established precedent and policy objectives, industry conditions and fundamentals, and independent estimates of the ROE for benchmark groups of electric utilities and non-utility firms. As I discuss below, my evaluation also took into account the discrete purpose for which this ROE is being established.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with and have considered the details of specific FERC polices and decisions related to ROE and have submitted testimony in numerous proceedings at the Commission dealing with required rates of return for electric utilities. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to APCO. I also reviewed information relating generally to capital markets and specifically to investor perceptions, requirements, and expectations for regulated utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of ROE issues affecting APCO and are the basis of my conclusions.

Q. WHAT IS THE PRACTICAL TEST OF THE REASONABLENESS OF THE ROE USED IN SETTING A UTILITY'S RATES?

A. The ROE compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[2] and *Hope*[3] cases, a utility's allowed return on common equity should be sufficient to: (1) fairly compensate investors for capital they have invested in the utility; (2) enable the utility to offer a return adequate to attract new capital on reasonable terms; and (3) maintain the utility's financial integrity.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first reviewed the operations and finances of APCO, as well as general condition in the electric utility industry and the capital markets. With this background, I conducted various quantitative analyses to estimate the current cost of equity. Specifically, I relied on the Discounted Cash Flow ("DCF") methodology currently prescribed by the Commission, and applied it to a national proxy group of other electric utilities with comparable investment risks. In addition, I examined the results of alternative ROE benchmarks that included applications of the equity risk premium approachbased on ROEs previously approved by the Commission, DCF cost of equity estimates for a proxy group of low-risk industrial firms, the Capital Asset Pricing Model ("CAPM"), and expected earned rates of return for utilities. Based on the cost of equity estimates indicated by my analyses, I evaluated APCO's requested ROE taking into account the discrete purpose for which this ROE is being established and other factors (*e.g.*, flotation costs) that are properly considered in setting a fair ROE.

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[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[3] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

C. Summary and Conclusions

Q. BASED ON YOUR EVALUATION, WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF THE 10.4% ROE REQUESTED BY APCO?

A. It is my conclusion that the 10.4% ROE requested by APCO is reasonable and should be approved. This ROE falls well within the 6.1% to 15.2% zone of reasonableness produced by applying the Commission-approved DCF approach to a national proxy group of 30 risk comparable electric utilities, and is bracketed by the midpoint and median values. The reasonableness of the 10.4% ROE requested by APCO is also demonstrated by reference to alternative ROE benchmarks, which consistently support an allowed return considerably above the DCF median for the proxy group.

The bases for my conclusion are summarized below:

- Application of the Commission's DCF model to a proxy group of comparable risk electric utilities resulted in an adjusted range of reasonableness of 6.1% to 15.2%;
- APCO's requested ROE of 10.4% falls well within the ROE zone of reasonableness produced by the Commission's DCF approach;
- An ROE of 10.4% falls below the 10.7% midpoint of the DCF range;
- The 8.9% median value indicated by the Commission's DCF method is far too low to be considered a credible estimate of investors' required ROE;
- Alternative ROE benchmarks consistently support the requested 10.4% ROE:
  - Applying the risk premium approach based on allowed ROEs for FERC-jurisdictional electric utilities suggest a current cost of equity on the order of 10.7% to 10.9%;
  - Reference to the ROEs approved by the Commission for natural gas pipelines implies a current cost of equity for an electric utility of approximately 10.5%;
  - DCF estimates for a low-risk group of non-utility firms suggest a cost of equity of approximately 12.0%;
  - Application of the CAPM using forward-looking estimates suggests an ROE range for electric utilities on the order of 10.6% to 11.8%;
  - Expected returns for electric utilities also confirmed my conclusion that a median value of 8.9% falls far short of a reasonable ROE;

- The Commission has demonstrated a willingness to adapt its policies and adjust the application of its methods to reflect changed circumstances and achieve a balanced outcome. Hewing to a mechanical approach in determining ROE, such as sole reliance on the median, must be tempered when the end result violates regulatory standards and undermines the Commission's policy goals, as it would in this case; and
- My conclusions are reinforced by the need to consider flotation costs, the expected upward trend in capital costs, and the need to support financial integrity and fund crucial capital investment even under adverse circumstances.

In addition, an ROE of 10.4% is supported by the facts and circumstances specific to this case, and is consistent with the ROE that has been recently approved by the SCC for Virginia retail customers. RAA charges are ultimately passed on to shopping retail customers in Virginia, and there is no risk differential associated with wholesale services at issue in this proceeding that would justify a lower ROE than is warranted for other capacity charges that are ultimately recovered from retail customers in APCO's Virginia service territory. Taken together, these considerations confirm the reasonableness of a 10.4% ROE for APCO.

II. FUNDAMENTAL ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to my quantitative analyses, this section briefly reviews the operations and finances of APCO. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion about investor expectations and requirements that form basis of a fair ROE.

A. APCO Company

Q. BRIEFLY DESCRIBE APCO AND ITS ELECTRIC UTILITY OPERATIONS.

A. APCO, a wholly-owned subsidiary of AEP, is principally engaged in the generation, transmission and distribution of electric power. APCO is the largest subsidiary within the AEP system and provides electric utility service to approximately 960,000 retail customers in the southwestern portion of Virginia and southern West Virginia. Among the principal industries served by APCo are coal mining, primary metals, and chemicals. The Company also provides electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities, and its affiliate, Kingsport Power Company ("Kingsport"). Kingsport, which purchases all of its electric power needs from APCO, provides electric service to approximately 47,000 retail customers in northeastern Tennessee.

APCo operates approximately 6,000 megawatts ("MW") of generating capacity and, along with other operating subsidiaries of AEP, is party to an interconnection agreement that defines how they share the costs and benefits associated with their respective generating plants. The Company's transmission and distribution facilities consist of over 52,000 miles of transmission and distribution lines. APCO is a member of PJM Interconnection, LLC ("PJM"), a FERC-approved Regional Transmission Organization ("RTO"), and has turned over functional control of its respective transmission facilities to PJM and provides regional transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT").

Q. PLEASE DESCRIBE AEP.

A. AEP delivers electricity to more than 5 million customers across 11 states, including Ohio, Indiana, West Virginia, Virginia, Kentucky, Michigan, Tennessee, Oklahoma, Texas, Louisiana, and Arkansas. AEP is one of the largest electric utilities in the U.S., with its combined utility system including approximately 37,000 MW of generating capacity and over 224,000 miles of transmission and distribution lines. During 2011, AEP's revenues totaled approximately $15.1 billion, with total assets at year-end of $52.2 billion.

Q. WHERE DOES APCO OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A. As a wholly-owned subsidiary of AEP, APCO obtains common equity capital solely from its parent, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by AEP, APCO also issues debt securities directly under its own name.

Q. DOES APCO ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A. Yes. APCO will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund new investment in electric generation, transmission and distribution facilities. AEP's capital spending for regulated operations is expected to total on the order of $3.4 - $3.5 billion in 2013 and 2014.[4] In addition to refinancing $1.2 billion in scheduled maturities over the next three years, combined construction expenditures at APCO are anticipated to total over $447 million in

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[4] American Electric Power Company, Inc., *Bank of America Merrill Lynch Power & Gas Leaders Conference*, New York, NY (Sep. 20, 2012).

2012 alone.[5] Support for APCO's financial integrity and flexibility will be instrumental in attracting the capital required to fund these needs in an effective manner.

Q. WHAT CREDIT RATINGS ARE ASSIGNED TO APCO?

A. Currently, APCO is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P"), while Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "Baa1". Fitch Ratings Ltd. ("Fitch") maintains a "BBB-" issuer default rating for APCO.

B. Electric Power Industry

Q. WHAT GENERAL CONDITIONS HAVE CHARACTERIZED THE ELECTRIC POWER INDUSTRY?

A. Since the 1990s, the industry has experienced significant structural change resulting from market forces and regulatory initiatives, with FERC being a proponent for actions designed to foster greater competition in markets for wholesale power supply. In 1996, FERC adopted Order No. 888,[6] which mandated open access to the wholesale transmission facilities of jurisdictional electric utilities. The Commission later addressed improvements to the transmission system, including the establishment of regional transmission organizations (RTO), and has continued to pursue the goal of creating "seamless" wholesale power markets that facilitate transactions across transmission grid boundaries, among other objectives.

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[5] *Id.*

[6] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

Q. WHAT PRINCIPAL FACTORS ARE CONSIDERED BY INVESTORS IN ASSESSING RISKS IN THE ELECTRIC UTILITY INDUSTRY?

A. Investors are aware of numerous challenges that impact their perceptions of the relative risks inherent in the utility industry and have implications for the financial standing of the utilities themselves, including APCO. In recent years, utilities and their customers have had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets, and investors recognize the potential for further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. While current expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. For example, recurring political crises in the Middle East have led to sharp increases in petroleum prices. Moody's concluded that utilities remain exposed to fluctuations in energy prices, observing, "This view, that commodity prices remain low, could easily be proved incorrect, due to the evidence of historical volatility."[7]

Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[8] As S&P recently noted:

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[7] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).
[8] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).

> To fund future capital spending, companies will need access to external capital markets for incremental funding beyond their internally generated cash – and maintaining solid credit quality will help them do so in a cost-effective and timely manner. … With the anticipated rise in capital spending needs, maintaining access to both the debt and equity markets, at favorable terms, will be crucial for these companies.[9]

As noted earlier, investors anticipate that APCO and AEP will undertake significant electric utility capital expenditures. While enhancing the infrastructure necessary to meet the energy needs of customers is certainly desirable, the magnitude of the associated capital expenditures imposes additional financial responsibilities that are heightened during times of capital market turmoil.

Increased environmental pressures and speculation over the potential costs associated with new regulatory mandates have also created uncertainties. Moody's noted that, "the sector is exposed to increasingly stringent environmental mandates."[10] While the momentum for carbon emissions legislation has slowed, expectations for eventual regulations continue to pose uncertainty, especially for utilities like APCO that rely significantly on coal-fired generating capacity. Fitch recently noted that it, "expects the thrust of the EPA's agenda will continue to challenge the creditworthiness of issuers in the utility and power sector."[11]

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[9] Standard & Poor's Corporation, "U.S. Utilities' Capital Spending Is Rising, And Cost Recovery Is Vital," *RatingsDirect* (May 14, 2012).
[10] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).
[11] Fitch Ratings Ltd., New EPA Rules: Ready or Not," *Special Report* (Mar. 1, 2012).

Q. HAVE INVESTORS RECOGNIZED THAT ELECTRIC UTILITIES FACE ADDITIONAL RISKS BECAUSE OF THE IMPACT OF INDUSTRY RESTRUCTURING ON TRANSMISSION OPERATIONS?

A. Yes. Transmission operations have become increasingly complex, and investors have recognized that difficulties in obtaining permits and uncertainty over the adequacy of allowed rates of return have contributed to heightened risk and fueled concerns regarding the adequacy of investment in the transmission sector of the electric power industry. At the same time, the development of competitive regional wholesale power markets and renewable generation has resulted in increased demand for transmission resources.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING ACCESS TO CAPITAL FOR APCO?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to APCO's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

The major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of current financial and operating pressures in the utility industry. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered firsthand how difficult and complex it can be to remedy the situation after the fact. Investors' increased reticence to supply additional capital during times of crisis highlights the need for regulatory decisions that preserve a utility's financial flexibility and recognize the importance of allowing an adequate ROE.

Q. HOW DOES THE ROE IN THIS CASE RELATE TO THE COMMISSION'S EFFORTS TO ENCOURAGE FUTURE INVESTMENT IN WHOLESALE INFRASTRUCTURE?

A. The Commission has achieved success in attracting an enormous commitment of private capital to expand the wholesale power system, reduce congestion, improve reliability, and secure access to new sources of generation, and utilities and their investors are answering the Commission's call for investment. Now that these commitments are being made, the Commission should be wary of imposing through regulation an ROE that is not sufficient to meet the requirements of competitive capital markets. Awarding a downward-biased ROE by mechanically applying a particular formula, without evaluating the outcome against regulatory standards or underlying policies, would undermine the confidence and expectations that the Commission has so carefully fostered over the past years.

Adopting inadequate ROEs for wholesale investment would have a chilling effect on investors' future willingness to support expansion of electric power infrastructure. It is only rational for potential investors to consider the current regulatory treatment afforded to utilities such as APCO in evaluating whether or not to commit new capital, and at what cost. If the Commission were to adopt an inadequate base ROE in this proceeding, the obvious conclusion for potential investors in wholesale electricity infrastructure is that the Commission is no longer willing to follow through on its promises of fair returns to investors over the medium and long-term. In those instances where there is no regulatory obligation to undertake system expansion, a downward-biased ROE that favors rote application of a formula over investors' requirements may thwart new entry and investment.

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. Establishing an ROE and capital structure that is sufficient to maintain APCO's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired.

C. Impact of Capital Market Conditions

Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. Investors have recently faced a myriad of challenges and uncertainties, with Value Line recently observing, "The situation is notably worse on the global front, where China is growing more slowly and Europe's outlook is deteriorating, particularly across its southern tier."[12] Meanwhile, there is ongoing speculation that the economy remains exposed to a potential "double-dip" recession, with unemployment remaining stubbornly high, concern over the "fiscal cliff" of mandated tax hikes and spending cuts scheduled for year-end, and continued weakness plaguing the real estate sector.

While stock prices have trended higher, market sentiment remains highly sensitive to disappointment, and Value Line recently noted, "we caution that stocks are

[12] The Value Line Investment Survey, *Selection and Opinion* (Oct. 12, 2012).

now more richly valued, making them vulnerable to possible event risks."[13] The dramatic rise in the price of gold also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. S&P noted that, "The effect of a potential financial collapse in the eurozone spreading to our shores is at the top of the list of events that could push the U.S. into recession."[14] With respect to utilities, Moody's has noted the dangers to credit availability associated with potential turmoil in the global credit markets.[15]

Q. DO CURRENT CAPITAL MARKET CONDITIONS PROVIDE A REPRESENTATIVE BASIS ON WHICH TO EVALUATE A FAIR ROE?

A. No. Current capital market conditions reflect the legacy of the Great Recession, but they are not representative of what investors expect in the future. As discussed earlier, investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds.

In an effort to jumpstart a flagging economy and bolster employment, the Federal Reserve has continued its policy of keeping short-term interest rates near zero, and implementing measures designed to push long-term rates to historically low levels. In

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[13] The Value Line Investment Survey, *Selection & Opinion* (Sep. 21, 2012).

[14] Standard & Poor's Corporation, "Economic Research: U.S. Economic Forecast: Just Like Ol' Times," *RatingsDirect* (Jan 12, 2012).

[15] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

September 2011, for example, the Federal Reserve announced "Operation Twist," involving the exchange of short-term Treasury instruments for longer-term government bonds, in an effort to put downward pressure on long-term interest rates. In addition, the Federal Reserve has repeatedly implemented "quantitative easing," which involves the central bank's purchase of long-term financial assets on the secondary market, in order to affect a reduction in long-term borrowing costs. While the Federal Reserve's actions have directly impacted the yields on government securities, they have continued to moderate corporate debt costs as well.

Q. HOW DO CURRENT YIELDS ON PUBLIC UTILITY BONDS COMPARE WITH WHAT INVESTORS HAVE EXPERIENCED IN THE PAST?

A. The yields on utility bonds are at their lowest levels in modern history. Figure WEA-1, below, compares the current yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

FIGURE WEA-1
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience.

Q. DO INVESTORS ANTICIPATE THAT THESE LOW INTEREST RATES WILL CONTINUE INTO THE FUTURE?

A. No they do not. It is widely anticipated that as the economy stabilizes and resumes a more robust pattern of growth, long-term capital costs will increase significantly from present levels. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):[16]

TABLE WEA-1
INTEREST RATE TRENDS

	Current (a)	2013	2014	2015	2016	2017
30-Yr. Treasury						
Value Line (b)	2.8%	3.7%	4.0%	4.6%	5.0%	--
IHS Global Insight (c)	2.8%	3.7%	4.1%	4.6%	5.4%	5.5%
Blue Chip (d)	2.8%	3.7%	4.2%	4.9%	5.3%	5.5%
AAA Corporate						
Value Line (b)	3.6%	4.4%	4.7%	5.5%	6.0%	
IHS Global Insight (c)	3.6%	4.4%	4.7%	5.5%	6.2%	6.3%
Blue Chip (d)	3.6%	4.4%	4.9%	5.6%	6.0%	6.2%
S&P (e)	3.6%	4.0%	4.7%	5.5%		
AA Utility						
IHS Global Insight (c)	3.8%	4.8%	5.2%	6.0%	6.7%	6.9%
EIA (f)	3.8%	5.0%	5.8%	6.7%	7.0%	7.1%

(a) Based on monthly average bond yields for the six-month period Apr. 2012 - Sep. 2012 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.
(b) Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 24, 2012)
(c) IHS Global Insight, *U.S. Economic Outlook* at 19 (May 2012)
(d) *Blue Chip Financial Forecasts,* Vol. 31, No. 6 (Jun. 1, 2012)
(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Keeping The Ball In Play," *RatingsDirect* (Aug. 17, 2012)
(f) Energy Information Administration, *Annual Energy Outlook 2012* (Jun. 25, 2012)

As evidenced above, there is a clear consensus that the cost of long-term capital will be significantly higher over the 2013-2017 period than it is currently.

