REDACTED VERSION OHIO POWER COMPANY'S RESPONSES TO
SIERRA CLUB'S DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
SECOND SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-2-080 Refer to pages 11-12 of the Vegas Testimony.

a. Produce all AEP economic analyses that led to announced retirement of AEP generation resources in the Midwest since 2008.

b. Produce all AEP economic analyses regarding the decision of whether to retire PPA units if the PPA is not approved, or prior to consideration of the PPA.

RESPONSE

a. The Company objects to the extent the request seeks information which is outside the scope of the case and is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. The Company further objects to this request as being vague. Without waiving these objection(s) or any general objection the Company may have, the information referenced below regarding generating assets owned previously by AEP Ohio, and are now owned by AEP Generation Resources, is being provided based on the Company's understanding of the question and while preserving the ability to add additional reasons or supporting arguments later.

The retirement of Sporn Unit 5 was the subject of Case No. 10-1454-EL-RDR before this Commission. The Company's Application in that filing included the economic analysis relevant to the retirement of Sporn Unit 5, which occurred in February 2012.

The other plants currently owned by AEP Generation Resources whose retirements have been announced since 2008 include Conesville Unit 3, Kammer Units 1-3, Muskingum River Units 1-5, Picway Unit 5, and Sporn Units 2 and 4. The retirement of these units had been considered for some years due to the inability to justify major capital investments needed to potentially comply with future regulations, as well as the inclusion of some of these units in the New Source Review Consent Decree into which AEP entered with the Department of Justice and other parties in October 2007.

Ultimately, the decision to retire these generating units was made when the Mercury and Air Toxics Standards (MATS Rule) was made final in April 2012. At that point there was no new economic analysis that was performed, the rule only confirmed the retirement dates of the generating units in the form of a compliance date. The costs of retrofitting these generating units, as well as their inclusion in the Consent Decree, were discussed in the Company's AEP-East Integrated Resource Plan in 2011. The public version of this IRP is included as SC-RPD-2-080 Attachment 1.

b. As discussed in the Direct testimony of Company witnesses Vegas and Thomas in this proceeding, the Company has not yet made any decision to retire the plants included in the proposed PPA. The PPA will reduce the likelihood that the units will be retired prematurely.

Prepared by: Pablo A. Vegas and Toby L. Thomas

APPALACHIAN POWER COMPANY

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

September 1, 2011

PUBLIC VERSION

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1.0 Executive Summary

Appalachian Power Company's (APCo, or "the Company") energy and peak requirements are expected to grow at 0.6% per year through 2025. To meet these requirements, APCo analyzed three distinct resource portfolios – one that relies on the capacity and energy markets through 2025 (the "Market" plan), one that provides for the addition of generating assets beginning in 2017 (the "Build" plan), and finally, one that meets APCo's energy requirements with renewables, energy efficiency, natural gas and smart grid technologies such that 40% of APCo's energy would come from clean energy resources by 2040 (Clean Energy Standard, or the "CES" plan).

The "Market" and "Build" plans resulted in almost identical costs to customers, and lower overall costs through 2040, on a present value basis, than the "CES" plan. Given the uncertainty surrounding the final outcome of both the EGU MACT rulemaking expected in November 2011, and the modifications to the AEP Pool expected by 2014, the Company is proposing the plan which has the maximum flexibility – the "Market" plan. The "Market" plan allows the Company to take advantage of favorable bilateral deals (either as part of a modified Pool construct, if such option is available, or with third parties), the PJM RPM auction, and/or generation asset purchases, but also preserves the option to self-build at any point if long-term purchase prices exceed the cost of a new natural gas plant. The supply-side expansion plan represented in both the "Market" and "Build" plans is also influenced by APCo's commitment to DSM programs, renewables, and to the need for compliance with environmental regulations.

1.1 Company Operations and Relationship with the AEP System

APCo serves a population of about 2.0 million (961,000 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 requirements power at wholesale to an affiliated company, state agency, private systems, municipalities and electric cooperatives, and participates, as part of the AEP-East System, in off-system sales to 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 the total internal energy requirement of 38,625 gigawatt-hours (GWh) for APCo in 2010, residential, commercial, and industrial energy sales accounted for 34%, 19%, and 28% respectively. Public street and highway lighting, sales–for-resale, and all other categories accounted for the remaining 19%.

In 2010, APCo's Virginia total internal energy requirements were 19,440 GWh, with residential, commercial and industrial accounting for 36%, 18% and 28% respectively. The remaining energy requirements are comprised of other sales to public authorities, other sales for resale, and all other categories.

In comparison, the AEP-East Zone (AEP-East) collectively serves a population of about 7.2 million (3.2 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. In 2010 the residential, commercial, and industrial customers accounted for 30.7%, 23.2%, and 33.0%, respectively, of AEP-East total internal energy requirements of 125,381 GWh. The remaining 13.1% was supplied for use in the public street and highway lighting, sales-for-resale, and all other categories.

AEP-East experienced its all-time peak internal demand of 22,411 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 (off-system sales) are included, AEP-East reached its all-time peak total demand of 26,467 MW on August 21, 2003.

AEP-East 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-East 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 AEP-East system to the PJM regional transmission organization (RTO) in 2004. This transfer was approved by the

Virginia State Corporation Commission (SCC) in Case No. PUE 2000-00550, by order dated August 30, 2004. PJM assumed the monitoring, market operations and planning responsibilities of the AEP-East 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-East transmission system. PJM also became the North American Electric Reliability Council (NERC) Reliability Coordinator for the AEP-East 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 -East generating resources to meet minute-to-minute loads and determines the planning reserve required to maintain generation resource adequacy.

1.1.1 AEP-East Pool Status

As communicated to the SCC on January 4, 2011, on December 17, 2010, pursuant to Article 13 of the FERC-approved AEP Interconnection Agreement ("IA," "Interconnection Agreement" or "AEP Pool"), each of the AEP Pool members gave written notice to the other members, and to American Electric Power Service Corporation ("AEPSC"), the AEP Pool's agent, of its revocable intent to terminate the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC. Because the IA is a rate schedule on file at FERC, its termination will not be effective until accepted for filing by FERC.

The Interim Allowance Agreement among the AEP companies ("IAA"), which was most recently modified in 1996 and deals with sulfur dioxide (SO_2) emissions and allowances, would also be terminated. Environmental regulations have expanded beyond those covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of nitrogen oxides (NO_X). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions.

By giving notice to terminate the IA and the IAA, the AEP Pool members are providing a framework and timeline within which all interested stakeholders have an opportunity to participate in the determination of how the AEP-East operating companies should operate prospectively. This process has already begun, as APCo has engaged with several stakeholders in

Virginia and West Virginia. Other AEP Pool members have made similar contacts with stakeholders in their respective state jurisdictions.

Assuming this AEP Pool termination notice is not revoked or significantly modified, beginning in 2014, APCo's resource planning relationship with the other AEP-East companies could take one of a number of plausible forms. Rather than plan for every potential outcome, which would not be particularly efficient or beneficial, APCo has planned for two potential conditions. First, an integrated resource plan (IRP or the "Plan") for APCo as a stand-alone entity beginning in 2014 has been created. A second plan with APCo as part of the AEP-East Pool in its existing construct has also been prepared.

This IRP document neither pre-supposes the Pool/Stand-Alone end-state, nor does it make any recommendation regarding AEP-East company relationships in a "post-AEP Pool" world. Rather, it merely presents a plan for APCo to meet its obligations under the two potential governance scenarios outlined above.

1.1.2 Environmental Compliance Issues

The 2011 IRP considers final and proposed future United States Environmental Protection Agency (EPA) regulations that will impact fossil-fueled electric generating units (EGU).

The EPA has issued final rulemaking to replace the former Clean Air Interstate Rule (CAIR) for the regulation of SO_2 and NO_X which had previously been remanded by the federal courts. The EPA issued the Cross-State Air Pollution Rule (CSAPR) to establish state-specific emission budgets for SO_2 and both annual and seasonal (May-September) NO_X with a two-phase emission reduction beginning in 2012. Further, the federal EPA proposed the EGU Maximum Achievable Control Technology (MACT) rule in March 2011 to replace the court vacated Clean Air Mercury Rule (CAMR). EGU MACT will regulate emissions of hazardous air pollutants (HAPs) such as mercury, arsenic, chromium, nickel, certain acid gases and organic HAP compounds and is expected to be finalized in November 2011 with full implementation in 2015. EPA is also expected to propose first-ever requirements regulating greenhouse gas emissions later this year, but the substance of those requirements is not known. Combined, the CSAPR, MACT rule, and other impending federal air regulatory programs will require significant emission reductions from all U.S. coal and lignite-fired units. Emission reductions will be achieved beginning in 2012 as a result of unit retirements, unit curtailments, and installation of emission control technologies, including flue gas desulphurization (FGD) or dry sorbent injection (DSI), selective catalytic reduction (SCR), activated carbon injection (ACI), and fabric filter systems. In the AEP-East states, these new and proposed emission reduction programs will accelerate planned environmental retrofit projects and will drive unit curtailments beginning in 2012.

In addition, a new rule on the handling and disposal of coal combustion residuals (CCR) is being developed by the EPA, which, as proposed, would require significant additional capital investment in the coal-fired EGU to convert "wet" ash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to "dry" systems and in addition build waste-water treatment facilities to process plant groundwater run-off before discharge. EPA is developing regulations with respect to the intake of cooling water and discharge of wastewater, which also has the potential to require significant capital investment for compliance.

The cumulative cost of complying with these final and proposed environmental rules will be highly burdensome to APCo, the AEP-East operating companies, and their customers. Such requirements could also accelerate proposed retirement dates of any currently non-retrofitted coal unit in the AEP-East fleet as established within this 2011 IRP, as discussed below.

1.1.3 Compliance With Conditions Set Forth in the 2009 IRP Order

APCo filed its first IRP on September 1, 2009. The SCC, in its findings, required that APCo's IRP should not concentrate as heavily on planning for AEP-East as a whole but should be more focused on cost reduction and planning for APCo individually. To address this finding, APCo has modified its modeling such that APCo-specific portfolios are now being analyzed and developed. APCo also completely reformatted the IRP report itself, focusing more on APCo-specific issues. The SCC also stated that APCo needs to address more fully (i) its continued capacity deficit position; (ii) the pattern of being assigned higher cost capacity than is assigned to other AEP-East companies; and (iii) ways to reduce APCo's capacity equalization charges. APCo addressed these concerns in its "Report on Capacity Matters" provided to the SCC on January 4, 2011 and attached as an addendum to this IRP.

Finally, during the APCo IRP proceedings, APCo committed to meeting with stakeholders prior to preparing the 2011 IRP. APCo and AEPSC representatives have engaged certain stakeholders that had participated in the 2009 APCo IRP proceeding including the SCC Staff, the

Office of the Attorney General, Southern Environmental Law Center, and Old Dominion Committee for Fair Utility Rates. These organizations have expressed their general views that, while the approach and specific methodologies and models utilized are reasonable, the Company should be specifically mindful of: a) the rate impact of its plans, and b) also consider the IRP's environmental consequences. APCo has considered the input received from these stakeholders in developing this resource plan by (1) presenting a plan with limited capital investment in the near term, and (2) evaluating an alternate plan which meets the potential standards of a "clean energy portfolio."

1.2. Summary of APCo and AEP-East Resource Plans

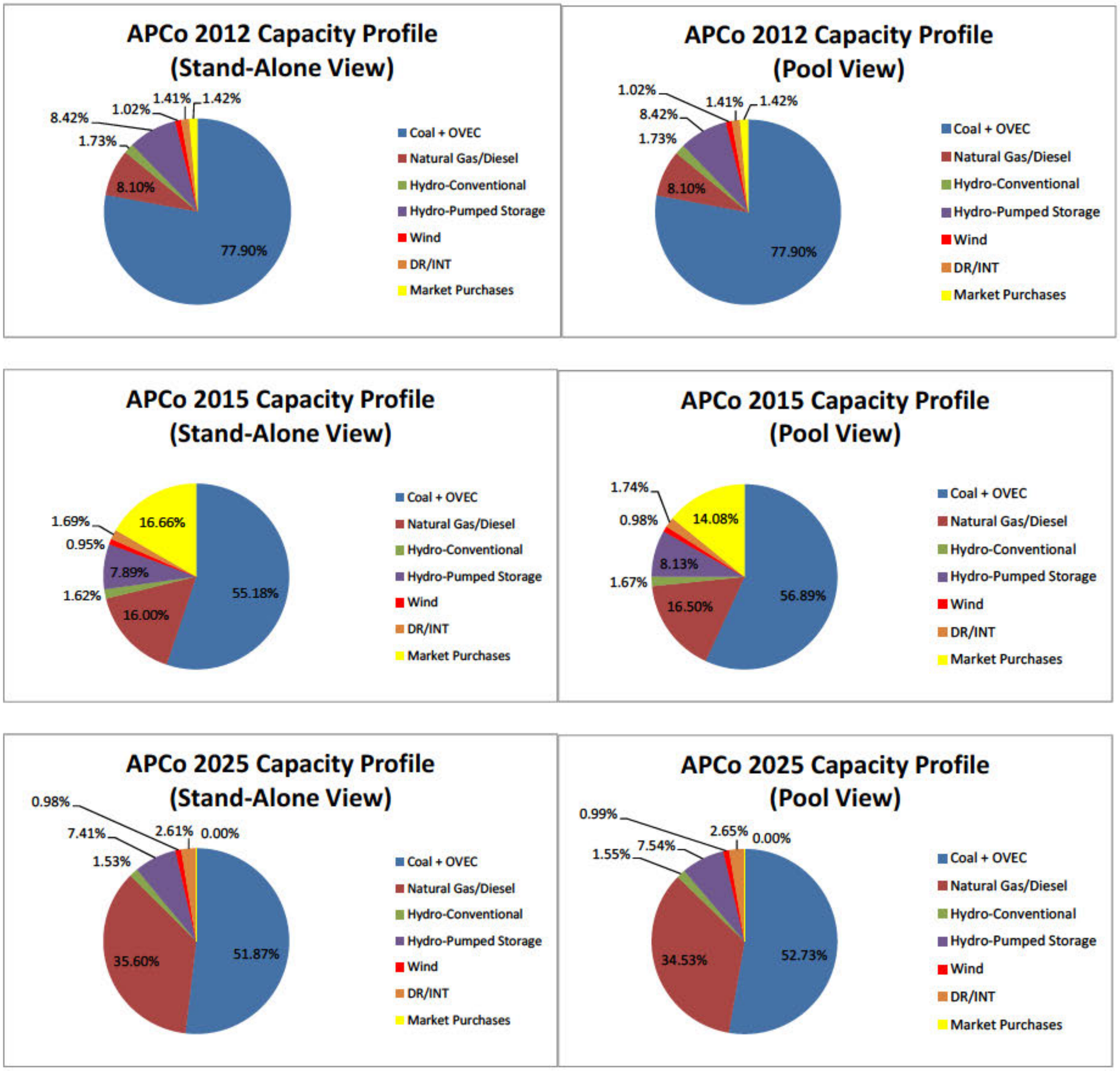
An IRP explains how a utility company will meet the projected capacity (*i.e.*, peak demand) and energy requirements of its customers. By Virginia rule, APCo is required to provide an IRP that encompasses a 15-year planning period.

The internally-generated 2011 load forecast projects compound average growth rates (CAGR) for APCo peak demand of 0.6% for the winter season and 0.8% for the summer season for the 15-year period 2011-2025. Even at these different growth rates, APCo is expected to remain winter-peaking. In comparison, the CAGRs for the AEP System-East Zone are 0.3% for winter and 0.5% for summer. Correspondingly, APCo internal energy requirements are projected to grow at a 0.6% CAGR and AEP-East at a 0.3% CAGR.

By 2025, potential installed energy efficiency (EE) and grid efficiency programs totaling 2,250 GWh (5.9%) of retail sales are projected to achieve demand reductions of approximately 151 MW from the winter season forecasted peak demand and 140 MW from the summer peak demand and reduce energy requirements by 939 GWh by the same year relative to the business as usual forecast. Incremental demand response programs will have the ability to reduce summer peak demand by an additional 217 MWs. This "base case" of demand-side programs represents a consistent and moderate approach to demand-side programs. More aggressive pursuit of programs may become a favored approach in light of potentially increasing avoided costs.

The projected capacity changes for this planning cycle for APCo are shown in **Exhibit 1-1** both as APCo as a stand-alone entity in PJM and also as a member of the AEP Pool. APCo's capacity portfolio changes significantly from 2012 to 2015, then again in 2025.

Exhibit 1-1: APCo's Capacity Make-Up Over the IRP Period



Source: AEP Resource Planning

Specific capacity additions are listed in **Table 1** for APCo as a stand-alone entity and in **Table 1A** as a member of the AEP Pool, and for AEP-East in **Table 2**. For APCo this includes completion of the Dresden natural gas combined cycle (NGCC) plant in 2012 and the construction or acquisition of additional intermediate capacity in 2025. Also for APCo, additional wind purchases in 2023 are projected to meet voluntary renewable goals established in the Commonwealth of Virginia. Table 1 also shows market purchases required to meet minimum reserve criteria in PJM.

Table 1

APCo Resource Plan to Meet PJM Reserve Margin Requirements

APCo Capacity Portfolio (Stand-Alone View)

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011		(10)				3	121	
2012					580	10	121	
2013						22	121	
2014						89	121	1,238
2015	(1,245)	(46)				136	121	1,354
2016						203	121	1,367
2017						266	121	1,377
2018						282	121	1,439
2019						297	121	1,497
2020						311	121	1,548
2021						321	121	1,637
2022						331	121	1,709
2023			50	7		339	121	1,761
2024						349	121	1,812
2025					2,248	357	121	
	(1,245)	**(56)**	**50**	**7**	**2,828**	**357**	**121**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

Table 1A shows purchased capacity that would be assigned to APCo under the existing Pool construct. In the column labeled "Market Purchase Alternatives, Directly Assigned (Long Term)," the capacity assignment is based on AEP-East making long-term purchases of market capacity to meet PJM margin requirements and allocating that capacity to APCo and other AEP-East deficit companies. This capacity assignment will reduce APCo's capacity deficit position in the AEP Pool. An alternate view is shown in the column labeled "Market Purchases Alternatives MLR Share (Short Term)." In this view, AEP-East would make short-term capacity purchases which are then allocated to all the AEP-East companies based on their Member Load Ratio (MLR). In this case the capacity allocation does not reduce APCo's capacity deficit position in the AEP Pool.

Table 1A

APCo Resource Plan as Part of AEP Pool

APCo Capacity Portfolio (Pool View)										
Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/ NT (MW) (c)(d)		Market Purchase Alternatives (MW)		
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	Directly Assigned (Long Term)	OR	MLR Share (Short Term)
2011		(10)				3	121			
2012					580	10	121			
2013						22	121			
2014						89	121	1,015		570
2015	(1,245)	(46)				136	121	939		530
2016						203	121	648		273
2017						266	121	568		246
2018						282	121	617		268
2019						297	121	675		290
2020						311	121	673		289
2021						321	121	827		346
2022						331	121	888		382
2023			50	7		339	121	913		406
2024						349	121	1,302		567
2025					1,360	357	121			
	(1,245)	**(56)**	**50**	**7**	**1,940**	**357**	**121**			

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

Table 2

AEP-East Resource Plan to Meet PJM Reserve Margin Requirments

AEP-East Capacity Portfolio								
Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011		(10)				123	519	
2012	(560)	(10)	117	20	580	199	519	
2013			120	21		302	519	
2014	(380)		232	38		570	519	1,776
2015	(3,367)	(136)	215	32		823	519	1,643
2016	(278)	0	150	20	602	1,100	519	843
2017			150	20		1,365	519	757
2018			117	20		1,478	519	823
2019			100	13		1,617	519	888
2020		35	271	40		1,765	519	885
2021			100	13		1,870	519	1,052
2022			100	13		1,955	519	1,158
2023			200	26		2,026	519	1,230
2024			21	8		2,080	519	1,718
2025	(500)				2,236	2,130	519	
	(5,085)	**(121)**	**1,893**	**282**	**3,418**	**2,130**	**519**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

The plan provides for reliable electric utility service, at reasonable cost, through a combination of traditional supply, market (purchased power) options, renewable supply and demand side programs. APCo and AEP-East will provide for adequate capacity resources to serve their customers' peak demand and required (PJM) reserve margin needs throughout the forecast period, as shown on **Schedules 16a** and **16b**.

In addition to this “Base” plan, this report also identifies two *additional* planning scenarios that generally seek to:

- Analyze the relative cost impact of a larger APCo thermal generating fleet (i.e., lesser dependence on purchases from the AEP Pool or, in lieu of the AEP Pool, "market" purchases going forward; and
- Analyze the relative cost impact of a larger "non-traditional" portfolio, namely, Demand-Side Management (DSM) and Renewable resources.

1.3 Conclusion

This IRP is being presented at a time of great uncertainty with regard to the future status of APCo and the relationship of the AEP-East generating companies. The final outcome of pending environmental regulations may require a significant level of capacity retirements in a relatively short period of time. The AEP Pool construct, which has been in place since 1951 (with modifications over time) will likely be modified by 2014. The final outcome of this uncertainty makes it a challenge to commit to large capital investments in new generating capacity in the near term. Over the next six to twelve months, environmental rules will be finalized and AEP Pool negotiations will be underway, and that may provide a higher level of certainty with regard to actions the Company should embrace. Until that certainty is realized, the Company’s plan is to maintain optionality and flexibility in meeting the requirements of its customers.

Therefore, in this Plan, future market purchases (both for APCo and AEP-East) over this 15-year planning horizon ideally represent initial “placeholders” for such incremental capacity resource needs. It is the Company’s intent to continually investigate and analyze the economic merits of future opportunities to build (or acquire) “owned-resources” in lieu of such purchases to ensure greater (local) electrical reliability and price certainty for its customers. However, it should be considered that in the PJM region, most load serving entities (LSE) receive capacity through the market construct known as the Reliability Pricing Model (RPM) auction process. So while the concept of relying on a market may be a different approach for AEP-East, it is an accepted practice for many utilities in the region.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource 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, as the future is highly uncertain. In light of the current economic conditions and the movement towards increasing use of renewable generation and end-use efficiency, as well as known and proposed environmental rulemaking to further control fossil plant emissions which will likely result in the retirement, conversion or retrofit of existing generating units, supply of capacity and energy to APCo will continue to be impacted. The resource planning process is becoming increasingly complex given such pending legislative and regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and energy efficiency advancements all of which necessitate flexibility in any ongoing planning activity and processes. Lastly, the ability to invest in extremely capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on APCo customers will be a primary consideration in this report.

