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May 1, 2017

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The Honorable Joel H. Peck, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23219

**Re: In re: Appalachian Power Company's Integrated Resource Plan filing
Case No. PUR-2017-00045**

Dear Mr. Peck:

Pursuant to §§ 56-597 and 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, Case No. PUE-2008-00099, (IRP Guidelines), enclosed for filing, **UNDER SEAL**, are an original and fifteen copies of the 2017 Integrated Resource Plan (IRP) of Appalachian Power Company (APCo or 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 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.

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 amendments to § 56-599 of the Code.

Sincerely,

Noelle J. Coates

Enclosures

cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
James R. Bacha, Esq.
Mr. William K. Castle

APPALACHIAN POWER

An AEP Company

BOUNDLESS ENERGY

INTEGRATED RESOURCE PLANNING REPORT

TO THE

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

CASE NO. PUR-2017-00045

PUBLIC VERSION

May 1, 2017

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Executive Summary

This Integrated Resource Plan (IRP, Plan, or Report) is submitted by Appalachian Power Company (APCo or Company) based upon the best information available at the time of preparation. However, changes that impact this Plan can occur without notice. Therefore this Plan is not a commitment to specific resource additions or other courses of action, as 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 status of the U.S. Environmental Protection Agency's (EPA) Final Clean Power Plan (CPP).

The Virginia State Corporation Commission's (Commission or SCC) December 14, 2016 Order in APCo's 2016 IRP case (2016 IRP Final Order) directed the Company to present potential plans compliant with multiple scenarios of the CPP, as well as a "No Carbon" scenario. This direction was similar to that which was provided by the Commission in its February 1, 2016 Order following the Company's 2015 IRP (2015 IRP Final Order). Recognizing many uncertainties, this IRP provides useful information to assess potential approaches for compliance with, and the possible costs and rate impacts of, the CPP. The specific locations within this IRP filing, which respond to each requirement of the IRP, appear in the Appendix as part of APCo's larger index (Exhibit D).

On June 9, 2015, the Federal Energy Regulatory Commission (FERC) issued an order pertaining to PJM's proposed Capacity Performance construct, thereby providing guidance to PJM on its capacity market proposals. FERC allowed an exemption from the Capacity Performance rules for companies which utilize the Fixed Resource Requirement (FRR) (i.e. self-supply) alternative through 2018/19. APCo has elected the FRR alternative to fulfill its capacity obligations through 2019/20. Until APCo has actual experience with the Capacity Performance Construct, its effects will remain uncertain.

In addition to those described above, APCo faced a number of other dynamic circumstances as it developed this IRP. Those circumstances are discussed throughout this Report. Given all of these circumstances, this IRP, and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

An IRP explains how a utility company plans to meet the projected capacity (*i.e.,* peak demand) and energy requirements of its customers. APCo is required to provide an IRP that encompasses a 15-year forecast period (in this filing, 2017-2031). This IRP has been developed using the Company's current long-term 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 impacts.

APCo considered the effect of environmental rules and guidelines, such as the CPP, which has the potential to add significant costs and present significant challenges to operations. The CPP is still being reviewed by the courts, and, if it were to move forward, individual state plans to implement it may not be finalized – let alone approved - for a number of years. In preparing this Report, APCo has analyzed multiple scenarios, with differing commodity pricing conditions, as well as multiple internal load conditions. As with the 2016 IRP, APCo has also conducted analyses that specifically address certain aspects of compliance with the CPP, per the 2016 Final Order. In March 2017, President Trump issued a series of executive orders designed to allow the EPA to review and take appropriate action to revise or rescind regulatory requirements that place undue burdens on affected entities, including specific orders directing the EPA to review rules that unnecessarily burden the production and use of energy. The EPA has published notice and an opportunity to comment on how to identify such requirements and what steps can be taken to reduce or eliminate such burdens. Future changes that result from this effort may affect APCo's compliance plans.

To meet its customers' future energy requirements, APCo will continue the operation of, and ongoing investment in, its existing fleet of generation resources including the base-load coal units at Amos and Mountaineer, the natural gas combined-cycle (Dresden) and combustion turbine (Ceredo) units, its two gas-steam units at Clinch River and the Company's hydro-electric generators, including Smith Mountain Lake; it will also continue to purchase power from various generators under contract including over 375MW (nameplate) of wind resources. Another consideration in this IRP is the increased adoption of distributed rooftop solar resources by APCo's customers. While APCo does not have control over where, and to what extent, such resources are deployed, it recognizes that distributed rooftop solar will reduce APCo's growth in capacity and energy requirements to some degree. From a capacity viewpoint, the 2020/2021 planning year is when PJM's new Capacity Performance construct will take full effect, potentially limiting the capacity value of intermittent resources, such as run-of-river hydro, wind, solar, as well as pumped storage[1]. Keeping these considerations in mind, APCo has developed an IRP that provides adequate supply and demand resources to meet peak load obligations for the next fifteen years. The key components of this Plan are for APCo to:

- Continue to diversify its mix of supply-side resources through the addition of cost-effective wind and large-scale solar;
- incorporate demand-side resources, including but not limited to additional Energy Efficiency (EE) programs and Volt VAR Optimization (VVO) installations; and
- recognize that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar (i.e. Distributed Generation [DG]).

Key Changes from 2016 IRP

This IRP includes the following changes from the Company's 2016 IRP:

- Utilizes the Company's most recent 2016 H2 fundamentals forecast;
- Assumes an increase in the PJM capacity credit for Smith Mountain from 385MW to 585MW. This increase leaves APCo in a position of sufficient capacity until the assumed retirement of Clinch River units 1 and 2 in 2026; and

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

- Incorporates a two-year delay (from 2022 to 2024) in the beginning of CPP emission targets for modeling purposes. This results in a two-year delay in APCo's assumed mass-based and rate-based CO_2 emission targets which are used for modeling scenarios compliant with the CPP.

The Clean Power Plan (CPP) and APCo's Preliminary Modeling Assessment

On October 23, 2015, the EPA published a final rule – the Clean Power Plan or CPP - in the *Federal Register* establishing carbon dioxide (CO_2) emission guidelines for existing fossil fueled electric generating units under Section 111(d) of the Clean Air Act. The CPP established interim and final uniform national emission standards for two subcategories of generating units: (1) fossil-fueled electric steam generating units; and (2) natural gas-fired combined-cycle units. The EPA also determined equivalent state-specific CO_2 emission rate-based goals and mass-based goals. The interim goals decline over the period from 2022-2029, with final goals effective in 2030 and beyond.

The CPP requires states to develop plans to implement the national uniform CO_2 emission standards or state goals, and to submit a final state plan or a request for extension by September 6, 2016. Twenty-seven states, many utilities, coal producers, unions, national business associations and other interested parties challenged the final rule, and sought to stay its implementation pending judicial review. Although the D.C. Circuit denied these motions for stay, on February 9, 2016, the U.S. Supreme Court granted the applications, staying implementation of the CPP during review by the D.C. Circuit and any subsequent petitions for review by the Supreme Court.

More recently, the President's "Promoting Energy Independence and Economic Growth" Executive Order, signed on March 28, 2017, directs the EPA to review, among other things, the CPP. Following that Executive Order, the Deputy Assistant Attorney General asked the D.C. Circuit Court to hold in abeyance its review of the CPP. Although these further developments cloud the future of the CPP, APCo continues to include an analysis of the CPP in this IRP, consistent with the 2016 IRP Final Order. At this time the Company cannot reasonably predict the outcome of the numerous challenges to the CPP.

Despite the fact that the CPP has been stayed, the Governor of Virginia has announced that the Commonwealth will proceed with efforts to develop a state plan. Given this announcement, the uncertainty of the outcome in the courts, the Trump Administration's Executive Order, and the Commission's directives in its 2016 IRP Final Order, APCo's IRP continues to consider strategies to comply with the CPP and emerging state and/or federal compliance plans. Such strategies will be strongly influenced by the resolution of the pending litigation and the development of various state plans. Particularly for multi-state utilities like APCo, it will be critical to leverage the investments in and operations of utility assets across multiple jurisdictions. APCo has used the model EPA rules to inform its preliminary examination of compliance options, but the final emission guidelines provide a wide range of program design options for the states. The choices states will make about whether to use a rate-based or mass-based compliance methodology, whether to allow interstate trading of compliance instruments, which activities or facilities will be eligible to receive credits or allowances, how such credits or allowances will be distributed, and many other issues will have a profound impact on the costs of compliance. Additionally, many states, including those in which APCo has operations or facilities, are deferring plan development while the stay remains in effect. At this time, there is limited information available about which options may be pursued by each of those states, if the CPP is ultimately implemented.

The Commission directed in its 2015 IRP Final Order that APCo present preliminary analyses of multiple potentially CPP-compliant plans. In order to establish a baseline, APCo also modeled another view assuming no CPP impact. As the Commission suggested, the suite of modeling performed was based on a host of assumptions that may or may not be applicable depending upon the ultimate outcome of the CPP. Given that, these analyses, while informative, should be considered as quite preliminary and will be subject to change over time. The Commission's 2016 IRP Final Order in APCo's 2016 IRP case directed APCo to present updated analyses in its 2017 IRP.

The following initial observations can be drawn from these analyses:

- A CPP-compliant resource plan could result in incremental costs to APCo of approximately $1.6 billion;
- there are likely minimal material cost differences for APCo between a "mass-based" or a "rate-based" compliance approach;
- an approach that assumes an interstate-market for trading of allowances (or emission reduction credits) appears preferable to APCo being essentially self-compliant as "an island," as the latter view could result in incremental costs to APCo of approximately $700 to $750 million; and
- a federal plan based upon the model rule could result in higher incremental costs, when compared to the presumed state plan, of up to $340 million.

Additional supporting information pertaining to these initial observations, as well as the Company's response to other requests for information and comments can be found in Section 5 of this Report.

Summary of APCo Resource Plan

APCo's total internal energy requirements are forecasted to increase at a compound average growth rate (CAGR) of 0.1% through 2031. APCo's peak internal demand is forecasted to decrease at a CAGR of -0.1%, with annual peak demand expected to occur in the winter season through 2031. Figure ES-1, below, shows APCo's "going-in" (i.e. *before* resource additions) capacity position over the planning period, which uses the summer peak to determine resource requirements. Through 2025, APCo has capacity resources to meet its forecasted internal demand, but, in 2026 APCo is anticipated to experience a capacity shortfall based upon APCo's assumptions regarding the retirement of Clinch River Units 1 and 2, which is evident from the (slight) gap between the stacked bar of available resources and the black line representing APCo's load demand, plus PJM reserve margin requirements. This expected capacity deficiency is smaller, and occurs later, than in APCo's 2016 IRP because of an increase in the PJM capacity credit attributed to the Smith Mountain pumped storage units.

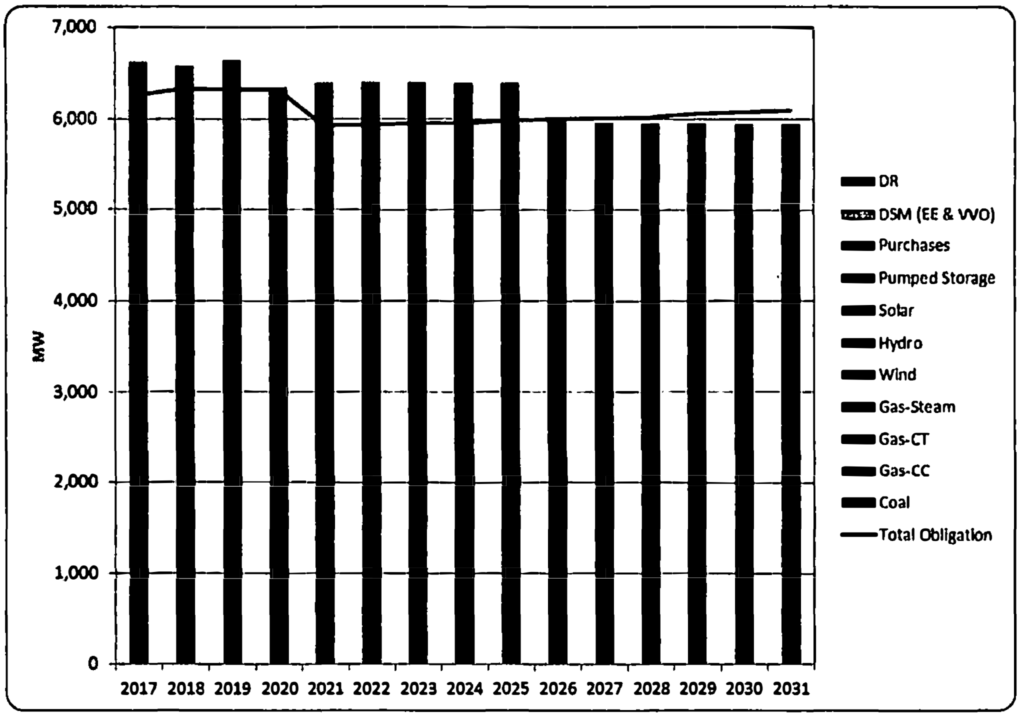

Figure ES-1. APCo "Going-In" PJM Capacity Position (MW)

To determine the appropriate level and mix of incremental supply-side and demand-side resources required to address the indicated going-in capacity deficiencies, APCo utilized the *Plexos*® Linear Program 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 2031), the *Plexos*® modeling was performed through the year 2036, 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 "Preferred Plan." To arrive at the Preferred Plan composition, APCo developed *Plexos*®-derived, "optimum" portfolios under four long-term commodity price forecasts, and two "load sensitivity" forecasts. The Preferred Plan is presented as an option that attempts to balance cost and other factors while meeting APCo's peak load obligations. In addition, this IRP considers existing and future environmental requirements, including those that may result from the CPP, and the practical limitations of customer self-generation.

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In summary, the Preferred Plan:

- Assumes 25MW (nameplate) of new large-scale solar energy in 2019, with subsequent additions throughout the planning period, for a total of 525MW (nameplate) by 2031;
- includes 120MW (nameplate) of approved new wind energy in 2018; assumes 225MW (nameplate) of new wind energy in 2019; and adds 300MW (nameplate) of incremental wind energy by 2020, with subsequent additions throughout the planning period, for a total of 1,695MW (nameplate) of incremental wind energy by 2031;
- implements customer and grid EE programs, including VVO, reducing energy requirements by 850GWh annually and summer capacity requirements by 203MW by 2031;
- assumes APCo's customers add distributed generation (DG) (i.e. rooftop solar) capacity totaling over 123MW (nameplate) by 2031. (Note 1);
- adds 10MW (nameplate) of battery storage resources in 2025;
- assumes a host facility is identified such that a Combined Heat and Power (CHP) project can be implemented by 2021;
- addresses expected PJM Capacity Performance rule impacts on APCo's capacity position beginning with the 2020/2021 PJM planning year. Among other things, it assumes that the rule may result in APCo:
  - reducing wind resources from prior PJM-recognized capacity levels (i.e. from 13% to 5% of nameplate capacity); and
  - reducing run-of-river hydro contributions to 25% of nameplate rating;
- continues operation of APCo's facilities including the Amos Units 1-3 and Mountaineer Unit 1 coal-fired facilities, the Ceredo and Dresden natural gas facilities and operating hydro facilities. Maintains APCo's share of Ohio Valley Electric Company (OVEC) solid-fuel facilities: Clifty Creek Units 1-6 and Kyger Creek Units 1-5; and
- retires gas-steam Clinch River Units 1 and 2 in 2026.

Note 1: APCo does not have control over the amount, location or timing of these additions.

Specific APCo capacity changes over the 15-year planning period associated with the Preferred Plan are shown in Figure ES-2 and Figure ES-3, and their relative impacts to APCo's annual energy position are shown in Figure ES-4 and Figure ES-5.

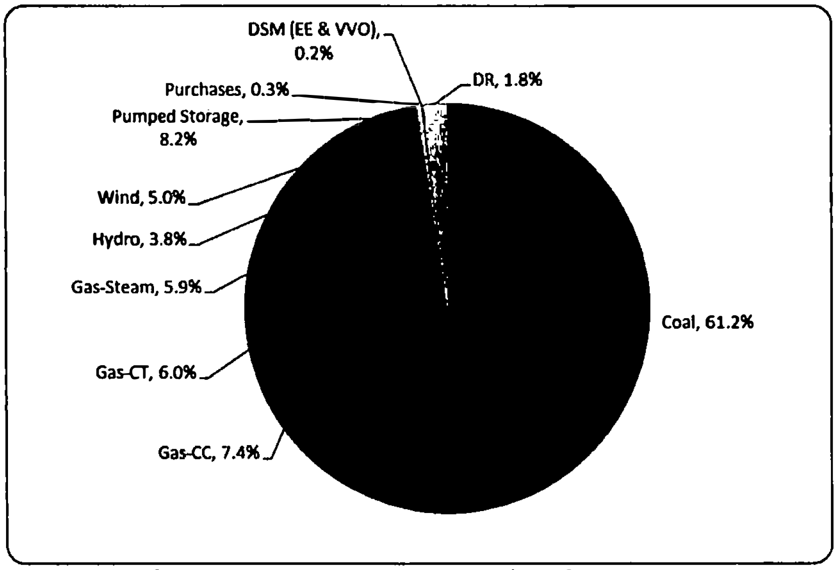

Figure ES-2. 2017 APCo Nameplate Capacity Mix

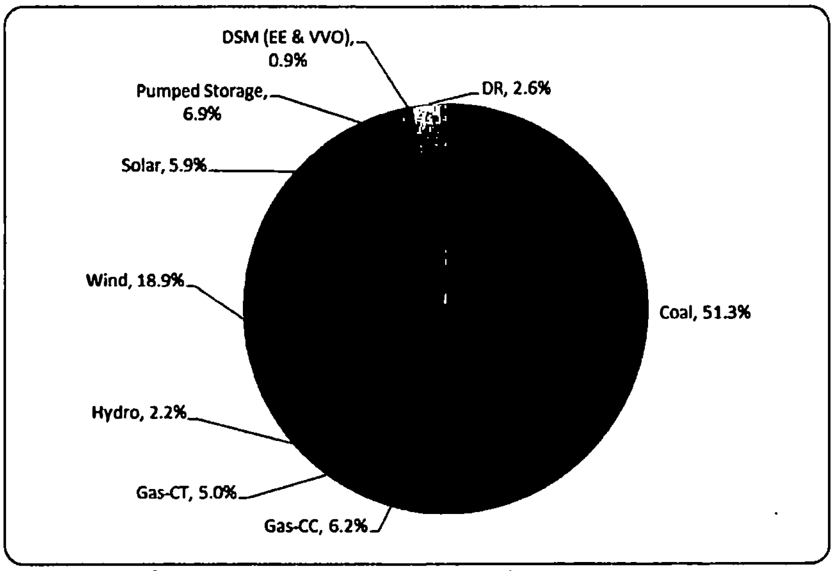

Figure ES-3. 2031 APCo Nameplate Capacity Mix

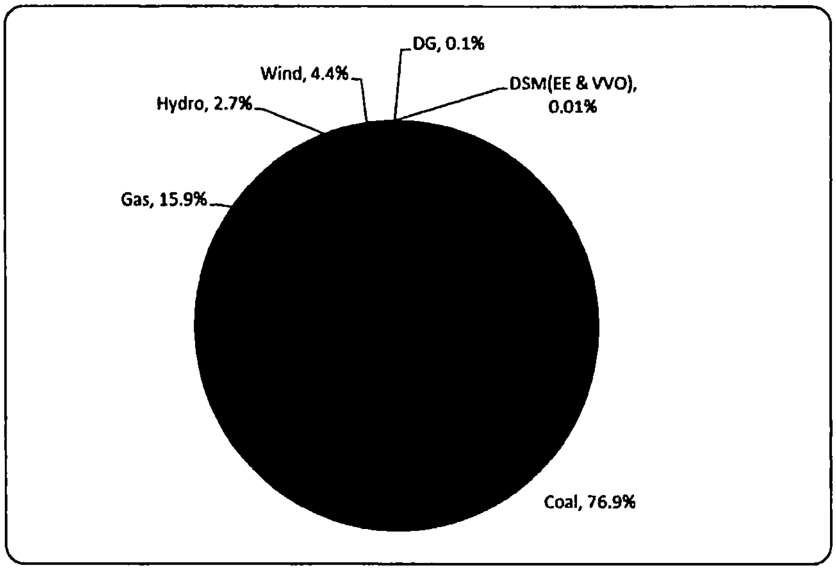

Figure ES-4. 2017 APCo Energy Mix

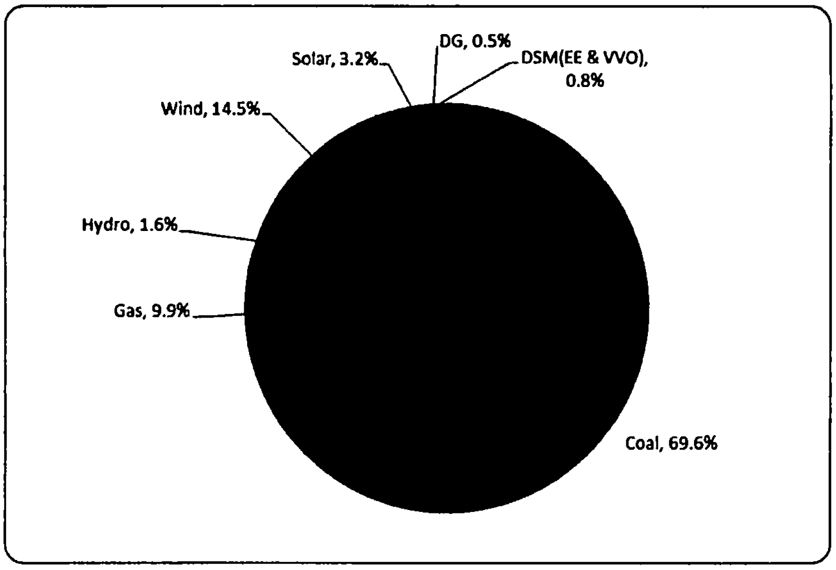

Figure ES-5. 2031 APCo Energy Mix

Figure ES-2 through Figure ES-5 indicate that this Preferred Plan would reduce APCo's reliance on coal-based generation and increase reliance on demand-side and renewable resources, further diversifying the portfolio. Specifically, over the 15-year planning horizon the Company's nameplate capacity mix attributable to coal-fired assets would decline from 61.2% to 51.3%.

Wind and solar assets climb from 5% to 24.8%, and demand-side resources (including EE, VVO, DG, Demand Response [DR], and Combined Heat and Power [CHP]) increase from 2.0% to 3.5% over the planning period.

APCo's energy output attributable to coal-fired generation shows a decrease from 76.9% to 69.6% over the period. The Preferred Plan shows a significant increase in renewable energy (wind and solar), from 4.4% to 17.6%. Energy from these renewable resources, combined with EE and VVO energy savings reduce APCo's exposure to energy, fuel and potential carbon prices.

Figure ES-6 and Figure ES-7 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements.

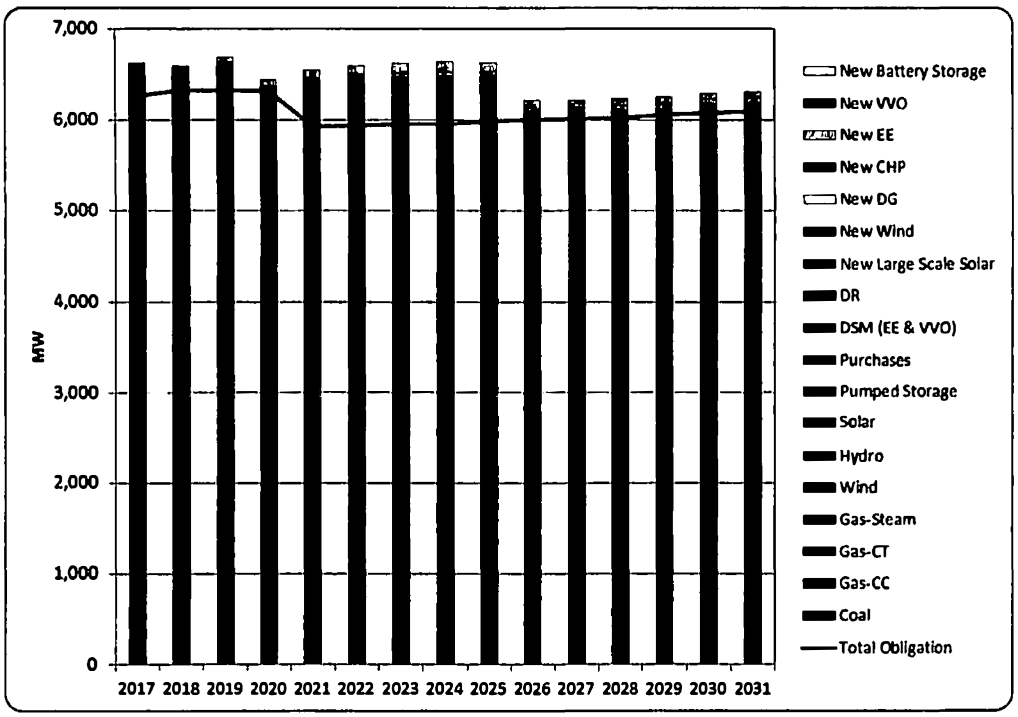

Figure ES-6. APCo Annual PJM Capacity Position (MW) According to Preferred Plan

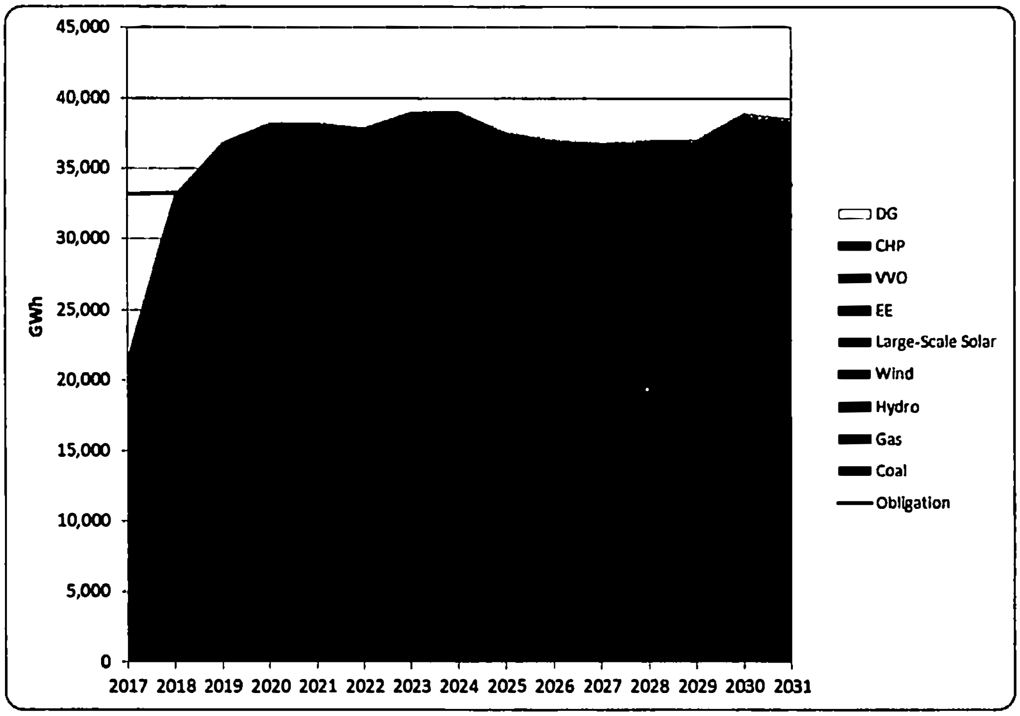

Figure ES-7. APCo Annual Energy Position (GWh) According to Preferred Plan

The capacity contribution from renewable resources is fairly modest due to the implications of PJM's Capacity Performance rule reducing the amount of capacity credit for intermittent resources; however, those resources (particularly wind) provide a significant volume of energy. APCo's model selected those wind resources because they were lower cost than alternative energy resources. When comparing the capacity values in Figure ES-6 with those in Figure ES-2 and Figure ES-3, it is important to note that Figure ES-6 provides an analysis of PJM-recognized capacity, while Figure ES-2 and Figure ES-3 depict nameplate capacity.

Table ES-1 below provides a summary of the Preferred Plan, which resulted from analysis of optimization modeling under load and commodity pricing scenarios, giving consideration to APCo's CPP modeling:

Table ES-1. Preferred Plan Cumulative Capacity Additions throughout Planning Period (2017-2031)

IRP Period Yr.	PJM Planning Year[A]	Planning Peak Load MW	(1) (Cumulative) Existing Fleet: Unit Uprates & Derates MW	(2) (Cumulative) Existing Fleet: PJM Capacity Perf. Impact (UCAP Reduction)[B] MW	(3) New-Build: NG CHP MW	(4) New-Build: NG CC MW	(5) Energy Efficiency (EE): 'Embedded' Federal EE Regulations (Non-DSM EE)[B] MW	(6) Energy Efficiency (EE): Current DSM Programs[C] MW	(7) Energy Efficiency (EE): New MW	(8) VVO: New MW	(9) DR: Pre-Existing DR Programs[C] MW	(10) Wind[D] MW	(11) Solar[E]: Large Scale MW	(12) Solar[E]: DG MW	(13) Battery[F] MW	(14)=(1)+(2)+(3...13) (Cumul.) NET 'RESOURCE' CHANGE[G] MW	(15) Resulting APCo Reserves Above PJM Minimum Reserve[H] MW	(16) PJM Reserve Margin %	(17) (Cumulative) 'NAMEPLATE' ADDITIONS: Wind[D] MW	(18) Solar[E]: Large Scale MW	(19) Solar[E]: DG MW	(20) Battery[F] MW
1	2017	5,619	(34) [a]	-	-	-	391	13	0	-	149	-	-	6	-	134	365	6.5%	-	-	16	-
2	2018	5,676	(34) [b]	-	-	-	417	19	0	-	149	6	-	12	-	152	264	4.6%	120	-	31	-
3	2019	5,664	2	-	-	-	442	19	30	-	149	17	10	17	-	245	368	6.5%	345	25	46	-
4	2020	5,668	2	(290)	-	-	473	19	52	-	149	32	17	18	-	1	122	2.1%	645	45	48	-
5	2021 [A]	5,207	2	(334)	14	-	[illegible]	19	73	-	119	47	25	20	-	(15)	618	11.9%	945	65	53	-
6	2022	5,211	2	(334)	14	-	[illegible]	19	95	-	119	62	32	22	-	32	656	12.6%	1,245	85	59	-
7	2023	5,227	2	(334)	14	-	[illegible]	19	117	-	119	70	40	24	-	71	670	12.8%	1,395	105	64	-
8	2024	5,233	2	(334)	14	-	[illegible]	19	138	-	119	70	48	31	-	106	688	13.2%	1,395	125	81	-
9	2025	5,265	2	(334)	14	-	579	19	142	-	119	70	55	33	5	125	648	12.3%	1,395	145	86	10
10	2026	5,279	(438) [c]	(334)	14	-	[illegible]	19	145	-	119	70	63	35	5	(302)	222	4.2%	1,395	165	93	10
11	2027	5,298	(438)	(274)	14	-	[illegible]	19	156	17	119	70	86	37	5	(190)	205	3.9%	1,395	225	98	10
12	2028	5,303	(438)	(267)	14	-	622	19	167	17	119	70	108	39	5	(147)	214	4.0%	1,395	285	104	10
13	2029	5,340	(438)	(254)	14	-	[illegible]	19	180	17	119	77	131	42	5	(88)	200	3.8%	1,545	345	110	10
14	2030	5,358	(438)	(244)	14	-	649	19	182	17	119	85	177	44	5	(20)	219	4.1%	1,695	465	117	10
15	2031	5,377	(438)	(244)	14	-	653	19	185	17	119	85	200	47	5	9	216	4.0%	1,695	525	123	10
								222 TOTAL Increm' Energy Efficiency												648 'TOTAL' Solar		

[A] PJM Planning Year is effective 6/1/XXXX. In 2021, Load Forecast moves from the PJM forecast to APCo's internal forecast.
[B] Represents estimated (post-2005) energy efficiency levels already 'embedded' into APCo's long-term load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standards (EPAct 2005; 2007 EISA, 2009 ARRA).
[C] Represents estimated contribution from current/known APCo DSM-EE and Demand Response (Interruptible, DLC/ELM) program activity through 2018; values are baselined from 2016
[D] Values in 2018 and 2019 represent the 2016 RFP amounts, due to the intermittency of wind resources, APCo assumes 5% of nameplate' MW rating are included for capacity resource determination purposes beyond 2020.
[E] Value in 2019 represent the 2017 RFP expected amount, due to the intermittency of solar resources, Utility and Distributed Solar receive 38% of nameplate MW rating for capacity resource determination purposes.
[F] Due to the intermittency of battery/storage resources, APCo assumes 50% of nameplate MW rating for capacity resource determination purposes.

