FILE

RECEIVED-DOCKETING DIV
2009 SEP 18 PM 5:02
PUCO

44

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility.	)	Case No. 05-376-EL-UNC

INDUSTRIAL ENERGY USERS-OHIO'S MOTION REQUESTING THAT THE COMMISSION DIRECT AEP-OHIO TO REFUND IGCC REVENUE COLLECTED OR SHOW CAUSE WHY THE REVENUE SHOULD NOT BE IMMEDIATELY REFUNDED

Samuel C. Randazzo, Trial Attorney
Lisa G. McAlister
Joseph M. Clark
MCNEES WALLACE & NURICK LLC
21 East State Street, 17th Floor
Columbus, OH 43215-4228
Telephone: (614) 469-8000
Telecopier: (614) 469-4653
sam@mwncmh.com
lmcalister@mwncmh.com
jclark@mwncmh.com

September 18, 2009

Attorneys for Industrial Energy Users-Ohio

This is to certify that the images appearing are an accurate and complete reproduction of a case file document delivered in the regular course of business.
Technician SM Date Processed SEP 21 2009

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility.	)	Case No. 05-376-EL-UNC

INDUSTRIAL ENERGY USERS-OHIO'S MOTION REQUESTING THAT THE COMMISSION DIRECT AEP-OHIO TO REFUND IGCC REVENUE COLLECTED OR SHOW CAUSE WHY THE REVENUE SHOULD NOT BE IMMEDIATELY REFUNDED

On April 10, 2006, the Public Utilities Commission of Ohio ("Commission") issued an Opinion and Order that, among other things, permitted Columbus Southern Power Company ("CSP") and Ohio Power Company [("OP") (collectively "AEP-Ohio")] to collect revenue from Ohio customers associated with the preconstruction costs including engineering and scoping study costs ("Phase I costs") of a hypothetical integrated gasification combined cycle ("IGCC") generation plant. On June 28, 2006, the Commission issued an Entry on Rehearing that conditioned the revenue recovery authority granted by requiring that all Phase I costs would be subject to subsequent audits and if "AEP-Ohio has not commenced a continuous course of construction of the proposed facility within five years of the date of issuance of this entry on rehearing, all Phase I charges collected for expenditures associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest." Entry on Rehearing at 16.

According to the letter filed by CSP and OP in this proceeding on February 6, 2009, CSP and OP have not commenced construction of the IGCC plant that was the subject of their application seeking cost recovery assurances. On September 1, 2009, an AEP-Ohio affiliate, Appalachian Power Company ("APCo"), filed an integrated resource plan ("IRP")[1] at the Virginia State Corporation Commission ("SCC") that includes information pertaining to the entire eastern system of AEP-Ohio's parent company, American Electric Power ("AEP"), including CSP and OP. Based upon the Virginia IRP, neither AEP-Ohio specifically, nor AEP, has any plans that include initiation of construction of any IGCC plant prior to June 28, 2011.

Thus, for the reasons described in the attached memorandum in support, Industrial Energy Users-Ohio ("IEU-Ohio") respectfully requests that the Commission either direct AEP-Ohio to refund, with interest, the revenue it billed and collected or direct AEP-Ohio to forthwith show cause why such revenue and interest should not be promptly refunded to the customers from which it was collected.

Respectfully submitted,

Samuel C. Randazzo, Trial Attorney
Lisa G. McAlister
Joseph M. Clark
McNees Wallace & Nurick LLC
21 East State Street, 17th Floor
Columbus, OH 43215-4228
Telephone: (614) 469-8000
Telecopier: (614) 469-4653

Attorneys for Industrial Energy Users-Ohio

[1] *In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code Section 56-598 et seq.*, Case No. PUE-2009-97 (September 1, 2009) (available online at http://docket.scc.virginia.gov/vaprod/main.asp) (last viewed on September 17, 2009) (hereinafter "Virginia IRP").

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility.	)	Case No. 05-376-EL-UNC

MEMORANDUM IN SUPPORT

I. Background

On March 18, 2005, AEP-Ohio filed an Application seeking approval of mechanisms to provide it with cost recovery assurances for a hypothetical IGCC plant that AEP-Ohio indicated it may construct in Meigs County, Ohio. On April 10, 2006, the Commission issued an Opinion and Order that, among other things, authorized AEP-Ohio to recover certain costs associated with the hypothetical IGCC generating plant and treated the costs as being associated with ancillary service necessary to provide retail distribution service to Ohio customers (hereinafter "April 10, 2006 Order"). AEP-Ohio described the costs as being preconstruction costs including engineering and scoping study costs. April 10, 2006 Order at 11.

On June 28, 2006, the Commission issued an Entry on Rehearing that conditioned its approval of AEP-Ohio's Application by requiring that all Phase I costs would be subject to subsequent audits and if "AEP-Ohio has not commenced a continuous course of construction of the proposed facility within five years of the date of issuance of this entry on rehearing, all Phase I charges collected for expenditures

associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest."[2]

IEU-Ohio, among others, appealed the Commission's decision to the Supreme Court of Ohio. *Indus. Energy Users-Ohio v. Pub. Util. Comm.*, 117 Ohio St.3d 486 (2008). On March 13, 2008, the Court affirmed, in part, reversed, in part, and remanded the Commission's Order. The Ohio Supreme Court held that while there may be merit to the Commission's regulation of the design, construction and operation of the hypothetical IGCC plant, the "evidence does not support the order permitting AEP to recover the costs associated with the research and development of the proposed generation facility." *Id.* at 493. Accordingly, the Court remanded the case to the Commission to "supplement the record with evidence to support its order and must verify that AEP has complied with the application requirements under R.C. 4909.18." *Id.* Additionally, the Court directed the Commission to address compliance with the "75 percent used-and-useful standard" because AEP-Ohio had not yet begun construction of the hypothetical IGCC plant. *Id.* Finally, the Court declined to rule on IEU-Ohio's request for a refund of costs already collected from AEP-Ohio's customers because of its remand to the Commission for further development of the record and because the conditional refund provision added in the Commission's Entry on Rehearing remained in effect. *Id.* at 494.

On September 17, 2008, the Office of the Ohio Consumers' Counsel ("OCC") filed a Motion on Remand requesting that the Commission order AEP-Ohio to refund to

[2] *Entry on Rehearing* at 16, 17.

customers, with interest, the revenue collected for the design, construction, and operation of the IGCC electric generation facility.

On January 8, 2009, the Attorney Examiner issued an Entry directing AEP-Ohio to provide a detailed statement outlining the status of the construction of the IGCC facility, including whether AEP-Ohio is engaged in a continuous course of construction of the IGCC facility. Specifically, the Entry stated:

> To provide the Commission with additional information, and to further develop the record in this matter, the Attorney Examiner believes it is imperative that AEP-Ohio provide a detailed statement outlining the status of the construction of the IGCC facility, including whether AEP-Ohio is engaged in a continuous course of construction on the IGCC facility.

January 8, 2009 Entry at 3.

On February 6, 2009, AEP-Ohio filed a two page response that states:

> At this time, AEP Ohio has not commenced construction of the IGCC facility. While we recognize that in enacting SB 221 the General Assembly addressed the need for advanced energy resources such as IGCC technology, AEP Ohio believes that there still exist real statutory barriers to the construction of any new base load generation in Ohio, including IGCC facilities.
>
> **Although construction of the Great Bend IGCC facility has not commenced**, and, based on the current state of the economy and uncertainty regarding load growth as well as the current law, **might not commence by June 2011,** a variety of changes could result in construction of the IGCC facility commencing on a continuous basis by June 2011. Such changes could include the enactment of carbon or other environmental legislation, changes in Ohio law or changes in AEP Ohio available generating capacity.
>
> AEP Ohio continues to believe that there are substantial reasons for pursuing the construction of an IGCC generating facility and still favors the Great Bend location. It believes that such a project, with appropriate rate recovery provisions, would be good for the State of Ohio's economy, for AEP Ohio's customers as well as for AEP Ohio.

Columbus Southern Power Company's and Ohio Power Company's Response to the Attorney Examiner's January 8, 2009 Entry at 1-2 (February 6, 2009) (emphasis added).

Beyond the actions that produced the mostly uninformative two-page report described above, neither the Commission nor AEP-Ohio has taken any actions to supplement the record or otherwise demonstrate that the hypothetical IGCC plant may be used for purposes of complying with AEP-Ohio's provider of last resort ("POLR") obligations, complies with the "75 percent used-and-useful standard" or that AEP-Ohio has any serious intention to commence a continuous course of construction at any time prior to June 28, 2011.

II. As AEP-Ohio has not initiated construction of the IGCC plant and has no plans to do so any time prior to June 28, 2011, the Commission should either direct AEP-Ohio to refund, with interest, the revenue it billed and collected or direct AEP-Ohio to forthwith show cause why such revenue and interest should not be promptly refunded to the customers from which it was collected.

AEP-Ohio's two-page letter filed in this proceeding on February 6, 2009 makes it clear that AEP-Ohio has not initiated construction of the IGCC plant that was the subject of its application for cost recovery assurances. While the February 6, 2009 letter suggests that something might happen to cause such construction to commence prior to June, 2011, on September 1, 2009, pursuant to Virginia Code Section 56-598 et seq., AEP-Ohio's affiliate, APCo, filed an IRP at the SCC.[3] The 15-year IRP forecast states that it is for AEP's entire eastern zone ("AEP East"), including CSP and OP, because it

[3] Virginia IRP. The executive summary is attached hereto as Attachment A for the Commission's convenience. *See also, Commonwealth of Virginia, ex rel., Concerning Electric utility Integrated Resource Planning Pursuant to Sections 56-597 et seq. of the Code of Virginia,* Case No. PUE-2008-99, Order Proposing Guidelines and Directing the Filing of Integrated Resource Plans (November 12, 2008) (available online at: http://www.scc.virginia.gov/newsrel/e_irp_08.pdf, last viewed on September 18, 2009).

is "planned and operated on a wholly integrated basis" and because of this relationship, individual operating companies' resource plans must be considered in the context of AEP East.[4] The IRP does not indicate that the IGCC facility will be placed into service in the Great Bend location at any time during the 15 year period covered by the forecast. In fact, the IRP indicates that AEP is not contemplating **any new baseload units in the forecast period:**

> In spite of the potential retirement of up to 3,470 MW of older, coal-fired units over the planning period due largely to external factors including known or anticipated environmental initiatives as well as the December 2007, stipulated New Source Review (NSR) Consent Decree, this AEP-East IRP requires no new baseload units in the forecast period. Rather, a unit uprate project at Cook Nuclear Plant during the 2014-2018 time period and a 2018 peaking resource, in addition to increased wind purchases and demand response programs are proposed to be added to maintain anticipated minimum PJM nominal reserve margin requirements of approximately 16.2%. Additional peaking and intermediate capacity will be added after 2020 to meet future load obligations.