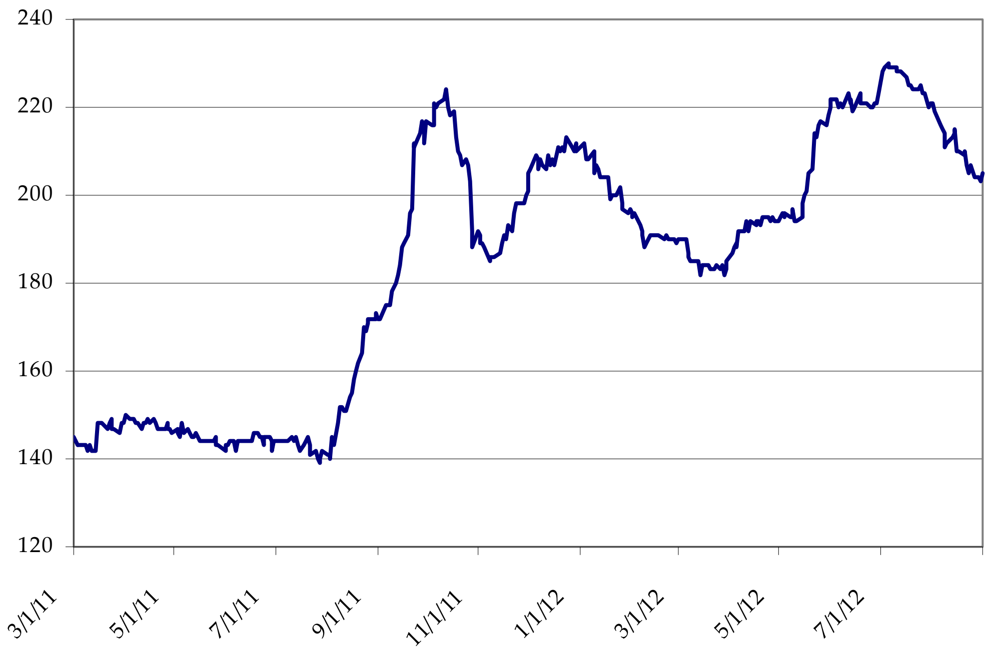
Q. DO TRENDS IN GOVERNMENT BOND YIELDS PROVIDE A BAROMETER FOR THE COST OF EQUITY CAPITAL FOR REGULATED ELECTRIC UTILITIES, SUCH AS APCO?

A. No. As noted earlier, Treasury bond yields have been pushed significantly lower due to a global "flight to safety" in the face of rising political, economic, and capital market risks, and as the result of Federal Reserve policies. In turn, this has led to a significant increase

[16] Value Line does not publish projections beyond 2016, or for double-A rated utility bond yields.

in risk premiums, as illustrated by the spreads between triple-B utility bond yields and 30-year Treasuries shown in Figure WEA-2, below:

FIGURE WEA-2
YIELD SPREAD (BASIS POINTS) – BBB UTILITY – 30-YR. TREASURY



This increase in the yield spread indicates that the additional compensation investors demand to take on higher risks has increased. As S&P observed:

> During periods of stress, correlations frequently increase among risky asset classes such as the relationship between the return on speculative-grade bonds and the return from equities.[17]

While the cost of equity cannot be directly observed in capital markets like the yields on bonds, there is every reason to believe that the required return to attract risk capital to utilities has increased relative to the yield on utility bonds. As illustrated below in Figure

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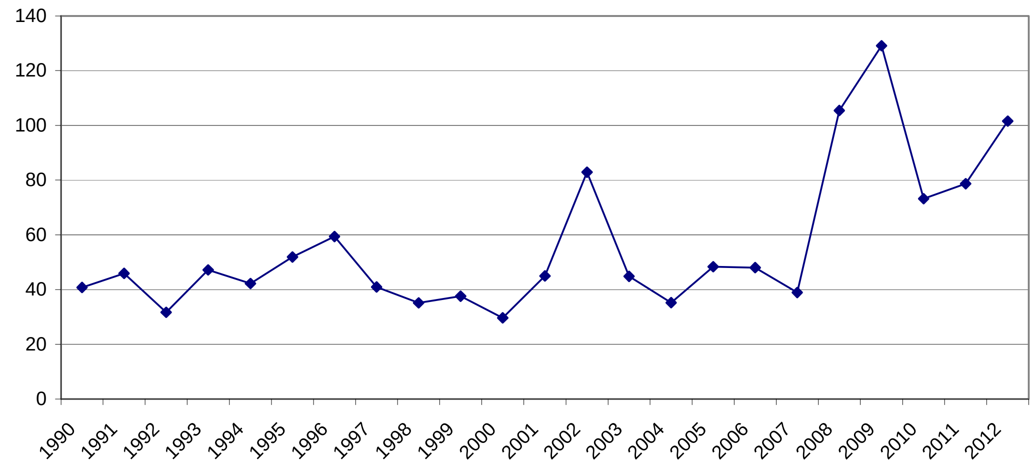
[17] Standard & Poor's Corporation, "Recent Expansion In Credit Spreads Shows Bond Market Stress, But Less Severe Than During The Financial Crisis," *RatingsDirect* (Oct. 11, 2011).

WEA-3, the spread between bonds of different ratings has clearly expanded in the last few years:

FIGURE WEA-3
YIELD SPREAD – BBB / AA UTILITY BONDS
(BASIS POINTS)



Sourc Source: Moody's Investors Service.

If investors require more additional return to bear the risk of BBB bonds relative to AA bonds, it is likely that they also require addition return to shift from the relative safety of bonds to the higher risk of utility equity.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR APCO?

A. Current capital market conditions continue to reflect the legacy of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets. As a result, current capital costs are not representative of what is likely to prevail over the near-term future, with this conclusion being demonstrated by comparisons to the historical record and independent forecasts. Recognized economic forecasting services project that long-term capital costs will increase from present levels, which should be considered in order to ensure that the ROE allowed in this proceeding will give APCO the ability to compete for capital with other opportunities of comparable risk.

III. FERC DCF APPROACH

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

A. In this section, I develop estimates of the cost of equity for a proxy group of comparable risk electric utilities using the Commission's DCF approach. First, I address the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe the specific DCF analyses I conducted to estimate the current cost of equity for the proxy group.

A. Cost of Equity Concept

Q. WHAT ROLE DOES THE RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as

$$k_i = R_f + RP_i$$

where: R_f = risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset is a function of: (1) the yield on risk-free assets; and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets—including common stock—required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line with respect to a claim on the utility's assets are common shareholders. They receive only the net revenues that remain, if any, after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Development and Selection of a Proxy Group

Q. HOW DID YOU IMPLEMENT THE DCF METHOD TO ESTIMATE THE COST OF COMMON EQUITY FOR THE PROJECTS?

A. Application of the DCF model to estimate the cost of equity requires observable capital market data, such as stock prices. Even for a firm with publicly traded stock, however, the cost of equity can only be estimated. As a result, applying quantitative models using observable market data produces a result that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk comparable. The results of the analysis for the sample of companies are relied upon to establish a range of reasonableness for the cost of equity applicable to the specific company at issue.

Q. WHAT SPECIFIC PROXY GROUP DID YOU RELY ON FOR YOUR ANALYSES?

A. My DCF analyses focused on a national group of other utilities that meet the following criteria:

1. Companies that are included in the Electric Utility Industry groups compiled by Value Line;
2. Electric utilities that paid common dividends over the last six months and have not announced a dividend cut since that time;
3. Electric utilities with no ongoing involvement in a major merger or acquisition;

4. Electric utilities that have been assigned an S&P corporate credit rating between "BBB-" and "BBB+", and have an investment-grade rating by Moody's;

5. Electric utilities that have been assigned a Value Line Safety Rank of "2" or "3";

6. Electric utilities with a market capitalization of approximately $1.6 billion or greater; and,

7. Companies with a published 5-year consensus earnings growth forecast from IBES, and coverage by at least two industry analysts.[18]

As shown on Exhibit No. AEP-402, these criteria resulted in a proxy group composed of 30 companies, which I refer to as the "National Group." This national group of risk-comparable utilities follows the same general approach approved in *SoCal Edison*.[19]

Q. WHAT WAS THE BASIS FOR THE RANGE OF S&P CREDIT RATINGS USED TO IDENTIFY THE NATIONAL GROUP?

A. In evaluating credit ratings to identify a proxy group of utilities with comparable risks, the Commission has adopted a "comparable risk band", interpreted as one "notch" higher or lower than the corporate credit ratings of the utility at issue and within the investment grade ratings scale.[20] As noted earlier, APCO has been assigned an S&P corporate credit rating of "BBB." Expanding this "BBB" rating by one notch, consistent with the Commission's guidelines, results in the "BBB-" to "BBB+" range used to identify the National Group.

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[18] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.
[19] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 51 (2010) ("*SoCal Edison*").
[20] *See, e.g., SoCal Edison*, 131 FERC ¶ 61,020 at P 53 (2010); *Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 77 (2008).

Q. IS THERE OBJECTIVE EVIDENCE THAT INVESTORS WOULD VIEW THE FIRMS IN THE NATIONAL GROUP AS RISK-COMPARABLE TO APCO?

A. Yes. My evaluation included a comparison of four objective measures of the investment risks associated with bonds and common stocks – S&P's corporate credit rating and Value Line's Safety Rank, Financial Strength Rating, and beta.

Credit ratings are assigned by independent rating agencies to provide investors with a broad assessment of the creditworthiness of a firm. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity. The Commission has determined that "corporate credit ratings are a reasonable measure to use to screen for investment risk," and concluded that, "[c]redit ratings are a key consideration in developing a proxy group that is risk-comparable."[21] The Commission has also determined that the comparable risk band afforded by its credit rating screen alone is a sufficient test of comparable investment risks.[22]

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Given that Value Line is perhaps the most widely available source of investment advisory

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[21] *Potomac-Appalachian Transmission Highline, LLC*, 133 FERC ¶ 61,152 at P 63 (2010).
[22] *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 52, n.70 (2011).

information, its rankings provide useful guidance regarding the risk perceptions of investors. The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Most Risky). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength.[23] The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUP COMPARE WITH APCO?

A. The average risk measures for the National Group are shown on Exhibit No. AEP-402, and summarized in Table WEA-2, below, along with comparable data for APCO:[24]

TABLE WEA-2
COMPARISON OF AVERAGE RISK INDICATORS

Proxy Group	S&P Credit Rating	Safety Rank	Value Line Financial Strength	Beta
National Group	BBB	2	B++	0.74

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[23] The Commission has previously considered Value Line's Safety Rank in evaluating relative risks. *Potomac-Appalachian Transmission Highline, LLC*, 133 FERC ¶ 61,152 at n.90.

[24] Because APCO does not have publicly traded common stock, Value Line does not publish risk measures for the Company. Accordingly, the average Value Line risk measures reflected in Table WEA-2 are based on data for its parent, AEP.

APCO	BBB	3	B++	0.70

Q. DOES THIS COMPARISON INDICATE THAT INVESTORS WOULD VIEW THE FIRMS IN YOUR PROXY GROUP AS RISK-COMPARABLE TO APCO?

A. Yes. The average S&P credit rating and Value Line Financial Strength Rating for the utilities in the National Group are identical to APCO. While Value Line's beta for AEP is lower than the proxy group average, its Safety Rank indicates greater risk. Considered together, these screening criteria, which reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, indicate that investors are likely to regard this group as having risks and prospects comparable to APCO.

C. Discounted Cash Flow Analysis

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. Thus, the cash flows that investors expect from a stock are estimated, and given the stock's current market price, we can back into the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Thus, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, after making certain assumptions, the DCF model can be simplified to a "constant growth" form:

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity;
g = Investors' long-term growth expectations.

The cost of equity (k_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. HOW DID YOU CALCULATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. Following Commission policy, average low and high indicated dividend yields were calculated for each electric utility during the six months from May through October 2012. As indicated on Exhibit No. AEP-403, these six-month average low and high historical dividend yields were also increased by one-half of the low and high growth rates discussed subsequently $(1 + 0.5g)$ to convert them to adjusted dividend yields.

Q. WHAT GROWTH RATES ARE USED IN THE COMMISSION'S ONE-STEP DCF METHOD FOR ELECTRIC UTILITIES?

A. The one-step DCF method for electric utilities adopted by the Commission employs two growth rates for each firm. The first growth rate is a "sustainable" growth rate calculated by the following formula:

$$g = br + sv$$

where:
b = expected retention ratio;
r = expected earned rate of return;
s = percent of common equity expected to be issued annually as new common stock;
v = equity accretion ratio.

The second growth rate is the IBES consensus 5-year earnings growth forecast. These two growth rates are combined with the adjusted dividend yields to develop a cost of equity range for each company.

Q. HOW DID YOU CALCULATE THE SUSTAINABLE GROWTH RATE?

A. For each electric utility, the expected retention ratio (b) was calculated based on projected dividends and earnings per share from Value Line for 2012, 2013, and their 2015-2017 forecast horizon. Consistent with the Commission's DCF method, each firm's expected earned rate of return (r) was based on Value Line's end-of-year forecasts.[25] In *Southern California Edison*, the Commission correctly recognized that if the rate of return, or "r" component of the br + sv growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year.[26] Accordingly, consistent with the Commission's findings and the theory underlying this approach to estimating investors' growth expectations, an adjustment was incorporated to compute an average rate of return.[27] Finally, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding over Value Line's forecast horizon, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio. The calculation of the sustainable growth rate for each electric utility in the National Group is shown on Exhibit No. AEP-404.

Q. WHAT ARE INVESTMENT ANALYSTS' PROJECTED GROWTH RATES FOR THE PROXY COMPANIES?

A. The five-year IBES earnings growth forecasts for each electric utility in the proxy group are shown in column (d) on Exhibit No. AEP-403.

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[25] *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 at P 19 (2008).
[26] *Southern California Edison Co.*, 92 FERC ¶ 61.070 at 61,263, n.38 (2000).
[27] Use of an average return in developing the sustainable growth rate is well supported. *See, e.g.*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-306, which discusses the need to adjust Value Line's end-of-year data, consistent with the Commission's findings.

Q. WHAT WERE THE RESULTS OF APPLYING THE COMMISSION'S ONE-STEP DCF APPROACH TO THE PROXY GROUP?

A. As shown on Exhibit No. AEP-403, application of the Commission's DCF model to the National Group resulted in current cost of equity estimates ranging from –9.4% to 15.2%.

D. Evaluation of DCF Results

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT ARE EXTREME OUTLIERS?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for the risk they assume. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF range must be adjusted to eliminate cost of equity estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

The practice of eliminating low-end outliers has been affirmed in numerous proceedings,[28] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it

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[28] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).

is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[29]

Q. WHAT DOES THE COMMISSION'S TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE NATIONAL GROUP?

A. As shown on Exhibit No. AEP-403, five utilities in the proxy group had low-end DCF estimates that ranged from –9.4% to 5.9%. All of these utilities are rated triple-B,[30] with Moody's monthly yields on triple-B utility bonds averaging approximately 4.8% over the six-month period ending October 2012.[31] These low-end DCF outliers are displayed in Table WEA-3, below, along with the implied spread above the average utility bond yield:

TABLE WEA-3
LOW-END DCF OUTLIERS

Company	S&P Rating	Low-end Dcf	BBB Bond Yield	Spread
Exelon Corp.	BBB	-9.4%	4.8%	-14.2%
PPL Corp.	BBB	-3.5%	4.8%	-8.3%
Ameren Corp.	BBB-	0.5%	4.8%	-4.3%
PG&E Corp.	BBB	2.7%	4.8%	-2.1%
Edison International	BBB-	5.9%	4.8%	1.1%

As shown above, these estimates were below current utility bond yields, or within approximately 100 basis points of this threshold. In light of the risk-return tradeoff principle and the tests applied by the Commission in prior decisions, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of

[29] *SoCal Edison*, 131 FERC ¶ 61,020 at P 55 (2010).
[30] Exhibit No. APC-102.
[31] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

economic logic applied by FERC, these values cannot be considered credible estimates of investors' required return on equity capital and should be excluded.

Q. WHAT ELSE SUPPORTS YOUR ELIMINATION OF THESE LOW-END ESTIMATES?

A. As indicated earlier, it is generally expected that long-term interest rates will rise as the economy and financial markets returns to more stable patterns. As shown in Table WEA-4 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 7.24% over the period 2013-2017:

TABLE WEA-4
IMPLIED BBB BOND YIELD

	2013-17
Projected AA Utility Yield	
IHS Global Insight (a)	5.92%
EIA (b)	6.33%
Average	6.13%
Current BBB - AA Yield Spread (c)	1.11%
Implied Triple-B Utility Yield	**7.24%**

(a) IHS Global Insight, U.S. Economic Outlook at 19 (May 2012)
(b) Energy Information Administration, Annual Energy Outlook 2012 (Jun. 25, 2012)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period May 2012 - Oct. 2012

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb on the order of 200 basis points through the period 2012 through 2018.[32] These projections suggest that my earlier evaluation of low-end DCF

[32] *Blue Chip Financial Forecasts*, Vol. 31, No. 6 (Jun. 1, 2012).

outliers is conservative, and would support excluding additional values at the low end of the DCF range.

Q. IS THERE ANY BASIS TO EXCLUDE THE 15.2% AND 14.8% COST OF EQUITY ESTIMATES AT THE HIGH END OF THE DCF RANGE?

A. No. In a November 2004 Order in *Bangor Hydro*, the Commission determined that a cost of equity estimate at the high end of the range of reasonableness might also be excluded if it is determined to be an extreme outlier.[33] The Commission found that a 17.7% cost of equity estimate for PPL Corporation ("PPL") was "extreme" and that including this result would "skew the results."[34] The Commission also expressed concern regarding the sustainability of the underlying 13.3% growth estimate for PPL,[35] and has also referenced this threshold as a test of reasonableness.[36]

The 15.2% and 14.8% high-end DCF estimates for Empire District Electric Company ("Empire District") and Great Plains Energy Inc. ("Great Plains") fall far below the 17.7% threshold established in *Bangor Hydro*. Similarly, the 10.2% and 10.5% growth rates underlying these cost of equity estimates are also significantly less than the 13.3% growth rate benchmark that has been used by the Commission to evaluate values at the high end of the DCF range. Moreover, the 15.2% and 14.8% values at the upper end of the DCF range are not "extreme outliers" when compared with the ROE

[33] *ISO New England, Inc., et al*, 109 FERC ¶ 61,147 at P 205 (2004) ("*Bangor Hydro*").
[34] *Id.*
[35] *Id.*
[36] *See, e.g., SoCal Edison*, 131 FERC ¶ 61,020 at P 57 (2010).

ranges approved by the Commission in the past.[37] Accordingly, these high-end cost of equity estimates are is properly included under the rationale adopted by the Commission.

In addition, while cost of equity estimates of 15.2% and 14.8% may exceed expectations for most electric utilities, remaining low-end estimates on the order of 6.1% to 6.9% are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return.