2.0 Introduction to APCo, AEP-East, and the IRP Process

This report documents the processes and assumptions required to develop the recommended IRP for APCo and AEP-East. The IRP process consists of the following steps:

- Description of the company, the resource planning process in general, and the implications of current issues as they relate to resource planning (**Section 2**).
- Provide projected growth in demand and energy which serves as the underpinning of the plan (**Section 3**).
- Identify and discuss demand-side options **(Section 4)**
- Identify current supply resources, including projected changes to those resources (e.g. de-rates or retirements), and transmission system integration issues (**Section 5**).
- Identify and describe supply-side resource options (**Section 6**).
- Describe the analysis and assumptions that will be used to develop the plan such as RTO reserve margin criteria (**Section 7**), and fundamental modeling parameters (**Section 8**).
- Perform resource modeling and use the results to develop portfolios, including the selection of the ultimate plan. (**Section 9**).
- Utilize risk analysis techniques on selected portfolios (**Section 10**).
- Present the findings and recommendations, action plan and, finally, plan implications on APCo and AEP-East (**Section 11**).

2.1 IRP Process Overview

The objective of a resource planning effort is to recommend a system expansion plan that balances "least-cost" objectives with planning flexibility, asset mix considerations, adaptability to risk, conformance with applicable NERC and RTO criteria, and customer affordability. In addition, given the unique impact of generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the EPA-driven environmental compliance planning process.

This report presents the results of the IRP analysis for APCo, which is currently part of the AEP-East (PJM) zone of the AEP System, covering the fifteen year period of 2011-2025

(Planning Period), with extended plan modeling and studies conducted through the year 2040 (extended Study Period). The information presented in this IRP includes descriptions of assumptions, study parameters, methodologies, and results including the integration of supply and demand side resources.

In addition to the need to set forth a long-term strategy for achieving regional reliability and reserve margin requirements, capacity resource planning is critical to APCo due to its impact on:

- **Capital Expenditure Requirements**
- **Customer Rates**
- **Integration with other Strategic Business Initiatives e.g.,** corporate sustainability goals, environmental compliance, transmission planning, etc.

2.2 Introduction to APCo

APCo serves a population of about 2.0 million (961,000 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 requirements power at wholesale to an affiliated company, state agency, private systems, municipalities, and electric cooperatives, and participates, as part of the AEP-East System, in off-system sales to entities participating in the wholesale power market.

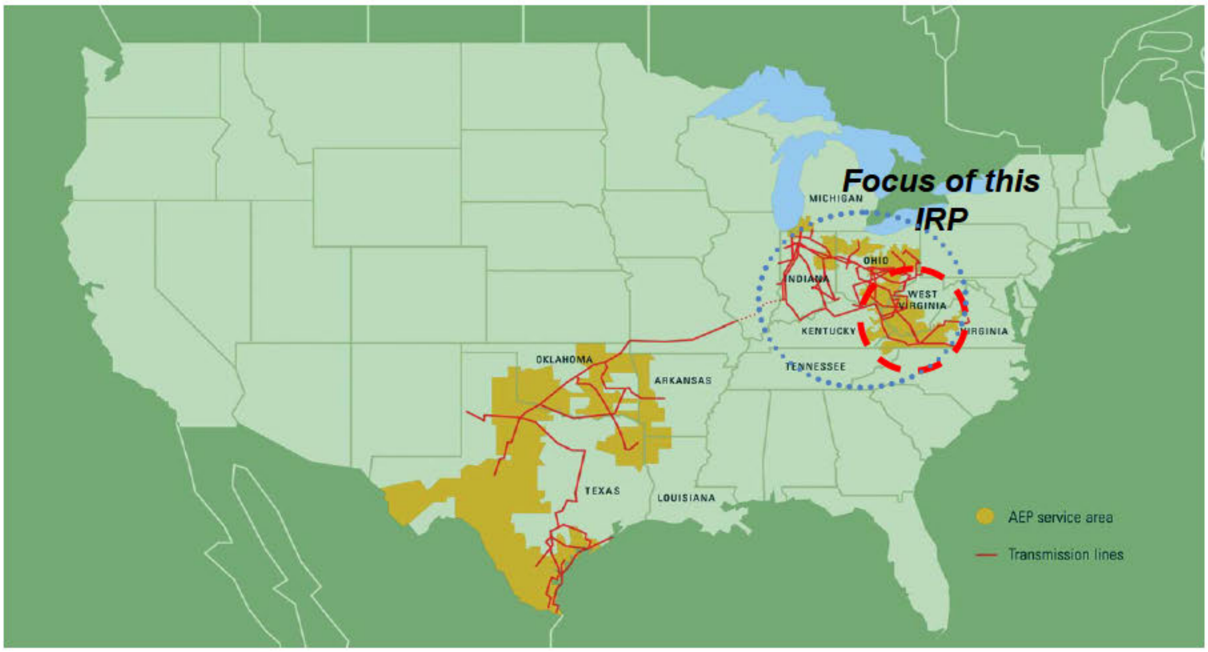
APCo's internal load usually peaks in the winter; the all-time peak internal demand of 8,308 megawatts (MW) occurred on January 16, 2009. On August 9, 2007, an all-time summer peak internal demand of 6,755 MW was experienced. Of APCo's total internal energy requirements in 2010, which amounted to 38,625 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 34%, 19%, and 28%, respectively. FERC requirements customers, including Kingsport Power, public street and highway lighting, losses, and all other categories accounted for the remaining 19%.

In 2010, APCo's Virginia total internal energy requirements were 19,440 GWh, with residential, commercial and industrial accounting for 36%, 18% and 28% respectively. The remaining energy requirements are comprised of other sales to public authorities, other sales for resale, and all other categories.

2.3 Introduction to AEP

AEP is one of the country's largest investor-owned utilities with more than five million retail customers in parts of 11 states. The service territory covers 200,000 square miles in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia (see **Exhibit 2-1**).

Exhibit 2-1: AEP System, East and West Zones



Source: AEP Internal Communications

AEP owns and/or operates 80 generating stations in the United States, with a capacity of approximately 38,000 megawatts. AEP's customers are served by one of the world's largest transmission and distribution systems. System-wide there are more than 39,000 circuit miles of transmission lines and more than 216,000 miles of distribution lines.

AEP's operating companies are managed in two geographic zones: AEP-East is comprised of APCo, Indiana Michigan Power Company (I&M), Kentucky Power Company (KPCo), Ohio Power Company (OPCo), Columbus Southern Power Company (CSP), Kingsport Power Company (KgP), and Wheeling Power Company (WPCo); and AEP-West, which, for resource planning purposes within the Southwest Power Pool (SPP), comprises the Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO). CSP and

OPCo, which have recently operated as a single business unit called AEP-Ohio, are seeking regulatory authorization to formally merge into a single legal entity. While approval of this merger is anticipated, such authorization has not yet been received and its timing is uncertain.

This document will only address capacity and energy resource planning for APCo and the AEP-East zone.

2.3.1 AEP-East Zone–PJM:

AEP-East operating companies collectively serve a population of about 7.2 million (3.26 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The internal (native) customer base is fairly diversified. In 2010, residential, commercial, and industrial customers accounted for 30.7%, 23.2%, and 33.0%, respectively; of AEP-East's total internal energy requirements of 125,381 GWh. The remaining 13.1% was supplied for street and highway lighting, firm (long-term full requirement) wholesale customers, and to supply line and other transmission and distribution equipment losses. Off-system sales or sales of opportunity are not part of internal load thus not planned for in a utility IRP.

AEP-East experienced its historic peak internal demand of 22,411 MW on August 8, 2007. The historic 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, including off-system sales, on August 21, 2003.

2.3.2 AEP-East Pool

The 1951 AEP Interconnection Agreement was established to obtain efficient and coordinated expansion and operation of electric power facilities in its eastern zone. This includes the coordinated and integrated determination of load and peak demand obligations for each of the member companies. Further, to "rectify or alleviate" any relative member company capacity deficits of an extended nature and maintain an "equalization" over time, capacity planning is performed on an AEP-East integrated basis, with capacity assignments made to the pool members based on their relative deficiency within the AEP Pool.

2.4 Industry Issues and Implications

2.4.1 Environmental Rulemakings and Legislation

This 2011 IRP considered final and proposed EPA regulations. In addition, the IRP development process assumed there will be future legislation to control greenhouse gas/carbon dioxide (CO_2) emissions which would become effective at some point in the 2017 -to- 2022 timeframe. Emission compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. Moreover, the cumulative cost of complying with these rules will ultimately have an impact on proposed retirement dates of existing coal-fueled units that would be forced to install emission control equipment.

2.4.1.1 Cross State Air Pollution Rule (CSAPR)

On July 7, 2011, the EPA issued its final federal rulemaking regulating annual SO_2 and NO_X and seasonal NO_X emissions from stationary generating facilities. CSAPR replaces the Clean Air Interstate Rule (CAIR), which the D.C. District Court of Appeals remanded to the EPA for revision in 2008 because it had significant flaws.

Twenty-eight (28) states are covered by the new rule. All states in which AEP owns and/or operates power plants are included in at least one of the CSAPR programs. Indiana, Kentucky, Michigan, Ohio, Texas, Virginia and West Virginia fall under all the programs regulating annual SO_2, and both annual and seasonal NO_X. Arkansas, Louisiana and Oklahoma fall under the CSPAR seasonal NO_X program only.

For AEP, there are two significant differences from the original proposed CAIR replacement (known as the Clean Air Transport Rule). The first is that Texas is now included in all of the programs including the annual SO_2 and NO_X programs, when it previously was only included in the seasonal NO_X program. Second, Louisiana, which initially was included in the annual SO_2 and NO_X programs, has been excluded from those programs and is included in the seasonal NO_X program only.

CSAPR has an initial compliance phase deadline for the SO_2 and NO_X programs beginning on January 1, 2012 (“Phase 1”). A second, more stringent compliance phase for SO_2 emissions limits (only) will take effect beginning on January 1, 2014 (“Phase 2”). Prescribed Annual and

Seasonal NO_X emission limits, however, will remain approximately at “Phase 1” levels. Developing and implementing a new compliance plan within six months to address significant SO_2 reductions in the AEP-East will be a challenge.

> “In comments on EPA’s proposed rules, AEP and others presented the argument that 2014 does not provide enough time to install controls. We are extremely disappointed that EPA did not take these comments into account and appears to have actually accelerated the more significant compliance requirements to the beginning of 2012,”
>
> --- *John McManus, Vice President – AEPSC Environmental Services*.

For instance, AEP has engineered and constructed nine FGD systems in the past decade to address SO_2 emissions—most recently at APCo Amos Units 1 and 2. APCo has the experience and knowledge to know that a period of approximately 52-56 months is essential to permit, design and engineer, construct and commission such a system. This timeframe approaches five years or more when also considering any up-front regulatory (*i.e.*, “need”) approvals required.

2.4.1.2 CSAPR Allocation

Also complicating the lack of flexibility on compliance timeframes is the fact that EPA reduced SO_2 and NO_X state (emission) allowance allocation budgets from the levels it originally had proposed in March 2011. Such allowance allocation budgets are established at the state level, which, in turn, are allocated to individual generating units. Specifically, for APCo’s Virginia and West Virginia-domiciled units, the final SO_2 (Phase 1 & Phase 2), Annual NO_X and Seasonal NO_X are as follows:

Plant Name	State	SO_2 Allocation 2012 (tons)	SO_2 Allocation 2014 (tons)	NOx Annual Allocation 2012 (tons)	NOx Annual Allocation 2014 (tons)	NOx OS Allocation 2012 (tons)	NOx OS Allocation 2014 (tons)
Amos 1,2, 3 (APCo Share)	West Virginia	30,857	14,215	11,070	10,158	4,512	4,252
Clinch River	Virginia	8,974	3,970	2,746	2,746	1,094	1,094
Glen Lyn	Virginia	3,974	1,758	1,216	1,216	470	470
Ceredo	West Virginia	0	0	22	22	12	12
Kanawha River	West Virginia	3,663	1,688	1,314	1,205	611	551
Mountaineer	West Virginia	15,635	7,203	5,609	5,147	1,898	1,898
Sporn	West Virginia	2,877	1,325	1,032	947	446	402
		65,980	**30,159**	**23,009**	**21,441**	**9,043**	**8,679**

Although final CSAPR Annual and Seasonal NO_X allowance limits have been somewhat relaxed versus originally-proposed levels, final Phase 1 and Phase 2 SO_2 allowance limits have been severely reduced, particularly for APCo’s West Virginia units. Given also the current uncertainty around availability of a regional emission allowance market as described below, APCo and AEP are currently evaluating possible emission mitigation strategies including:

- low-cost and quick-to-install environmental retrofits options;
- fuel switching options (to lower sulfur-content coals and repowering to natural gas); and
- dispatch optimization options (including the possibility of unit generation curtailments)

CSAPR allows for limited emissions trading between states. However, certain "assurance provisions" in the rule stipulate that each state cannot exceed its budget by more than 18 percent to 21 percent using *out-of-state* allowances before additional allowance deductions will be imposed. Additionally, EPA divided the SO_2 impacted states into two groups and does not allow SO_2 trading between these two groups. This restriction means that the states in AEP's eastern area, as part of Group "1." cannot trade SO_2 allowances with AEP's western area (*i.e.*, Texas), which is part of Group "2." Given the assurance provisions highlighted, at this point it is unclear as to the liquidity of any 'regional' allowance markets.

2.4.1.3 What CSAPR Could Mean for APCo and AEP

Developing and implementing a new compliance plan within a period of less than six months to address the significant SO_2 reductions in the East (including APCo's West Virginia units), and NO_X reductions in the West; represents a significant challenge. Compliance plans are still being developed (as of the preparation of this report) and it is anticipated that strategies will be put in place that will seek to mitigate the incremental cost exposure to APCo and AEP's customers prior to this 2012 CSAPR implementation date.

CSAPR automatically goes into effect unless EPA takes administrative action to reconsider it or a Court of Appeals issues a stay. Appeals and petitions for reconsideration must be filed within 60 days from the date the rule is published in the Federal Register.

Finally, since APCo and AEP have not yet determined what course of action they may take in response to these new CSAPR limits, the original Clean Air Transport Rule limits were used to prepare the required schedules in **Section 13** of this report. For purposes of this IRP and accompanying schedules, however, the final CSAPR is <u>not</u> assumed to accelerate unit retirements, which are more directly tied to the requirements of the proposed EGU MACT rules and timelines. For long term optimization modeling (Section 9 of this report) the CSAPR limits were used to evaluate the various plan costs.

2.4.2 EGU MACT Rule

To replace the federal court vacated Clean Air Mercury Rule (CAMR), the EPA proposed a rule in March 2011 designed to reduce and regulate emissions of mercury and other toxic metals and acid gases at electric generating units by using maximum achievable control technology (EGU MACT) emission standards. The Clean Air Act (CAA) requires compliance within 3 years after the issuance of this final rulemaking, which in this case, would be at approximately the end of 2014, but also provides a one year extension which could potentially delay implementation to the end of 2015 if specific criteria are satisfied. The proposed EGU MACT emission limits will require the installation of emission control equipment, such as FGD, SCR, DSI, and ACI on coal-fired utility units, as well as the performance of upgrades to some existing emission control systems in order to achieve the required emission rates.

2.4.3 Coal Combustion Residuals (CCR) Rule

The EPA issued a proposed rule in June 2010, with final rulemaking anticipated in early 2012, to address the management of residual byproducts from the combustion of coal in power plants (coal ash) and captured by emission control technologies, such as FGD. The proposed rule includes specific design and monitoring standards for new and existing landfills and surface impoundments, as well as measures to ensure and maintain the structural integrity of surface impoundment/ponds. The proposed CCR rulemaking would require the conversion of most "wet" ash impoundments to "dry" ash landfills, the relining or closing of any remaining ash impoundment ponds, and the construction of additional waste water treatment facilities by approximately January 1, 2018. Even if these residual materials are categorized as "Subtitle D," or non-hazardous materials[1]—each and every coal unit in the AEP fleet, including all APCo coal facilities, would require plant modifications and capital expenditures to address CCR requirements.

[1] As set forth under the current Resource Conservation and Recovery Act (RCRA)

2.4.4 Clean Water Act "316(b)" Rule

A proposed rule for the Clean Water Act 316(b) was issued by the EPA on March 28, 2011 and final rulemaking is expected mid-2012. The proposed rule prescribes technology standards for cooling water intake structures that would decrease interference with fish and other aquatic organisms. Given that APCo's supercritical units are already equipped with natural draft, hyperbolic cooling towers, the most significant potential impact of the proposed rule would be the need to install additional fish screening at the front of the water intake structure. Compliance requirements for the smaller subcritical coal plants that do not utilize a closed-loop cooling system would have to be determined based on a site-specific study. The implementation schedule for this rule could extend late into this decade due to the site specific nature of the permitting process.

2.4.5 New Source Review—Consent Decree

In December 2007, AEP entered into a settlement of outstanding litigation around New Source Review compliance. Under the terms of the settlement, AEP will complete its environmental retrofit program on its operated Eastern units, operate the units under an annually declining cap on total SO_2 and NO_X emissions, and install additional control technologies at certain units. The most significant additional control projects involve installing FGD and SCR systems at nine AEP-East coal-fired units (Amos 1-3, Big Sandy 2, Cardinal 1, Conesville 4, Muskingum River 5 and Rockport 1 and 2) over an 11 year period beginning in 2009. APCo's Amos 1-3, as well as the Cardinal 1 and Conesville 4 retrofits have now been installed. Additionally, the Consent Decree called for APCo's Clinch River units (1-3) to install Selective Non-Catalytic Reduction (SNCR) for NO_X reduction. Those retrofits have been completed.

2.4.6 Carbon and Greenhouse Gas (GHG) Legislation

For many years, the potential for requirements to reduce greenhouse gas emissions, including carbon dioxide, has been one of the most significant sustainability issues facing APCo and AEP. AEP and APCo have relied on coal for a number of reasons: coal provides an affordable, reliable, and sustainable source of energy; AEP and APCo are located in close proximity to the nation's coal supply; AEP and APCo have a legacy in coal-fired generation as demonstrated by the huge investments made and the engineering and operational expertise developed over more than a century. As a result, coal is expected to remain a key part of AEP's fuel portfolio for many years to come. AEP is one of the largest consumers of coal in the Western Hemisphere and coal currently accounts for about 80 percent of the energy that AEP generates.

EPA is poised to propose first-ever greenhouse gas requirements for power plants late in 2011. Given that there are currently no cost-effective post combustion control technologies available, the standards are anticipated to focus on energy efficiency opportunities, but the substantive requirements of the EPA proposal are not yet known. AEP supports a legislative approach to resolve the GHG issue rather than a regulatory approach. Without this certainty, it is impossible to justify expenditures in the billions of dollars in GHG mitigation strategies that might otherwise put the company and its shareholders at risk. Such legislation appears unlikely in this Congress and diminished somewhat in future Congresses.

2.5 Additional Implications of Environmental Legislation – Unit Disposition Analysis

The 2009 IRP included results from an AEP-East unit disposition study undertaken by an IRP Unit Disposition evaluation team involving numerous APCo and AEP functional disciplines. In this previous review, the predominant focus was on the roughly 5,300 MW of older-vintage, less-efficient, non-environmentally controlled (*i.e.*, “Fully-Exposed”) coal units in the AEP-East fleet. These reviews had concluded that it would not be prudent to add expensive environmental controls to these facilities. Rather, these Fully Exposed units would be retired during the presumed compliance plan implementation period.

In this 2011 IRP cycle review, the team considered financial implications of the potential impacts associated with costs to comply with the then-proposed Clean Air Transport Rule (which CSAPR replaced), EGU MACT and CCR rulemakings. For AEP-East, these evaluations primarily focused on those currently non (or partially)-environmentally controlled (i.e., no FGD and/or SCR retrofits), larger, more efficient units of the fleet including I&M’s Rockport Units 1 and 2 and Tanners Creek Unit 4, KPCo’s Big Sandy Unit 2, and OPCo’s Muskingum River Unit 5. APCo does not have units in this review category as its larger, more efficient units—Amos 1-3 and Mountaineer—have both FGD and SCR technology installed. The result of these indicative evaluations were mixed; the Rockport and Tanners Creek units would likely continue to operate as coal fired units with additional environmental controls, whereas Big Sandy 2 would potentially be retired and Muskingum River 5 would potentially be converted to burn natural gas.

It should be noted that the conclusions of this updated unit disposition study are for the specific purpose of performing this overall long-term IRP analysis and reflect on-going and evolving disposition assessments. ***From a capacity and energy planning perspective, these represent indicative plans as no formal decisions have been made with respect to specific timing of any such unit retirements, retrofits or fuel conversions***, with the exception of those units that are identified in the stipulated Consent Decree related to the NSR litigation or where filings have been made for authorization to proceed with such plans (Indiana).