Changes to existing resources Post-January 1, 2017:
[a] Mountaineer turbine upgrade.
[b] Clinch River 1&2 Gas Conversion unit rerate in 2017 and retirement in 2026
[c] Beginning in 2020, assumes removal of 75% Run-of-River Hydro capacity, 50% reduction in Existing DR and a 95% reduction of (Existing) Wind capacity to achieve PJM 'Capacity Performance' criteria

[G] Includes changes in existing resources plus plan additions, excluding "embedded" EE and existing DR programs.
[H] PJM minimum criterion @18.6% as a function of peak demand effective with the 2019/20 PY.

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Conclusion

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

Moreover, this IRP also addresses APCo's energy short position. The Preferred 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 long-term exposure of the Company's customers to PJM energy markets.

Recognizing PJM's Capacity Performance construct, the portfolios discussed in this Report attribute limited capacity value for certain intermittent resources (solar, wind and run-of-river hydro). It is possible that intermittent resources can be combined, or "coupled," and offered into the PJM market as Capacity Performance resources. The Company will continue to investigate methods to maximize the utilization of its intermittent resource portfolio within that construct.

This IRP also addresses this Commission's specific 2017 IRP requirements to perform analyses associated with the requirements of the CPP, compared to a least-cost non-compliant analysis. Each of the Commission's requirements has been examined and, despite the uncertainty surrounding the legal status of the CPP and various other uncertainties, the Company has made a good-faith effort to provide both appropriate responses to the Commission's inquiries and reasonable analyses under the circumstances.

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; an IRP is simply a snapshot of the future at a given 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 exacerbate the need for flexibility and adaptability in any ongoing planning activity and resource planning process.

To that end, APCo intends to pursue the following five-year action plan:

1. Complete implementation activities necessary to purchase renewable energy from approved 120MW wind resource beginning in 2018.
2. Obtain regulatory approval of 225MW of additional wind energy, and have these resources in-service beginning in 2019.
3. Continue evaluation, due diligence, and regulatory activities necessary to select a 25MW solar resource, obtain regulatory approval, and have the resource in-service beginning in 2019.
4. Continue the planning and regulatory actions necessary to implement economic EE programs in Virginia and West Virginia.
5. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, pursue competitive solicitations that would include self-build or acquisition options.
6. Pursue opportunities to identify a suitable host facility for a CHP installation.
7. Monitor developments associated with PJM's Capacity Performance rule; continue to investigate opportunities to couple/hedge traditional hydro and renewable resources (wind and solar) as reasonable Capacity Performance products.
8. Monitor the status of, and participate in formulating, Virginia (as well as West Virginia, Ohio and Indiana) state plans pertaining to the CPP. Once established, perform specific assessments as to the implications of the CPP on APCo's resource profile.
9. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

1.0 Introduction

1.1 Overview

This Report presents the 2017 Integrated Resource Plan (IRP, Plan, or Report) for Appalachian Power Company (APCo or Company) including descriptions of assumptions, study parameters, and methodologies. The results integrate supply- and demand-side resources.

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, resource planning is critical to APCo due to its impact on:

- Determining capital expenditure requirements;
- rate case planning; and
- environmental compliance and other planning processes.

1.2 Integrated Resource Plan (IRP) Process

This Report covers the processes and assumptions required to develop an IRP for the Company. 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 (EE) measures, Demand Response (DR) and Distributed Generation (DG);
- identify current supply-side 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; and

- perform resource modeling, including modeling for possible Clean Power Plan (CPP) effects, 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 (see Figure 1). Currently, APCo serves approximately 957,000 retail customers in those states, including approximately 528,000 and 429,000 in the states of Virginia and West Virginia, respectively. 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 all-time highest recorded peak demand was 8,708MW, which occurred in February 2015; and the highest recorded summer peak was 6,755MW, which occurred in August 2007. The most recent (summer 2016 and winter 2016/17) actual APCo summer and winter peak demands were 5,885MW and 6,984MW, occurring on July 25, 2016 and January 9, 2017, respectively.

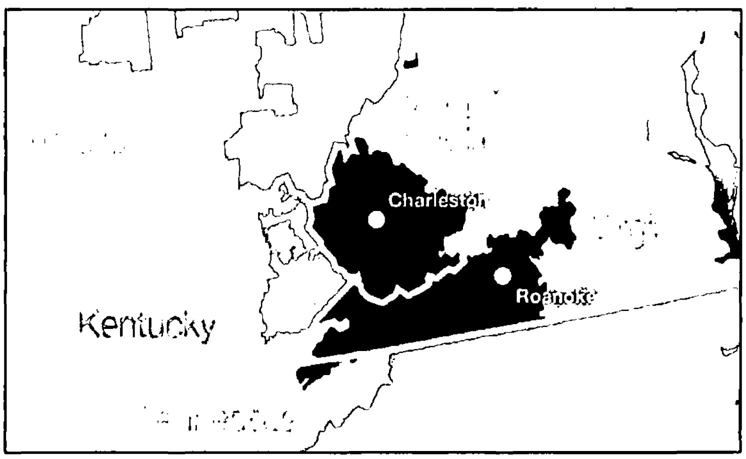

Figure 1. APCo Service Territory

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, is uncertain, particularly in light of current economic conditions, the increasing use of renewable generation and end-use efficiency, as well as potential of regulations to control greenhouse gases.

The action items described herein are subject to change as new information becomes available or as circumstances warrant. This IRP report is being filed by May 1, 2017 in compliance with Virginia Senate Bill 1349. Senate Bill 1349 amended Section 56-599 of the Code of Virginia and required that electric utilities file an updated IRP by July 1, 2015, followed by annual updated IRPs due each year on May 1. Section 56-599 also required electric utilities to consider six factors in each IRP.

The first four factors to be considered relate to options (i.e. options for maintaining and enhancing rate stability; energy independence; economic development, including the retention and expansion of energy intensive industries; and, service reliability). The fifth and sixth factors relate to environmental regulations and require consideration of the effect of current and pending state and federal environmental regulations upon the continued operations of existing electric generation facilities or options for constructing new electric generation facilities; and, 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. As indicated throughout this Report, APCo's IRP process takes these requirements into account and attempts to strike a reasonable balance among these various factors.

2.0 Load Forecast and Forecasting Methodology

2.1 Summary of APCo Load Forecast

The APCo load forecast was developed by the American Electric Power Service Corporation (AEPSC) Economic Forecasting organization and completed in June 2016.[2] The final load forecast is the culmination of a series of underlying forecasts that build upon each other. In other words, 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 (2017-2031)[3], APCo's service territory is expected to see population and non-farm employment growth of 0.1% and 0.5% per year, respectively. APCo is projected to see customer count growth remain relatively flat over this period. Over the same forecast period, APCo's retail sales are projected to grow at 0.1% per year with stronger growth expected from the industrial class (+0.4% per year) while the residential class experiences a slight decline over the forecast horizon. Finally, APCo's internal energy and peak demand are expected to change at an average rate of 0.1% and -0.1% per year, respectively, through 2031.

2.2 Forecast Assumptions

2.2.1 Economic Assumptions

The load forecasts for APCo and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in December 2016.

[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.

[3] 15 year forecast periods begin with the first full forecast year, 2017.

Moody's Analytics projects moderate growth in the U.S. economy during the 2017-2031 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.1% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.5% per year during the same period. Moody's projects employment growth of 0.5% per year during the forecast period and real regional income per-capita annual growth of 1.7% 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 the U.S. Department of Energy (DOE) Energy Information Administration (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 are in frequent touch with industrial and commercial customers about their needs and activities. From these discussions, expected load additions or deletions are relayed to the Company.

2.2.4 Weather Assumptions

Where appropriate, the Company includes weather as an explanatory variable in its energy sales models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

2.2.5 Demand Side Management (DSM) Assumptions

The Company's long term load forecast models account for trends in EE both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards (Energy Policy Act of 2005 [EPAct], Energy

Independence and Security Act [EISA] of 2007, etc.) modeled by the EIA. In addition to general trends in appliance efficiencies, the Company also administers multiple Demand-Side Management (DSM) programs that the Commissions approve as part of its DSM portfolio. The load forecast utilizes the most current Commission-approved programs at the time the load forecast is created to adjust the forecast for the impact of these programs.

2.3 Overview of Forecast Methodology

APCo's load forecasts are based mostly on econometric, statistically adjusted end-use and analyses 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 forecast 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 in energy sales for short-term applications like capital budgeting and resource allocation. While these models produce extremely 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 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.

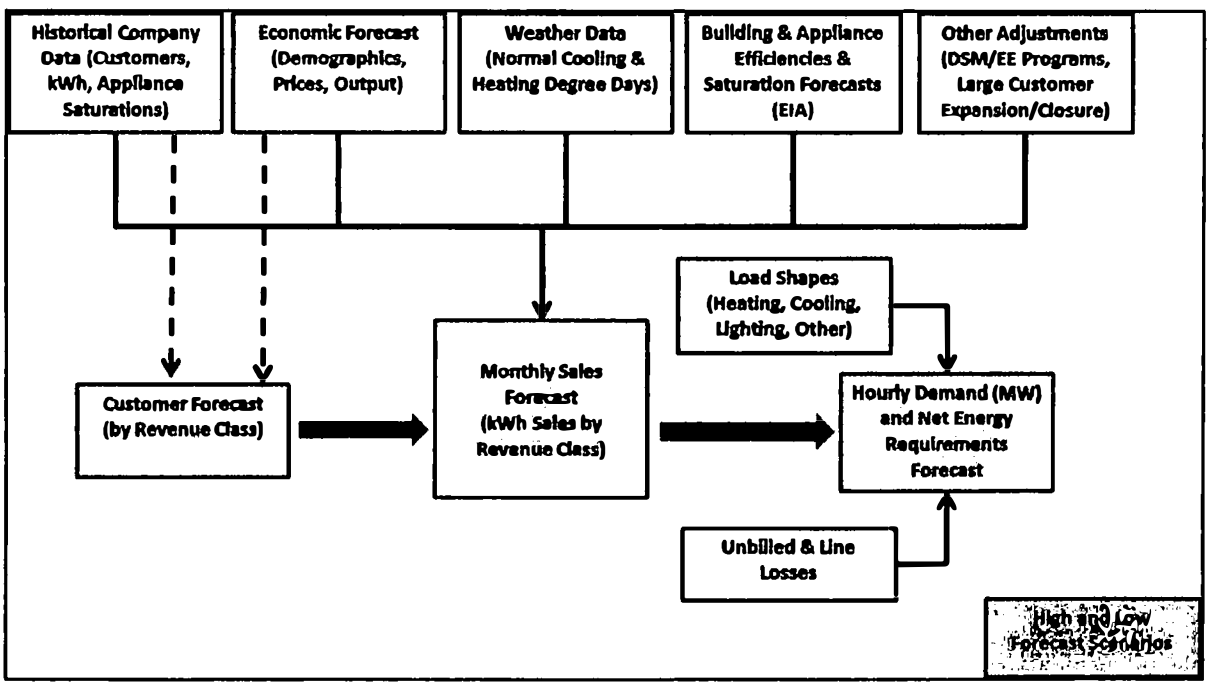

Figure 2. APCo Internal Energy Requirements and Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast

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 jurisdictional economic and demographic variables include gross regional product, employment, mortgage rate, population, real personal income and households are used in various combinations. 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 relied on 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 2006 through January 2016. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 22 large industrial models and models for the remainder of the industrial sector. The wholesale forecast is developed using models for the cities of Radford and Salem, Craig-Botetourt Electric Cooperative, Old Dominion Electric Cooperative, Virginia Tech and a private system customer in West Virginia. Kingsport Power Company, an affiliated company in Tennessee, is also a wholesale requirements customer of

APCo, whose forecast is developed similar to those for the Company's Virginia and West Virginia jurisdictions.

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast as they are not requirements load or relevant to determining capacity and energy requirements in 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 1995-2014 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.

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 natural gas price and coal production models for APCo's Virginia and West Virginia 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 natural gas prices for each state's 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 sectoral prices, with the forecast being obtained from EIA's "2015 Annual Energy Outlook." The natural gas price model is based upon 1980-2015 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 EIA's "2015 Annual Energy Outlook." The estimation period for the model was 1998-2015.

2.4.4.2 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.

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 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 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 2016. It is important to note, as will be discussed later, that this modeling *has* incorporated the reductive effects of the EPAct, 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 based on analysis by the EIA regarding appliance efficiency trends.

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 SAE models. These models are similar to the residential SAE models. These models utilize efficiencies, square footage and equipment saturations for the East North Central Region, along with electric prices, economic drivers from Moody's Analytics, heating and cooling degree-days, and billing cycle days. As with the residential models, there are Xheat, Xcool and Xother variables derived within the model framework. The commercial SAE models are estimated similarly to the residential SAE models.

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 separately 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, 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 2016.

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, and service area mine power electricity prices. 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 2016.

2.4.4.5 All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales to either service area employment or service area population and binary variables.

Wholesale energy sales are modeled relating energy sales to economic variables such as service area employment, energy prices, 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. Kingsport Power's load is modelled similarly to APCo's retail sales, with the exception that Kingsport Power does not have mine power energy sales.

2.4.5 Internal Energy Forecast

2.4.5.1 Blending Short and Long-Term Sales

Forecast values for 2016 and 2017 are taken from the short-term process. Forecast values for 2018 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 2018 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 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 Federal Energy Regulatory Commission (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, 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

All tables referenced in this section can be found in the Appendix of this Report in Exhibit A.

2.5.1 Load Forecast

Exhibit A-1 presents APCo's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other internal sales and losses) on an actual basis for the years 2013-2016 and on a forecast basis for the years 2017-2031. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the Company's Virginia and West Virginia service areas are given in Exhibits A-2A and A-2B.

2.5.2 Peak Demand and Load Factor

Exhibit A-3 provides APCo's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2013-2016 and on a forecast basis for the years 2017-2031. The table also shows annual growth rates for both the historical and forecast periods.

2.5.3 Weather Normalization

The load forecast presented in this Report assumes normal weather. To the extent that weather is included as an explanatory variable in various short- and long-term models, the weather drivers are assumed to be normal for the forecast period.

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, below, presents APCo's historical and forecasted residential and commercial usage per customer between 1991 and 2020. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 1.3% per year while the commercial usage grew by 0.6% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.9% per year while the commercial class usage decreased by 0.3% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 0.8% per year while the commercial usage decreases by an average of 0.6% per year. It is worth noting that the decline in residential and commercial usage accelerated between 2008 and 2016, with usage declining at average annual rates of 1.2% and 1.1% for residential and commercial sectors, respectively, over that period.

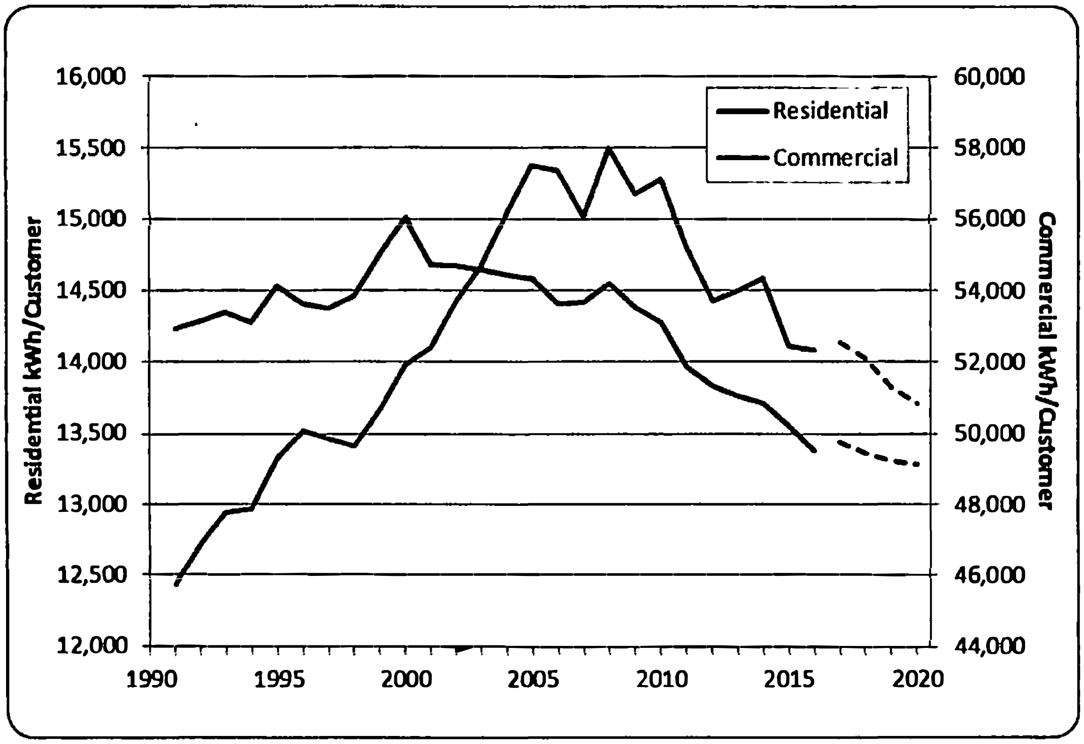

Figure 3. APCo Normalized Use per Customer (kWh)

The SAE 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 various enacted federal policies mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. 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 Seasonal Energy Efficiency Ratio (SEER) for central air conditioning is projected to increase from 11.6 in 2010 to over 13.6 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units. Figure 5 shows similar improvements in the efficiencies of lighting and clothes washers over the same period.

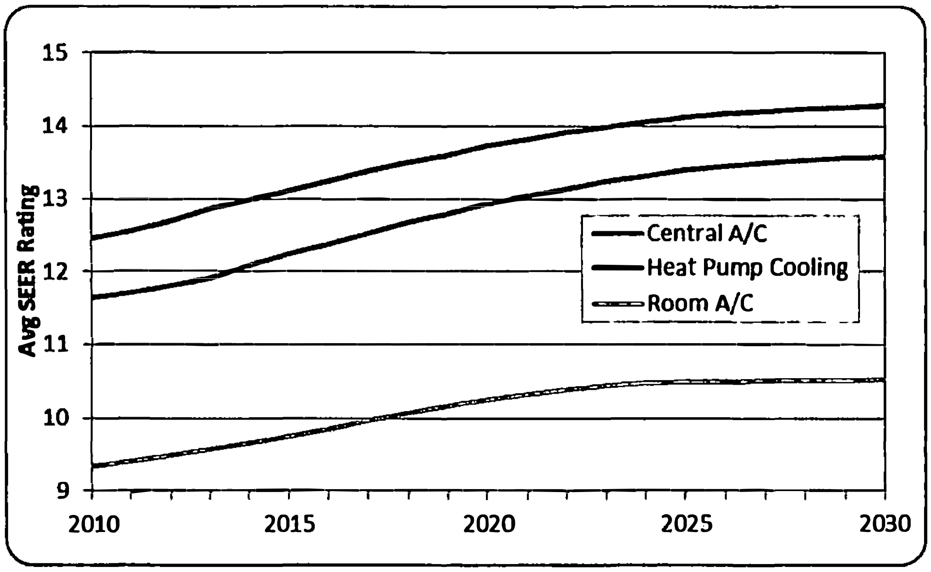

Figure 4. Projected Changes in Cooling Efficiencies, 2010-2030

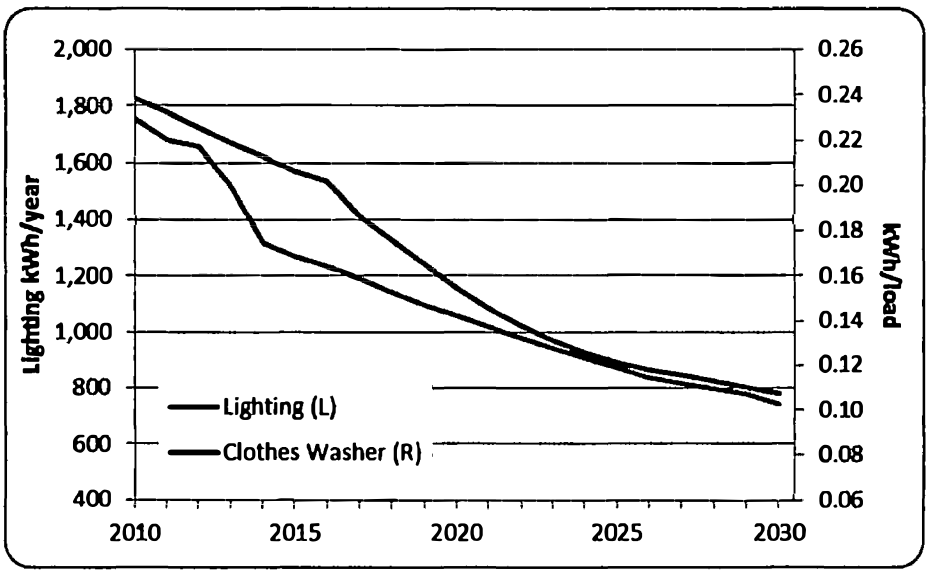

Figure 5. Projected Changes in Lighting and Clothes Washer Efficiencies, 2010-2030

2.6.2 Demand-Side Management (DSM) Impacts on the Load Forecast

The end-use load forecasting models account for changing trends and saturations of energy efficient technologies throughout the forecast horizon. However, the Company is also actively engaged in administering various commission approved DSM and EE programs which would further accelerate the adoption of energy efficient technology within its service territory. As a result, the base load forecast is adjusted to account for the impact of these programs that is not already embedded in the forecast.

For the near term horizon (through 2018), the load forecast uses assumptions from the latest commission approved DSM programs. For the years beyond 2018, the IRP model selected optimal levels of economic EE, which may differ from the levels currently being implemented, based on projections of future market conditions. The initial base load forecast accounts for the evolution of market and industry efficiency standards. As a result, energy savings for a specific EE program are degraded over the expected life of the program. Exhibit A-9 details the impacts of the approved EE programs included in the load forecast, which represent the cumulative degraded value of EE program impacts throughout the forecast period. The IRP process then adds the selected optimal economic EE, resulting in the total IRP EE program savings.

Exhibit A-4 provides the DSM/EE 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 and West Virginia jurisdictions.

2.6.3 Interruptible Load

The Company has seven customers with interruptible provisions in their contracts. These customers have interruptible contract capacity of 306MW. However, these customers are expected to have 141MW and 185MW available for interruption at the time of the winter and summer peaks, respectively. An additional five customers have 33MW available for interruption in emergency situations in DR agreements. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking. As such, estimates for DR impacts are reflected by APCo in determination of PJM-required resource adequacy (i.e., APCo's projected capacity position). Further discussion of the determination of DR is included in Section 3.4.3.1.

2.6.4 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. Exhibit A-5 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, all of the wholesale forecasts utilize the long-term model results.

In general, forecast values for the year 2017 were typically taken from the short-term process. Forecast values for 2018 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 2018 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. Figure 6 illustrates a hypothetical example of the blending process (details of this illustration are shown in Exhibit A-6). However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

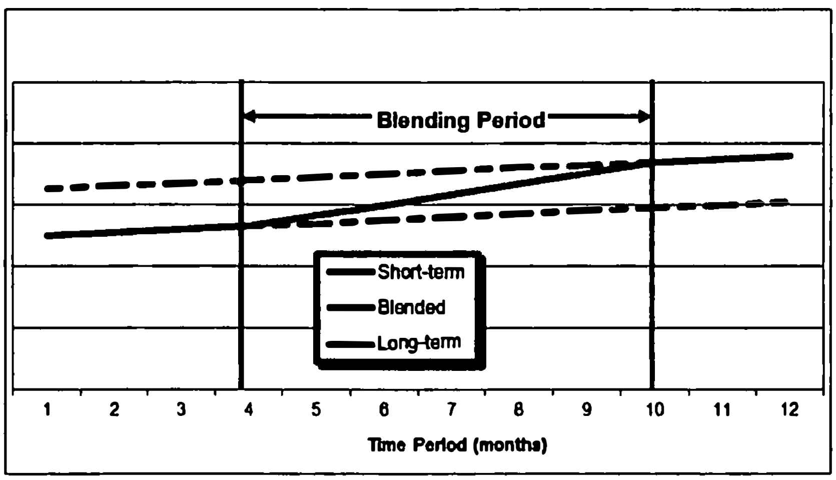

Figure 6. Load Forecast Blending Illustration

2.6.5 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 additional factors may be used to reflect those large changes that differ from the forecast models' output.

2.6.6 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs.

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 a more exact quantification of outcomes, but the reality is if all possible outcomes were known with a degree of certainty, then they 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 2016 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.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for APCo are tabulated in Exhibit A-7. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for APCo are shown in Exhibit A-8.

For APCo, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2031, represent deviations of about 8.3% below and 9.0% above, respectively, the base-case forecast.

2.8 Economic Development

A requirement set forth by Senate Bill 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 whether 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 a 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 endeavors 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.

Additionally, some large customers have corporate requirements to supply their energy solely from renewable sources. To accommodate these customers, the Company may have to procure and dedicate specific renewable resources to serve that load.

2.8.1 Economic Development Programs

The Company has economic development programs designed to attract new businesses and expand and retain existing businesses in 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 firm's other plants, in different parts of the country or world, for expansion or a potential new plant for the firm. In Virginia, APCo can provide incentives from 25-35% of the demand charge and 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 opportunities.

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 considerations;
- changes resulting from decisions surrounding unit disposition evaluations;
- regional and sub-regional capacity and transmission constraints/limitations;
- load and peak demand;
- current DR/EE; and
- 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 PJM Installed Reserve Margin (IRM) of 16.6 percent.[4] The ultimate reserve margin is determined from the PJM Forecast Pool Requirement (FPR) which considers the IRM and PJM's Pool-Wide Average Equivalent Demand Forced Outage Rate ($EFOR_D$).[5] The PJM FPR is 9.67% for the 2017/2018 PJM planning year, and decreases to 8.92% for the remainder of the planning period, which ends with the 2031/2032 PJM planning year. Table 1 displays key parameters for APCo's current supply-side resources.

[4] Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Effective: December 22, 2016). 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 October 26, 2015, which reflect PJM's Capacity Performance proposal.

[5] Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Effective: December 22, 2016).
$FPR = (1 + IRM) * (1 - EFOR_D)$. Reserve Margin = FPR – 1.

Table 1. Current Supply-Side Resources, as of April 1, 2017

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	PJM Capacity (MW)[2]	
Amos 1	St. Albans, WV	Steam	Coal	1971	800	
Amos 2	St. Albans, WV	Steam	Coal	1972	800	
Amos 3	St. Albans, WV	Steam	Coal	1973	1,330	
Ceredo 1	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 2	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 3	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 4	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 5	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Ceredo 6	Ceredo, WV	Combustion Turbine	Gas	2001	75	
Clinch River 1	Carbo, VA	Steam	Gas	1958	230	
Clinch River 2	Carbo, VA	Steam	Gas	1958	210	
Dresden	Dresden, OH	Combined Cycle	Gas	2012	555	
Mountaineer 1	New Haven, WV	Steam	Coal	1980	1,305	
Buck 1 - 3	Ivanhoe, VA	Hydro	--	1912	9	
Byllesby 1 - 4	Byllesby, VA	Hydro	--	1912	22	
Claytor 1 - 4	Radford, VA	Hydro	--	1939	75	
Leesville 1 - 2	Leesville, VA	Hydro	--	1964	50	
London 1 - 3	Montgomery, WV	Hydro	--	1935	14	
Marmet 1 - 3	Marmet, WV	Hydro	--	1935	14	
Niagara 1 - 2	Roanoke, VA	Hydro	--	1924	2	
Winfield 1 - 3	Winfield, WV	Hydro	--	1938	15	
Smith Mountain 1	Penhook, VA	Pump. Stor.	--	1965	70	(A)
Smith Mountain 2	Penhook, VA	Pump. Stor.	--	1965	185	(A)
Smith Mountain 3	Penhook, VA	Pump. Stor.	--	1980	105	(A)
Smith Mountain 4	Penhook, VA	Pump. Stor.	--	1966	185	(A)
Smith Mountain 5	Penhook, VA	Pump. Stor.	--	1966	70	(A)
Clifty Creek 1-6	Madison, IN	Steam	--	1956	179	(B)
Kyger Creek	Cheshire, OH	Steam	--	1955	147	(B)
Beech Ridge 1	Greenbriar County, WV	Wind	--	2009	15	(C)
Camp Grove	Marshall County, IL	Wind	--	2008	11	(C)
Fowler Ridge	Benton County, IN	Wind	--	2009	13	(C)
Grand Ridge 2-3	Marseilles, IL	Wind	--	2009	17	(C)
Summersville 1-2	Summersville, WV	Hydro	--	2001	80	(C)
					6,958	

(1) Commercial operation date.
(2) Peak net capability as of filing.
(A) Units 1, 3 & 5 have pump-back capability, units 2 & 4 are generation only.
(B) Represents APCo's share of these units
(C) Respresents capacity from Power Purchase Agreements (PPAs)

Figure 7, below, depicts all generation sources employed to meet the APCo needs, along with their current age. Unit ratings displayed in this figure are nameplate ratings.