Q. EMPIRE DISTRICT CUT ITS DIVIDEND PAYMENT IN 2011. DOES THIS PROVIDE A BASIS FOR EXCLUDING THIS COMPANY FROM THE PROXY GROUP?

A. No. Following a tornado that hit Empire District's service territory on May 22, 1011, the utility's Board of Directors announced their decision to suspend dividend payments for the remainder of 2011.[38] The Board also indicated its expectation that the quarterly dividend would be reestablished at $0.25 per share after a two-quarter suspension. Empire District subsequently resumed regular quarterly dividend payments at $0.25 per share in the first quarter of 2012, which was well before the six-month period referenced for the stock prices and dividend payments used in my DCF analysis. And while this storm resulted in the loss of approximately 4000 poles and 100 miles of line in Empire District's distribution system, by year-end 2011 the utility announced that its system-wide

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[37] For example, the upper-end of the DCF range approved by the Commission for Tallgrass Transmission, LLC and Prairie Wind Transmission, LLC was 16.9%. *Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 78. The upper end of the DCF range approved by the Commission for Northern Pass Transmission LLC was 16.4%. *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 53 and Exhibit No. NPT-603.

[38] "The Empire District Electric Company Announces Temporary Suspension of Dividend, *Press Release* (May 25, 2011).

customer count was down by only 1,800 from previous levels.[39] Empire District has been accepted as a valid proxy by the Commission in prior proceedings,[40] and there is no justification to exclude it here.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO EXCLUDE PPL'S HIGH-END VALUE SIMPLY BECAUSE ITS LOW-END DCF ESTIMATE IS ILLOGICAL?

A. No. I do not believe that it is necessary or appropriate to remove a company from the proxy group altogether when just one of its DCF values fails the test of logic. Because there is no infallible method for assessing what the growth rate is precisely, it is customary to consider alternative growth estimates, with the IBES and sustainable, "br+sv" growth rates being two widely referenced proxies for investors' expectations. Reliance on these alternative growth sources is analogous to the logic underlying the use of a proxy group to estimate the cost of equity – the cost of equity is inherently unobservable and cannot be precisely estimated. Evaluating both IBES and sustainable growth rates recognizes the importance of examining alternative sources and approaches to estimate investors' growth expectations in order to reduce error and enhance confidence in the reliability of the DCF results. An illogical cost of equity estimate does not imply that the underlying company is not of comparable risk or otherwise unsuitable. The problem is not with the company, but with the particular DCF estimate. In other words, the particular application of the model to a specific set of data produces an illogical and therefore unreliable result.

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[39] "Empire District Electric Company Honored for Tornado Restoration," *Press Release* (Mar. 21, 2012).
[40] *See, e.g., Atlantic Grid Operations A LLC*, 135 FERC ¶ 61,144 at PP 13 n.11, 88 (2011); *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 45 n.58 and P 53 (2011); *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281 at P 94 n.85 (2009); *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 at P 78 n.82 (2008).

The two estimated growth rates relied on by the Commission – IBES and Value Line "br+sv" – are entirely distinct sources and employ alternative approaches to measure investors' growth expectations. The fact that one growth rate estimate may produce a cost of equity that fails tests of economic logic says nothing about the veracity of the second, independent value. In fact, it was the recognition that estimates can and do vary prompted the Commission to consider alternative growth measures in applying the DCF model. Each cost of equity estimate is evaluated for reasonableness on a stand-alone basis and there is no requirement for a symmetrical elimination of equal numbers of estimates at the high and low end. For example, the simple fact that a 5.0% cost of equity estimate is patently illogical when evaluated against observable yields on long-term utility debt says nothing whatsoever with respect to a second value of 10.9% for the same company derived using different input data. Similarly, there would be no reason to eliminate a DCF estimate of 9.0% simply because the a higher estimate for the same utility is considered to be an extreme outlier. While considering alternative growth rates helps to reduce the potential for skewed results by providing additional information regarding investors' expectations, once illogical values are eliminated there is no evidence to suggest that retaining all valid DCF estimates would somehow impose bias on the results. Indeed, the canons of statistical reasoning dictate that no data should be discarded unless it is found to be suspect on objective grounds.

Moreover, the fact that a single growth estimate may produce an illogical cost of equity estimate does not indicate some "flaw" associated with the specific utility that would justify excluding it from the proxy group. Rather, it only serves to illustrate that growth rates and the resulting cost of equity values are imperfect estimates of investors' required return. While PPL's high-end DCF value does not establish the upper end of my DCF range, there is nonetheless no economic basis for excluding it from consideration in evaluating the range of results.[41]

Q. WHAT IS THE ADJUSTED ROE RANGE FOR THE PROXY GROUP?

A. Eliminating the illogical low -end outliers shaded on Exhibit No. AEP-403 resulted in an adjusted range of reasonableness for the National Group ranging from 6.1% to 15.2%. As shown on Exhibit No. AEP-403, the midpoint of this ROE zone of reasonableness is 10.7%, with a median of 8.9%.

E. Evaluating an ROE Point Estimate

Q. WHAT ULTIMATELY GOVERNS THE SELECTION OF A POINT ESTIMATE FROM WITHIN THE ROE ZONE OF REASONABLENESS?

A. The Commission has recognized that a reasonable point-estimate ROE should be determined based on the facts specific to each proceeding, as the Commission explained in *Midwest ISO*:

> As an initial matter, we emphasize that the primary question to be considered here is not what constitutes the best overall method for determining ROE generically (i.e., the midpoint versus the median or mean); it is whether use of the midpoint is most appropriate in this case.[42]

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[41] The Commission has not uniformly eliminated proxy companies when one DCF value has been determined to be an outlier. In *Southern California Edison*, which established the Commission's DCF approach for electric utilities, the Commission eliminated the low-end return for one of the firms in the proxy group, while retaining the high-end value. *Southern California Edison Co.*, 92 FERC at 61,266 (2000). Again in *Atlantic Path 15*, the Commission determined an ROE range of reasonableness where the upper-end boundary was established using a high-end value for a utility whose low-end DCF estimate had been excluded. *Atlantic Path 15*, 122 FERC ¶ 61,135 at P 20 (2008); *Prepared Direct Testimony of James M. Coyne*, Exhibit. No. ATL-7 at 2. Similarly, in *Startrans IO, L.L.C.*, the Commission once more determined the ROE using a proxy group in which the low-end result for a utility was excluded but the high-end result was included. *Startrans IO, L.L.C.*, 122 FERC ¶ 61,306 at P 26 (2008).

[42] *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302 at P 8 (2004).

The paramount consideration that must be reflected in the choice of a point estimate is the need to ensure that the end result meets the standards mandated by the Supreme Court to ensure that a utility can attract capital.[43] This determination is not a quest to ordain a single statistical measure of central tendency. Rather, it challenges the Commission to consider the available evidence and identify an ROE that is just, reasonable, and sufficient to support the Commission's goal of encouraging investment in wholesale utility infrastructure.

Q. WHAT IS THE COMMISSION'S USUAL PRACTICE IN DETERMINING A POINT ESTIMATE FROM WITHIN THE ROE ZONE OF REASONABLENESS?

A. For an individual utility applicant, the Commission has most recently adopted the median in evaluating a point estimate from within the DCF zone of reasonableness.[44] When establishing a single ROE for a group of utilities within a transmission organization, the Commission applies the midpoint.[45]

Q. WOULD IT MAKE SENSE TO APPLY THIS GENERAL PRACTICE IN DETERMINING A FAIR ROE FOR APCO IN THIS CASE?

A. No. The 8.9% median value that currently results from the application of the Commission's DCF model falls far below a reasonable estimate of investors' required return, and would violate accepted regulatory standards because it would be inadequate to attract capital. As discussed subsequently, the results of other methods and prior ROE findings at the Commission confirm that this 8.9% value is not credible. Investors react

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[43] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 391, 1944).
[44] *See, e.g., Southern California Edison Co.*, 137 FERC ¶ 61,106 at P 25 (2011).
[45] *See, e.g., SoCal Edison*, 131 FERC ¶ 61,020 at P 90 (2010).

swiftly and negatively to evidence of waning regulatory support, and such an extreme outcome would severely undermine investor confidence and the Commission's policy goals.

Q. IS REFERENCE TO THE MEDIAN CONSISTENT WITH PAST PRECEDENT?

A. No. The recent Commission preference for the median is a break with historic precedent. Historically, the Commission was consistent in using the midpoint of the zone of reasonableness as the basis for allowed ROEs for electric utilities, as evidenced by *Southern California Edison* and numerous other electric cases.[46] For example, in *Consumers Energy*, the Commission reversed an initial decision in which the Presiding Judge had relied on the median of the zone of reasonableness, rather than the midpoint. The Commission concluded that:

> The precedent on which the judge and Staff rely in this instance was developed in the context of setting the rate of return for gas pipelines. In this case, there has been no reason provided to depart from our precedent in Opinion Nos. 445 and 446, setting the return at the midpoint of the zone of reasonableness.[47]

Q. WHAT RATIONALE DID THE COMMISSION ADVANCE TO SUPPORT ADOPTING THE MEDIAN, RATHER THAN THE MIDPOINT, IN SETTING THE ROE FOR AN INDIVIDUAL UTILITY?

A. The Commission determined that the median 1) "takes into account more of the companies in the proxy group", and 2) "minimizes the impact of a potentially skewed proxy group."[48]

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[46] *See, e.g., Utah Power and Light Co.*, 44 FERC ¶ 61,166 (1988); *Consumers Energy Co.*, 85 FERC ¶ 61,100 (1998).
[47] *Consumers Energy Co.*, 98 FERC ¶ 61,333, at 62,416 (2002).
[48] *SoCal Edison*, 131 FERC ¶ 61,020 at P 92 (2010).

Q. DO YOU AGREE THAT THE MEDIAN IS A SUPERIOR MEASURE OF CENTRAL TENDENCY WHEN EVALUATING THE ROE FOR A STAND-ALONE UTILITY?

A. No. I disagree with both of the findings underlying the Commission's decision to rely on the median DCF estimate when establishing the ROE for a single utility.

Q. DOES THE MEDIAN "TAKE INTO ACCOUNT MORE OF THE COMPANIES IN THE PROXY GROUP" THAN DOES THE MIDPOINT?

A. No. The median actually considers less information about the distribution of reasonable DCF results for the proxy group than does the midpoint. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a **single number**, *e.g.*, the sixth number in an eleven-number set. If the number of estimates is an even number, then the median is the arithmetic average of the two numbers falling in the middle. Thus, if there were twelve estimates, then the median would in fact be the average of the sixth and seventh estimates arrayed from highest to lowest. As such, the median doesn't expressly "take into account" any information regarding the individual DCF estimates for the proxy companies that are above or below the single number (or average of two single numbers) that fall in the middle of the distribution.

While arguments against the midpoint frequently hinge on the contention that this value relies on only the top and bottom numbers in the range and ignores the rest, this argument is incorrect. As the D.C. Circuit has held, "[t]he midpoint doesn't 'completely disregard the middle three numbers'; the highest and lowest numbers achieve their status by reference to all five numbers."[49] Consider this example of a five-estimate sample to illustrate the point made by the D.C. Circuit. The estimates are 8.0%, 8.1%, 8.2%, 15.0%, and 15.1%. The median is 8.2%, while the range is 8.0% to 15.1%, with a midpoint of 11.55%. The median of 8.2% does not reflect the range of values nor does it include information about the 15.0% 15.1% values that define the upper end of the range.

In fact, the median could be more readily criticized for under-weighting the results of the proxy group analysis, since it ignores the range of reasonable returns entirely. As the D.C. Circuit observed in approving the use of the midpoint for setting the ROE for the Midwest ISO:

> [P]etitioners [arguing in support of the median] are correct in noting that all measures of central tendency 'consider' the entire proxy group range, in the sense that all are influenced – at least indirectly – by each data point in the range. But only the midpoint *emphasizes* that range, as it is equally placed between the top and bottom values.[50]

The median's arbitrariness in its ability to reflect the full range of values can be illustrated by again considering the five-estimate sample referenced above, which had a median value of 8.2%. If the company corresponding to the 8.2% DCF estimate were excluded from the proxy group for some reason (*e.g.,* a merger announcement) the new median of the sample (now consisting of 8.0%, 8.1%, 15.0%, and 15.1% values) would be 11.6%. In other words, even though the range of reasonable results applicable to the proxy group did not change, the median value would increase by 340 basis points. The dramatic swing in median results in these two examples – from 8.2% initially to 11.6%

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[49] *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 298 (D.C. Cir. 2001).
[50] *Public Service Commission of the Commonwealth of Kentucky, v. FERC*, 397 F.3d 1004, 1010 (D.C. Cir. 2005).

when just one number was removed from a range of values that retained the same general pattern – reflects the arbitrary results that can be produced by the median and its inability to reliably reflect the characteristics of the DCF range. The purpose of the Commission's DCF analysis is to produce a zone of reasonableness, and the midpoint provides a better representation of a single ROE applicable to this range than does the median, which ignores the boundaries of the range entirely.

Q. DO CONCERNS OVER SKEWED DCF RESULTS FAVOR THE MEDIAN OVER THE MIDPOINT?

A. No. Calculation of the median does not involve any examination of the reasonableness of individual cost of equity estimates; rather, it is simply a single number that divides a set of observed values in two equal halves, so that half of the values are below it, and half are above. Moreover, the Commission's DCF approach already establishes a framework to address concerns over skewed results by evaluating and excluding individual cost of equity estimates that are extreme outliers. In others words, eliminating illogical low and high-end DCF estimates when evaluating the results of the Commission's DCF approach also negates this second rationale advanced for reliance on the median.

Q. DOES IT MAKE SENSE TO DISTINGUISH BETWEEN FILINGS INVOLVING INDIVIDUAL COMPANIES AND THOSE INVOLVING GROUPS OF REGIONAL UTILITIES WHEN EVALUATING CENTRAL TENDENCY?

A. No. As noted above, the outcome of the Commission's DCF approach is a zone of reasonableness that reflects investors' required rate of return for a proxy group that is comparable in risk to the applicant, irrespective of whether the filing concerns a stand-alone utility or multiple members of a regional organization. In each case the object of the analysis is to obtain a reasonable and reliable range of the unobservable cost of equity based on objective estimates that contain unknown errors. Given the importance of the zone of reasonableness in framing the ROE under the Commission's precedent for electric utilities, the midpoint is more relevant in establishing a central point estimate that expressly considers this range.

Moreover, establishing different measures of central tendency based on whether a party files as a single utility or as part of a joint filing made up of multiple companies within a region creates the potential that different ROEs could be established for the same utility, solely depending on the nature of the filing. Such a perverse economic outcome has no logical relationship to changes in underlying capital market conditions or investors' risk perceptions or requirements, and it directly contradicts the Commission's well-articulated policy goals of reducing regulatory impediments to investment in utility infrastructure and encouraging new capital investment, especially in transmission.

Q. HOW ELSE MIGHT THE COMMISSION APPROACH THE DETERMINATION OF A SINGLE POINT ESTIMATE FROM WITHIN THE ROE RANGE?

A. The Commission has recognized that the determination of a reasonable point-estimate ROE ultimately should be governed by the facts specific to each proceeding, as the Commission explained in *Midwest ISO*:

> As an initial matter, we emphasize that the primary question to be considered here is not what constitutes the best overall method for determining ROE generically (i.e., the midpoint versus the median or mean); it is whether use of the midpoint is most appropriate in this case.[51]

The paramount consideration that must be reflected in the choice of a point estimate is the need to ensure that the end result meets the standards mandated by the Supreme Court

[51] *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302 at P 8 (2004).

to ensure that a utility can attract capital.[52] This determination is not a quest to ordain a single statistical measure of central tendency. Rather, it challenges the Commission to consider the available evidence in this case and identify an ROE that is just, reasonable, and sufficient to support the Commission's goal of encouraging investment in wholesale utility infrastructure.

While I believe the midpoint provides a better representation of a single ROE applicable to the DCF zone of reasonableness, the Commission and other stakeholders might be better served by abandoning a policy of mechanistically determining the point estimate on a single statistic. Both the midpoint and the median are recognized statistical measures of central tendency and the Commission is free to weigh each of these values in its assessment of a fair ROE. As the Commission has recognized, "Each measure (median, average and midpoint) has advantages and drawbacks."[53] Considering both the midpoint and the median would be consistent with statistical principles, which favor retaining and evaluating all useful information in order to obtain the most reliable conclusion. Moreover, such a policy recognizes the inherent imprecision in estimating the cost of equity and the important role of informed judgment in evaluating the results of any quantitative analysis.

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[52] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 391, 1944).
[53] *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302 at P 11 (2004).

Q. WOULD THE COMMISSION INCREASE REGULATORY RISK BY ELECTING TO CONSIDER MORE THAN ONE STATISTICAL INDICATOR WHEN DETERMINING A FAIR ROE?

A. No. Investors are far more concerned with the end-result and the implications for the utility's finances than with adherence to specific rules or precedent. As S&P noted:

> As much as possible, regulators should, in our opinion, have the flexibility to react quickly and prudently to new situations as they develop. This is the sort of flexibility that we believe comes under principles-based regulation rather than rules-based regulation. In the latter, a regulator may attempt to set down every possible rule that can apply to a given situation that may arise in an industry. In the former, the regulator generally has the authority to achieve certain ends and some flexibility in how to achieve them.[54]

A mechanical policy of referencing only the median of the DCF estimates leaves the Commission with little flexibility when the result fails to reflect a fair and reasonable ROE, or is inadequate to support established policy goals. In this instance, any benefit of consistency is more than overwhelmed by the risks that an unresponsive, mechanical policy will lead to inadequate returns. The Commission has previously recognized the key role of regulatory standards in evaluating a measure of central tendency, and has affirmed that the preeminent consideration in establishing an ROE is to ensure a reasonable end-result.[55] The Commission has also acknowledged the dangers of

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[54] Standard & Poor's Corporation, "Executive Comment: What Characterizes Effective Regulation? Understanding, Manageability, And Consistency," *RatingsDirect* (May 5, 2010).