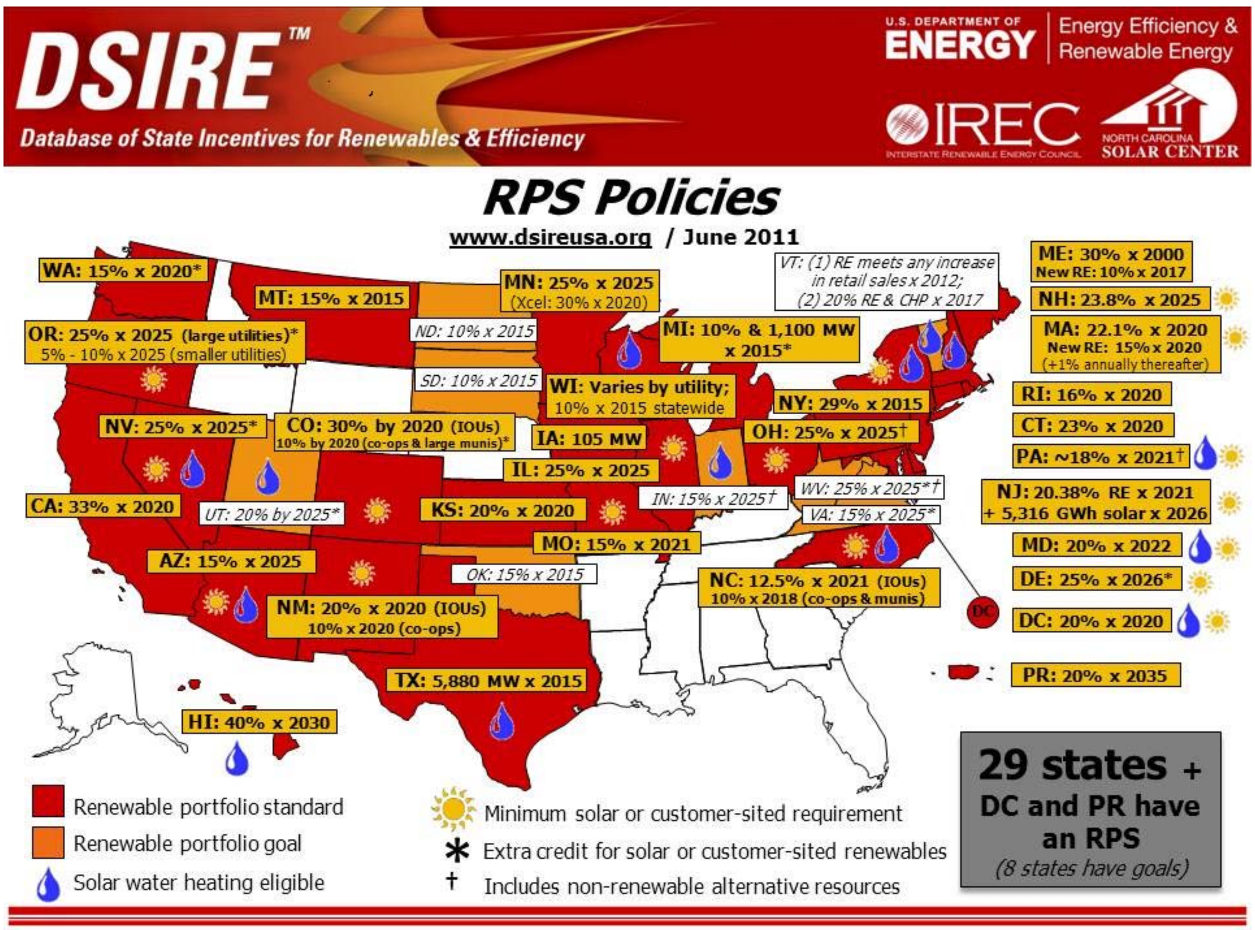
2.6 Renewable and Clean Energy Portfolio Standards

As identified in **Exhibit 2-2**, 29 states and the District of Columbia have set standards specifying that electric utilities generate a certain amount of electricity from renewable sources. Seven other states have also established renewable energy goals. Most of these requirements take the form of "renewable portfolio standards," or RPS, which require a certain percentage of a utility's energy sales to ultimate customers come from renewable generation sources by a given date. The standards range from modest to ambitious, and definitions of renewable energy vary by jurisdiction. Though climate change concerns may not always be the primary motivation behind some of these standards, the use of renewable energy does deliver significant GHG reductions. For instance, Texas is expected to avoid nearly 10 million tons of CO_2 emissions annually with its RPS, which requires 5,880 MW of new renewable generation by 2015.

In lieu of GHG legislation, another possibility is a federal clean energy standard (CES). The existing environmental regulatory scheme directed toward clean energy is a hodgepodge and is conducted in siloed processes that do not adequately consider the impact of previous or upcoming regulations, the economic costs and benefits to communities, or the time required for compliance. A comprehensive federal legislative approach could achieve significant energy savings, foster domestic energy supplies and provide more rational environmental regulation. Even so, this legislation may be difficult to achieve.

During his 2011 State of the Union speech, President Obama proposed a federal standard that sets an 80 percent clean energy goal by 2035. Our ability to achieve this goal will hinge on details such as whether "units" of natural gas, nuclear, hydro, and coal generation with CCS technology count fully, only "partially," or not at all; as well as setting interim targets that would have to be achieved. For instance, in the wake of the Japanese nuclear crisis, the role that nuclear power may play in meeting such a standard is uncertain. APCo and AEP are concerned about the inequities that could occur in the potential pursuit of the President's "Clean Energy" plan. For example, some states in the Pacific Northwest are already producing more than 90 percent of their electricity from clean sources, thanks to significant hydro resources in that region. The plan could lead to huge surpluses of clean energy credits for states and utilities with large hydro or nuclear capacity today, and huge deficits for "AEP" states such as Virginia, West Virginia, Ohio, Kentucky, and Indiana, which rely heavily on coal. Some method to deal with these potential inequities would be required.

Exhibit 2-2: Renewable Standards by State



2.6.1 Implication of RPS/CES on the APCo and AEP-East IRP

Renewable Portfolio Standards and goals have been enacted in over half of the states in the U.S. and over two-thirds of the PJM states. Adoption of further RPS at the state level or the enactment of Federal carbon limitations and/or an RPS will increase the need for adding more renewables resulting in a significant increase in investments across the renewable resource industry.

Wind is currently one of the most viable large-scale renewable technologies and has been added to utility portfolios mainly via long-term renewable energy purchase agreements (REPA). Recently, many utilities have begun to add wind projects—be they owned or purchased—to their generation portfolios. The best sites in terms of wind resource and transmission are rapidly being secured by developers. Further, while an extension of the Federal Production Tax Credit (PTC) and investment tax credits (ITC) for wind projects—to the end of 2012—was enacted by Congress in February 2009, it may not be extended further as the potential future implementation of federal carbon or renewable standards is expected to make unnecessary the development incentive provided by the PTC/ITC. Acquiring this renewable energy and/or the associated Renewable Energy Credit/Certificate (REC) sooner may limit the risk of increased cost that comes with waiting for further legislative clarity nationally, or in the AEP states, combined with the likely expiration of these federal incentives. AEP has experienced, however, that regulators in states *without* mandatory standards—such as Virginia—have been reluctant to approve REPAs that result in any increased costs to electricity consumers. As of June 1, 2011, AEP operating companies APCo, I&M, and AEP-Ohio (CSP & OPCo) are receiving energy from 7 wind contracts and 1 solar project, with total nameplate ratings of 626 MW. **Exhibit 2-3** summarizes the AEP-East renewable plan, by operating company.

2.6.2 Virginia Voluntary Renewable Portfolio Standard

Virginia Code section 56-585.2 creates incentives for utilities to meet voluntary renewable energy goals. The basis of the goals is energy sales in 2007; less energy provided by nuclear plants. The goals are 4% of that fixed sales figure by 2010, 7% by 2016, 12% by 2022, and 15% by 2025. Double credit is given for energy from solar or wind projects. Including the projects in the current plan along with existing run-of-river hydroelectric plants, APCo met the 2010 voluntary goals and expects to meet future voluntary goals for each year of the Planning Period.

2.6.3 West Virginia Alternative and Renewable Energy Portfolio Act

West Virginia Code Chapter 24, Article 2F established renewable and alternative energy requirements for electric utilities serving retail customers in the State. The Act requires that a utility obtain credits equal to 25% of a utilities retail sales by 2025, with intermediate targets beginning in 2015. Credits can be earned from energy generated from renewable sources such as wind, solar and hydro, advanced coal technologies and natural gas generation, as well as from energy efficiency programs . Credits may be banked and carried over from prior years to meet future year targets. APCo's current renewable resources, in addition to ongoing energy efficiency programs and planned generation portfolio, is projected to be sufficient to meet the intermediate and final targets of the Act.

2.7 Energy Efficiency Mandates

The Federal Energy Independence and Security Act of 2007 ("EISA"), along with other Federal legislation, requires, among other things, a phase-in of lighting efficiency standards, appliance standards, and building codes. The increased standards will have a discernible effect on energy consumption. Additionally, in AEP-East mandated levels of demand reduction and/or energy efficiency attainment, subject to cost effectiveness criteria, are in place in Ohio, Indiana and Michigan. For instance, the Ohio standard, if cost-effective criteria are met, will result in installed energy efficiency measures equal to over 20 percent of all energy otherwise supplied by 2025. Indiana's standard achieves installed energy efficiency reductions of 13.9% by 2020 while Michigan's standard achieves 10.55% in the same year. Virginia has a voluntary 10% EE target by 2020, while West Virginia allows EE to count towards its renewable standard. No mandate currently exists in Kentucky; however KPCo has offered DR/EE programs to customers since the mid-1990's.

Exhibit 2-3: Renewable Energy Plan Through 2030

AEP System - East Zone

***Potential Renewables Profile to Achieve Known or Emerging State Mandates* [(a)]**

2011 APCo IRP

Year		APCo			I&M			KPCo			AEP-Ohio			AEP-East		
		Solar Nameplate (MW)	Wind Nameplate (MW)	Renewable Energy as % of Total Energy Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Renewable Energy as % of Total Energy Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Renewable Energy as % of Total Energy Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Renewable Energy as % of Total Energy Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Renewable Energy as % of Total Energy Sales
2009		0	276	1.4%	0	150	1.1%	0	0	0.0%	0	100	0.1%	0	526	0.7%
2010		0	376	2.6%	0	150	2.0%	0	0	0.0%	10	100	0.7%	10	626	1.6%
2011		0	376	3.3%	0	150	1.9%	0	0	0.0%	10	100	0.8%	10	626	1.8%
2012		0	376	3.0%	0	150	1.9%	0	0	0.0%	27	200	1.6%	27	726	2.0%
2013	(b)	0	**376**	3.0%	0	**250**	3.3%	0	**0**	0.0%	45	**200**	2.2%	45	**826**	2.6%
2014		0	376	3.0%	0	350	4.5%	0	0	0.0%	76	300	3.0%	76	1,026	3.1%
2015		0	376	2.9%	0	450	5.7%	0	0	0.0%	89	400	3.8%	89	1,226	3.7%
2016		0	376	2.9%	0	450	5.8%	0	0	0.0%	89	550	4.9%	89	1,376	4.1%
2017		0	376	2.9%	0	450	5.8%	0	0	0.0%	89	700	6.0%	89	1,526	4.4%
2018		0	376	2.9%	0	450	5.8%	0	0	0.0%	106	800	6.7%	106	1,626	4.7%
2019		0	376	2.9%	0	450	5.8%	0	0	0.0%	106	900	7.5%	106	1,726	5.0%
2020		0	376	2.9%	0	550	7.1%	0	0	0.0%	127	1,050	8.7%	127	1,976	5.6%
2021		0	376	2.8%	0	550	7.0%	0	0	0.0%	127	1,150	9.4%	127	2,076	5.9%
2022		0	376	2.8%	0	550	7.0%	0	0	0.0%	127	1,250	10.1%	127	2,176	6.1%
2023		0	426	3.2%	0	550	7.0%	0	0	0.0%	127	1,400	11.2%	127	2,376	6.6%
2024		0	426	3.1%	0	550	6.9%	0	0	0.0%	148	1,400	12.2%	148	2,376	6.9%
2025		0	426	3.1%	0	550	6.9%	0	0	0.0%	148	1,400	12.1%	148	2,376	6.9%
2026		0	426	3.1%	0	550	6.8%	0	0	0.0%	148	1,400	12.0%	148	2,376	6.8%
2027		0	426	3.1%	0	650	8.0%	0	0	0.0%	148	1,400	12.9%	148	2,476	7.4%
2028		0	476	3.4%	0	650	7.9%	0	0	0.0%	148	1,400	12.8%	148	2,526	7.4%
2029		0	476	3.3%	0	650	7.8%	0	0	0.0%	148	1,400	12.7%	148	2,526	7.4%
2030		0	476	3.3%	0	650	7.8%	0	0	0.0%	148	1,400	12.5%	148	2,526	7.3%

(a) Data excludes conventional (run-of-river) hydro energy as a renewable source as it has been excluded from certain state and proposed federal RPS criteria.

(b) 2012/2013 represent the initial years for Federal RPS/RES mandates as currently proposed by several draft bills before Congress. Further, 2013 would represent the initial year after the likely expiration of Production Tax Credits (PTC) for, particularly, wind resources. Establishment of a federal renewables standard would likely eliminate further extension of such PTC opportunities.

Source: AEP Resource Planning

2.7.1 Implication of Efficiency Mandates: DR/EE

The AEP System (East and West zones) has committed to achieve system-wide peak demand reductions of 1,000 MW by year-end 2012 and energy reductions of 2,250 GWh, approximately 60-65% of which is in the AEP-East zone. Through 2010, AEP has achieved 1,116 GWh of installed energy efficiency (406 MW). Concurrently, several states served by the AEP System have mandated levels of DR/EE. Within AEP-East, Ohio and Michigan have statutory benchmarks which took effect in 2009. As a result of the DSM generic case in Indiana, regulatory benchmarks have been put into effect beginning in 2010. In lieu of mandates or benchmarks, stakeholders expect realistic levels of cost-effective demand-side measures to be employed. The ratemaking process in the individual states will ultimately shape the amount and timing of DR/EE investment.

2.7.2 Smart Grid Initiatives

The IRP also takes into account other technology initiatives designed to improve the efficiency of the AEP energy delivery and distribution systems. These initiatives include the demonstration of technologies for more effective integrated volt/var controls (IVVC) and community energy storage (CES) on the distribution system that would reduce customer usage, as well as advanced transmission infrastructure technologies to reduce energy losses through more precise voltage regulation made possible with "smart grid" infrastructure.

2.8 Transportation Sector (Electric Cars)

Production of electric cars by major auto manufacturers began in late-2010, notably the Chevrolet Volt and the Nissan Leaf. These cars are capable of traveling three to four miles on one (1) kilowatt hour of energy at a cost of about three cents a mile for the consumer. This compares favorably with the thirteen cents per mile it costs to operate a similar gasoline powered vehicle. While there are limitations to the electric car, including the driving range on a charge, and the time required to recharge the vehicle, the low cost of operation may result in its gradual adoption.

Running scenarios of market penetration trajectories of one and two percent adoption by 2020 revealed that no incremental generation would be required prior to 2027 in either case. This assumed somewhat staggered charging times, with the majority of charging being non-coincident with the (summer) peak. Tariffs that encourage off-peak charging may be needed to shape consumer behavior.

Recently, with the adoption of a 54.6 mpg CAFÉ (Corporate Average Fuel Economy) standard, it has been estimated that it will necessitate electric car penetration of 10% by 2025. As these trends develop, future IRPs will address the evolving planning requirements. Currently, neither the load forecast nor the IRP has included increased load associated with the transportation sector.

2.9 Issues Summary

The increasing number of variables and their uncertainty has added to the complexity of producing an IRP. No longer are the variables merely the cost to build and operate a specific generating source, a forecast of fuel prices and growth in demand. Volatile fuel prices and uncertainty surrounding the economy and environmental legislation require that the process used to determine the traditional "supply and demand" elements of a resource plan is sufficiently flexible to incorporate more uncertain criteria. High-capital construction/fixed cost exposures tend to weigh unfavorably on solid-fuel and nuclear options, but these conclusions must be tempered with the knowledge that there is a great deal of uncertainty.

One way of dealing with this uncertainty is to maintain optionality. For example, adding diversity to the generating portfolio reduces the risk of the overall portfolio. This may not always be the least expensive portfolio in a "base" (or most probable) case, but it minimizes exposure to adverse future events and could reduce the ultimate cost to ratepayers over the planning horizon.

3.0 Load Forecast

3.1 Summary of APCo Load Forecast

The load forecasts presented herein were developed in late 2010 and finalized in February 2011.[2]

APCo's forecasts of energy consumption for the major customer classes were developed by using both short-term and long-term econometric models. These energy forecasts were determined in part by forecasts of the regional economy, which, in turn, are based on the October 2010 national economic forecast of Moody's Analytics. Customer service engineers also provide valuable feedback on large customer load changes. The forecasts of seasonal peak demands were developed using an analysis of energy, load shapes and load factor that estimates hourly demand.

Some of the key assumptions on which the load forecast is based include:

- moderate economic growth characterized by GDP growth averaging 2.5% over the forecast horizon;
- federal and state energy efficiency legislation will have an impact on energy consumption;
- electricity prices are based on company analytics and an Energy Information Administration (EIA) long-term outlook;
- generally slow (0.2% per year) growth in the Company's service-area population;
- normal weather.

Table 2 provides a summary of the forecasts of the seasonal peak internal demands and annual energy requirements for APCo and AEP-East for the 15-year period: 2011 to 2025. The forecast data shown on this table reflects adjustments for planned DSM programs within the AEP-East companies. In addition, inherent in the forecast are the impacts of past customer conservation and load management activities, including DSM programs already in place.

[2] The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load,* which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

As Table 2 indicates, during the period 2011-2025, APCo's internal energy requirements are forecasted to increase at an average annual rate of 0.6%, while the corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 0.8% and 0.6%, respectively. APCo's annual peak demand is expected to continue to occur in the winter season.

TABLE 2

APCo and AEP-East
Forecast of Peak Internal Demand and Energy Requirements
After Planned DSM Programs
2011-2025

Year	APCo			AEP East		
	Peak Internal Demand		Internal Energy Req'ts (GWh)	Peak Internal Demand		Internal Energy Req'ts (GWh)
	Summer (MW)	Winter* Following (MW)		Summer (MW)	Winter Following (MW)	
2011	6,145	7,404	37,542	21,052	20,895	125,265
2012	6,177	7,457	37,805	21,264	21,172	127,117
2013	6,231	7,503	37,903	21,474	21,172	128,161
2014	6,280	7,548	38,078	21,508	21,151	128,055
2015	6,337	7,563	38,297	21,531	21,083	127,890
2016	6,372	7,578	38,490	21,521	21,065	127,885
2017	6,412	7,611	38,627	21,585	21,096	127,921
2018	6,462	7,656	38,805	21,668	21,136	128,107
2019	6,517	7,682	39,021	21,750	21,082	128,260
2020	6,566	7,777	39,296	21,780	21,275	128,449
2021	6,655	7,839	39,653	21,949	21,370	129,004
2022	6,724	7,861	39,981	22,076	21,365	129,564
2023	6,773	7,896	40,306	22,175	21,390	130,139
2024	6,821	7,981	40,612	22,275	21,600	130,774
2025	6,904	8,046	40,933	22,492	21,748	131,473
% Average Growth Rate, 2011-2025	0.8	0.6	0.6	0.5	0.3	0.3

***APCo experienced an internal peak demand of 7,623 MW in the winter of 2010/11. This demand was normalized to 7,182 MW.**

Note: AEP –East Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 553 MW (summer) and 519 MW (winter) throughout the forecast period. The APCo peak internal demand forecast has assumed interruptible loads of 98 MW (summer) and 121 MW (winter) throughout the forecast period.

Similarly, the AEP-East internal energy requirements during the forecast period are projected to increase at an average annual rate of 0.3% over the 2011-2025 period, while the corresponding summer and winter peak internal demands are projected to grow at average annual rates of 0.5% and 0.3%, respectively. The AEP-East annual peak demand is expected to occur in the summer season.

3.1.1 Forecast Assumptions

The load forecasts for APCo and the other operating companies in the AEP System are based on a forecast of U.S. economic growth provided by Moody's Analytics. The load forecasts presented herein are based on a Moody's Analytics economic forecast issued in October 2010 and on AEP load experience prior to 2010. Moody's Analytics projects moderate growth in the U.S. economy during the 2011-2025 forecast period, characterized by a 2.5% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the consumer price index expected to rise by 1.8% per year. Industrial output, as measured by the Federal Reserve Board's (FRB's) index of industrial production, is expected to grow at 1.2% per year during the same period. The outlook for APCo's Virginia service area projects employment growth of 0.8% per year during the forecast period and real regional income per-capita growth of 1.0%.

Inherent in the load forecasts are the impacts of past customer energy conservation and load management activities, including company-sponsored DSM programs already implemented. The load impacts of future, or expanded, DSM programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts.

3.1.2 Forecast Highlights

APCo's total internal energy requirements, after consideration of the effects of planned DSM programs, are forecasted to increase at an average annual rate of 0.6% for the 15-year period from 2011 to 2025. The planned DSM programs reflect those DSM programs that the Company expects to come to fruition over the forecast period. The corresponding summer and winter peak internal demands are forecasted to grow at an average annual rate of 0.8% and 0.6%, respectively. APCo's annual peak demand is expected to continue to occur in the winter season.

The AEP-East internal energy requirements during the forecast period are projected to increase at an average annual rate of 0.3% between 2011 and 2025, after consideration of the effects of planned DSM programs. Summer and winter peak internal demands are expected to grow at average annual rates of 0.5% and 0.3%, respectively. The AEP-East annual peak is projected to continue to occur in the summer season.

The load effects of planned DSM programs generally increase in time throughout the forecast period. Over the 15-year forecast period, the projected planned DSM programs reduce the load growth rate. For APCo, the planned DSM programs result in a 0.2% reduction in average annual growth rate for seasonal peak demands and internal energy requirements. The AEP System-East Zone has some states with more vigorous DSM programs and planned DSM programs in this forecast resulted in 0.4% reduction in average annual growth rate. The planned DSM programs and demand response programs, which are not included in this analysis, will be discussed in Chapter 4.

3.2. Overview Of Forecast Methodology

APCo's load forecasts are based mostly on econometric, supplemented with state-of-the-art statistically adjusted end-use, analyses of time-series data – producing an internally consistent forecast. This consistency is enhanced by model logic expressed in mathematical terms and quantifiable forecast assumptions. This is helpful when analyzing future scenarios and developing confidence bands. Additionally, econometric analysis lends itself to objective model verification by using standard statistical criteria.

APCo's energy requirements forecast is derived from two sets of econometric models: 1) a set of monthly short-term models and 2) a set of long-term models, with some using monthly data and others using quarterly data. This procedure permits easier adaptation of the forecast to the various short- and long-term planning purposes that it serves. The forecast methodology uses a process that takes advantage of the relative analytical strengths of both the short- and long-term methods.

For the first full year of the forecast, the forecast values are generally governed by the short-term models, using billed or metered energy sales. The long-term sales are billed.

The short-term and long-term forecasts are blended during the second six months of the second year of the forecast. The blending ensures a smooth transition from the short-term to the long-term forecast.

