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July 1, 2015

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The Honorable Joel H. Peck, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23218

Re: Commonwealth of Virginia, ex rel. State Corporation Commission
In re: Appalachian Power Company's Integrated Resource Plan pursuant to Virginia Code § 56-597 et seq., Case No. PUE-2015-00036

Dear Mr. Peck:

Under §§56-597 – 56-599 of the Code of Virginia, the Commission's Rules of Practice and Procedure, and the December 23, 2008 "Order Establishing Guidelines for Developing Integrated Resource Plans" in Case No. PUE-2008-00099 ("IRP Guidelines"), enclosed for filing, **UNDER SEAL**, are an original and fifteen (15) copies of the 2015 Integrated Resource Plan ("IRP") of Appalachian Power Company.

This filing contains confidential information and is made **UNDER SEAL** pursuant to Rule 5 VAC 5-20-170 of the Commission's Rules of Practice and Procedure and section (E) (third paragraph) of the IRP Guidelines. As required by the Commission's rules, the Company is filing separately today a motion for protective treatment of the confidential information and is providing, by copy of this letter, an original and one copy of a public version of the filing (with confidential information redacted) for the use of the public. Also enclosed herewith as part of the filing, pursuant to IRP Guidelines section (E), are a proposed public notice (attached to this letter) and electronic media of the required schedules.

The Company suggests that the public notice be published on one occasion in newspapers of general circulation throughout the Company's service territory within Virginia and that a time interval of approximately four weeks each be used 1) from the date that the Commission enters a procedural order directing Appalachian to publish the notice until the publication deadline, and 2) from the notice publication date until the filing deadline for comments, notices of participation and requests for hearing.

Copies of the public version of the filing have been sent to the Division of Consumer Counsel, Office of the Attorney General and to the legislative officials specified in the recent amendments to § 56-599 of the Code (2015 Acts of Assembly, Chapt. 6).

Thank you for your assistance in this matter.

Sincerely,

Anthony Gambardella

Enclosures

cc: William H. Chambliss, General Counsel

NOTICE TO THE PUBLIC OF A FILING BY
APPALACHIAN POWER COMPANY
OF AN INTEGRATED RESOURCE PLAN
CASE NO. PUE-2015-00036

On July 1, 2015, Appalachian Power Company ("APCo" or "Company") filed with the State Corporation Commission ("Commission") the Company's Integrated Resource Plan ("IRP") pursuant to §56-599 A of the Code of Virginia ("Code").

An IRP, as defined by §56-597 of the Code, is a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years. Pursuant to §56-599 C of the Code, the Commission is to make a determination as to whether APCo's IRP is reasonable and is in the public interest.

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

Interested persons may receive a copy of a public version of the IRP and the Commission's Order, at no charge, by requesting it in writing from APCo's counsel, Anthony Gambardella, Esquire, Woods Rogers PLC, Riverfront Plaza, West Tower, 901 East Byrd Street, Suite 1550, Richmond, Virginia 23219. Copies of the public version of the IRP and related documents are also available for review in the Commission's Document Control Center, located on the First Floor of the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, between the hours of 8:15 a.m. and 5:00 p.m., Monday through Friday, excluding holidays. In addition, unofficial copies of the Company's IRP, Commission Orders entered in this docket, the Commission's Rules of Practice and Procedure ("Rules of Practice"), as well as other information concerning the Commission and the statutes it administers, may be viewed on the Commission's website: http://www.scc.virginia.gov/case.

As provided by 5 VAC 5-20-80 C, *Public witnesses,* of the Rules of Practice, any person desiring to file written comments concerning the issues in this case shall file, on or before ______________, 2015, such comments with Joel H. Peck, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. All comments shall refer to Case No. PUE-2015-00036. Any person desiring to file comments electronically may do so, on or before ___________, 2015, by following the instructions on the Commission's website: http://www.scc.virginia.gov/case.

On or before __________, 2015, any interested person may participate as a respondent in this proceeding by filing a notice of participation in accordance with 5 VAC 5-20-140, *Filing and service,* and 5 VAC 5-20-150, *Copies and format,* of the Rules of Practice. If not filed electronically, an original and fifteen (15) copies of the notice of participation shall be submitted to the Clerk of the Commission at the address set forth above. Any interested person shall also serve a copy of the notice of participation simultaneously upon counsel to the Company at the address set forth above. Pursuant to 5 VAC 5-20-80 B, *Participation as a respondent,* of the Rules of Practice, any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent then known; and (iii) the factual and legal basis for the action. All filings shall refer to Case No. PUE-2015-00036.

On or before __________, 2015, interested persons may request that the Commission convene a hearing on the Company's IRP by filing a request for hearing with the Clerk of the Commission at the address set forth above. Requests for hearing must refer to Case No. PUE-2015-00036 and include: (i) a precise statement of the filing party's interest in the proceeding; (ii) a statement of the specific action sought to the extent then known; (iii) a statement of the legal basis for such action; and (iv) a precise statement why a hearing should be conducted in this matter. A copy of any request for hearing shall be served upon counsel to the Company at the address set forth above on the day it is filed.

APPALACHIAN POWER COMPANY

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APPALACHIAN POWER®

A unit of American Electric Power

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

PUE-2015-00036

PUBLIC VERSION

July 1, 2015

15071001

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Executive Summary

The Integrated Resource Plan (IRP or Plan), including Appalachian Power's (APCo or Company) Five-Year Action Plan, is based upon the best available information at the time of preparation. However, changes that may impact this Plan can and will occur, both with and without notice. Therefore this Plan is not a commitment to specific resource additions or other courses of action, since the future is highly uncertain, particularly in light of current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as current and future environmental regulations, including the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP). In addition, APCo faced a number of other dynamic circumstances as it developed the assumptions and analyses outlined in this IRP Report. Over the next several months, various court orders and agency rules that will likely impact the PJM market, especially with regard to capacity, are expected to be issued. Each of these items may have an impact on the assumptions and analyses within this document and consequently the results. For example, on June 9, 2015, the Federal Energy Regulatory Commission (FERC) issued its Capacity Performance Order providing guidance to PJM on its capacity market proposals. While the Company incorporated its expectations regarding Capacity Performance into this Report, APCo is still evaluating the FERC order, the full impact of which will not be known until tariffs are filed and accepted by the FERC. Thus, this IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant. The Company notes that the required IRP to be filed in West Virginia in January 2016, and its next Virginia IRP, which is required to be filed on May 1, 2016, are likely to reflect updated assumptions, analyses, and results.

An IRP explains how a utility company plans to 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 forecast period (2015-2029). APCo's 2015 IRP has been developed using the Company's current assumptions for:

- Customer load requirements – peak demand and energy;
- Commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- Supply-side alternative costs – including fossil fuel and renewable generation

resources; and

- Demand-side program costs and analysis.

In addition, APCo must consider the impact of proposed environmental rules, specifically associated with greenhouse gas (GHG) emissions that, in their current form, would add significant costs and operational challenges. These rules are still being developed, and individual state plans may not be finalized and approved for a number of years. Even so, APCo has considered a portfolio of resources that will provide a path to reduce the intensity of its carbon emissions.

To meet its customers' future energy requirements, APCo will continue operation and the ongoing investment in its existing fleet of generation resources including its base-load coal plants at Amos and Mountaineer, and its combined-cycle and combustion turbine plants. Another consideration in this 2015 IRP is the increased adoption of distributed rooftop solar resources by APCo's customers. While APCo does not have control over how, and to what extent this resource is deployed, it recognizes that distributed rooftop solar will reduce APCo's capacity and energy requirements. From a capacity viewpoint, the 2020/2021 planning year is when PJM's new Capacity Performance rule will take full effect, limiting the capacity value of intermittent resources (hydro, wind, solar and pumped storage)[1] and thereby creating a need within APCo for additional capacity. Keeping these considerations in mind, APCo has developed an IRP that provides adequate supply and demand resources to meet its peak load obligations for the next fifteen years. The key components of this Plan are for APCo to:

- Finish the conversion of Clinch River Units 1 and 2 from coal to natural gas fuel.
- Diversify its mix of supply-side resources through the addition of cost-effective wind, utility-scale solar, and natural gas-fired generation resources, as necessary;
- Implement demand-side resources in the form of additional energy efficiency programs and Volt-VAR Optimization (VVO) installations;
- Recognize that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar.

[1]The FERC's June 9, 2015 CP order indicates that there may be a further opportunity to aggregate the capacity value of some of these intermittent resources.

Environmental Compliance Issues

This 2015 IRP considers the impacts of final and proposed EPA regulations on APCo generating facilities. In addition, the IRP development process conservatively assumes there may be future regulation of GHG/carbon dioxide (CO_2) emissions which will, if established, become effective at some point in the 2020-2025 timeframe. Environmental 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. While a proposed GHG/CO_2 rule applicable to existing fossil-fired units has been published by the EPA, there is significant uncertainty regarding how any final rule will be implemented by individual states. This 2015 IRP includes a tax on CO_2 beginning in 2022, which is a reasonable proxy for future CO_2 regulation at this time. The Company will not be able to reasonably model the impact of any final rule until such a rule is promulgated, and states have the opportunity to create implementation plans for compliance with such a rulemaking.

Virginia IRP Process

This IRP report is being filed in July of 2015 in compliance with Virginia Senate Bill 1349. Senate Bill 1349 amends Section 56-599 of the Code of Virginia by requiring electric utilities to file an IRP by July 1, 2015, followed by an annual IRP's due each year on May 1. The amended code also requires electric utilities to consider the following additional factors in each IRP:

- Options for maintaining and enhancing rate stability
- Options for maintaining and enhancing energy independence
- Options for maintaining and enhancing economic development including retention and expansion of energy-intensive industries
- Options for maintaining and enhancing service reliability
- The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities
- The most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize

effects on customer rates of such regulations

APCo's IRP process both takes into account and attempts to strike a reasonable balance among these various factors.

Summary of APCo Resource Plan

APCo's total internal energy requirements are forecasted to increase at a compound average growth rate (CAGR) of 0.17% over the IRP planning period (through 2029). APCo's corresponding summer and winter peak internal demands are forecasted to increase at CAGRs of 0.19% and 0.09%, respectively, with annual peak demand expected to continue to occur in the winter season through 2029. Figure ES-1, below, shows APCo's "going-in" (i.e. *before* resource additions) capacity position over the planning period. Through 2019 APCo has resources to meet its internal demand; however, in 2020 APCo is anticipated to experience a capacity shortfall based upon APCo's assumptions regarding the timing and parameters of PJM's Capacity Performance rule, which is evident from the gap between the stacked bar of available resources and the black line representing APCo's load demand plus reserve margin requirements.