Id. at Section 2. AEP-East Integrated Resource Plan, Executive Summary at ii. Moreover, the Virginia IRP states that the 2009 plan does not include any coal fired baseload additions but does include a phase-in of carbon capture and sequestration technology:

> **Carbon Capture and Sequestration Technology**
> The 2009 plan does not include any coal fired baseload additions but does recognize that the existing fossil fleet may be subject to reduced C02 limits in the future. Therefore, the plan includes the continued phase-in of Carbon Capture and Sequestration (CCS) at Mountaineer Plant as a practical and cost-effective method. It is essential that the successful demonstration of this technology will be necessary before it is rolled out on a larger scale.

Id. at iv.

[4] Virginia IRP at 1-1.

Based upon the AEP East IRP filed in Virginia, it appears that neither AEP-Ohio nor AEP East currently has plans to commence a continuous course of construction of the proposed IGCC facility prior to June 2011 in Ohio or any other location within the AEP East footprint.

III. Conclusion

For the reasons stated herein, IEU-Ohio respectfully requests that the Commission either direct AEP-Ohio to refund, with interest, the revenue it billed and collected or direct AEP-Ohio to forthwith show cause why such revenue and interest should not be promptly refunded to the customers from which it was collected. Given that interest will be due on top of any refund ordered by the Commission, unless AEP-Ohio can demonstrate otherwise, it is in AEP-Ohio's and the public interest for the Commission to order a refund immediately instead of waiting until June 2011. Moreover, anything other than the action requested by IEU-Ohio herein results in an unlawful, unjust and unreasonable failure to comply with the Ohio Supreme Court's mandate issued in *Indus. Energy Users-Ohio v. Pub. Util. Comm.*, 117 Ohio St.3d 486 (2008).

Respectfully submitted,

Samuel C. Randazzo, Trial Attorney
Lisa G. McAlister
Joseph M. Clark
McNees Wallace & Nurick LLC
21 East State Street, 17th Floor
Columbus, OH 43215-4228
Telephone: (614) 469-8000
Telecopier: (614) 469-4653
sam@mwncmh.com
lmcalister@mwncmh.com
jclark@mwncmh.com

Attorneys for Industrial Energy Users-Ohio

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Industrial Energy Users-Ohio's Motion Requesting that the Commission Direct AEP-Ohio to Refund IGCC Revenue Collected or Show Cause Why the Revenue Should Not Be Immediately Refunded* was served upon the following parties of record this 18th day of September, 2009, *via* electronic transmission, hand-delivery, or ordinary U.S. mail, postage prepaid.

Lisa G. McAlister

Marvin I. Resnik
Sandra K. Williams
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, OH 43215

Daniel R. Conway
Porter Wright Morris and Arthur LLP
41 South High Street
Columbus, OH 43215-6194

ON BEHALF OF COLUMBUS SOUTHERN POWER COMPANY AND OHIO POWER COMPANY

David F. Boehm
Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

ON BEHALF OF THE OHIO ENERGY GROUP

Kathy Kolich
Senior Attorney
FirstEnergy Service Company
76 South Main Street
Akron, OH 44308

ON BEHALF OF FIRSTENERGY SOLUTIONS CORP.

Jeffrey L. Small
Assistant Consumers' Counsel
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, OH 43215-3485

ON BEHALF OF OHIO CONSUMERS' COUNSEL

Richard A. Kanoff
Senior Counsel
Calpine Corporation
Two Atlantic Avenue, Third Avenue
Boston, MA 02110

ON BEHALF OF CALPINE CORPORATION

Thomas E. Lodge
Thompson Hine LLP
10 West Broad Street, Suite 700
Columbus, OH 43215-3435

ON BEHALF OF LIMA ENERGY COMPANY

John W. Bentine
Mark S. Yurick
Chester, Willcox & Saxbe LLP
65 East State Street, Suite 1000
Columbus, OH 43215-4213

ON BEHALF OF AMERICAN MUNICIPAL POWER-OHIO

CERTIFICATE OF SERVICE

Thomas L. Rosenberg
Jessica L. Davis
Roetzel & Andress, LPA
National City Center
155 East Broad St., 12th Floor
Columbus, OH 43215

ON BEHALF OF INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL #970, UNITED ASSOCIATION OF JOURNEYMEN AND APPRENTICES OF THE PLUMBING AND PIPE FITTING INDUSTRY OF THE UNITED STATES AND CANADA LOCAL #168 AND PARKERSBURG-MARIETTA BUILDING AND CONSTRUCTION TRADES COUNCIL AFL-CIO &

ON BEHALF OF IRONWORKERS LOCAL #787

William A. Adams
Dane Stinson
Bailey Cavalieri LLC
10 West Broad Street, Suite 2100
Columbus, OH 43215

ON BEHALF OF DIRECT ENERGY SERVICES, LLC

M. Howard Petricoff
Vorys, Sater, Seymour and Pease LLP
52 East Gay Street
P.O. Box 1008
Columbus, OH 43216-1008

ON BEHALF OF BAARD GENERATION LLC &

ON BEHALF OF CONSTELLATION GENERATION GROUP, LLC, CONSTELLATION ENERGY COMMODITIES GROUP, INC., AND CONSTELLATION NEWENERGY, INC.

David C. Rinebolt
Ohio Partners for Affordable Energy
231 West Lima Street
PO Box 1793
Findlay OH 45839-1793

ON BEHALF OF OHIO PARTNERS FOR AFFORDABLE ENERGY

Michael D. Dortch
Kravitz Brown & Dortch LLC
145 E. Rich St.
Columbus, OH 43215

ON BEHALF OF GE ENERGY (USA) LLC AND BECHTEL POWER CORPORATION

Thomas McNamee
Assistant Attorney General
Public Utilities Section
180 East Broad Street
Columbus, OH 43215

ON BEHALF OF THE PUBLIC UTILITIES COMMISSION OF OHIO

Christine Pirik
Greta See
Attorney Examiners
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, OH 43215

ATTORNEY EXAMINER

ATTACHMENT A

WOODS ROGERS PLC
ATTORNEYS AT LAW

CLERK'S OFFICE

2009 SEP -1 P 3:43

DOCUMENT CONTROL

ANTHONY GAMBARDELLA
(804) 343-5022
gambardella@woodsrogers.com

September 1, 2009

VIA HAND DELIVERY

Joel H. Peck, Clerk
State Corporation Commission
Commonwealth of Virginia
1300 East Main Street
Richmond, VA 23219

Re: Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code § 56-598 et seq., Case No. PUE-2009-00097

Dear Mr. Peck:

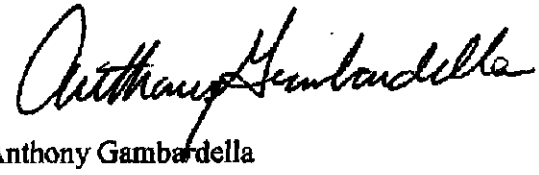
Enclosed for filing, pursuant to the Commission's Rules of Practice of Procedure (5 VAC 5-20-10, *et seq.*) and the Commission December 23, 2008 "Order Establishing Guidelines for Developing Integrated Resource Plans" in Case No. PUE-2008 00099 ("IRP Guidelines Order"), are an original and fifteen (15) copies of the Integrated Resource Plan ("IRP") of Appalachian Power Company.

Also enclosed herewith as part of the filing, pursuant to IRP Guidelines section (E), are a proposed public notice (attached hereto) and electronic media of the required schedules. The Company suggests that the notice be published on one occasion in newspapers of general circulation throughout the Company's service territory within Virginia and that a time interval of approximately four weeks each be used 1) from the date that the Commission enters a procedural order directing Appalachian to publish the notice until the publication deadline, and 2) from the notice publication date until the filing deadline for comments, notices of participation and requests for hearing.

Pursuant to Rule 5 VAC 5-20-170 of the Commission's Rules of Practice and Procedure and section (E) of the IRP Guidelines, the Company is separately filing confidential information under seal as well as a motion for protective treatment of that information.

Copies of the filing also have been sent to the Commission's General Counsel and to the Division of Consumer Counsel, Office of the Attorney General. We enclose an extra copy of the filing to be date stamped and returned to us by the courier. Thank you for your assistance in this matter.

Sincerely yours,



Anthony Gambardella

Enclosures
cc: William H. Chambliss, General Counsel
C. Meade Browder, Jr., Senior Assistant Attorney General

NOTICE TO THE PUBLIC OF A FILING
BY APPALACHIAN POWER COMPANY
OF AN INTEGRATED RESOURCE PLAN
CASE NO. PUE-2009-00097

On September 1, 2009, Appalachian Power Company ("Appalachian" or the "Company") filed with the State Corporation Commission ("Commission") its Integrated Resource Plan ("IRP"), pursuant to Va. Code § 56-597 et seq. An IRP, as defined by Va. Code § 56-597 is a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing fifteen years to promote reasonable prices, reliable service, energy independence, and environmental responsibility. Pursuant to Va. Code § 56-599 E, the Commission will analyze Appalachian's IRP and make a determination as to whether the Company's IRP is reasonable and in the public interest.

Appalachian states that as it operates as part of the integrated AEP-East system of its parent company, American Electric Power Corporation, ("AEP-East"), the Company's resource planning is conducted jointly as part of the resource planning for the AEP-East system. Appalachian states that it is filing in Virginia a copy of the current AEP-East IRP, together with supplemental materials to provide information consistent with the Commission's December 23, 2008 Order Establishing Guidelines for Developing Integrated Resource Plans in Case No. PUE-2008-00099.

The Commission entered an Order for Notice and Comment that, among other things, directed the Company to provide notice to the public and provided interested persons an opportunity to comment and/or request a hearing on the Company's IRP filing.