For those long-term forecasts that are quarterly, a monthly load shape is applied to the forecast based on analysis from the short-term models. The blended sales forecasts are converted to billed and accrued energy sales, which are consistent with the energy generated.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic conditions and demographics, energy prices, weather factors, special information such as known plans of specific major customers, and informed judgment are all used in producing the forecasts. The major difference between the two is that the short-term models use mostly trend, seasonal, and weather variables, while the long-term models use structural variables, such as population, income, employment, energy prices, and weather factors, as well as trends. Supporting forecasting models are used to predict some inputs to the long-term energy models. For example, natural gas models are used to predict sectoral natural gas prices that then serve as inputs.

Either directly, through national economic inputs to the forecast models, or indirectly, through inputs from supporting models, APCo's load forecasts are influenced greatly by the outlook for the national economy. For the load forecasts reported herein, Moody's Analytics October 2010 forecast was used as the basis for that outlook. Moody's Analytics regional forecast, which is consistent with its national economic forecast, was used for the regional economic forecast of income, employment, households, output, and population.

The energy forecast for the AEP System–East Zone, by customer class, is obtained by summing the forecasts, by customer class, of each of the AEP System–East Zone operating companies. The same method is used to determine the forecast of peak internal demand and adjusting for diversity.

The demand forecast model is a series of algorithms for allocating the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

Flow charts depicting the structure of the models used in projecting APCo's electric load requirements are shown at the end of this Section 3 in **Exhibits 3-1** and **3-2**. Page 1 of Exhibit 3-1 depicts the stages in the development of the Company's short-term and long-term internal energy requirements forecasts, along with the stages of the development of the commercial and residential Statistically Adjusted End-Use models. Exhibit 3-2 presents a schematic of the sequential steps for the peak demand and internal energy requirements forecasting.

3.3. Forecast Methodology For Internal Energy Requirements

3.3.1 General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of APCo's energy consumption, by customer class. For the purposes of the load forecast, the short term is defined as the first 12 to 24 months, and the long term as the forecast years beyond the short term.

Conceptually, the difference between short and long term energy consumption relates to changes in the stock of electricity-using equipment and economic influences, rather than the passage of time. The short term covers the period during which changes are minimal, and the long term covers the period during which changes can be significant. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology determine the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include all or most of them in the formulation of long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to impact them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

3.3.2. Short-term Forecasting Models

The goal of APCo's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on autoregressive integrated moving average (ARIMA) models.

There are separate models for the Virginia and West Virginia Jurisdictions of the Company. The estimation period for the short-term models was January 1998 through September 2010.

3.3.2.1 Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

3.3.2.2 Industrial Energy Sales

Short-term industrial energy sales are forecast separately for 10 large industrial customers in Virginia and 13 large industrial customers in West Virginia and for the remainder of industrial energy customers segregated into manufacturing and mining load. These 12 short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 10 large industrial customers and the forecasts for the remainder of the manufacturing and mining customers. Customer service engineers also provide input into the forecast for specific large customers.

3.3.2.3 All Other Energy Sales

The All Other Energy Sales category for APCo includes public street and highway lighting (or other retail sales) and sales to municipals. APCo's Virginia wholesale customers include the cities of Radford and Salem in Virginia, Old Dominion Electric Cooperative, Craig-Botetourt Electric Cooperative and Virginia Tech. The Company's wholesale customers in West Virginia are the Musser Companies. In addition, Kingsport Power, an affiliated company in Tennessee, is a full requirements wholesale customer. These wholesale loads are generally longer term, full requirements, cost-of-service base contracts.

Both the other retail and municipal models are estimated using ARIMA models. APCo's short-term forecasting model for public street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale model includes binaries, heating and cooling degree-days, lagged error terms and lagged energy sales.

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast as they are not requirements load or part of the IRP process.

3.3.2.4 Losses and Unaccounted-For Energy

The forecast losses for APCo are based on an analysis of the historical relationship between energy sales and generation and company loss studies.

3.3.2.5 Billed/Unbilled Analysis

Unbilled energy sales are forecast using the same methodology that is used by the Company to compute actual unbilled sales each month as part of its closing process. The Company starts with the projected monthly internal energy requirements forecast, subtracts the forecasted billed sales and estimate for line losses to derive the forecasted net unbilled sales.

3.3.3 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the APCo service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1984-2010. The long-term energy sales forecast is developed by blending of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

3.3.3.1 Supporting Models

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including a natural gas price model and a regional coal production model for APCo’s Virginia and West Virginia service areas. These models are discussed below.

3.3.3.1.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of state natural gas prices for four primary consuming sectors: residential, commercial, industrial and electric utilities. In the state natural gas price models sectoral prices are related to U.S. sectoral prices, as well as binary variables. The U.S. natural gas price forecasts were obtained from U.S. DOE/EIA’s “2010 Annual Energy Outlook”. The estimation interval for the natural gas price model, which is an annual model, was 1973-2009.

3.3.3.1.2 Regional Coal Production Model

A regional coal production forecast is used as an input in the mine power energy sales model. In the coal model, regional production depends mainly on the level of demand for U.S. coal for consumption by electric utilities and U.S. coal production, as well as on binary variables that reflect the impacts of special occurrences, such as strikes. In the development of the regional coal production forecast, projections of U.S. coal production were obtained from U.S. DOE/EIA's "2010 Annual Energy Outlook." The estimation period for the model was 1975-2009.

3.3.3.2 Residential Energy Sales

Residential energy sales for APCo are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

3.3.3.2.1 Residential Customer Forecasts

The long-term residential customer forecasting model is linear and monthly. The model for the Company's Virginia service area is depicted as follows:

$$Customers = f(households, realpersonalincome, customers_{-1})$$

Service area households provide a measure for customer change, while service area real personal income provides a measure of economic growth in the region, which will also affect customer growth. The lagged dependent variable captures the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The customer forecast is blended with the short-term residential customer forecast to produce a final forecast. A similar model is estimated for the Company's West Virginia service area.

3.3.3.2.2 Residential Energy Usage Per Customer

The residential usage model is estimated using a Statistically Adjusted End-Use Model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool and other. The SAE model constructs variables to be used in an econometric equation like the following:

$$Use = f(Xheat, Xcool, Xother)$$

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from APCo’s residential customer survey. The saturation forecasts are based on U.S. Department of Energy (DOE) forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody’s Analytics and the electricity price forecast is developed internally.

The SAE model is estimated using a linear regression model. It is a monthly model for the period January 1995 through September 2010. This model incorporates the effects of the Energy Policy Act of 2005 (EPAct, the Energy Independence and Security Act of 2007 (EISA), American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential energy.

The graphical depiction of the residential SAE model is provided in Exhibit 3-1, pages 2 through 5.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

Separate residential SAE models are estimated for the Company's Virginia and West Virginia jurisdictions.

3.3.3.3 Commercial Energy Sales

Long-term commercial energy sales are forecast using a SAE model. This model is similar to the residential SAE model. The functional model is as follows:

$$Energy = f\,(Xheat, Xcool, Xother)$$

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from DOE's 2010 Annual Energy Outlook. Billing days and electricity prices are developed internally. The commercial output measure is real commercial gross regional product from Moody's Analytics. The equipment stock and square footage information are for the East North Central Census Region.

The SAE is a linear regression for the period January 1996 through September 2010. As with the residential SAE model, the effects EPAct, EISA, ARRA and EIEA2008 are captured in this model.

The graphical depiction of the commercial SAE model is provided in Exhibit 3-1, pages 6 through 9.

Separate commercial SAE models are estimated for the Company's Virginia and West Virginia jurisdictions.

3.3.3.4 Industrial Energy Sales

3.3.3.4.1 Manufacturing

Virginia manufacturing energy sales are estimated using a quarterly model, which is depicted as follows:

$$Energy = f(electricprice, grossregionalformanufacturing)$$

The manufacturing forecasting model relates energy sales to the real price of electricity, service area gross regional product for manufacturing and binary variables. The prices are modeled using twelve-quarter moving averages. The independent variables are modeled in logarithmic form.

A similar model structure is used for Company's West Virginia manufacturing energy sales.

3.3.3.4.2 Mine Power

Mine Power energy sales are estimated using a quarterly model, which is depicted as follows:

$$Energy = f(electricprice, coalproduction)$$

The forecast of APCo Virginia's mine power energy consumption for non-associated mining companies is produced with a model relating mine power energy sales to regional coal production and a 12-quarter moving average of electric price to mine power customers. This model is specified as linear, with the dependent and independent variables in logarithmic form.

A similar model structure is used for the Company's West Virginia mine power energy sales.

3.3.3.5 All Other Energy Sales

The forecast of public street and highway lighting relates energy sales to service area commercial employment and binary variables. The model is specified linear with the dependent and independent variables in linear form.

The municipal energy sales model is specified linear with the dependent and independent variables in linear form. Wholesale energy sales are modeled relating energy sales to economic variables such as service area gross regional product, heating and cooling degree-days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition of new customers.

3.3.3.6 Blending Short and Long-Term Sales

Forecast values for 2011 are taken from the short-term process. Forecast values for 2012 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by the end of 2012 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results.

3.3.3.7 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, company loss study results are incorporated to apply losses to each revenue class.

3.4 Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The inputs into forecasting hourly demand are blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. The end-use and class profiles were obtained from Itron, Inc. Energy Forecasting load shape library and modeled to represent each company or jurisdiction service area.

In forecasting, the weather profiles and calendars dictate which profile to apply and the sales plus losses results dictate the volume of energy under the profile. In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of APCo and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West (SPP), or total AEP system. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

3.5 Load Forecast Results

3.5.1 Load Forecast After DSM Adjustments

Exhibit 3-3 present APCo's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial and other internal sales, as well as losses) on an actual basis for the years 2008-2010 and on a forecast basis for the years 2011-2025. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the Company’s Virginia Retail service area is given on **Exhibit 3-4**.

Exhibit 3-3

Appalachian Power Company
Actual and Forecast
Internal Energy (GWh) Requirements by Sector

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other* Energy Requirements	Growth Rate	Total Internal Energy Requirments	Growth Rate
Actual										
2008	12,523	---	7,057	---	13,794	---	7,320	---	40,695	---
2009	12,218	-2.4	6,974	-1.2	10,388	-24.7	6,998	-4.4	36,577	-10.1
2010	13,127	7.4	7,208	3.4	10,774	3.7	7,527	7.6	38,636	5.6
Forecast										
2011	12,368	-5.8	6,936	-3.8	10,827	0.5	7,411	-1.5	37,542	-2.8
2012	12,501	1.1	7,066	1.9	11,016	1.8	7,221	-2.6	37,805	0.7
2013	12,529	0.2	7,117	0.7	11,034	0.2	7,224	0.0	37,903	0.3
2014	12,538	0.1	7,167	0.7	11,058	0.2	7,316	1.3	38,078	0.5
2015	12,581	0.3	7,268	1.4	11,118	0.5	7,329	0.2	38,297	0.6
2016	12,581	0.0	7,352	1.2	11,184	0.6	7,373	0.6	38,490	0.5
2017	12,579	0.0	7,425	1.0	11,212	0.3	7,410	0.5	38,627	0.4
2018	12,593	0.1	7,509	1.1	11,249	0.3	7,453	0.6	38,805	0.5
2019	12,615	0.2	7,600	1.2	11,297	0.4	7,508	0.7	39,021	0.6
2020	12,642	0.2	7,693	1.2	11,370	0.6	7,592	1.1	39,296	0.7
2021	12,706	0.5	7,814	1.6	11,485	1.0	7,648	0.7	39,653	0.9
2022	12,757	0.4	7,925	1.4	11,554	0.6	7,746	1.3	39,981	0.8
2023	12,821	0.5	8,035	1.4	11,628	0.6	7,822	1.0	40,306	0.8
2024	12,897	0.6	8,143	1.3	11,689	0.5	7,883	0.8	40,612	0.8
2025	12,970	0.6	8,262	1.5	11,774	0.7	7,927	0.6	40,933	0.8

***Other energy requirements include other retail sales, wholesale sales and losses.**

Source: AEP Economic Forecasting

Exhibit 3-4

Appalachian Power Company - Virginia
Actual and Forecast
Internal Energy (GWh) Requirements by Sector

Year	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other* Energy Requirements	Growth Rate	Total Internal Energy Requirments	Growth Rate
Actual										
2008	6,638	---	3,361	---	5,551	---	3,458	---	19,008	---
2009	6,478	-2.4	3,313	-1.4	5,126	-7.7	3,356	-2.9	18,273	-3.9
2010	6,920	6.8	3,415	3.1	5,435	6.0	3,577	6.6	19,347	5.9
Forecast										
2011	6,598	-4.7	3,285	-3.8	5,511	1.4	3,665	2.5	19,060	-1.5
2012	6,674	1.2	3,357	2.2	5,584	1.3	3,592	-2.0	19,207	0.8
2013	6,712	0.6	3,404	1.4	5,585	0.0	3,583	-0.3	19,284	0.4
2014	6,722	0.2	3,442	1.1	5,581	-0.1	3,651	1.9	19,396	0.6
2015	6,744	0.3	3,480	1.1	5,586	0.1	3,673	0.6	19,483	0.4
2016	6,739	-0.1	3,505	0.7	5,594	0.1	3,706	0.9	19,543	0.3
2017	6,738	0.0	3,527	0.7	5,619	0.4	3,729	0.6	19,612	0.4
2018	6,746	0.1	3,566	1.1	5,653	0.6	3,757	0.8	19,722	0.6
2019	6,758	0.2	3,608	1.2	5,693	0.7	3,790	0.9	19,848	0.6
2020	6,770	0.2	3,652	1.2	5,742	0.9	3,838	1.3	20,002	0.8
2021	6,801	0.4	3,707	1.5	5,806	1.1	3,868	0.8	20,181	0.9
2022	6,822	0.3	3,756	1.3	5,842	0.6	3,919	1.3	20,339	0.8
2023	6,846	0.4	3,803	1.3	5,888	0.8	3,960	1.0	20,498	0.8
2024	6,875	0.4	3,850	1.2	5,930	0.7	3,993	0.8	20,648	0.7
2025	6,902	0.4	3,902	1.4	5,981	0.8	4,018	0.6	20,802	0.7

***Other energy requirements include other retail sales, wholesale sales and losses.**

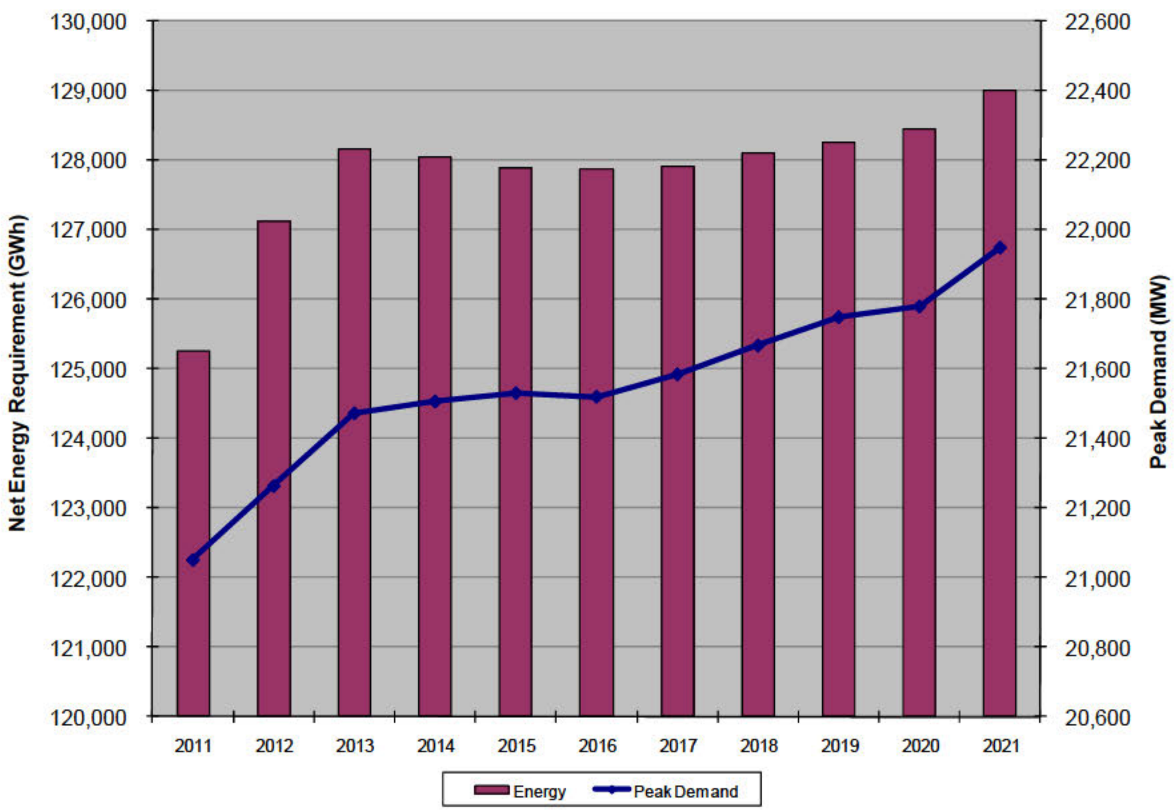
Source: AEP Economic Forecasting

3.6 AEP-East Peak Demand Forecast

Exhibit 3-5 reflects the AEP Economic Forecasting Group's forecast of annual peak demand for the AEP-East, utilized in this IRP.

Specifically, Exhibit 3-5 identifies the AEP-East internal demand profile as having a 0.42% CAGR including the impacts of projected (embedded) DR/EE which will be discussed later in this document. This equates to a **90 MW per year increase** over the 10-year period through 2021 if the load growth was steady. As the graph shows, the impact of the existing recession depresses peak demand in 2011 with an increase in 2012 and 2013 from the assumed economic recovery. In addition, the chart indicates a 0.29% CAGR, reflective of forecasted DR/EE impacts, for internal energy sales over the 10-year period.

Exhibit 3-5: AEP-East Peak Demand and Energy Projection



Source: AEP Economic Forecasting

Exhibits 3-6 and 3-7 show the current energy and demand forecasts, respectively, compared to historical actual data and the previous forecast. Note that for both demand and energy, in the current forecast is significantly lower than the normalized highs in 2008 as recessionary impacts on demand are being reflected. The impact of future energy efficiency (DSM) programs is expected to have a moderate impact on the load forecast.

Exhibit 3-6: AEP-East Internal Energy - Actual and Forecast

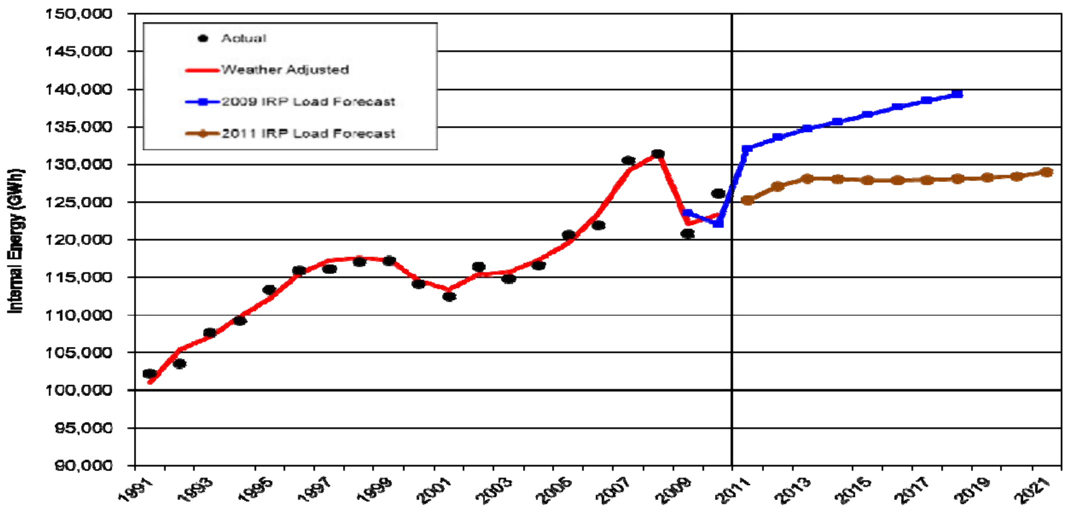
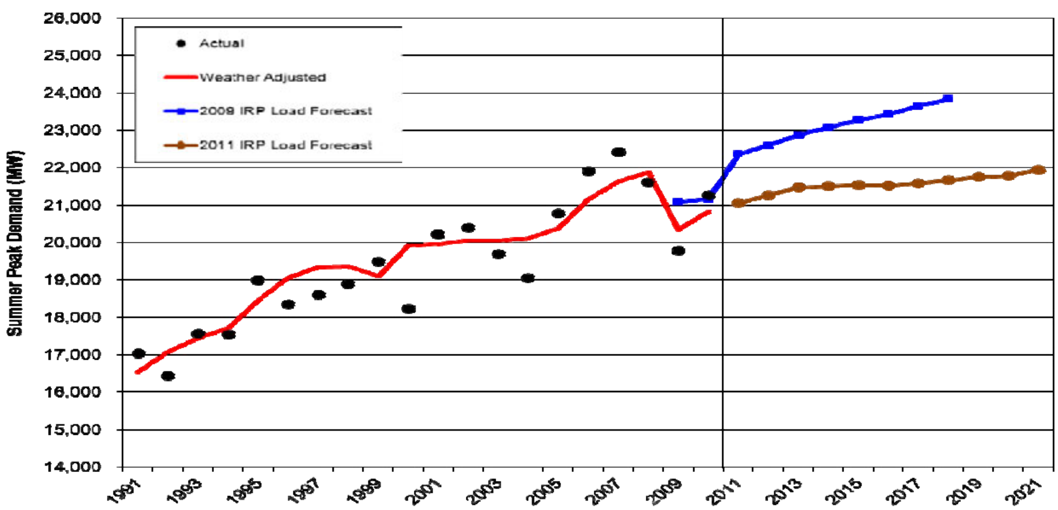


Exhibit 3-7: AEP-East Summer Peak - Actual and Forecast



Source: AEP Economic Forecasting

3.7 Exhibits 3-1 and 3-2

Exhibit 3-1

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Appalachian Power Company
Internal Energy Requirements Forecasting Method