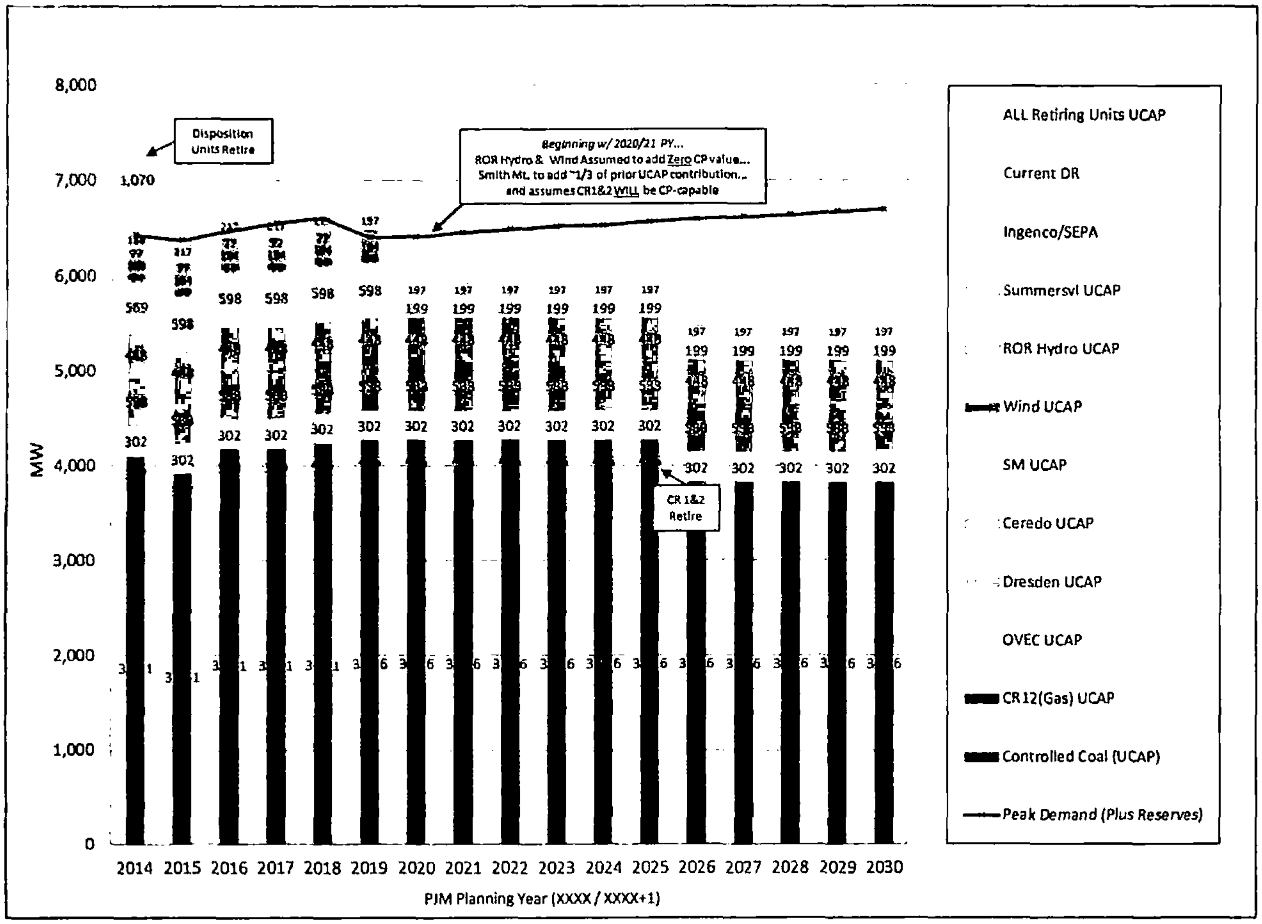

Figure ES-1. APCo "Going-In" PJM Capacity Position (MW)

To determine the appropriate level and mix of incremental supply and demand-side resources required to address the indicated going-in capacity deficiencies, APCo utilized the *Plexos*® Linear Program (LP) optimization model to develop least cost resource portfolios under a variety of pricing and load scenarios. Although the IRP planning period is limited to 15 years (through 2029), the *Plexos*® modeling was performed through the year 2045 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

APCo used the results of the modeling to develop a "Hybrid Plan". To arrive at the Hybrid Plan composition, APCo developed *Plexos*®-derived, "optimum" portfolios under five long-term commodity price forecasts and two "load sensitivity" forecasts. The Hybrid Plan is presented as an option that attempts to balance cost and other factors, including the requirements of Senate Bill 1349, to cost effectively meet APCo's peak load obligations. In addition, this IRP considers environmental constraints, while also reflecting an emerging preference for, and the viability of customer self-generation.

Specific APCo capacity and energy production changes over the 15-year planning period associated with the Hybrid Plan are shown in Figure ES-2 through Figure ES-5 respectively, and their relative impacts to APCo's annual capacity and energy position are shown in Figure ES-6 and Figure ES-7 respectively.

In summary, the Hybrid Plan:

APCo's Hybrid Plan

- Addresses expected PJM Capacity Performance rule impacts on APCo's capacity position. (Note 1)
- Adds 10 MW of utility-scale solar energy in 2016, followed by 50 MW per year beginning in 2020; for a total of 510 MW (nameplate) of utility-scale solar over the 15-year planning period. (Note 2)
- Adds 150 MW wind energy in 2016, followed by 150 MW per year beginning in 2022; for a total of 1,350 MW (nameplate) of wind over the 15-year planning period. (Note 2)
- Implements customer and grid energy efficiency, including VVO programs reducing energy requirements by 419 GWh (or 1% of projected energy needs) and capacity requirements by 109 MW by 2029.
- Assumes APCo's customers add distributed solar capacity, starting in 2015, of more than 0.5 MW (nameplate) per year for a total of 25 MW (nameplate) total by 2029. (Note 3)
- Adds 835 MW of natural gas combined-cycle resources over the 15-year planning period.
- Continues operation of APCo's solid fuel facilities: Amos Units 1-3, Mountaineer Unit 1. Maintains APCo's stake in Ohio Valley Electric Company (OVEC) solid-fuel facilities: Clifty Creek Units 1-6 and Kyger Creek Units 1-5.
- Retires Clinch River (Natural Gas) Units 1 and 2 in 2026.

Note 1: The modeling for this IRP was conducted prior to the issuance of FERC's June 9, 2015 order regarding PJM's Capacity Performance Proposal. That order may result in changes in future IRPs

Note 2: These renewable resources are timed to take advantage of current federal tax incentives, which are reduced or expire at the end of 2016. It is uncertain whether suitable opportunities exist, and any decisions to proceed would be subject to applicable regulatory approvals.

Note 3: APCo does not have control over the amount or timing of these additions.