[55] *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302 at PP 13 & 14 (2004). The Commission observed that, "we are guided by the principle, enunciated by the Supreme Court, that an approved ROE should be 'reasonably sufficient to assure confidence in the financial soundness of the utility [or, in this case, utilities] and should be adequate under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.'" The Commission concluded, "we believe that the midpoint approach results in a ROE that is sufficient to assure confidence in the financial integrity of the member companies, so as to maintain credit and attract capital."

inflexible criteria in evaluating a fair ROE for transmission operations.[56] Thus, the Commission should not limit itself arbitrarily to the consideration of only certain types of evidence or the mechanical application of only a single type of analysis.

As discussed above, I do not support or recommend sole reliance on the median to evaluate the ROE for APCO. The median value for the proxy group of electric utilities produced using the Commission's DCF methodology falls significantly below the midpoint, and both should be evaluated using alternative ROE benchmarks, and in light of today's unique economic and financial conditions. This extreme downward bias, which is corroborated subsequently by the results of other methods, indicates that a median value of 8.9% is entirely inadequate to ensure APCO's ability to maintain credit and attract capital, and would undermine investors' confidence.

IV. FERC RISK PREMIUM MODEL

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

A. This section outlines the support for reference to additional ROE benchmarks in confirming the results of the DCF model, and evaluating a point estimate from within the zone of reasonableness. In addition, I present the results of a risk premium approach that is based directly on the Commission's prior findings with respect to the fair ROE for utilities under its jurisdiction. Considering the anomalous conditions that characterize today's capital markets, relying on past ROE determinations of the Commission provides an important reference point to evaluate current DCF results.

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[56] *Commonwealth Edison Co.*, 124 FERC ¶ 61,231 at fn. 30 (2008).

Q. WHAT EVIDENCE SUPPORTS YOUR REFERENCE TO ALTERNATIVE ROE BENCHMARKS?

A. I am well aware that the Commission has narrowed the focus of its ROE evaluation to a particular variant of the DCF approach. Nevertheless, because the cost of equity is unobservable, no single method should be viewed in isolation. Regulators have customarily considered the results of alternative approaches in determining allowed returns.[57] It is widely recognized that no single method can be regarded as a panacea; with all approaches having advantages and shortcomings. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[58]

As the Federal Communications Commission recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied

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[57] For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

[58] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.

> mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[59]

In addition, as I have discussed earlier, current capital market conditions are anomalous. Under these circumstances, I concluded that it is appropriate to test the results of the DCF analysis against a number of other ROE models and benchmarks, including the risk premium approach.

Q. HAS THE COMMISSION ALSO RECOGNIZED THAT IT MAY BE APPROPRIATE TO CONSIDER THE RESULTS OF ALTERNATIVE METHODS?

A. Yes. For example, the Commission concluded in *Distrigas of Massachusetts Corp.* that, "no one methodology is preferred to the exclusion of all others. The . . . DCF methodology, which we endorse, is but one analytical tool."[60] FERC has also granted that "[i]n some instances, the DCF methodology alone may be inappropriate,"[61] and in its decision in *Southern California Edison*, which first established the current DCF approach, the Commission noted that, "Should circumstances in the industry change, in the future, we will reevaluate our methodology, as necessary."[62] While electing not to make "broadly applicable changes to how the Commission has traditionally performed its DCF analysis," *Order No. 679* noted the opinion that "there is a benefit to introducing more information into the analysis process," and FERC indicated a willingness to

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[59] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).
[60] *Distrigas of Massachusetts. Corp.*, 41 FERC ¶ 61,205 at 61,550 (1987), *modified on reh'g,* 42 FERC ¶ 61,225 (1988).
[61] *Williston Basin Interstate Pipeline Co.*, 50 FERC ¶ 61,284 at 61,913 n.90 (1990), *vacated on other grounds*, 931 F.2d 949 (D.C. Cir. 1991).
[62] *Southern California Edison Co.*, 92 FERC at 61,070 (2000).

consider modifications to its standard approach on a case-by-case basis.[63] More recently, in *SoCal Edison*, the Commission determined that additional methods could be used to test or corroborate the results of its preferred DCF approach.[64] Consideration of alternative ROE benchmarks is consistent with Chairman Wellinghoff's view that, "I have not foreclosed considering variations on the DCF methodology or other methods to determine the cost of equity."[65]

Q. DR. AVERA, ARE YOU SAYING THAT A FAIR ROE FOR APCO SHOULD BE ESTABLISHED DIRECTLY ON THE ALTERNATIVE ANALYSES YOU PRESENT BELOW?

A. No. I recognize that the Commission has elected to rely primarily on the DCF model in establishing an ROE zone of reasonableness for utilities under its jurisdiction. However, I believe it is important to consider the results of other methods in evaluating a fair ROE, in order to either corroborate or call into question the ROE result arrived at using the DCF approach. The risk premium approach, along with the results of other methods discussed subsequently in my testimony, provides useful information in determining whether a proposed ROE is just and reasonable, or evaluating a fair ROE from within the DCF zone of reasonableness.

Q. BRIEFLY DESCRIBE THE RISK PREMIUM APPROACH.

A. The risk premium approach to common stocks the risk-return tradeoff observed with bonds. The cost of equity is estimated by first determining the additional return investors

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[63] *Order No. 679*, 116 FERC ¶ 61,057 at P 102 (2006); *Order No. 679-A*, 117 FERC ¶ 61,327 at P 63 (2006).
[64] *SoCal Edison*, 131 FERC ¶ 61,020 at P 116 (2010).
[65] *American Electric Power Service Corporation*, 118 FERC ¶ 61,041 (2007) (Commissioner Wellinghoff concurring).

require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM APPROACH?

A. I applied the risk premium approach directly using ROEs approved by the Commission for electric utilities since 2006 after the Energy Policy Act of 2005 was enacted. These authorized ROEs presumably reflect the Commission's best judgment of the cost of equity, however determined, at the time they were approved. Such returns should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, ROEs approved by the Commission are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. HAS THE COMMISSION STAFF PREVIOUSLY RECOGNIZED THE MERITS OF THIS RISK PREMIUM APPROACH?

A. Yes. In a 1992 study, FERC Staff observed that a risk premium approach based on previously authorized ROEs "provides a powerful tool to the Financial Analysis Branch to help it formulate its recommendations on electric utilities' cost of common equity."[66]

The Staff noted that:

> The results of our independent Risk Premium analysis are intended to complement the Discounted Cash Flow Model – the predominate model in use at the Commission.

This is exactly the approach I am recommending in this proceeding.

Q. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS USED IN YOUR STUDY?

A. As shown on page 2 of Exhibit No. AEP-405, the corresponding six-month average yield for triple-B public utility bonds is subtracted from the allowed ROE approved by the Commission to calculate an implied equity risk premium. In addition, because the Commission also routinely references 10-year Treasury bond yields in the context of updating ROE findings, I also developed implied equity risk premiums based on this series of government bond yields. As shown on page 4 of Exhibit No. AEP-405, between 2006 and 2012, the equity risk premium implied by the Commission's authorized ROEs for electric utilities averaged 4.10% over triple-B utility bond yields, and 7.33% over the yield on 10-year Treasury bonds.

Q. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM APPROACH?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[67] In

[66] *Risk Premium Study*, Federal Energy Regulatory Commission, Office of Electric Power Regulation, Division of Electric Power Investigation, Financial Analysis Branch, at 1-2 (Aug. 4, 1992).

other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Therefore, when implementing the risk premium method, adjustments are required to adjust for the fact that current interest rate levels are lower than the average interest rate level represented in the data set. As Staff noted in its 1992 report, "the lower the bond yield the higher the risk premium."[68]

Q. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM APPROACH BASED ON ROES APPROVED BY THE COMMISSION?

A. As shown on page 1 of Exhibit No. AEP-405, adding an equity risk premium corresponding to current interest rate levels to the average yield on triple-B utility bonds for the six-months ending October 2012 of 4.83% implies a current cost of equity for electric utilities of approximately 10.7%.[69] Similarly, applying the risk premium approach using 10-year Treasury bond yields also produces a current cost of equity of approximately 10.7%.

(. . . continued)

[67] *See, e.g.,* Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992). The California Public Utilities Commission also recognizes that the cost of equity does not move in tandem with interest rates, and its long-standing practice has been to adjust the cost of equity by one-half to two-thirds of the change in bond yields. *See, e.g.,* Decision 08-05-035 (May 29, 2008). Similarly, the Mississippi also relies on a risk premium approach that is directly analogous to my analysis here. *See, e.g.,* Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf.

[68] *Risk Premium Study*, Federal Energy Regulatory Commission, Office of Electric Power Regulation, Division of Electric Power Investigation, Financial Analysis Branch, at 6 (Aug. 4, 1992).

[69] As shown in Table WEA-4, the average rating for the National Group is "BBB." Accordingly, I based my application of the RPM on average yield for triple-B public utility bonds.

Q. WHAT OTHER BENCHMARKS ARE USEFUL IN EVALUATING A FAIR ROE FOR APCO?

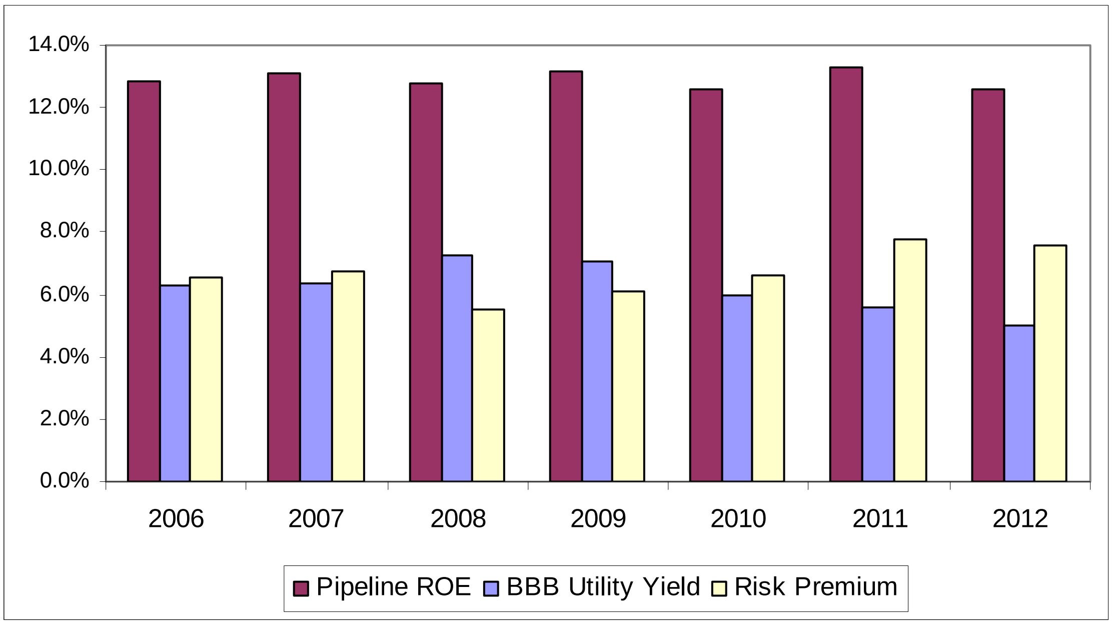
A. The Commission has previously rejected using DCF analyses for natural gas pipelines in establishing a fair ROE for electric utility operations because of differences between the two industries. Still, the Commission's ROE determinations for natural gas pipelines offer important information about a fair and reasonable ROE. Assuming that the differences between the natural gas pipeline and electric utility industries cited by the Commission are fairly stable over relatively short periods of time, allowed ROEs for gas pipeline operations provide another benchmark that is useful in evaluating a fair ROE for APCO.

Q. HOW DID YOU USE THE INFORMATION CONTAINED IN ROE DETERMINATIONS FOR NATURAL GAS PIPELINES TO DEVELOP AN ROE BENCHMARK FOR ELECTRIC UTILITIES?

A. If we assume that the risk differences between the natural gas pipeline and electric utility industries have remained relatively stable – and there is no evidence to the contrary – then the risk premium between the return that investors require to invest in gas pipelines versus electric utility operations should remain fairly constant. Accordingly, my analysis examined the historical ROE differential between the two industries, and then applied it to current allowed ROEs for natural gas pipelines to infer a corresponding ROE for electric utilities. As a result, this approach relies directly on the Commission's own determination as to the impact of relative industry risks and current returns.

Allowed ROEs approved by the Commission for natural gas pipelines for the years 2006 through 2012 are presented on pages 2 and 3 of Exhibit No. AEP-406, along with the implied equity risk premiums above triple-B public utility and 10-year Treasury bond yields. The average annual ROE, the corresponding average bond yields, and implied risk premiums are summarized on page 1 of Exhibit No. AEP-406, with equity risk premiums over utility bond yields being illustrated in Figure WEA-4, below:

FIGURE WEA-4
EQUITY RISK PREMIUM - GAS PIPELINE ROE VS. BBB UTILITY BOND YIELDS



As shown above, consistent with Commission-approved ROEs for electric utilities, the implied equity risk premiums for gas pipelines increase as interest rates decline, and vice versa.

Q. WHAT CURRENT COST OF EQUITY IS IMPLIED FOR AN ELECTRIC UTILITY BASED ON THESE ALLOWED ROES?

A. As shown in the lower portion of page 1 of Exhibit No. AEP-406, the average ROE for natural gas pipelines has exceeded the ROE approved by the Commission for electric utilities by 2.13% between 2006 and 2011.[70] Subtracting this spread from the 12.59%

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[70] As shown on page 1 of Exhibit No. APC-106, the average ROE for natural gas pipelines was 12.97%, versus 10.84% for electric utilities.

average ROE approved for natural gas pipelines during 2012 results in a current implied ROE for an electric utility of approximately 10.5%.

Q. DR. AVERA, ARE YOU SAYING THAT A FAIR ROE FOR APCO SHOULD BE ESTABLISHED DIRECTLY ON THESE RISK PREMIUM ANALYSES?

A. No. Again, I recognize that the Commission has elected to rely primarily on the DCF model in establishing an ROE zone of reasonableness for utilities under its jurisdiction. However, I believe it is important to consider the results of other methods in evaluating a fair ROE. As the Staff has previously recognized, these applications of the risk premium approach based on the Commission's own findings provide a powerful tool in evaluating where a fair ROE might lie within the DCF zone of reasonableness. Specifically, the results of both of these analyses based on prior Commission findings demonstrate that the 8.9% median value for the National Group is far too low to be considered credible, and that APCO's requested 10.4% ROE is generally consistent with the implications of the Commission's ROE findings since 2006.

V. OTHER ROE BENCHMARKS

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. I also evaluated the cost of equity for APCO against ROE benchmarks developed by: (1) applying the DCF model to a group of low-risk non-utility companies; (2) using the CAPM; and (3) reference to expected earned rates of return for electric utilities.

A. Non-Utility DCF Model

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR APCO?

A. Consistent with underlying economic and regulatory standards, I also applied the DCF model to a reference group of low-risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Group."

Q. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a wide range of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk.[71] Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER REQUIRED RETURNS FOR NON-UTILITY COMPANIES?

A. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.

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[71] Even for a single utility, capital will be allocated between competing uses in part based on opportunity costs. Where the utility has no regulatory obligation to undertake a particular project, an anemic return may foreclose investment altogether.

The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties."[72] It does not restrict consideration to other utilities. Indeed, if the requirement is business in the same part of the country and the utility has the exclusive franchise, then the Court could only be referring to non-utility businesses and any nearby utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[73]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a

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[72] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[73] *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 591, (1944)).

Financial Strength Rating of "B++" or greater; (4) have a beta less of 0.60 or less; and (5) have investment grade credit ratings from S&P.

Q. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE NATIONAL GROUP AND APCO?

A. Table WEA-5 compares the Non-Utility Group with the National Group and APCO across four objective indicators of investment risk:

TABLE WEA-5
COMPARISON OF RISK INDICATORS

		Value Line		
Proxy Group	S&P Credit Rating	Safety Rank	Financial Strength	Beta
Non-Utility Group	A	1	A+	0.58
National Group	BBB	2	B++	0.74
APCO	BBB	3	B++	0.70

As shown above, the average credit ratings, Safety Rank, Financial Strength Rating, and beta for the Non-Utility Group suggest less risk than for the proxy group of electric utilities and APCO. When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the National Group and APCO are greater than those of the firms in the Non-Utility Group.

The 13 companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Colgate-Palmolive, McDonalds, and Wal-Mart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A. The results of my DCF analysis for the Non-Utility Group are presented in Exhibit No. AEP-407, with the sustainable, br+sv growth rates being developed on Exhibit No. AEP-408. As shown there, after eliminating illogical values, application of the constant growth DCF model resulted in an ROE range of reasonableness of 7.3% to 16.6%, with a midpoint and median of 12.0%.

Q. HOW CAN YOU RECONCILE THESE DCF RESULTS FOR THE NON-UTILITY GROUP AGAINST THE SIGNIFICANTLY LOWER ESTIMATES PRODUCED FOR YOUR PROXY GROUP OF UTILITIES?

A. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As I documented earlier, the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and beta – are lower than the risks investors associate with the National Group. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for APCO. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector. In fact, considering the prominence of the 13 non-utility companies, the diversification afforded by considering multiple industries, and the scrutiny that analysts' afford to these paragons of American industry, the divergence between the DCF estimates for the group of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result.

B. Capital Asset Pricing Model

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. I also evaluated the cost of equity for APCO against ROE benchmarks developed using the CAPM. As noted above, the Commission has recognized that it may be appropriate to consider the results of alternative methods on a case-by-case basis, with the CAPM being the dominant model for estimating the cost of equity outside the regulatory sphere.[74] In contrast to applications of the CAPM using historical, realized rates of return, which have been largely rejected by the Commission in the past, my CAPM analysis specifically incorporated forward-looking expectations that are consistent with the assumptions of this approach.

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[74] *See*, *e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," *Financial Practice and Education* (1998).

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. The CAPM assumes that investors are fully diversified, so that the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole. Beta reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond relatively less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: Rj = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market.