A copy of the public version of Appalachian's IRP may be obtained, at no charge, by requesting it in writing from Appalachian's counsel, Anthony Gambardella, Esq., Woods Rogers PLC, 823 E. Main Street, Suite 1200, Richmond, Virginia 23219. Copies of the public version of the IRP and related documents are also available for review in the Commission's Document Control Center, located on the first floor of the Tyler Building, 1300 East Main Street, Richmond, Virginia, between the hours of 8:15 a.m. and 5:00 p.m., Monday through Friday, excluding holidays. Interested persons may also download unofficial copies from the Commission's website: http://www.scc.virginia.gov.case.

On or before _____, 2009, interested persons may file written comments concerning the issues in this case with Joel H. Peck, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. Interested persons desiring to submit comments

electronically may do so following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. Comments shall refer to Case No. PUE-2009-_____.

On or before _____, 2009, interested persons may request that the Commission convene a hearing on the Company's IRP by filing a request for a hearing at the address set forth above. Requests for hearing must include: (i) a precise statement of the filing party's interest in the proceeding, (ii) a statement of the specific action sought to the extent then known, (iii) a statement of the legal basis for such action; and (iv) a precise statement why a hearing should be conducted in this matter.

Any interested person may participate as a respondent in this proceeding by filing on or before _____, 2009, an original and fifteen (15) copies of a notice of participation with the Clerk of the Commission at the address set forth above and shall simultaneously serve a copy of the notice of participation on counsel to Appalachian at the address set forth above. Pursuant to 5 VAC 5-20-80 of the Commission's Rules of Practice and Procedure, any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent then known; and (iii) the factual and legal basis for the action. Interested persons shall refer in all filed papers to Case No. PUE-2009-_____.

APPALACHIAN POWER COMPANY

APPALACHIAN POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PUE-2009-_____

September 1, 2009

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	
A. COMPANY OPERATIONS AND INTERRELATIONSHIP WITH THE AEP SYSTEM	1-1
B. SUMMARY OF VA SUPPLEMENTAL IRP INFORMATION	1-2
C. CONCLUSION	1-3
2. 2009 AEP-EAST INTEGRATED RESOURCE PLAN	
3. APCO LOAD FORECAST	
A. SUMMARY OF APCO LOAD FORECASTS	
A.1. Forecast Assumptions	3-3
A.2. Forecast Highlights	3-3
B. OVERVIEW OF FORECAST METHODOLOGY	3-4
C. FORECAST METHODOLOGY FOR INTERNAL ENERGY REQUIREMENTS	
C.1. General	3-5
C.2. Short-term Forecasting Models	3-6
C.2.a. Residential and Commercial Energy Sales	3-6
C.2.b. Industrial Energy Sales	3-6
C.2.c. All Other Energy Sales	3-7
C.2.d. Losses and Unaccounted-For Energy	3-7
C.2.e. Billed/Unbilled Analysis	3-7
C.3. Long-term Forecasting Models	3-7
C.3.a Supporting Models	3-8
C.3.a.1. Natural Gas Price Model	3-8
C.3.a.2. Regional Coal Production Model	3-9
C.3.b. Residential Energy Sales	3-9
C.3.b.1. Residential Customer Forecasts	3-9
C.3.b.2. Residential Energy Usage Per Customer	3-9
C.3.c. Commercial Energy Sales	3-10
C.3.d. Industrial Energy Sales	
C. 3.d.1. Manufacturing	3-11
C. 3.d.2. Mine Power	3-11
C.3.e. All Other Energy Sales	3-12
C.3.f. Blending Short and Long-Term Sales	3-12
C.3.g. Losses and Unaccounted-For Energy	3-12
D. FORECAST METHODOLOGY FOR SEASONAL PEAK INTERNAL DEMAND	3-13
E. LOAD FORECAST RESULTS	3-13
E.1. Load Forecast After Filed DSM Adjustments (Base Forecast)	3-13
F. Section 3 EXHIBITS	
4. APCO DEMAND-SIDE OPTIONS	

A. SUMMARY OF APCO DEMAND-SIDE OPTIONS AND IMPACTS	
B. CURRENT DEMAND-SIDE OPTIONS	4-1
C. EVALUATING APCO'S DEMAND-SIDE OPTIONS FOR FUTURE PERIODS	
C.1. Energy Efficiency/Demand Response Mandates and Goals	4-1
C.2. Assessment of Achievable Potential	4-1
C.3. Expected Program Costs and Benefits	4-2
D. LOW INCOME ENERGY ASSISTANCE IN VIRGINIA	4-2
D.1. Weatherization	4-3
D.2. Billing Assistance	4-4
D.3. Miscellaneous Low Income Efforts	4-4
5. APCO SUPPLY-SIDE RESOURCE EXPANSION	5-1
6. APCO FIVE-YEAR ACTION PLAN	6-1
7. CROSS REFERENCE TABLE TO VIRGINIA IRP REQUIREMENTS	7-1
8. REQUIRED SCHEDULES	

1. EXECUTIVE SUMMARY

1. EXECUTIVE SUMMARY

A. COMPANY OPERATIONS AND INTERRELATIONSHIP WITH THE AEP SYSTEM

Appalachian Power serves a population of about 2.2 million (958,000 retail customers) in a 19,260 square-mile area in the southwestern portions of Virginia and West Virginia. The principal industries served include primary metals, chemicals and allied products, paper and allied products and coal mining. The Company also sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives, and non-utility entities engaged in the wholesale power market.

APCo's internal load usually peaks in the winter; the all-time peak internal demand of 8,308 megawatts (MW) occurred on January 16, 2009. On August 9, 2007, an all-time summer peak internal demand of 6,755 MW was experienced. Of APCo's total internal energy requirements in 2008, which amounted to 40,695 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 31%, 17%, and 34%, respectively. Public street and highway lighting, sales–for-resale, and all other categories accounted for the remaining 18%.

APCo is one of the operating companies of the AEP System–East Zone ("AEP-East Zone" or "AEP-East"), which is planned and operated on a wholly integrated basis. Because of this relationship, APCo's resource plans must be considered in the context of the AEP System-East Zone. The AEP System-East Zone collectively serves a population of about 7.2 million (3.3 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. In 2008 the residential, commercial, and industrial customers accounted for 28.4%, 22.2%, and 35.9%, respectively, of the System's total internal energy requirements of 131,466 GWh. The remaining 13.5% was supplied for use in the public street and highway lighting, sales-for-resale, and all other categories.

The AEP System-East Zone experienced its all-time peak internal demand of 22,413 MW in the summer season of 2007, on August 8th. The all-time winter peak internal demand, 22,270 MW, was experienced on January 16, 2009. If sales to non-affiliated power systems are included, the AEP System-East Zone reached its all-time peak total demand of 26,467 MW on August 21, 2003.

The AEP System-East Zone generating companies, including APCO, are electrically interconnected by a high capacity transmission system extending from Virginia to Michigan. This eastern transmission system, consisting of an integrated 765-kV, 500-kV, and 345-kV, extra-high-voltage (EHV) network, together with an extensive underlying 138-kV transmission network, and numerous interconnections with neighboring power systems, is planned, constructed, and operated to provide a reliable mechanism to transmit the electrical output from the AEP System–East Zone generating plants to the principal load centers and to provide open access transmission service pursuant to FERC Order No. 888.

AEP transferred functional control of transmission facilities in the Eastern part of its system to the PJM Interconnection, LLC a regional transmission organization (RTO) in 2004. This transfer was approved by the Virginia State Corporation Commission (SCC) in PUE 2000-00550 order dated August 30, 2004. The PJM RTO assumed the monitoring, market operations and planning responsibilities of these facilities. In addition, PJM assumed the Open Access Same Time Information System (OASIS) responsibility including the evaluation and disposition of requests for transmission services over the AEP System–East Zone transmission system. PJM also became the North American Electric Reliability Council (NERC) Reliablity Coordinator for the AEP System-East Zone transmission system. AEP-East continues to maintain and physically operate all of its transmission facilities. AEP-East retains operational responsibility for those facilities that are not under PJM functional control, and is involved in the various operations, and planning stakeholder processes of PJM. In addition, PJM directs the dispatch of the AEP System-East Zone generating resources to meet minute-to-minute loads and determines the planning reserve required to maintain generation resource adequacy.

B. SUMMARY OF VA SUPPLEMENTAL IRP INFORMATION

The 2009 AEP-East Integrated Resource Plan (IRP) reflects a ten year planning period. The information contained in the Virginia Supplemental Information portion of this report (Sections 3 through 8) supplements the AEP East IRP through 2023. Likewise, supplemental information has been included to address specific requirements of the Virginia IRP guidelines.

The 2009 load forecast projects compound average growth rates (CAGR) for APCo peak demand of 1.1% for Winter and 1.5% for the Summer. Even at these different growth rates, APCO is expected to remain winter-peaking. In comparison, the similar rates for the AEP System-East Zone are 1.1% for Winter and 1.2% for Summer. APCo energy requirements are projected to grow at 1.5% CAGR and AEP System-East Zone at 1.1% CAGR (*See VA Supplemental IRP Information APCo Load Forecast).*

Potentional APCo Demand Response and Energy Efficiency programs are projected to achieve demand reductions of about 125 MW in Winter and 415 MW in Summer by 2015. Energy Efficiency is projected to reduce energy requirements by 700 GWh by the same year (*See VA Supplemental IRP Information APCo Demand-Side Options*).

The projected capacity for the AEP System-East Zone as a result of this planning cycle is shown in Table 1. For APCo this includes completion of the Dresden plant in 2013 and the construction or acquisition of additional intermediate and peaking capacity in the period 2018 and beyond. Also, for APCO additional wind purchases are projected for the short term (by 2013) and biomass cofiring (by 2019) to meet System goals (*See VA Supplemental IRPInformation APCo Supply Resource Expansion*).

The plan provides for reliable electric utility service, at the lowest reasonable cost through a combination of traditional supply, renewable supply and demand-side programs. The AEP System-East Zone (including APCo) is expected to have adequate resources to serve its customers' requirements throughout the forecast period, as shown on Schedules 6b and 16b. See Table 4 and Schedule 6a for APCo's reserve margin position for the forecast period.