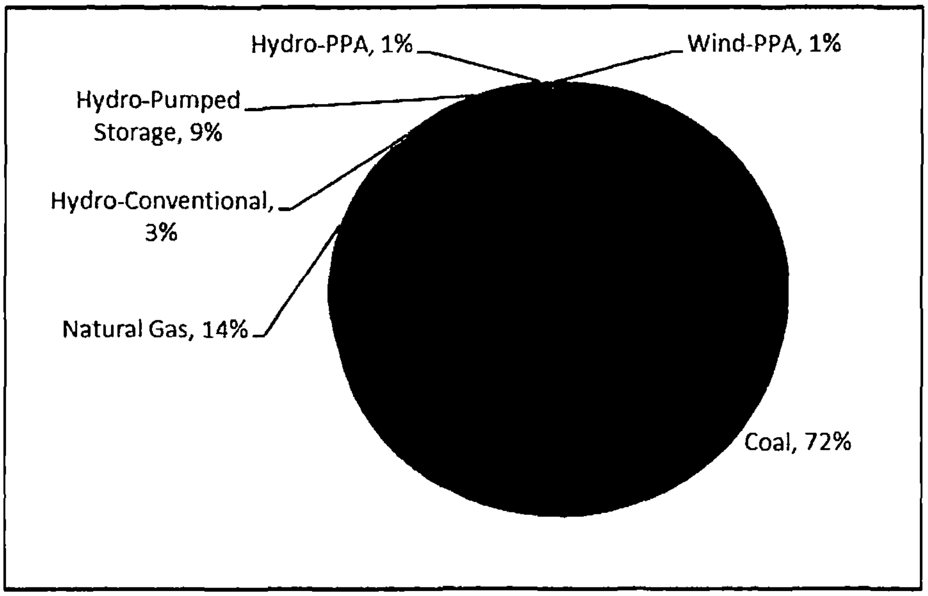

Figure ES-2. 2015 APCo Nameplate Capacity Mix

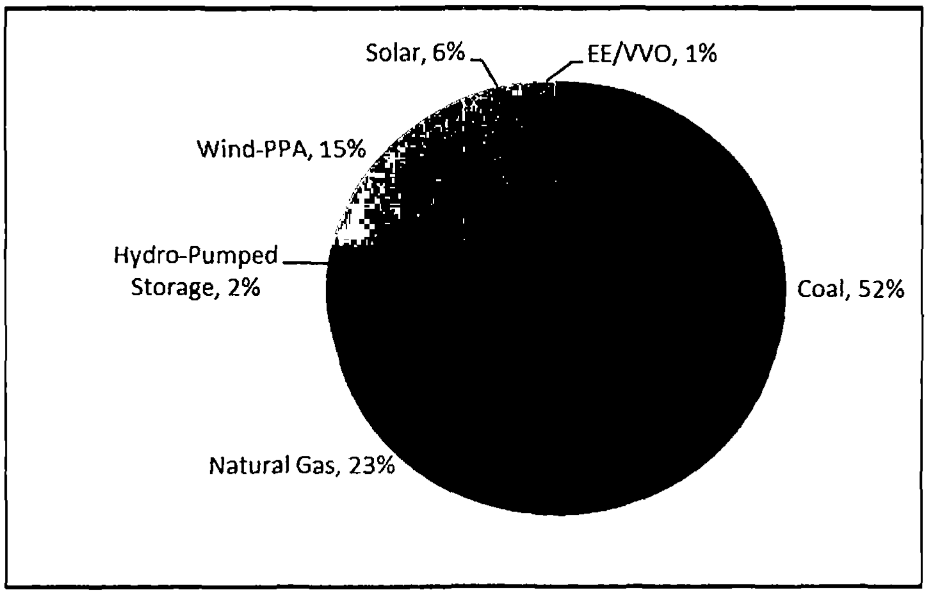

Figure ES-3. 2029 APCo Nameplate Capacity Mix

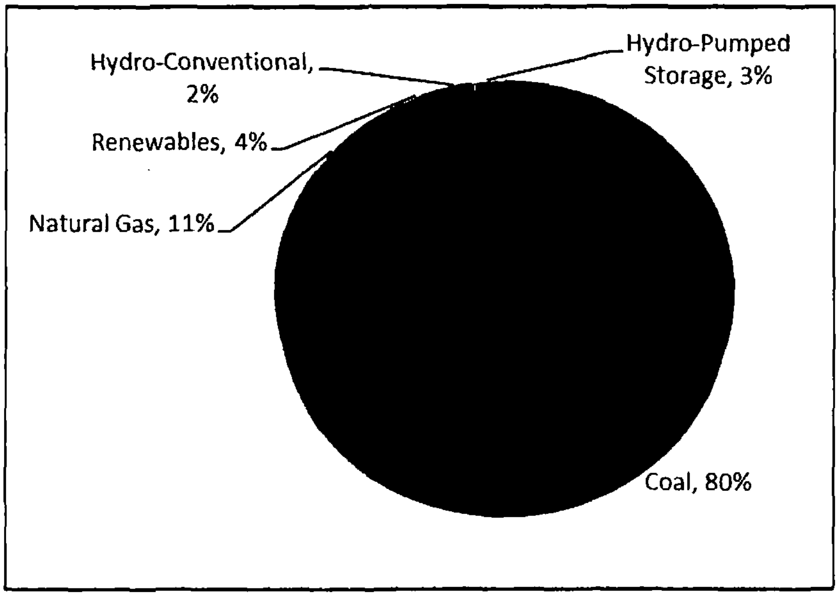

Figure ES-4. 2015 APCo Energy Mix

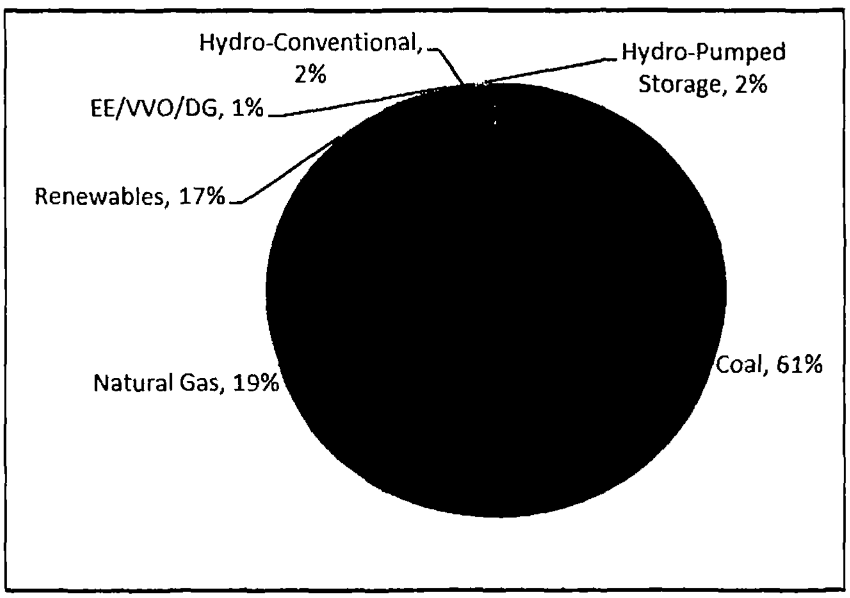

Figure ES-5. 2029 APCo Energy Mix

Figure ES-2 through Figure ES-5 indicate that this Hybrid Plan would reduce APCo's reliance on solid fuel-based generation, and increase reliance on demand-side, natural gas, and renewable resources, improving fuel diversity. Specifically, over the 15-year planning horizon the Company's nameplate capacity mix attributable to solid fuel-fired assets would decline from 72% to 52%, and natural gas assets would increase from 14% to 23%. Renewable assets (wind and solar) climb from 1% to 21%, and demand-side and energy-efficiency measures increase from 0% to 1% over the planning period.

APCo's energy output attributable to solid fuel-fired generation shows a substantial decrease from 80% to 61% over the period, while energy from natural gas resources increases from 11% to 19%. The Hybrid Plan shows a significant increase in renewable energy, from 4% to 17%. Energy from these renewable resources, combined with EE and VVO energy savings serve to reduce APCo's exposure to energy, fuel and potential carbon prices.

Figure ES-6 and Figure ES-7 show the changes in capacity and energy mix, respectively, on an annual basis, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest; however, those resources provide a significant volume of energy, particularly wind resources. APCo's model selected those wind resources because they add more value (lowered APCo cost) than alternative resources.

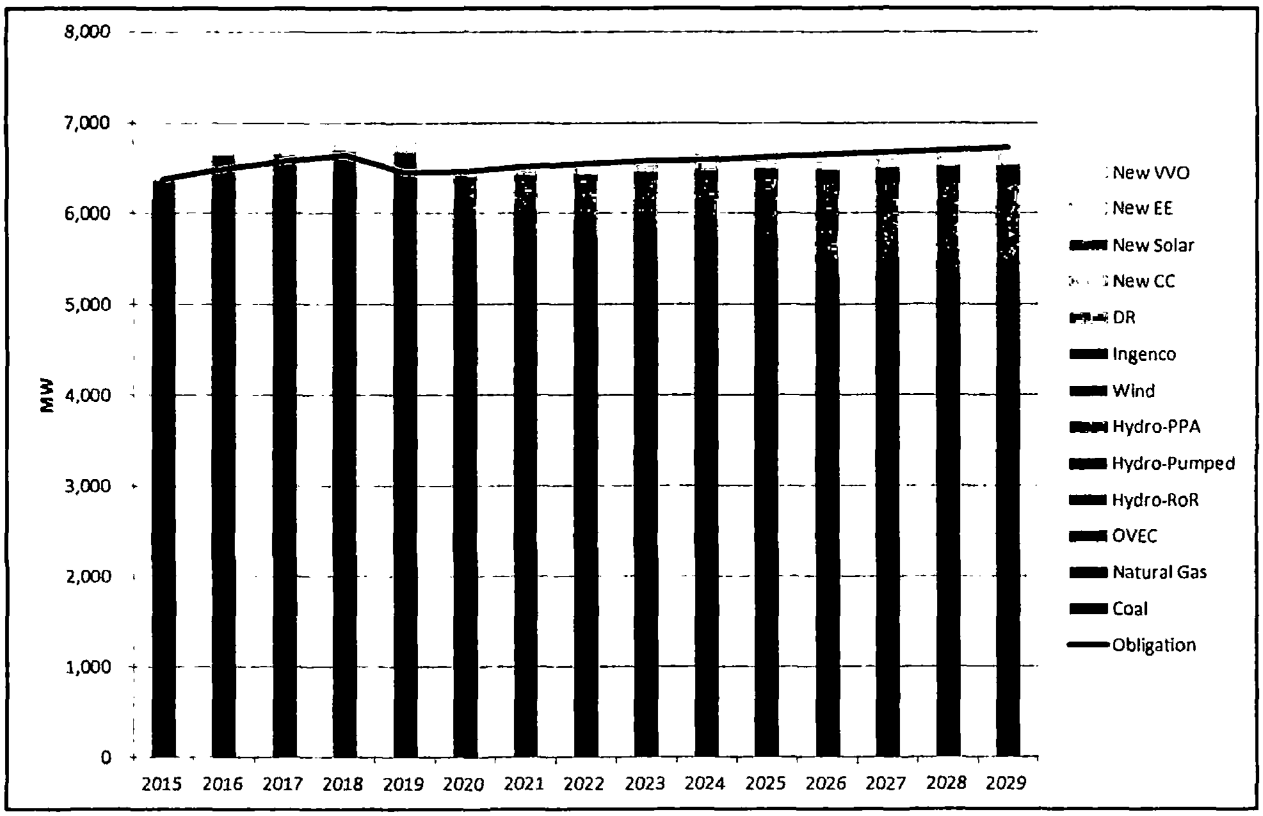

Figure ES-6. APCo Annual PJM Capacity Position (MW)

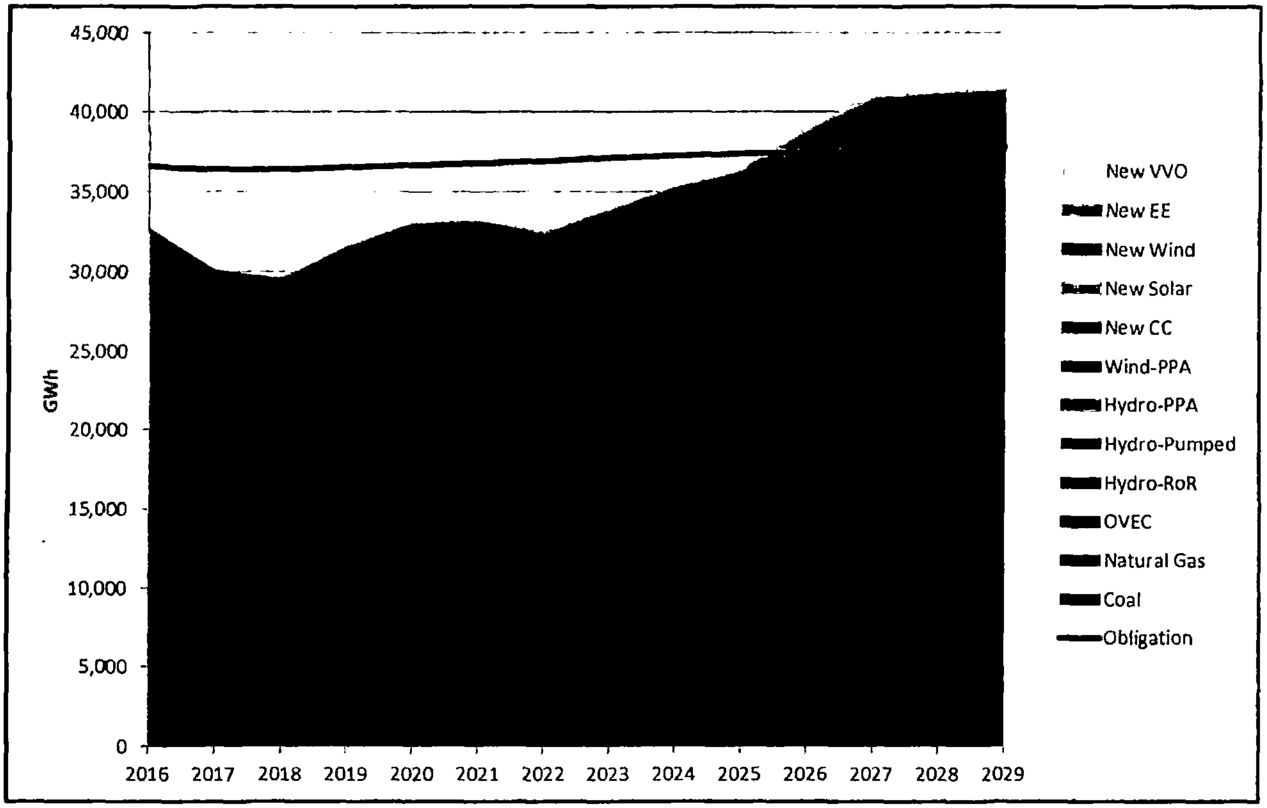

Figure ES-7. 2029 APCo Annual Energy Position (GWh)

Table ES-1 provides a summary of the Hybrid Plan, which resulted from analysis of optimization modeling under the load and commodity pricing scenarios:

Table ES-1. Summary of APCo Hybrid Plan Resource Additions from a Capacity (MW) Viewpoint

Appalachian Power Company
2015 Integrated Resource Plan
Cumulative Capacity Resource Changes