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A. Application of the CAPM based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. AEP-409. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was based on the year-ahead projections obtained from Value Line. The growth rate was equal to the consensus earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 384 individual firms, current estimates imply an average growth rate over the next five years of 10.3%. Combining this average growth rate with an adjusted dividend yield of 2.6% results in a current cost of common equity estimate for the market as a whole of approximately 12.9%. Subtracting a 2.8% risk-free rate based on the average yield on 30-year Treasury bonds over the six months ended October 2012 produced a market equity risk premium of 10.1%.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly-based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[75]

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[75] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 71 (2006).

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[76]

Because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[77] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of 6.1% for a company in the first decile (market capitalization less than $207 million), to a reduction of 38 basis points for firms in the tenth decile (market capitalization between $15.5 billion and $354.4 billion). Accordingly, my CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by market capitalization.

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[76] *Morningstar*, "Ibbotson SBBI 2012 Valuation Yearbook," at p. 85.
[77] *Id.* at Table C-1.

Q. WHAT COST OF EQUITY ESTIMATE WAS INDICATED FOR THE NATIONAL GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. As shown on page 1 of Exhibit No. AEP-409, application of the forward-looking CAPM approach resulted in an unadjusted ROE range of 8.4% to 11.9%, with a midpoint cost of equity estimate of 10.1% and a median of 10.4%. After adjusting for the impact of firm size, the CAPM approach implied an ROE range of 8.0% to 13.7%, with a midpoint cost of equity estimate of 10.9% and a median of 11.3%.

Q. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight, and Blue Chip.

Q. WHAT COST OF EQUITY WAS PRODUCED BY THE CAPM AFTER INCORPORATING FORECASTED BOND YIELDS?

A. As shown on page 2 of Exhibit No. AEP-409, incorporating a forecasted yield for 2013-2017 implied an unadjusted CAPM range of 9.2% to 12.1%, with a midpoint cost of equity estimate of 10.6% and a median of 10.8%. After incorporating the impact of firm size, the CAPM approach implied an ROE range of 8.8% to 13.8%, with a midpoint cost of equity estimate of 11.3% and a median of 11.8%.

Q. SHOULD THE CAPM APPROACH BE APPLIED USING HISTORICAL RATES OF RETURN?

A. No. While investors undoubtedly consider historical information as one facet in their evaluation of future expectations, the cost of capital is a forward-looking concept. Because the CAPM is focused solely on the perceptions of today's capital market investors, it should not be applied using historical rates of return. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and the Federal Reserve has continued to employ various policy measures in order to effect a reduction in long-term borrowing costs. These policy measures and the "flight to safety" have pushed Treasury yields significantly lower. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely.

C. Expected Earnings Approach

Q. WHAT OTHER BENCHMARKS DID YOU DEVELOP TO EVALUATE THE ROE FOR APCO?

A. As I noted earlier, I also evaluated the ROE by reference to expected rates of return for electric utilities. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This approach is consistent with the economic underpinnings for a fair rate of return, as reflected in the comparable earnings test established by the Supreme Court in *Hope* and *Bluefield.* Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but fundamental concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital.

Q. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison. My application of the expected earnings approach was focused exclusively on forward-looking projections, not historical data.

Moreover, regulators do not set the returns that investors earn in the capital markets—they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5% over its 2015-2017 forecast horizon.[78] Meanwhile, for the firms in the National Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit No. AEP-410. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit No. AEP-404. As shown on

[78] The Value Line Investment Survey at 901 (Sep. 21, 2012).

Exhibit No. AEP-410, Value Line's projections for the National Group suggest an ROE range of 7.6% to 13.3%, with a midpoint of 10.4% and a median of 9.8%.

D. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN EVALUATING THE ROE FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds, with the need for a flotation cost adjustment having been documented in the financial literature.[79]

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[79] *See, e.g.*, Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly* (May, 2, 1985); Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF COMMON EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. While there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. A review of the finance literature and other studies of issuance costs prepared by the investment community suggest an average flotation cost percentage in the range of 3.6% to 10%.[80] Applying these expense percentages to a representative dividend yield for a utility of 4.5% implies a flotation cost adjustment on the order of 16 to 45 basis points. While my DCF range does not include an adjustment for flotation costs, this is a legitimate consideration in evaluating a fair ROE for APCO in this case.[81]

VI. ROE RECOMMENDATION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. The cost of equity estimates produced by the analyses described in my testimony are summarized in Table WEA-6, below:

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[80] *See, e.g.*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006); *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1.

[81] FERC Staff has previously recommended, and the Commission has approved, a flotation cost allowance in establishing a fair ROE. *See Golden Spread Electric Cooperative, Inc. et al.*, 115 FERC ¶ 63,043 at P 96 (2006), 123 FERC ¶ 61,047 at P 65 (2008).

TABLE WEA-6
SUMMARY OF COST OF EQUITY ESTIMATES

	Adjusted Range				
DCF Method	**Low**		**High**	**Midpoint**	**Median**
National Proxy Group	6.1%	--	15.2%	10.7%	8.9%
Non-Utility Proxy Group	7.3%	--	16.6%	12.0%	12.0%
FERC Allowed ROEs					
Utility - Current Bond Yields				10.7%	
Utility - Projected Bond Yields				10.9%	
Treasury - Current Bond Yields				10.7%	
Treasury - Projected Bond Yields				10.8%	
Gas Pipeline ROE Spread				10.5%	
CAPM - Current Bond Yields					
Unadjusted	8.4%	--	11.9%	10.1%	10.4%
Size Adjusted	8.0%	--	13.7%	10.9%	11.3%
CAPM - Projected Bond Yields					
Unadjusted	9.2%	--	12.1%	10.6%	10.8%
Size Adjusted	8.8%	--	13.8%	11.3%	11.8%
Expected Earnings Approach					
Value Line Electric Utilities				10.5%	
National Proxy Group	7.6%	--	13.3%	10.4%	9.8%

Q. WHAT ROE RANGE OF REASONABLENESS DOES THE COMMISSION'S DCF APPROACH INDICATE FOR APCO?

A. Based on the adjusted range of reasonableness produced by applying the Commission's DCF approach to the National Group, I recommend an ROE range of reasonableness of 6.1% to 15.2%.

Q. GIVEN THE RESULTS OF YOUR EVALUATION, WHAT IS YOUR CONCLUSION REGARDING THE REASONABLENESS OF THE 10.4% ROE REQUESTED BY APCO?

A. Based on my assessment of the relative strengths and weaknesses inherent in the alternative results, it is my opinion that 10.4% represents a reasonable ROE for APCO. The Commission has recognized that the determination of a reasonable point-estimate

ROE ultimately should be governed by the facts specific to each proceeding.[82] An ROE of 10.4% falls within the DCF zone of reasonable, is bracketed by the midpoint and median results, and is supported by the facts and circumstances in this case. As noted earlier, the ROE addressed here will apply to the RAA capacity charges assessed to AES providers of retail electric service in Virginia. The 10.4% ROE requested by APCO for the RRA is identical to the ROE recently approved by the SCC.

While ROEs approved in retail rate proceedings certainly do not limit the Commission's authority, there is a sound basis for using the same 10.4% ROE adopted by the SCC because RAA capacity charges are ultimately recovered from retail ratepayers in the Company's Virginia service territory. In other words, this is not a situation where a utility is asking the Commission to sanction the use of an ROE approved for retail customers for an entirely different set of wholesale customers. An ROE of 10.4% falls well within the ROE range of reasonableness determined by the Commission's DCF model, and there is no basis to distinguish the risks of capacity services provided under the RAA, versus those covered by retail rates established by the SCC.

Q. IS THE REASONABLENESS OF THIS CONCLUSION SUPPORTED BY OTHER ROE BENCHMARKS?

A. Yes. As discussed earlier in my testimony, current cost of equity estimates implied by prior ROEs approved by the Commission fall in the range of 10.5% to 10.9%. The DCF results for the Non-Utility Group also provide compelling evidence that suggests a significant downward bias in the 8.9% median value produced by the Commission's DCF approach for the National Group. While my recommended ROE range was based solely

[82] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302 at P 8 (2004).

on the results for the proxy group of utilities, I considered this downward bias in my evaluation of the base ROE from within the zone of reasonableness.

Applications of the CAPM implied an ROE on the order of 10.1% to 11.3%, or 10.6% to 11.8% after considering expectations for higher bond yields. Finally, expected returns for electric utilities also confirmed my conclusion that a median value of 8.9% falls far short of a reasonable ROE. The results of these alternative benchmarks confirm my conclusion that the 10.4% ROE requested by APCO is reasonable. Because these alternative indicators also consistently support an ROE that is considerably above the 8.9% median indicated by the Commission's DCF method for the proxy group of electric utilities, it is my conclusion that this value does not represent a credible estimate of investors' required rate of return.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH ESTABLISHED COMMISSION POLICY?

A. Yes. The Commission's supportive regulatory actions have been successful in promoting much needed investment in wholesale electric infrastructure. Unresponsive, mechanical decision making that favors consistency but leads to inadequate returns will undermine the Commission's goal and the legislative mandate to promote capital investment. The Commission has recognized the need to support wholesale power markets by adjusting its methods and instituting reforms in response to changed circumstances, as exemplified by *Order No. 1000*.[83] Evaluating alternative measures of central tendency and considering the results of well-accepted ROE benchmarks provides the Commission with the flexibility to ensure a reasonable end result that does not undermine its policy objectives.

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[83] *Order No. 1000*, 136 FERC ¶ 61,051 (2011).

Apart from the results of quantitative methods, it is crucial to recognize the importance of maintaining a strong financial position so that APCO remains prepared to respond to unforeseen events that may materialize in the future. While this imperative is reinforced by recent capital market conditions, it extends well beyond the financial markets and includes the APCO's ability to weather unsettled conditions in restructured power markets, as well as other development in the electric utility industry, such as heightened exposure to regulatory risks and the need for significant capital investment. My conclusions are reinforced by the need to consider flotation costs, and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond. Coupled with the need to provide an ROE that supports APCO's credit standing while funding substantial investments in utility infrastructure, these considerations indicate that a 10.4% ROE is reasonable and consistent with the facts and circumstances specific to this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Appalachian Power Company, Inc. **Docket No. ER13-____-000**

AFFIDAVIT OF WILLIAM E. AVERA

William E. Avera, being first duly sworn, deposes and says that he is the William E. Avera referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

William E. Avera

Subscribed and sworn to before me this 29th day of November, 2012.

Notary Public

Commission Expires on: 1/10/15

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

WILLIAM E. AVERA

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, *Economic Research Division*, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to

Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

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"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

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“Making Utility Regulation Work at the Public Utility Commission of Texas,” Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

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“Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation,” with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

NATIONAL GROUP

			(a)	(b)			(b)
			S&P	Value Line			
			Credit	Safety	Financial		Market
	Company	SYM	Rating	Rank	Strength	Beta	Cap
1	ALLETE	ALE	BBB+	2	A	0.70	$1,543
2	Alliant Energy	LNT	BBB+	2	A	0.70	$5,077
3	Ameren Corp.	AEE	BBB-	3	B++	0.80	$8,062
4	American Elec Pwr	AEP	BBB	3	B++	0.70	$20,009
5	Avista Corp.	AVA	BBB	2	A	0.70	$1,591
6	Black Hills Corp.	BKH	BBB-	3	B+	0.80	$1,383
7	CenterPoint Energy	CNP	BBB+	2	B++	0.80	$8,815
8	DTE Energy Co.	DTE	BBB+	3	B+	0.75	$10,076
9	Edison International	EIX	BBB-	3	B+	0.75	$15,075
10	El Paso Electric	EE	BBB	2	B++	0.70	$1,361
11	Empire District Elec	EDE	BBB-	2	B++	0.65	$896
12	Exelon Corp.	EXC	BBB	2	A	0.80	$32,008
13	FirstEnergy Corp.	FE	BBB-	2	B++	0.80	$20,526
14	Great Plains Energy	GXP	BBB	3	B+	0.75	$2,990
15	Hawaiian Elec.	HE	BBB-	3	B++	0.70	$2,769
16	IDACORP, Inc.	IDA	BBB	3	B+	0.70	$2,150
17	NorthWestern Corp.	NWE	BBB	3	B+	0.70	$1,363
18	OGE Energy Corp.	OGE	BBB+	2	A	0.75	$5,060
19	Otter Tail Corp.	OTTR	BBB-	3	B+	0.90	$846
20	Pepco Holdings	POM	BBB+	3	B	0.75	$4,403
21	PG&E Corp.	PCG	BBB	3	B++	0.55	$18,775
22	Pinnacle West Capital	PNW	BBB	2	B++	0.70	$5,716
23	Portland General Elec.	POR	BBB	2	B++	0.75	$2,034
24	PPL Corp.	PPL	BBB	3	B++	0.65	$16,308
25	Pub Sv Enterprise Grp	PEG	BBB	2	A	0.75	$16,320
26	SCANA Corp.	SCG	BBB+	2	B++	0.65	$6,296
27	Sempra Energy	SRE	BBB+	2	A	0.80	$16,457
28	TECO Energy	TE	BBB+	2	B++	0.85	$3,902
29	UIL Holdings	UIL	BBB	2	B++	0.70	$1,864
30	Westar Energy	WR	BBB	2	B++	0.75	$3,846
			BBB	**2**	**B++**	**0.74**	**$7,917**

(a) Corporate credit rating from www.standardandpoors.com (retrieved Oct. 15, 2012).
(b) The Value Line Investment Survey (Aug. 24, Sep. 21, & Nov. 2, 2012).

FERC DCF MODEL **Exhibit No. AEP-403**

NATIONAL GROUP

		(a)		(b)		(c)	(d)				
		6 Mo. Div. Yield		Adjusted Div. Yield		Growth Rates		Implied Cost of Equity			
	Company	**Low**	**High**	**Low**	**High**	**br + sv**	**IBES**	**Low**		**High**	**Average**
1	ALLETE	4.4%	4.6%	4.5%	4.7%	3.7%	6.0%	8.2%	--	10.7%	9.5%
2	Alliant Energy	3.9%	4.1%	4.0%	4.2%	4.4%	5.8%	8.4%	--	10.0%	9.2%
3	Ameren Corp.	4.7%	5.0%	4.6%	5.1%	2.2%	-4.1%	0.5%	--	7.3%	--
4	American Elec Pwr	4.4%	4.7%	4.5%	4.8%	4.0%	3.4%	7.9%	--	8.8%	8.4%
5	Avista Corp.	4.3%	4.6%	4.4%	4.7%	2.5%	4.0%	6.9%	--	8.7%	7.8%
6	Black Hills Corp.	4.3%	4.6%	4.3%	4.7%	2.3%	6.0%	6.6%	--	10.7%	8.7%
7	CenterPoint Energy	3.8%	4.0%	3.9%	4.1%	4.8%	6.1%	8.7%	--	10.2%	9.5%
8	DTE Energy Co.	3.9%	4.2%	4.0%	4.3%	3.8%	4.8%	7.8%	--	9.1%	8.5%
9	Edison International	2.8%	2.9%	2.8%	3.0%	4.4%	3.1%	5.9%	--	7.4%	--
10	El Paso Electric	2.9%	3.1%	3.0%	3.2%	5.5%	3.7%	6.7%	--	8.7%	
11	Empire District Elec	4.6%	4.8%	4.7%	5.0%	2.3%	10.2%	7.0%	--	15.2%	11.1%
12	Exelon Corp.	5.4%	5.8%	5.0%	5.9%	5.0%	-14.4%	-9.4%	--	10.9%	--
13	FirstEnergy Corp.	4.5%	4.9%	4.6%	5.0%	2.7%	2.5%	7.1%	--	7.7%	7.4%
14	Great Plains Energy	3.9%	4.1%	3.9%	4.3%	2.2%	10.5%	6.1%	--	14.8%	10.5%
15	Hawaiian Elec.	4.4%	4.7%	4.5%	4.9%	4.5%	7.9%	9.0%	--	12.8%	10.9%
16	IDACORP, Inc.	3.1%	3.3%	3.2%	3.4%	4.9%	4.0%	7.2%	--	8.3%	7.8%
17	NorthWestern Corp.	4.0%	4.2%	4.1%	4.3%	3.7%	6.7%	7.8%	--	11.0%	9.4%
18	OGE Energy Corp.	2.8%	3.0%	2.9%	3.1%	6.9%	5.4%	8.3%	--	10.0%	9.2%
19	Otter Tail Corp.	5.1%	5.4%	5.1%	5.5%	1.5%	5.0%	6.6%	--	10.5%	8.6%
20	Pepco Holdings	5.5%	5.7%	5.5%	5.8%	1.7%	4.9%	7.2%	--	10.7%	9.0%
21	PG&E Corp.	4.0%	4.2%	4.0%	4.3%	3.3%	-1.3%	2.7%	--	7.6%	--
22	Pinnacle West Capital	4.0%	4.2%	4.1%	4.3%	4.0%	5.9%	8.1%	--	10.2%	9.2%
23	Portland General Elec.	3.9%	4.1%	4.0%	4.2%	3.7%	3.4%	7.4%	--	7.9%	7.7%
24	PPL Corp.	4.9%	5.2%	4.7%	5.4%	6.8%	-8.2%	-3.5%	--	12.2%	--
25	Pub Sv Enterprise Grp	4.3%	4.5%	4.3%	4.6%	5.0%	2.0%	6.3%	--	9.6%	8.0%
26	SCANA Corp.	4.0%	4.2%	4.1%	4.3%	4.7%	5.0%	8.8%	--	9.3%	9.1%
27	Sempra Energy	3.5%	3.7%	3.6%	3.8%	5.1%	7.0%	8.7%	--	10.8%	9.8%
28	TECO Energy	4.8%	5.1%	4.9%	5.2%	4.4%	3.3%	8.2%	--	9.6%	8.9%
29	UIL Holdings	4.7%	5.0%	4.8%	5.1%	2.4%	4.1%	7.2%	--	9.2%	8.2%
30	Westar Energy	4.3%	4.6%	4.4%	4.7%	3.1%	4.8%	7.5%	--	9.5%	8.5%
	Range of Reasonableness							**-9.4%**	--	**15.2%**	
	Adjusted Range of Reasonableness (e)							**6.1%**	--	**15.2%**	
	Midpoint								**10.7%**		
	Median (f)										**8.9%**

(a) Six-month average dividend yield for May - Oct. 2012.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) See Exhibit No. AEP-404.
(d) www.finance.yahoo.com (retrieved Nov. 5, 2012).
(e) Excludes highlighted values.
(f) Based on the average of the low and high DCF estimates for all companies with two valid observations.