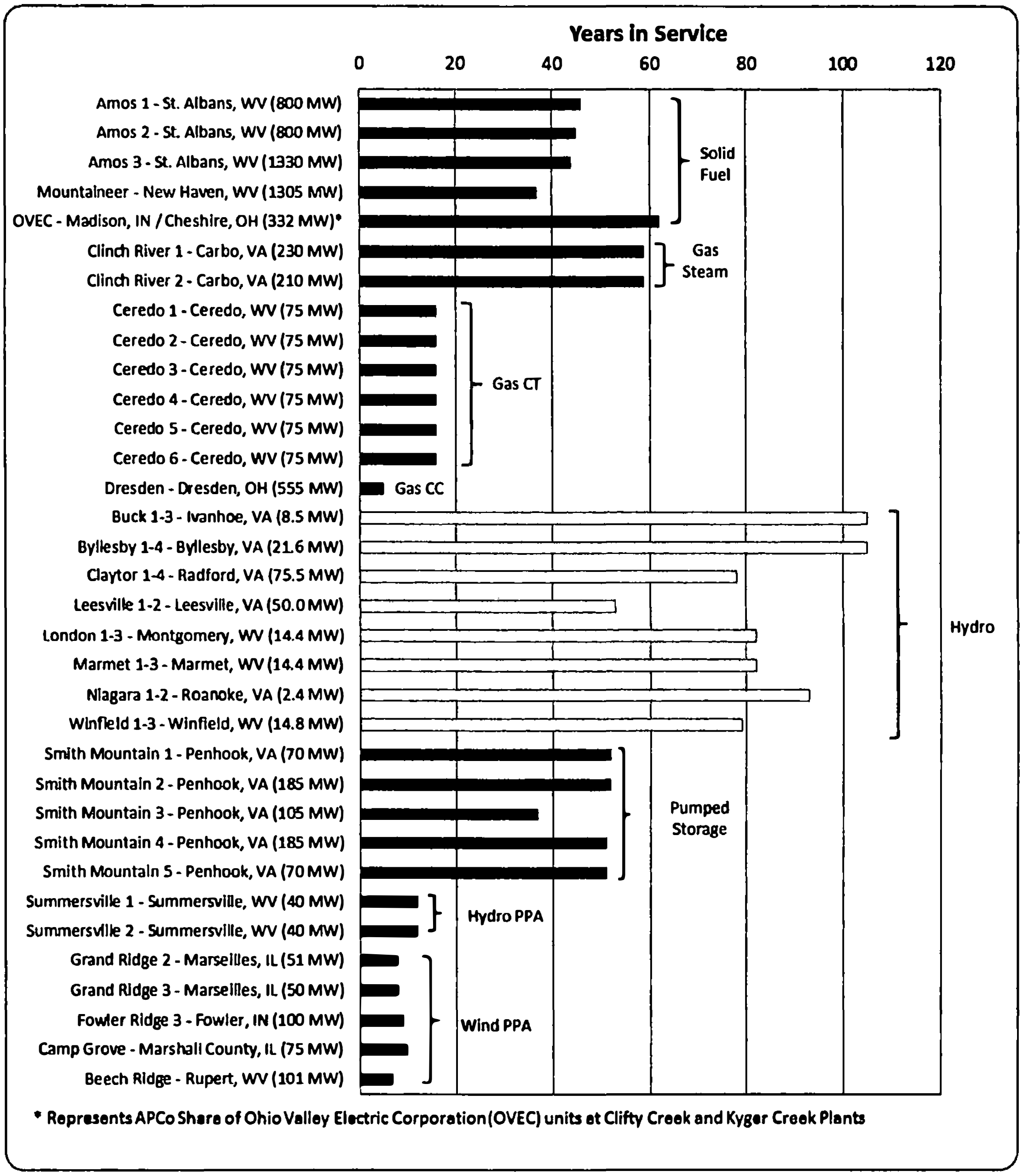

Figure 7. Current Resource Fleet (Owned and Contracted) with Years in Service, as of April 1, 2017

APCo currently utilizes several capacity entitlements to meet the minimum PJM reserve margin requirement, including generation from Company owned assets, joint ventures, and hydro and wind Power Purchase Agreements (PPAs). In addition to the current assets shown above, APCo's "Going-In" resource position includes a 120MW (nameplate) wind Renewable Energy

1725 9 1 5 9 7 5

Purchase Agreement (REPA) which, having been approved by this Commission and the Public Service Commission of West Virginia, will take effect in 2018. The "Going-In" position also includes an additional 225MW (nameplate) of wind resources and 25MW (nameplate) of solar resources in 2019. These resources reflect APCo's current plans to pursue additional renewable energy resources in the near future.

3.2.1 PJM Capacity Performance Rule Implications

On June 9, 2015 FERC issued an order largely accepting PJM's proposal to establish a new "Capacity Performance" product. The resulting PJM rule requires future capacity auctions to transition from current or "Base" capacity products to Capacity Performance products. Capacity Performance resources will be held to stricter requirements than current Base resources and will be assessed heavy penalties for failing to deliver energy when called upon.

This IRP incorporates the following assumptions for Capacity Performance values for certain gas-fired and intermittent resources, in order to address the Capacity Performance rulemaking effective with the 2020/2021 PJM planning year:

- Gas generation resources may require a firm natural gas supply or dual-fuel (gas/oil) capability to hedge against non-performance due to lack of firm gas supply;
- run-of-river hydro units valued at 25% of nameplate capacity rating;
- solar resources will be valued at 38% of nameplate capacity rating, consistent with current PJM rating for new solar sources;
- wind resources will be valued at 5% of nameplate capacity rating, a reduction from current PJM rating of 13.5% for new wind sources; and
- DR resources will be reduced to 50% of currently planned levels. This reduction is in anticipation of current DR customers electing not to renew DR contracts due to uncertainty associated with penalties for non-performance. This assumption will be revisited in future IRP's as participation in the Company's proposed DR tariffs is realized.

APCo's 2016 IRP assumed 2/3 of the nameplate capacity (385MW of the 585MW available) from the Smith Mountain pumped storage site as its Capacity Performance rating. The details of how FRR entities will be treated under the Capacity Performance rule have become clearer. In APCo's 2017 IRP, this clarity led to using the full nameplate capacity of Smith Mountain when determining the Capacity Performance rating in this IRP.

This IRP assumes that during the 2020/2021 PJM planning year all capacity resources will need to be Capacity Performance products. In accordance with PJM's Capacity Performance rule, some resources could be combined, or "coupled", to meet Capacity Performance requirements. The assumed values for intermittent resources included in this IRP are based on these resources being coupled from a capacity performance perspective. The Company will continue to investigate methods to maximize the utilization of its current (and future) intermittent resource portfolio within that construct. An example could be the coupling of run-of-river hydro, pumped storage, wind and potential solar resources in a manner that would mitigate non-performance risk. The potential exists that a strategy could be formulated such that a portion of the over 200MW of run-of-river hydro generating capability, which is not currently recognized in APCo's ultimate Preferred Plan 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 further into the future.

3.3 Environmental Issues and Implications

It should be noted that the following discussion of environmental regulations is based on the assumptions made by the Company and incorporated into its analysis within this IRP. Activity including but not limited to Presidential Executive Orders, litigation, petitions for review, and EPA proposals may delay the implementation of these rules, or eventually affect the requirements set forth by these regulations. While such activity has the potential to materially change the regulatory requirements the Company will face in the future, those potential changes cannot be reasonably foreseen or estimated at this time. The Company is committed to closely following developments related to environmental regulations, and will update its analysis of compliance options and timelines when sufficient information becomes available to make such judgments. At this time, the Company does not have sufficient information regarding these developments to justify the alteration of current compliance assumptions and plans.

3.3.1 Mercury and Air Toxics Standards (MATS)

The final Mercury and Air Toxics Standard (MATS) Rule became effective on April 16, 2012 and required compliance by April 16, 2015.[6] This rule regulates emissions of hazardous air pollutants from coal and oil-fired Electric Generating Units (EGUs). Hazardous air pollutants regulated by this rule are: 1) mercury; 2) certain non-mercury metals such as arsenic, lead, cadmium and selenium; 3) certain acid gases, including Hydrochloric Acid (HCl); and 4) certain organic hazardous air pollutants. The MATS Rule establishes stringent emission rate limits for mercury, filterable Particulate Matter (PM) as a surrogate for all non-mercury toxic metals, and HCl as a surrogate for all acid gases. Alternative emission limits were also established for the individual non-mercury metals and for sulfur dioxide (SO_2) (alternate to HCl) for generating units that have operating Flue Gas Desulfurization (FGD) systems. The rule regulates organic hazardous air pollutants through work practice standards.

In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit remanded the Mercury and Air Toxics Standards (MATS) rule for further proceedings consistent with the U.S. Supreme Court's decision that the EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants.

[6] APCo received an extension through May 31, 2015 for Kanawha River Units 1&2, Sporn Units 1&3, Glen Lyn Units 5&6, and Clinch River Unit 3. An extension to April 16, 2016 was received for Clinch River Units 1&2.

The EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. In April 2016, the EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. Petitions for review of the EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument is scheduled in May 2017, but in April 2017 the EPA requested that oral argument be postponed to facilitate its review of the rule. The rule remains in effect.

APCo's supercritical units (Amos Units 1-3, Mountaineer Unit 1) are able to meet the MATS Rule requirements as a result of previously installed control equipment including Selective Catalytic Reduction (SCR) for mitigation of nitrogen oxide (NO_x) emissions and FGD systems for mitigation of SO_2 emissions, which together achieve a co-benefit removal of mercury as well. APCo's sub-critical units could not meet all of the MATS requirements in their existing configuration, and have either been refueled to consume natural gas (Clinch River Units 1 & 2) or were retired as of June 1, 2015 (Kanawha River Units 1 & 2, Glen Lyn Units 5 & 6, Clinch River Unit 3 and Sporn Units 1 & 3).

3.3.2 Cross-State Air Pollution Rule (CSAPR)

In 2011, the EPA issued CSAPR as a replacement for the Clean Air Interstate Rule (CAIR), a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind nonattainment with the 1997 ozone and PM NAAQS. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. In 2012, the court issued a decision vacating and remanding CSAPR to the EPA with instructions to continue implementing CAIR until a replacement rule is finalized. The EPA and other parties filed a petition for review in the U.S. Supreme Court, which was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the EPA's motion. The parties filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place.

In October 2016, a final rule was issued to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduces ozone season budgets in many states and discounts the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed.

APCO will rely on the installed SCR and FGD systems' respective emission reductions of NO_x and SO_2, the use of allocated NOx and SO_2 emission allowances in conjunction with adjusted banked allowances, and the purchase of additional allowances as needed through the open market to comply with CSAPR Phase 2 and the CSAPR Update.

3.3.3 National Ambient Air Quality Standards (NAAQS)

The Clean Air Act (CAA) requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. The EPA issued new, more stringent national ambient air quality standards (NAAQS) for PM in 2012, SO_2 in 2010 and ozone in 2015. Reviews of the PM, NO_2 and SO_2 standards are underway. States are still in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the 2010 SO_2 NAAQS and may develop additional requirements for our facilities as a result of those evaluations. In April 2017, the EPA requested a stay of proceedings in the U.S. Circuit Court for the District of Columbia Circuit where challenges to the 2015 ozone standard are pending, to allow reconsideration of that standard by the new administration. Management cannot currently predict the nature, stringency or timing of additional requirements for our facilities based on the outcome of these activities.

3.3.4 Coal Combustion Residuals (CCR) Rule

In April 2015, the EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and FGD gypsum generated at some coal-fired plants.

The final rule became effective in October 2015. The EPA regulates CCR as a non-hazardous solid waste by its issuance of new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four year implementation period. Challenges to the rule by industry associations of which AEP is a member are proceeding.

In December 2016, the U.S. Congress passed legislation authorizing states to submit programs to regulate CCR facilities, and the EPA to approve such programs if they are no less stringent than the minimum federal standards. The EPA may also enforce compliance with the minimum standards until a state program is approved or if states fail to adopt their own programs.

While the necessary site-specific analyses to determine the requirements under the final CCR Rule are ongoing, initial estimates of anticipated plant modifications and capital expenditures are factored into this IRP. It should be noted that APCo's Amos and Mountaineer Plants are already equipped with dry fly ash handling systems and dry ash landfills to meet current permit requirements, and that these projects also position the plants well for future compliance with the CCR rulemaking.

Based on the timing of the gas conversion for Units 1 and 2 at the Clinch River Plant, that landfill is not subject to the requirements of the final CCR Rule. However, the ash pond 1a/1b is, as an inactive surface impoundment captured by the rule.

3.3.5 Effluent Limitations Guidelines

In November 2015, the EPA issued a final rule revising Effluent Limitation Guidelines (ELG) for electricity generating facilities. The final rule establishes limits on flue gas desulfurization wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, a petition for reconsideration of the rule was filed with the EPA. In April 2017, the EPA announced its intent to grant reconsideration of the rule and issued a stay of the rule's future compliance deadlines. The EPA also filed a motion seeking a stay of the litigation in the U.S. Court of Appeals for the Fifth Circuit for 120 days, which was granted by the Court on April 24, 2017.

To ensure compliance with the ELG Rule, APCo has determined that wastewater treatment projects will be necessary at its supercritical coal-fired units and these have been considered as part of the respective long-term unit evaluations. Both the Amos and Mountaineer Plants utilize wet bottom ash handling systems, while the Amos Plant operates a FGD wastewater treatment system without biological treatment. Initial estimates of the necessary plant modifications and capital expenditures to comply with the ELG Rule are not expected to impact APCo's future resource decisions. Similar to the effect on CCR compliance mentioned above the existing dry fly ash handling systems and dry ash landfills, along with existing wastewater treatment plants for FGD blowdown at both the Amos and Mountaineer Plants position them well for compliance with the final ELG rulemaking.

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3.3.6 Clean Water Act 316(b) Rule

A final rule under Section 316(b) of the Clean Water Act was issued by the EPA on August 15, 2014, with an effective date of October 14, 2014, and affects all existing power plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water intake systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats.

Facilities with existing closed cycle recirculating cooling systems, including the Amos, Clinch River, Dresden, and Mountaineer Plants, may not be required to make any technology changes. This determination would be made by the applicable state environmental agency during the plants' next National Pollutant Discharge Elimination System (NPDES) permit renewal cycle. If additional capital investment is required, the magnitude is expected to be relatively small compared to the investment that could be needed if the plants were not equipped with cooling towers. Given that all of APCo's active units are already equipped with either natural draft, hyperbolic or forced draft mechanical cooling towers, and these units withdraw less than 125 million gallons of water per day, the anticipated impact of the 316(b) rule is assumed to be limited to the installation of flow monitoring equipment.

3.3.7 New Source Review Consent Decree

In December 2007, AEP companies entered into a settlement of outstanding litigation (Consent Decree) around New Source Review compliance. Pursuant to the terms of the settlement, AEP has completed environmental retrofit projects on its Eastern units, is operating the units under a declining cap on total SO_2 and NO_x emissions, and will install additional control technologies at certain units. For APCo, the most significant control projects under the

Consent Decree involved continuing the installation of previously planned SCR and FGD systems at Amos Units 1-3 and Mountaineer Unit 1. Additionally, the Consent Decree called for APCo's Clinch River units (1-3) to install Selective Non-Catalytic Reduction (SNCR) for NO_x reduction. The retrofits to the APCo plants have been completed.

Two minor modifications to the Consent Decree were made in 2009 and 2010 to adjust the FGD retrofit dates for APCo's Amos Units 1 and 2. In May 2013, a third modification to the Consent Decree was approved that contains specific retrofit requirements for APCo's affiliates, as well as reductions to the caps for SO_2 emissions for the AEP eastern fleet. In January 2017, a fourth modification to the Consent Decree was approved to facilitate the sale of the Gavin units. It is projected that the system caps, as modified, will have little or no effect on the operation of APCo's electric generating facilities.

The annual NO_X and SO_2 caps contained within the Modified New Source Review Consent Decree for the coal units owned by AEP-East operating companies, including APCo, are displayed in Table 2 and Table 3.

Table 2. Consent Decree Annual NO_x Cap for AEP-East

Calendar Year	Annual Tonnage Limitations for NO_x
2009	96,000
2010	92,500
2011	92,500
2012	85,000
2013	85,000
2014	85,000
2015	75,000
2016, and each year thereafter	72,000

Table 3. Modified Consent Decree Annual SO_2 Cap for AEP-East

Calendar Year	Annual Tonnage Limitations for SO_2
2016	145,000
2017	145,000
2018	145,000
2019-2021	113,000
2022-2025	110,000
2026-2028	102,000
2029, and each year thereafter	94,000

3.3.8 Carbon Dioxide (CO_2) Regulations, Including the Clean Power Plan (CPP)

On October 23, 2015, the EPA published two final rules to regulate carbon dioxide (CO_2) emissions from fossil fuel-based electric generating units. The EPA finalized New Source Performance Standards (NSPS) under Section 111(b) of the CAA that apply to new fossil units, as well as separate standards for modified or reconstructed existing fossil steam units. Separately, the EPA finalized a rule referred to as the CPP, which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the CAA. The EPA also issued for public comment a proposed federal plan to implement the CPP if states fail to submit or do not develop an approvable state plan for compliance.

The EPA finalized CO_2 NSPS for *new* sources at 1,400 pounds CO_2 per megawatt-hour gross (lb/MWh-g) for new coal units based on the agency's assumption that carbon capture and storage technology can be implemented. Reconstructed coal units have a limit of 1,800 or 2,000 lb/MWh-g based on the size of the unit. The NSPS for modified coal units is site-specific based on historical operations. For new and reconstructed Natural Gas Combined-Cycle (NGCC) units, the NSPS was finalized at 1,000 lb/MWh-g based on the use of efficient combustion turbine designs. No limit was proposed for modified NGCC or simple cycle units.

The CPP for *existing* sources establishes separate, uniform national CO_2 emission performance rates for fossil steam units (coal-, oil-, and gas-steam based units) and for stationary combustion turbines (which the EPA defines as natural gas combined cycle units). The rates were established based on EPA's application of three building blocks as the Best System of Emission Reduction (BSER) for existing fossil generating units. Block 1 assumes efficiency improvements at existing coal units. Building Block 2 assumes the increased use of NGCC units that would displace coal based generation. Building Block 3 entails the expansion of renewable energy sources that would displace generation from both coal and NGCC units. Excluded from the BSER process was consideration of nuclear energy, simple cycle gas turbines, and energy efficiency measures (originally proposed by the EPA as Building Block 4), all of which had been included in the 2014 proposed rule.

From the national emission performance rates, the EPA also developed equivalent state-specific emission rate goals and equivalent state-specific mass-based goals as alternatives for the interim period (2022-2029) and the final period (2030 and beyond). States may use the national emission performance rate, the interim and final emission rate goals, or the interim and final mass-based goals to develop their state plans, or demonstrate that alternative goals are justified based on state-specific circumstances and seek EPA approval through the state plan. For the states in which APCo-owned or purchased fossil generation reside, EPA's state-specific equivalent mass-based goals for the interim and final compliance periods - are included in Table 4. Table 5 contains the equivalent rate-based goals for the same compliance periods.

Table 4. APCo State Mass-Based Clean Power Plan Goals

	Short Tons of CO_2				
	Annual Average Interim Goal - Step 1	Annual Average Interim Goal - Step 2	Annual Average Interim Goal - Step 3	Annual Average Interim Goal	Annual Average Final Goal
State	**2022 - 2024**	**2025 - 2027**	**2028 - 2029**	**2022 - 2029**	**2030+**
Indiana	92,010,787	83,700,336	78,901,574	85,617,065	76,113,835
Ohio	88,512,313	80,704,944	76,280,168	82,526,513	73,769,806
Virginia	31,290,209	28,990,999	27,898,475	29,580,072	27,433,111
West Virginia	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342

Table 5. APCo State Rate-Based Clean Power Plan Goals

	lb/MWh CO_2 Emission Rate				
	Annual Average Interim Goal - Step 1	Annual Average Interim Goal - Step 2	Annual Average Interim Goal - Step 3	Annual Average Interim Goal	Annual Average Final Goal
State	2022 - 2024	2025 - 2027	2028 - 2029	2022 - 2029	2030+
Indiana	1,578	1,419	1,309	1,451	1,242
Ohio	1,501	1,353	1,252	1,383	1,190
Virginia	1,120	1,026	966	1,047	934
West Virginia	1,671	1,500	1,380	1,534	1,305

Note: As will be described later in this document, APCo has assumed a composite state approach when addressing the implication that the CPP could have across its existing fossil generation sources. For example, when determining the impacts of a (intensity) rate-based implementation approach, it was assumed that all resources, regardless of location, would utilize a rate-based approach. This was done for both consistency and to simplify the overall implications to the whole of APCo.

The EPA delayed the start of the initial compliance period from 2020 in the proposed rule to 2022 in the final rule. States that decide to develop a state plan to implement the CPP have the option of developing a single state plan, a multi-state plan, or a "trading ready" plan that satisfies the EPA's requirements for linking state plans to facilitate multi-state trading of emissions allowances among states that use a mass-based approach, or emission rate credits among states that use a rate-based approach. A final state plan or request for extension must be submitted to the EPA by September 6, 2016. A two-year extension for submitting a final state plan is available if certain criteria are met by the state.

The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review.

In March 2017, the EPA filed in the U.S. Court of Appeals for the District of Columbia Circuit notice of 1) an Executive Order from the President of the United States titled "Promoting Energy Independence and Economic Growth" directing the EPA to review the Clean Power Plan and related rules; 2) the EPA's initiation of a review of the Clean Power Plan and 3) if the EPA determines appropriate, a forthcoming rulemaking related to the Clean Power Plan consistent with the Executive Order. In this same filing, the EPA also presented a motion to hold the litigation in abeyance until 30 days after the conclusion of review and any resulting rulemaking. The motion is still pending.

3.3.8.1 The Proposed Federal Plan and Model Rules

On the same day that the CPP was published, the EPA proposed model rules that states can use to develop "trading ready" plans based on either the state rate or mass goals, and that will provide a framework for the development of a federal plan if a state plan is either not submitted or is disapproved by EPA. These proposed rules can also be used as a backstop regulatory measure for a "state measures" plan that includes programs or activities beyond those that were included in the "BSER" the EPA developed as a basis for the state plans and model rules. As proposed rules, which are subject to public notice and comment, there is the potential that key elements of the model rules or the EPA's proposed approach to developing a federal plan could change significantly before they are finalized and implemented.

The EPA intends to finalize model rules for both the rate-based state planning option and the mass-based state planning option. The EPA has proposed the same two options for a federal plan, but the EPA has indicated that it would prefer to finalize only one approach that would be applied to all states that become subject to a federal plan. This would allow interstate trading among all states that become subject to a federal plan, and other states that have adopted a trading ready plan based on the same compliance pathway (rate or mass).

However, there are several key distinctions between the proposed federal plan and state plan options which could potentially affect compliance decisions and customer costs. Under the rate-based federal plan, the EPA would not allow for the use of EE measures to generate

Emission Reduction Credits (ERCs). This could significantly reduce the supply of ERCs for a state subject to a federal plan. Also, under the mass-based federal plan, the EPA would use an allowance allocation methodology based on historic generation that includes allowance set-asides to address leakage, including providing allowances to new renewable energy sources and natural gas combined cycle units that achieve utilization rates above 50 percent. While APCo has attempted to approximate the effect of such measures within this filing, many elements of the federal plan will remain uncertain and speculative until finalized.

Following the President's Executive Orders directing the EPA to review the CPP, the EPA announced on April 3, 2017, that it is withdrawing both the Model Trading Rules and the Clean Energy Incentive Program Design Details.

Following the President's Executive Order directing the EPA to review the CPP, the EPA announced on April 3, 2017, that it is withdrawing both the Model Trading Rules and the Clean Energy Incentive Program Design Details.

The following Sections of this IRP, from 3.3.8.2 through 3.3.8.8, are based on requirements set by the Commission in the SCC's Final Order on APCo's 2015 IRP, and continue to be included in the Company's IRP for information purposes. While there has been much activity regarding the CPP in recent months, none of that activity has yet resulted in substantial changes to the rule or its implementation. For that reason the Company continues to include this analysis in its IRP, until such time that development regarding the regulation will warrant updating the analysis included in these sections.

3.3.8.2 Virginia-Specific Target Rates Versus Subcategory-Specific Rates

If Virginia elects to pursue a state plan approach that is based on a carbon intensity rate (i.e., pounds of CO_2 per MWh of electricity produced (lb./MWh)), there are several options for program design. As noted above, the EPA has established uniform national emission rates for two sub-categories: (1) existing fossil steam units (any unit that fires coal, oil, or natural gas alone or in combination with other fuels to produce steam in a boiler which is then used to produce electricity); and (2) existing natural gas-fired combined cycle units. The interim rates for steam units must average 1,534 lb./MWh over the period from 2022-2029, and eventually decline to 1,305 lb./MWh in 2030 and thereafter. For gas combined cycle units the interim rate must average 832 lb./MWh during 2022-2029 and decline to 771 lb./MWh in 2030 and thereafter.

These emission rates cannot be achieved in practice by existing units, whose emission rates vary significantly, but in 2012 were about 2,200 lb./MWh for coal steam units and about 900 lb./MWh for combined cycle units on a national basis. Accordingly, if these emission rates become enforceable obligations for each affected unit located within Virginia, then the owners and operators of each affected unit must collect a sufficient number of ERCs to demonstrate compliance on a unit-specific basis through the calculations provided in EPA's emission guidelines. Virginia can choose to participate in multi-state trading schemes for ERCs with states also utilizing a subcategory rate approach in order to allow unit owners and operators to take advantage of the benefits of a broader trading market.

Alternatively, the EPA has calculated an emission rate target for Virginia, based upon the characteristics of the fleet of affected units operating in Virginia in 2012, and their contribution to the total amount of electricity generated by affected units in that year. During the interim period, Virginia's state-specific target begins at 1,120 lb./MWh and ends at 934 lb./MWh in 2030 and beyond. If the state-specific target rates are used as the basis for the CPP, owners and operators of affected units must still assure that in the aggregate, they possess sufficient ERCs to demonstrate compliance on a state-wide basis. However, use of a Virginia specific rate approach would restrict the potential for ERC trading to credits solely generated within Virginia.

APCo would expect that, given the multi-state operations of the utilities serving the majority of Virginia electricity customers, and the advantages of participating in a multi-state trading program, choosing a program design based on the subcategory-specific rates and allowing interstate trading of ERCs would provide the greatest benefits for Virginia customers. However, further analysis of these options and their impacts should be undertaken using a production cost model capable of analyzing multiple states and their potential plan structures before a firm commitment to a particular program design is made.

3.3.8.3 Leakage and Treatment of New Units

The EPA requires states that elect to adopt a mass-based emission allowance program instead of the unit-specific emission rates or equivalent state-specific rate goals described in the emission guidelines to include measures to address what it terms "leakage." The EPA describes the concept of "leakage" as follows:

> "Where shifts in generation to unaffected fossil-fuel sources result in increased emissions, relative to what would have happened had generation shifts consistent with the BSER occurred."

In general, EPA's modeling projects that if states adopt a mass-based allowance program instead of a rate-based program, new NGCC units will displace a larger portion of the generation from existing sources, and total sector emissions (that is, emissions from both new and existing sources) will be greater.

The EPA provides two methods to address the "leakage" issue in a mass-based state plan. First, states can elect to include new units in the mass-based compliance program, and the EPA has calculated a "new source complement" that provides additional allowances to accommodate the new sources. Alternatively, the EPA has designed two allowance set-asides that would be withheld from general distribution, and instead awarded to new renewable resources or existing NGCC units that operate at capacity factors above 50 percent. While the new source complement does permanently restrain growth in emissions from electric generating units, the set-asides may not have the same effect in individual states, particularly if the state participates in a broader regional or national trading system.

EPA's authority to regulate total sector emissions under a program developed under Section 111(d), which is particularly targeted at existing units, is questionable, and the methodology used by the EPA to calculate the new source complement may not be sound and provides no flexibility for unanticipated changes. States are afforded an opportunity to demonstrate that "leakage" does not need to be addressed in their plans. AEP continues to work with its states to explore ways to make such a demonstration.

3.3.8.4 Potential for Early Action ERCs/Allowances

As part of the final emission guidelines, the EPA proposed to include a Clean Energy Incentive Program (CEIP) as a mechanism to award up to an additional 300 million ERCs or allowances to certain types of projects that commence construction after the date for submittal of a final plan and operate during 2020 and 2021. For purposes of the federal plan that the EPA would administer, only wind and solar renewable energy projects that produce revenue-quality metered electricity would be eligible. States can include broader categories of renewable resources in the plans they submit for EPA approval. The EPA has also proposed to award ERCs or allowances to certain energy efficiency projects in low income communities, but the details of the program have not been fully developed.

The CEIP provides credit for a very narrow range of activities, and requires states to "match" the federal credits or allowances with ERCs or allowances that are "borrowed" from their state budgets. The EPA has solicited comments on all aspects of the CEIP and may substantially change the program in its final model rules. Until there is some certainly regarding eligibility and the mechanics of applying for and receiving credit for early actions, it is not possible to quantify its impact.

3.3.8.5 Trading of Emissions Allowances or Emission Reduction Credits (ERCs) and Role of Renewable Resources

APCo currently owns two existing natural gas-fired steam generating units in Virginia, four existing coal-fired steam generating units in West Virginia, an existing NGCC facility in Ohio, and purchases energy from an existing coal-fired generating station in Ohio and an existing coal-fired generating facility in Indiana. APCo also owns existing hydroelectric facilities in Virginia and West Virginia, and purchases power from renewable energy facilities in West Virginia, Indiana and Illinois, but these facilities are not eligible to participate in any of the programs under the CPP.

Adoption of a regional or national trading system for allowances or ERCs by the states within which APCo is operating is likely to reduce the overall costs of compliance and allow for greater compliance flexibility. It may not be necessary to define a specific "region" in order to take advantage of the benefits of a trading program. EPA guidelines would allow states to trade freely with other states that choose the same fundamental program design (rate- or mass-based) and whose "currency" (allowances or ERCs) are generated and tracked through an EPA-administered or EPA–approved program as outlined in the model trading rules.

The benefits gained by participation in a broader market-based system result from the market's greater liquidity which allows for more efficient use of available compliance instruments. Interstate trading would also enable affected sources to take advantage of the best geographic locations available to generate renewable energy to either provide supplemental energy for Virginia customers under a mass-based program or generate ERCs to assist in compliance with a rate-based program. It is not possible to reach a firm conclusion about the most cost-effective approach for Virginia without more detailed information and better insight into the final framework of the CPP, and the approaches that other states are likely to take. However, prior analyses by various regional transmission organizations, including PJM Interconnection, LLC, the Midwest Independent System Operator (MISO), and the Southwest Power Pool, suggest that a multi-state trading program would be more cost-effective. Further analysis by these organizations may bring better focus to this issue.

It seems unlikely that a state-specific program with limited in-state trading would be the most cost-effective option for APCo customers under either a rate-based or mass-based approach. Broader markets generally produce more cost-effective reductions, and several of Virginia's utilities have operations in multiple states, so compliance planning and optimization of the most cost-effective compliance strategies across multiple jurisdictions would be facilitated by a more robust interstate trading program.