Hybrid Plan

MW		(1) (Cumulative) RETIREMENTS	(2) (Cumulative) PJM "Capcty Perf" (ICAP) DISALLOW.	(3) (Cumulative) PJM-"Capacity Performance" Resource ADDITIONS — New-Build Capacity	(4)	(5)	(6) Energy Efficiency (EE)	(7)	(8)	(9) VVO	(10) DR	(11) Wind[D]	(12) Solar[E]	(13)	(14) Cumul. NET CHANGE	(15) Resulting APCo Reserves	(16)	(17) (Cumulative) 'NAMEPLATE' ADDITIONS — Wind[D]	(18) Solar[E]	(19)
(VA) IRP Period	PJM Planning Year[A]	Coal & Gas-Steam	ROR Hydro, Wind & (Partial) P.S.	CC	(Frame) CTs	(Flex) CTs	'Embedded' Federal EE Regulations[B]	Anticipated Programs (Thru-'18)[C]	New (Post-'18)		Existing Programs[C]		Utility-Scale	Distributed	Sum: col.(1)-(13), excl col. (6)	Above PJM Minimum Rqrmnt	Margin %		Utility-Scale	Distributed
Yr.		MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW	MW	MW	MW		MW	MW	MW
0	2014															1,116	36.4%			
1	2015	(1,237) [F]	-	-	-	-	405	27		1	209	-	-	-	(1,030)	(6)	15.5%	-	-	-
2	2016	(1,237)	-	-	-	-	426	50		1	209	-	4	0.8	(973)	160	18.6%	150	10	2.0
3	2017	(1,237)	-	-	-	-	432	73		1	209	-	4	1.1	(950)	87	17.2%	150	10	3.0
4	2018	(1,237)	-	-	-	-	436	94		1	209	-	4	1.9	(935)	93	17.3%	150	10	5.0
5	2019	(1,237)	-	-	-	-	451	94	2	1	191	-	4	2.3	(943)	291	21.0%	150	10	6.0
6	2020	(1,237)	(751) [G]	418	-	-	468	94	4	1	191	-	23	3.0	(1,253)	20	16.1%	150	60	8.0
7	2021	(1,237)	(751)	418	-	-	487	94	7	28	191	-	42	3.4	(1,205)	17	16.0%	150	110	9.0
8	2022	(1,237)	(751)	418	-	-	503	94	9	28	191	-	61	4.2	(1,183)	25	16.2%	300	160	11.0
9	2023	(1,237)	(751)	418	-	-	516	94	11	28	191	-	80	4.9	(1,161)	32	16.3%	450	210	13.0
10	2024	(1,237)	(751)	418	-	-	526	94	13	28	191	-	99	5.7	(1,139)	45	16.5%	600	260	15.0
11	2025	(1,237)	(751)	418	-	-	538	94	15	48	191	-	118	6.5	(1,097)	111	17.7%	750	310	17.0
12	2026	(1,711) [H]	(751)	836	-	-	529	94	22	65	191	-	137	7.2	(1,110)	83	17.2%	900	360	19.0
13	2027	(1,711)	(659) [I]	836	-	-	533	94	25	65	191	-	156	8.0	(934)	80	17.1%	1,050	410	21.0
14	2028	(1,711)	(647)	836	-	-	545	94	26	65	191	-	175	8.7	(952)	84	17.2%	1,200	460	23.0
15	2029	(1,711)	(630)	836	-	-	558	94	27	82	191	-	194	9.5	(902)	66	16.9%	1,350	510	25.0
							'TOTAL' Energy Efficiency: 679												'TOTAL' Solar: 535	

[A] PJM Planning Year is effective 6/1/XXXX thru 5/31/XXXX+1

[B] Represents 'post-2005' estimated energy efficiency levels *already 'embedded'* into APCo's long-term (SAE) load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standareds (starting w/ EPAct 2005; then 2007 EISA; then ARRA of 2009).

[C] Represents estimated contribution from current/anticipated APCo DSM-EE (Va and WVa) and Demand Response (e.g. Interruptible) program activity.

[D] Due to the intermittency of wind resources and the proposed PJM-RPM "Capacity Performance" construct, it is assumed none of the wind resource 'nameplate' MW rating are included for capacity resource determination purposes.

[E] Due to the intermittency of solar resources, only 38% of solar resource 'nameplate' MW rating are included for capacity resource determination purposes. Further, it is assumed that such amounts would continue to qualify as a "Capacity Performance" resource in the new construct

ANTICIPATED RETIREMENTS & (PJM) 'CAPACITY PERFORMANCE' IMPACTS:

[F] Sporn Units 1&3, Glen Lyn Units 5&6, Kanawha River Units 1&2; Clinch River Unit 3

[G] Effective with the 2020/21 PJM PY, reflects the PJM-proposed 'CP' construct elimination of all 'non-qualifying' capacity: Run-of-rive hydro capacity (285 MW), all wind capacity credits in PJM (56 MW), and an estimated ~2/3 of the UCAP value of Smith Mt. pumped storage (410 MW)

[H] Clinch River 1&2 (Gas-Steam)

[I] Relative changes in such CP 'disallowances' are a function of the expiration of APCo's current wind REPA's over the course of the next decade.

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Clean Power Plan Implications

The EPA published proposed rules in June 2014 to address how states may reduce GHG/CO_2 emissions. The proposed rule, known as the Clean Power Plan (CPP), sets state-specific interim CO_2 emission rate targets beginning in 2020, with final target achievement by 2030. Targets were set based on four building blocks that include plant efficiency improvements, the increased dispatch of natural gas combined cycle plants, additional renewable (including no retirement of at-risk nuclear) resources, and incremental energy efficiency. The comment period for the CPP ran through December 1, 2014, and EPA now expects to issue a final rule during the summer, 2015. EPA has received over four million comments on the rule, including critical comments from various public agencies in the states served by APCo, reliability organizations including PJM, and research organizations such as the Electric Power Research Institute (EPRI) in addition to APCo's parent American Electric Power Company, Inc. (AEP). These criticisms question the scope, timing and legality of the CPP based on EPA's authority under the Clean Air Act, the reliability impacts associated with the timeline to implement the rule, and technical errors made by EPA in calculating the state-specific CO_2 rates resulting from the application of the four building blocks.

APCo cannot reasonably predict what form the final rule will take, or what will be required of the Company in state plans that are developed by the states and ultimately approved by the EPA. It is not practical for APCo to identify a CPP compliance strategy at this time, because it is not yet clear how any actions the Company may take would count toward compliance with a rulemaking that is not yet final. As a proxy for modeling the effect of, and a cost-effective means of complying with, this pending environmental regulation, this IRP utilizes a carbon tax, in conjunction with an "Early Coal Retirement" scenario.

Conclusion

This IRP, based upon various assumptions, provides for adequate capacity resources, at reasonable cost, through a combination of supply-side resources, renewable supply- and demand-side programs throughout the forecast period.

Moreover, this IRP also recognizes APCo's *energy* position prospectively. The Hybrid Plan offers incremental resources that will provide—in addition to the needed PJM installed *capacity* to achieve mandatory PJM (summer) peak demand requirements—additional *energy* to reduce the exposure of the Company's customers to PJM energy markets that could be influenced by many external factors, including the impact of carbon regulation, going-forward.

The portfolios discussed in this report attribute no capacity value for certain intermittent resources (run-of-river hydro and wind). It is possible that intermittent resources can be combined, or "coupled", and offered into the PJM market as Capacity Performance resources. Once the final PJM Capacity Performance tariffs are published, the Company will investigate methods to maximize the utilization of its current (and future) intermittent resource portfolio within that construct. An example could be the additional coupling of run-of-river hydro and Smith Mountain pumped-storage capability in a manner that would mitigate non-performance risk. The potential exists that an offer strategy could be formulated such that a portion of the approximate 670 MW of hydro/pumped storage generating capability, which is not currently recognized in this IRP as being 'Capacity Performance-eligible', could count as capacity in future PJM planning years. If that were to occur, then there is a reasonable prospect that the need for incremental capacity resources set forth in the various portfolios in this report could be deferred beyond the end of the planning period.

The IRP process is a continuous activity; assumptions and plans are reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource portfolios reported herein reflect, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. As noted previously, this IRP is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. The resource planning process is becoming increasingly complex when considering pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and end-use efficiency improvements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. To that end, APCo intends to pursue the following Five-Year Action Plan:

1. Continue the planning and regulatory actions necessary to implement economic energy efficiency programs in Virginia and West Virginia.
2. Continue to monitor market prices for renewable resources, particularly wind, and if economically advantageous, pursue appropriate Power Purchase Agreements (PPAs).

3. Investigate opportunities to install utility-scale solar projects in the near future to take advantage of the 30% Investment Tax Credit.
4. Monitor status of PJM's Capacity Performance rule and, if necessary, begin planning activities to formulate a Request for Proposal (RFP) for natural gas generation.[2]
5. Monitor the status of GHG rules and state plans.
6. Be ready to adjust this Action Plan and future IRPs to reflect changing circumstances.

[2] Capacity additions in excess of 100MW require APCo to issue a Request for Proposal (RFP) in accordance with a settlement agreement approved by the Public Service Commission of West Virginia in Case No. 14-0546-E-PC

1.0 Introduction

1.1 Overview

This report presents the 2015 Integrated Resource Plan for APCo including descriptions of assumptions, study parameters, and methodologies. The results incorporate the integration of supply-side resources and demand-side management (DSM) activity.

The goal of the IRP process is to identify the ***amount****,* ***timing*** *and* ***type*** *of resources required to ensure a reliable supply of power and energy to customers at the least reasonable cost.*

In addition to developing a long-term strategy for achieving reliability/reserve margin requirements as set forth by PJM, capacity resource planning is critical to APCo due to its impact on:

- Determining Capital Expenditure Requirements
- Rate Case Planning
- Environmental Compliance and Other Planning Processes

1.2 IRP Process

This report covers the processes and assumptions required to develop an IRP for APCo. The IRP process for APCo includes the following components/steps:

- Description of the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning.
- Provide projected growth in demand and energy which serves as the underpinning of the Plan.
- Identify and evaluate demand-side options such as energy efficiency measures, demand response and distributed generation.
- Identify current supply resources, including projected changes to those resources (*e.g.*, de-rates or retirements), and transmission system integration issues.
- Identify and evaluate supply-side resource options.
- Describe the analysis and assumptions that were used to develop the IRP, such as Regional Transmission Organization (RTO) reserve margin criteria, fundamental

modeling parameters, and consideration of the factors enumerated in Section 56-599 of the Code of Virginia.

- Perform resource modeling and use the results to develop various portfolios

1.3 Introduction to APCo

APCo's customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Virginia, West Virginia and Tennessee (Figure 1). The Company serves a population of approximately 2.2 million in a 19,260 square-mile area. Currently, APCo has approximately 958,000 retail customers in those states, including over 524,000 in the Commonwealth of Virginia. The peak load requirement of APCo's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. APCo's historical all-time highest recorded peak demand was 8,708 MW, which occurred in February 2015; and the highest recorded summer peak was 6,755 MW, which occurred in August 2007. The most recent actual APCo summer and winter peak demands were significant at 5,649 MW and 8,708 MW, occurring on July 2, 2014 and February 20, 2015, respectively.

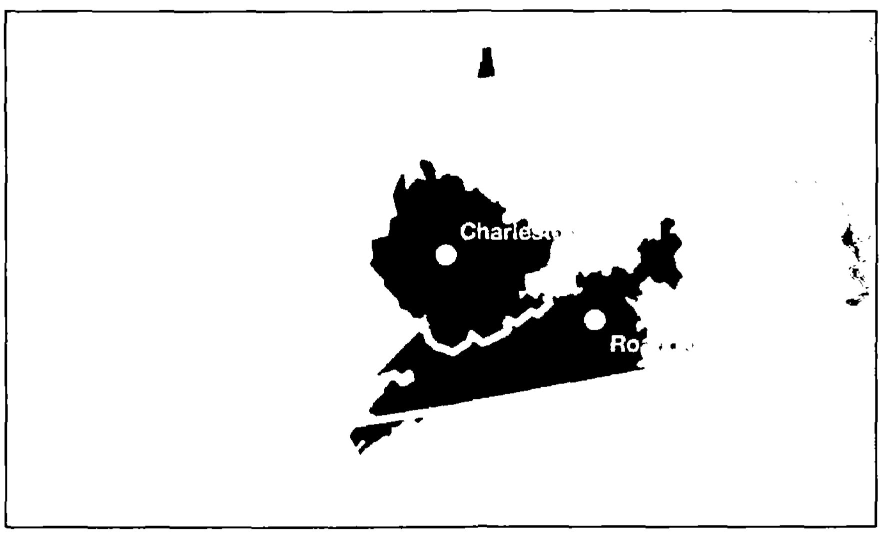

Figure 1. APCo Service Territory

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

The action items described herein are subject to change as new information becomes available or as circumstances warrant.