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		(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(c)	(c)	(d)	(e)		
		2012				2013				2016						Adjustment		Avg	Avg
	Company	EPS	DPS	b	r	EPS	DPS	b	r	EPS	DPS	b	r	Avg b	Avg r	Factor	Adjstd r	br	br + sv
1	ALLETE	$2.55	$1.84	27.8%	8.5%	$2.70	$1.88	30.4%	8.5%	$3.75	$2.10	44.0%	10.5%	34.1%	9.2%	1.0382	9.5%	3.2%	**3.7%**
2	Alliant Energy	$2.95	$1.80	39.0%	10.0%	$3.10	$1.90	38.7%	10.0%	$3.60	$2.20	38.9%	11.0%	38.9%	10.3%	1.0222	10.6%	4.1%	**4.4%**
3	Ameren Corp.	$2.40	$1.61	32.9%	7.5%	$2.25	$1.65	26.7%	7.0%	$2.50	$1.80	28.0%	7.5%	29.2%	7.3%	1.0100	7.4%	2.2%	**2.2%**
4	American Elec Pwr	$3.10	$1.90	38.7%	10.0%	$3.10	$1.96	36.8%	9.5%	$3.50	$2.15	38.6%	9.5%	38.0%	9.7%	1.0222	9.9%	3.8%	**4.0%**
5	Avista Corp.	$1.50	$1.16	22.7%	7.0%	$1.70	$1.20	29.4%	8.0%	$2.00	$1.30	35.0%	8.5%	29.0%	7.8%	1.0200	8.0%	2.3%	**2.5%**
6	Black Hills Corp.	$1.85	$1.48	20.0%	6.5%	$2.20	$1.50	31.8%	8.0%	$2.50	$1.60	36.0%	8.0%	29.3%	7.5%	1.0126	7.6%	2.2%	**2.3%**
7	CenterPoint Energy	$1.25	$0.81	35.2%	12.0%	$1.30	$0.83	36.2%	12.0%	$1.50	$0.90	40.0%	12.0%	37.1%	12.0%	1.0263	12.3%	4.6%	**4.8%**
8	DTE Energy Co.	$3.85	$2.42	37.1%	8.5%	$3.95	$2.52	36.2%	9.0%	$4.75	$2.80	41.1%	9.5%	38.1%	9.0%	1.0257	9.2%	3.5%	**3.8%**
9	Edison International	$2.60	$1.31	49.6%	8.5%	$2.65	$1.33	49.8%	8.0%	$3.25	$1.55	52.3%	9.0%	50.6%	8.5%	1.0190	8.7%	4.4%	**4.4%**
10	El Paso Electric	$2.25	$0.97	56.9%	11.0%	$2.25	$1.06	52.9%	10.5%	$2.50	$1.30	48.0%	10.5%	52.6%	10.7%	1.0218	10.9%	5.7%	**5.5%**
11	Empire District Elec	$1.25	$1.00	20.0%	7.5%	$1.40	$1.00	28.6%	8.0%	$1.75	$1.20	31.4%	9.0%	26.7%	8.2%	1.0151	8.3%	2.2%	**2.3%**
12	Exelon Corp.	$2.00	$2.10	-5.0%	7.5%	$2.85	$2.10	26.3%	11.0%	$3.50	$2.10	40.0%	12.5%	20.4%	10.3%	1.0497	10.8%	2.2%	**5.0%**
13	FirstEnergy Corp.	$2.80	$2.20	21.4%	8.5%	$3.10	$2.20	29.0%	9.5%	$3.75	$2.40	36.0%	10.0%	28.8%	9.3%	1.0153	9.5%	2.7%	**2.7%**
14	Great Plains Energy	$1.35	$0.86	36.3%	6.0%	$1.40	$0.88	37.1%	6.5%	$1.75	$1.10	37.1%	7.5%	36.9%	6.7%	1.0218	6.8%	2.5%	**2.2%**
15	Hawaiian Elec.	$1.60	$1.24	22.5%	10.0%	$1.70	$1.24	27.1%	9.5%	$2.00	$1.40	30.0%	10.0%	26.5%	9.8%	1.0478	10.3%	2.7%	**4.5%**
16	IDACORP, Inc.	$3.30	$1.37	58.5%	9.5%	$3.25	$1.52	53.2%	8.5%	$3.40	$1.90	44.1%	8.5%	51.9%	8.8%	1.0237	9.0%	4.7%	**4.9%**
17	NorthWestern Corp.	$2.25	$1.48	34.2%	9.0%	$2.30	$1.52	33.9%	9.0%	$2.75	$1.80	34.5%	10.0%	34.2%	9.3%	1.0257	9.6%	3.3%	**3.7%**
18	OGE Energy Corp.	$3.50	$1.59	54.6%	12.5%	$3.65	$1.66	54.5%	12.0%	$4.00	$1.90	52.5%	11.0%	53.9%	11.8%	1.0339	12.2%	6.6%	**6.9%**
19	Otter Tail Corp.	$1.10	$1.19	-8.2%	7.0%	$1.25	$1.19	4.8%	7.0%	$1.85	$1.30	29.7%	9.5%	8.8%	7.8%	1.0335	8.1%	0.7%	**1.5%**
20	Pepco Holdings	$1.20	$1.08	10.0%	6.0%	$1.30	$1.12	13.8%	7.0%	$1.70	$1.16	31.8%	8.0%	18.5%	7.0%	1.0236	7.2%	1.3%	**1.7%**
21	PG&E Corp.	$2.25	$1.82	19.1%	7.5%	$2.75	$1.82	33.8%	8.5%	$3.50	$2.00	42.9%	10.0%	31.9%	8.7%	1.0292	8.9%	2.8%	**3.3%**
22	Pinnacle West Capital	$3.45	$2.12	38.6%	9.5%	$3.50	$2.20	37.1%	9.5%	$3.75	$2.45	34.7%	9.0%	36.8%	9.3%	1.0245	9.6%	3.5%	**4.0%**
23	Portland General Elec.	$1.90	$1.08	43.2%	8.0%	$1.95	$1.11	43.1%	8.0%	$2.25	$1.25	44.4%	9.0%	43.6%	8.3%	1.0184	8.5%	3.7%	**3.7%**
24	PPL Corp.	$2.55	$1.44	43.5%	12.5%	$2.40	$1.48	38.3%	10.5%	$3.00	$1.70	43.3%	11.5%	41.7%	11.5%	1.0492	12.1%	5.0%	**6.8%**
25	Pub Sv Enterprise Grp	$2.45	$1.42	42.0%	11.5%	$2.50	$1.46	41.6%	11.0%	$3.00	$1.55	48.3%	11.0%	44.0%	11.2%	1.0253	11.4%	5.0%	**5.0%**
26	SCANA Corp.	$3.15	$1.98	37.1%	10.0%	$3.35	$2.02	39.7%	9.5%	$3.75	$2.15	42.7%	9.5%	39.8%	9.7%	1.0457	10.1%	4.0%	**4.7%**
27	Sempra Energy	$4.20	$2.40	42.9%	10.0%	$4.25	$2.50	41.2%	10.0%	$5.75	$2.80	51.3%	11.5%	45.1%	10.5%	1.0245	10.8%	4.9%	**5.1%**
28	TECO Energy	$1.25	$0.88	29.6%	11.5%	$1.30	$0.90	30.8%	11.5%	$1.65	$1.00	39.4%	13.0%	33.3%	12.0%	1.0247	12.3%	4.1%	**4.4%**
29	UIL Holdings	$2.10	$1.73	17.6%	9.5%	$2.30	$1.73	24.8%	10.0%	$2.45	$1.73	29.4%	9.5%	23.9%	9.7%	1.0163	9.8%	2.4%	**2.4%**
30	Westar Energy	$1.95	$1.32	32.3%	8.5%	$2.05	$1.36	33.7%	8.0%	$2.40	$1.48	38.3%	8.5%	34.8%	8.3%	1.0318	8.6%	3.0%	**3.1%**

BR + SV GROWTH RATE

NATIONAL PROXY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(a)	(h)	(a)	(a)	(g)	(i)	(j)	
		2011			2016			Chg	2016 Price			2016		No. Shares			"sv" Factor		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	BVPS	M/B	2011	2016	Growth	s	v	sv
1	ALLETE	55.7%	$1,937	$1,079	56.0%	$2,825	$1,582	8.0%	$50.00	$35.00	$42.50	$35.00	1.214	37.5	41.5	2.05%	0.0249	0.1765	0.44%
2	Alliant Energy	50.9%	$5,921	$3,014	50.5%	$7,455	$3,765	4.5%	$55.00	$40.00	$47.50	$32.60	1.457	111.0	115.0	0.71%	0.0103	0.3137	0.32%
3	Ameren Corp.	53.7%	$14,738	$7,914	54.0%	$16,200	$8,748	2.0%	$45.00	$30.00	$37.50	$34.50	1.087	242.6	255.0	1.00%	0.0109	0.0800	0.09%
4	American Elec Pwr	49.3%	$29,747	$14,665	51.0%	$35,900	$18,309	4.5%	$55.00	$40.00	$47.50	$36.75	1.293	483.4	500.0	0.68%	0.0087	0.2263	0.20%
5	Avista Corp.	48.6%	$2,440	$1,186	47.5%	$3,050	$1,449	4.1%	$30.00	$25.00	$27.50	$23.25	1.183	58.4	62.0	1.20%	0.0142	0.1545	0.22%
6	Black Hills Corp.	48.6%	$2,490	$1,210	49.0%	$2,800	$1,372	2.5%	$40.00	$25.00	$32.50	$30.50	1.066	43.9	45.0	0.49%	0.0052	0.0615	0.03%
7	CenterPoint Energy	32.8%	$12,863	$4,219	39.5%	$13,900	$5,491	5.4%	$25.00	$17.00	$21.00	$12.75	1.647	426.0	432.0	0.28%	0.0046	0.3929	0.18%
8	DTE Energy Co.	49.4%	$14,196	$7,013	49.0%	$18,500	$9,065	5.3%	$70.00	$50.00	$60.00	$49.75	1.206	169.3	181.0	1.35%	0.0163	0.1708	0.28%
9	Edison International	40.6%	$24,773	$10,058	38.5%	$31,600	$12,166	3.9%	$55.00	$35.00	$45.00	$37.50	1.200	325.8	325.8	0.00%	-	0.1667	0.00%
10	El Paso Electric	48.2%	$1,577	$760	45.0%	$2,100	$945	4.5%	$45.00	$30.00	$37.50	$24.50	1.531	40.0	39.0	-0.49%	(0.0074)	0.3467	-0.26%
11	Empire District Elec	50.1%	$1,386	$694	50.5%	$1,600	$808	3.1%	$25.00	$19.00	$22.00	$18.50	1.189	42.0	43.3	0.60%	0.0071	0.1591	0.11%
12	Exelon Corp.	54.0%	$26,661	$14,397	52.5%	$45,100	$23,678	10.5%	$55.00	$40.00	$47.50	$28.75	1.652	663.0	820.0	4.34%	0.0717	0.3947	2.83%
13	FirstEnergy Corp.	45.8%	$28,996	$13,280	45.0%	$34,400	$15,480	3.1%	$60.00	$45.00	$52.50	$37.00	1.419	418.2	418.2	0.00%	-	0.2952	0.00%
14	Great Plains Energy	51.6%	$5,741	$2,962	55.0%	$6,700	$3,685	4.5%	$25.00	$17.00	$21.00	$24.00	0.875	136.1	153.5	2.43%	0.0213	(0.1429)	-0.30%
15	Hawaiian Elec.	53.9%	$2,841	$1,531	54.0%	$4,575	$2,471	10.0%	$30.00	$25.00	$27.50	$20.25	1.358	96.0	122.0	4.90%	0.0666	0.2636	1.75%
16	IDACORP, Inc.	54.4%	$3,045	$1,657	52.5%	$4,000	$2,100	4.9%	$55.00	$35.00	$45.00	$39.35	1.144	50.0	53.0	1.19%	0.0136	0.1256	0.17%
17	NorthWestern Corp.	47.8%	$1,797	$859	50.5%	$2,200	$1,111	5.3%	$45.00	$30.00	$37.50	$28.50	1.316	36.3	38.5	1.19%	0.0157	0.2400	0.38%
18	OGE Energy Corp.	48.4%	$5,300	$2,565	49.0%	$7,350	$3,602	7.0%	$65.00	$50.00	$57.50	$35.75	1.608	98.1	101.0	0.58%	0.0094	0.3783	0.36%
19	Otter Tail Corp.	54.0%	$1,059	$572	56.5%	$1,415	$799	6.9%	$35.00	$20.00	$27.50	$20.00	1.375	36.1	40.0	2.07%	0.0285	0.2727	0.78%
20	Pepco Holdings	50.9%	$8,516	$4,335	50.0%	$10,980	$5,490	4.8%	$30.00	$19.00	$24.50	$21.50	1.140	227.5	255.0	2.31%	0.0263	0.1224	0.32%
21	PG&E Corp.	50.2%	$24,119	$12,108	51.5%	$31,500	$16,223	6.0%	$55.00	$35.00	$45.00	$36.00	1.250	412.3	450.0	1.77%	0.0221	0.2000	0.44%
22	Pinnacle West Capital	55.9%	$6,841	$3,824	57.5%	$8,500	$4,888	5.0%	$60.00	$45.00	$52.50	$41.50	1.265	109.3	118.5	1.64%	0.0207	0.2095	0.43%
23	Portland General Elec.	50.4%	$3,298	$1,662	54.0%	$3,700	$1,998	3.7%	$30.00	$25.00	$27.50	$26.00	1.058	75.4	76.5	0.30%	0.0032	0.0545	0.02%
24	PPL Corp.	37.2%	$29,071	$10,814	51.0%	$34,700	$17,697	10.4%	$45.00	$30.00	$37.50	$25.50	1.471	578.4	695.0	3.74%	0.0550	0.3200	1.76%
25	Pub Sv Enterprise Grp	57.9%	$17,731	$10,266	56.0%	$23,600	$13,216	5.2%	$45.00	$35.00	$40.00	$26.25	1.524	506.0	506.0	0.00%	0.0000	0.3438	0.00%
26	SCANA Corp.	45.7%	$8,511	$3,890	47.0%	$13,075	$6,145	9.6%	$55.00	$40.00	$47.50	$39.75	1.195	130.0	155.0	3.58%	0.0428	0.1632	0.70%
27	Sempra Energy	49.2%	$20,015	$9,847	48.0%	$26,200	$12,576	5.0%	$85.00	$65.00	$75.00	$51.00	1.471	239.9	246.0	0.50%	0.0074	0.3200	0.24%
28	TECO Energy	45.8%	$4,954	$2,269	44.5%	$6,525	$2,904	5.1%	$25.00	$18.00	$21.50	$13.00	1.654	215.8	221.0	0.48%	0.0079	0.3953	0.31%
29	UIL Holdings	41.4%	$2,643	$1,094	46.0%	$2,800	$1,288	3.3%	$45.00	$35.00	$40.00	$25.50	1.569	50.7	51.0	0.14%	0.0022	0.3625	0.08%
30	Westar Energy	50.0%	$5,531	$2,766	50.0%	$7,600	$3,800	6.6%	$35.00	$25.00	$30.00	$28.35	1.058	125.7	134.0	1.29%	0.0136	0.0550	0.07%

(a) The Value Line Investment Survey (Aug. 24, Sep. 21, & Nov. 2, 2012).
(b) Computed as (EPS - DPS) / EPS.
(c) Average of values for 2012, 2013, and 2016.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2012, 2013, and 2016 and Adjustment Factor.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2016 BVPS.
(i) Product of change in common shares outstanding and M/B Ratio.
(j) Computed as 1 - B/M Ratio.

CURRENT BOND YIELDS

		BBB Utility Bonds	10-Yr Treasury Bonds
	Current Equity Risk Premium		
(a)	Avg. Yield Over Study Period	6.73%	3.50%
(b)	6-Mo. Average Bond Yield	4.83%	1.68%
	Change in Bond Yield	-1.90%	-1.82%
(c)	Risk Premium/Interest Rate Relationship	-0.9374	-0.9421
	Adjustment to Average Risk Premium	1.78%	1.72%
(a)	Average Risk Premium over Study Period	4.10%	7.33%
	Adjusted Risk Premium	**5.88%**	**9.04%**
(b)	Current 6-Mo. Average Yield	4.83%	1.68%
	Adjusted Equity Risk Premium	5.88%	9.04%
	Risk Premium Cost of Equity	**10.71%**	**10.72%**

(a) See Exhibit No. AEP-405, p. 4.

(b) Average of monthly yields from May 2012 - Oct. 2012 based on data from from Moody's Investors Service, www.credittrends.com and the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.

(c) See Exhibit No. AEP-405, p. 5.

PROJECTED BOND YIELDS

	BBB Utility Bonds	10-Yr Treasury Bonds
Current Equity Risk Premium		
(a) Avg. Yield Over Study Period	6.73%	3.50%
(b) Projected Bond Yield	7.24%	3.52%
Change in Bond Yield	0.51%	0.02%
(c) Risk Premium/Interest Rate Relationship	-0.9374	-0.9421
Adjustment to Average Risk Premium	-0.48%	-0.02%
(a) Average Risk Premium over Study Period	4.10%	7.33%
Adjusted Risk Premium	**3.62%**	**7.31%**
(b) Projected Bond Yield	7.24%	3.52%
Adjusted Equity Risk Premium	3.62%	7.31%
Risk Premium Cost of Equity	**10.86%**	**10.83%**

(a) See Exhibit No. AEP-405, p. 4.

(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 19 (May 2012); Energy Information Administration, Annual Energy Outlook 2012 (Jun. 25, 2012); Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 24, 2012); Blue Chip Financial Forecasts, Vol. 31, No. 6 (Jun. 1, 2012); Moody's Investors Service at www.credittrends.com; & Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.