3.3.8.6 Other States' Compliance Planning Approaches

As of the date of this filing, Indiana, Ohio, and West Virginia have not determined specific compliance planning approaches. As a result of the stay issued by the U.S. Supreme

Court, there are currently no additional compliance activities planned by these states until after judicial review is completed.

3.3.8.7 Long-Term Recommendations

Given the significant issues regarding EPA's authority to adopt and implement the CPP, the changes that might be made to the proposed federal plan and model rules based on comments received, and the limited state planning that has occurred, it is not possible to provide any long-term recommendations at this time. However, as discussed later in this Report, the Company believes that the resource plan being proposed in this IRP should preserve reasonable CPP implementation optionality regardless of the rule's ultimate outcome and, with that, any attendant future cost exposures to its customers.

3.3.8.8 Potential Need for Changes in Virginia Law to Implement the CPP

Because no specific information about the potential structure of a state plan to implement the CPP is available, it is difficult to provide any comprehensive view of the changes that might be needed to Virginia law. Currently, the Air Pollution Control Board (the Board) has authority to develop and adopt regulations governing air pollutant emissions from stationary sources like power plants, but beyond regulating air emissions, the Board has no regulatory authority over the operation of existing electric generating units, nor any authority to require the construction or use of specific types of new generation, particularly non-emitting forms.

The General Assembly has given the Board limited authority to develop emissions trading programs in Code § 10.0-1322.3. The General Assembly authorized the Board to develop emissions trading programs solely for the purpose of achieving and maintaining the national ambient air quality standards (NAAQS) under Section 108 of the CAA. Such programs must result in net emissions reductions, create economic incentives for reducing air emissions, and allow for continued economic growth. In addition, for electric generating units specifically, such programs must foster competition and encourage the construction of new clean generating units. Specific requirements for new unit set-asides, offsets, trading with mobile sources, and consideration of allocations are also provided in the statute. Regulations adopted by the Board cannot prohibit trading of credits or allowances between private industries, provided that trades do not adversely impact Virginia air quality. Substantial additional authority would have to be granted to the Board by the General Assembly to fully implement the CPP.

Certain aspects of the CPP may also conflict with Virginia's integrated resource planning structure or other aspects of Virginia utility law and regulations. For example, Virginia's IRP authorizing statutes direct electric utilities to formulate a plan that "is most likely to provide the electric generation supply needed to meet the forecasted demand, net of any reductions from demand side programs, so that the utility will continue to provide reliable service at reasonable prices over the long term. " Va. Code § 56-598 2a. An IRP should also "reduc[e] load growth and peak demand growth through cost-effective demand reduction programs. " *Id.* at 1c. Moreover, the Commission's Integrated Resource Planning Guidelines ("Guidelines") direct that utilities provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side and demand side options, Guidelines § F7, and engage in a "comprehensive analysis of all existing and new resource options . . . necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period. " Guidelines at § C 2.

In anticipation of the CPP, the Virginia General Assembly enacted Senate Bill 1349, establishing the Virginia Transitional Rate Period. *See* Virginia Code §§ 56-585.1:1 (Transitional Rate Period: review of rates, terms and conditions for utility generation facilities); 56-599 (Integrated Resource Plan Required). The legislation directed the Commission to report to legislators annually on the projected cost and anticipated rate impacts of various CPP compliance options. Va. Code § 56-599 A; 56-585.1:1 F1-2. In order to fulfill these requirements, the Commission ordered electric utilities to provide in their 2016 IRPs "multiple plans that are each compliant with the Clean Power Plan, under both a mass-based approach and an intensity-based approach . . . ." *See, e.g.* In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597, *et seq.*, Case No. PUE-2015-00036, Final Order entered February 1, 2016 at 4-5). It also ordered APCo to include in its IRP "a least-cost compliant plan where the Plexos model is allowed to choose the least-cost path given the emission constraints imposed by the Clean Power Plan." *Id.* at 4.

Assuming the CPP is implemented in its current form after review by the U.S. Supreme Court, APCo's least-cost compliant plan will depend not only on the choices made by Virginia regulators, but also on the choices made by regulators in other states. While Virginia could attempt to structure its CPP state plan submittal to allow for separate CPP compliance pathways for each regulated utility that represents a "least-cost compliant plan" based on the current integrated resource planning statutes and regulations, Virginia legislators may need to provide utilities with greater flexibility in formulating such plans, and to allow the Commission greater discretion in evaluating a CPP-compliant IRP. EPA's model rules contemplate a much different approach, where multiple states adopt "trading ready" programs that can interact with one another.

In addition, statutes and regulations governing the selection of individual resource options may need to be harmonized with whatever state or federal CPP compliance plan emerges, as well as with each other. Virginia utility law currently provides utilities with a menu of resource options with which to meet forecasted demand and ensure reliability of service. The CPP, on the other hand, sets broad emissions targets, but does not mandate the means by which individual utilities must achieve compliance. During Virginia's Transitional Rate Period retirement of an electric power generation facility is restricted pending CPP implementation. Va. Code § 56-585.1:1 E. The statute also creates incentives for construction or purchase of certain solar generation facilities located within the Commonwealth and establishes a statutorily-mandated, *prima facie* finding that such facilities are in the public interest regardless of whether they are located within the utility's service territory. Va. Code § 56-585.1:1 G. Other, non-solar new generation facilities remain subject to approval based on a finding that such facilities are "necessary to enable the public utility to furnish reasonably adequate service and facilities at reasonable and just rates." Va. Code § 56-234.3. Utility-sponsored DSM programs, on the other hand, are subject to approval according to a rigorous cost/benefit analysis. 20 VAC 5-304-20; 20 VAC 5-304-30. The legislature may need to consider the impact of these provisions on the practicality of implementing either a state or federal plan, and adjust the requirements for approval of potentially CPP-compliant resource options.

Based on all of the foregoing considerations, and others that have not yet been identified, the existing authorities granted to the Board and/or the Commission may not be sufficient to create an optimal state plan, or facilitate the implementation of a federal plan as envisioned by the CPP. However, obligations related to the development of a state plan have been stayed, and the federal plan has not yet been finalized, so it is not possible at this time to describe any necessary state law changes with specificity.

3.4 APCo Current Demand-Side Programs

3.4.1 Background

DSM refers to, for the purposes of this IRP, utility programs, including tariffs, which encourage reduced energy consumption, either at times of peak consumption or throughout the day/year. Programs or tariffs that reduce consumption primarily at periods of peak consumption are DR programs, while around-the-clock measures are typically categorized as EE programs. The distinction between DR and EE is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.

Included in the load forecast discussed in Section 2.0 of this Report are the demand and energy impacts associated with APCo's DSM programs that have been approved in Virginia and West Virginia prior to preparation of this IRP. As will be discussed later, within the IRP process, the potential for additional or "incremental" demand-side resources, including EE activity—over and above the levels embedded in the load forecast—as well as other grid related projects such as Volt VAR Optimization (VVO), are modeled on the same economic basis as supply-side resources. However, because customer-based EE programs are limited by factors such as customer acceptance and saturation, an estimate as to their costs, timing and maximum impacts must be formulated. For the year 2017, the Company anticipates 162MW of peak DR (total company basis); consisting of 13MW and 149MW of "passive" EE and "active" DR activity, respectively.[7] In 2020, when Capacity Performance is in effect, the Company anticipates "active" DR will be reduced to 119MW, as discussed in Section 3.2.1.

3.4.2 Impacts of Existing and Future Codes and Standards

The EISA requires, among other things, a phase-in of heightened lighting efficiency standards, appliance standards, and building codes. The increased standards will have a pronounced effect on energy consumption as explained in Section 2.6. Many of the standards already in place impact lighting. For instance, since 2013 and 2014 common residential incandescent lighting options have been phased out as have common commercial lighting fixtures. Given that "lighting" measures have comprised a large portion of utility-sponsored EE programs prior to the phase-out, this pre-established transition is already incorporated into the SAE long-term load forecast modeling previously described in Section 2.4.4 and may greatly affect the market potential of utility EE programs in the near and intermediate term. Table 6 and Table 7 depict the current schedule for the implementation of new EISA codes and standards.

Table 6. Forecasted View of Relevant Residential Energy Efficiency Code Improvements

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Central AC	SEER 13; SEER 14 in South										
Room AC	EER 11.0										
Heat Pump	SEER 14.0/HSPF 8.0										
Water Heater (<=55gallons)	[redacted]										
Water Heater (>55gallons)	[redacted]										
Screw-in/Pin Lamps	Advanced Incandescent (20 lumens/watt)					[redacted]					
Linear Fluorescent	T8 (89 lumens/watt)			[redacted]							
Refrigerator	25% more efficient										
Freezer	25% more efficient										
Clothes Washer	1.29 IMEF top loader			[redacted]							
Clothes Dryer	3.73 Combined EF										
Furnace Fans	Conventional				[redacted]						

[7] "Passive" demand reductions are achieved via "around-the-clock" *EE* program activity as well as voluntary price response programs; "Active" DR is centered on summer peak reduction initiatives, including interruptible contracts, tariffs, and direct load control programs.

Table 7. Forecasted View of Relevant Non-Residential Energy Efficiency Code Improvements

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chillers	2007 ASHRAE 90.1										
Roof Top Units	EER 11.0/11.2										
PTAC	EER 11.7		[redacted]								
Heat Pump	EER 11.0/COP 3.3										
PTHP	EER 11.9/COP 3.3										
Ventilation	Constant Air Volume/Variable Air Volume										
Screw-in/Pin Lamps	Advanced Incandescent (20				[redacted]						
Linear Fluorescent	T8 (89 lumens/watt)			[redacted]							
High Intensity Discharge	EPACT 2005		[redacted]								
Water Heater	EF 0.97										
Walk-in Refrigerator/Freezer	EISA 2007		[redacted]								
Reach-in Refrigerator/Freezer	EPACT 2005		[redacted]								
Glass Door Display	EPACT 2005		[redacted]								
Open Display Case	EPACT 2005		[redacted]								
Ice maker	EPACT 2005			[redacted]							
Pre-rinse Spray Valve	1.6 GPM				[redacted]						
Motors	EISA 2007	[redacted]									

The impact of total energy efficiency, including codes and standards, is expected to reduce retail load by nearly 7%, as shown in Figure 8.

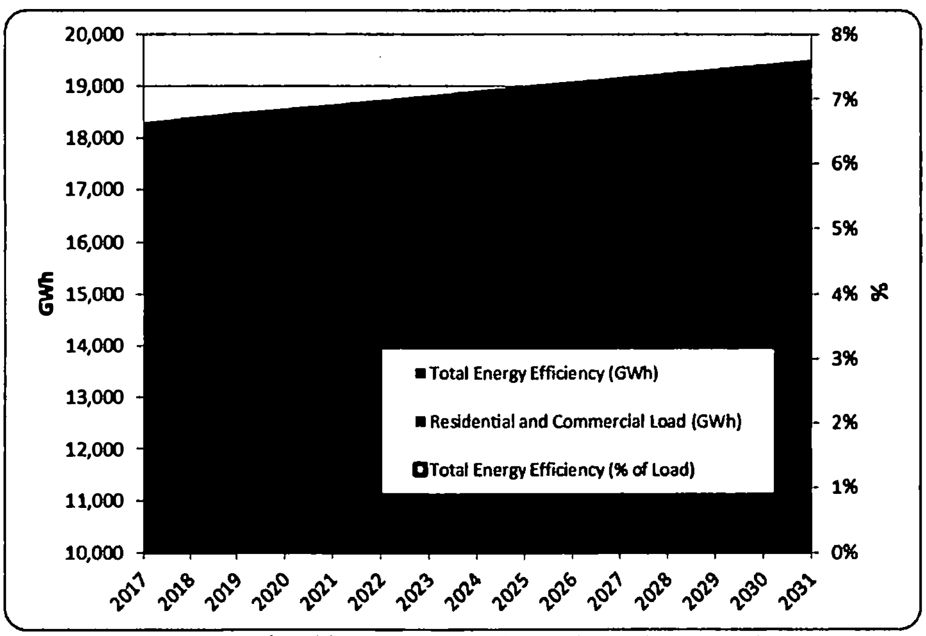

Figure 8. Total Energy Efficiency (GWh) Compared with Total Residential and Commercial Load (GWh)

3.4.3 Demand Response (DR)

Peak demand, measured in MW, can be thought of as the amount of power used at the time of maximum customer usage. APCo's maximum (system peak) demand is likely to occur on the coldest winter weekday of the year, in the morning. This happens as a result of the near-simultaneous use of electric heating by the majority of customers, as well as the normal use of other appliances and, commercial equipment, and (industrial) machinery. At other times during the day, and throughout the year, the use of power is less. In the context of capacity planning for PJM, it is the consumption of energy coincident with PJM's five highest summer peaks.

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 can be reduced. This can be addressed several ways via both "active" and "passive" measures:

- *Interruptible loads (Active DR).* 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 (Active DR).* 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 radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Time-differentiated rates (Active DR).* This 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) to as often as 15-minute increments in what is known as "real-time pricing." Accomplishing real-time pricing requires digital (smart) metering.
- *EE measures (Passive DR).* If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less.

- *Voltage Regulation (Passive DR).* Certain technologies can be deployed that allow for improved monitoring of voltage throughout the distribution system. The ability to deliver electricity at design voltages improves the efficiency of many end use devices, resulting in less energy consumption.

What may not be apparent is that, with the exception of EE and voltage regulation measures, the remaining DR programs do not significantly reduce the amount of energy consumed by customers. Less energy may be consumed at the time of peak load, but that energy will be consumed at some point during the day. For example, if rates encourage customers to avoid running their clothes dryer at 4:00 P.M.; they will run it at some other point in the day. This is often referred to as load shifting.

3.4.3.1 Existing Levels of Active Demand Response (DR)

APCo currently has active DR programs totaling 149MW of peak DR capability. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control. In 2015 APCo launched a DR program for residential customers. Demand reduction is achieved by cycling customer air conditioning units on and off during periods of high demand in the summer. Each participating resident is compensated for this service with a credit to their bill. The current Virginia program is designed to allow 3,000 residential customers to sign up each year during 2015, 2016, and 2017. Each block of 3,000 customers is estimated to provide up to 2.7MW in demand savings. APCo's West Virginia jurisdiction has a similarly sized program.

3.4.4 Energy Efficiency (EE)

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

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

EE measures will reduce the amount of energy consumed but 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. However, market barriers to EE may exist for the potential participant. To overcome participant barriers, a portfolio of EE 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 EE measure adoption.

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 IRP begins adding new demand-side resources in 2019 that are incremental to currently approved programs.

3.4.4.1 Existing Levels of Energy Efficiency (EE)

APCo currently has EE programs in place in its Virginia and West Virginia service territories. Both states have approved rate-design programs to promote EE programs. APCo has installed EE measures that reduced peak demand in 2017 by 12.9MW and reduced 2017 energy consumption by 83GWh.

3.4.5 Distributed Generation (DG)

DG typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. APCo's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate.

The economics of DG, particularly solar, continue to improve. Figure 9, below, charts the fairly rapid decline of expected installed solar costs, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) Installed Cost of Solar forecast.

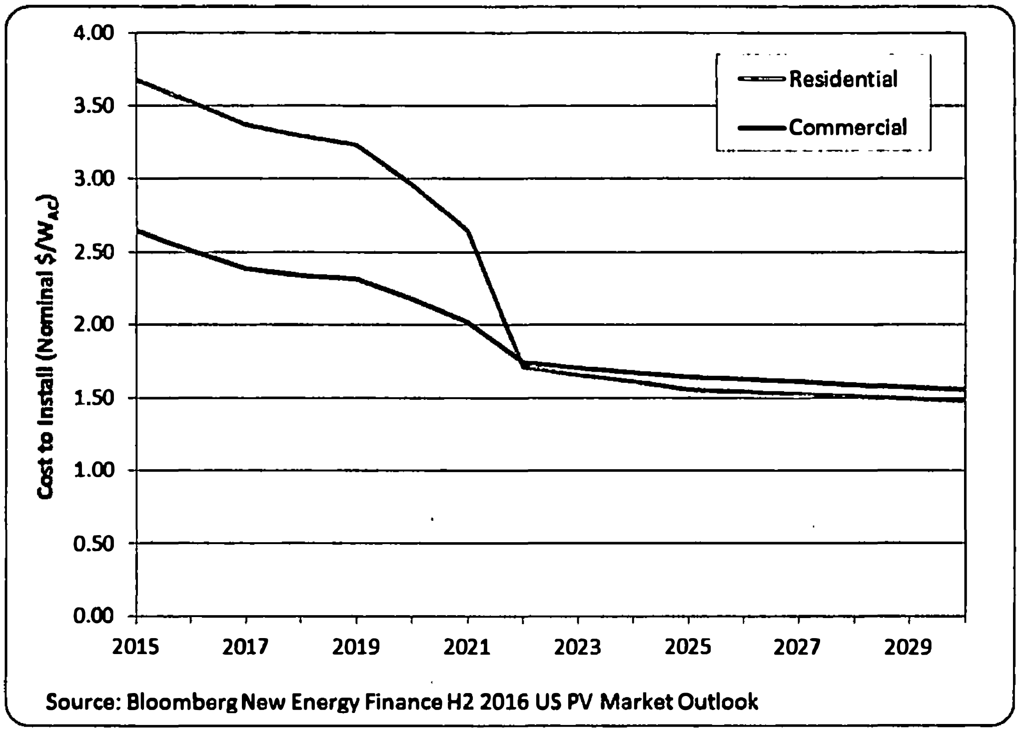

Figure 9. Residential and Commercial Forecasted Solar Installed Costs (Nominal $/W$_{AC}$) for APCo States

Prior to 2022, during the ITC phase out for residential systems, costs for residential customers are expected to decline rapidly. This decline, which is forecasted to bring residential costs down to commercial cost levels, is attributed to a shift from value-based pricing to cost-plus-margin pricing. Installers are expected to spend less on customer acquisition and less on customer specific solutions as they aim for the lowest cost installations possible.

While the cost to install residential solar continues to decline, the economics of such an investment are not favorable for the customer for a number of years. Figure 10, below, illustrates, by APCo state jurisdictional residential sector, the equivalent value a customer would need to achieve, on a dollars per watt-AC ($\$/W_{AC}$) basis, in order to breakeven on their investment, assuming a 25 year life of the installed solar panels based on the customer's avoided retail rate. Also included is the average cost of solar residential installations in PJM. Figure 10, below, shows that the current cost of residential solar exceeds the cost which would allow a customer to breakeven on an investment over a 25 year period.

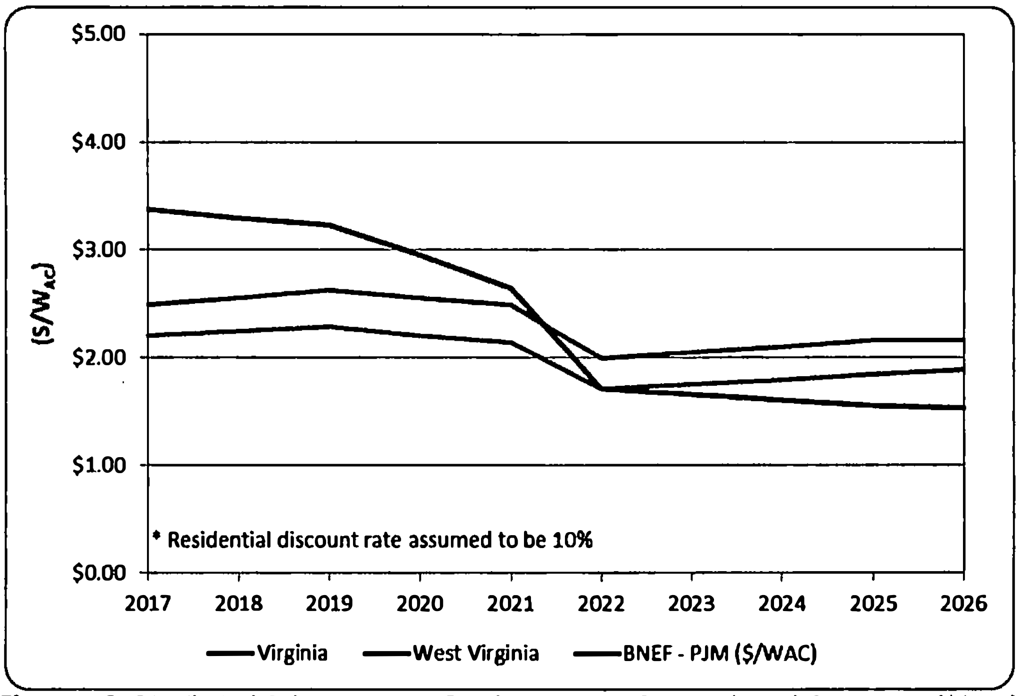

Figure 10. Distributed Solar Customer Breakeven Costs for Residential Customers ($\$/W_{AC}$)

A challenge of determining the value of a residential solar system is assigning an appropriate cost of capital or discount rate. Discount rates for residential investments vary dramatically and are based on each individual's financial situation. Figure 11, below, shows how the value of a residential customer's DG system can vary based on discount rate.

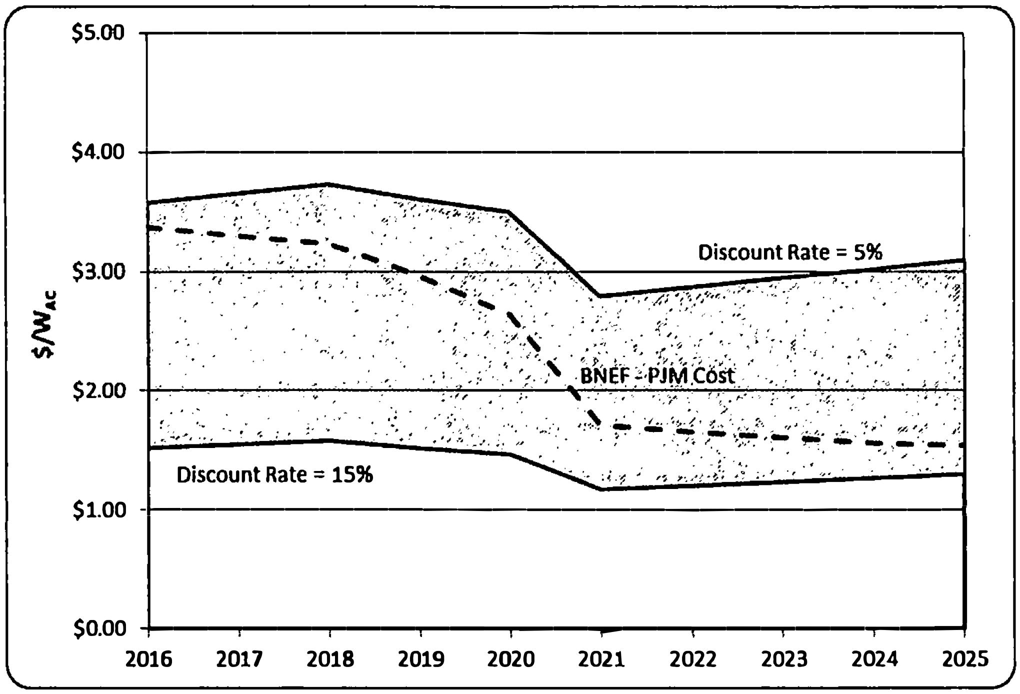

Figure 11. Range of Residential Distributed Solar Breakeven Values Based on Discount Rate

3.4.5.1 Existing Levels of Distributed Generation (DG)

As of the end of 2016 APCo has a total of 5.4MW of DG installed throughout the service territory, consisting of 0.2MW in Tennessee, 4.4MW in Virginia, and 0.8MW in West Virginia.

3.4.5.2 Load Characteristics of Net-Metered Customers

APCo's net-metered customers are able to realize energy "credits" during the times when generation from their rooftop solar system is greater than their own demand. This is particularly true for solar generators during summer months when rooftop panels are able to generate close to their rated capacity for more hours of the day. Figure 12 below, illustrates the average summer load profile for a representative customer with rooftop solar (blue line) and without rooftop solar (red line).

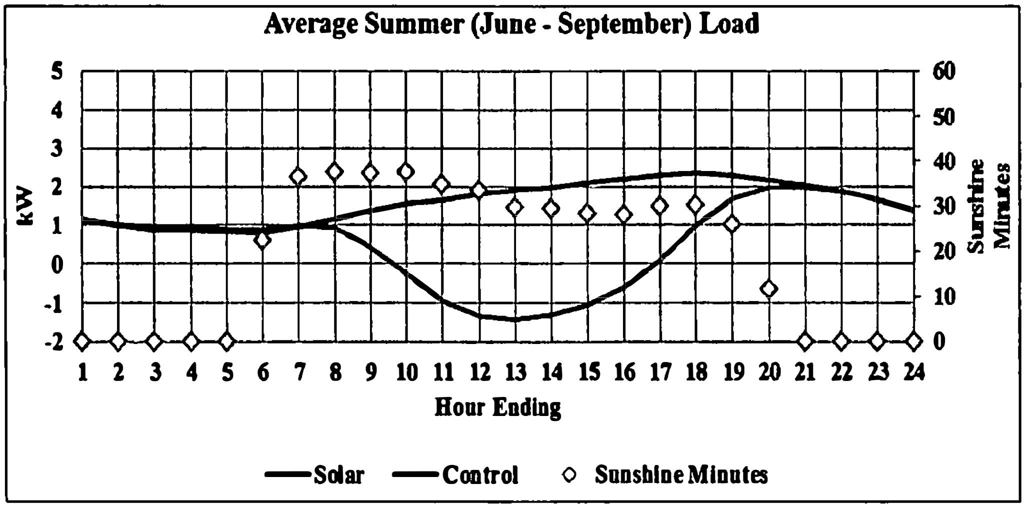

Figure 12. Average Summer (June – September) Load Profile for Representative Net-Metered Customer with Rooftop Solar Installation

Figure 12 indicates that on average, during summer months, from approximately 10am until 5pm, a customer with rooftop solar would be supplying electricity to the grid, as evident by the negative load requirement. Figure 13 illustrates the average winter load profile for a representative customer with rooftop solar (blue line) and without rooftop solar (red line).

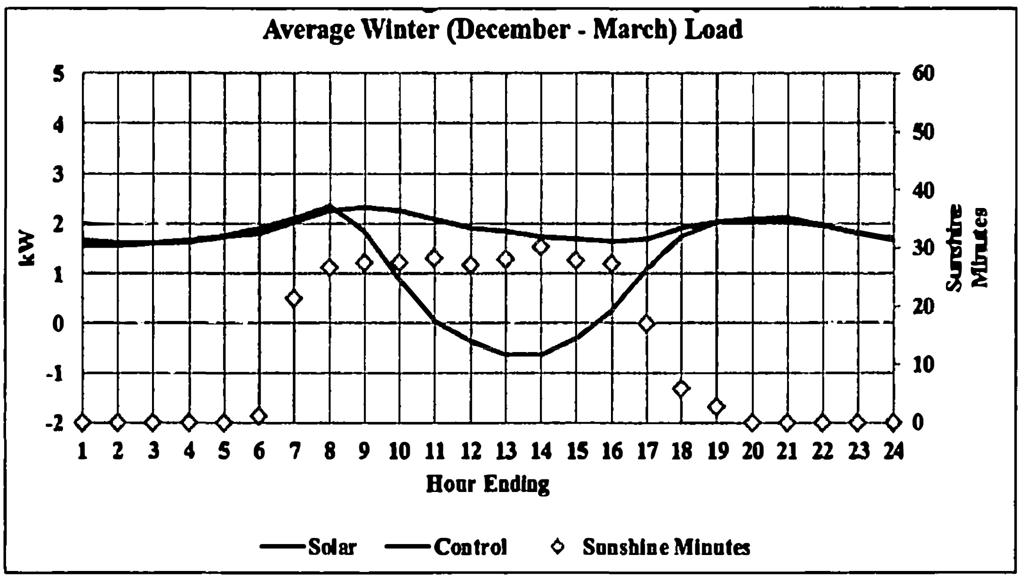

Figure 13. Average Winter (December - March) Load Profile for Representative Net-Metered Customer with Rooftop Solar Installation

Figure 13 indicates that on average, during winter months, from approximately 11am until 3:30pm, a customer with rooftop solar would be supplying electricity to the grid, as evident by the negative load requirement. During periods when DG systems are generating they are offsetting the Company's total generation requirement, however the total offset is both difficult to quantify and plan for due to the variability of system output.

3.4.5.3 Impacts of Increased Levels of Distributed Generation (DG)

As mentioned previously, rooftop solar installations allow a customer to reduce their energy consumption from the utility and potentially reduce their peak demand. While the latter benefit could lead to a lower overall PJM peak demand for APCo it does not reduce APCo's true peak demand. As discussed in Section 2.0, APCo's overall peak demand generally occurs in the early morning on a winter day. As shown above in Figure 13, during these times of peak demand rooftop solar installations are providing little to no demand savings.

Increasing levels of DG present challenges for the Company from a distribution planning perspective. Higher penetration of DG can potentially mask the true load on distribution circuits and stations if the instantaneous output of connected DG is not known, which can lead to under-planning for the load that must be served should DG become unavailable. Increased levels of DG could lead to a requirement that DG installations include smart inverters so that voltage and other circuit parameters can be controlled within required levels. Additional performance monitoring capabilities for DG systems will facilitate accurate tracking and integration of DG generators into the existing resource mix.

Currently, DG applicants in APCo's Virginia and West Virginia jurisdictions are required to fund any improvements needed to mitigate impacts to the operation and power quality of affected distribution stations and circuits. As DG penetration grows there is potential that the "next" applicant would be required to fund improvements that are a result of the aggregate impacts of previous DG customers because the incremental impact of the "next" customer now drives a need for improvements. This could lead to inequities among DG customers if necessary improvements are not planned appropriately.

3.4.6 Volt VAR Optimization (VVO)

An emerging technology known as VVO represents a form of voltage control that allows the grid to operate more efficiently. Depicted at a high-level in Figure 14, with VVO, sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor and voltage levels. Power factor is the ratio of real power to apparent power, and is a characteristic of electric power flow which is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. VVO 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. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies. Early results from limited rollouts in AEP affiliate operating companies indicate a range of 0.7% to 1.2% of energy demand reduction for each 1% voltage reduction is possible.

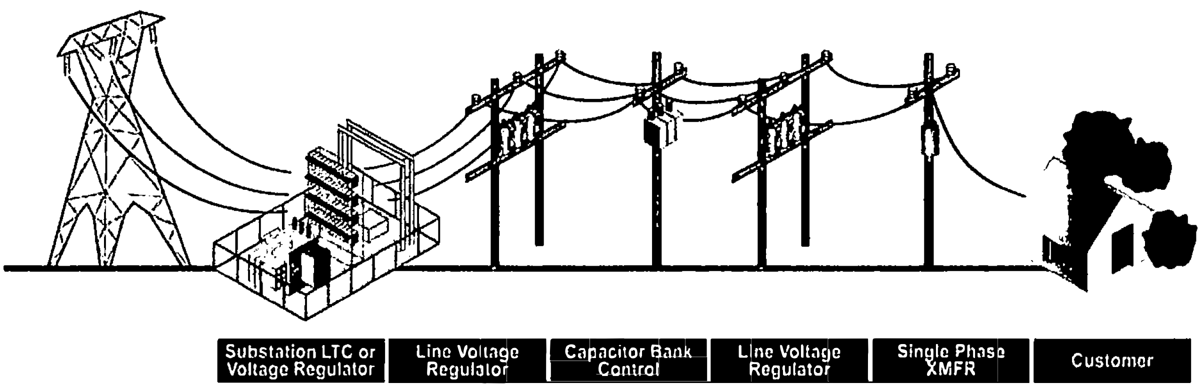

Figure 14. Volt VAR Optimization Schematic

While there is no "embedded" VVO load reduction impacts implicit in the base load forecast case, VVO has been modeled as a unique EE resource. Furthermore, in late 2016 APCo placed in service a VVO pilot on 3 circuits. The estimated energy and capacity savings are included in the IRP results discussed in Section 5.0.