2.0 Load Forecast, Forecast Methodology and Economic Development

2.1 Summary of APCo Load Forecast

The APCo load forecast was developed by AEP's Economic Forecasting organization and completed in June 2014.[3] The final load forecast is the culmination of a series of underlying forecasts that build on each other. The economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 15 year period (2015-2029), APCo's service territory is expected to see population and non-farm employment growth of 0.2% per year. Not surprisingly, APCo is projected to see customer count growth of 0.2% per year as well. Over the same forecast period, APCo's retail sales are projected to grow at 0.15% per year with stronger growth expected from the Industrial class (+0.3% per year) while the Residential class experiences a modest decline (-0.04% per year) over the forecast horizon. The projected growth in APCo's internal energy over the next 15 years is consistent with the assumed growth in customer counts (0.2% per year). Finally, APCo's peak demand is expected to grow at an average rate of 0.1% per year through 2029.

2.2 Forecast Assumptions

2.2.1 Economic Assumptions

The load forecasts for APCo incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic

[3]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.

forecast issued in January 2014. Moody's Analytics projects moderate growth in the U.S. economy during the 2015-2029 forecast period, characterized by a 2.0% annual rise in real GDP, and moderate inflation as well, with the implicit GDP price deflator expected to rise by 1.5% per year. Industrial output, as measured by the Federal Reserve Board's (FRBs) index of industrial production, is expected to grow at 1.9% per year during the same period. Moody's projected employment growth of 0.2% per year during the forecast period and real regional income per-capita annual growth of 1.6% for the APCo service area.

2.2.2 Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and EIA outlook for the East North Central Census Region for the longer term. These price forecasts are incorporated into the Company's energy sales models, where appropriate.

2.2.3 Specific Large Customer Assumptions

APCo's customer service engineers maintain frequent contact with industrial and commercial customers about their needs and future plans. From these discussions, expected load additions or deletions are collected and incorporated into the Company's load projections where appropriate.

2.2.4 Weather Assumptions

The Company also includes weather as an explanatory variable in its energy sales and peak demand models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

2.2.5 Energy Efficiency & DSM Assumptions

Inherent in the historical data used to specify the load forecast models are the impacts of past customer energy conservation and load management behaviors. Energy usage is being impacted by a combination of federal and/or state efficiency mandates in addition to company sponsored energy efficiency and DSM programs. The statistical adjusted end-use models incorporate changing saturations and efficiencies of the various end-use appliances which results in a certain amount of energy efficiency to be "embedded" into the load forecast.

In addition to the "embedded" energy efficiency, the Company also accounts for Commission approved DSM program impacts in the load forecasting process. New or "incremental" DSM resources over-and-above those levels are analyzed and projected separately as part of the IRP development process.

2.3 Overview of Forecast Methodology

APCo's load forecasts are derived from mostly econometric, statistically adjusted end-use models in addition to analysis of time-series data. This is helpful when analyzing future scenarios and developing confidence bands in addition to objective model verification by using standard statistical criteria.

APCo utilizes two sets of econometric models: 1) a set of monthly short-term models which extends for approximately 24 months and 2) a set of monthly long-term models which extends for approximately 30 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast that is used for various planning purposes.

For the first full year of the forecast, the values are generally governed by the short-term models. The short term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation and patterns in energy sales for short-term applications like capital budgeting and resource allocation. While these models generally produce more accurate forecasts in the short run, without logical ties to economic factors they are less capable of capturing structural trends in electricity consumption that are more important for longer term resource planning applications.

The long term models are econometric, and statistically adjusted end-use models which are specifically equipped to account for structural changes in the economy as well as changes in customer consumption due to increased energy efficiency. The long term forecast models incorporate regional economic forecast data for income, employment, households, output, and population.

The short-term and long-term forecasts are then blended to ensure a smooth transition from the short-term to the long-term forecast horizon for each major revenue class. There are some instances when the short-term and long-term forecasts diverge, especially when the long term models are incorporating a structural shift in the underlying economy that is expected to occur within the first 24 months of the forecast horizon. In these instances, professional judgment is used to ensure that the final forecast that will be used in the peak models is reasonable. The class level sales are then summed and adjusted for losses to produce monthly net internal energy sales for the system.

The demand forecast model utilizes a series of algorithms and load shapes to allocate 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.

A flow chart depicting the sequence of models used in projecting APCo's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 2 below.

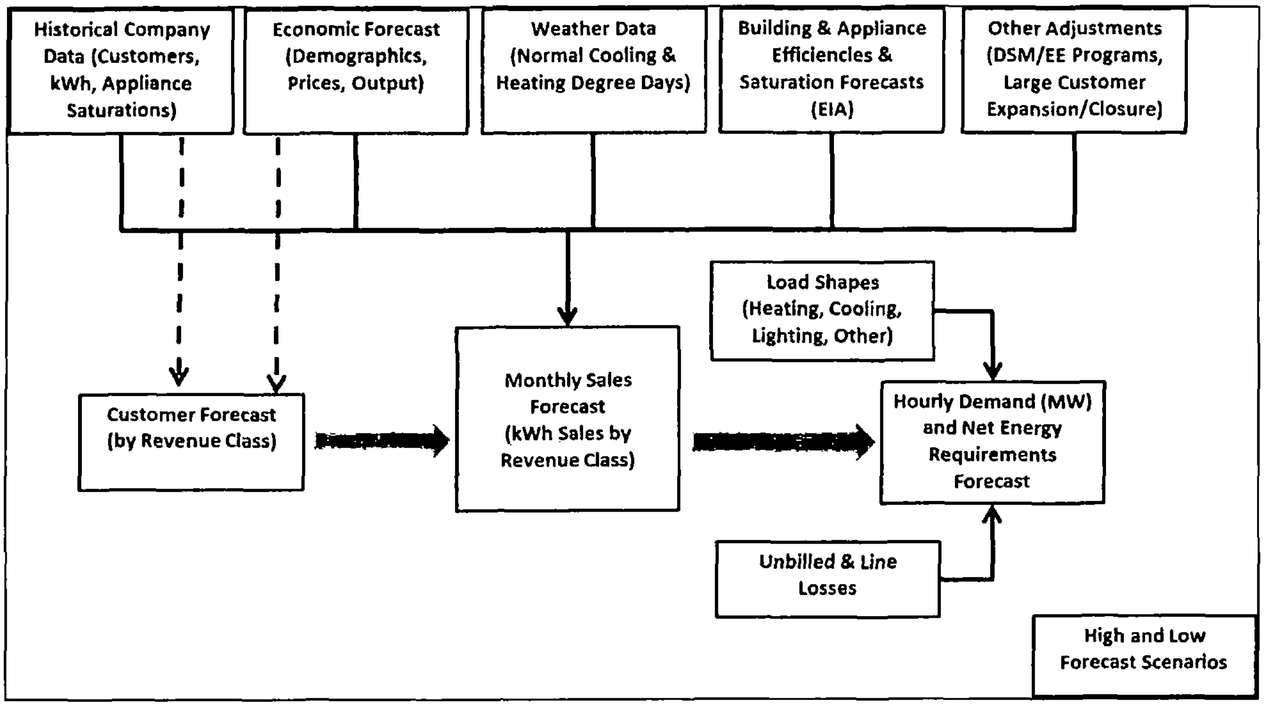

Figure 2. APCo Internal Energy Requirements and Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast Methodology

2.4.1 General

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of APCo's energy consumption, by customer class.

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. 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 influence 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.

2.4.2 Customer Forecast Models

The Company also utilizes both short-term and long-term models to develop the final customer count forecast. The short-term customer forecast models are time series models with intervention (when needed) using Autoregressive Integrated Moving Average (ARIMA) methods of estimation. These models typically extend for 24 months into the forecast horizon.

The long-term residential customer forecasting models are also monthly but extend for 30 years. The explanatory economic and demographic variables include mortgage interest rates, real personal income, population and households are used in various combinations for each jurisdiction. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture 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 short-term and long-term customer forecasts are blended as was described earlier to arrive at the final customer forecast that will be used as a primary input into both short-term and long-term usage forecast models.

2.4.3 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 rely on ARIMA models.

There are separate models for the Virginia Jurisdictions of the Company. The estimation period for the short-term models was January 2004 through January 2014.

2.4.3.1 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 blended customer forecasts.

2.4.3.2 Industrial Energy Sales

Short-term industrial energy sales are forecast separately for 23 large industrial customers of APCo and for the remainder of industrial energy. These short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables for each of the Company's jurisdictions. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 23 large industrial customers and the forecasts for the remainder of the manufacturing customers. Customer service engineers also provide input into the forecast for specific large customers.

2.4.3.3 All Other Energy Sales

The All Other Energy Sales category for APCo includes public authorities, public street and highway lighting (or other retail sales for those two items combined) and sales to wholesale customers. APCo-Virginia wholesale requirements customers include the cities of Radford and Salem, Craig-Botetourt Electric Cooperative, Old Dominion Electric Cooperative and Virginia Tech. There are private system customers in West Virginia. Kingsport Power Company, an affiliated company in Tennessee, is also a wholesale requirements customer of APCo. These wholesale loads are generally longer term, full requirements, and cost-of-service based contracts.

Both the other retail and municipal models are estimated using ARIMA models. APCo's short-term forecasting model for other retail energy sales includes binaries, heating and cooling degree-days, and lagged energy sales. The sales-for-resale models excluding Kingsport Power Company include binaries, heating and cooling degree-days, and lagged energy sales. Kingsport Power Company is modeled by revenue class, with models similar to the APCo jurisdictional models.

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.

2.4.4 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 1995-2013. The long-term energy sales forecast is developed by blending 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.

2.4.4.1 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 for APCo's Virginia, West Virginia and Tennessee service areas. These models are discussed below.

2.4.4.1.1 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 three primary consuming sectors: residential, commercial, and industrial. In the state natural gas price models sectoral prices are related to East North Central Census region's sectorial prices, with the forecast being obtained from U.S. DOE/EIA's "2014 Annual Energy Outlook." The natural gas price model is based upon 1980-2013 historical data.

2.4.4.1.2 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 on mainly Appalachian 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 Appalachian and U.S. coal production were obtained from U.S. DOE/EIA's "2014 Annual Energy Outlook." The estimation period for the model was 1998-2013.

2.4.4.2 Residential Energy Sales

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 usage will fall into one of three categories: heating, cooling and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool and Xother variables.

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) EIA 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 residential models are estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2014. It is important to note, as will be discussed later in this document, that this modeling *has* incorporated the reductive 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 (and commercial) energy usage.