Table 1

AEP System-East Zone Resource Plan
2009 IRP

MW	Planned Resource Reductions (A)		Planned Resource Additions (A)						
			DR/EE		RENEWABLE				
	Unit Retirements (summer rating)	Environmental Retrofits(E)	Embedded Demand Reduction(B) (Cumul. Contribution)	New Demand Reduction(C) (Cumul. Contribution)	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate/ New Facility)(D)	Duty Cycle Type: BL=Baseload INT=Intermediate PKG=Peaking	Ownership
2009			58	0	0	200			
2010	(440)	MT-Ph1GCS (4 MW) RK1&2 ACI	146	179	10	350			
2011			267	358	5	601			
2012	(640)	AM2 FGD (10 MW)	269	537	2	700	(0) / 60		
2013		AMI FGD CV5&6 SCR (196MW)	271	716	14	500		(Dresden) 640-MW INT	APCo
2014	(395)	MT-Ph2 (31 MW)	272	894	14		(43) / 0	(Cook 2)+45MW BL	I&M
2015	(415)	MR5/BS2 FGD (60 MW)	273	1,079	14			(Cook 1&2)+188MW BL	I&M
2016			273	1,073	14	100		(Cook 1)+68MW BL	I&M
2017	(600)	RK1 FGD	273	1,073	13			(Cook 2)+68MW BL	I&M
2018	(580)		273	1,073	17		(41) / 127	628-MW PKG (Cook 1) +68MW BL	APCo/KPCo 50/50 I&M
2019	(480)	RK2 FGD	273	1,073	17				
2020		MT-Ph3 (160)	273	1,073	16	200			
2021	(690)		273	1,073	35	150	(0) / 127	611-MW INT	APCo
2022			273	1,073	52	100	(41) / 0	628-MW PKG	APCo
2023	(680)		273	1,073	0	100		611-MW INT	APCo/KPCo 50/50
2023 Cumul. Contribution (Nameplate)	*(4,520)*	*(273)*	*273*	*1,073*	*220*	*3,001*	*189*	*3,435*	
(PJM) Capacity Value (Wind 13%; Solar 70%(est.))					*154*	*390*			
Cumul. (Nameplate) Contribution thru '23			*3%*	*13%*	*3%*	*37%*	*2%*	*42%*	
Cumul. (Capacity) Contribution thru '23			*5%*	*19%*	*3%*	*7%*	*3%*	*62%*	
								Peaking 1,256	*37%*
								Intermediate (incl. Dresden) 1,762	*51%*
								Baseload (D.C. Cook Uprates) 417	*12%*
								3,435	

'NET' CAPACITY RESOURCE ADDITIONS:	
2009-2023	*422*

(A) Not shown are smaller unit derates and uprates embedded in the current plan which are largely offsetting.
(B) "Embedded" DR/EE represents 'known & measurable', commission-approved program activity or programs filed with commissions, as projected by AEP-Economic Forecasting in the most recent load forecast.
(C) "New" DR/EE represents projected incremental activity, based on estimated contribution & program cost (vs. avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan. '09 study identifying a "Realistically Achievable Potential." Note: Such 'New' (incremental) DR/EE activity is not modeled to grow after 2015.
(D) Derate represents a blended-fuel biomass w/ separate injection. New Facility reflects repowered, dedicated, biomass units rebuilt from retired coal-fired units; and a 60 MW PPA.
(E) DCS retrofit technology assumed to be chilled ammonia with a 15% parasitic load.

Conclusion:

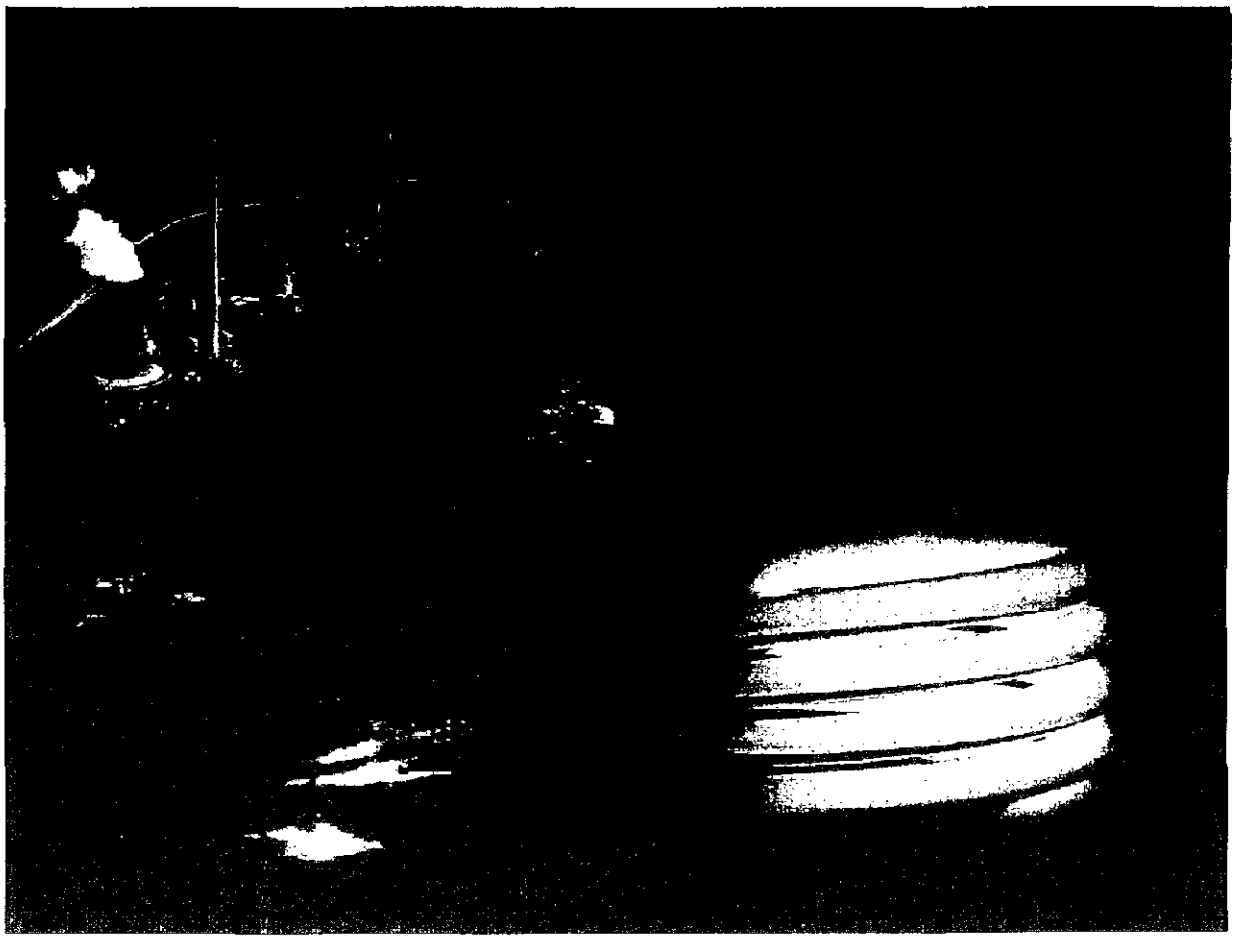
The planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the resource expansion plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. It is not a commitment to a specific course of action, since the future is highly uncertain, now more than ever, in light of the current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative proposals to control "greenhouse gases" which could result in the retirement or retrofit of existing generating units, impacting the supply of capacity and energy to Appalachian Power Company. The resource planning process is becoming increasingly complex given pending legislative and regulatory restrictions, technology advancement, changing energy supply fundamentals, uncertainty of demand and energy efficiency advancements all of which necessitate flexibility in any ongoing plan. The ability to invest in capital intensive infrastructure is increasingly challenged in light of current economic conditions and the impact on Appalachian Power Company's customers will be a primary consideration.

2. 2009 AEP-EAST INTEGRATED RESOURCE PLAN

AMERICAN® ELECTRIC POWER

2009 AEP-EAST

INTEGRATED RESOURCE PLAN



2010-2019

Date Issued: July 2009

Business Confidential

Copy Control # _____

The Integrated Resource Plan (IRP) is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore **this plan is not a commitment to a specific course of action**, since the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative proposals to control "greenhouse gases."

The implementation action items as described herein are subject to change as new information becomes available or as circumstances warrant. It is AEP's intention to revisit and refresh the IRP annually.

The contents of this report contain the Company's forward-looking projections and recommendations concerning the capacity resource profile of its affiliated operating companies located in the PJM Regional Transmission Organization. This report contains information that may be viewed by the public. Business sensitive information has been excluded from this document, but will be made available in a confidential supplement on an as needed basis to third parties subject to execution of a confidentiality agreement. The confidential supplement should be considered strictly **business sensitive and proprietary** and should not be duplicated or transmitted in any manner. Any questions or requests for additional copies of this document should be directed to:

Scott C. Weaver
Managing Director—Resource Planning and Operational Analysis
Corporate Planning & Budgeting
(614) 716-1373 (audinet: 200-1373)
scweaver@aep.com

Table of Contents

Executive Summary i

1.0 Introduction 1
1.1 IRP Process Overview 1
1.2 Introduction to AEP 2
2.0 Current Resource Planning Issues in the Electric Utility Industry 5
2.1 Regulatory Issues 5
2.2 Climate Change and Greenhouse Gases 5
2.3 Role and Impact of Commodity Pricing on Planning 11
2.4 Issues Summary 17
3.0 Implications of Industry Issues in this IRP Cycle 21
3.1 Unit Disposition and Acquisition 21
3.2 Demand Response/Energy Efficiency (DR/EE) 21
3.3 Renewables 21
3.4 Carbon Capture & Storage/Sequestration (CCS) 24
3.5 Emission Compliance 25
3.6 Planning Constructs 26
4.0 Current Supply Resources 27
4.1 Existing AEP Generation Resources 27
4.2 Capacity Impacts of Generation Efficiency Projects 27
4.3 Capacity Impacts of Environmental Compliance Plan 28
4.4 Existing Unit Disposition 28
4.5 AEP Eastern Transmission Overview 33
5.0 Demand Projections 37
5.1 Load and Demand Forecast—A Process Overview 37
5.2 Peak Demand Forecasts 38
5.3 *Current* DR/EE Programs 42
6.0 Capacity Needs Assessment 43
6.1 RTO Requirements 45
6.2 Capacity Positions—Historical Perspective 45
7.0 Planning Objectives 47
7.1 Planning Flexibility—Covering Capacity Deficient Positions with Market Opportunities 47
7.2 Planning Horizon 47
7.3 Establishing the Optimal Asset Mix 47
7.4 Other Operational Factors 49
7.5 Affordability 50
8.0 Resource Options 51
8.1 Market Options and "Build vs. Buy" Considerations 51
8.2 Traditional Capacity-Build Options 53
8.3 Renewable Alternatives 59
8.4 Carbon Capture 66
8.5 Demand Side Alternatives 67
9.0 Evaluating DR/EE Impacts for the 2009 IRP 71
9.1 gridSMART[SM] 71
9.2 Demand Response/Energy Efficiency Mandates and Goals 71
9.3 Assessment of Achievable Potential 72
9.4 Determining Programs for the IRP 73
9.5 Discussion and Conclusion 77
10.0 Fundamental Modeling Parameters 79
10.1 Modeling and Planning Process—An Overview 79