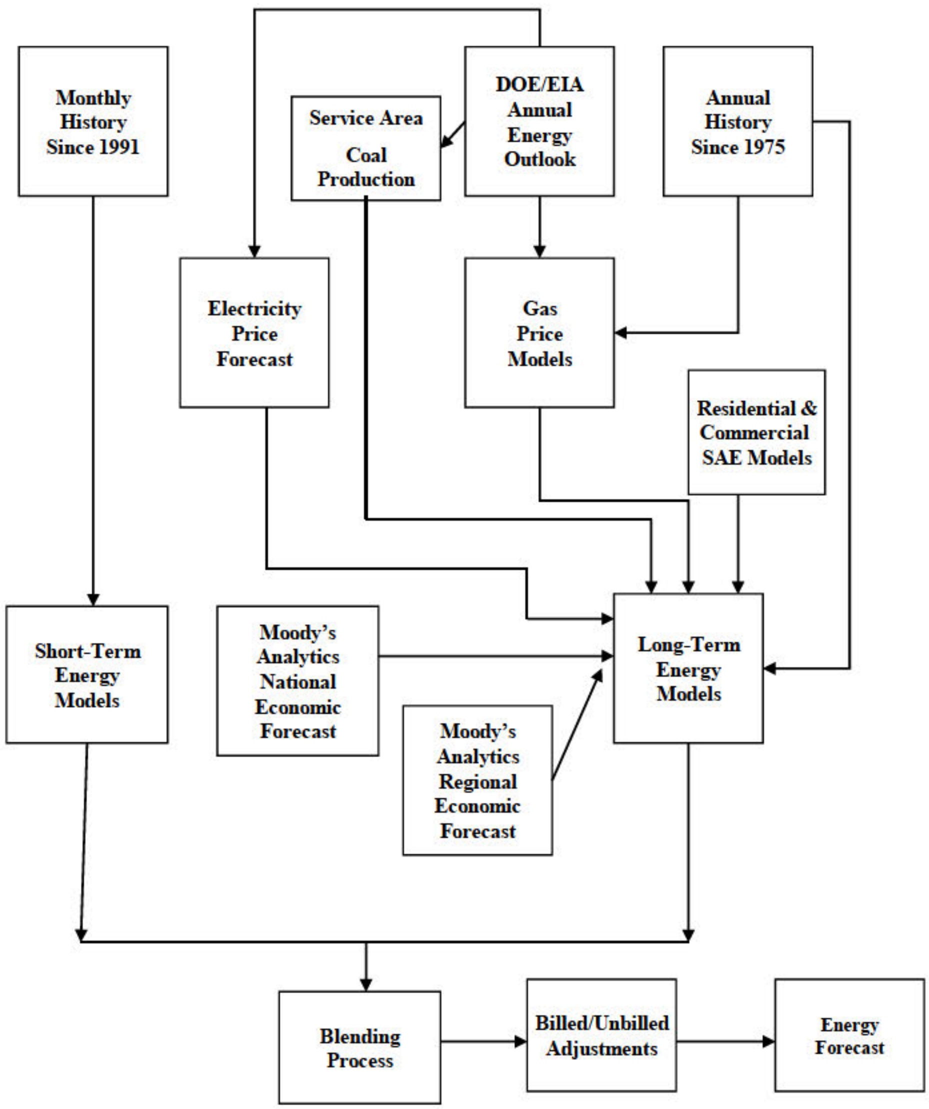


Exhibit 3-1

Page 2 of 9

Appalachian Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X heat Variable

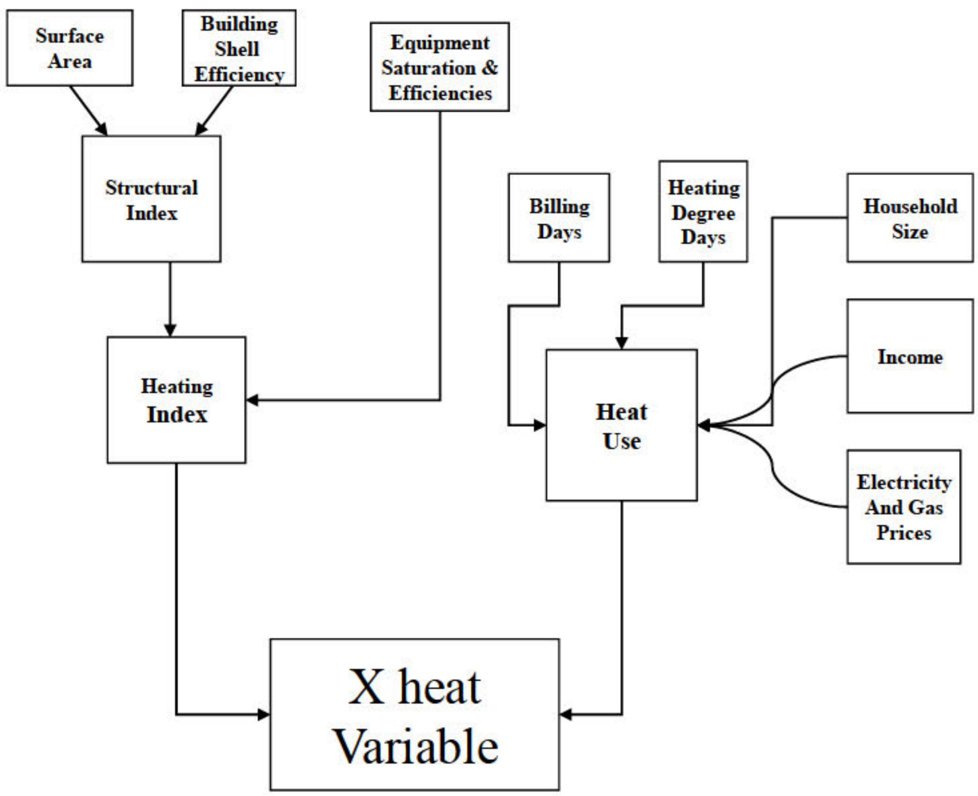


Exhibit 3-1

Page 3 of 9

Appalachian Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X cool Variable

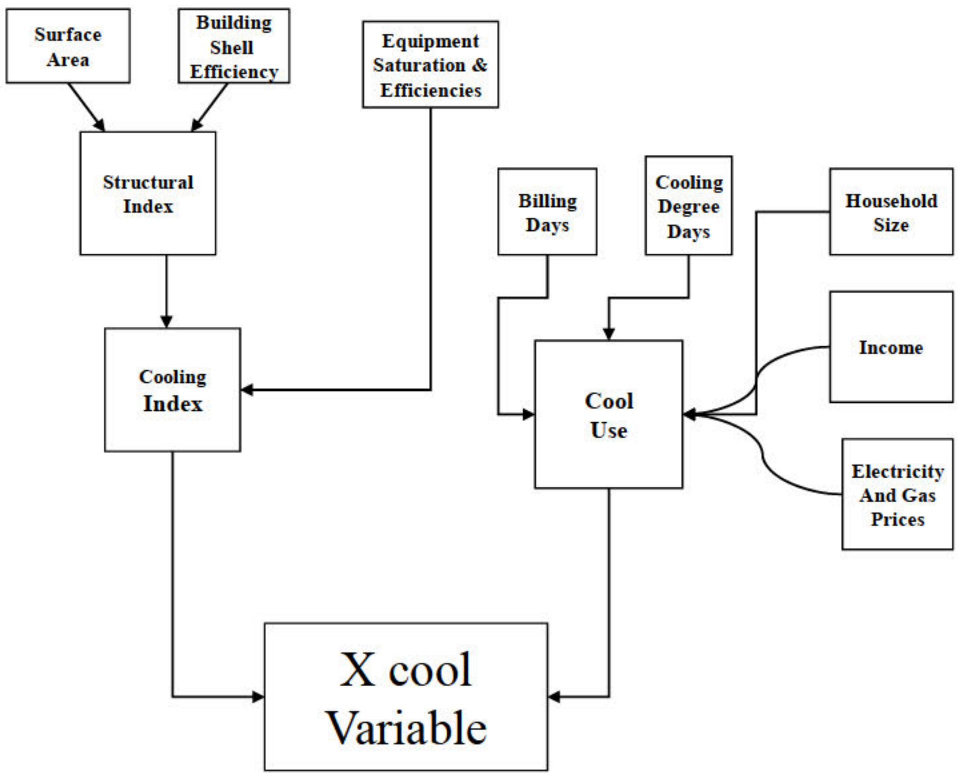


Exhibit 3-1

Page 4 of 9

Appalachian Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X other Variable

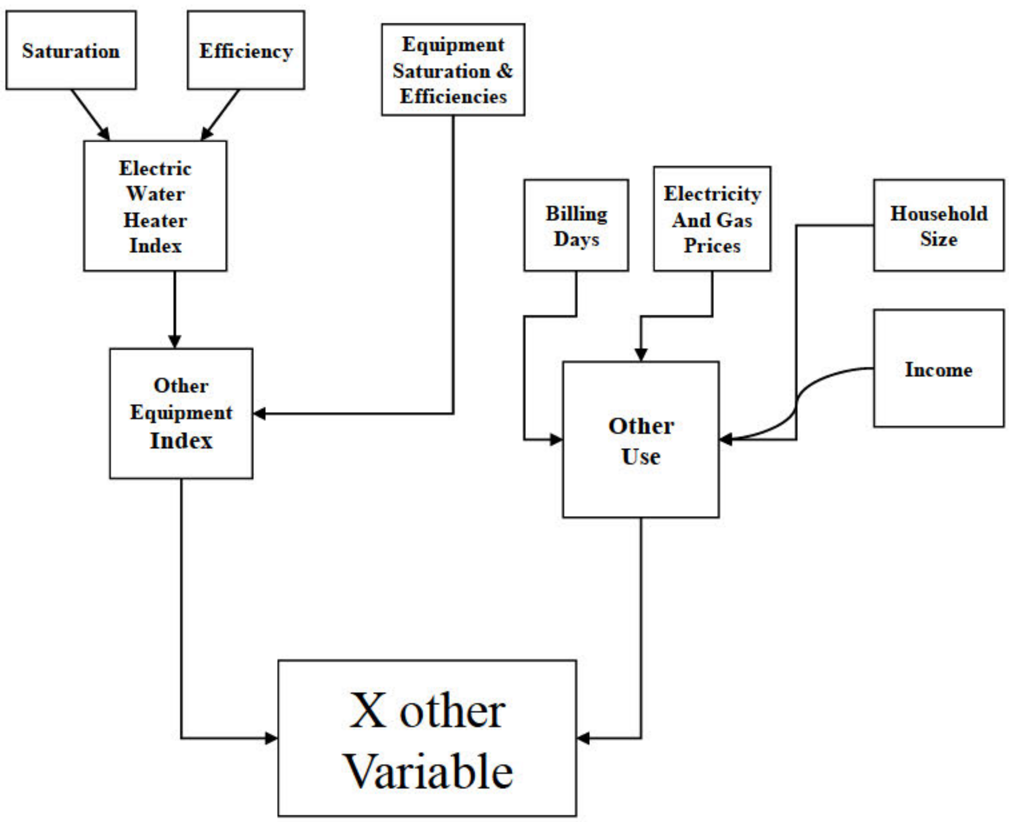


Exhibit 3-1

Page 5 of 9

Appalachian Power Company
Residential Statistically Adjusted End-Use Model (SAE)

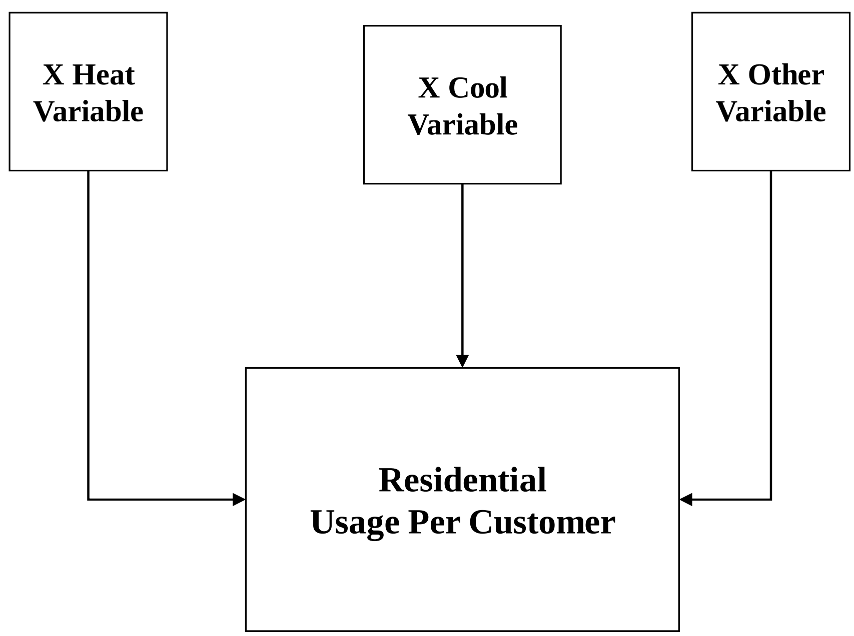
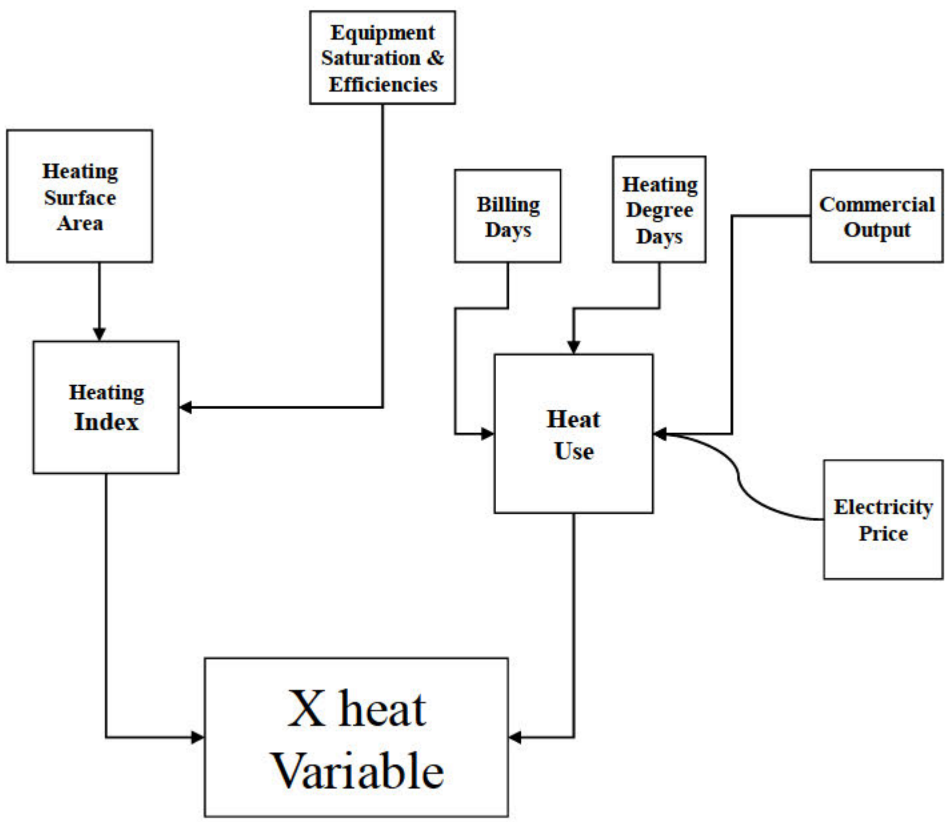


Exhibit 3-1

Page 6 of 9

Appalachian Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X heat Variable



Appalachian Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X cool Variable

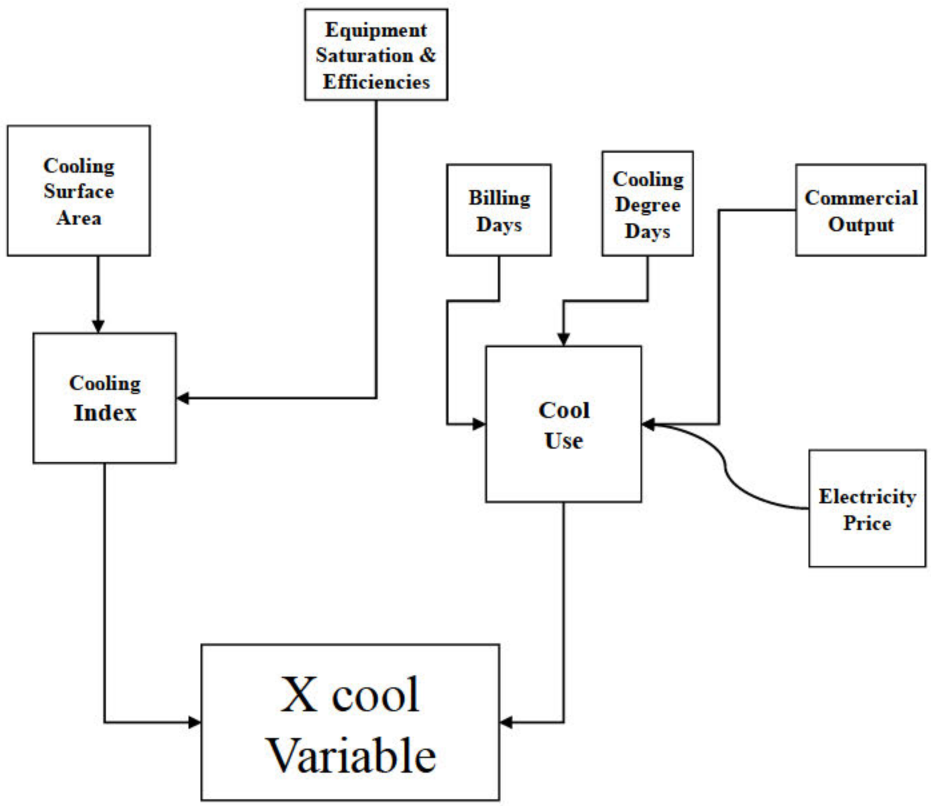


Exhibit 3-1

Page 8 of 9

Appalachian Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X other Variable

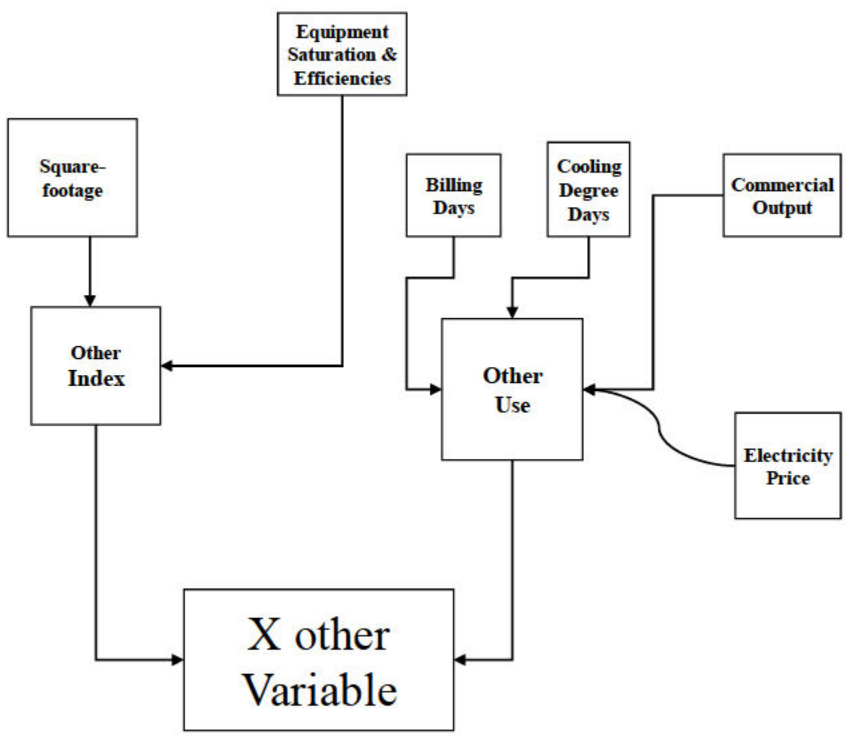
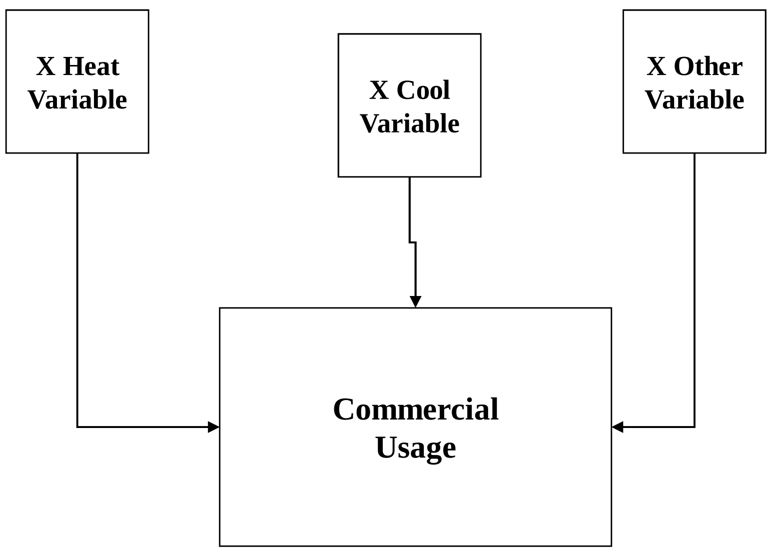


Exhibit 3-1

Page 9 of 9

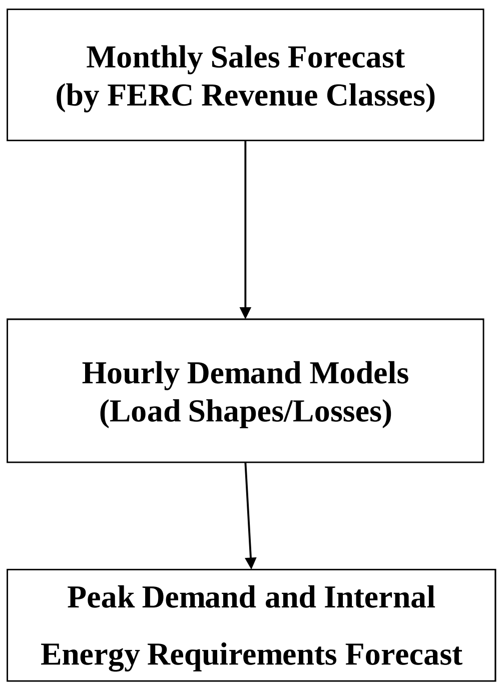
Appalachian Power Company
Commercial Statistically Adjusted End-Use Model (SAE)



Source: AEP Economic Forecasting

Exhibit 3-2

Appalachian Power Company
Peak Demand and
Internal Energy Requirements
Forecast Process – Sequential Steps



Source: AEP Economic Forecasting

4.0 Demand-Side Options

4.1 Summary of APCo Demand-Side Options and Impacts

APCo currently offers DSM pricing programs designed to reduce the level of peak demands. These programs consist of Time of Day tariff offerings for all customer classes, Advanced Time of Day (ATOD) pricing and Interruptible contracts. As described in **Section 4.7**, below, APCo is considering and evaluating potential additional energy efficiency and demand response programs, as well as Smart Grid technologies.