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.

2.4.4.3 Commercial Energy Sales

Long-term commercial energy sales are forecast using a SAE model. These models are similar to the residential SAE models, where commercial usage is a function of Xheat, Xcool and Xother variables.

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 EIA's 2013 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 which is typically January 2001 through January 2014. As with the residential SAE model, the effects of EPAct, EISA, ARRA and EIEA2008 are captured in this model. Separate commercial SAE models are estimated for the Company's Virginia and West Virginia jurisdictions.

2.4.4.4 Industrial Energy Sales

Based on the size and importance of the Mine Power sector to the overall APCo Industrial base as well as the unique outlook for the mining sector in the long run, the Company models the Mine Power sales separate from the rest of the Industrial manufacturing sales in the long-term forecast models.

2.4.4.4.1 Manufacturing Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, service area manufacturing employment, FRB industrial production indexes, service area industrial electricity prices and state industrial natural gas price. In addition binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Virginia and West Virginia jurisdictions. The last actual data point for the industrial energy sales models is January 2014.

2.4.4.4.2 Mine Power Energy Sales

For its mine power energy sales models, the Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product mining, regional coal production, service area mine power electricity prices and real oil price index. In addition binary variables for months are special occurrences and are incorporated into the models. Based on information from customer service engineers there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Virginia and West Virginia jurisdictions. The last actual data point for the industrial energy sales models is January 2014.

2.4.4.5 All Other Energy Sales

The forecasts of other retail energy sales relates energy sales to some combination service area commercial employment, service area population, service area gross regional product, service area heating and cooling degree-days, and binary variables.

Wholesale energy sales are modeled relating energy sales to explanatory variables such as service area gross regional product, service area gross regional product for commercial entities, service area population, heating and cooling degree-days, real average service area wholesale prices, service area commercial employment, service area employment 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. Kingsport Power's load is modelled similar to APCo's retail sales, with the exception that Kingsport Power does not have mine power energy sales.

2.4.5 Final Monthly Internal Energy Forecast

2.4.5.1 Blending Short and Long-Term Forecasts

Forecast values for 2014 and 2015 are taken from the short-term process. Forecast values for 2016 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 July of 2016 the entire forecast is from the long-term models. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. However, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon.

2.4.5.2 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then add factors may be used to reflect those large changes that are different from those from the forecast models' output.

2.4.5.3 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 applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

2.4.6 Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended 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.

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).

2.5 Load Forecast Results and Issues

2.5.1 Load Forecast

Table 1 presents APCo's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial and other energy, which is comprised of other retail sales, wholesale sales and losses) on an actual basis for the years 2012-2014 and on a forecast basis for the years 2015-2029. Table 1 includes annual growth rates for both the historical and forecast periods. Corresponding energy requirements information for the Company's Virginia service area is given in Table 2.

Table 1. APCo 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 Requirements	Growth Rate
ACTUAL										
2012	11,395	---	6,794	---	10,778	---	6,847	---	35,813	---
2013	11,914	4.6	6,828	0.5	10,393	-3.6	6,855	0.1	35,990	0.5
2014	12,183	2.3	6,829	0.0	10,314	-0.8	6,904	0.7	36,230	0.7
FORECAST										
2015	11,838	-2.8	6,818	-0.2	11,033	7.0	7,021	1.7	36,710	1.3
2016	11,828	-0.1	6,780	-0.6	11,160	1.2	7,076	0.8	36,845	0.4
2017	11,699	-1.1	6,723	-0.9	11,207	0.4	7,092	0.2	36,720	-0.3
2018	11,644	-0.5	6,703	-0.3	11,246	0.3	7,078	-0.2	36,671	-0.1
2019	11,600	-0.4	6,698	-0.1	11,285	0.3	7,096	0.3	36,680	0.0
2020	11,593	-0.1	6,697	0.0	11,305	0.2	7,110	0.2	36,706	0.1
2021	11,605	0.1	6,712	0.2	11,319	0.1	7,130	0.3	36,767	0.2
2022	11,629	0.2	6,737	0.4	11,339	0.2	7,153	0.3	36,858	0.2
2023	11,652	0.2	6,769	0.5	11,372	0.3	7,179	0.4	36,973	0.3
2024	11,657	0.0	6,802	0.5	11,398	0.2	7,206	0.4	37,064	0.2
2025	11,674	0.1	6,836	0.5	11,416	0.2	7,227	0.3	37,153	0.2
2026	11,696	0.2	6,872	0.5	11,430	0.1	7,246	0.3	37,243	0.2
2027	11,710	0.1	6,912	0.6	11,450	0.2	7,270	0.3	37,342	0.3
2028	11,737	0.2	6,952	0.6	11,472	0.2	7,289	0.3	37,450	0.3
2029	11,760	0.2	6,988	0.5	11,497	0.2	7,314	0.3	37,557	0.3

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

Table 2. APCo - Virginia Actual and Forecast Internal Energy (GWh) Requirements by Sector

	Residential	Growth Rate	Commercial	Growth Rate	Industrial	Growth Rate	Other* Energy Requirements	Growth Rate	Total Internal Energy Requirements	Growth Rate
ACTUAL										
2012	6,030	---	3,204	---	5,502	---	3,538	---	18,274	---
2013	6,297	4.4	3,208	0.1	5,474	-0.5	3,190	-9.8	18,170	-0.6
2014	6,461	2.6	3,223	0.5	5,488	0.2	3,233	1.3	18,404	1.3
FORECAST										
2015	6,315	-2.3	3,197	-0.8	5,539	0.9	3,550	9.8	18,601	1.1
2016	6,272	-0.7	3,156	-1.3	5,553	0.3	3,569	0.5	18,550	-0.3
2017	6,230	-0.7	3,112	-1.4	5,551	0.0	3,579	0.3	18,473	-0.4
2018	6,206	-0.4	3,096	-0.5	5,564	0.2	3,575	-0.1	18,441	-0.2
2019	6,192	-0.2	3,086	-0.3	5,575	0.2	3,585	0.3	18,437	0.0
2020	6,198	0.1	3,079	-0.2	5,585	0.2	3,595	0.3	18,456	0.1
2021	6,212	0.2	3,079	0.0	5,601	0.3	3,609	0.4	18,501	0.2
2022	6,230	0.3	3,084	0.2	5,626	0.4	3,626	0.5	18,566	0.4
2023	6,251	0.3	3,094	0.3	5,659	0.6	3,645	0.5	18,648	0.4
2024	6,264	0.2	3,106	0.4	5,688	0.5	3,662	0.5	18,721	0.4
2025	6,285	0.3	3,121	0.5	5,713	0.4	3,677	0.4	18,796	0.4
2026	6,307	0.4	3,138	0.6	5,738	0.4	3,692	0.4	18,875	0.4
2027	6,326	0.3	3,158	0.6	5,767	0.5	3,710	0.5	18,961	0.5
2028	6,350	0.4	3,178	0.6	5,799	0.5	3,726	0.4	19,053	0.5
2029	6,373	0.4	3,197	0.6	5,829	0.5	3,743	0.5	19,142	0.5

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

2.5.2 Peak Demand and Load Factor

Table 3 provides APCo's seasonal peak demand, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2012 - 2014 and on a forecast basis for the year 2015-2029. The table also shows annual growth rates for both the historical and forecast periods.

Table 3. APCo Winter, Summer, and Annual Peak Demand (MW), Internal Energy Requirements (GWh) and Load Factor (%)

Year	Summer Peak Demand	Preceding Winter Peak Demand	Annual Peak Demand	Internal Energy Requirements	Load Factor
ACTUAL					
2012	6,391	6,881	6,881	35,813	59.3
2013	5,902	6,839	6,839	35,990	60.1
2014	5,649	8,460	8,460	36,230	48.9
FORECAST					
2015	6,058	7,404	7,404	36,710	56.6
2016	6,070	7,388	7,388	36,845	56.8
2017	6,077	7,368	7,368	36,720	56.9
2018	6,077	7,348	7,348	36,671	57.0
2019	6,085	7,336	7,336	36,680	57.1
2020	6,082	7,312	7,312	36,706	57.1
2021	6,116	7,346	7,346	36,767	57.1
2022	6,140	7,360	7,360	36,858	57.2
2023	6,165	7,374	7,374	36,973	57.2
2024	6,171	7,361	7,361	37,064	57.3
2025	6,208	7,402	7,402	37,153	57.3
2026	6,232	7,418	7,418	37,243	57.3
2027	6,257	7,436	7,436	37,342	57.3
2028	6,271	7,432	7,432	37,450	57.4
2029	6,306	7,473	7,473	37,557	57.4

2.5.3 DSM Impacts on the Load Forecast

Table 4 provides the DSM/Energy Efficiency impacts incorporated in APCo's load forecast provided in this report. Annual energy and seasonal peak demand impacts are provided for the Company and its Virginia jurisdiction.

Table 4. APCo and Virginia DSM/EE in Load Forecast Energy (GWh) and Coincident Peak Demand (MW)

Year	APCo DSM/EE			APCo Virginia DSM/EE		
	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2015	139.9	25.3	19.5	39.1	6.6	5.1
2016	252.8	46.1	36.0	112.5	19.1	14.9
2017	346.5	64.0	50.2	174.7	30.0	23.5
2018	422.0	78.9	62.2	225.6	39.2	30.9
2019	481.3	91.1	72.1	266.0	46.8	37.3
2020	526.4	100.5	79.9	297.0	52.8	42.4
2021	559.5	108.5	86.4	320.1	57.9	46.8
2022	582.7	114.4	91.2	336.8	61.7	50.1
2023	597.8	118.5	94.6	348.3	64.5	52.7
2024	606.4	121.1	96.7	355.8	66.5	54.4
2025	610.6	123.1	98.3	359.9	68.3	55.9
2026	612.1	124.1	99.1	361.4	69.3	56.7
2027	612.1	124.1	99.1	361.4	69.3	56.7
2028	612.1	123.7	98.9	361.4	69.0	56.6
2029	612.1	124.0	99.0	361.4	69.2	56.6

*Demand coincident with Company's seasonal peak demand.

2.5.4 Blended Load Forecast

As noted above, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon. Table 5 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, eight of the nine wholesale forecasts utilize the long-term forecast model results and the uses the blended model results.

Table 5. APCo Short-Term Load Forecast Blended Forecast vs. Long-Term Model Results

Class	Virginia	West Virginia
Residential	Long-Term	Blend
Commercial	Blend	Long-Term
Industrial	Long-Term	Long-Term
Other Retail	Long-Term	Long-Term

2.5.5 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then add factors may be used to reflect those large changes that are different from those from the forecast models' output.

2.6 Load Forecast Trends & Issues

2.6.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 3 presents APCo's historical and forecasted residential and commercial usage per customer between 1991 and 2021. During the first decade shown (1991-2000), Residential usage per customer grew at an average rate of 1.2% per year while the Commercial usage grew by 0.2% per year. Over the next decade (2001-2010), growth in Residential usage slowed to 0.8% per year while the Commercial class usage actually declined by 0.3% per year. In the last decade shown (2011-2020) Residential usage is projected to decline at a rate of 0.5% per year while the Commercial usage is falls by an average of 0.6% per year.