10.2 Methodology 79
10.3 Key Fundamental Modeling Input Parameters 81
11.0 Resource Portfolio Modeling 85
11.1 The *Strategist* Model 85
11.2 Resource Options/Characteristics and Screening 86
11.3 *Strategist* Optimization 88
11.4 Optimum Build Portfolios for Four Economic Scenarios 89
12.0 Risk Analysis 101
12.1 The URSA Model 101
12.2 URSA Modeling Results 102
12.3 Installed Capital Cost Risk Assessment 104
12.4 Results Including Installed Capital Cost Risk 104
12.5 Conclusion From Risk Modeling 106
13.0 Findings and Recommendations 107
13.1 Capacity and Energy Plan 110
13.2 Comparison to 2008 IRP: 112
13.3 Plan Impact on CO_2 Emissions (*"Prism" Analysis)* 113
14.0 AEP-East Operating Companies—Plan Implications 117
14.1 AEP-East—Overview of Potential Resource Assignment by Operating Company 117
14.2 AEP-East "Pool" Impacts 119
15.0 Implementation 121
15.1 Current Commitments 121

Exhibits

Exhibit 1-1: IRP Process Overview 2
Exhibit 1-2: AEP System, East and West Zone 3
Exhibit 2-1: Fossil Fuel-to-Electricity Emissions, by Fuel Type 6
Exhibit 2-2: CO_2 Price Forecast 7
Exhibit 2-3: Renewable Standards by State 8
Exhibit 2-4: CO_2 Capture and Sequestration Process 10
Exhibit 2-5: Power Price Layers 11
Exhibit 2-6: AEP Hub On-Peak Price Index 12
Exhibit 2-7: Natural Gas Price Index 12
Exhibit 2-8: CAPP Coal Price Index 13
Exhibit 2-9: SO_2 Emission Price Index 16
Exhibit 2-10: CO_2 Emission Price Index 16
Exhibit 2-11: 2H08 vs. 1H09 Commodities Comparison 19
Exhibit 3-1: Renewable Energy Plan Through 2030 22
Exhibit 3-2: Ohio Renewable Energy Plan 23
Exhibit 3-3: AEP I&M-Michigan Renewable Plan through 2020 24
Exhibit 4-1: AEP-East Capacity Changes As of June 2009 27
Exhibit 4-2: AEP East Unit Disposition/Retirement Profile 31
Exhibit 4-3: AEP-PJM Zones and Associated Companies 33
Exhibit 5-1: Load and Demand Forecast Process—Sequential Steps 37
Exhibit 5-2: AEP-East Peak Demand and Energy Projection 39
Exhibit 5-3: AEP-East Peak Actual and Forecast Trendline 40
Exhibit 5-4: AEP-East Internal Energy Actual and Forecast Trendline 40
Exhibit 5-5: AEP-East Embedded DR/EE Programs 42
Exhibit 6-1: Summary of Capacity vs. PJM Minimum Required Reserves 44
Exhibit 6-2: Summary of Capacity Deficiency vs. PJM Minimum Required Reserves 44
Exhibit 6-3: AEP Eastern Zone, Historical Capacity Position 46
Exhibit 7-1: Annual Energy Position of Evaluated Portfolios 48
Exhibit 7-2: AEP East 2017 Load Duration Curve 49
Exhibit 8-1: Regional Summer Reserve Margin Projections 51
Exhibit 8-2: Recent Merchant Generation Purchases 53
Exhibit 8-3: United States Wind Power Locations 61
Exhibit 8-4: United States Solar Power Locations 62
Exhibit 8-5: Land Area Required to Support Biomass Facility 63
Exhibit 8-6: Biomass Resources in the United States 64
Exhibit 8-7: Renewable Sources Included in AEP-East and AEP-SPP 2009 IRP 65
Exhibit 8-8: Typical DR/EE Measure Conservation Load Factor 70
Exhibit 9-1: Impact of Legislation on Energy Consumption 71
Exhibit 9-2: Achievable versus Technical Potential (Illustrative) 72
Exhibit 9-3: Cost Effectiveness of Relative Programs 74
Exhibit 9-4: DR/EE Proxy Blocks 75
Exhibit 9-5: DR/EE Modeling Constraints 76
Exhibit 9-6: DR/EE Blocks Selected By During Resource Modeling 76
Exhibit 9-7: AEP Internal EE Target vs. 2009 IRP 77
Exhibit 9-8: DR/EE Assumption Summary 78
Exhibit 10-1: IRP Modeling and Planning Process Flow Chart 80
Exhibit 10-2: Long-term Forecast Process Flow 81
Exhibit 10-3: Input Scenarios 82
Exhibit 11-1: Model Optimized Portfolios Under Various Power Pricing Scenarios 89

Exhibit 11-2: Portfolio Summary 91
Exhibit 11-3: Optimized Plan Results (2009-2035) Under Various Pricing Scenarios 95
Exhibit 11-3: (Cont'd) Optimized Plan Results (2009-2035) Under Various Pricing Scenarios 96
Exhibit 11-4: Hybrid Plan 98
Exhibit 12-1: Key Risk Factors–Weighted Means for 2009-2035 101
Exhibit 12-2: Cumulative Probability Distribution of AEP-East Revenue Requirement 103
Exhibit 12-3: Probability Distribution of AEP-East Revenue Requirement 103
Exhibit 12-4: Basis of Installed Capital Cost Distributions 104
Exhibit 12-5: Risk-Adjusted CPW 2009-2035 Revenue Requirement ($ Millions) 104
Exhibit 12-6: Distribution Function for All Portfolios 105
Exhibit 12-7: Distribution Function for All Portfolios at > 95% Probability 105
Exhibit 13-1: AEP-East Generation Capacity 108
Exhibit 13-2: AEP-East Current Capacity Mix 109
Exhibit 13-3: AEP-East 2019 Capacity Mix 109
Exhibit 13-4: AEP-East 2030 Capacity Mix 110
Exhibit 13-5: Change in Energy Mix With Hybrid Plan Current vs. 2019 and 2030 111
Exhibit 13-6: Comparison of 2008 IRP to 2009 IRP 112
Exhibit 13-7: AEP System CO_2 Emission Reductions, by "Prism" Component 113
Exhibit 13-8: Comparison of CO_2 Emission Levels vs. W-M "Targets" 114
Exhibit 13-9: Comparison of CO_2 Emission Levels vs. W-M Allowance Allocations 115
Exhibit 14-1: AEP-East New Capacity Resource Assignments 118
Exhibit 14-2: Projected AEP-East Reserve Margin, By Company and System for IRP Period 119
Exhibit 14-3: Incremental Capacity Settlement Impacts of the IRP 119

Appendices

Appendix A, Figure 1 Existing Generation Capacity, AEP-East Zone: 124
Appendix A, Figure 2 Existing Generating Capacity, AEP-East Zone (cont'd): 125
Appendix B, Figure 1 Assumed FGD Scrubber Efficiency and Timing 126
Appendix B, Figure 2 Assumed Capacity Changes Incorporated into Long Range Plan 127
Appendix C, (Public) Figure 1 Key Supply Side Resource Assumptions 128
Appendix D, Figure 1 Economically Screened Renewable Alternatives 129
Appendix E, Figure 1 AEP-East Summer Peak Demands, Capabilities and Margins 130
Appendix F, Figure 1 Plan to Meet 10% of Renewable Energy Target by 2020 131
Appendix G, DSM by Company 132

Acknowledgements

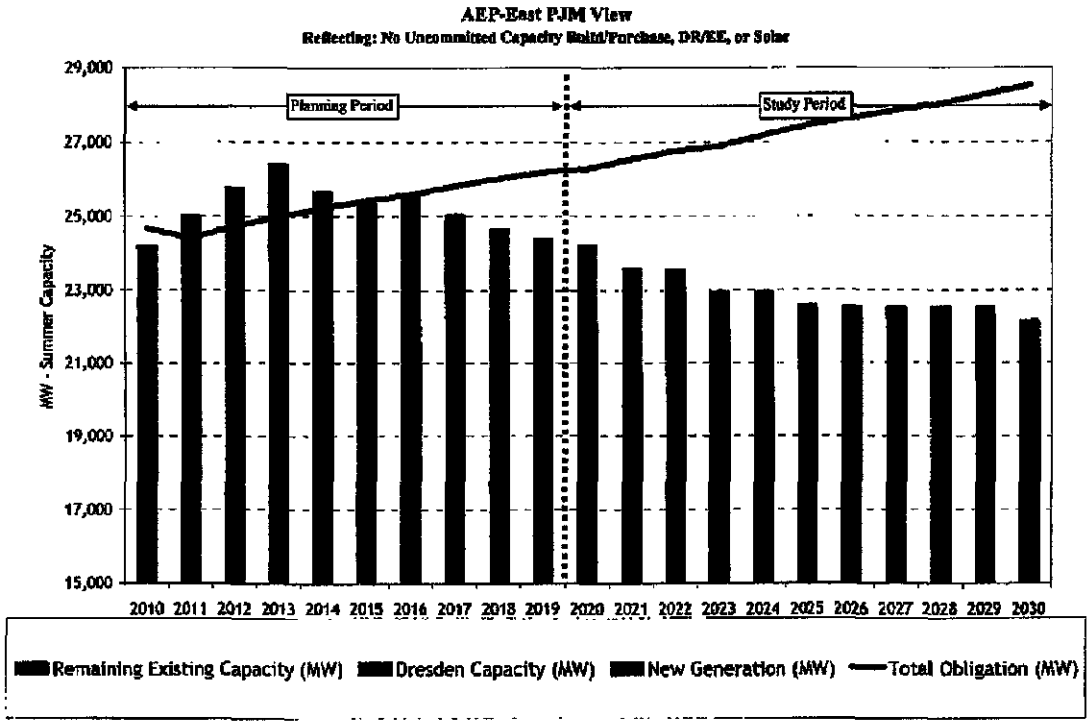
The Resource Planning group appreciates the support and input of the various individuals throughout the Service Corporation who provided input into the development of this Integrated Resource Plan document. In addition, a number of people provided valuable comments as the report was being developed including the operating company regulatory support staffs.