4.1.1 Current Demand-Side Options

During the current decade, APCo, and other AEP-East operating companies have offered a portfolio of demand response programs. These programs, generally consisting of demand-related "pricing" tariffs and programs, have benefitted all AEP member companies, including APCo and its customers by deferring the need to build additional capacity. The demand impacts from these programs are detailed in **Schedule 16**. Additionally, APCo in Virginia, has recently filed to expand its demand-side portfolio to include demand response tariffs that offer comparable terms to those DR programs offered by PJM.

In APCo's Virginia territory, Low Income Weather Assistance programs are currently being offered by a number of entities, and recently have been greatly expanded. A full assessment of these low income programs in the state is included in **Section 4.10** below.

4.1.2 Energy Efficiency (EE)

EE measures save money for customers billed on a "per kilowatt-hour" usage basis. The trade-off is the reduced utility bill for any up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If the consumer feels that the new technology is a viable substitute and will pay him or her back in the form of reduced bills over an acceptable period, he or she will adopt it.

EE measures include efficient lighting, weatherization, efficient pumps and motors, efficient HVAC infrastructure, and efficient appliances, most commonly. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will, in all cases, reduce the amount of energy consumed, but some measures may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. According to a March 2007 DOE study such benefits include:

Economics	Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
Environment	Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change
Infrastructure	Lower demand lessens constraints and congestion on the electric transmission and distribution systems
Security	EE can lessen our vulnerability to events that cut off energy supplies

Numerous studies have been published which quantify the amount of available "cost-effective" EE. Typically, and for the purposes of this IRP, this has meant measures that pass the "total resource cost" (TRC) test, meaning that the measure "pays for itself" in energy and capacity savings, regardless of whether or not its cost may be subsidized. The results of some notable studies are summarized below:

	Economic Potential		
Study	Utility Programs	Other	Total
EPRI 2009 (National)	13%	N/A	N/A
ACEEE 2008 (Virginia)	20%	10%	30%
Summit Blue 2009 (APCo VA)	27%	N/A	N/A
McKinsey & Company 2009 (national)	N/A	N/A	23%

While there is some disagreement about what the actual number may be and some differences in methodologies, it is reasonable to assume that there is a fairly large well of latent cost-effective EE available. What becomes a question of policy is how much of the available efficiency should be pursued with utility-sponsored programs, and included as a resource.

Unlike supply-side resources, demand-side resources, particularly EE resources require the participation of thousands of consumers. While the math may indicate that an "investment" in a particular measure is cost-effective, it does not guarantee that it will be universally adopted.

Market barriers to EE exist which limit the rate and ultimate level at which efficiency measures are adopted by consumers (program participants).

Market Barriers to Energy Efficiency	
High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of EE options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for EE services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the EE measure may be different from those benefiting from the investment (e.g. rental property).
Product/Service Unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings.

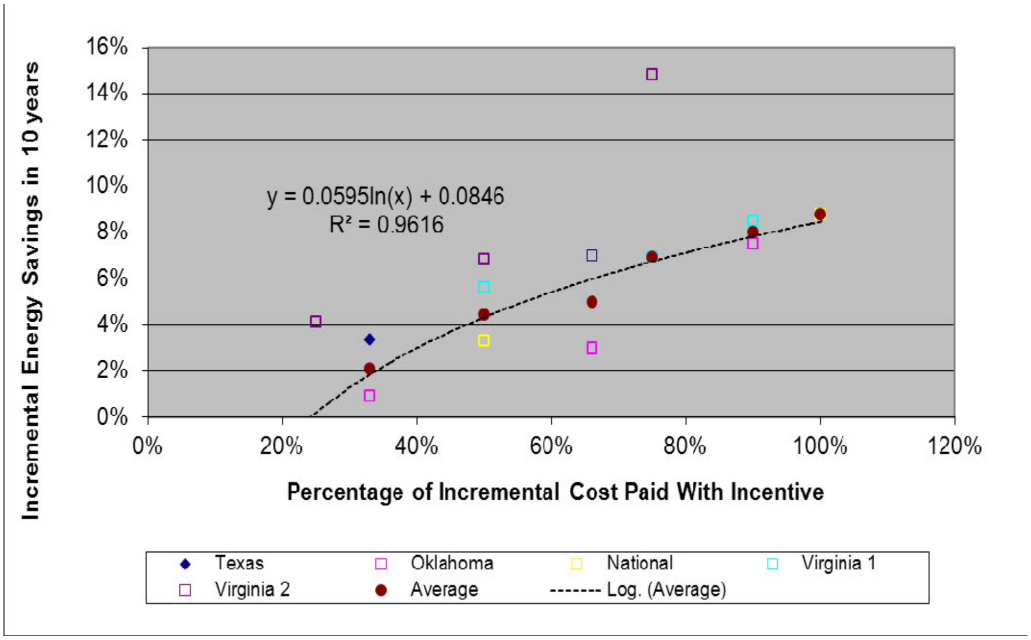
Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

To overcome many of the participant barriers noted above, a portfolio of programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of market transformation and measure adoption. To achieve rapid adoption of efficiency measures, it is reasonable to expect increased program costs associated with higher consumer incentives, higher administrative burdens and marketing. A market penetration function was derived from market potential studies for APCo and other AEP jurisdictions. **Exhibit 4-1** shows that higher levels of EE can be achieved as the subsidies to participants (incentives) are increased. It also shows an intuitive degree of diminishing returns where increases in the incentive (expressed as a percentage of the measure cost) have a decreasing effectiveness.

Exhibit 4-1: Relationship Between Energy Savings and Subsidies



Source: Resource Planning

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This 2011 APCo IRP begins adding demand-side resources in Virginia in 2013 and in West Virginia in 2011.

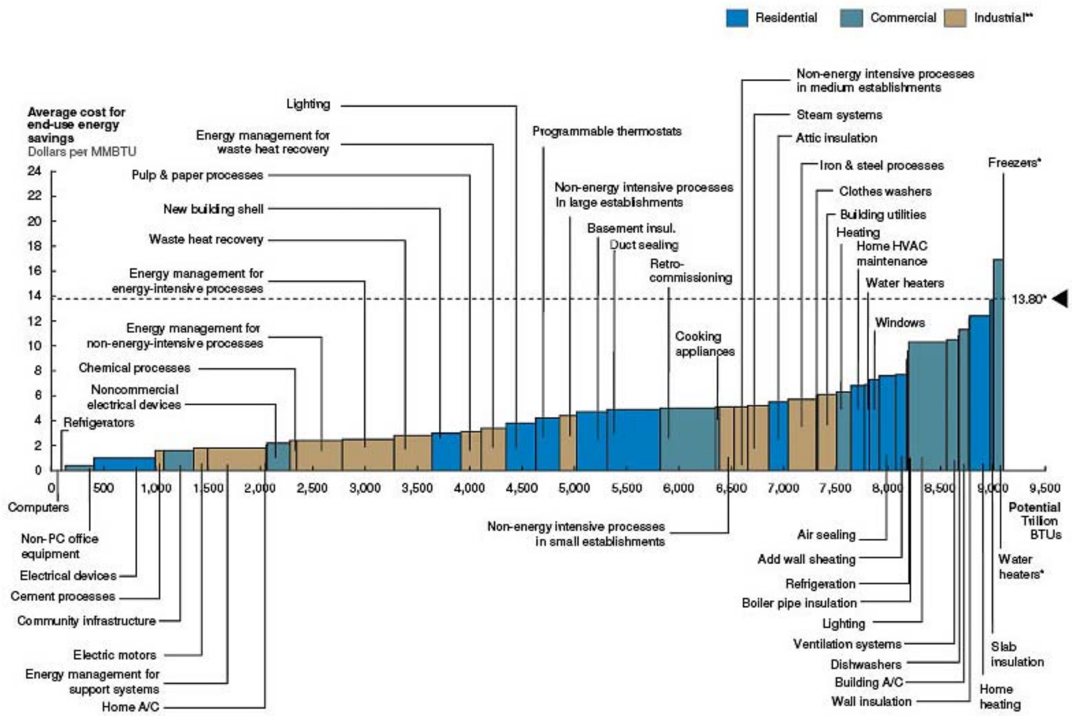
4.2 Cost Effectiveness of Energy Efficiency

While it is accepted that substantial amounts of EE are available, the cost-effectiveness of the resources was validated within the Company's proprietary *Strategist*® long-term, resource optimization model (see Section 9 for a complete description of the *Strategist*® model). The following method was employed:

1. Assemble a "weighted" EE portfolio of representative measures (end uses).
2. Construct a composite load shape associated with that weighted EE portfolio.
3. Determine the revenue requirements of supply portfolios with varying levels of EE to determine the benefits of EE portfolios at differing levels.
4. Determine the cost of those unique EE portfolios.
5. Compare the benefits of the EE portfolios to its attendant cost.

While EE measures have a wide range of costs and thus have a "supply curve" similar to other assets, as depicted in **Exhibit 4-2**, it is not practically true that the cheapest options will be done first and ahead of more expensive options. Typically, a utility-sponsored program will be required to provide a "range" of efficiency measures.

Exhibit 4-2: EE Supply Curve



* Average price of avoided energy consumption at the industrial price; $35.60/MMBTU represents the highest regional electricity price used; new build cost based on AEO 2008 future construction costs

** Our 49th source of savings, refining processes, offers no NPV-positive savings

Source: EIA AEO 2008, McKinsey analysis

The levelized resource cost of the EE portfolio, in aggregate, was assumed to be $40/MWh which is consistent with numerous studies (approximately equivalent to $4.00/MMBtu). The absolute value is not critical to this analysis as will be shown. The real variable from the perspective of the utility and utility commissions is how much will a program cost and what results can be expected.

For this 2011 APCo IRP, two levels of EE were evaluated in Virginia. The first, or base level, represents an installed base of 4.9% in ten years (2022) of energy consumed in a business-as-usual forecast. The second is a level two times higher than the base case. For APCo as a whole, the levels are similar (4.5% installed in 2022). In February 2011, West Virginia approved a two-year program that will result in 1.1% of installed saving in 2012. This IRP assumes a similar level of investment through 2025 in West Virginia.

4.3 Value of Energy Efficiency Portfolio

By evaluating the base portfolio with and without EE, the difference can be considered the value, or benefit of the efficiency portfolio. This can then be compared to the costs of the EE portfolios. Because the per-unit cost of the measures are held constant, the variation in the portfolio costs (program costs) are due to the levels of EE and the incentive necessary to achieve those levels. Also, a break-even analysis was completed to determine the aggregate average measure cost that cannot be exceeded for the portfolio to be cost-effective from a total resource perspective.

	PV of Benefits ($000)	PV of Costs ($000)	Net Benefit ($000)	Incentive level	Break-even cost of Efficiency ($/MMBtu)
Base Case EE	229,034	229,004	31	52%	6.30
200% EE	460,489	458,007	2,481	100%	6.33

Both EE portfolios provide incremental net benefits from the utility perspective; however, there is, as expected, a diminishing returns effect on the larger portfolio. Another interpretation is that utilities have a fair amount of latitude in choosing measures for the efficiency portfolios as much of the available EE comes at a cost which is less than that.

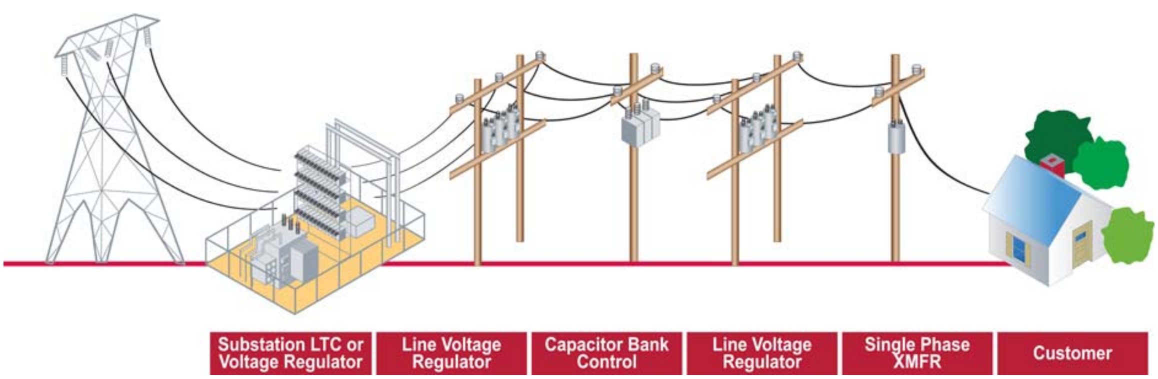
Because EE is an investment today for future savings and also results in spreading current fixed costs among fewer kilowatt hours, the net result is often an increase in rates, *even as* total bills (revenue requirements) decrease. Thus, a balance is sought between aggressive pursuit of efficiency and the full acknowledgement of this expected impact on rates.

4.4 Smart Grid - Integrated Voltage/ VaR Control (IVVC)

IVVC provides all of the benefits of power factor correction, voltage optimization, and condition-based maintenance in a single, optimized package. In addition, IVVC enables conservation voltage reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. A 1% reduction in voltage typically results in a 0.5% to 0.7% reduction in load.

As the electric infrastructure was built out in the last century, distribution systems were designed to assure end-users received voltages ranging from 114 to 126 volts in accordance with national standards. Most utility systems were designed so that customers close to the substation received voltages close to 126 volts and customers farther from the substation received lower voltages. This design kept line construction costs low because voltage regulating equipment was only applied when necessary to assure the required minimum voltages were provided. However, since most devices operated by electricity, especially motors, are designed to operate most efficiently at 115 volts, any "excess" voltage is typically wasted, usually in the form of heat. Tighter voltage regulation, enabled by smart-grid infrastructure, allows end-use devices to operate more efficiently without any action on the part of consumers (**Exhibit 4-3**). Consumers will simply use less energy to accomplish the same tasks.

Exhibit 4-3: Integrated Voltage/VaR Control



Source: Resource Planning

4.4.1 Valuing IVVC

Similar to EE, the base portfolio was prepared with *and* without IVVC and compared to the costs.

	Peak Demand Savings (MW)	Annual Energy Savings (GWh)	PV of Benefits ($000)	PV of Costs ($000)
IVV	20	92	59,309	36,868

4.5 gridSMART^{TM} Smart Meter Pilots

Smart meter pilots are underway in Indiana and Ohio. As of June 1st, 2011, over 140,000 customers have been equipped with the new meters. An additional 310,000 meters have been installed in AEP-Texas. The meters allow for time-differentiated pricing which should result in more efficient customer use of electricity and peak usage reductions.

The more comprehensive gridSMART^{TM} demonstration project involves approximately 130,000 customers in central Ohio. Paid for in part with a $75 million grant from the DOE, the $150 million project will include smart meters, distribution automation equipment to better manage the grid, community energy storage devices, smart appliances and home energy management systems, a new cyber security center, PHEV (Plug-in/hybrid electric vehicle) demonstrations, and installation of utility-activated control technologies that will reduce demand and energy consumption without requiring customers to take action. This last technology also encompasses IVVC.

There is currently no gridSMART^{TM} initiative underway in APCo or its Virginia jurisdiction.

4.6 Demand Response

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. In the PJM zone, this maximum (System peak) is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak must be reduced. In addition to “passive” or “non-dispatchable” resources like EE and IVVC, “active” or “dispatchable” resources, which have impacts primarily only at times of peak demand, include:

- *Interruptible loads*. This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.
- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through various media such as FM-radio signals that activate switches, or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Time-differentiated rates*. Offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) and to as often as 15-minute increments known as "real-time pricing." Accomplishing real-time pricing would typically require digital (smart) metering to "download" pricing signals from a utility host system.

APCo currently has 14 (15) MW total of summer (winter) "interruptible" and 107 (83) MW of "Advanced Time of Day" (ATOD) capacity. These contracts apply to larger industrial users.

Expanding DR options beyond interruptible industrial contracts is likely necessary to achieve increased peak demand reductions. Many commercial businesses participate in DR activities that selectively reduce load in exchange for capacity payments from PJM. For this IRP, it is assumed that future demand reduction programs would consist of additional tariffs (summer and winter impacts) as well as Company-offered, summer-only demand response similar to what is currently required within PJM.

On a broad scale, direct load control-type programs are typically more expensive as similar infrastructure is needed to achieve smaller load reductions. Moreover, these programs can also introduce consumer dissatisfaction since the "economic choice" is removed from the customer.

4.6.1 Valuing Demand Response

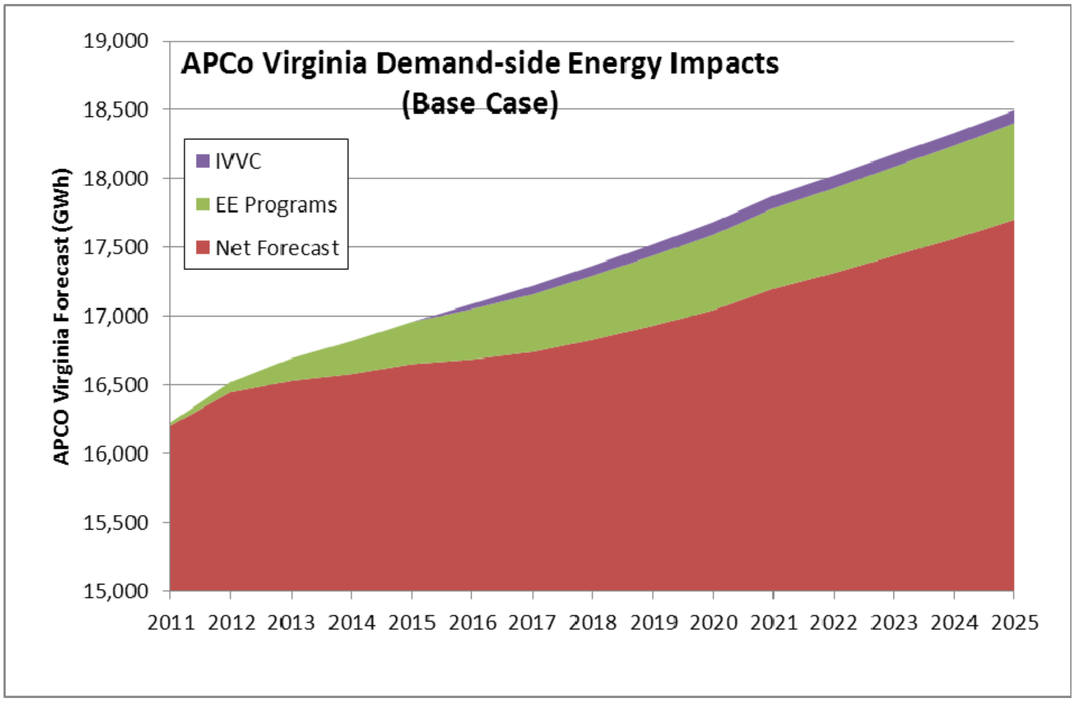
As before, the base portfolio evaluation is completed with and without DR program/assets to determine its benefit. From there a break-even cost is calculated which becomes a cost-to-beat as DR options are pursued during the implementation phase.

	Peak Demand Savings (MW)	PV of Benefits ($000)	Benefit Levelized ($/kW-yr)
Base	105	109,286	111
2x	210	213,307	109

4.7 Demand-Side Resources – APCo-Virginia

Exhibit 4-4 shows the expected impact of the base portfolio of EE and smart grid resources on APCo Virginia's Energy forecast.

Exhibit 4-4: APCo VA Demand Side Impacts



Source: Resource Planning

The 2011 APCo IRP includes achievable levels of EE, Smart-Grid infrastructure, and DR. Analyses utilizing the *Strategist®* optimization model indicate that these options are cost effective and should be considered for inclusion in the mix of assets utilized to meet reliability requirements. Increased levels of demand-side options were also evaluated and found to be cost-effective. However, the value achieved is increasingly diminished in the case of EE and DR as participants will typically require greater payment for increased participation.