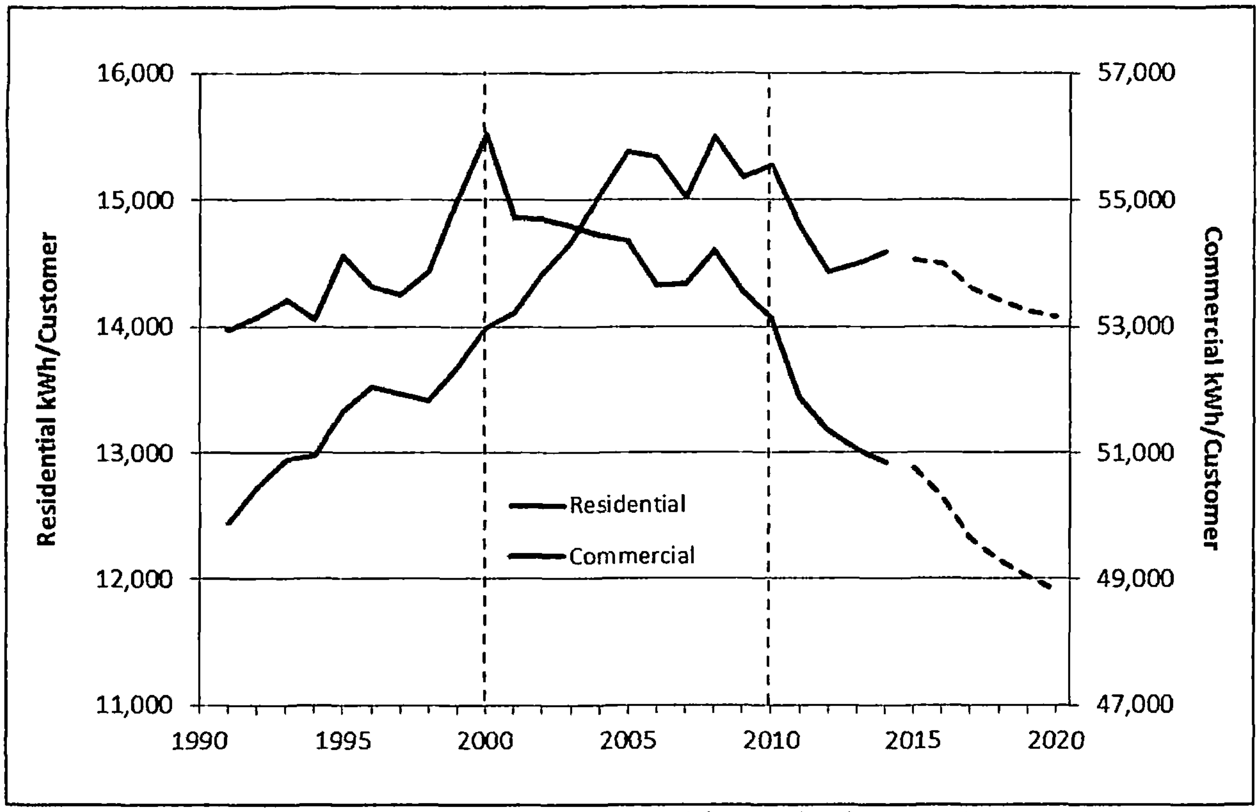

Figure 3. APCo Residential and Commercial Normalized Use per Customer

2.6.2 Energy Efficiency Embedded in the Load Forecast

The statistically adjusted end-use models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every 3-4 years, the Company conducts a Residential Appliance Saturation Survey to monitor the saturation and age of the various appliances in the Residential home. This information is then matched up with the saturation and efficiency projections from the EIA which includes the projected impacts from the various enacted federal policy mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected energy efficiency. For example, Figure 4 below shows the assumed cooling efficiencies embedded in the statistically adjusted end-use models for cooling loads. It shows that the average SEER (Seasonal Energy Efficiency Ratio) for central air conditioning is projected to increase from 12.6 in 2010 to over 14.8 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units as well.

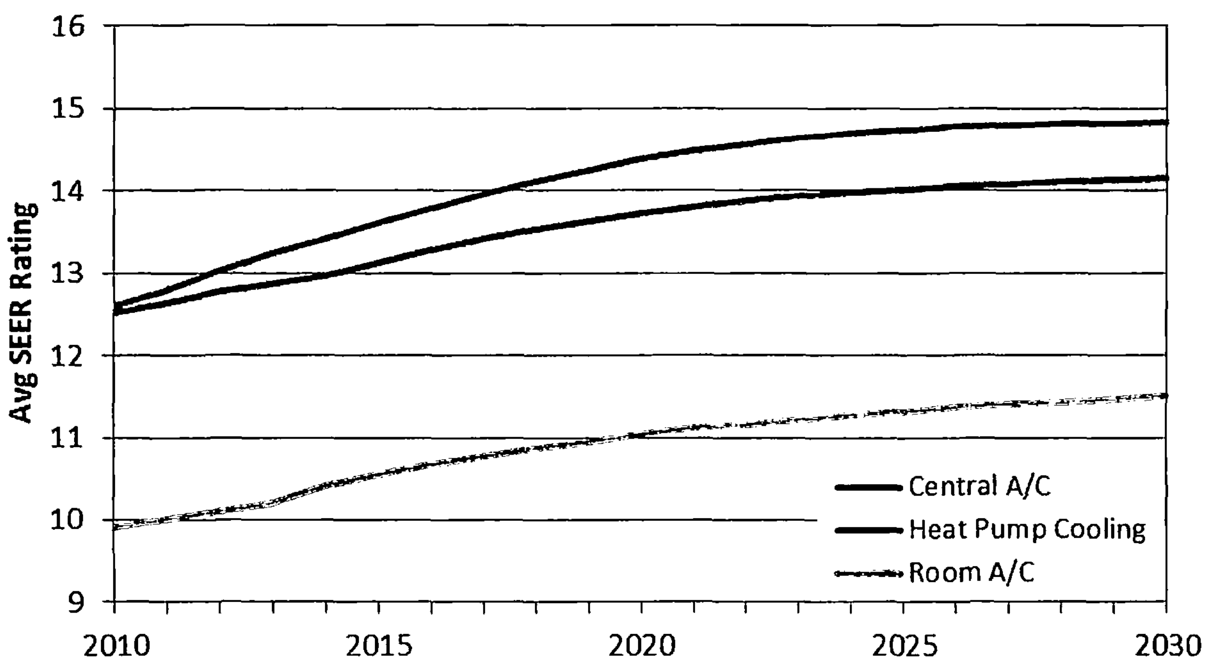

Figure 4. APCo Projected Cooling Efficiencies, 2010-2030

Cooling loads are certainly not the only appliances assumed to see significant increases in appliance efficiency. Figure 5 below shows the projected energy usage for lighting as well as clothes dryers and in both instances, you see a dramatic decline in the average energy usage.

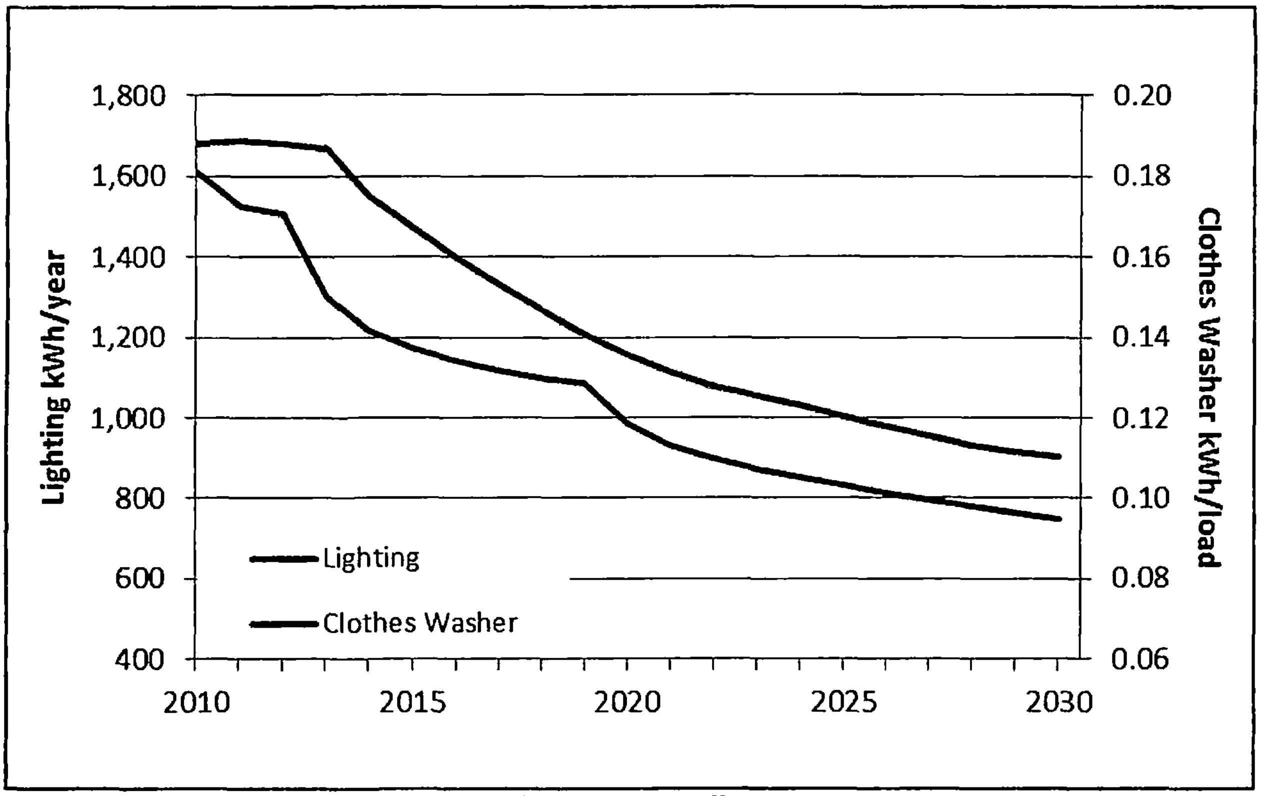

Figure 5. APCo Select Appliance Efficiencies, 2010-2030

2.7 Load Forecast Scenarios

The base case load forecast is the expected path for load growth that the Company uses for planning. There are a number of known and unknown potentials that could drive load growth different from the base case. While potential scenarios could be quantified at varying levels of assumptions and preciseness, the Company has chosen to frame the possible outcomes around the base case. The Company recognizes the potential desire for exact quantification of outcomes, but the reality is if the all possible outcomes were known with a degree of certainty, then it would become part of the base case.

Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2014 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

2.7.1 "Low Load" Sensitivity Case

The Low Load forecast reflects the impact of low economic growth for the region and consistent with the low economic growth presented by EIA.

The Low Load forecast projects firm peak load growth to average -0.6% per year on a compound basis. Total energy growth is also projected to average about -0.5% per year. The load factor is unchanged from the Base Case at about 57%. The low forecast for energy is 9.0% below the base forecast in 2029.

2.7.2 "High Load" Sensitivity Case

The High Load forecast represents a scenario of more sustained growth for the residential, commercial and industrial customer classes. As with the Low Load Case Load Forecast the high economic growth scenario is consistent with EIA high growth in its economic scenario.