Executive Summary

The goal of resource planning is to match a utility's future suite of resources with projected demand for those resources. As such the plan lays out the amount, timing and type of resources that achieve this goal at the lowest reasonable cost, considering all the various constraints – reserve margins, emission limitations, renewable and energy efficiency requirements – that it is mandated to meet. Planning for future resource requirements during volatile periods can be challenging. Unprecedented economic contraction and varying levels of proposed regulation regarding greenhouse gases and renewable energy are two major drivers of uncertainty that must be addressed during the planning process. Over the 10-year, 2010-2019 Integrated Resource Plan (IRP or "Plan") forecast period (Planning Period), the AEP integrated eastern zone (AEP-East) internal peak demand is expected to grow by about 0.88 percent or 200 MW annually. This growth can be considered as occurring in two phases. In the first phase, through 2014 peak demand is expected to grow at 1.8% annually as the region rebounds from the current recession; thereafter annual peak demand growth of 0.64% is expected, the reduction representing the end of the economic rebound combined with the impact of assumed CO_2 legislation on the price of electricity.

The following **Summary Exhibit 1** offers the "going-in" capacity need of the AEP-East zone prior to *any* uncommitted capacity additions. It amplifies that the region's overall capacity need occurs beginning in the 2015-2018 period. Committed new capacity includes completion of the 540 MW Dresden combined cycle facility in 2013, and executed purchase power agreements for renewable energy (wind) resources.

Summary Exhibit 1

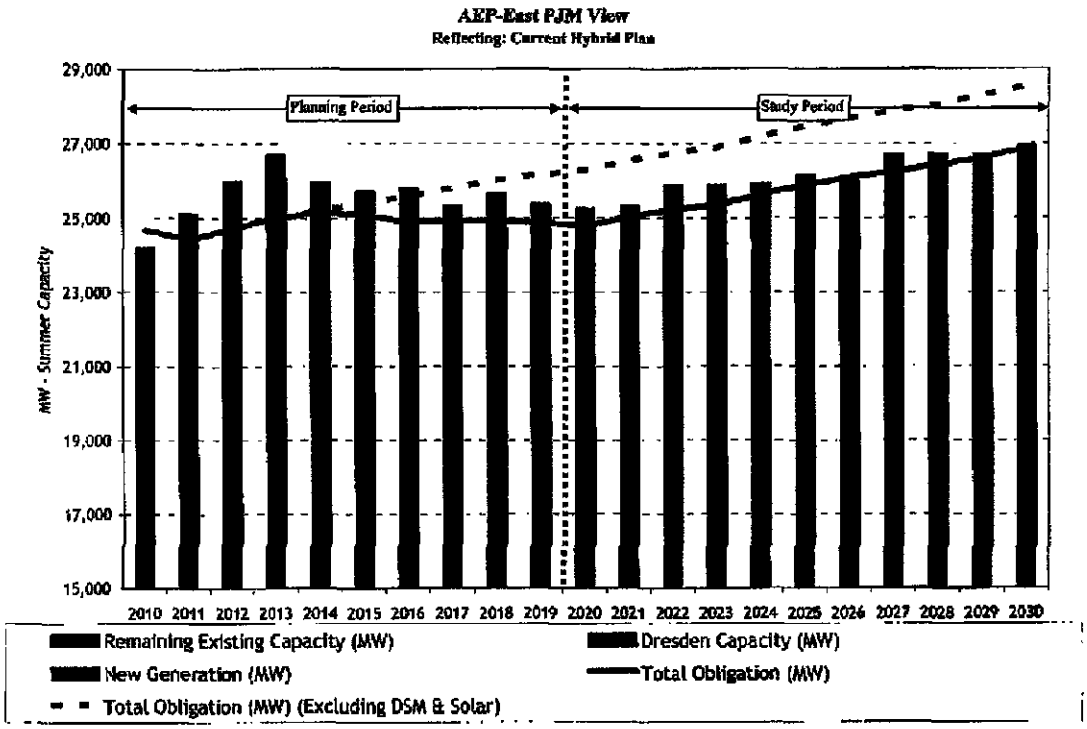


Source: AEP Resource Planning

In spite of the potential retirement of up to 3,470 MW of older, coal-fired units over the planning period due largely to external factors including known or anticipated environmental initiatives as well as the December 2007, stipulated New Source Review (NSR) Consent Decree, this AEP-East IRP requires no new baseload units in the forecast period. Rather, a unit uprate project at Cook Nuclear Plant during the 2014-2018 time period and a 2018 peaking resource, in addition to increased wind purchases and demand response programs are proposed to be added to maintain anticipated minimum PJM nominal reserve margin requirements of approximately 16.2%. Additional peaking and intermediate capacity will be added after 2020 to meet future load obligations.

Summary Exhibit 2 below shows AEP-East's capacity position relative to the PJM requirement, including capacity additions as proposed in this 2009 IRP. As this table shows, the combination of supply side additions and demand side measures that provide demand reductions/energy efficiency (DR/EE or "DSM") allow AEP-East to meet the PJM margin requirements.

Summary Exhibit 2



Source: AEP Resource Planning

Major Drivers:

Global Climate Change

This 2009 IRP for AEP-East is consistent with the AEP 2009 Corporate Sustainability Report with regard to the assumption of emerging legislation related to greenhouse gas (GHG)/carbon dioxide (CO_2) emissions, renewable portfolio standards (RPS), and energy efficiency. The pricing assumptions and requirements for CO_2 used in this IRP were developed prior to the passage of the Waxman-Marley draft. Future IRP's will reflect legislation that is developed or enacted after this report is issued. The driving planning assumptions in this IRP include:

- CO_2 mitigation in the form of substantive CO_2 reduction legislation effective by 2015 with a cap-and-trade regime effective in the same year.
- Prospect of a future Federal RPS or a critical mass or "patchwork" of AEP state-legislated RPS initiatives—which could be in the range of 10%, or more.

AEP

With that, AEP has positioned itself by assuming an aggressive posture in the adoption of renewable alternatives including a 2,000 MW system-wide renewable initiative (by 2011). That strategy would be an underpinning of an overall renewable energy target of 10% of sales by 2020 and is consistent with the existing state renewable energy targets.

Demand Reduction and Energy Efficiency

Recognizing the prospects of higher (avoided) costs, AEP initiatives to improve grid efficiency and install advanced metering, and a national groundswell focused on efficiency, the AEP-East IRP reflects approximately 537 MW of incremental peak demand reduction (above the current 269 MW of embedded peak demand reduction included in the load forecast and above the 473 MW interruptible load) by 2012, growing to 1,074 by 2015, amounts significantly exceeding those forecasted in prior planning cycles. These incremental reductions in demand result from both energy efficiency programs (474 MW) and demand response (600MW).

In Ohio, Substitute Senate Bill 221 was signed into law on May 1, 2008 and became effective on July 31, 2008. The bill sets significant and aggressive DR/EE benchmarks as well as renewable and advanced energy requirements. These goals, as well as a similar mandate in Michigan, were considered while developing the DR/EE levels recommended in this plan for AEP-East.

Potential Unit Disposition

An AEP-East unit disposition study was undertaken by an IRP Unit Disposition Working Group (WG) involving numerous AEP functional disciplines. This Q4-2008 effort was a follow-up to earlier studies performed annually since 2005. As before, the WG's primary intent was to assess the relative composition and timing of potential retirement "tranches". As in previous reviews, the predominant focus was again on the older-vintage, less-efficient, uncontrolled subcritical units in the AEP-East fleet.

In this cycle review, the WG considered financial implications of the potential (dispatch) cost impacts associated with CO_2 emissions. In addition, factors including PJM operational flexibility,

emerging unit liabilities, and workforce/community factors were considered when recommending the relative multi-tier profile of potential unit retirements.

It should be noted that the conclusions of this study are for the expressed purpose of performing this overall long-term IRP analysis and reflect on-going and evolving disposition assessments. ***From a capacity perspective, no formal decisions have been made with respect to specific timing of any such unit retirements***, with the exception of those units that are identified in the stipulated settlement agreement related to the NSR litigation. In fact, the Unit Disposition WG's formal recommendation suggested that the units operate and budget under a "Hold & Maintain" status. These disposition analyses and renderings are deemed necessary so that the *prospects* for such ultimate decisions can be integrated into a capacity replacement plan in a manner that is ratable and practical from both a financial and operational perspective.

In addition, according to the AEP Environmental Group, Federal action is anticipated and could become effective in 2014 when a command-and-control policy could require all coal units to install either a mercury-specific control technology such as ACI or FGD/SCR emissions control equipment. There is also a strong possibility that a plant-by-plant standard will replace a mercury trading system. If this is the case, a dispatch price would not be required, but additional controls such as baghouses or ACI would be needed. This could have an impact on proposed retirement dates of these older, non-controlled units and ultimately the timing for new capacity.

Carbon Capture and Sequestration Technology

The 2009 plan does not include any coal fired baseload additions but does recognize that the existing fossil fleet may be subject to reduced CO_2 limits in the future. Therefore, the plan includes the continued phase-in of Carbon Capture and Sequestration (CCS) at Mountaineer Plant as a practical and cost-effective method. It is essential that the successful demonstration of this technology will be necessary before it is rolled out on a larger scale.