3.5 AEP-PJM Transmission

3.5.1 General Description

The AEP eastern transmission system (eastern zone) consists of the transmission facilities of the ten eastern AEP operating or Transmission companies (APCo, Ohio Power Company [OPCo], Indiana Michigan Power [I&M], Kentucky Power Company [KPCo], Wheeling Power Company [WPCo], Kingsport Power Company [KgPCo], AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company). This portion of the transmission system is composed of approximately 14,500 miles of circuitry operating at or above 100kV. The eastern zone includes over 2,100 miles of 765kV transmission lines overlaying 3,500 miles of 345kV lines and over 8,600 miles of 138kV circuitry. This expansive system allows the economical and reliable delivery of electric power to approximately 24,200MW of customer demand connected to the AEP eastern transmission system that takes transmission service under the PJM open access transmission tariff.

The AEP eastern transmission system is part of the Eastern Interconnection, the most integrated transmission system in North America. The entire AEP eastern transmission system is located within the Reliability*First* Corporation (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization (RTO) and now participates in the PJM markets.

As a result of the AEP eastern transmission system's geographical location and expanse as well as its numerous interconnections, the eastern transmission system can be influenced by both internal and external factors. Facility outages, load changes, or generation re-dispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the AEP eastern transmission system is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern transmission system conforms to the NERC Reliability Standards and applicable RFC standards and performance criteria.

Despite the robust nature of the eastern transmission system, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant 765kV transmission line enhancement to the AEP eastern transmission system over the last few years was completed in 2006. This was the construction of a 90-mile 765kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. In addition, Extra High Voltage (EHV) transformer capacity has been increased at various stations across the eastern transmission system.

AEP's eastern transmission system assets are aging. Figure 15 below demonstrates the development of AEP's eastern Transmission Bulk Electric System. In order to maintain reliability, significant investments will have to be made in the rehabilitation of existing assets over the next decade.

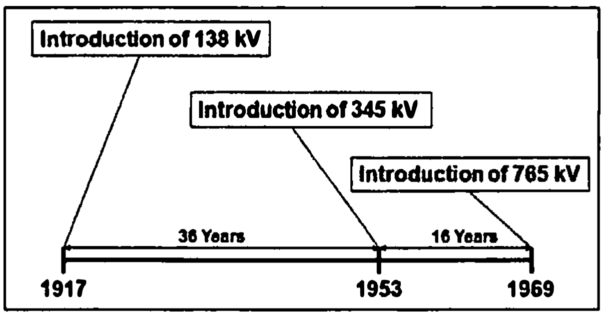

Figure 15. AEP Eastern Transmission System Development Milestones

Over the years, AEP, and now PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern transmission system. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers. Approximately 5,000 MW of generation additions are planned to be connected to the eastern transmission system over the next several years (including upgrades to existing facilities and based on executed agreements as of December 31st, 2016). There are also significant amounts of merchant generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern transmission system required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and adjacent markets, such as MISO and NYISO.

The transmission line circuit miles in APCo's Virginia service territory include approximately 349 miles of 765kV, 96 miles of 500kV, 69 miles of 345kV, 15 miles of 230kV, 1,613 miles of 138kV, 628 miles of 69kV, 48 miles of 46kV and 98 miles of 34.5kV lines. APCo's West Virginia service territory includes approximately 382 miles of 765kV, 311 miles of 345kV, 1,110 miles of 138kV, 37 miles of 88kV, 349 miles of 69kV, 682 miles of 46kV, and 56 miles of 34.5kV lines.

The retirement of 13,000MW of generation in PJM, including 325MW at Glen Lynn in Virginia, coupled with the 800MW at Big Sandy in Kentucky, 400MW at Kanawha River, 630MW at Kammer, and 1050MW at Sporn in West Virginia, has created a need to develop transmission improvements within the APCo footprint. The retirement of these units requires deployment of improvements of the Virginia/West Virginia/Ohio/Kentucky infrastructure. There are three areas in particular that require transmission enhancements to maintain and allow sustainable reliable operation of the transmission network in the area encompassing APCo's Virginia and West Virginia service areas:

- **AEP-Dominion Interface** – The power flow patterns of the interface driven by generation availability, winter loading conditions, peak and off-peak load levels, will require significant transmission enhancements, additions of reactive support - both static and dynamic. The Cloverdale Station Improvements and re-conductor of the Cloverdale-Lexington 500kV line will address a majority of these issues in the near term. Additional major 765/138kV improvements like the Wythe Area Improvements will also address the mitigation of voltage problems which have been previously identified.

- **Megawatt Valley** — the Gavin/Amos/Mountaineer/Flatlick area currently has stability limitations and reliability issues during multiple transmission outages. Multiple overlapping transmission outages may require the reduction of generation levels in this area to ensure continued reliable transmission operation, although such conditions are expected to occur infrequently. Generation resource additions and retirements in the Gavin/Amos/Mountaineer/Flatlick area are influencing these stability constraints, requiring transmission enhancements–possibly including the construction of EHV lines and/or the addition of multiple large transformers– to more fully integrate the transmission facilities in this generation-rich area.
- **The Kanawha Valley** — Power plant retirements in the Kanawha and Ohio River valleys have changed the way electric power flows on the electric transmission grid. To accommodate those changes and address additional issues identified by PJM, upgrades are needed to the grid in West Virginia, with most of the work slated for the Kanawha Valley. The Kanawha Valley Area Transmission Reinforcement project, along with the Kammer Area Improvements will address these issues.

3.5.2 Transmission Planning Process

AEP and PJM coordinate the planning of the transmission facilities in the AEP System-East Zone through a "bottom up/top down" approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM's transmission planning process. PJM will incorporate AEP's expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its Regional Transmission Expansion Plan (RTEP) process. The PJM assessment will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue to take the lead for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement. By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process, ensuring a consistent view of needs and expansion timing while minimizing expenditures. When the RTEP identifies system upgrade requirements, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable and economical integrated transmission reinforcement plan for the entire region, while blending the local expertise of the transmission owners such as APCo with a regional view and formalized open stakeholder input.

AEP's transmission planning criteria are consistent with North American Electric Reliability Corporation (NERC) and RFC reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 and these planning criteria are posted on the AEP website[8]. Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address anticipated deficiencies.

PJM also coordinates its regional expansion plan on behalf of the member utilities with the neighboring utilities and/or RTOs, including the MISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and the MISO provides for joint transmission planning.

3.5.3 System-Wide Reliability Measures

Transmission reliability studies are conducted routinely for seasonal, near-term, and long-term horizons to assess the anticipated performance of the transmission system. The reliability impact of resource adequacy (either supply or demand side) would be evaluated as an inherent part of these overall reliability assessments. If reliability studies indicate the potential for inadequate transmission reliability, transmission expansion alternatives and/or operational remedial measures would be identified.

[8]http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/docs/2017/AEP_East%20FERC%20715_2017_Final_Part%204.pdf

3.5.4 Evaluation of Adequacy for Load Growth

As part of the on-going near-term/long-term planning process, AEP and PJM use the latest load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable operating problems under adverse system conditions. Whenever a potential problem is identified, PJM and AEP seek solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission project reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads with a high degree of reliability.

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[9] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

3.5.5 Evaluation of Other Factors

As a member of PJM, and in compliance with FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in AEP's eastern transmission system to support the power supply and transmission reliability needs of the entire PJM – MISO joint market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects

[9] 90% probability that the actual peak load will be lower than the forecasted peak load and 10% probability that the actual peak load will be higher than the forecasted peak load.

and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement. The amount of this planned generation that will actually come to fruition is unknown at this time.

3.5.6 Transmission Expansion Plans

The transmission system expansion plans for the AEP eastern system are developed and reviewed through the PJM stakeholder process to meet projected future requirements. AEP and PJM use power flow analyses to simulate normal conditions, and credible single and double contingencies to determine the potential thermal and voltage impact on the transmission system in meeting the future requirements.

As discussed earlier, AEP will continue to develop transmission reinforcements to serve its own load areas, in coordination with PJM, to ensure compatibility, reliability and cost efficiency.

3.5.7 FERC Form 715 Information

A discussion of the eastern AEP System reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's 2017 FERC Form 715 Annual Transmission Planning and Evaluation Report. That filing also provides transmission maps, and pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's eastern transmission system.

As the transmission planner for AEP and AEP subsidiaries in the east, PJM performs all required studies to assess the robustness of the Bulk Electric System. All the models used for these studies are created by and maintained by PJM with input from all transmission owners, including AEP and its subsidiaries. Information about current cases, models, or results can be requested from PJM directly. PJM is responsible for ensuring that AEP meets all NERC transmission planning requirements, including stability of the system.

Performance standards establish the basis for determining whether system response to credible events is acceptable. Depending on the nature of the study, one or more of the following performance standards will be assessed: thermal, voltage, relay, stability, and short circuit. In general, system response to events evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

The planning process for AEP's transmission network embraces two major sets of contingency tests to ensure reliability. The first set, which applies to both bulk and local area transmission assessment and planning, includes all significant single contingencies. The second set, which is applicable only to the Bulk Electric System, includes multiple and more extreme contingencies. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance.

Sufficient modeling of neighboring systems is essential in any study of the Bulk Electric System. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) power flow library, the PJM base cases, and neighboring companies themselves. In general, sufficient detail is obtained to adequately assess all events, outages and changes in generation dispatch, which are contemplated in any given study.

3.5.8 Transmission Project Details

A detailed list and discussion of certain transmission projects undertaken by APCo, or its affiliates AEP West Virginia Transmission Company, Inc. (WV Transco) and Transource West Virginia, that have recently been completed or are presently underway in Virginia and West Virginia can be found below. In addition, several other projects outside of Virginia and West

Virginia area have also been completed or are underway across the AEP System-East Zone. These projects contribute to the robust health and capacity of the overall transmission grid, which benefits all customers.

AEP's transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for APCo's customers.

A brief summary of the major transmission projects in APCo's Virginia and West Virginia service territory for the 2016-2021 timeframe is provided below. Project information includes the project name and a brief description of the project scope.

Cloverdale Station Improvements: The upgrades are required in order to mitigate issues identified with transmission planning criteria, improve the reliability of the transmission system in the Roanoke, Virginia area and the interface capacity and operational performance between AEP and Dominion Virginia Power by eliminating congestion and reinforcing the existing network for future growth. In summary, the major scope of work included establishing a new Cloverdale East 500kV station, installation of a new 765/500kV, 2250MVA transformer and replacement of various transformers and associated circuit breakers.

Cloverdale-Lexington 500kV Re-Conductor: This project was developed in order to mitigate issues with planning criteria, address identified congestion issues, maintain adequate and reliable electrical service to the surrounding area, and to relieve the significant market congestion on the AEP-Dominion interface. The major scope of work includes re-conductoring 36 miles of the AEP owned portion of the Cloverdale-Lexington 500kV line in order to increase the thermal capability improving the reliability of the regional transmission system and operational performance.

Christiansburg Area Improvements: An analysis identified that during projected summer 2015 peak load conditions, a single contingency outage of the 138kV Merrimac Tap Line, Merrimac 138/69kV transformer, or the North Blacksburg 138/69kV transformer would overload the Midway-South Christiansburg 69kV sub-transmission circuit serving the Town of Christiansburg beyond its maximum allowable thermal limit, which could have jeopardized service to over 160MW of sub-transmission load. The major scope of work, which has been completed, included the construction of a 138kV line between the Falling Branch and Merrimac Substations on the east side of Christiansburg establishing two-way service to the existing Vicker and Merrimac Substations, increasing transmission service reliability to the area. Also, a new 138/69kV transformer has been installed at Merrimac Substation to improve reliability and prevent thermal violations.

South Lynchburg Area Improvements: The South Lynchburg area has approximately 65MW of combined load served from Brush Tavern, George Street, and Lawyers Substations which are served radially by a transmission source. In order to provide adequate service reliability to these radially served substations, this project will provide two-way service by constructing approximately 4.0 miles of new 138kV line from Brush Tavern to a newly established 138/12kV distribution station (Lynbrook) and rebuilding the 69kV line to 138kV between South Lynchburg and Lawyers stations. The new Lynbrook station will replace the existing Lawyers station and will be located approximately 1 mile south of Lawyers station. George St. Station will be converted to 138kV by replacing the 69/12kV transformer with a 138/12kV 20MVA transformer. The new Lynbrook station will include a new 138/12kV 20MVA transformer. In addition, new 138kV breakers are being installed at New London, Brush Tavern and South Lynchburg stations, improving the reliability of the 138kV system.

Wythe Area Improvements: The Wythe Area Improvements project addresses transmission planning voltage deviation criteria violations in excess of 8%, improved the reliability of the existing transmission network in the Wytheville, VA area, and reinforced the electrical infrastructure for future growth. The major scope of work consists of constructing a 17 mile line from Jacksons Ferry to Progress Park and Wythe Substations. Also, a second 765/138kV transformer was installed at Jacksons Ferry. In summary, the project will mitigate planning voltage criteria issues, enhance operational performance and reliability to over 295MW of load, introduce a new source into the Wythe area and provide flexibility for routine maintenance of the transmission system.

Abingdon Area Improvements: The Abingdon Area Improvements addresses an overload on the Abingdon-Hillman Highway 69kV line and the Abingdon 138/69kV transformer due to the outage of the Meadowview 138/69kV transformer. The major scope of work includes construction of a new 138/69/12kV South Abingdon Station connected to the Broadford-Wolf Hills 138kV circuit via a new double circuit 138kV line and a new 69kV line between the new South Abingdon and Arrowhead Station.

Bland Area Improvements: The Bland Area Improvements addresses thermal criteria issues on the Tazewell-Buckhorn line in addition to voltage magnitude issues in the South Princeton area for the outage combination of Glen Lyn-Hinton 138kV and Jim Branch-Switchback 138kV lines. The major scope of work includes rebuilding the Wythe-South Bluefield 69kV to 138kV, re-routing the new line into Progress Park 138kV station, and replacing Bland 69kV station with Town Creek 138kV station.

Tazewell-Bearwallow 138kV: A comprehensive program to replace the aging 69kV sub-transmission system in Tazewell County, Virginia with a new 138kV transmission network includes rebuilding approximately 12.5 miles of the existing

Tazewell-Bearwallow 69kV line, of which 7.8 miles is located in Virginia; the remaining line is located in McDowell County, West Virginia.

Richlands-Whitewood Rebuild: A new 8.0 mile 138kV line from Richlands to Whitewood is to be constructed in Tazewell and Buchanan Counties in addition to a new switchyard. This solution addresses thermal and voltage issues projected in 2017.

Other major transmission projects previously undertaken, or currently being performed by APCo, and/or WV Transco, are as follows:

Kanawha Valley Area Transmission Reinforcement Project: As addressed previously, power plant retirements in the Kanawha and Ohio River valleys changed the way electric power flows on the electric transmission grid. To accommodate those changes and address additional issues identified by PJM, existing transmission lines and substations in the Kanawha Valley have been rebuilt and upgraded, respectively. The bulk of the remaining Kanawha Valley work will take place between APCo's Amos Plant and its Turner and Cabin Creek substations, with a key loop in the Cross Lanes area and another in the Kanawha City area. Additional work will be done to facilities that feed off the backbone transmission line that runs from Poca to Cabin Creek.

Fayette County Area Transmission Improvements: PJM has identified voltage, thermal, and reliability concerns in Fayette County, West Virginia and in the surrounding areas. The Fayette County Project entails constructing certain transmission facilities in the vicinity of Beckley and elsewhere in Fayette, Greenbrier and Raleigh Counties. Specifically the Fayette County Project includes: constructing new Beury Mountain and Brackens Creek Stations, constructing approximately twelve miles of 138kV transmission line between the new Beury Mountain and Brackens Creek Stations, constructing approximately two miles of new 138kV transmission line, rebuilding and upgrading approximately thirteen miles of existing 69kV transmission line to 138kV between the McClung and Brackens Creek Stations, and installing equipment at three existing stations.

<u>McDowell Area Improvement Project:</u> The McDowell Area Improvement Project will boost the electric transmission grid reliability in the region. The McDowell Area Improvements Project will also provide southern West Virginia with an infrastructure capable of handling future economic growth. The project includes: removal of approximately 35 miles of existing 88kV transmission line, rebuilding and upgrading approximately 17 miles of an existing transmission line to 138kV, retirement of two substations, construction of three new substations, and upgrades at various existing substations.

<u>Wyoming 765kV Reactor Addition:</u> This project was developed in order to mitigate operational high voltage constraints identified on the APCo 765kV system during off peak time periods. The major scope of work includes the addition of a new 300 MVAR shunt reactor connected via a new 765kV circuit breaker at Wyoming station.

<u>Thorofare Project:</u> This project was proposed by an AEP affiliate, Transource West Virginia, to address a Transmission Planning Criteria violation that is expected to occur in 2019 in the area northeast of Charleston, West Virginia. The major scope of work includes the addition of a new 138kV switching station (Linden Road Station) off First Energy's Powell Mountain – Goff Run 138kV transmission line and the construction of a new 138kV transmission line to connect the new Linden Road Station to APCo's existing Thorofare Creek switching station.

4.0 Modeling Parameters

4.1 Modeling and Planning Process – An Overview

The objective of a resource planning effort is to recommend a system resource expansion plan that balances "least-cost" objectives with planning flexibility, asset mix considerations, adaptability to risk, and conformance with applicable NERC and RTO criteria. In addition, the planning effort must ultimately be in concert with anticipated long-term requirements established by the EPA-driven environmental compliance planning process. Resources selected through the modeling process are not locational specific.

The information presented with this IRP includes descriptions of assumptions, study parameters, methodologies, and results including the integration of supply-side resources and DSM programs.

In general, assumptions and plans are continually reviewed and modified as new information becomes available to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are routinely reassessed to ensure optimal capacity resource planning.

Further impacting this process are a growing number of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the APCo IRP process. Therefore, as a result, the "objective function" of the modeling applications utilized in this process is the establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. Other factors–some more difficult to monetize than others–were considered in the determination of the Preferred Plan. Sensitivity analyses were performed to understand the impact of addressing factors which may increase costs.

4.2 Methodology

The IRP process aims to address the long-term "gap" between resource needs and current resources. Given the various assets and resources that can satisfy this expected long-term gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution–or portfolio–subject to constraints. *Plexos®* is the primary modeling application, used by APCo and AEP for identifying and ranking portfolios that address the gap between needs and current available resources.[10] Given the cost and performance parameters around sets of potentially-available supply- and demand-side proxy resources and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, *Plexos®* will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the Cumulative Present Worth (CPW), of the resulting stream of revenue requirements. The least cost option is considered the "optimum" portfolio for that unique input parameter scenario.

4.3 Fundamental Modeling Input Parameters

The AEP Fundamental Analysis group prepares the Long-Term North American Energy Market Forecast ("Fundamentals Forecast") with support from the proprietary AURORA^{xmp} Energy Market Model ("AURORA^{xmp}"). Similar to Plexos®, AURORA^{xmp} is a long-term fundamental production cost-based energy and capacity price forecasting tool developed by EPIS, Inc., that is driven by comprehensive, user-defined commodity input parameters. For example, nearer-term unit-specific fuel delivery and emission allowance price forecasts, based upon actual transactions, which are established by AEP Fundamental Analysis and AEP Fuel, Emissions and Logistics, are input into AURORA^{xmp}. Estimates of longer-term natural gas and coal pricing are provided by AEP Fundamental Analysis in conjunction with input received from consultants, industry groups, trade press, governmental agencies, and others. Similarly, capital

[10] *Plexos®* is a production cost-based resource optimization model, which was developed and supported by Energy Exemplar, LLC. The *Plexos®* model is currently licensed for use in 37 countries throughout the world.

costs and performance parameters for various new-build generating options, by duty-type are vetted through AEP Engineering Services and incorporated into the tool. Other information specific to the thousands of generating units being modeled is researched from Velocity Suite, an on-line information database maintained by Ventyx, an ABB Company. This includes data such as unit capacity, heat rates, retirement dates and emission controls status. Finally, the model maintains and determines region-specific resource adequacy based on regional load estimates provided by AEP Economic Forecasting, as well as current regional reserve margin criterion. AEP uses AURORA^{xmp} to model long-term (market) energy and capacity prices for the entire U.S. eastern interconnect as well as Electric Reliability Council of Texas (ERCOT). The projection of a CO_2 pricing proxy is based on assumptions developed in conjunction with the AEP Strategic Policy Analysis organization. Figure 16 shows the Fundamentals process flow for solution of the long-term commodity forecast. The input assumptions are initially used to generate the output report. The output is used as feedback to change the base input assumptions. This iterative process is repeated until the output is congruent with the input assumptions (*e.g.*, level of natural gas consumption is suitable for the established price and all emission constraints are met).

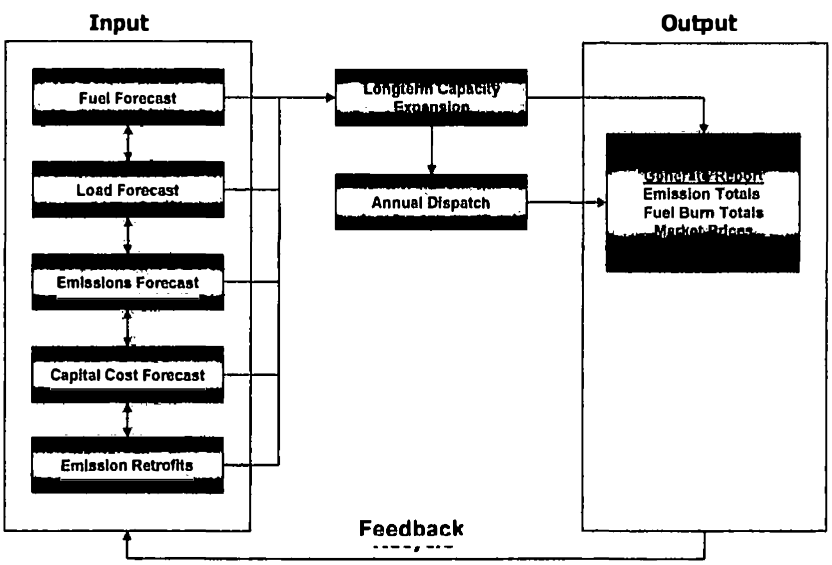

Figure 16. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Four commodity pricing scenarios were developed by AEP Fundamental Analysis for APCo to enable *Plexos*® to construct resource plans under various long-term pricing conditions. In this Report, the four distinct long-term commodity pricing scenarios that were developed for *Plexos*® are the Mid, Low Band, High Band, and No Carbon scenarios. The overall fundamental forecasting effort was completed in October of 2016. The Mid, Low Band, and High Band scenarios each consider the potential impact of carbon regulations. The modeling associated with these scenarios determined the appropriate combination of CO_2 and energy prices which would provide for nationwide compliance with the CPP on a mass basis, considering compliance beginning in 2024. These CO_2 allowance values vary across the three scenarios and support the premise that CO_2 values are highly dependent upon fuel price assumptions – particularly natural gas. Each scenario is described below.

4.3.1.1 Emission Reduction Credit (ERC) Pricing

As indicated, for purpose of the CPP modeling performed by the Company, AEP Fundamental Analysis created a set of CO_2 allowance pricing scenarios predicated upon national compliance under a mass-based approach. This was done as a matter of modeling convenience given that a) the underlying AURORA^{xmp} (dispatch) modeling framework itself was more conducive to the use of a mass-based commodity approach and, b) there are greater uncertainties surrounding wide implementation approaches for an Emission Reduction Credit (ERC) or rate-based pricing scheme. This action, however, neither introduces nor presumes any bias toward a fundamental pricing basis for one CPP pricing approach (mass-based 'allowance') versus the other (rate-based 'ERC').

In fact, based on mass-based versus rate-based pricing approaches from other observed projections, overall mass versus rate pricing profiles were generally consistent. For this reason the Company assumed that, for the purpose of the *Plexos*® optimization modeling exercise, a reasonable proxy for such a forecast of ERC pricing would be *equal to* the pricing point established for the mass-based approach. For example, a \$10 per ton allowance price in a given year, would also be assumed to equal a \$10/MWh ERC price in that same year.

4.3.1.2 Mid Scenario

This scenario recognizes the following major assumptions:

- MATS Rule implementation beginning in 2015;
- relatively lower natural gas price due to the emergence of shale gas plays; and
- CO_2 emission pricing beginning in 2024

As mentioned above, the Mid, Low Band, and High Band scenarios include CO_2 pricing as a result of the assumed implementation of CO_2 reduction regulation. Also, the specific effects of the MATS Rule are modeled in the development of the long-term commodity forecast by retiring the smaller, older solid-fuel (i.e., coal and lignite) units which would not be economic to retrofit with emission control equipment. The retirement time frame modeled runs through 2017. Those remaining solid-fuel generating units will have some combination of controls necessary to comply with EPA rules. Incremental regional capacity and reserve requirements will largely be addressed with new natural gas plants. One effect of the expected retirements on the emission control retrofit scenario is an over-compliance of the CSAPR emission limits. This will drive the emission allowance prices for SO_2 and NO_x to zero by 2018 or 2019.

4.3.1.3 Low Band Scenario

This scenario is best viewed as a plausible lower natural gas/solid-fuel/energy price profile compared to the Mid scenario. In the near term, Low Band natural gas prices largely track Mid prices but, in the longer term, natural gas prices represent an even more significant reduction of shale gas exploration costs. From a statistical perspective, this long-term pricing scenario is approximately one (negative) standard deviation (-1.0σ) from the Mid scenario and illustrates the effects of coal-to-gas substitution at plausibly lower gas prices. Like the Mid scenario, CO_2 pricing is assumed to start in 2024.

4.3.1.4 High Band Scenario

Alternatively, the High Band scenario offers a plausible, higher natural gas/solid-fuel/energy price profile compared to the Mid scenario. High Band natural gas prices reflect certain impediments to shale gas developments including stalled technological advances (drilling and completion techniques) and as yet unseen exploration and development environmental costs. The pace of environmental regulation implementation is in line with the Mid and Low Band scenarios. Analogous to the Low Band scenario, this High Band view, from a statistical perspective, is approximately, one (positive) standard deviation ($+1.0\sigma$) from the Mid. Also, like the Mid and Low Band scenarios, CO_2 pricing is assumed to begin in 2024.

4.3.1.5 No Carbon Scenario

This scenario does not consider a price for CO_2 emissions, and so includes the necessary correlative fuel price adjustments. It also serves as a baseline to understand the impact of a price of CO_2 emissions on unit dispatch. Consequently, the No Carbon Scenario has a generation fleet that is unaffected by the cost of impending CO_2 mitigation regulations and results in greater coal consumption and relatively higher power prices in the near term.

4.3.1.6 Forecasted Fundamental Parameters

Figure 17 through Figure 23 below illustrate the forecasted fundamental parameters included in this IRP.