The High Load forecast projects firm peak load growth to average 0.5% per year. Energy growth is also projected to average 0.6 % per year with a load factor of 57%. The high forecast for energy is 7.3% above the base forecast in 2029.

2.8 Economic Development

2.8.1 Overview

One of the requirements set forth by SB 1349 is that "the IRP shall consider options for maintaining and enhancing economic development including retention and expansion of energy-intensive industries." This IRP sets forth portfolios to meet these and other needs in a reasonable cost manner. The improvement in fuel diversity, including the addition of zero variable cost renewable resources, helps to mitigate the volatility inherent in fuel and purchase power costs. Predictability in retail rates is an important determinant in an energy-intensive company's decision process to expand within a utility's service territory. Predictability around one of the larger input costs reduces the risk associated with any expansion or relocation investment, in turn reducing capital costs, which engenders more investment.

It is worth noting that pricing is only one of many considerations for firm's decision in locating or retaining plants. Other variables such as power reliability, taxes, site availability and socio-economic considerations have varying degrees of importance. The Company attempts to maintain its transmission and distribution systems to assure acceptable power quality and reliability. The Company does not promote economic development alone, rather it works in concert with local and state economic development teams.

2.8.2 Economic Development Programs

The Company has economic development programs designed to attract new businesses and expand and retain existing businesses to its service territory. These programs benefit not only APCo through increased electricity sales, but have direct and indirect impacts on jobs for the region. The spillover effects associated with these jobs include the increased income associated with job creation which will result in increased activity for local businesses and the creation of additional jobs. The increased activity will not be confined to the APCo service area but rather further increases economic activity in other parts of the Commonwealth, as well. An equally important economic development activity is in the retention of existing jobs. Just as there is a positive ripple effect of adding new jobs to a region, there are negative economic ripple effects associated with losing jobs for the region and the Commonwealth as a whole.

The Company, for potential business expansions or new customer additions, can employ its Economic Development Rider (EDR). The EDR assists both the Company's existing customers and potential new customers. The EDR provides an incentive for customers with 1,000 kW or larger demand who may be associated with new investment and job growth. The EDR assists existing plants that may be in competition with a company's other plants, in different parts of the country or world, for expansion or a potential new plant for the Company. In Virginia, APCo can provide incentives from 25-35% of the demand charge and they can extend it for a term of up to five years. The EDR allows APCo the flexibility to compete with other utilities when vying for development deals.

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3.0 Resource Evaluation

3.1 Current Resources

An initial step in the IRP process is the demonstration of the capacity resource requirements. This "needs" assessment must consider projections of:

- Existing capacity resources—current levels and anticipated changes
- Anticipated changes in capability due to efficiency and/or environmental retrofit projects
- Changes resulting from decisions surrounding unit disposition evaluations
- Regional and sub-regional capacity and transmission constraints/limitations
- Load and peak demand
- Current DR/EE
- PJM capacity reserve margin and reliability criteria

3.2 Existing APCo Generating Resources

The underlying minimum reserve margin criterion to be utilized in the determination of APCo's capacity needs is based on the current PJM Installed Reserve Margin (IRM) of 15.7 percent.[4] The ultimate reserve margin of 8.35 percent is determined from the PJM Forecast Pool Requirement (FPR) which considers the IRM and PJM's Pool-Wide Average Equivalent Demand Forced Outage Rate ($EFOR_D$) of 6.35 percent.[5]

Schedule 16 provides the Company's detailed Capacity, Load and Reserves (CLR) report for the 15-year period through the year 2029. In addition to identifying current projected peak

[4] Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Latest Revision: January 30, 2014). PJM Planning Parameters are updated each year prior to the upcoming Base Residual Auction. These values can be obtained from http://pjm.com/markets-and-operations/rpm.aspx. This IRP uses the PJM Planning Parameters published on May 19, 2015, which reflect PJM's Capacity Performance proposal.
[5] Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Latest Revision: January 30, 2014). $FPR = (1 + IRM) * (1 - EFOR_D)$. Reserve Margin = FPR – 1.

demand requirements of its internal customers, this "going-in" position also identifies the MW capability of resources that are projected to be required to meet the minimum PJM reserve margin criterion. For instance, at the beginning of the first forecasted PJM planning year (2015),[6] Schedule 16 indicates APCo is expected to rely on 6,364 MW of generating (seasonal ratings) and Demand Side Management capability to achieve this threshold.

Table 6 displays key parameters for the generation resources currently owned by APCo and Figure 6 depicts all generation sources employed to meet APCo's needs, along with their current age.

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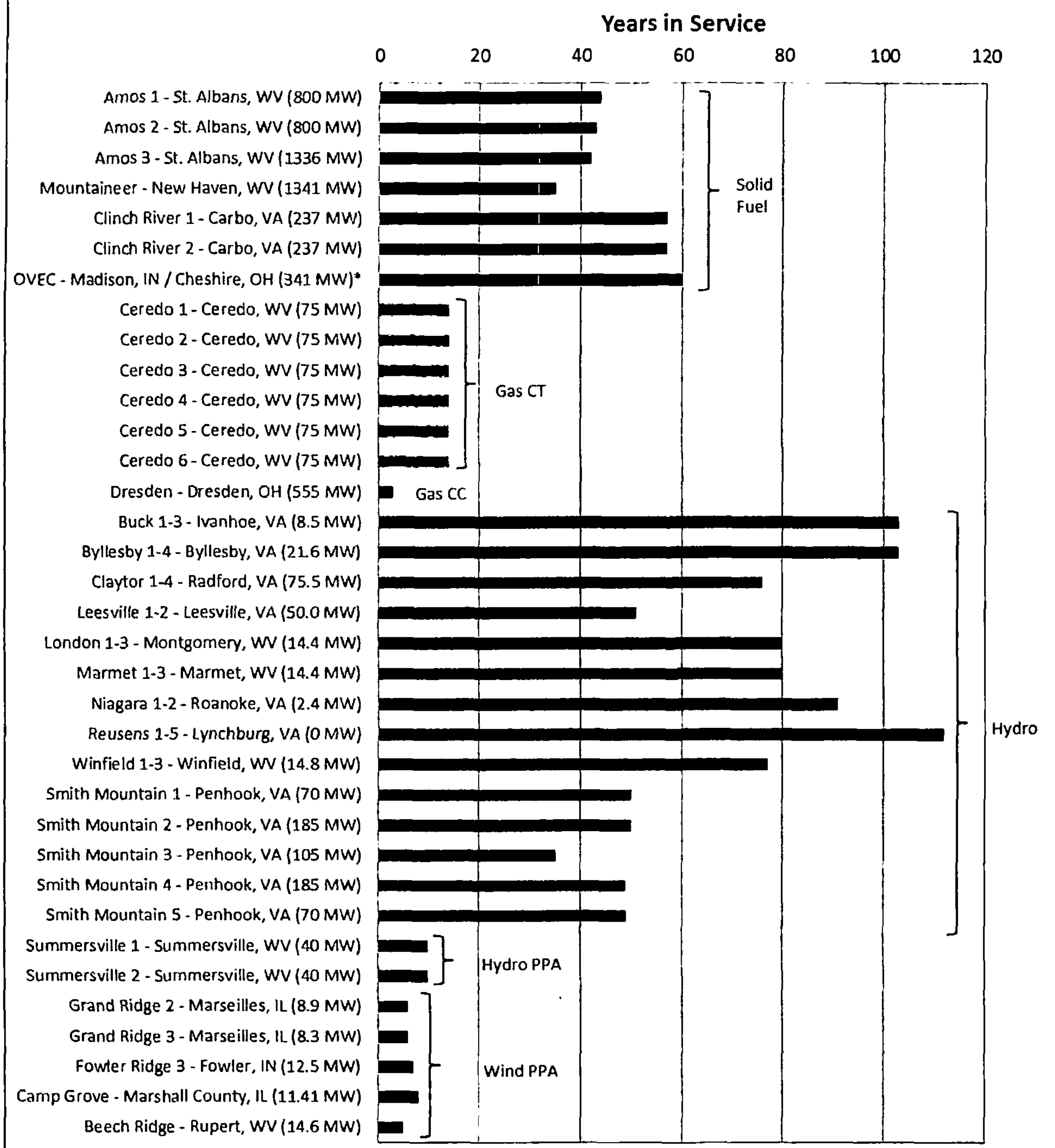
6 For capacity planning/reporting purposes, PJM operates on a June (Year X) -through- May (Year X+1) fiscal year basis.

Table 6. Current APCo-Owned Supply Side Resources

Plant	Unit	Location	Type	Primary Fuel	C.O.D. [1]	Winter Rating MW [2]		Summer Rating MW [2]		PJM Rating MW [2]	
Amos	1	St. Albans, WV	Steam	Coal - Bituminous	1971	800		800		800	
	2				1972	800		800		800	
	3				1973	1,300		1,300		1,300	
Mountaineer	1	New Haven, WV	Steam	Coal - Bituminous	1980	1,356		1,341		1,341	
Ceredo	1	Ceredo, WV	Combustion Turbine	Gas	2001	86		75		75	
	2				2001	86		75		75	
	3				2001	86		75		75	
	4				2001	86		75		75	
	5				2001	86		75		75	
	6				2001	86		75		75	
Dresden	1	Dresden, OH	Combined Cycle	Gas	2012	613		555		555	
Clinch River	1	Carbo, VA	Steam	Gas	2015	237		237		237	(A)
	2				2016	237		237		237	(A)
Buck	1-3	Ivanhoe, VA	Hydro	–	1912	5.3		3.0	(B)	8.5	
Byllesby	1-4	Byllesby, VA	Hydro	–	1912	7.9		4.4	(B)	21.6	
Claytor	1-4	Radford, VA	Hydro	–	1939	28.2		14.7	(B)	75.2	
Leesville	1-2	Leesville, VA	Hydro	–	1964	9.0		4.5	(B)	50.0	
London	1-3	Montgomery, WV	Hydro	–	1935	11.5		6.9	(B)	14.4	
Marmet	1-3	Marmet, WV	Hydro	–	1935	11.3		5.6	(B)	14.4	
Niagara	1-2	Roanoke, VA	Hydro	–	1924	1.4		0.6	(B)	2.4	
Reusens	1-5	Lynchburg, VA	Hydro	–	1903	0.0		0.0	(B)	0.0	
Winfield	1-3	Winfield, VA	Hydro	–	1938	14.5		8.9	(B)	14.8	
Smith Mountain	1	Penhook, VA	Pumped Storage	–	1965	70	(C)	70		70	(C)
	2			–	1965	185	(C)	185		185	(C)
	3			–	1980	105	(C)	105		105	(C)
	4			–	1966	185	(C)	185		185	(C)
	5			–	1966	70	(C)	70		70	(C)
						6,563		6,384		6,536	

Notes:
(1) Commercial operation date.
(2) Peak net dependable capability as of filing.
(A) Clinch River Units 1 and 2 are being converted from coal to gas in 2015 and 2016, respectively.
(B) Estimated summer net capability
(C) Units 1, 3 & 5 have pump-back capability, units 2 & 4 are generation only

Figure 6 depicts all generation sources employed to meet the APCo needs, along with their current age.



* Represents APCo Share of Ohio Valley Electric Corporation (OVEC) units at Clifty Creek and Kyger Creek Plants.

Figure 6. Current Resource Fleet (Owned and Contracted) with Years in Service