> "If this technology ultimately is not available to us and the industry, and in fact global warming legislation is passed and we can't address ourselves to the post-combustion answer, our company, our investors and everyone else in this face what I have called an economic brownout, because we simply won't have adequate electricity to energize the U.S. economy."
>
> Mike Morris, AEP Chairman, President and CEO

Wind and Other Renewable Resources

Along with the prospects of CO_2 legislation, the possible introduction of a Federal (or "en masse" state) RPS, helped justify the planned system-wide purchase of 2,000 MW of renewable resources—for planning purposes assumed to be in the form of wind power—by 12/31/2011. The largest portion of these purchases (1,926 MW, nameplate) is assumed to be applicable to AEP-East.[1] Placed in addition to current and planned AEP-West region affiliates' (PSO and SWEPCO) long-term wind purchases as well as economically-screened wind and biomass co-firing opportunities beyond

[1] Note: Recognizing also that firm "capacity" attributable to wind would be limited to roughly 13% of that amount for purposes of capacity planning in PJM.

the 10-year IRP period, AEP is positioned to achieving 10% of energy sales from renewable sources, again consistent with Ohio Substitute S.B. 221 and other state mandated renewable goals.

Emerging Technology

AEP is committed to pursuing emerging technologies that fit into the capacity resource planning process, including Sodium Sulfur (NaS) Batteries, fuel cells, solar panels, and "smart" grid enabling meters. These "distributed" technologies, while currently expensive relative to traditional demand and supply options, have the capacity to evolve into common resource options as costs come down and the capabilities continue to improve. For each of these options, both the technology and associated costs will continue to be monitored for increased inclusion in future planning cycles, if warranted.

AEP East Recommended Plan (Including AEP-East Company Ownership):

- ✓ Complete the 540 MW Dresden Combined Cycle Facility by 2013 (APCo)
- ✓ As part of the life extension component replacement program required under the 20 year operating license extension received in August 2005, uprate the D.C. Cook Units 1 and 2 by 417 MW over the 2014 to 2018 timeframe (I&M)
- ✓ Construct or acquire 628 MW of peaking (e.g., Combustion Turbine) capacity by 2018 (APCo & KPCo, 50/50 Ownership)
- ✓ Purchase or construct 2,451 MW (nameplate) of wind generation (Various companies) in addition to 75 MW already in operation by 2009 bringing total nameplate wind capacity to 2,526 MW by 2019
- ✓ Construct or acquire 187 MW of biomass generation by 2018 (CSP & OPCo)
- ✓ Continue the Carbon Capture and Sequestration Demonstration project at the Mountaineer facility (APCo)
- ✓ Implement Demand Response totaling 1,073 MW by 2015 (Various)

On July 28, 2009 AEP was informed that Ormet will shut down its Hannibal, Ohio operations indefinitely. Future AEP-East planning will reflect this change.

The following **Summary Exhibit 3** offers a view of the 2009 AEP-East IRP:

Summary Exhibit 3

2009 IRP for *AEP-East*

	Planned Resource Reductions (MW) [A]		*Planned Resource Additions (MW)* [A]						
			DSM		RENEWABLE				
	Unit Refinements (summer-rating)	Environmental Retrofits [F]	Embedded Demand Reduction [B] (Cumul. Contribution)	New Demand Reduction [C] (Cumul. Contribution)	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate / New Facility [D])	Duty Cycle Type: BL=Baseload INT=Intermediate/Cycl ic PKG=Peaking	*Ownership*
2009			58	0	0	200			
2010	(440)	MT-Ph1CCS(4 MW) RK1&2 ACI	145	179	10	350			
2011			287	358	3	601			
2012	(560)	AM2 FGD (10 MW)	269	537	2	700	(0) / 60		
2013		AM1 FGD CV5&6 SCR(18MW)	271	716	14	600		(Dresden) 540-MW INT	*APCo*
2014	(395)	MT-Ph2 CCS (31 MW)	272	894	14		(43) / 0	(Cook 2)+46MW BL	*I&M*
2015	(415)	MR5/BS2 FGD (50 MW)	273	1,073	14			(Cook 1&2)+168MW BL	*I&M*
2016			273	1,073	14	100		(Cook 1)+68MW BL	*I&M*
2017	(600)	RK1 FGD	273	1,073	13			(Cook 2)+68MW BL	*I&M*
2018	(580)		273	1,073	17		(41) / 127	(Cook 1)+ 68MW BL and 628-MW PKG	*PKG: APCo/KPCo 50/50; BL: I&M*
2019	(480)	RK2 FGD	273	1,073	17				
2019 Cumul. Contribution/Nameplate	*(2,470)*	*(113)*	*273*	*1,073*	*118*	*2,451*	*103*	*1,585*	
(PJM) Capacity Value [E]					*83*	*319*			
Cumul. (Nameplate) Contribution			*5%*	*19%*	*2%*	*44%*	*2%*	*28%*	
Cumul. (Capacity) Contribution			*8%*	*31%*	*2%*	*9%*	*3%*	*46%*	

Peaking	628	40%
Intermediate (incl. Dresden)	540	34%
Baseload (D.C. Cook Uprates)	417	26%
	1,585	

"NET" CAPACITY RESOURCE ADDITIONS:	
Additions - Reductions =	*(147)*

(A) Not shown are smaller unit derates and uprates embedded in the current plan which are largely offsetting

(B) "Embedded" DSM represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast

(C) "New" DSM represents incremental activity projected based on estimated contribution & program cost (vs. avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan. '09 study identifying a "Realistically Achievable Potential"... Note: Such 'New' (increm) DSM activity modeled thru 2015 only

(D) Derate represents a blended fuel biomass unit, New Facility reflects a single repowered, (100%) dedicated biomass (e.g. stoker) unit from MR 1-4 and a 60 MW PPA

(E) Capacity value in PJM is initially set at 13% of nameplate for wind and 70% of nameplate for solar

(F) CCS retrofit technology assumed to be chilled ammonia with a 15% parasitic load

Source: AEP Resource Planning

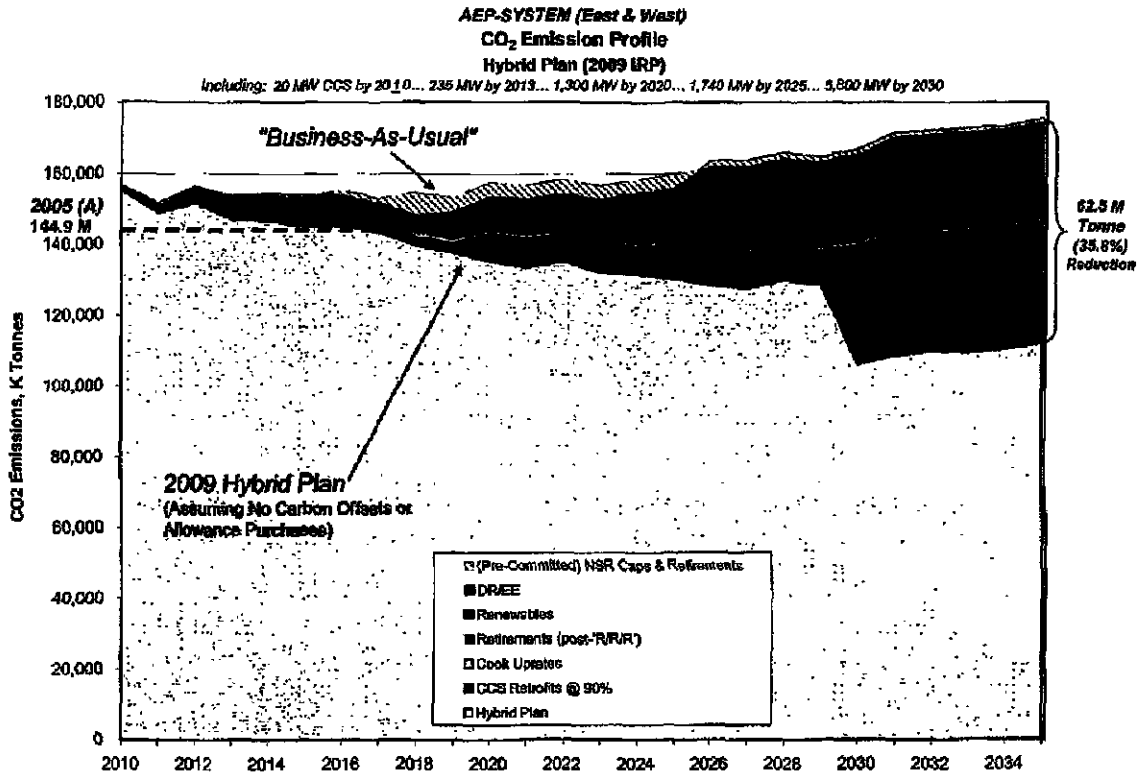
Plan Impact on Carbon Mitigation (*"Prism" Analysis*)

Global Climate Change and the prospect for comprehensive CO_2 legislation has had a direct bearing on the outcome of the 2009 AEP-East Plan. To gauge the respective CO_2 mitigation impacts incorporated into this resource planning, an assessment was performed that emulates an approach undertaken by the Electric Power Research Institute (EPRI). This profiling seeks to measure the contributions of various "portfolio" components that could, when taken together, effectively achieve such carbon mitigation:

- Energy Efficiency
- Renewable Generation
- Fossil Plant Efficiency, including coal-unit retirements
- Nuclear Generation
- Technology Solutions, including Carbon Capture and Sequestration

The following **Summary Exhibit 4** reflects those comparable components within this 2009 IRP–set forth as uniquely-colored "prisms"—that are anticipated to contribute to the overall AEP system's (*combined East and West regions*) initiatives to reduce its carbon footprint:

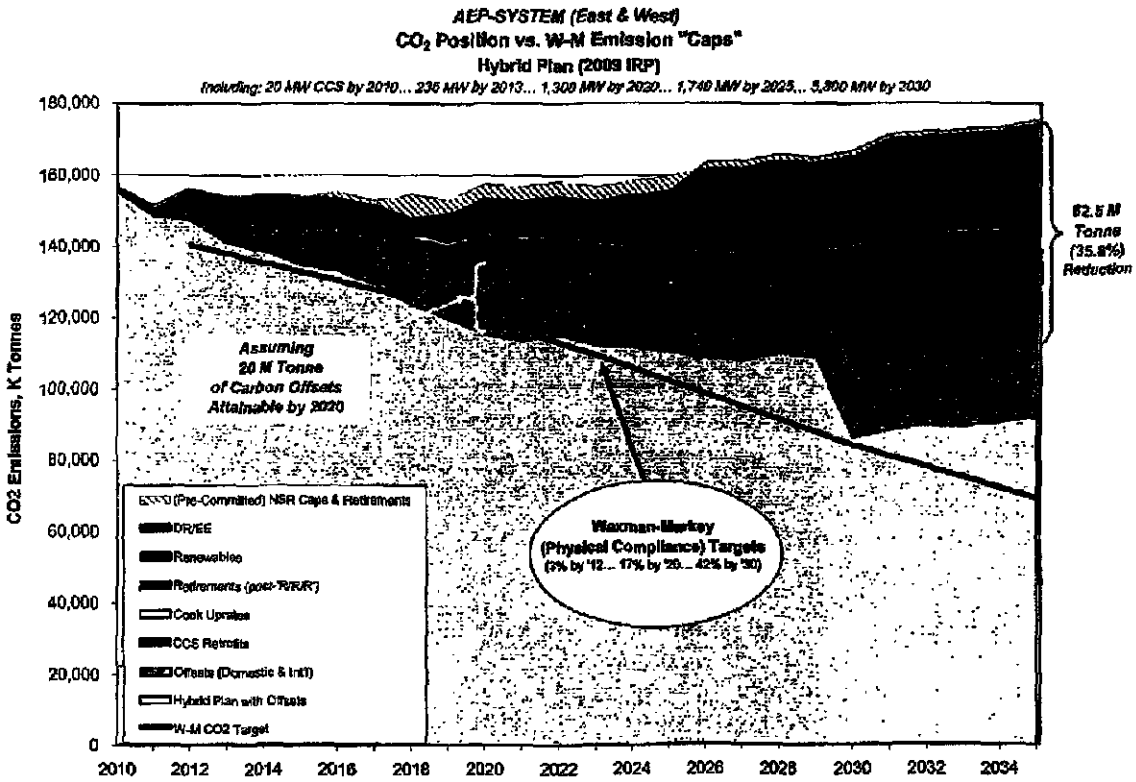
Summary Exhibit 4



Source: AEP Resource Planning

While these results would suggest significant improvement in the AEP System CO_2 emission profile over time, it could still fall short of prospective legislation that would attempt to further limit CO_2. Specifically, using H.R. 2454 (the Waxman-Markey Bill) that passed the U.S. House in June, 2009 as a proxy, this profile would require reduction in CO_2 emissions that would have to consider acquisition of carbon "offsets"—financial instruments that represent certified initiative to remove 1 ton of carbon—to begin to approximate the levels of reduction set forth by such mandates. The following **Summary Exhibit 5** offers such a comparison for the AEP System:

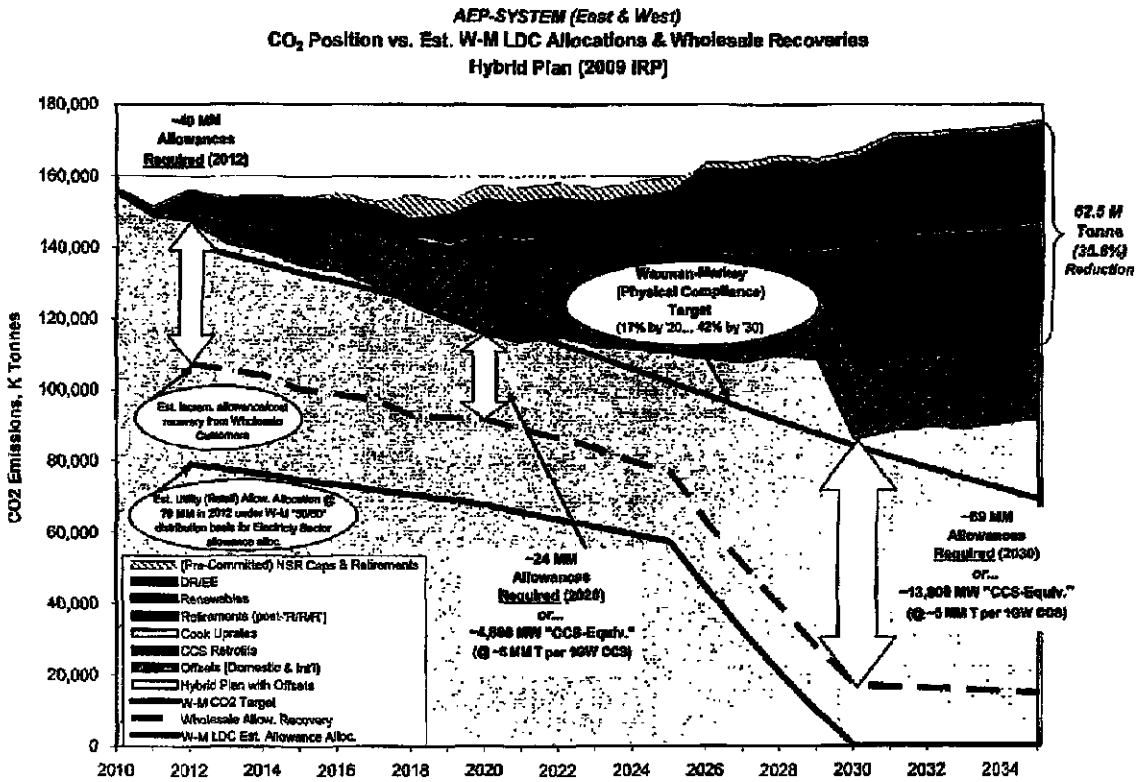
Summary Exhibit 5



Source: AEP Resource Planning

Further, under the assumption that a cap-and-trade mechanism could emerge from any set of carbon legislation, it is reasonable to assume that such CO_2 mitigation efforts, inclusive of offset acquisitions, may not provide for an adequate CO_2 position within that mechanism. Specifically, if the legislation provides for the *allocation* of an insufficient level of (free) CO_2 allowances to the utility, any such remaining CO_2 position "shortfall" must subsequently be borne by the utilities' customers through additional, potentially more costly, CO_2 mitigation efforts, including the purchase of additional allowances. The following **Summary Exhibit 6** identifies this potential position based on the current allowance allocation format set forth by the Waxman-Markey Bill:

Summary Exhibit 6



Source: AEP Resource Planning

In summary, this prism analysis would suggest that the carbon mitigation requirements in the AEP-East 2009 IRP offer a meaningful pathway to the attainment of potential Climate Change/CO_2 legislation, however, **additional** contributions–over-and-above the acquisition of CO_2 allowances—may be required in future planning cycles to protect AEP's customers from significant cost exposures.

Plan Impact on Capital Requirements

This Plan includes new capacity additions, as well as unit uprates and environmental retrofits. Such generation additions require a *significant* investment of capital. Some of these projects are still conceptual in nature, others do not have site specific information to perform detailed estimates; however, it is important to provide an order of magnitude cost estimate for the projects included in this plan. As some of the initiatives represented in this plan span both East and West AEP zones, this **Summary Exhibit 7** includes estimates for projects over the entire AEP system Generation (G) functional discipline.

Summary Exhibit 7

AEP System (East & West)
PRELIMINARY (Incremental) "G" Capex Spend
Reflecting...
2009 IRP (EAW)
Assuming 1,300 MW CCS (MT only) by 2020... (w/ 1,740 MW by 2025 ... 5,600 MW by 2030)

2010-2019
($Millions)

By Type...	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL (2010-2019)	Group %
IRP (New Generation)	382	306	321	110	175	281	306	302	177	634	2,974	29%
IRP (Response to Carbon / RPS Legislation)	-	-	-	44	147	381	349	548	848	623	2,941	24%
Subtotal	382	306	321	154	322	662	655	850	1,025	1,257	5,915	
Plus:												
Environmental Compliance / Cook License Extension	58	242	518	794	1,039	1,287	865	639	439	33	6,126	51%
TOTAL INCREMENTAL "G" CAPEX	420	548	849	948	1,361	1,969	1,521	1,689	1,464	1,290	12,041	
Annual %	3%	5%	7%	8%	11%	16%	13%	14%	12%	11%		

By Operating Company...	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL (2010-2019)
AEG	4	5	90	37	50	135	246	370	228	17	1,172
APCo	14	15	14	15	68	298	251	646	723	582	2,565
CSP	0	0	13	30	70	98	8	0	100	125	444
I&M	90	90	110	152	352	664	642	470	220	63	2,842
KPCo	2	72	100	150	190	154	102	90	5	0	911
OPCo	4	3	33	95	164	158	73	69	30	88	748
PSO	0	5	63	203	258	331	128	23	153	271	1,436
SWEPCO	306	412	417	267	179	72	70	122	15	114	2,033
TOTAL INCREMENTAL "G" CAPEX	420	548	849	948	1,361	1,969	1,521	1,689	1,464	1,290	12,041

Source: AEP Resource Planning

It is important to reiterate the capital spend level reflected on the Summary Exhibit 7 is "incremental" in that it does not include "base"/business-as-usual capital expenditure requirements of the "G" sector. Achieving this additional level of expenditure will therefore be a significant challenge going-forward and would suggest the Plan itself *will remain under constant evaluation and subject to change.*

Conclusion:

The recommended capacity resource plan provides the "lowest reasonable cost" solution through a combination of traditional supply, renewable and demand side investments. The tempered load growth combined with additional renewable resources, increased DR/EE initiatives and the uprate of the Cook Nuclear facility allow AEP-East to meet its reserve requirements until 2018, at which point new peaking capacity will be required. No new baseload capacity is required over the term of the forecast period.

The plan positions AEP-East to meet state renewable portfolio standards and energy efficiency requirements, and sets in place the framework to meet potential CO_2 reduction targets at the intended least reasonable cost to its customers.

Keep in mind that the planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the resource expansion plan reported herein reflects, to a large extent, assumptions that are subject to change. It is simply a snapshot of the future at this time. The Plan is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative proposals to control "greenhouse gases" which could

result in the retirement or retrofit of existing generating units, impacting the supply of capacity and energy to AEP-East companies. The resource planning process is becoming increasingly complex given pending legislative and regulatory restrictions, technology advancement, changing energy supply fundamentals, uncertainty of demand and energy efficiency advancements all of which necessitate flexibility in any ongoing plan. The ability to invest in capital intensive infrastructure is increasingly challenged in light of current economic conditions, and the impact on the AEP-East customers will continue to be a primary planning consideration.