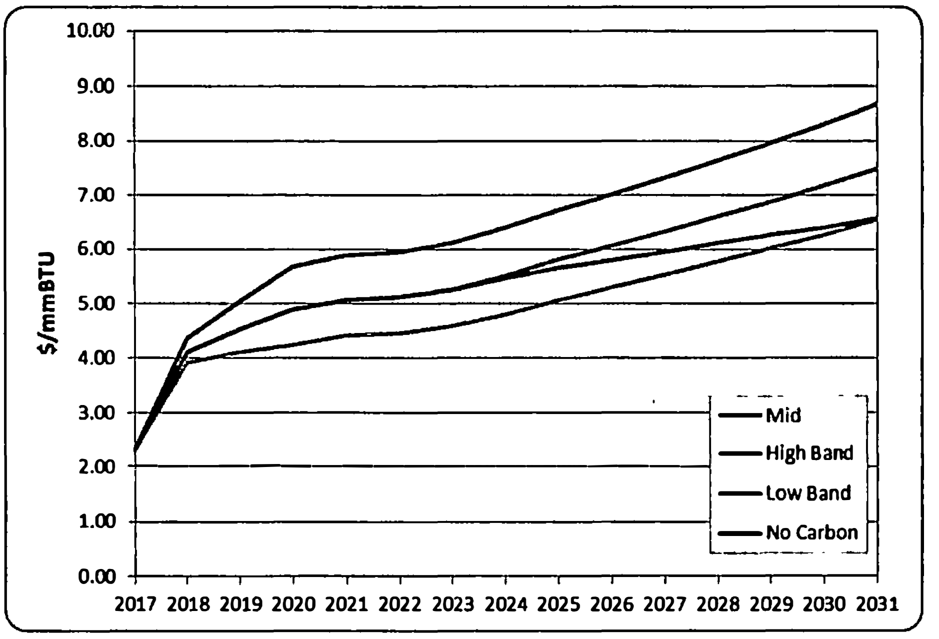

Figure 17. Dominion South Natural Gas Prices (Nominal $/mmBTU)

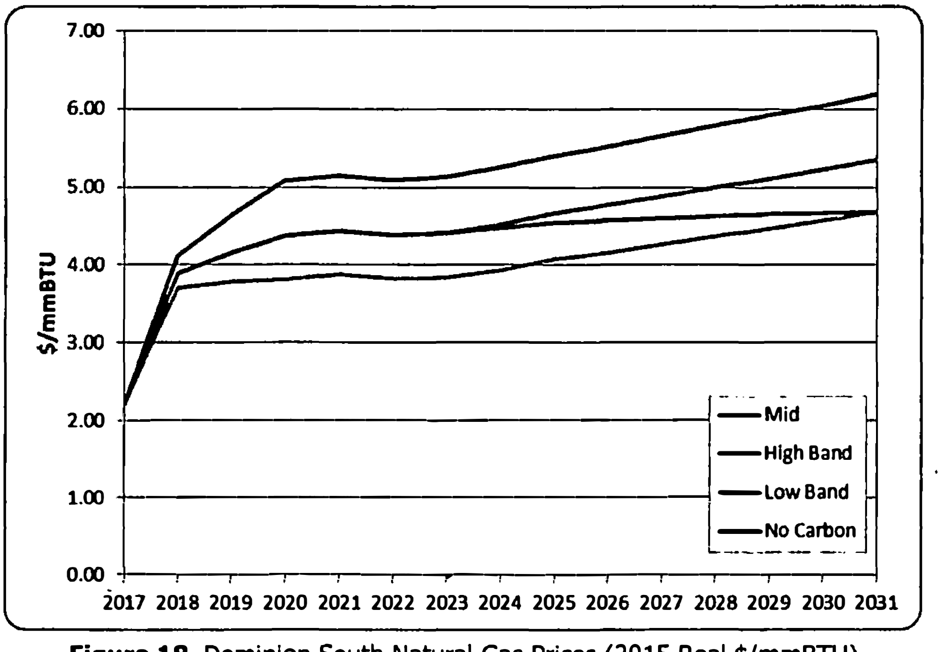

Figure 18. Dominion South Natural Gas Prices (2015 Real $/mmBTU)

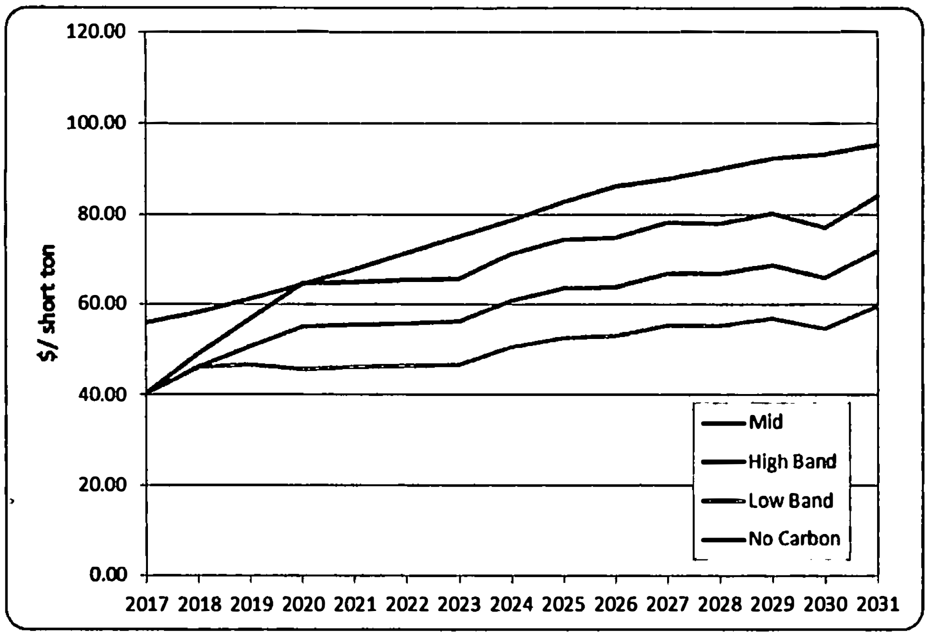

Figure 19. NAPP High Sulfur Coal Prices (Nominal $/ton, FOB origin)

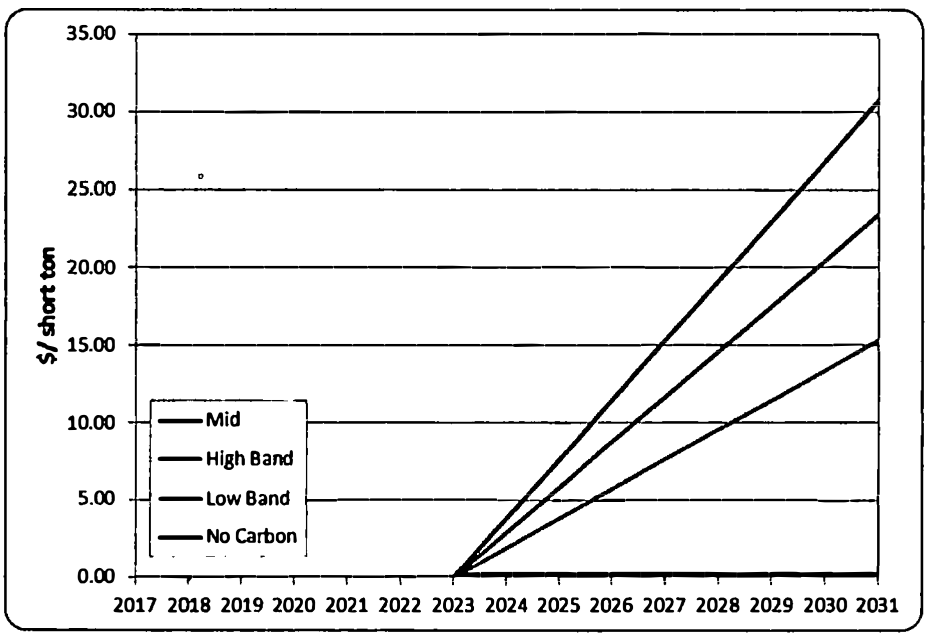

Figure 20. CO_2 Prices (Nominal $/short ton)

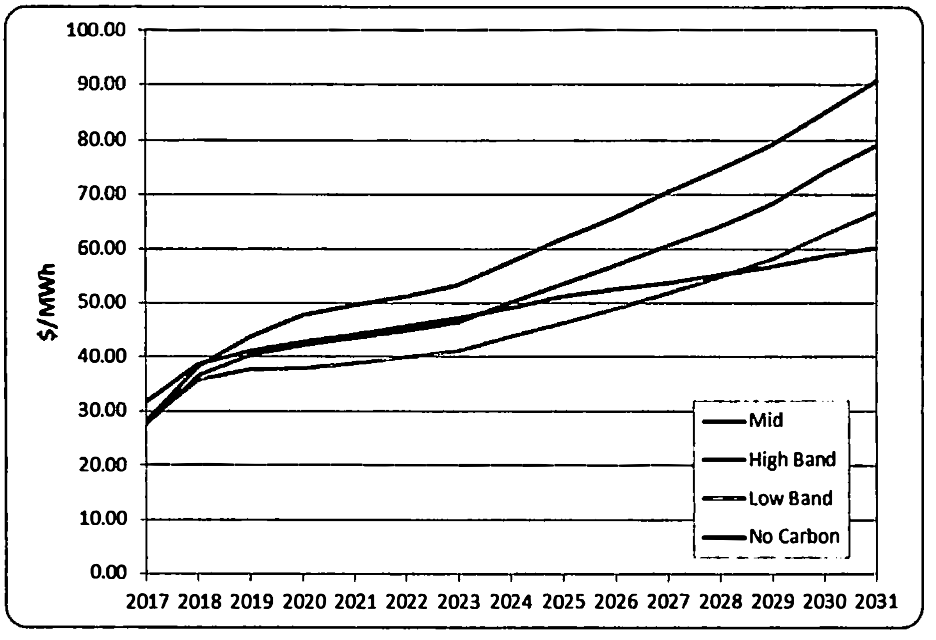

Figure 21. PJM On-Peak Energy Prices (Nominal $/MWh)

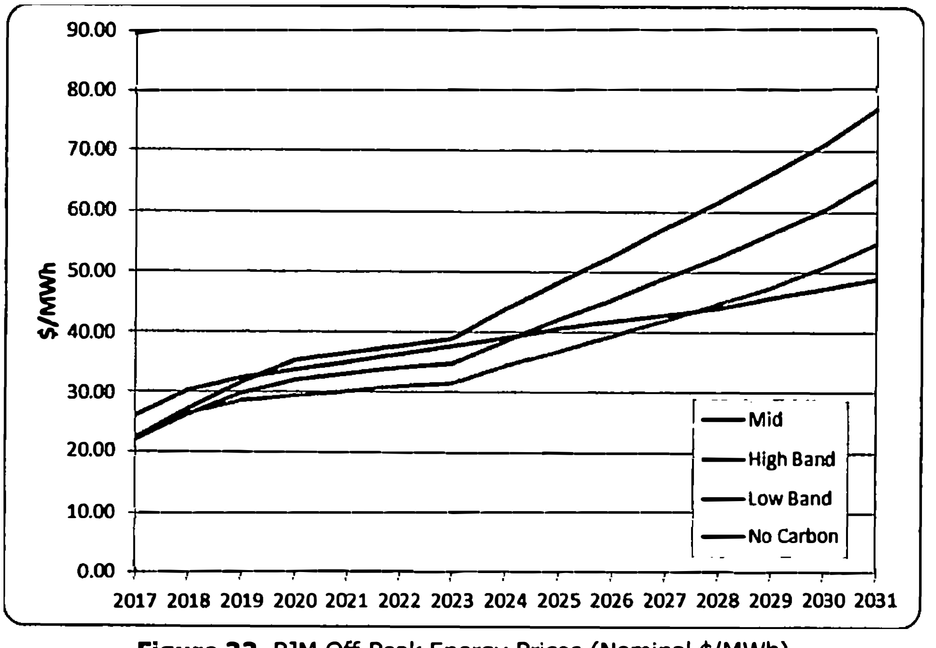

Figure 22. PJM Off-Peak Energy Prices (Nominal $/MWh)

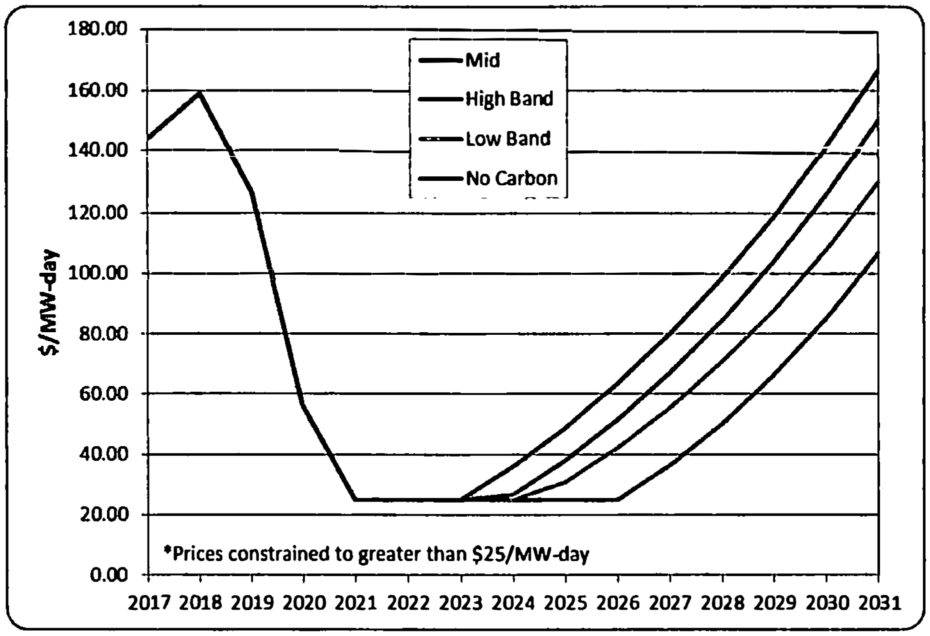

Figure 23. PJM Capacity Prices (Nominal $/MW-Day)

4.4 Demand-Side Management (DSM) Program Screening & Evaluation Process

4.4.1 Overview

The process for evaluating DSM impacts for APCo is divided into two spheres: "existing DSM programs" and "incremental DSM programs." Existing DSM programs are those that are known or are reasonably well-defined, and follow a pre-existing process for screening and determining ultimate regulatory approval. The impacts of APCo's existing DSM programs are propagated throughout the long-term load forecast. Incremental DSM program impacts which are, naturally, less-defined, are developed with a dynamic modeling process using more generic cost and performance parameter data.

For APCo, the potential incremental DSM programs were developed and ultimately modeled based on the Electric Power Research Institute's (EPRI) "2014 U.S. Energy Efficiency Potential Through 2035" report. This report served as the basic underpinning for the establishment of potential EE "bundles", developed for residential and commercial customers that were then introduced as a resource option in the *Plexos*® optimization model. In order to reflect potential energy savings available in the industrial sector, the end-usage associated with lighting was combined for both the commercial and industrial sectors. The indoor and outdoor lighting bundles shown below in Table 11 reflect the potential energy savings for both sectors.

4.4.2 Achievable Potential (AP)

The amount of available EE is typically described in three sets: technical potential, economic potential, and achievable potential. The previously-cited EPRI report breaks down the achievable potential into a High Achievable Potential (HAP) and an Achievable Potential (AP), with the HAP having a higher utility cost than the AP. Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether it is cost-effective (i.e., all EE measures would be adopted if technically feasible). The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic potential. This compares the avoided cost savings achieved over the life of a measure/program with the cost to implement it, regardless of who paid for it and regardless of the age and remaining economic life of any system/equipment that would be replaced (i.e., all EE measures would be adopted if economic). The third set of efficiency assets is that which is achievable. As highlighted above, the HAP is the economic potential discounted for market barriers such as customer preferences and supply chain maturity; the AP is additionally discounted for programmatic barriers such as program budgets and execution proficiency.

Of the total technical potential, typically only a fraction is ultimately achievable and only then over time due to the existence of market barriers. The question of how much effort and money is to be deployed towards removing or lowering the barriers is a decision made by state governing bodies (legislatures, regulators or both).

The AP range is typically a fraction of the economic potential range. This achievable amount must be further split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards. Both amounts are represented in this IRP as reductions to what would otherwise be in the load forecast.

4.4.3 Evaluating Incremental Demand-Side Resources

The *Plexos*® model allows the user to input incremental CHP, EE, DG, DR and VVO as resources, thereby considering such alternatives in the model on equal-footing with more traditional "supply-side" generation resource options.

4.4.3.1 Incremental Energy Efficiency (EE) Modeled

To determine the economic demand-side EE activity to be modeled that would be over-and-above existing EE program offerings in the load forecast, a determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs. It was assumed that the incremental programs modeled would be effective in 2019, due to the time needed to develop specific program cost and measures and receive regulatory approval to implement such programs. Figure 24 and Figure 25 show the "going-in" make-up of projected end-usage in APCo's residential and commercial sectors in the year 2019. Future incremental EE activity can further target these areas or address other end-uses.

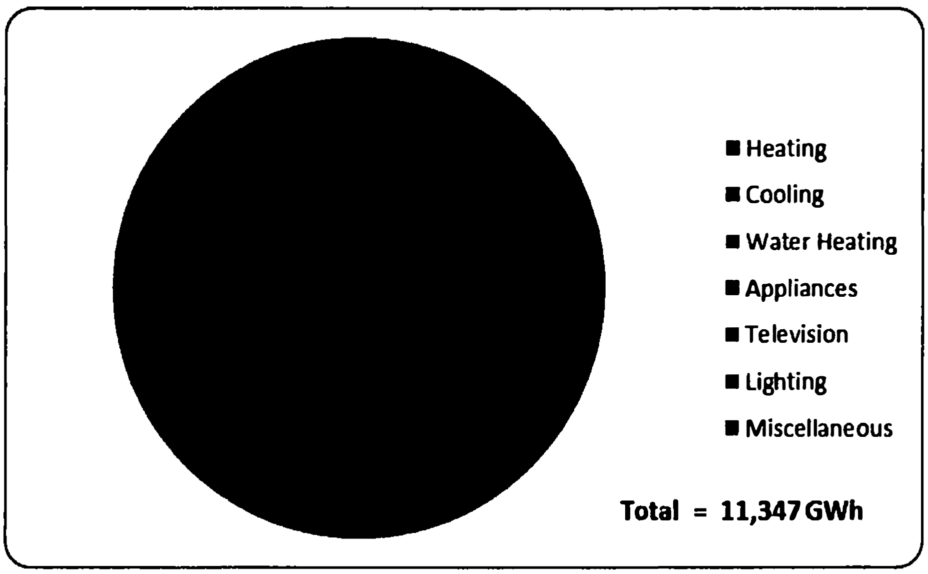

Figure 24. 2019 APCo Residential End-Use (GWh)

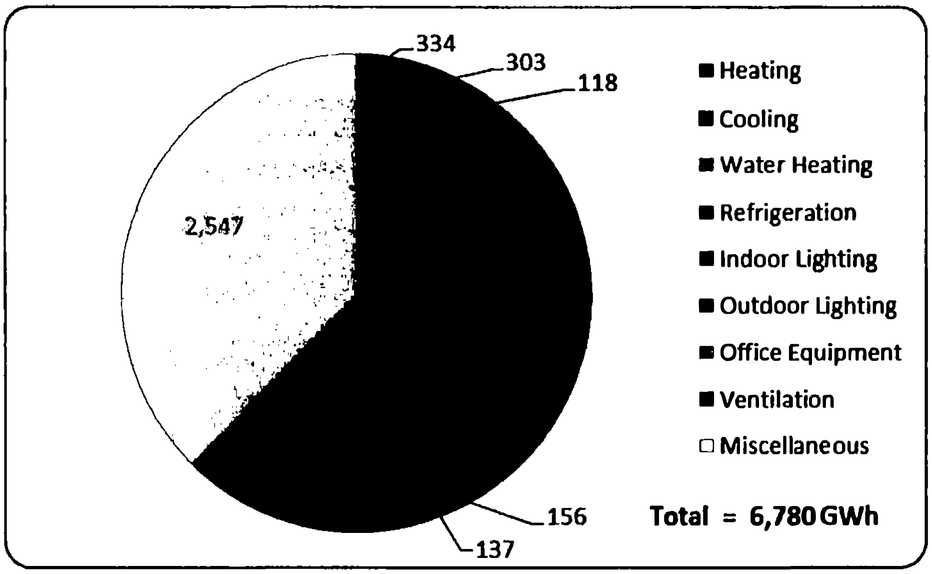

Figure 25. 2019 APCo Commercial End-use (GWh)

To determine which end-uses are targeted, and in what amounts, APCo looked at the previously-cited 2014 EPRI report. The EPRI report provides information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. APCo utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 8 and Table 9, from the EPRI report, list the individual measure categories considered for both the residential and commercial sectors.

Table 8. Residential Sector Energy Efficiency (EE) Measure Categories

Central Air Conditioning	Programmable Thermostat	Storm Doors	Dishwashers
Air-Source Heat Pumps	Water Heating	External Shades	Clothes Washers
Ground-Source Heat Pumps	Faucet Aerators	Ceiling Insulation	Clothes Dryers
Room Air Conditioning	Pipe Insulation	Foundation Insulation	Refrigerators
Air Conditioning Maintenance	Low-Flow Showerheads	Duct Insulation	Freezers
Heat Pump Maintenance	Duct Repair	Wall Insulation	Cooking
Attic Fan	Dehumidifier	Windows	Televisions
Furnace Fans	Lighting – Linear Fluorescent	Reflective Roof	Personal Computers
Ceiling Fan	Lighting – Screw-in	Infiltration Control	Smart Plug Strips, Reduce Standby Wattage
Whole-House Fan	Enhanced Customer Bill Presentment		

Table 9. Commercial Sector Energy Efficiency (EE) Measure Categories

Heat Pumps	Water Heater	Energy-Efficient Motors	Lighting – Screw-in
Central Air Conditioning	Water Temperature Reset	Variable Speed Controls	Anti-Sweat Heater Controls
Chiller	Computers	Programmable Thermostat	Floating Head Pressure Controls
Cool Roof	Servers	Duct Testing and Sealing	Installation of Glass Doors
Economizer	Displays	HVAC Retro-commissioning	High-Efficiency Vending Machine
Energy Management System	Copiers Printers	Efficient Windows	Icemakers
Roof Insulation	Other Electronics	Lighting – Linear Fluorescent	Reach-in Coolers and Freezers
Duct Insulation			

What can be derived from the tables is that the 2014 EPRI report has taken a comprehensive approach to identifying available EE measures. From this information, APCo has developed proxy EE bundles for residential, commercial and industrial customer classes to be modeled within *Plexos*®. These bundles are based on measure characteristics identified within the EPRI report and APCo customer usage.

Table 10 and Table 11 list the energy and cost profiles of EE resource "bundles" for the residential and commercial sectors, respectively. In order to reflect the potential EE savings available in the industrial sector, each of the lighting bundles shown in Table 11 includes potential savings for both commercial and industrial customers.

Table 10. Incremental Residential Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2019-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Bundle Life
Thermal Shell - AP	$0.24	3,926	2,977	4,639	10
Thermal Shell - HAP	$0.37	19,550	20,762	10,523	10
Heat Pump - AP	$1.49	11,664	4,548	1,013	18
Heat Pump - HAP	$2.23	14,139	976	0	18
Water Heating - AP	$0.05	2,229	922	1,053	10
Water Heating - HAP	$0.07	11,035	9,626	3,842	10
Appliances - AP	$0.16	13,236	3,379	2,129	16
Appliances - HAP	$0.26	30,541	15,843	7,504	17
Lighting - AP	$0.03	33,538	0	0	30
Lighting - HAP	$0.04	60,868	23,971	4,398	30
Enhanced Customer Bill	$0.67	40,722	0	57	10

Table 11. Incremental Commercial and Industrial (Lighting) Energy Efficiency (EE) Bundle Summary

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2019-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2040	Bundle Life
Heat Pump - AP	$4.95	10,226	3,937	0	15
Heat Pump - HAP	$7.43	12,031	416	0	15
HVAC Equipment - AP	$0.55	5,452	1,809	1,691	15
HVAC Equipment - HAP	$0.82	9,889	3,515	82	15
Indoor Screw-In Lighting - AP	$0.01	14,807	1,779	405	6
Indoor Screw-In Lighting - HAP	$0.02	21,840	6,940	1,388	6
Indoor Fluorescent Lighting - AP	$0.12	36,830	11,685	0	10
Indoor Fluorescent Lighting - HAP	$0.18	43,329	1,433	0	10
Outdoor Lighting - AP	$0.09	13,617	4,582	0	11
Outdoor Lighting - HAP	$0.14	16,019	536	0	11

As can be seen from the tables, each program has both AP and HAP characteristics. The development of these characteristics is based on the 2014 EPRI EE Potential report that has been previously referenced. This report further identifies Market Acceptance Ratios (MAR) and Program Implementation Factors (PIF) to apply to primary measure savings, as well as Application Factors for secondary measures. Secondary measures are not consumers of energy, but do influence the system that is consuming energy. The Residential Thermal Shell, Residential Water Heating and Commercial Cooling bundles—in both AP and HAP—include secondary measures. The MAR and PIF are utilized to develop the incremental AP program characteristics and the MAR only is used to develop the incremental HAP program characteristics.

Figure 26 below shows the Levelized Cost of Electricity (LCOE) and potential energy savings in 2019 for each of the bundles offered into the model as a potential resource. To preserve a reasonable scale for illustrative purposes, the two bundles with the highest LCOE, Commercial Heat Pump AP and Commercial Heat Pump HAP, were omitted from Figure 26. The total potential energy savings for EE programs in 2019 is 448GWh, 4% of APCo's total load, or 8% of APCo's total residential and commercial load.

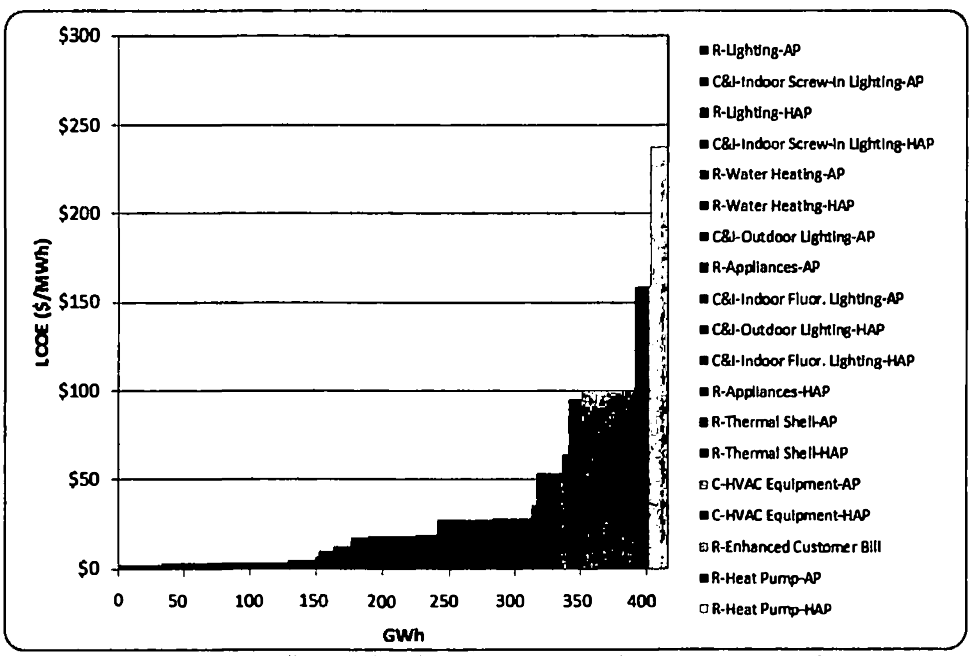

Figure 26. EE Bundle Levelized Cost vs. Potential Energy Savings for 2019

Each EE bundle is offered into the model as a stand-alone resource with its own unique cost and potential energy savings. Should the model determine that a bundle is economical, that bundle will be included in the portfolio of optimized resources. APCo will consider the details of which EE bundles were selected by the Plexos model, and included in the Preferred Plan, to develop appropriate EE offerings to propose for APCo's customers in Virginia and West Virginia. Efforts to determine program attributes such as participant costs, penetration rates, and bill savings, prior to that point in time would be highly speculative and potentially inaccurate.

4.4.3.2 Volt VAR Optimization (VVO) Modeled

Potential future VVO circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 15 "tranches" based on the relative potential peak demand and energy reduction of each tranche of circuits. The *Plexos®* model was able to pick the most cost-effective tranches first and add subsequent tranches as merited. Each VVO tranche is estimated to encompass 37 circuits. Table 12, details all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in 2016 dollars.

Table 12. Volt VAR Optimization (VVO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	37	$12,358,000	$370,740	15,362	63,250
2	37	$12,358,000	$370,740	12,027	49,516
3	37	$12,358,000	$370,740	10,367	42,681
4	37	$12,358,000	$370,740	9,211	37,922
5	37	$12,358,000	$370,740	8,646	35,596
6	37	$12,358,000	$370,740	8,169	33,633
7	37	$12,358,000	$370,740	7,817	32,182
8	37	$12,358,000	$370,740	7,530	31,004
9	37	$12,358,000	$370,740	7,272	29,942
10	37	$12,358,000	$370,740	6,984	28,753
11	37	$12,358,000	$370,740	6,675	27,481
12	37	$12,358,000	$370,740	6,309	25,977
13	37	$12,358,000	$370,740	5,985	24,640
14	37	$12,358,000	$370,740	5,730	23,590
15	37	$12,358,000	$370,740	5,507	22,674

4.4.3.3 Demand Response (DR) Modeled

Incremental levels of DR were included in the IRP model. These resources, which are included in the model as a resource for the entire operating company, were modeled based on the Bring Your Own Thermostat (BYOT) program, which reduces demand by cycling customer air conditioners, APCo recently proposed the BYOT program in its West Virginia jurisdiction. In the BYOT program, customers would own and self-install Wi-Fi enabled thermostats, which will communicate with APCo. Table 12, below, shows the DR resource offered into the model for residential and commercial customers. The model may select up to four units, each comprised of 3,000 customers, in any calendar year, beginning with 2019. Each unit has a service life of seven years.

Table 13. Incremental Demand Response (DR) Resource

Sector	Participants	Demand Savings (kW)	Energy Savings (kWh)	Installation Cost	Annual Cost	Total First Year Cost	Service Life (Years)
Residential / Commercial	3,000	2,810	126,600	$142,000	$837,000	$979,000	7

4.4.3.4 Distributed Generation (DG) Modeled

DG resources were evaluated assuming a residential rooftop solar resource, as this is the primary distributed resource. To determine the level of customer penetration APCo referenced a forecast conducted by IHS Inc. on behalf of PJM[11]. This forecast considered the level of solar photovoltaic (PV) installations over the period of 2017-2032. The forecast included levels of large-scale solar PV, but did not consider state caps for net-metering which exist in Virginia and West Virginia. Figure 27 below depicts the forecast of DG resources in APCo over the planning period. To determine the level of DG penetration APCo created a forecast using existing levels of DG, as well as the incremental additions from PJM's forecast. This forecast is shown as the

[11] Solar PV Capacity Addition Forecast for PJM States: 2017-2032. Available at http://www.pjm.com/~/media/planning/res-adeq/load-forecast/ihs-pjm-pv-forecast-report.ashx

red line in Figure 27 below. The green line in Figure 27 utilizes the same forecast method but incorporates Virginia's state cap on net-metering, which is expected to affect the forecast beginning in 2019. The capped forecast (green line, or PJM Forecast w/VA Cap in Figure 27), is the level of DG resources included in this IRP.

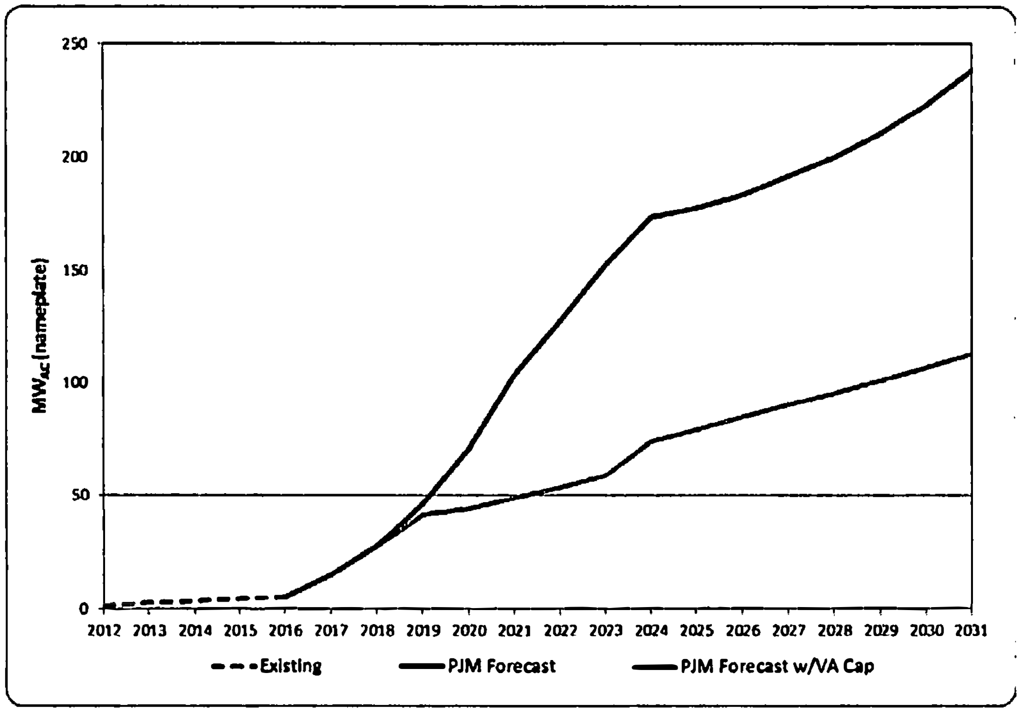

Figure 27. APCo Forecasted Distributed Generation Installed, or Nameplate, Capacity (MW)

PJM's forecast issued in October 2016 represents a significant increase in DG penetration from the same forecast issued one year prior. APCo intends to closely monitor the levels of DG installed throughout its service territory to observe any potential divergence from the forecast shown above.

It is significant to note that rooftop solar does not represent the most economic means for APCo to add renewable generation as the cost of rooftop solar remains considerably higher than the cost of large-scale solar, the cost of which is discussed in Section 4.5.5.1.1.