(c) See Exhibit No. AEP-405, p. 5.

IMPLIED RISK PREMIUM

				(a)		(b)	
				BBB Utility		10-Year Treasury	
			Base	Bond	Risk	Bond	Risk
Date	Utility	Docket No.	ROE	Yield	Premium	Yield	Premium
Apr-06	Baltimore Gas & Elec.	ER05-515	10.80%	6.22%	4.58%	4.62%	6.18%
Apr-06	Baltimore Gas & Elec.	ER05-515	11.30%	6.22%	5.08%	4.62%	6.68%
Aug-06	Westar Energy Inc.	ER05-925	10.80%	6.51%	4.29%	4.98%	5.82%
Oct-06	Bangor Hydro-Elec. Co.	ER04-157	11.14%	6.46%	4.68%	4.94%	6.20%
Apr-07	San Diego Gas & Elec.	ER07-284	11.35%	6.12%	5.24%	4.65%	6.70%
Jul-07	Wisconsin Elec. Pwr. Co.	ER06-1320	11.00%	6.28%	4.72%	4.80%	6.20%
Jul-07	Idaho Power Co.	ER06-787	10.70%	6.28%	4.42%	4.80%	5.90%
Oct-07	Commonwealth Edison Co.	ER07-583	11.00%	6.43%	4.57%	4.76%	6.24%
Nov-07	Duquesne Light Co.	EL06-109	10.90%	6.44%	4.46%	4.66%	6.24%
Nov-07	Pepco Holdings, Inc.	ER08-10	10.80%	6.44%	4.36%	4.66%	6.14%
Feb-08	Atlantic Path 15	ER08-374	10.65%	6.42%	4.23%	4.13%	6.52%
Mar-08	Startrans IO, LLC	ER08-413	10.65%	6.46%	4.19%	3.96%	6.69%
Mar-08	Westar Energy Inc.	ER08-396	10.80%	6.46%	4.34%	3.96%	6.84%
Apr-08	Virginia Elec. & Power Co.	ER08-92	10.90%	6.54%	4.36%	3.82%	7.08%
Apr-08	Trans-Allegheny	ER07-562	11.20%	6.54%	4.66%	3.82%	7.38%
Apr-08	Golden Spread	EL05-19	9.33%	6.54%	2.79%	3.82%	5.51%
Apr-08	NSTAR Elec. Co.	ER07-549	10.90%	6.54%	4.36%	3.82%	7.08%
Jul-08	Arizona Public Service Co.	ER07-1142	10.75%	6.80%	3.95%	3.82%	6.93%
Jul-08	So. Cal Edison (c)	ER08-375	9.54%	6.80%	2.74%	3.82%	5.72%
Aug-08	Virginia Elec. & Power Co.	ER08-1207	10.90%	6.86%	4.04%	3.85%	7.06%
Aug-08	Pepco Holdings, Inc.	ER08-686	11.30%	6.86%	4.44%	3.85%	7.46%
Aug-08	New England Pwr. Co.	ER07-694	11.14%	6.86%	4.28%	3.85%	7.30%
Sep-08	Public Service Elec. & Gas	ER08-1233	11.18%	6.94%	4.24%	3.88%	7.31%
Oct-08	Pepco Holdings, Inc.	ER08-1423	10.80%	7.23%	3.57%	3.90%	6.90%
Oct-08	Central Maine Power Co.	EL08-74	11.14%	7.23%	3.91%	3.90%	7.24%
Oct-08	Duquesne Light Co.	ER08-1402	10.90%	7.23%	3.67%	3.90%	7.00%
Nov-08	Northeast Utils Service Co.	ER08-1548	11.14%	7.60%	3.54%	3.84%	7.30%
Nov-08	Central Maine Power Co.	EL08-77	11.14%	7.60%	3.54%	3.84%	7.30%
Dec-08	NSTAR Elec. Co.	ER09-14	11.14%	7.80%	3.34%	3.56%	7.58%
Dec-08	Tallgrass / Prairie Wind	ER09-35/36	10.80%	7.80%	3.00%	3.56%	7.24%
Feb-09	Black Hills Power Co.	ER08-1584	10.80%	8.08%	2.72%	3.14%	7.66%
Mar-09	AEP - SPP Zone	ER07-1069	10.70%	8.22%	2.48%	3.00%	7.71%
Mar-09	Pioneer Transmission	ER09-75	10.54%	8.22%	2.32%	3.00%	7.55%
Mar-09	ITC Great Plains	ER09-548	10.66%	8.22%	2.44%	3.00%	7.67%
Mar-09	Public Service Elec. & Gas	ER09-249	11.18%	8.22%	2.96%	3.00%	8.19%
Apr-09	Green Power Express	ER09-681	10.78%	8.13%	2.65%	2.85%	7.93%
May-09	PPL Elec. Utilities Corp.	ER08-1457	11.10%	7.93%	3.17%	2.81%	8.29%
May-09	PPL Elec. Utilities Corp.	ER08-1457	11.14%	7.93%	3.21%	2.81%	8.33%
May-09	PPL Elec. Utilities Corp.	ER08-1457	11.18%	7.93%	3.25%	2.81%	8.37%

IMPLIED RISK PREMIUM

				(a) BBB Utility		(b) 10-Year Treasury	
Date	**Utility**	**Docket No.**	**Base ROE**	**Bond Yield**	**Risk Premium**	**Bond Yield**	**Risk Premium**
May-09	Baltimore Gas & Elec.	ER09-745	11.30%	7.93%	3.37%	2.81%	8.49%
May-09	Niagara Mohawk Pwr. Co.	ER08-552	11.00%	7.93%	3.07%	2.81%	8.19%
May-09	Oklahoma Gas & Elec.	ER08-281	10.60%	7.93%	2.67%	2.81%	7.79%
Jun-09	Kentucky Utilities Co.	ER08-1588	11.00%	7.79%	3.21%	3.03%	7.98%
Aug-09	Westar Energy Inc.	ER07-1344	10.80%	7.39%	3.41%	3.32%	7.48%
Aug-09	So. Cal Edison (d)	ER09-187	10.04%	7.39%	2.65%	3.32%	6.72%
Oct-09	Xcel Energy	ER08-313	10.77%	6.76%	4.01%	3.49%	7.28%
Nov-09	National Grid Generation LLC	ER09-628	10.75%	6.50%	4.25%	3.51%	7.24%
Nov-09	Westar Energy Inc.	ER09-1762	10.80%	6.50%	4.30%	3.51%	7.29%
May-10	AEP - PJM Zone	ER08-1329	10.99%	6.21%	4.79%	3.67%	7.32%
Oct-10	AEP Transco	ER10-355	10.99%	5.84%	5.16%	2.92%	8.07%
Oct-10	KCPL	ER10-230	10.60%	5.84%	4.77%	2.92%	7.68%
Sep-10	So. Cal Edison (e)	ER10-160	10.33%	5.93%	4.40%	3.14%	7.19%
Feb-11	Northern Pass Transmission	ER11-2377	10.40%	5.87%	4.53%	3.04%	7.37%
May-11	Ameren	EL10-80	12.38%	5.98%	6.40%	3.38%	9.00%
May-11	Atlantic Grid Operations	EL11-13	10.09%	5.98%	4.11%	3.38%	6.71%
Jun-11	Xcel Energy	ER10-1377	10.40%	5.92%	4.48%	3.34%	7.07%
Jun-11	PJM & PSE&G	ER11-3352	11.18%	5.92%	5.26%	3.34%	7.85%
Jun-11	South Carolina Elec. & Gas	ER10-516	10.55%	5.92%	4.63%	3.34%	7.22%
Oct-11	Duke Energy Carolinas	ER11-2895	10.20%	5.45%	4.75%	2.60%	7.60%
Oct-11	RITELine	ER11-4069	9.93%	5.45%	4.48%	2.60%	7.33%
Nov-11	PATH	ER08-386	10.40%	5.31%	5.09%	2.41%	7.99%
Dec-11	PJM & PSE&G	ER12-296	11.18%	5.21%	5.97%	2.24%	8.94%
May-12	Public Service Colorado	ER11-2853	10.10%	5.06%	5.04%	1.99%	8.11%
May-12	Public Service Colorado	ER11-2853	10.40%	5.06%	5.34%	1.99%	8.41%
Jun-12	DATC Midwest Holdings	ER12-1593	12.38%	5.03%	7.35%	1.93%	10.45%
	Average			**6.73%**	**4.10%**	**3.50%**	**7.33%**

(a) Moody's Investors Service, www.credittrends.com.
(b) Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(c) Order issued April 15, 2010, with ROE applied for March 1, 2008 through December 31, 2008.
(d) Order issued April 19, 2012, with ROE applied for January 1, 2009 through May 31, 2010.
(e) Order issued April 19, 2012, with ROE applied for June 1, 2010 through December 31, 2010.

REGRESSION RESULTS

SUMMARY OUTPUT -- BBB UTILITY BONDS

Regression Statistics	
Multiple R	0.865533771
R Square	0.749148708
Adjusted R Square	0.745166941
Standard Error	0.00495312
Observations	65

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.004615832	0.004615832	188.1448097	1.38889E-20
Residual	63	0.001545604	2.45334E-05		
Total	64	0.006161436			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.104055638	0.00464011	22.42525053	9.85068E-32	0.094783112	0.113328165	0.094783112	0.113328165
X Variable 1	-0.93743352	0.06834305	-13.71658885	1.38889E-20	-1.074006291	-0.800860749	-1.074006291	-0.800860749

SUMMARY OUTPUT -- 10-YEAR TREASURY BONDS

Regression Statistics	
Multiple R	0.81930476
R Square	0.67126029
Adjusted R Square	0.6660422
Standard Error	0.004966846
Observations	65

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.003173516	0.003173516	128.6409795	7.32368E-17
Residual	63	0.001554182	2.46696E-05		
Total	64	0.004727699			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.106239358	0.002972598	35.73956737	1.52358E-43	0.100299092	0.112179625	0.100299092	0.112179625
X Variable 1	-0.942108101	0.083063661	-11.34200068	7.32368E-17	-1.108097684	-0.776118519	-1.108097684	-0.776118519

ANALYSIS OF FERC ROE

	(a) Average Pipeline	BBB Utility		10-Year Treasury	
Year	**ROE**	(b) **Bond Yield**	**Risk Premium**	(c) **Bond Yield**	**Risk Premium**
2006	12.86%	6.32%	6.54%	4.79%	8.07%
2007	13.07%	6.33%	6.74%	4.63%	8.44%
2008	12.79%	7.25%	5.55%	3.67%	9.12%
2009	13.18%	7.06%	6.12%	3.26%	9.92%
2010	12.61%	5.98%	6.63%	3.21%	9.40%
2011	13.31%	5.57%	7.74%	2.79%	10.52%
2012	12.59%	5.03%	7.56%	1.93%	10.66%

Year	**Average Pipeline ROE**	(d) **Average Electric Base ROE**	**Spread**
2006	12.86%	11.01%	1.85%
2007	13.07%	10.96%	2.11%
2008	12.79%	10.82%	1.98%
2009	13.18%	10.84%	2.34%
2010	12.61%	10.73%	1.88%
2011	13.31%	10.67%	2.64%
	12.97%	10.84%	2.13%

Average Pipeline ROE - 2012	12.59%
Less: Average Spread	2.13%
Implied Electric ROE	**10.46%**

(a) Exhibit No. AEP-406, pp. 2-3.
(b) Moody's Investors Service, www.credittrends.com.
(c) Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(d) Exhibit No. AEP-405, pp. 2-3.

GAS PIPELINES

ALLOWED ROE

Date	Docket No.	Company	ROE
Feb-06	RP06-63	Guardian Pipeline LLC.	14.00%
Mar-06	CP05-372	Midwestern Gas Transmission Co.	13.00%
Mar-06	RP04-274	Kern River Gas Transmission Co.	9.34%
May-06	CP02-378	Cameron Interstate Pipeline, LLC	14.00%
Jun-06	CP04-411	Crown Landing LLC; Texas Eastern Transmission, LP	12.75%
Jun-06	CP05-83	Port Arthur Pipeline, L.P.	14.00%
Jun-06	CP05-130	Dominion Cove Point LNG	13.00%
Jun-06	CP05-360	Creole Trail LNG, L.P.	14.00%
Jul-06	CP06-71	Carolina Gas Transmission Corp.; SCG Pipeline, Inc.	12.70%
Jul-06	CP06-5	Empire State Pipeline	12.50%
Sep-06	CP06-354	Rockies Express Pipeline LLC	13.00%
Sep-06	CP06-167	Questar Overthrust Pipeline Co.	11.75%
Oct-06	RP04-274	Kern River Gas Transmission Co.	11.20%
Oct-06	CP06-61	North Baja Pipeline, LLC	14.00%
Dec-06	CP06-5	Empire Pipeline, Inc.	12.50%
Dec-06	CP98-150	Millennium Pipeline Co.	14.00%
Feb-07	CP06-403	Northern Natural Gas Co.	13.42%
Mar-07	CP06-448	Kinder Morgan Louisiana Pipeline LLC	14.00%
Apr-07	CP07-25	Questar Pipeline Company	11.75%
Apr-07	CP06-407	Missouri Interstate Gas	11.20%
Apr-07	CP06-89	WTG Hugoton, LP and Northern Natural Gas Co.	11.20%
Apr-07	CP06-471	Elba Express Co.	14.00%
May-07	CP07-44	Southeast Supply Header, LLC	13.50%
Jun-07	CP06-115	Texas Eastern Transmission LP	12.75%
Jun-07	CP00-6	Gulfstream Natural Gas Supply, L.L.C.	14.00%
Jun-07	CP07-14	Wyoming Interstate Co., Ltd.	12.50%
Jul-07	CP06-454	Kinder Morgan Illinois Pipeline LLC	13.00%
Jul-07	CP07-76	Sonora Pipeline, LLC	14.00%
Sep-07	CP07-32	Gulf South Pipeline LP	12.25%
Sep-07	CP05-91	Calhoun LNG/Point Comfort Pipeline, LP	14.00%
Oct-07	RP07-38	Eastern Shore Natural Gas Co.	13.60%
Dec-07	CP07-8	Guardian Pipeline, L.L.C.	14.00%
Apr-08	CP07-398	Gulf Crossing Pipeline LLC	13.50%
May-08	CP07-208	Rockies Express Pipeline LLC	13.00%
May-08	CP07-417	Texas Gas Transmission. LLC	11.50%

ALLOWED ROE

Jul-08	CP08-65	Midcontinent Express Pipeline LLC	13.00%
Jul-08	CP08-17	Cimarron River Pipeline LLC	11.20%
Jul-08	CP08-5	Southern Natural Gas Co.	12.00%
Aug-08	CP08-65	Tennessee Gas Pipeline Co.	11.50%
Aug-08	CP08-398	White River Hub, LLC	13.00%
Sep-08	CP06-365	Bradwood Landing LLC/NorthernStar Energy LLC	14.00%
Sep-08	CP08-152	North Baja Pipeline LLC	14.00%
Nov-08	RP08-632	MarkWest Pioneer, L.L.C.	14.00%
Jan-09	CP07-62	AES Sparrows Point LNG/Mid-Atlantic Express L.L.C.	14.00%
Jan-09	RP08-350	Southern Star Central Pipeline, Inc.	11.25%
	RP04-274	Kern River Gas Transmission Co.	11.55%
Feb-09	CP09-3	T.W. Phillips Pipeline Corp.	14.00%
Jun-09	CP08-429	Kern River Gas Transmission Co.	13.25%
Sep-09	CP09-54	Ruby Pipeline, L.L.C.	14.00%
Nov-09	CP09-17	Florida Gas Transmission Co.	13.00%
Nov-09	CP09-68	Texas Eastern Transmission, LP	12.75%
Dec-09	CP09-433	Fayetteville Express Pipeline LLC	14.00%
Dec-09	CP07-442	Pacific Connector Gas Pipeline, LP	14.00%
Apr-10	CP09-161	Bison Pipeline LLC	14.00%
Apr-10	CP09-460	ETC Tiger Pipeline	14.00%
May-10	CP09-444	Tennessee Gas Pipeline Co.	11.50%
Sep-10	CP10-14	Kern River Transmission Co.	11.55%
Nov-10	CP10-468	Northern Border Pipeline Co.	12.00%
Jan-11	CP10-194	Central New York Oil & Gas Co.	13.50%
Feb-11	RP08-306	Portland Natural Gas Transmission System	12.99%
Apr-11	CP11-19	Trunkline Gas Co., LLC	12.56%
Jul-11	CP09-54	Ruby Pipeline L.L.C.	14.00%
Nov-11	CP10-480	Central New York Oil & Gas Co.	13.50%
Jan-12	CP11-46	Kern River Gas Transmission Co.	11.55%
Feb-12	CP11-508	Texas Eastern Transmission, LP	12.75%
May-12	CP11-56	Texas Eastern Transmission, LP	12.75%
May-12	CP12-31	Southern LNG, L.L.C.	12.50%
Jun-12	CP12-4	Southern Natural Gas Co.-High Point Gas Trans.	12.99%
Jun-12	CP11-543	ANR Pipeline Co.-TC Offshore LLC	12.99%

DCF MODEL

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		(a)		(b)		(c)	(d)				
		6 Mo. Div. Yield		**Adjusted Div. Yield**		**Growth Rates**		**Implied Cost of Equity**			
	Company	**Low**	**High**	**Low**	**High**	**br + sv**	**IBES**	**Low**		**High**	**Average**
1	Abbott Labs.	3.0%	3.2%	3.2%	3.5%	17.9%	9.2%	12.4%	--	21.4%	--
2	Bard (C.R.)	0.7%	0.8%	0.8%	0.9%	22.7%	7.9%	8.7%	--	23.6%	--
3	Church & Dwight	1.7%	1.9%	1.8%	2.0%	10.5%	11.2%	12.3%	--	13.2%	12.8%
4	Coca-Cola Co.	2.6%	2.8%	2.6%	2.9%	5.0%	8.2%	7.6%	--	11.1%	9.4%
5	Colgate-Palmolive	2.3%	2.5%	2.4%	2.8%	24.1%	8.4%	10.9%	--	26.9%	--
6	Gen'l Mills	3.2%	3.4%	3.3%	3.6%	10.7%	7.4%	10.7%	--	14.3%	12.5%
7	Kellogg	3.4%	3.6%	3.5%	4.0%	22.9%	6.1%	9.6%	--	26.9%	--
8	Kimberly-Clark	3.5%	3.7%	3.6%	3.9%	12.7%	10.1%	13.7%	--	16.6%	15.1%
9	McCormick & Co.	2.0%	2.1%	2.1%	2.3%	12.6%	8.5%	10.6%	--	14.9%	--
10	McDonald's Corp.	3.0%	3.2%	3.1%	3.4%	9.6%	8.3%	11.5%	--	12.9%	12.2%
11	PepsiCo, Inc.	3.0%	3.2%	3.1%	3.3%	10.2%	4.3%	7.3%	--	13.5%	10.4%
12	Procter & Gamble	3.4%	3.6%	3.4%	3.7%	5.2%	8.0%	8.7%	--	11.7%	10.2%
13	Wal-Mart Stores	2.2%	2.3%	2.3%	2.5%	9.6%	9.2%	11.5%	--	12.0%	11.8%
	Range of Reasonableness							**7.3%**	--	**26.9%**	
	Adjusted Range of Reasonableness (e)							**7.3%**	--	**16.6%**	
	Midpoint								**12.0%**		
	Median (f)										**12.0%**

(a) Six-month average dividend yield for May - October 2012.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) See Exhibit No. AEP-408.
(d) www.finance.yahoo.com (retrieved Nov. 8, 2012).
(e) Excludes highlighted values.
(f) Based on the average of the low and high DCF estimates for all companies with two valid observations.