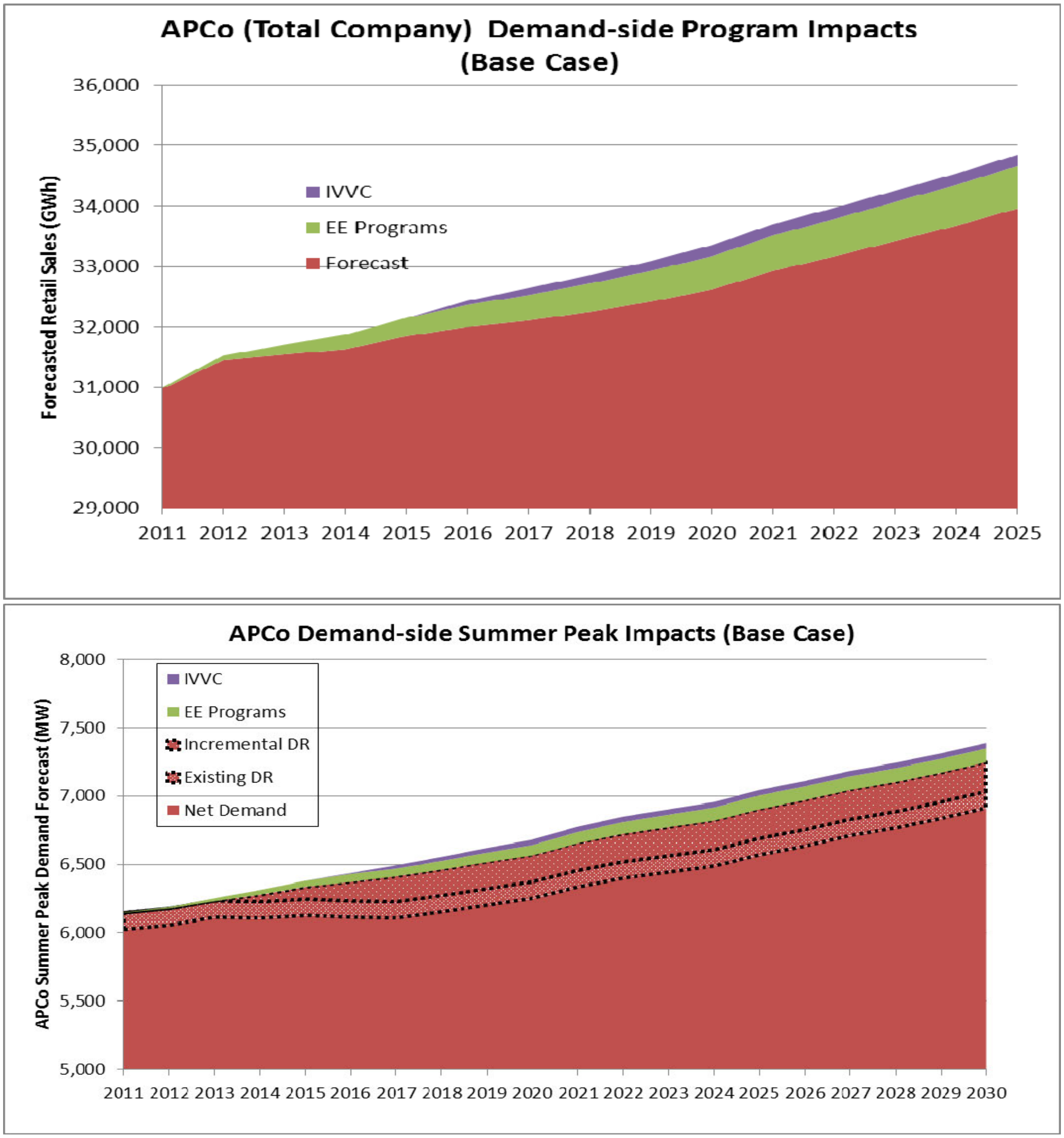
APCo favors a portfolio approach to DSM, employing all options in moderate, achievable amounts that will keep rate impacts muted as revenue requirements decline.

4.8 Demand-Side Resources – APCo-West Virginia

The West Virginia Public Utilities Commission has approved a two-year Energy Efficiency program for APCo's West Virginia jurisdiction. The approved levels in West Virginia are similar to those contemplated in Virginia. APCo began implementing EE programs in 2011 in West Virginia. A level similar to what was approved was continued through the forecast period. West Virginia's approved portfolio of programs consist of residential and commercial programs.

The combined effect of the Virginia and West Virginia portfolios is shown in the **Exhibit 4-5** below:

Exhibit 4-5: APCo Base DSM



Source: Resource Planning

4.9 Demand-Side Resources – AEP-East

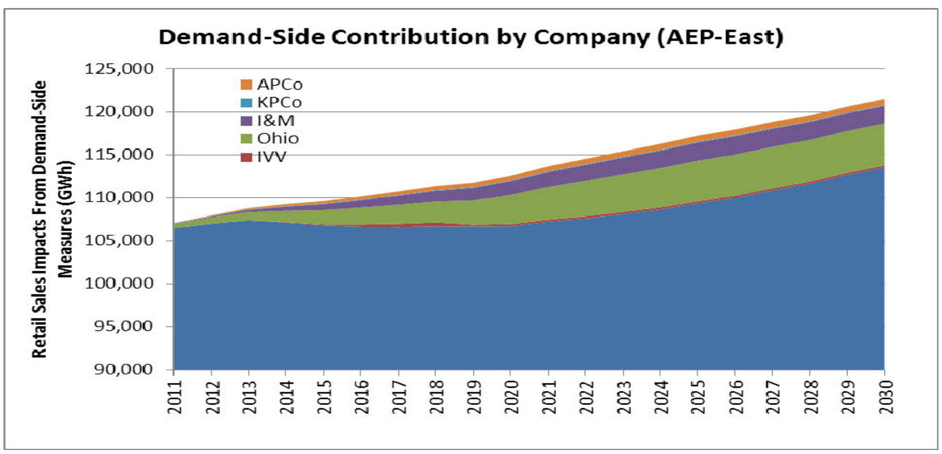
As of June 1, 2011, active EE programs exist in Kentucky, Ohio, Michigan, Indiana and West Virginia. DR programs, consisting of interruptible tariffs, time-differentiated rates, and direct load control, are currently being offered. The demand and energy impacts of the installed programs (as of December, 2010) are shown in **Exhibit 4-6**.

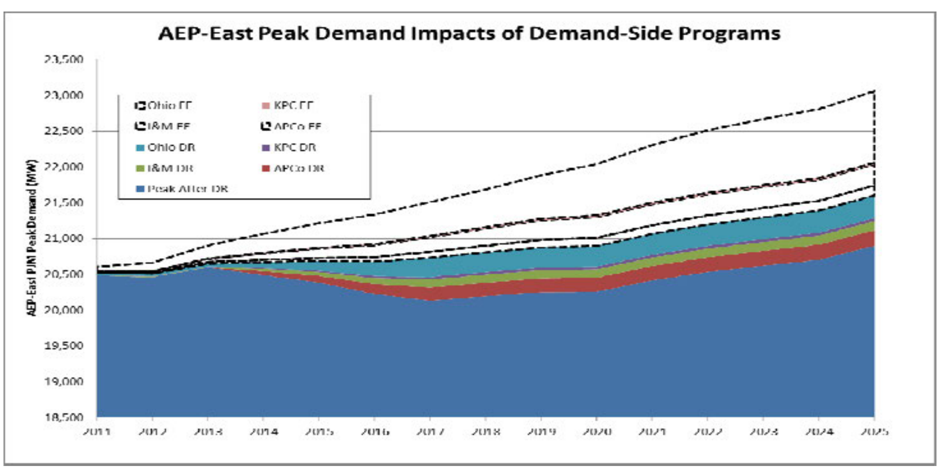
Exhibit 4-6: Forecasted Energy Efficiency and Demand Response- AEP-East

AEP-East Installed Demand-side Capacity (Year-end 2010)				
	Installed Energy Efficiency (MW, 2008-2010)	Interruptible	ATOD	Total
Ohio	158	140	-	298
APCo	-	14	107	121
I&M	19	258	-	277
Kentucky	30	-	-	30
AEP-East	208	412	107	727

Exhibit 4-7 shows the projected impacts of AEP-East demand-side programs over the forecast period. Aggressive programs resulting from mandates in Ohio and Indiana should result in a significant reduction in demand and energy requirements of APCo affiliates in these states.

Exhibit 4-7: Forecasted Energy Efficiency and Demand Response- AEP-East





Source: Resource Planning

4.10 APCo Virginia DSM Program Implementation Approaches

4.10.1 gridSMART™ Smart Meter Pilots

As stated earlier, there is currently no gridSMART™ initiative underway in APCo or its Virginia jurisdiction.

4.10.2 Virginia Low Income Energy Assistance

Energy assistance for low and moderate income residential customers in Virginia is currently delivered through a combination of governmental, utility, and community non-profit initiatives, with direct bill assistance and weatherization programs providing the greatest impact. Funding for these programs comes primarily from governmental sources – federal and state – with additional bill assistance coming from utilities and community non-profit groups. Administration of programs is accomplished through a coordinated effort involving governmental, utility, and non-profit groups.

4.10.3 Virginia Weatherization

Twenty-two non-profit agencies provide weatherization services to income eligible households within Virginia under direction of the Virginia Department of Housing and Community Development (DHCD). The US Departments of Energy (DOE) and Health and Human Services (through the Low Income Home Energy Assistance Program, or LIHEAP) provide funding to DHCD, which is then distributed to these agencies based on a formula using heating degree-days, low income population, and square miles of agency service area. Agencies are held responsible for administering these weatherization services within DHCD guidelines and industry-accepted quality standards.

DOE weatherization funding was boosted for the 2009-2010 fiscal year to $8.5 million from $4.0 million the previous season. Concurrently, LIHEAP weatherization funding was increased from $6.6 million to $19.3 million. Historically, the weatherization agencies were unable to fully satisfy client need due to lack of funding and consequently these additional funds were welcome.

Early in 2009, the federal government announced that $96.4 million in weatherization funds from the American Recovery and Reinvestment Act (ARRA) would be made available to supplement the DOE weatherization funds. This ten-fold increase in

DOE funding provided challenges to DHCD and the 22 agencies – especially with regard to obtaining and training adequate personnel for the substantial increase in production. Eligibility guidelines were relaxed to increase the pool of eligible households and weatherization guidelines were expanded to allow increased structural repair and more thorough envelope and systems work.[3] Funding is specifically provided for training and equipment (funding for program administration, training, and equipment represent 20% of total) to ensure the latest weatherization technology is employed. The ARRA funded program began in May 2009 and funds are available through mid-2011. Weatherization agencies will initially receive 50% of total production funds, with DOE evaluating the success of state programs prior to release of the remaining 50%.

Appalachian Power has discussed and expects to file with the State Corporation Commission information on demand-side management and energy efficiency (DSM/EE) programs that may have potential for implementation in Virginia. Included in this filing would be an overview of a weatherization program similar in nature to the DOE program template. The Residential Low Income Program (RLIP), if it were selected as a viable program, would target low income customers with high electrical usage who could benefit from cost-effective electrical energy savings measures.

4.10.4 Virginia Billing Assistance

All major electric utilities in Virginia participate in customer billing assistance programs targeted to low income households, particularly those households paying a high proportion of income for home energy. Generally speaking, these programs are not intended to meet the household's total home energy costs, with most benefits provided on a once-per-season basis. Administration of billing assistance programs are in conjunction with the Virginia Department of Social Services (DSS), who uses utility generated funds to supplement LIHEAP bill assistance funds. Local social services organizations – both governmental and non-profit – also provide billing assistance, with DSS providing administrative oversight to ensure efforts are not duplicated.

[3] US Department of Social Services LIHEAP funding for Virginia is administered by the Virginia Department of Social Services (DSS). LIHEAP weatherization funds are routed to DHCD by DSS to supplement the DHCD DOE funded weatherization efforts.

APCo's bill assistance program – Neighbor-to-Neighbor – has been in existence since 1983, coupling customer and shareholder contributions to assist low income customers. During the 2010-2011 heating season, 1,742 customers shared in the $569,026 of Neighbor-to-Neighbor contributions, of which $500,000 came from a direct APCo contribution to the program. In addition to the Neighbor-to-Neighbor program, APCo's Virginia customers receive approximately $10 million annually in billing assistance from LIHEAP funds.

5.0 Current Resources

A summary of all supply resources for APCo and AEP-East as of June 1, 2011 is shown below in **Exhibit 5-1** and **Exhibit 5-2**, respectively (with detail appearing in **Schedules 14a, and 14b**).

Exhibit 5-1: APCo Installed Capacity as of June 2011

Supply Resource Type	**APCo Capacity (as of 6-1-2011) Winter Rating**		**PJM Rating (ICAP)**	
	MW	%of Total	MW	%of Total
Coal	5,427	80.77%	5,360	79.29%
Nuclear	0	0.00%	0	0.00%
Hydro	705	10.50%	880	13.01%
Gas/Diesel	516	7.68%	450	6.66%
Wind [(a)]	70.74	1.05%	70.74	1.05%
Solar [(b)]	0.00	0.00%	0.00	0.00%
Total	**6,719**		**6,760**	

(a) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit, 13% of the nameplate capacity
(b) The capacity of the Solar Energy Projects are listed at the preliminary PJM credit, 6.67%(winter) and 38%(summer) of the nameplate capacity

Source: AEP Resource Planning

The AEP-East winter and summer supply is composed of the following resource components (the coal resources include AEP's share of OVEC):

Exhibit 5-2: AEP-East Installed Capacity as of June 2011

Supply Resource Type	**AEP East Capacity (as of 6-1-2011) Winter Rating**		**PJM Rating (ICAP)**	
	MW	%of Total	MW	%of Total
Coal	22,181	78.00%	21,938	77.42%
Nuclear	2,205	7.75%	2,078	7.33%
Hydro	746	2.62%	949	3.35%
Gas/Diesel	3,191	11.22%	3,256	11.49%
Wind [(a)]	112.15	0.39%	112.15	0.40%
Solar [(b)]	0.67	0.00%	3.83	0.01%
Total	**28,435**		**28,337**	

(a) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit, 13% of the nameplate capacity
(b) The capacity of the Solar Energy Projects are listed at the preliminary PJM credit, 6.67%(winter) and 38%(summer) of the nameplate capacity

Source: AEP Resource Planning

5.1 Capacity Impacts of Generation Efficiency Projects

As detailed in (Confidential) **Schedule 13**, the capability forecast of the existing APCo and AEP-East generating fleet reflects several unit "up-ratings" over the IRP period. Additionally, AEP continues to work towards improving heat rates of its generating fleet. Such improvements, while not necessarily increasing capacity, do improve fuel efficiency and, with that, contribute to reduced environmental emissions.

5.2 Capacity Impacts of Environmental Compliance Plan

As also detailed in (Confidential) Schedule 13, the capability forecast of the existing generating fleet reflects several unit de-ratings associated with environmental retrofits (largely scrubbers) over the 15-year IRP period. The "net" impact to existing units as a result of the planned up-ratings and de-ratings is also reflected in that Schedule.

5.3 Existing Unit Disposition

Another important initial process within this 2011 IRP cycle was the establishment of a long-term view of disposition alternatives facing older, smaller, currently uncontrolled coal-steam units in the AEP-East region. Prior "Unit Disposition" analyses identified 13 sets of aging APCo and AEP-East generating assets consisting of a total of 26 units (including 9 APCo units) with a PJM (summer) rating of 5,348 MW (including 1,705 MW for APCo).

APCo

- Clinch River Units 1-3 (690 MW) VA
- Glen Lyn Unit 5 (90 MW) and Unit 6 (235 MW) VA
- Kanawha River Units 1 & 2 (400 MW) WV
- Sporn Units 1 & 3 (290 MW) WV

AEP-Ohio

- Conesville Unit 3 (165 MW) OH
- Kammer Units 1-3 (600 MW) WV
- Muskingum River Units 1 & 3 (395 MW) OH
- Muskingum River Units 2 & 4 (395 MW) OH

- Picway Unit 5 (95 MW) OH
- Sporn Units 2 & 4 (290 MW) WV
- Sporn Unit 5 (440 MW) WV

I&M

- Tanners Creek Units 1-4 (985 MW) IN

KPCo

- Big Sandy Unit 1 (278 MW) KY

Among this group of units are several that were impacted by the Consent Decree from the previously-settled New Source Review (NSR) litigation. These units, and the dates by which, according to the agreement, they must be retired, repowered (as highly-thermally-efficient combined cycle units), or retrofitted with FGD and SCR systems ("R/R/R"), are:

- ✓ Conesville Unit 3, by **December 31, 2012**;
- ✓ Sporn Unit 5, by **December 31, 2013**;
- ✓ Muskingum River Units 1-4, by **December 31, 2015**; and
- ✓ A total of 600 MW from either: Sporn 1-4, Clinch River 1-3, Tanners Creek 1-3, or Kammer 1-3, by **December 31, 2018**.

Prior IRP cycle evaluations of unit conditions and related criteria laid the groundwork for purposes of determining a potential sequence of unit retirements for subsequent resource planning purposes. This sequencing also assumed a "staggered and extended" implementation of then-anticipated U.S. EPA rulemaking. Those dates typically had extended at least through this decade (12/2019).

However, with the new implementation dates contained in the final CSAPR recently issued, as well as EGU MACT and CCR rules proposed in 2011, such sequencing now may not be achievable. All units will need to be controlled under the proposed EGU MACT rule by January 2015 (or, potentially, January 2016 should a one-year extension be granted for that purpose). This new rule may have established the retirement date for each uncontrolled unit, with the exception of those units that would be able to operate with limited investment (e.g., I&M's Tanners Creek 4, a 500 MW unit, may be able to operate with investments of less than $100 million).

5.3.1 Retrofit Costs for Retirement Candidates

Alternatives to retirement have been and will continue to be evaluated for the uncontrolled units. At the time that this report was being prepared, a very high level cost estimate had been assembled for the purpose of evaluating continued operation into the foreseeable future, given the constraints of the EGU MACT and CSAPR rules for both Kanawha River units 1 and 2 and Sporn units 1-4 (APCo owns Sporn units 1 and 3). It is expected that the cost estimates would be of a similar magnitude on a dollar/kW basis for the Clinch River and Glen Lyn units. Three cases were considered offering a range of assumptions on the extent of the control technologies to be installed and the remaining unit life. In the first case, in order to minimize SO_2 and meet mass emissions constraints, a baghouse retrofit is considered to be required. Total costs account for retrofit of selective non-catalytic reduction (SNCR) for NO_X control in addition to activated carbon injection for mercury, dry ash conversions to minimize water consumption/release, waste water treatment and fish friendly water intakes for 316(b) compliance. For Kanawha River, these modifications are estimated to cost $939 million, or $2,407/kW. For Sporn 1 and 3, the cost is estimated at $584 million, or $1,999/kW.

A second case was evaluated wherein the remaining life of each of the units is assumed to be 10 years. In this case, Electrostatic Precipitator (ESP) performance is restored to original design specifications, in lieu of retrofitting the units with a baghouse. Dry Sorbent Injection (DSI) SO_2 reduction has not been demonstrated on any of these units but 20-35% may be possible, assuming SO_2 fuel content is 1.2 lb/MMBtu or less and mass emissions limits can be achieved with the ESP improvements (and likely given the size of the ESPs on each of these units). Restoration costs are reduced proportional to remaining unit life. For Kanawha River, these modifications are estimated to cost $366 million, or $914/kW. For Sporn 1 and 3, the cost is estimated at $280 million, or $934/kW.

A final case was evaluated in which the units are assumed to have a remaining life of five years and run at reduced capacity factor (~50%). The Kanawha River and Sporn units are retrofitted with DSI and ESP upgrades to reduce SO_2, acid gases and mass emissions as in the previous case. For all units, restoration costs are reduced proportionally; 316 (b) river intake modifications, activated carbon injection, bottom ash conversion, and waste water treatment investments are all eliminated with the abbreviated life. For Kanawha River, these modifications are estimated to cost $194 million, or $486/kW. For Sporn 1 and 3, the cost is estimated at $143 million, or $477/kW. While these investment levels are relatively low when compared to new capacity additions, they would have to be recovered in a much shorter timeframe (five years for a retrofit versus 30 or 40 years for new capacity), making the investment less attractive.

5.3.2 Fuel Switch Options for APCo Retirement Candidates

The retirement of Clinch River, Glen Lyn, Kanawha River and Sporn Plants will reduce APCo's capacity position whether it remains in a Pool-like construct or is a stand-alone company in PJM. The Company looked at the option of preserving capacity at these locations by switching the fuel source from coal to natural gas. To switch to natural gas, a number of factors must be considered, most importantly access to firm gas supply and cost to upgrade the gas infrastructure. A preliminary evaluation by the AEP Fuel, Emissions and Logistics group concluded that Clinch River Plant offered the best potential for gas fired operations of the APCo units, and that sufficient gas volume is available to supply up to two of the three units.

5.3.3 Findings and Recommendations—APCo and AEP-East Units

- ✓ For APCo - Kanawha River Units 1 and 2, Sporn Units 1 and 3, Glen Lyn Units 5 and 6, and Clinch River Unit 3 **are projected to be retired by January 1, 2015** in keeping with the proposed EGU MACT rulemaking. At this point, however, it is assumed that Clinch River Units 1 and 2 will be converted to burn natural gas.

- ✓ For the balance of AEP-East it is assumed that any initial unit retirements would include only those R/R/R units designated in the NSR Consent Decree. Through 2013, this would include Sporn 5, 440 MW, which has formally been proposed to be retired in 2011 (application pending before the Public Utility Commission of Ohio; and *preceding* its R/R/R date of 12/2013); as well as Conesville 3, 165 MW (R/R/R date of 12/2012).

- ✓ The remaining AEP-East "fully-exposed" units (with the exception of Tanners Creek Unit 4) identified in **Section 5.3** are **also projected to retire by January 1, 2015** per EGU MACT proposed rules. Tanners Creek Unit 4 will be equipped with a Direct Sorbent Injection (DSI) form of an FGD system and is expected to continue operating until 2025.

5.3.4 Reliability Issues Associated With Unit Retirements

In addition to providing electric power to the transmission system, most of the generating plants that may be retired provide a strategic and critical function in the event of a wide spread blackout involving the AEP transmission system. For example, two of the three generating units at Clinch River are equipped with Automatic Load Reject (ALR, or simply "black-start") capability. In the event of a blackout, a unit so equipped can automatically detect a pending blackout and disconnect from the system, islanding itself and self-supply local plant load. Generating plants that survive a blackout, and are strategically located, serve as the genesis locations for restoring the transmission system, and service to AEP's customers.

The transmission lines emanating from plants equipped with ALR would be re-energized to nearby plants to supply needed start-up power to those plants. As other generating units were restored to service, load, corresponding to the operating generating capacity, would be restored. These general processes would be continued until all generating units, and a sufficient amount of the transmission system was restored to service.

AEP has performed a study to determine the impact of these anticipated generating unit retirements. The study concluded that AEP would have insufficient black-start capability to re-energize the AEP transmission system, despite transmission improvements that will be necessary to maintain reliability absent these units, during 'normal' operating conditions. In order to "re-energize" the AEP system following a blackout, some of the generating units anticipated to be retired will need to be replaced, and must be in geographically strategic locations.

When PJM is provided a date certain retirement date for these black-start units, PJM and AEP will perform a joint study to determine, and presumably validate AEP's study conclusions, the amount and general location of new black-start capable units. PJM will then issue an RFP to solicit parties that may be interested in providing that black-start service. Given the geographical requirements, it would be expected that virtually all of this black-start capability will be 'new build' or conversions/re-powering of recently retired units. If PJM receives no acceptable proposals, AEP and PJM will develop plans and compensation, as per the PJM tariff.

6.0 Supply-Side Resource Options

In addition to the demand-side options discussed in Section 4, there are a variety of supply-side options available to APCo and AEP-East to meet the energy requirements of their customers. This section describes the attributes and characteristics of the options considered as part of the resource planning process.