Part 3

1 7 0 5 1 0 0 7 7

4.4.3.5 Optimizing Incremental Demand-side Resources

The *Plexos*® software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy.

4.4.3.6 Combined Heat and Power (CHP)

CHP (also known as Cogeneration) is a process where electricity is generated and the waste heat by-product is used for heating or other processes, raising the net thermal efficiency of the facility. To take advantage of the increased efficiency associated with CHP, the host must have a ready need for the heat that is otherwise potentially wasted in the generation of electricity.

APCo worked with AEP Generation Engineering to develop a generic CHP option. The CHP option developed is a 15MW facility utilizing a natural gas fired combustion turbine, Heat Recovery Steam Generator (HRSG) and SCR to control NO_x. A major assumption is that all of the steam is taken by the host and the efficiency of the modeled CHP resource is credited for the value of the steam provided to the host. The overnight installed cost is estimated to be $2,000/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%.

4.5 Identify and Screen Supply-side Resource Options

4.5.1 Capacity Resource Options

New construction supply-side alternatives were modeled to represent peaking and base-load/intermediate capacity resource options. To reduce the number of modeling permutations in *Plexos*®, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant.

When applicable, APCo may take advantage of economical market capacity and energy opportunities. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

4.5.2 New Supply-side Capacity Alternatives

Natural gas base/intermediate and peaking generating technologies were considered in this IRP as well as large-scale solar and wind. Further details on these technologies are available in Exhibit B of the Appendix. To reduce the computational problem size within *Plexos®*, the number of alternatives explicitly modeled was reduced through an economic screening process which analyzed various supply options and developed a quantitative comparison for each duty-cycle type of capacity (i.e., base-load, intermediate, and peaking) on a forty-year, levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed Operations and Maintenance (O&M) costs, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

The best of class technology, for each duty cycle, determined by this screening process was explicitly modeled in *Plexos®*. These generation technologies were intended to represent reasonable proxies for each capacity type (base-load, intermediate, peaking). Subsequent substitution of specific technologies could occur in any later plan, based on emerging economic or non-economic factors not yet identified.

AEP continually tracks and monitors changes in the estimated cost and performance parameters for a wide array of generation technologies. Access to industry collaborative organizations such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers, as well as its own experience and market intelligence, provides AEP with current estimates for the planning process. Table 14, below, offers a summary of the most recent technology performance parameter data developed. Additional parameters such as the quantities and rates of solid waste production, hazardous material consumption, and water consumption are significant; however the options which passed the screening phase and were included in *Plexos*® were natural gas facilities which generally have limited impacts on these areas of concern.

Table 14. New Generation Technology Options with Key Assumptions

Type	Capability	Emission Rates			Capacity Factor	Overall Availability
		SO_2	NO_x	CO_2		
	(MW)(a)	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	(%)	(%)
Base Load						
Nuclear	1610	0.0000	0.000	0.0	90	94
Base Load (90% CO2 Capture New Unit)						
Pulv. Coal (Ultra-Supercritical) (PRB)	540	0.1000	0.070	21.3	85	90
IGCC "F" Class (PRB)	490	0.0600	0.060	21.3	85	88
Base / Intermediate (b)						
Combined Cycle (1X1 "F" Class)	380	0.0007	0.009	117.1	60	89
Combined Cycle (1X1 "J" Class)	480	0.0007	0.007	117.1	60	89
Combined Cycle (2X1 "J" Class)	1070	0.0007	0.007	117.1	60	89
Combined Cycle (2X1 "H" Class)	1020	0.0007	0.007	117.1	60	89
Peaking						
Combustion Turbine (2 - "E" Class) (b)	170	0.0007	0.009	117.1	25	93
Combustion Turbine (2 - "F" Class, w/evap coolers) (b)	470	0.0007	0.009	117.1	25	93
Aero-Derivative (1 - Large Machine)	110	0.0007	0.007	117.1	25	97
Aero-Derivative (2 - Large Machines) (b)	200	0.0007	0.007	117.1	25	97
Aero-Derivative (2 - Small Machines) (b)	100	0.0007	0.007	117.1	25	97
Recip Engine Farm (3 Engines) (b)	50	0.0007	0.018	117.1	25	98
Battery Storage (Lithium-Ion)	10	-	-	-	25	94

Notes: (a) Capability at Standard ISO Conditions at 1,000 feet above sea level
(b) Includes Dual Fuel capability and SCR environmental installation

4.5.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by APCo but were not included in the *Plexos*® resource optimization modeling analyses. The forecasted difference between APCo's load forecast and existing resources is such that a large, central generating station would not be required. In addition, for coal generation resources, the proposed EPA NSPS rulemaking effectively makes the construction of new coal plants environmentally/economically impractical due to the implicit requirement of Carbon Capture and Sequestration (CCS) technology. New nuclear construction is financially impractical since it would potentially require an investment of $7,000/kW or more.

Intermediate generating sources are typically expected to serve a load-following and cycling duty and effectively shield base-load units from that obligation. Historically, many generators relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired or gas-steam units to serve such load-following roles. Over the last several years, these units have improved ramp rates and regulation capability, and reduced downturn (minimum load capabilities). With the retirement of APCo's subcritical units, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

4.5.3.1 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 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% Lower 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 base-load 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.

4.5.4 Peaking Alternatives

Peaking generating sources 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 relatively little energy over an annual load cycle. As a result, fuel efficiency and other variable costs applicable to these resources are of lesser concern. Rather, this capacity should be obtained at the lowest practical installed/fixed cost, despite the fact that such capacity often has very high energy costs. Ultimately, such "peaking" resource requirements are manifested in the system load duration curve.

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.

4.5.4.1 Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" Combustion Turbine (CT) systems, air compressed by an axial compressor is mixed with fuel and burned in a combustion chamber. The resulting hot gas then expands and cools while passing through a turbine. 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 CT 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% Lower Heating Value), they are inexpensive to purchase, compact, and simple to operate.

4.5.4.2 Aeroderivatives (AD)

Aeroderivatives (AD) 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 7E frame machine requires 20 to 30 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 considerably higher a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. ADs 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 ADs 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) base-load generation processes become more complex limiting their ability to load-follow and; C) more intermediate coal-fueled generating units are retired from commercial service.

AD units weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an AD over an industrial turbine. AD units in the less than 100MW 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 AD units.

4.5.4.3 Reciprocating Engines (RE)

The use of Reciprocating Engines (RE) or internal combustion engines has increased over the last twenty years. According to EPRI, in 1993 about 5% of the total RE units sold were natural gas-fired spark ignition engines and post 2000 sales of natural gas-fired generators have remained above 10% of total units sold worldwide.

Improvements in emission control systems and thermal efficiency have led to the increased utilization of natural gas-fired RE generators incorporated into multi-unit power generation stations for main grid applications. RE generators' high efficiency, flat heat rate curves and rapid response make this technology very well suited for peaking and intermediate load service and as back up to intermittent generating resources. Additionally, the fuel supply pressure required is in the range of 40 to 70 psig; this lower gas pressure gives this technology more flexibility when identifying locations. A further advantage of RE generators is that power output is less affected by increasing elevation and ambient temperature as compared to gas turbine technology. Also, a RE plant generally would consist of multiple units, which will be more efficient at part load operation than a single gas turbine unit of equivalent size because of the ability to shut down units and to operate the remaining units at higher load. Common RE unit sizes have generally ranged from 8MW to 18MW per machine with heat rates in the range of 8,100 –to- 8,600 Btu/kWh (Higher Heating Value).

Regarding operating cost, RE generators have a somewhat greater variable O&M than a comparable gas turbine; however, over the long term, maintenance costs of RE are generally lower because the operating hours between major maintenance can be twice as long as gas turbines of similar size.

4.5.4.4 Battery Storage

The modeling of Battery Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing platform for stationary storage applications. The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 30MWh, with a round trip efficiency of 87%. For Capacity Performance considerations the assumed PJM capacity rating that was modeled was 5MW. To develop this resource, Generation Engineering Services considered a wide range of sources including: the

DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI TAGWEB, BNEF and battery storage equipment suppliers.

4.5.5 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the recent past, development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

4.5.5.1 Solar

4.5.5.1.1 Large-Scale Solar

Solar power comes in two forms to produce electricity: concentrating and photovoltaics. Concentrating solar — which heats a working fluid to temperatures sufficient to generate steam to power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that respect. Photovoltaics produce electricity on a smaller scale (typically 2kW to 20MW per installation) and can be distributed throughout the grid.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline (see Figure 29 below). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well.

Large-scale solar plants require less lead time to build than fossil plants. There is no defined limit for how much utility solar can be built in a given time. However, in practice, solar facilities are not added in an unlimited fashion given siting and regulatory constraints.

Solar resources were made available in the *Plexos* model with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that large-scale solar resources were available in yearly quantities up to 120MWac[12] of nameplate capacity starting in 2019. A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources. Additionally, this 120MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted, constructed, and interconnected by APCo in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be in the 6 to 8 acres range, implying that 600 to 800 acres of land would be required to develop 100MW of solar annually. Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of APCo's UCAP load obligation or 905MW[13].

For this IRP, the overall threshold for intermittent resource capacity additions, 30% for wind and 15% for solar, exceeds the PJM study's recommendation by 15%; this assumes that the RTO and other key stakeholders will advance the understanding, forecasting and management of intermittent resources, ultimately supporting a higher penetration level.

Certainly, as APCo gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Solar resources were available in two tiers. The overall pricing trend over the planning period is based on the BNEF utility scale solar pricing forecast. These prices were adjusted down based on an initial review of the APCo solar RFP. Both solar pricing tiers are based on an initial screen of proposals that were more closely aligned with the RFP request of 25MW. The first tier was priced at a "Best-In-Class" level and represents approximately 17% of the

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[12] Manufacturers usually quote system performance in DC watts; however electric service from the utility is supplied in AC watts. An inverter converts the DC electrical current into AC electrical current. Depending on the inverter efficiency, the AC wattage may be anywhere from 80 to 95 percent of the DC wattage.

[13] PJM's Evolving Resource Mix and System Reliability, March 30, 2017, pages 4 and 34.

proposals. Resources from this tier were available in blocks of 60MW, which is comprised of three 20MW installations. The second tier was priced at the average of the remaining proposals that aligned with the initial screen, and represented approximately 26% of the responses. Resources from this tranche were also available in 60MW blocks, again comprised of three 20MW installations. The RFP pricing discounts to the BNEF values were recognized over the next four years, in a linear declining impact approach; by 2022 the solar pricing assumptions revert back to BNEF values for tier 2 and a 10% discount off of tier 2 for tier 1 pricing. Figure 28 below illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs, which were extended at the end of 2015.

The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a two-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits two years prior to commercial operation, as long as construction has been commenced. The ITC benefit is included through 2030. At this point in time the 10% ITC benefit would become indiscernible from potential variations in forecasted prices.

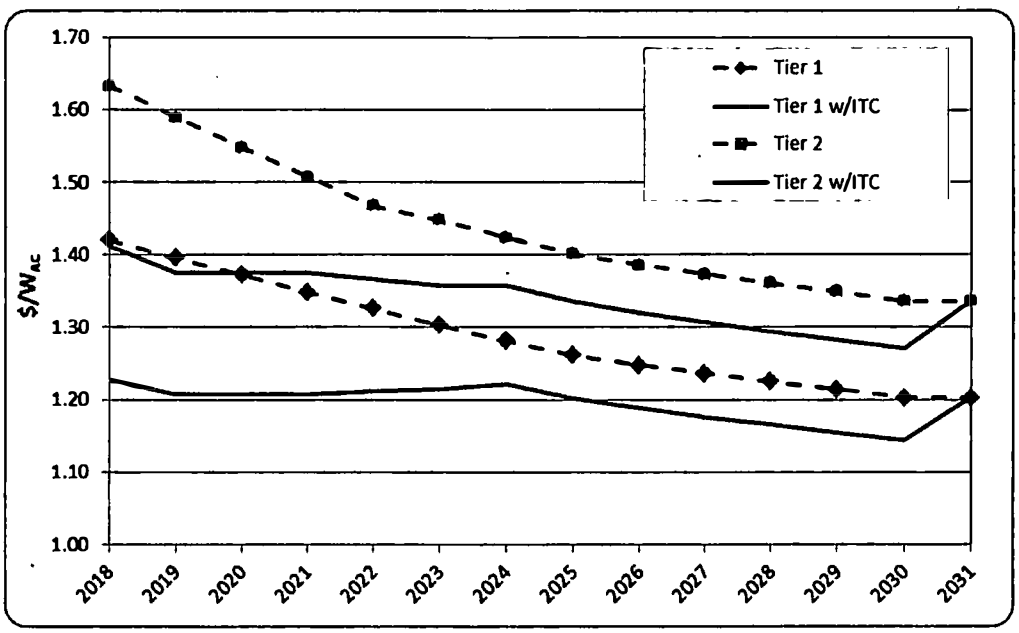

Figure 28. Large-Scale Solar Pricing Tiers

Solar resources' PJM capacity is less than its nameplate rating. This IRP assumes solar resources will have PJM capacity valued at 38% of nameplate rating.

4.5.5.1.2 Trends in Solar Energy Pricing

As mentioned above, solar energy prices have declined significantly in recent years as shown below in Figure 29. From 2010 to 2017 installation costs have declined by 50% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale installations costing 47% and 25% less than residential and commercial installations, respectively, based on 2017 costs.

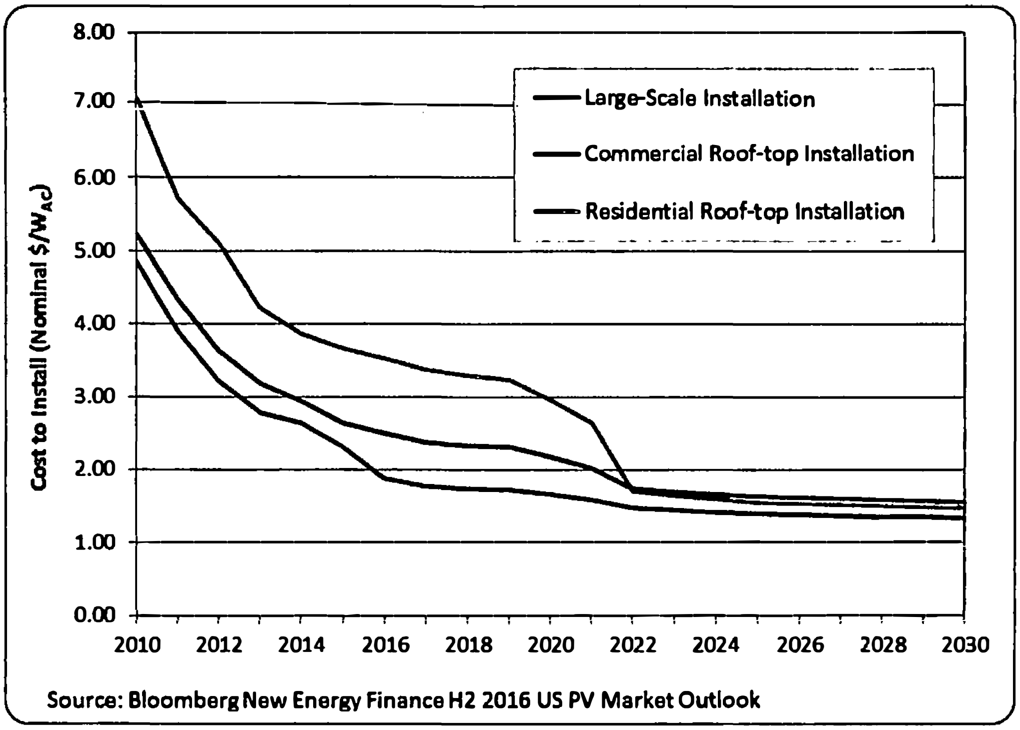

Figure 29. PJM Average Solar Photovoltaic (PV) Installation Cost (Nominal $/WAC) Trends, excluding Investment Tax Credit Benefits

4.5.5.2 Wind

Large-scale wind energy is generated by turbines ranging from 1.0 to 2.5MW. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical as not only does the wind resource vary by geography, but also its proximity to a transmission system with available capacity, which will factor into the cost.

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to over 50 percent (largely in more westerly portions of the U.S., including the Plains states), wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs.

Another consideration with wind power is that its most critical factors (*i.e.*, wind speed and sustainability) are typically highest in very remote locations, which forces the electricity to be transmitted long distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid.

In addition to already existing wind resources, APCo included 120MW (nameplate) of wind resources, which have been approved by both this Commission and the Public Service Commission of West Virginia, in the model, and assumed 225MW (nameplate) of wind resources would be added in 2019 as a result of its 2016 wind RFP. For modeling purposes, wind was considered under two 'blocks' or 'tranches' each year thereafter with different pricing and performance characteristics. The wind resources are first made available to the model in 2020, due to the amount of time necessary to obtain approval for and secure resources. Figure 30 below shows the LCOE prices of wind resource tranches assumed for the IRP. The first tranche of wind resources, Tranche A, was modeled as a 150MW resource, with a total of 300MW available each year through 2023. Beginning in 2024 a total of 150MW of Tranche A was available in each year. The change in the quantity available is intended to recognize a potential limit to the availability of quality wind resources within the PJM market. Tranche A has a 38% capacity factor load shape. The second tranche of wind resources, Tranche B, was modeled as a 150MW resource with a total of 150MW available in each year of the planning period. Tranche B has a 35% capacity factor load shape. The pricing of both tranches reflect the full value of Federal Production Tax Credits (PTCs) in 2020. After 2020 tax credits reduce to 80%, 60% and 40% of their 2020 value in 2021, 2022, and 2023, respectively. These PTC values are based on developers taking advantage of the safe-harbor guidelines which provide up to a four year delay in the effects of declining tax credits as long as adequate construction has commenced. Both tranches were assigned a capacity value of 5% of nameplate rating based upon APCo's current evaluation of the PJM Capacity Performance rule. Wind prices were developed based on the U.S. DOE's Wind Vision Report and market knowledge.[14]

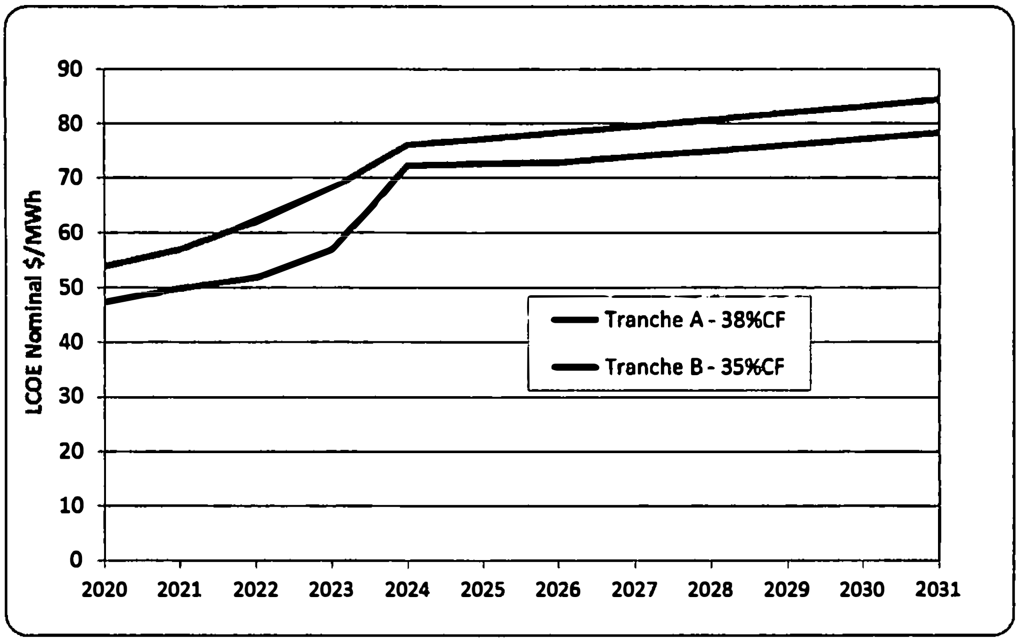

Figure 30. Levelized Cost of Electricity of Wind Resource Tranches (Nominal $/MWh)

The expected magnitude of wind resources available per year was limited to 450MW nameplate through 2023, and 300MW nameplate beginning in 2024. Wind resources were

[14] *Wind Vision: A New Era for Wind Power in the United States* (2015). Retrieved from http://www1.eere.energy.gov/library/default.aspx?Page=9

limited to a total of 1,800MW nameplate over the planning period. The annual limit on wind additions is based on APCo's ability to plan, manage and develop either the construction or the procurement of these resources. As with solar resource additions, as APCo gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater later). This cap is based on the DOE's Wind Vision Report[15] which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe. The cap for APCo allows the model to select up to 30% of generation capacity resources as wind-powered by 2035.

4.5.5.3 Hydro

The available sources of, particularly, larger hydroelectric potential have largely been exploited and those that remain must compete with the other uses, including recreation and navigation. The potentially lengthy time associated with environmental studies, Federal Army Corp of Engineer permitting, high up-front construction costs, and environmental issues (fish and wildlife) make new hydro prohibitive at this time. As such, no incremental hydroelectric resources were considered in this IRP.

4.5.5.4 Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switchgrass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials. Biomass costs will vary significantly depending upon the feedstock. Biomass is typically used in power generation to fuel a steam generator (boiler) that subsequently drives a steam turbine generator; similar to the same process of many traditional coal fired generation units. Some biomass generation facilities use biomass as the primary fuel, however, there are some existing coal-fired generating stations that will use biomass as a blend with the coal. Given these factors, plus the typical high cost and required

[15] Specifically, Figure 1-5, p.12

feedstock supply and attendant long-term pricing issues, no incremental biomass resources were considered in this IRP.

4.6 Integration of Supply-Side and Demand-Side Options within *Plexos®* Modeling

Each supply-side and demand-side resource is offered into the *Plexos®* model on an equivalent basis. Each resource has specific values for capacity, energy production (or savings), and cost. The *Plexos®* model selects resources in order to reduce the overall portfolio cost, regardless of whether the resource is on the supply- or demand-side.

4.6.1 Optimization of Expanded DSM Programs

As described in Section 4.4.3, EE and VVO options that would be incremental to the current programs were modeled as resources within *Plexos®*. In this regard, they are "demand-side power plants" that produce energy according to their end use load shape. They have an initial (program) cost with *no* subsequent annual operating costs. Likewise, they are "retired" at the end of their useful (EE measure) lives (see Table 10 and Table 11).

4.6.2 Optimization of Other Demand-Side Resources

Customer-sited DG, specifically rooftop solar, was not modeled. Instead, reductions in energy use and peak demand were built into the load forecast based on the adoption rates discussed in Section 4.4.3.4.

CHP was modeled as a high thermal efficiency, NGCC facility, as described in Section 4.4.3.6.

4.7 Market Alternatives

As discussed above, the IRP considers proxy supply- and demand-side resource options to develop an optimum solution based on the inputs provided. In developing the input resources' costs and performance characteristics, APCo works with various subject matter experts both within and external to the company to develop reasonable proxy resources to be modeled in the IRP. Typically, the experts will use various approaches to develop the proxy estimates. These approaches for example, could include market comparable, recent internal projects and industry collaboration.

Figure 31 below, prepared by IHS as part of their North American Power Update, published in March 2017, summarizes recent power purchase agreements by technology for the United States.

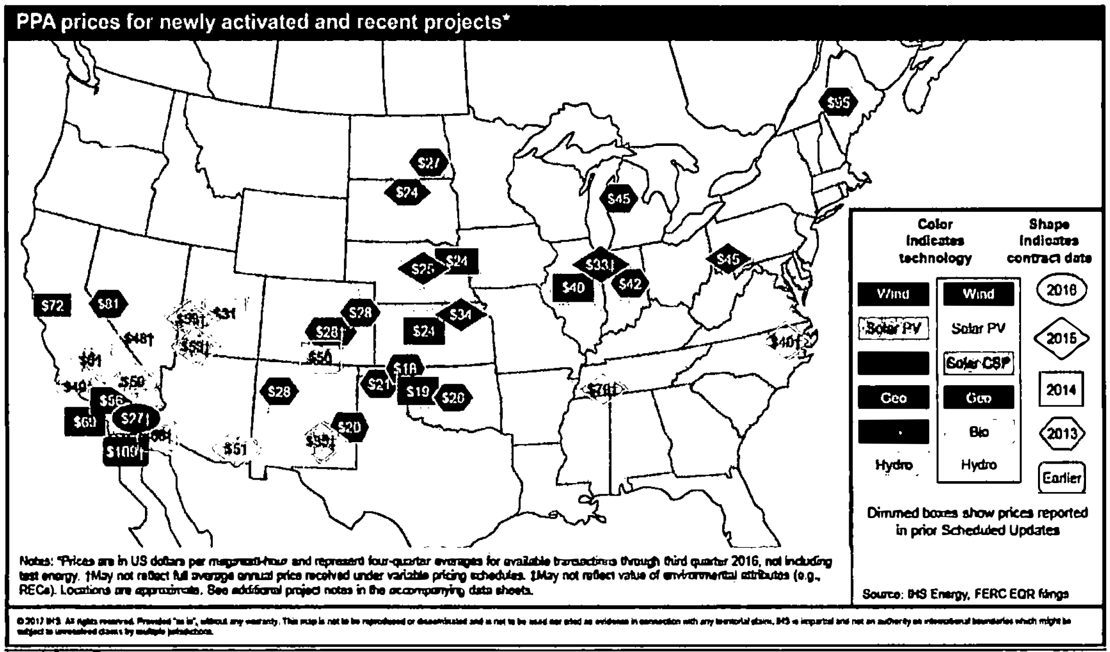

Figure 31. U.S. Renewable PPA Prices

This data set identifies key renewable technology that is being deployed and reported pricing within the U. S. and the PJM region. The data shows there is limited value to be gained for both wind and solar PPA transactions in PJM, especially related to recent transactions in 2016. The data shows one solar transaction in 2015 in the eastern portion of the U.S. and two 2015 wind transactions in PJM. Such limited data is of little value for APCo's IRP purposes.

APCo also examined planned new resource deployments through the use of SNL's dataset. Table 15 below shows new generating capacity within PJM which is scheduled to be in-service in 2017 or 2018.

1 7 0 5 1 0 0 7 7

Table 15. PJM Total New Generating Capacity and Cost by Type (Under Construction) – 2017 and 2018 In-Service Dates

Type of Capacity	Generating Capacity		Construction Cost (Est. Weighted)
	(MW)	(%)	($/kW)
Combined Cycle (CC)	***14,397***	***91.3%***	***1,081***
Renewables			
Wind	1,135	7.2%	1,934
Solar	53	0.3%	2,596
Total	***1,188***	***7.5%***	***1,963***
Internal Combustion			
Natural Gas	22	0.1%	1,200
Biomass	160	1.0%	6,250
Total	***182***	***1.2%***	***5,640***
Total PJM New Capacity)	**15,767**	**100.0%**	

Based upon a review of this market data and APCo's RFP data for wind and solar resources[16], APCo has concluded it is reasonable to rely primarily on RFP data for short-term IRP pricing assumptions for both wind and solar resources, and on the DOE Wind Vision report for wind, and BNEF for solar, long-term IRP pricing trends. A complete description of the solar resource assumptions is in Section 4.5.5.1 and the wind resource assumptions are in Section 4.5.5.2. For the combined cycle assumptions, APCo is utilizing a 25% share of an advanced gas turbine technology, in a 2x1 configuration, with an estimated cost of $1,000/kW, and a full load heat rate of approximately 6,300 Btu/kWh High Heating Value, as shown in Exhibit B.

[16] Wind RFP process took place from January 5, 2016 – April 1, 2016;
Solar RFP process took place from January 19, 2017 – March 9, 2017

5.0 Resource Portfolio Modeling

5.1 The *Plexos*® Model - An Overview

Plexos® LP long-term optimization model, also known as "LT Plan®," served as the basis from which the APCo-specific capacity requirement evaluations were examined and recommendations were made. The LT Plan® model finds the optimal portfolio of future capacity and energy resources, including DSM additions, which minimizes the CPW of a planning entity's generation-related variable and fixed costs over a long-term planning horizon. By minimizing CPW the model will provide optimized portfolios with the lowest and most stable customer rates, while adhering to the Company's constraints. Low, stable rates benefit the entire region by attracting new commercial and industrial customers, and retaining/expanding existing load.

Plexos® accomplishes this by using an objective function which seeks to minimize the aggregate of the following capital and production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, *i.e.,* carrying charges on incremental capacity additions (based on an APCo-specific, weighted average cost of capital), and fixed O&M;
- fixed costs of any capacity purchases;
- program costs of (incremental) DSM alternatives;
- variable costs associated with APCo generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances and/or carbon 'tax,' and variable O&M costs;
- distributed, or customer-domiciled, resources which were effectively valued at the equivalent of a full-retail "net metering" credit to those customers; and
- a 'netting' of the production revenue earned in the PJM power market from APCo's generation resource sales *and* the cost of energy – based on unique load shapes from PJM purchases necessary to meet APCo's load obligation.

Plexos® executes the objective function described above while abiding by the following possible constraints:

- Minimum and maximum reserve margins;
- resource additions (i.e., maximum units built);
- age and lifetime of power generation facilities;
- retrofit dependencies (SCR and FGD combinations);
- operation constraints such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- fuel burn minimum and maximums;
- emission limits on effluents such as SO_2 and NO_x; and
- energy contract parameters such as energy and capacity.

The model inputs that comprise the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. *Plexos*® does not develop a full regulatory Cost-of-Service (COS) profile. Rather, it typically considers only the relative load and generation COS *that changes from plan-to-plan*, and not fixed "embedded" costs associated with existing generating capacity and demand-side programs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital expenditures for transmission interconnection costs.

5.1.1 Key Input Parameters

Two of the major underpinnings in this IRP are long-term forecasts of APCo's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas and, potentially, CO_2/carbon. Both forecasts were created internally within AEP. The load forecast was created by the AEP Economic Forecasting organization, while the long-term commodity pricing forecast was created by the AEP

Fundamental Analysis group. These groups have many years of experience forecasting APCo and AEP system-wide demand and energy requirements and fundamental pricing for both internal operational and regulatory purposes. Moreover, the Fundamental Analysis group constantly performs peer review by way of comparing and contrasting its commodity pricing projections versus "consensus" pricing on the part of outside forecasting entities such as IHS-Cambridge Energy Research Associates (CERA), Petroleum Industry Research Associates (PIRA) and the EIA.

Another input parameter of note is the PJM capacity reserve margin. The PJM capacity reserve margin, combined with APCo's forecasted demand, set the limit for the minimum capacity required to maintain service reliability within the region. Each of the scenarios modeled below are optimized while adhering to this constraint. This ensures that each of the scenarios considered will result in an acceptable amount of generation available to APCo customers.

With regard to environmental regulations, the estimated, potential impact of current and pending regulations was factored into the analyses of potential resource plans by adding incremental costs to comply. As a proxy for modeling the effect of, and a cost-effective means of complying with, the CPP proposal this IRP analyzed both mass-based and rate-based approaches, and for each of those approaches it considered market, stand-alone (island), and federal plan views.

Additional critical input parameters include the installed cost of replacement capacity alternative options, as well as the attendant operating costs associated with those options. This data came from the AEP Engineering Services organization.