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		(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(c)	(c)	(d)	(e)		
		-------------- 2012 -------------				-------------- 2013 -------------				-------------- 2016 -------------						**Adjust.**		**Avg**	**Avg**
	Company	**EPS**	**DPS**	**b**	**r**	**EPS**	**DPS**	**b**	**r**	**EPS**	**DPS**	**b**	**r**	**Avg b**	**Avg r**	**Factor**	**Adj. r**	**br**	**br + sv**
1	Abbott Labs.	$5.10	$2.04	60.0%	30.0%	$5.50	$2.16	60.7%	30.0%	$6.50	$2.40	63.1%	29.0%	61.3%	29.7%	1.0345	30.7%	18.8%	**17.9%**
2	Bard (C.R.)	$6.65	$0.78	88.3%	31.0%	$7.15	$0.82	88.5%	29.5%	$8.90	$0.94	89.4%	25.0%	88.7%	28.5%	1.0480	29.9%	26.5%	**22.7%**
3	Church & Dwight	$2.43	$0.96	60.5%	17.5%	$2.80	$0.96	65.7%	17.5%	$3.75	$1.00	73.3%	15.0%	66.5%	16.7%	1.0525	17.5%	11.7%	**10.5%**
4	Coca-Cola Co.	$2.00	$1.02	49.0%	27.5%	$2.20	$1.10	50.0%	28.0%	$2.90	$1.45	50.0%	31.5%	49.7%	29.0%	1.0184	29.5%	14.7%	**5.0%**
5	Colgate-Palmolive	$5.30	$2.44	54.0%	111.0%	$5.85	$2.63	55.0%	125.0%	$7.80	$3.50	55.1%	76.0%	54.7%	104.0%	1.0616	110.4%	60.4%	**24.1%**
6	Gen'l Mills	$2.56	$1.22	52.3%	26.6%	$2.65	$1.32	50.2%	26.5%	$3.45	$1.65	52.2%	25.5%	51.6%	26.2%	1.0301	27.0%	13.9%	**10.7%**
7	Kellogg	$3.35	$1.74	48.1%	51.5%	$3.65	$1.76	51.8%	42.5%	$5.00	$2.15	57.0%	34.5%	52.3%	42.8%	1.1057	47.4%	24.8%	**22.9%**
8	Kimberly-Clark	$4.90	$2.92	40.4%	36.5%	$5.70	$3.08	46.0%	37.5%	$7.20	$3.60	50.0%	35.5%	45.5%	36.5%	1.0365	37.8%	17.2%	**12.7%**
9	McCormick & Co.	$3.10	$1.24	60.0%	23.0%	$3.40	$1.36	60.0%	22.0%	$4.35	$1.72	60.5%	20.0%	60.2%	21.7%	1.0565	22.9%	13.8%	**12.6%**
10	McDonald's Corp.	$5.45	$2.85	47.7%	39.5%	$6.00	$3.05	49.2%	42.0%	$7.50	$3.75	50.0%	41.5%	49.0%	41.0%	1.0167	41.7%	20.4%	**9.6%**
11	PepsiCo, Inc.	$4.05	$2.12	47.7%	29.0%	$4.40	$2.21	49.8%	28.0%	$6.15	$2.46	60.0%	28.0%	52.5%	28.3%	1.0456	29.6%	15.5%	**10.2%**
12	Procter & Gamble	$3.85	$2.14	44.4%	19.3%	$3.90	$2.29	41.3%	16.5%	$6.00	$3.00	50.0%	22.5%	45.2%	19.4%	1.0019	19.5%	8.8%	**5.2%**
13	Wal-Mart Stores	$4.95	$1.60	67.7%	21.5%	$5.40	$1.68	68.9%	21.5%	$7.00	$2.20	68.6%	21.0%	68.4%	21.3%	1.0343	22.1%	15.1%	**9.6%**

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		(a)	(a)	(g)	(a)	(a)		(a)	(h)	(a)	(a)	(g)	(i)	(j)	
		------- Common Equity -------			--------- 2016 Price --------			2016		-- Shares Outstanding --			--------- "sv" Factor --------		
	Company	2011	2016	Chg.	High	Low	Avg.	BVPS	M/B	2011	2016	Chg.	s	v	sv
1	Abbott Labs.	$24,440	$34,500	7.1%	$105.00	$90.00	$97.50	$22.25	4.382	1,570.4	1,550.0	-0.26%	(0.0114)	0.7718	-0.88%
2	Bard (C.R.)	$1,782	$2,880	10.1%	$175.00	$145.00	$160.00	$36.00	4.444	84.5	80.0	-1.10%	(0.0488)	0.7750	-3.78%
3	Church & Dwight	$2,041	$3,450	11.1%	$70.00	$55.00	$62.50	$25.20	2.480	142.3	137.0	-0.75%	(0.0187)	0.5968	-1.12%
4	Coca-Cola Co.	$31,635	$38,015	3.7%	$60.00	$50.00	$55.00	$9.25	5.946	4,526.0	4,100.0	-1.96%	(0.1164)	0.8318	-9.68%
5	Colgate-Palmolive	$2,375	$4,400	13.1%	$170.00	$140.00	$155.00	$10.50	14.762	480.0	420.0	-2.64%	(0.3891)	0.9323	-36.28%
6	Gen'l Mills	$6,366	$8,600	6.2%	$60.00	$50.00	$55.00	$14.10	3.901	644.8	610.0	-1.10%	(0.0430)	0.7436	-3.20%
7	Kellogg	$1,760	$5,085	23.6%	$90.00	$70.00	$80.00	$14.55	5.498	357.3	350.0	-0.41%	(0.0227)	0.8181	-1.85%
8	Kimberly-Clark	$5,249	$7,565	7.6%	$115.00	$95.00	$105.00	$20.15	5.211	395.7	375.0	-1.07%	(0.0557)	0.8081	-4.50%
9	McCormick & Co.	$1,619	$2,850	12.0%	$95.00	$80.00	$87.50	$21.85	4.005	133.1	130.5	-0.39%	(0.0155)	0.7503	-1.16%
10	McDonald's Corp.	$14,390	$17,000	3.4%	$130.00	$110.00	$120.00	$18.40	6.522	1,021.4	925.0	-1.96%	(0.1280)	0.8467	-10.84%
11	PepsiCo, Inc.	$20,899	$33,000	9.6%	$135.00	$110.00	$122.50	$22.00	5.568	1,564.0	1,475.0	-1.16%	(0.0649)	0.8204	-5.32%
12	Procter & Gamble	$68,001	$69,300	0.4%	$110.00	$90.00	$100.00	$26.75	3.738	2,765.7	2,590.0	-1.30%	(0.0488)	0.7325	-3.57%
13	Wal-Mart Stores	$71,315	$100,500	7.1%	$115.00	$95.00	$105.00	$33.50	3.134	3,418.0	3,000.0	-2.58%	(0.0807)	0.6810	-5.50%

(a) The Value Line Investment Survey (retrieved Nov. 8, 2012).
(b) Computed as (EPS - DPS) / EPS.
(c) Average of values for 2012, 2013, and 2016.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2012, 2013, and 2016 and Adjustment Factor.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2016 BVPS.
(i) Product of change in common shares outstanding and M/B Ratio.
(j) Computed as 1 - B/M Ratio.

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	Company	(a) Market Return (R_m) Div Yield	(b) Proj. Growth	(c) Cost of Equity	(d) Risk-Free Rate	(e) Risk Premium	(f) Beta	(g) Unadjusted K_e	(h) Market Cap	(i) Size Adjustment	(j) Implied Cost of Equity
1	ALLETE	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$1,543	1.75%	11.6%
2	Alliant Energy	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$5,077	0.94%	10.8%
3	Ameren Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.80	10.9%	$8,062	0.78%	11.7%
4	American Elec Pwr	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$20,009	-0.38%	9.5%
5	Avista Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$1,591	1.75%	11.6%
6	Black Hills Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.80	10.9%	$1,383	1.75%	12.6%
7	CenterPoint Energy	2.6%	10.3%	12.9%	2.8%	10.1%	0.80	10.9%	$8,815	0.78%	11.7%
8	DTE Energy Co.	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$10,076	0.78%	11.2%
9	Edison International	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$15,075	0.78%	11.2%
10	El Paso Electric	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$1,361	1.75%	11.6%
11	Empire District Elec	2.6%	10.3%	12.9%	2.8%	10.1%	0.65	9.4%	$896	1.77%	11.1%
12	Exelon Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.80	10.9%	$32,008	-0.38%	10.5%
13	FirstEnergy Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.80	10.9%	$20,526	-0.38%	10.5%
14	Great Plains Energy	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$2,990	1.17%	11.5%
15	Hawaiian Elec.	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$2,769	1.17%	11.0%
16	IDACORP, Inc.	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$2,150	1.74%	11.6%
17	NorthWestern Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$1,363	1.75%	11.6%
18	OGE Energy Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$5,060	0.94%	11.3%
19	Otter Tail Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.90	11.9%	$846	1.77%	13.7%
20	Pepco Holdings	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$4,403	0.94%	11.3%
21	PG&E Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.55	8.4%	$18,775	-0.38%	8.0%
22	Pinnacle West Capital	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$5,716	0.94%	10.8%
23	Portland General Elec.	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$2,034	1.74%	12.1%
24	PPL Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.65	9.4%	$16,308	-0.38%	9.0%
25	Pub Sv Enterprise Grp	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$16,320	-0.38%	10.0%
26	SCANA Corp.	2.6%	10.3%	12.9%	2.8%	10.1%	0.65	9.4%	$6,296	0.94%	10.3%
27	Sempra Energy	2.6%	10.3%	12.9%	2.8%	10.1%	0.80	10.9%	$16,457	-0.38%	10.5%
28	TECO Energy	2.6%	10.3%	12.9%	2.8%	10.1%	0.85	11.4%	$3,902	0.94%	12.3%
29	UIL Holdings	2.6%	10.3%	12.9%	2.8%	10.1%	0.70	9.9%	$1,864	1.74%	11.6%
30	Westar Energy	2.6%	10.3%	12.9%	2.8%	10.1%	0.75	10.4%	$3,846	0.94%	11.3%
	Range of Reasonableness							**8.4% -- 11.9%**			**8.0% -- 13.7%**
	Midpoint							**10.1%**			**10.9%**
	Median							**10.4%**			**11.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 26, 2012

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 26, 2012).

(c) (a) + (b).

(d) Six-month average yield on 30-year Treasury bonds for May 2012 - Oct. 2012 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.

(e) (c) - (d).

(f) See Exhibit No. AEP-402.

(g) (d) + (e) x (f)

(h) www.valueline.com (retrieved Oct. 15, 2012).

(i) *Morningstar* , "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).

(j) (g) + (h).

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	Company	(a) Market Return (R_m) Div Yield	(b) Proj. Growth	(c) Cost of Equity	(d) 2013-17 Risk-Free Rate	(e) Risk Premium	(f) Beta	(g) Unadjusted K_e	(h) Market Cap	(i) Size Adjustment	(j) Implied Cost of Equity
1	ALLETE	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$1,543	1.75%	12.2%
2	Alliant Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$5,077	0.94%	11.4%
3	Ameren Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	11.2%	$8,062	0.78%	12.0%
4	American Elec Pwr	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$20,009	-0.38%	10.0%
5	Avista Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$1,591	1.75%	12.2%
6	Black Hills Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	11.2%	$1,383	1.75%	13.0%
7	CenterPoint Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	11.2%	$8,815	0.78%	12.0%
8	DTE Energy Co.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$10,076	0.78%	11.6%
9	Edison International	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$15,075	0.78%	11.6%
10	El Paso Electric	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$1,361	1.75%	12.2%
11	Empire District Elec	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	10.0%	$896	1.77%	11.8%
12	Exelon Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	11.2%	$32,008	-0.38%	10.9%
13	FirstEnergy Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	11.2%	$20,526	-0.38%	10.9%
14	Great Plains Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$2,990	1.17%	12.0%
15	Hawaiian Elec.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$2,769	1.17%	11.6%
16	IDACORP, Inc.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$2,150	1.74%	12.2%
17	NorthWestern Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$1,363	1.75%	12.2%
18	OGE Energy Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$5,060	0.94%	11.8%
19	Otter Tail Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.90	12.1%	$846	1.77%	13.8%
20	Pepco Holdings	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$4,403	0.94%	11.8%
21	PG&E Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.55	9.2%	$18,775	-0.38%	8.8%
22	Pinnacle West Capital	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$5,716	0.94%	11.4%
23	Portland General Elec.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$2,034	1.74%	12.6%
24	PPL Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	10.0%	$16,308	-0.38%	9.6%
25	Pub Sv Enterprise Grp	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$16,320	-0.38%	10.4%
26	SCANA Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	10.0%	$6,296	0.94%	10.9%
27	Sempra Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	11.2%	$16,457	-0.38%	10.9%
28	TECO Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.85	11.7%	$3,902	0.94%	12.6%
29	UIL Holdings	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	10.4%	$1,864	1.74%	12.2%
30	Westar Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	10.8%	$3,846	0.94%	11.8%
	Range of Reasonableness							**9.2% -- 12.1%**			**8.8% -- 13.8%**
	Midpoint							**10.6%**			**11.3%**
	Median							**10.8%**			**11.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 26, 2012)
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 26, 2012).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2013-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 24, 2012); IHS Global Insight, U.S. Economic Outlook at 19 (May 2012); & Blue Chip Financial Forecasts, Vol. 31, No. 6 (Jun. 1, 2012).
(e) (c) - (d).
(f) See Exhibit No. AEP-402.
(g) (d) + (e) x (f)
(h) www.valueline.com (retrieved Oct. 15, 2012).
(i) *Morningstar* , "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).
(j) (g) + (h).

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	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	10.5%	1.0382	10.9%
2	Alliant Energy	11.0%	1.0222	11.2%
3	Ameren Corp.	7.5%	1.0100	7.6%
4	American Elec Pwr	9.5%	1.0222	9.7%
5	Avista Corp.	8.5%	1.0200	8.7%
6	Black Hills Corp.	8.0%	1.0126	8.1%
7	CenterPoint Energy	12.0%	1.0263	12.3%
8	DTE Energy Co.	9.5%	1.0257	9.7%
9	Edison International	9.0%	1.0190	9.2%
10	El Paso Electric	10.5%	1.0218	10.7%
11	Empire District Elec	9.0%	1.0151	9.1%
12	Exelon Corp.	12.5%	1.0497	13.1%
13	FirstEnergy Corp.	10.0%	1.0153	10.2%
14	Great Plains Energy	7.5%	1.0218	7.7%
15	Hawaiian Elec.	10.0%	1.0478	10.5%
16	IDACORP, Inc.	8.5%	1.0237	8.7%
17	NorthWestern Corp.	10.0%	1.0257	10.3%
18	OGE Energy Corp.	11.0%	1.0339	11.4%
19	Otter Tail Corp.	9.5%	1.0335	9.8%
20	Pepco Holdings	8.0%	1.0236	8.2%
21	PG&E Corp.	10.0%	1.0292	10.3%
22	Pinnacle West Capital	9.0%	1.0245	9.2%
23	Portland General Elec.	9.0%	1.0184	9.2%
24	PPL Corp.	11.5%	1.0492	12.1%
25	Pub Sv Enterprise Grp	11.0%	1.0253	11.3%
26	SCANA Corp.	9.5%	1.0457	9.9%
27	Sempra Energy	11.5%	1.0245	11.8%
28	TECO Energy	13.0%	1.0247	13.3%
29	UIL Holdings	9.5%	1.0163	9.7%
30	Westar Energy	8.5%	1.0318	8.8%
	Range of Reasonableness			**7.6% -- 13.3%**
	Midpoint			**10.4%**
	Median			**9.8%**

(a) The Value Line Investment Survey (Aug. 24, Sep. 21, & Nov. 2, 2012)
(b) Adjustment to convert year-end return to an average rate of return from Exhibit No. AEP-404
(c) (a) x (b).

Attachment L

Copy of Section D of Schedule 8.1 of the RAA

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. The set of Capacity Resources designated in the FRR Capacity Plan must meet the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement and the PJM Operating Agreement applicable to Capacity

Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity.

5. For each LDA for which the Office of the Interconnection has established a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA. Such minimum percentage ("Percentage Internal Resources Required") will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement.

6. An FRR Entity may reduce such minimum percentage as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the capacity emergency transfer limit for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days of the submittal of the FRR Capacity Plan. If the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's

capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000