6.1 Market Purchases

AEP's planning position for its East Zone and for APCo is to take advantage of market opportunities when they are available and economic, either in the form of limited-term bilateral capacity purchases from non-affiliated sources or by way of available, discounted, merchant generation asset purchases. Such market opportunities could be utilized to hedge capacity planning exposures should they emerge and create (energy) option value to the Company.

As with the need to maintain resource planning and implementation flexibility for various supply or demand exposures as identified above, the Plan should likewise seek to continually consider an array of solutions, *including* such market "buy" prospects, since:

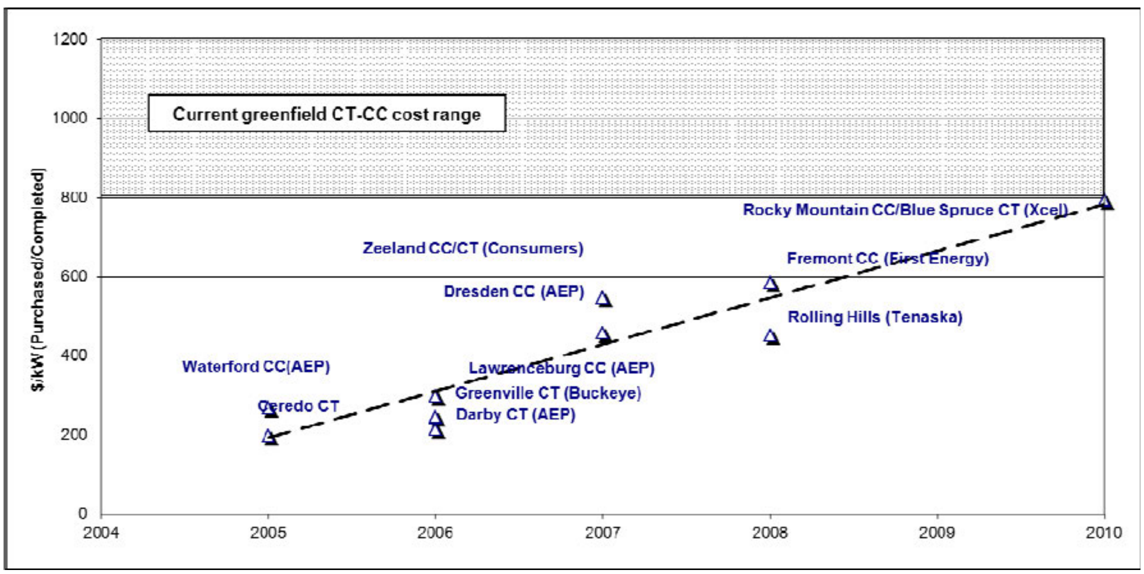
- As an underpinning, this IRP is based on the need to ultimately "build" generating capability to meet the requirements of its customers for which it has assumed an obligation to reliably serve;
- the regional (PJM) market price of capacity ultimately will likely begin to approach—and continue to vacillate around--the fixed cost of new-build generation; and
- the purchase of merchant generation assets relative to new-build generation represents a different risk profile with respect to siting, going-in costs and, if only partially-constructed, commercial schedule.

Another critical element ultimately impacting the availability of (bilateral) market capacity purchases is the PJM Reliability Pricing Model (RPM) capacity value construct, which is currently being debated through a PJM stakeholder process. Additionally, capacity outside the PJM RTO has to be delivered based on firm transmission which can be difficult to obtain.

6.2 Generation Acquisition Opportunities

Market purchase opportunities are constantly being explored in continued recognition of the need for additional capacity. AEP is continually investigating the viability of placing indicative offers on additional utility or IPP-owned natural gas peaking and combined cycle facilities as such opportunities arise. Analyses are performed in the *Strategist®* resource optimization model, using the most recent IRP profile, for purposes of estimating a “break-even” purchase price that could be paid for the prospect of an early acquisition of such an asset, in lieu of any ultimate greenfield new-builds per that formal planning. However, as shown in **Exhibit 6-1**, the cost of these available assets are now beginning to approach that of a generic, greenfield project.

Exhibit 6-1: Recent Merchant Generation Purchases



Source: AEP Resource Planning

6.3 Generation Technology Assessment and Overview

AEP’s Generation organization is responsible for the tracking and monitoring of estimated cost and performance parameters for a wide array of generation technologies. Utilizing access to industry collaboratives such as EPRI and Edison Electric Institute, AEP’s association with architect and engineering firms and original equipment manufacturers as well as its own experience and market intelligence, this group continually monitors supply-side trends. **Exhibit 6-2** (Public) offers a summary of the most recent technology performance parameter data developed.

Exhibit 6-2 (Public)Technology Options

AEP SYSTEM-EAST ZONE
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) Std. ISO	Trans. Cost (e) ($/kW)	Emission Rates SO_2 (g) (Lb/mmBtu)	Emission Rates NO_X (Lb/mmBtu)	Emission Rates CO_2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load							
Pulv. Coal (Ultra-Supercritical) (h)	618	24	0.0708	0 070	205.3	85	89.6
CFB (h)	585	26	0.0665	0.070	210.3	80	90.7
IGCC ("F"Class)(h)	618	24	0.0090	0.057	205.3	85	87.5
IGCC ("H"Class)(h)	862	17	0.0090	0.057	205.3	85	87.5
Nuclear (US ABWR)	1,606	64	0.0000	0.000	0.0	90	94.0
Base Load (90% CO2 Capture New Unit)							
Pulv. Coal (Ultra-Supercritical) (h)	526	29	0.0708	0.070	20.5	85	89.6
CFB (w/ CCS, Amine, NOAK)(h)	497	30	0.0665	0.070	20.5	80	89.6
IGCC ("F"Class, w/ CCS, NOAK)(h)	525	29	0.0090	0.057	20.5	85	87.5
IGCC ("F"Class w/ 20% Biomass, w/ CCS)(h)	473	32	0.0090	0.057	11.4	85	87.5
IGCC ("H"Class, w/ CCS)(h)	776	19	0.0090	0.057	20.5	85	87.5
Intermediate							
Combined Cycle (1X1 GE7FA)	307	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	600	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing, Blk Start)	600	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (1X1 GE7FH)	402	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (1X1 SW501G)	402	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (2X1 GE7FB, w/ Duct Firing)	652	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (2X1 M701G)	962	60	0.0007	0.011	116.0	60	89.1
Intermediate (90% CO2 Capture New Unit)							
Combined Cycle (2X1 GE7FB, w/ Amine Scrubbing)	554	71	0.0007	0.011	11.6	60	89.1
Combined Cycle (2X1 M701G, w/ Chilled Ammonia)	818	71	0.0007	0.011	11.6	60	89.1
Peaking							
Combustion Turbine (2X1GE7EA)	164	57	0.0007	0.033	116.0	3	90.1
Combustion Turbine (2X1GE7EA,w/ Blk Start)	164	57	0.0007	0.033	116.0	3	90.1
Combustion Turbine (2X1GE7EA,w/ Inlet Chillers)	164	59	0.0007	0.011	116.0	3	90.1
Combustion Turbine (2X1GE7FA)	332	57	0.0007	0.093	116.0	3	90.1
Combustion Turbine (2X1GE7FA, w/ Inlet Chillers)	332	59	0.0007	0.011	116.0	3	90.1
Aero-Derivative (1X GE LM6000PF)	46	60	0.0007	0.093	116.0	3	89.1
Aero-Derivative (1X GE LM6000PC)	60	60	0.0007	0.093	116.0	90	89.1
Aero-Derivative (1X GE LMS100PB, w/ Inlet Chillers)	98	59	0.0007	0.011	116.0	30	90.1
Aero-Derivative (2X GE LM6000PF)	92	60	0.0007	0.093	116.0	3	89.1
Aero-Derivative (2X GE LM6000PF, w/ Blk Start)	92	60	0.0007	0.093	116.0	3	89.1
Aero-Derivative (2X GE LMS100PB, w/ Blk Start)	196	59	0.0007	0.093	116.0	30	90.1
Aero-Derivative (2X GE LMS100PB, w/ Inlet Chillers)	196	59	0.0007	0.011	116.0	30	90.1
CAES Facility	300	60	0.0007	0.011	116.0	47	95.0

Notes: (a) Insta led cost, capability and heat rate numbers have been rounded.
(b) All costs in 2010 dollars. Assume 2.0% escalation rate for 2010 and beyond.
(c) $/kW costs are based on Standard ISO capability.
(d) Total Plant & Interconnection Cost w /AFUDC (AEP-East rate of 4.70%,site rating $/kW).
(e) Transmission Cost ($/kW,w /AFUDC).
(f) Levelized Fuel Cost (40-Yr. Period 2012-2051)
(g) Based on 4.5 lb. Coal.
(h) Pittsburgh #8 Coal.

Source: AEP Resource Planning

6.4 Baseload Alternatives

Coal-based technologies include pulverized coal (PC) combustion designs, integrated gasification combined cycle (IGCC), and circulating fluidized bed combustion (CFB) facilities. Nuclear is a viable option, and the application process for the construction of nuclear power plants has been initiated by several utilities. It is the current view of AEP that, while great difficulty and risk still exist in the siting and construction of nuclear power plants, nuclear power should be among the baseload options for the future. Nuclear power was not included in the final resource plan being recommended due to the uncertainties surrounding costs, schedules, and regulatory recovery.

6.4.1 Pulverized Coal

PC plants are the workhorse of the U.S. electric power generation industry. In a PC plant, the coal is ground into fine particles that are blown into a furnace where combustion takes place. The heat from the combustion of coal is used to generate steam to supply a steam turbine that drives a generator to produce electricity. Major by-products of combustion include SO_2, NO_X, CO_2, and ash, as well as various forms of elements in the coal ash including mercury (Hg). The ash byproduct is often used in concrete, paint, and plastic applications.

Steam cycle thermodynamics for the pulverized coal-fired units–which determines the efficiency of generating electricity– falls into one of two categories, *subcritical* or *supercritical*. Subcritical operating conditions are generally accepted to be at up to 2,400 psig/1,000°F superheated steam, with a single or double reheat systems to 1,000°F, while supercritical steam cycles typically operate at up to 3,600 psig, with 1,000-1,050°F main steam and reheat steam temperatures. AEP has recognized the benefits of the supercritical design for many years. All eighteen of the units in the AEP-East system built since 1964 have utilized the supercritical design, including APCo’s Mountaineer Plant and Amos units 1, 2 and 3.

There have been advances in the supercritical design over the years, and units are now being designed to operate at or above 3,600 psig and >1,100°F steam temperatures, known as an *ultra supercritical* (USC) design. AEP's Turk plant, which is currently under construction in Arkansas, is a new USC design.

The overall efficiency of the supercritical design is higher than the subcritical design by approximately 4% and USC design efficiency is higher than a supercritical design by approximately 4 to 5%. Additionally, the new variable pressure ultra supercritical units are projected to have an overall efficiency improvement throughout the entire load range, not just at full load conditions.

6.4.2 Integrated Gasification Combined Cycle

Given the long time-horizons of most resource planning exercises, IRP processes must be able to consider new technologies such as IGCC. The assessment of such technologies is based on cost and performance estimates from commonly cited public sources, consortia where AEP is actively engaged, and vendor relationships, as well as AEP's own experience and expertise.

IGCC is of particular interest to AEP in light of the abundance, accessibility, and affordability of high rank coals for the Company–particularly in its eastern zone. IGCC technology with carbon capture has the potential to achieve the environmental benefits closer to those of a natural gas-fired plant, and thermal performance closer to that of a combined cycle, yet with the low fuel cost associated with coal. The coal gasification process appears well-positioned for integration of ultimate carbon capture and storage technologies, which will be a critical measure in any future mitigation of greenhouse gas emissions associated with the generation of electricity. As an additional observation, the small number of IGCC equipment suppliers and few utility-scale facilities in commercial operation worldwide means a large share of technology and performance risk falls on owners, although the on-going collaboration with technology developers may mitigate some of this risk.

The IGCC process employs a gasifier in which coal is partially combusted with oxygen and steam to form what is commonly called "syngas"–a combination of carbon monoxide, methane, and hydrogen. The syngas produced by the gasifier then is cleaned to remove the particulate and sulfur compounds. Sulfur is converted to hydrogen sulfide and ash is converted into glassy slag. Mercury is removed in a bed of activated carbon.

The syngas then is fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG), where it produces steam that drives a steam turbine as would a natural gas-fired combined cycle unit.

IGCC enjoys thermal efficiencies comparable to USC-PC. Its ability to utilize a wide variety of coals and other fuels positions it extremely well to address the challenges of maintaining an adequate baseload capability with efficient, low-emitting, low-variable cost generating technology. Further, IGCC is in a unique position to be pre-positioned for carbon capture as, unlike PC technologies, it has the ability to perform such capture on a "pre-combustion" basis. It is believed that this will ultimately lead to improved net thermal efficiency than would be required by PC technology utilizing post-combustion carbon capture technology.

6.4.3 Circulating Fluidized Bed Combustion

A CFB plant is similar to a PC plant except that the coal is crushed rather than pulverized, and the coal is combusted in a reaction chamber rather than the furnace of a PC boiler. A CFB boiler is capable of burning bituminous and sub-bituminous coal plus a wide range of fuels that cannot be accommodated by PC designs. These fuels include, coal waste, lignite, petroleum coke, a variety of waste fuels, and biomass. Units are sometimes designed to fire using several fuels, which emphasizes this technology's major advantage: fuel flexibility. Coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air blown in from below through a series of nozzles. CFB boilers operate at lower temperatures than pulverized coal-fired boilers. The energy conversion efficiency of CFB plants tends to be slightly lower than that of pulverized coal-fired counterparts of the same size and steam conditions because of higher excess air and auxiliary power requirements.

CFB boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_X formation, and capture SO_2 in situ. Specifically, SO_2 is captured during the combustion process by limestone being fed into the bed of hot particles that are fluidized by the combustion air blown in from below. The limestone is converted into free lime, which reacts with the SO_2. Historically, the largest CFB unit in operation is 320 MW, but designs for units up to 600 MW have been developed by three of the major CFB suppliers. In July of 2009, the Lagisza Power Plant in Poland began commercial operations; the plant is the largest and first supercritical CFB in operation and is rated at 460 MW. AEP has no commercial operating experience with generation utilizing circulating fluidized bed boilers but is familiar with the technology through prior research, including the Tidd pressurized fluidized bed demonstration project. Commercial CFB units utilize a subcritical steam cycle, resulting in a lower thermal efficiency.

6.4.4 Nuclear

Although new reactor designs and ongoing improvements in safety systems make nuclear power an increasingly viable option as a new-build alternative due to it being an emission-free power source, concerns about public acceptance/permitting (especially since the recent disaster in Japan), spent nuclear fuel storage, long lead-time, high capital costs and the risk of cost overruns continue to significantly temper its appeal. For these reasons, among others, AEP does not currently view new nuclear capability as a viable option to meet the capacity resource needs of AEP-East within this planning period (2011-2025). However, both the economic and political viability of nuclear power and energy will continue to be explored given:

1) APCo and AEP-East zone's ultimate need for baseload capacity;
2) the cost and performance uncertainty surrounding the advancement and commercialization of clean coal technology, notably, IGCC;
3) the cost and performance uncertainty of carbon capture and storage technology;
4) the continued push to address AEP's carbon footprint and the mitigating impact additional nuclear power clearly would have in that regard; and
5) the prospect of a federal Clean Energy Standard that would effectively embrace the introduction of nuclear generation.

Growth in U.S. nuclear generation since 1977 has been primarily achieved through "uprating" – the practice of increasing capacity at an existing nuclear power plant. As of January 2010, the NRC had approved 124 uprates totaling 5,726 MW of capacity. That amount is equivalent to adding another five-to-six conventional-sized nuclear reactors to the electricity supply portfolio.

6.5 Intermediate Alternatives

Intermediate generating sources are typically expected to serve a load-following and cycling duty and shield baseload units from that obligation. Historically, many generators, such as AEP's eastern fleet, have relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired units to serve such load-following roles. Over the last several years, these units' staffs have made strides to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and subcritical units are retired, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

6.5.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a heat recovery steam generator (HRSG) producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-60% Low Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain baseload needs. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration ("black start") services. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is

cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.

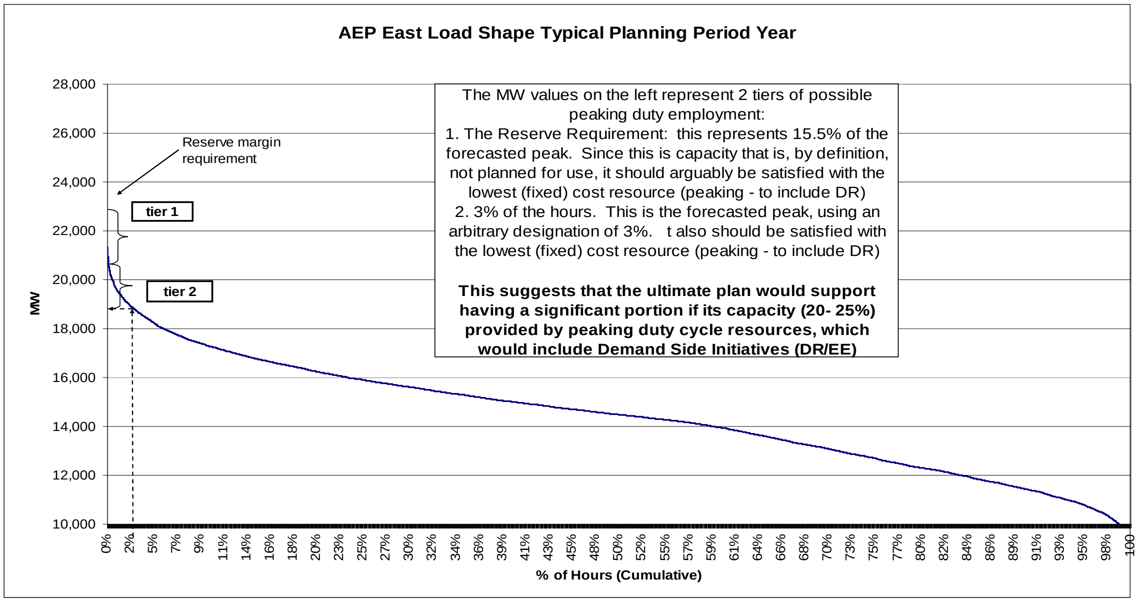
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

6.6 Peaking Alternatives

Peaking generating sources are required to provide needed capacity during extreme high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for “quick-response” capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide very little energy over an annual load cycle. As a result, fuel efficiency and other variable costs are of less concern. This capacity should be obtained at the lowest practical installed cost, despite the fact that such capacity often has very high energy costs. This peaking requirement is manifested in the system load duration curve, an example of which is shown in **Exhibit 6-3**. This curve shows the hourly demand for each hour in a typical year. Note that there is a notable drop off in demand after the highest 3% of the hourly loads. This drop off supports the position that the lowest installed cost investment, or lowest life cycle cost investment when considering the minimal capacity factors these peaking facilities will experience, are selected by optimization modeling.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency (Black Start) capability to the grid.

Exhibit 6-3: AEP-East Typical Load Duration Curve



Source: AEP Resource Planning

6.6.1 Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" combustion turbine systems, air compressed by an axial compressor (front section) is mixed with fuel and burned in a combustion chamber (middle section). The resulting hot gas then expands and cools while passing through a turbine (rear section). The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A simple cycle combustion turbine system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, i.e., not recovered as in a combined cycle design. While not as efficient (at 30-35% LHV), they are, however, inexpensive to purchase, compact, and simple to operate.

6.6.2 Aeroderivatives (AD)

Aeroderivatives are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7EA frame machine requires 20 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is on the order of 20% higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. The aeroderivatives can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide aeroderivatives the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: a) the penetration of variable renewables increase; b) baseload generation processes become more complex limiting their ability to load follow and; c) intermediate coal-fueled generating units are retired from commercial service.

Aeroderivatives weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an aeroderivative over an industrial turbine. Aeroderivatives in the less than 100 MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in the aeroderivative units.

Some of the better known aeroderivative vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.[4]

6.7 Energy Storage

Energy storage refers to technologies that allow for storage of energy during off-peak periods of demand and discharge of energy during periods of peak demand. This has the effect of flattening the load curve by reducing the peaks and “filling the valleys.” In this sense, it is considered a peaking asset. Energy storage can also be applied at other times to temporarily mitigate transmission congestion if it is economical to do so in

[4] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG

conjunction with generating resources that are curtailed by inadequate transmission infrastructure. Energy storage consists of batteries (Sodium Sulfur "NaS," Lithium Ion, and others), super capacitors, flywheels, compressed air energy storage (CAES) or pumped hydro storage. Pumped storage hydro uses two water reservoirs, separated vertically. During off peak hours water is pumped from the lower reservoir to the upper reservoir. When required, the water flow is reversed to generate electricity.

The investment requirements for pumped hydro storage are significant. Further, site-selection and attainment of FERC licensing represent huge challenges. NaS Batteries are the leading technology under consideration for prospective storage-related utility planning with several variations of compressed air energy storage in research and development, while lithium-ion batteries may be a quickly advancing technology.

6.7.1 Sodium Sulfur Batteries (NaS)

Storage technologies are receiving greater consideration due partly to the improved battery-storage technologies; efficiencies now are approaching 90%. That, coupled with the ability to offer market time-of-day pricing arbitrage by charging during low-cost off-peak periods and discharging at higher-cost daytime periods, works to its advantage. Battery installations can be located near load points, thus avoiding transmission and distribution line losses associated with traditional generation. Also, batteries can be deployed to support local circuits and take the strain off substations nearing capacity load. These batteries can support megawatt-sized loads for hours in the event of an outage. Their steady supply of power can also help alleviate certain power quality problems. They can delay the need for expensive substation upgrades facilitating a better prioritization of capital. Once station upgrades have been completed, the batteries are easily moved to a new location. The downside currently is the significant manufactured cost per kW, their weight resulting in transportation limitations, and total installed costs in the range of $2,000 per kW.

In 2006, Appalachian commissioned the first megawatt-class NaS battery to be used in North America at its Chemical Station in Charleston. This advanced energy storage technology can supply 7.2 megawatt-hours of energy, helping to ensure reliability to the area. This technology allowed Appalachian to defer the construction of a new substation