5.2 *Plexos*® Optimization

5.2.1 Modeling Options and Constraints

The major system parameters that were modeled are elaborated on below. The *Plexos* LT Plan® models these parameters in tandem with the objective function in order to yield the least-cost resource plan.

There are many variants of available supply-side and demand-side resource options and types. As a practical limitation, not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for baseload, intermediate, and peaking duty cycles.

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes. Other factors which will determine the ultimate technology type (e.g., choices for peaking technologies) are taken into consideration. The full list of screened supply options is included in Exhibit B of the Appendix.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Plexos*® for each designated duty cycle:

- *Peaking* capacity was modeled, effective in 2020 due to the anticipated period required to approve, site, engineer and construct, from:
    - A 50% share of two CT units consisting of "F" class turbines with evaporative coolers and dual fuel capability, rated at 470MW total at summer conditions.
    - AD units consisting of 1 GE LMS 100 turbines at 112MW total at summer conditions.
    - Battery Storage units available in 10MW blocks per year.
- *Intermediate-Baseload* capacity was modeled, effective in 2022 due to anticipated period required to approve, site, engineer and construct, from:
    - A 25% share of a NGCC (2x1 "J" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 1,373MW at summer conditions. The 25% interest assumes APCo coordinates the addition of this resource with other parties.
- Wind resources were made available up to 450MW annually through 2023, and 300MW thereafter. From 2020 to 2023, two units (150MW/each) of Tranche A were available and post 2023 150MW of Tranche A was available. One 150MW unit of Tranche B was available each year. Tranche A had a

LCOE of $47.50/MWh, in 2020 with the PTC. Tranche B had a LCOE of $54/MWh, in 2020 with the PTC. Wind resources were assumed to have a PJM capacity value equal to 5% of nameplate rating.

- Large-scale solar resources were made available in two tranches, with up to 60MW of each tier available each year, for a total of up to 120MW annually. Initial costs for Tier 1 were approximately $1,210/kW in 2020 with the ITC. Tier 2 has an initial cost of approximately $1,370/kW in 2020, with the ITC benefits. Solar resources were assumed to have a PJM capacity value equal to 38% of nameplate rating.
- DG, in the form of distributed solar resources, was embedded in incremental amounts equal to a CAGR of 22.5% over the planning period.
- CHP resources were made available in 15MW (nameplate) blocks, with an overnight installed cost of $2,000/kW and assuming full host compensation for thermal energy for an effective full load heat rate of ~4,800 Btu/kWh.
- EE resources—incremental to those already incorporated into the Company's long-term load and peak demand forecast—in up to 21 unique "bundles" of Residential, Commercial, and Industrial measures considering cost and performance parameters for both HAP and AP categories. Industrial measures were limited to lighting.
- VVO was available in 15 tranches of varying installed costs and number of circuits/sizes ranging from a low of 5.5MW, up to 15.3MW of demand savings potential.

5.2.2 Traditional Optimized Portfolios

The key decision to be made by APCo during the planning period is how to fill the resource need identified. Portfolios with various options addressing APCo's capacity and energy resource needs over time were optimized under various conditions. Six traditional scenarios were initially analyzed for this IRP, resulting in six unique portfolios. The modeled portfolios shown in Table 16, and discussed below, represent incremental resources which are in addition to those currently in-service. The portfolios do not include APCo's planned additions of wind and solar resources discussed in Section 3.2, which are assumed to be in-service in 2018 and 2019.

Table 16. Traditional Scenarios/Portfolios

Type	Name	Commodity Pricing Conditions	Load Conditions
Commodity Pricing Scenarios	No Carbon	No Carbon	Base
	Mid	Mid	Base
	Low Band	Low Band	Base
	High Band	High Band	Base
Load Scenarios	Low Load	Mid	Low
	High Load	Mid	High

Once the details of model inputs were finalized, an initial modeling exercise was conducted to validate these inputs and ensure the model was producing plausible optimized portfolios. The capacity additions for the optimized portfolio resulting from this exercise are shown below in Table 17. Note that the term "firm" in the following capacity addition tables represents PJM capacity.

Table 17. Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for Initial Modeling Exercise

Initial Exercise		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2017-2031)
Mid Commodity Prices, Base Load	Base/Intermediate																5,184	3,440
	Peaking																	
	Solar (Firm)							8	30	53	76	114	160	205	251	274		
	Solar (Nameplate)							20	80	140	200	300	420	540	660	720		
	Wind (Firm)				15	30	45	53	53	53	53	53	53	60	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350		
	Battery Storage																	
	Energy Efficiency			38	71	101	140	184	241	250	260	270	282	296	299	303		
	CHP																	
	VVO						17	30	30	30	30	41	41	41	41	41		
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; VVO=Volt VAR Optimization; DG=Distributed Generation

As shown above in Table 17, the initial modeling portfolio included significant levels of renewable energy and EE. Beginning in 2026, the model was initially constrained to select incremental resources only up to the point where APCo had a 15% reserve margin, which is about 6% greater than the 8.92% reserve margin required by PJM (see Section 3.2). The additional 6% equated to approximately 300MW of resources. The initial modeling portfolio approached the limit in each year from 2026-2036. The additional 300MW of capacity could present a risk to APCo customers in the event that market prices deviate from forecasted values. In order to mitigate the customers' exposure to market risk APCo opted to modify the reserve margin constraint to 150MW beyond the PJM requirement, in the years 2026-2036, for all other scenarios analyzed in this IRP.

5.2.2.1 No Carbon Commodity Pricing Portfolio

Table 18 below shows the results of the No Carbon scenario. The No Carbon portfolio sets out the resources which would be used to satisfy APCo's capacity and energy needs, absent any restrictions due to carbon regulations. Because it assumes no carbon regulation throughout the forecast period of this IRP, the commodity prices upon which the No Carbon portfolio is based are fundamentally different than those used in the CPP-compliant scenarios. Consequently, the No Carbon scenario should not be considered to be a baseline for comparison with CPP compliant plans. In the No Carbon scenario APCo would add 900MW (nameplate) of wind generation and 380MW (nameplate) of solar generation by the end of the planning period. This portfolio would also include demand-side resources consisting of VVO, EE and DG.

Table 18. Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for No Carbon Commodity Pricing Scenarios

Commodity Pricing Scenario		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2017-2031)
No Carbon	Base/Intermediate																238	1,664
	Peaking																	
	Solar (Firm)											23	46	76	122	144		
	Solar (Nameplate)											60	120	200	320	380		
	Wind (Firm)				15	30	45	45	45	45	45	45	45	45	45	45		
	Wind (Nameplate)				300	600	900	900	900	900	900	900	900	900	900	900		
	Battery Storage																	
	Energy Efficiency			30	55	75	98	126	150	155	159	169	181	194	198	202		
	CHP																	
	VVO											17	17	17	17	17		
	Demand Response																	
	DG	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; VVO=Volt VAR Optimization; DG=Distributed Generation

5.2.2.2 Mid, Low Band, High Band Commodity Pricing Portfolios

Table 19 below shows the capacity additions associated with the Mid, Low Band, and High Band commodity pricing scenarios. Recall from Section 4.3.1 that each of these scenarios includes a unique set of prices for CO_2 emission allowances.

Table 19. Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for Mid, Low Band and High Band Commodity Pricing Scenarios

Commodity Pricing Scenario		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2017-2031)
Mid	Base/Intermediate																4,185	2,873
	Peaking																	
	Solar (Firm)											23	46	68	114	137		
	Solar (Nameplate)											60	120	180	300	360		
	Wind (Firm)				15	30	45	53	53	53	53	53	53	60	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350		
	Battery Storage																	
	Energy Efficiency			30	52	73	95	117	138	142	145	156	167	180	182	186		
	CHP																	
	VVO											17	17	17	17	17		
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		
Low Band	Base/Intermediate																2,803	2,159
	Peaking																	
	Solar (Firm)											23	46	84	129	152		
	Solar (Nameplate)											60	120	220	340	400		
	Wind (Firm)				15	30	45	45	45	45	45	45	45	45	45	45		
	Wind (Nameplate)				300	600	900	900	900	900	900	900	900	900	900	900		
	Battery Storage																	
	Energy Efficiency			27	50	70	92	121	148	153	156	166	177	190	193	197		
	CHP																	
	VVO											17	17	17	17	17		
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		
High Band	Base/Intermediate																5,260	3,760
	Peaking																	
	Solar (Firm)											23	61	99	137	160		
	Solar (Nameplate)											59	159	259	359	420		
	Wind (Firm)				15	30	45	53	53	53	53	53	60	68	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350	1,350		
	Battery Storage																	
	Energy Efficiency			30	55	75	98	125	141	145	147	157	168	181	181	184		
	CHP																	
	VVO																	
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; VVO=Volt VAR Optimization; DG=Distributed Generation

All three portfolios include similar resource additions, such as:

- Wind resources of 900MW (nameplate) or more beginning in 2020;
- solar resources of 360MW (nameplate) or more beginning in 2027; and
- EE programs totaling 184MW or more by 2031

The total amount of resource additions is similar in each scenario given the model's constraint of limiting resource additions to only 150MW beyond the PJM requirement.

All three portfolios results in APCo having a positive annual net energy position in the last year of the planning period, 2031.

5.2.2.3 Load Sensitivity Scenario Portfolios

Table 20 below shows the capacity additions associated with the Low Load and High Load sensitivity scenarios, using Mid commodity prices.

Table 20. Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for Low Load and High Load Sensitivity Scenarios

Load Sensitivities		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2017-2031)
Low Load	Base/Intermediate																5,931	4,494
	Peaking																	
	Solar (Firm)												8	30	53	61		
	Solar (Nameplate)												20	80	140	160		
	Wind (Firm)				15	30	45	53	53	53	53	53	53	53	53	60		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,200		
	Battery Storage																	
	Energy Efficiency			25	44	57	69	82	85	86	88	97	108	118	118	121		
	CHP																	
	VVO																	
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		
High Load	Base/Intermediate										330	330	330	330	330	330	4,285	1,973
	Peaking																	
	Solar (Firm)								23	46	68	114	160	205	251	289		
	Solar (Nameplate)								60	120	180	300	420	540	660	760		
	Wind (Firm)				15	30	45	53	53	53	53	53	53	60	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350		
	Battery Storage																	
	Energy Efficiency			30	63	90	124	169	225	235	245	255	267	281	285	289		
	CHP																	
	VVO						17	17	17	17	17	30	41	51	61	69		
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

As expected, the overall capacity additions in the High Load scenario are naturally greater than those in the Low Load scenario. The High Load scenario calls for NGCC capacity (25% of a 2x1 facility), as well as higher quantities of wind and large-scale solar resources as compared to the Low Load scenario.

5.2.3 Clean Power Plan (CPP) Scenarios

In December of 2016 the Commission issued its Final Order in APCo's 2016 IRP. In its Order the Commission required, among other things, that APCo model and present, at a minimum, the following scenarios:

- *Least-cost base plan (non-compliant with the CPP);*

- *Least-cost CPP-compliant intensity-based plan (regional and island approaches);*
- *Least-cost CPP-compliant mass-based plan (regional and island approaches);*
- *Federal implementation plan, and*
- *Company-preferred plan, if any.*

Modeling compliance with the CPP presents challenges. CPP compliance plans could be implemented at various levels (e.g. state-specific, regional, national, etc.) and currently the four states in which APCo owns (or purchases) fossil generation – Virginia, West Virginia, Ohio and Indiana – have not provided guidance on preference for a type of plan or design elements. Furthermore, the stay issued by the U.S. Supreme Court and the review initiated by the Trump Administration will likely delay the development of compliance plans and strategies. Without knowing the specific details of each state's compliance strategy, any modeling results should be viewed as indicative only, based on the need to incorporate numerous assumptions for what today are large unknowns in both policy choices and market outcomes. With this in mind, the following portfolios should be reviewed with careful understanding of the parameters under which they were modeled. Furthermore, given the speculative nature of the assumptions used and the scope of the study, it is premature to make substantive conclusions from this analysis as to prudent state compliance decisions.

For this IRP, mass-based and rate-based CPP compliance scenarios were considered. In a mass-based scenario, APCo is assumed to be allocated a specific number of CO_2 emission allowances each year (i.e. an amount of CO_2 mass) for each applicable state. APCo's generation is then monitored throughout the year to determine the total mass of CO_2 which has been emitted by units in each state. Each ton of emissions requires one emission allowance for compliance purposes. In a rate-based scenario, APCo generates ERCs in MWh for eligible renewable energy and EE programs in each applicable state. APCo's generation is then monitored throughout the year to determine the amount of CO_2 emissions per MWh of generation. The ERCs are used to help demonstrate compliance by providing emission free MWhs in the rate calculation, which help to lower APCo's CO_2 emission rate. More details on the four compliance methods considered in this IRP are as follows:

- **Mass-based - Island**

APCo is constrained to comply with a total company total mass limit of CO_2 emissions absent access to additional emissions allowances from an external market. APCo's limit is determined by APCo's pro rata share of historical (2012), state-specific emissions in each state which APCo has generating assets (Indiana, Ohio, Virginia, and West Virginia). The assumed emission limit, which would correspond to an allocation of allowances, is speculative in that states ultimately have authority over the allocation of allowances and could utilize a different methodology. Additionally, this scenario assumes that allowances would be fungible across the four states in which APCo has affected generation and that allocations are received in perpetuity. Table 21 below displays the assumed allowance allocations for APCo.

Table 21. APCo Assumed Average Annual Allowance Allocations (short tons)

State	2012 *(Actual)*	2024-2026	2027-2029	2030-2031	2032+
Indiana	*1,019,000*	848,000	772,000	727,000	702,000
Ohio	*1,895,000*	1,638,000	1,493,000	1,411,000	1,365,000
Virginia	*1,016,000*	890,000	825,000	794,000	780,000
West Virginia	*23,354,000*	20,202,000	18,331,000	17,230,000	16,575,000
Total-APCo	***27,284,000***	**23,578,000**	**21,421,000**	**20,162,000**	**19,422,000**

- **Mass-based - Market**

APCo is constrained to comply with a total company mass limit of CO_2 emissions and is able to procure additional emissions allowances from an external market. Initial allowances are allocated in the same manner as the island approach above. Given that the Mass-based – Market CO_2 pricing and dispatch constraints were the same as those included in the Mid, Low Band, and High Band commodity pricing scenarios discussed above in Section 5.2.2.2, no additional scenarios were modeled.

- **Rate-based - Island**

APCo is constrained to comply with a total company rate-based limit of CO_2 emissions (lb./MWh), absent of access to ERC's from an external market. It was assumed that the ERCs generated by eligible renewables or EE would be fungible across the four states in which APCo has affected generation. Table 22 below shows the total company (i.e. state-composite) weighted ERC targets. The targets are based on the EPA's subcategory emissions rates for 'Fossil-Steam' and '(Existing) NGCC' resources, shown in Table 23.

Table 22. APCo Assumed Annual (Weighted) Emission Rate Credit (ERC) Targets (lb./MWh)

	2012 *(Actual)*	2024-2026	2027-2029	2030-2031	2032+
Total-APCo	*1,961*	1,599	1,442	1,330	1,262

Table 23. Sub-Category Emission Rate Credit (ERC) Targets (short tons)

Sub-Category	2024-2026	2027-2029	2030-2031	2032+
Fossil-Steam	1,671	1,500	1,380	1,305
NGCC	877	817	784	770

- **Rate-based - Market:**

APCo is constrained to comply with a total company rate-based limit of CO_2 emissions (lb./MWh), and is able to procure additional ERCs from an external market. Rate-based limits were determined in the same manner as the island approach discussed above.

The Mass and Rate emission targets shown above in Table 21 and Table 22 represent a two year delay in the implementation of the CPP. In other words, when compared to the EPA's emission goals discussed in Section 3.3.8 the targets above take effect two years later.

In order to provide flexibility to meet CPP-related constraints, additional supply-side resource options were made available to the model during the optimization of the CPP scenarios described above. The options only affected APCo's large coal-fired units at the Amos and Mountaineer plants, and consisted of the following:

- Unit curtailments were considered as alternatives for Amos Units 1, 2 and 3 and Mountaineer Unit 1;
- co-firing on natural gas was considered for Amos Units 2 and 3; and
- the retirement of Amos Unit 1.

5.2.3.1 Clean Power Plan Mass-Based Scenario Portfolios

5.2.3.1.1 Mass-Based- Island

Table 24 below shows the capacity additions associated with the Mass-Based – Island CPP scenario. In order to meet APCo's CO_2 limits without an external market the optimized portfolio includes the retirement of Amos Unit 1 in 2026, as well as unit curtailments. During the planning period Amos Units 2 and 3 were each curtailed to run at capacity factors as low as 35%. Mountaineer Unit 1 was curtailed to run at a capacity factor as low as 60%.

Table 24. Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for Mass-based – Island CPP Scenario

CPP Analyses		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2017-2031)
Mass Based - Island	Base/Intermediate										330	330	330	330	330	330	(1,555)	362
	Peaking																	
	Solar (Firm)					8	30	53	76	99	122	167	213	258	304	327		
	Solar (Nameplate)					20	80	140	200	260	320	440	560	680	800	860		
	Wind (Firm)				15	30	45	53	53	53	53	53	53	60	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350		
	Battery Storage																	
	Energy Efficiency			38	71	106	144	192	248	261	275	289	303	317	323	330		
	CHP																	
	VVO						17	30	41	51	61	69	69	69	78	86		
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

5.2.3.1.2 Mass-Based - Market

As mentioned above, the Mid, Low Band, and High Band commodity pricing portfolios represent compliance plans under a Mass-Based approach with access to allowances in an external market. Capacity additions associated with these portfolios are shown above in Table 19.

5.2.3.1.3 Clean Power Plan Mass-Based Portfolio CO_2 Emissions

Figure 32 below illustrates the emissions of CO_2 for each of the Mass-Based CPP scenario portfolios. The island approach forces the model to optimize the portfolio of resources such that CO_2 emissions stay below the Company limit. In the Mass-Based – Market scenarios each portfolio may emit more CO_2 than the initial limit due to the availability of additional allowances in an external market. The quantity of the additional allowances needed in each market plan is represented in Figure 32 as the distance between each market scenario trend line and the dashed black target line.

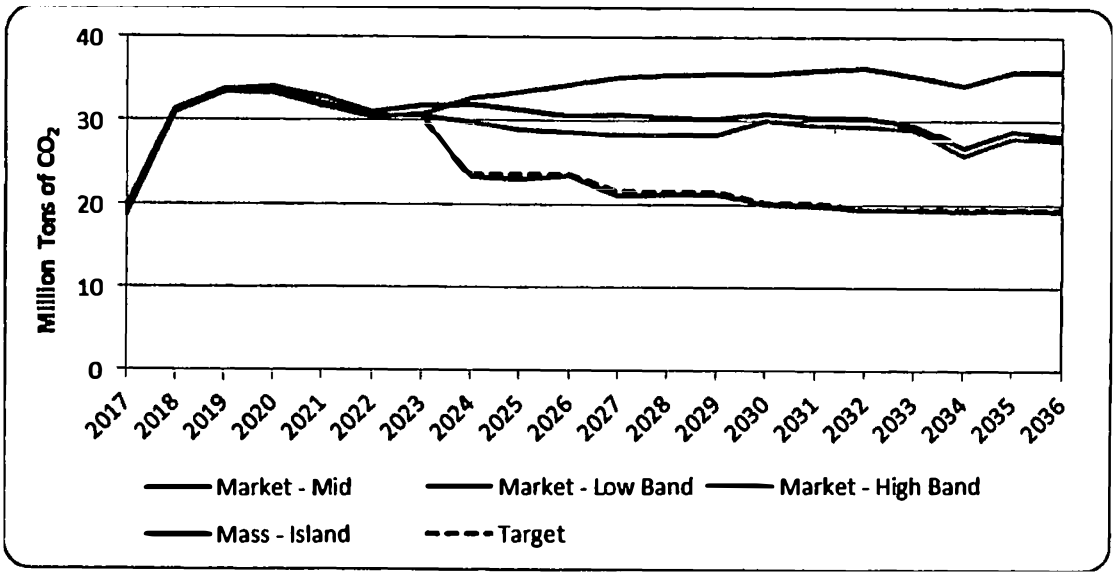

Figure 32. Mass-Based CPP Scenario Emissions (Million Tons of CO_2) vs. Target

5.2.3.2 Clean Power Plan Rate-Based Scenario Portfolios

5.2.3.2.1 Rate-Based - Island

Table 25 below shows the capacity additions associated with the Rate-Based – Island CPP scenario. The Rate-Based – Island plan calls for the addition of NGCC capacity in 2026 (25% of a 2x1 facility) as well as amounts of large-scale solar and wind generation. This portfolio further seeks to add additional carbon-free capacity resources with increased amounts of VVO (109MW). In order to meet APCo's CO_2 limits without an external market the optimized portfolio includes the retirement of Amos Unit 1 in 2026, as well as unit curtailments. During the planning period Amos Units 2 and 3 were each curtailed to run at capacity factors as low as 60%. Mountaineer Unit 1 was curtailed to run at a capacity factor as low as 70%.

Table 25. Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for Rate-based – Island CPP Scenario

CPP Analyses		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2017-2031)
Rate Based - Island	Base/Intermediate										330	330	330	330	330	330	874	3,180
	Peaking																	
	Solar (Firm)				23	46	68	91	137	182	220	266	312	334	334	334		
	Solar (Nameplate)				60	120	180	240	360	480	580	700	820	880	880	880		
	Wind (Firm)				15	30	45	53	53	53	53	53	60	68	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350	1,350		
	Battery Storage																	
	Energy Efficiency			38	71	106	144	192	249	262	276	289	305	320	324	329		
	CHP																	
	VVO			17	17	17	30	41	51	61	69	78	86	94	102	109		
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

5.2.3.2.2 Rate-Based - Market

Table 26 below shows the capacity additions associated with the Rate-Based – Market CPP scenario.

Table 26. Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for Rate-based – Market CPP Scenario

CPP Analyses		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2017-2031)
Rate Based - Market	Base/Intermediate																11,575	6,082
	Peaking																	
	Solar (Firm)											38	61	99	137	160		
	Solar (Nameplate)											100	160	260	360	420		
	Wind (Firm)				15	30	45	53	53	53	53	53	60	68	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350	1,350		
	Battery Storage																	
	Energy Efficiency			30	52	73	95	119	140	144	147	157	168	180	180	182		
	CHP																	
	VVO																	
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	91	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

The Rate-Based Market plan does not include unit retirements, curtailments, or co-firing. Substantial amounts of carbon-free energy and capacity are included with the addition of large-scale solar and wind resources.

5.2.3.2.3 Clean Power Plan Rate-Based Portfolio CO_2 Emissions

Figure 33 below illustrates the emission rates for each of the Rate-Based CPP scenario portfolios during select years. The island approach forces the model to optimize the portfolio of resources such that CO_2 emissions stay below the Company limit. In the Rate-Based Market scenarios each portfolio may emit CO_2 at a higher rate than the initial limit due to the availability of additional ERCs from an external market. The quantity of the additional ERC's needed in each market plan is represented in Figure 33 as the difference between the "Pre-ERC Market Rate" column in blue and the "Target" rate shown in green.

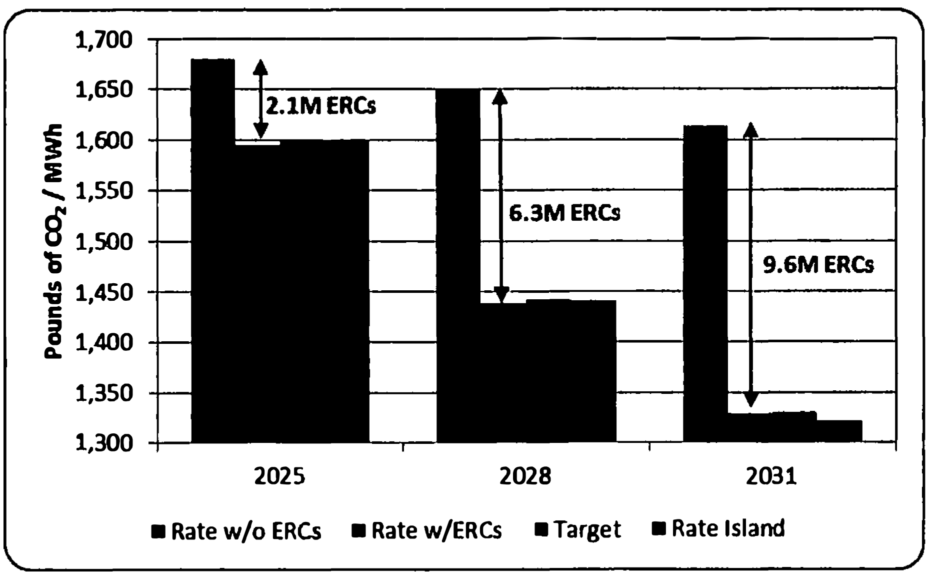

Figure 33. Rate-Based CPP Scenario Emissions (lbs. CO_2/MWh) vs. Target

5.2.3.3 Comparing Clean Power Plan Scenario Costs

The cost of the CPP compliant plans may be compared, to the extent they were developed using the same commodity pricing scenario, as shown below in Table 27. As the table shows, the

Rate-Based Market compliance strategy is the least costly (i.e. has a lower CPW of costs) of the CPP compliant portfolios.

Table 27. Clean Power Plan Compliance Scenario Cost Comparison ($000)

CPP Scenario	Plan CPW	Cost Above Lowest Cost CPP Compliant Plan
Rate-Based Market Plan	$21,815,378	Lowest Cost
Rate-Based Island Plan	$22,576,683	$761,305
Mass-Based Market Plan	$21,955,105	$139,727
Mass-Based Island Plan	$22,651,029	$835,651

5.2.3.4 Assessing the Cost of CPP Compliance

Determining the cost of CPP compliance is challenging due to the overall impact the CPP could have on the energy and energy-related markets. As shown in Section 4.3.1, carbon regulation can have a substantial impact on commodity prices, which will ultimately affect the dispatch of existing resources, as well as the selection of incremental resources.

A more accurate way to assess the cost of complying with the CPP would be to take the lowest cost CPP-complaint plan, determine the cost of the plan if it did not comply with the CPP, and compare the difference between the two values. The difference is considered to be the cost of CPP-compliance. Table 28 below shows this comparison for the Rate-Based Market view, which is the lowest cost CPP-compliant plan.

Table 28. Lowest Cost of Compliance with Clean Power Plan ($000)

Scenario	Plan CPW
Compliant Rate-Based Market Plan	$21,815,378
Non-Compliant Rate-Based Market Plan	$20,228,082
Cost of CPP Compliance	**$1,587,296**

5.2.3.5 Federal Implementation Plan Analyses

The proposed federal plans are market-based plans where either allowances (if mass-based) or ERCs (if rate-based) can be purchased on an open market. The federal plans are assumed to be more restrictive than what was assumed for the state market plans. For example, in the assumed mass-based federal plan, APCo's emission allowances will be reduced over time as the EPA has proposed that retired units would not receive an allocation in perpetuity. For the federal rate-based plan, it is assumed that EE projects would not be eligible for generating ERCs. As a result of these differences between the assumed federal and state plans, additional allowances or ERCs would need to be purchased. To determine the cost of a plan that complies with the draft federal rules, APCo used the market-based portfolios described above as starting points, then adjusted the APCo target (mass or rate) in accordance with the proposed federal plan rules to determine the incremental allowances or ERCs that would need to be procured. The cost (i.e., CPW) of the state and federal mass-based and rate-based plans are shown below in Table 29. Note that the cost difference is much more significant with the mass-based plans.

Table 29. Clean Power Plan Federal Implementation Plan Cost Comparison ($000)

Scenario	Plan CPW	Cost Above State Plan
Rate-Based Market - Federal	$21,842,180	$26,802
Rate-Based Market - State	$21,815,378	
Mass-Based Market - Federal	$22,295,136	$340,031
Mass-Based Market - State	$21,955,105	

5.2.3.6 Rate Impacts of Clean Power Plan Scenarios

The Company evaluated the rate impacts of the various presumptive CPP compliant portfolios, which were requested by the Commission and are discussed in this Report, relative to a least-cost scenario. Incremental rate impacts were calculated from the CPW of each plan as well as the Company's forecasted load. Figure 34 below illustrates the incremental rate impacts of the CPP-compliant scenarios. These rate impacts are in comparison to the lowest-cost non-compliant Rate-Based Market plan shown in Table 28.

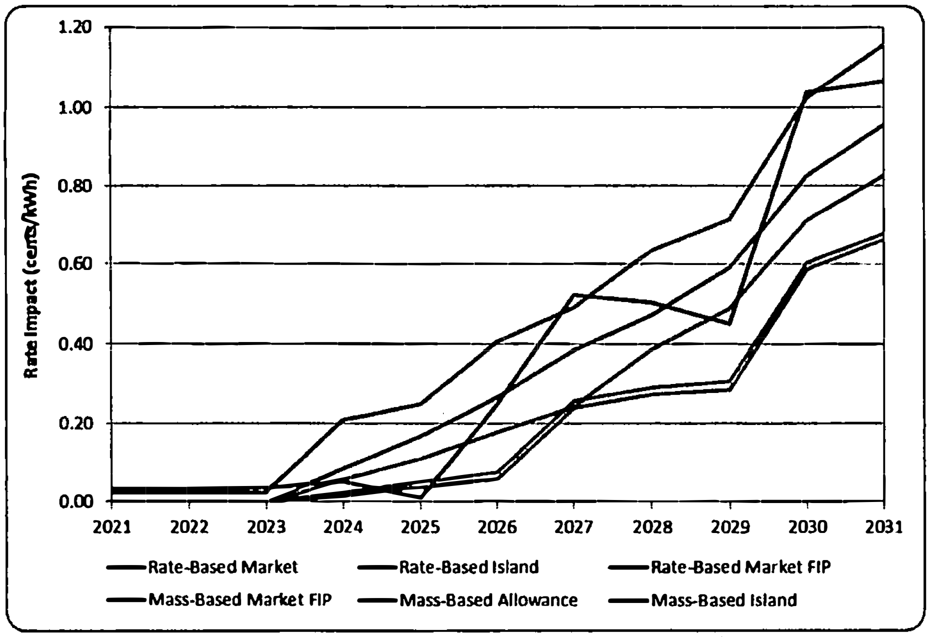

Figure 34. Rate Impacts (cents/kWh) of Clean Power Plan (CPP) Compliance Scenarios, Shown as Incremental Change from Least Cost Compliance Scenario

Figure 34 emphasizes the value of market-based approaches to compliance by illustrating the increased costs associated with island-based compliance approaches. It is important to remember that these increases are *over and above* any incremental costs to implement the Non-Compliant Rate-Based Market Approach (i.e. are not representative increases from current rates), and are highly dependent upon both the assumptions used in the Company's modeling and the uncertainties surrounding the CPP, as discussed throughout this Report. These projected increases are likely to change as better information becomes available.

5.3 Preferred Plan

Each of the scenarios analyzed provides insight into APCo's preferred potential mix of resources for the future. This mix is referred to as the Preferred Plan. APCo's Preferred Plan was developed based on certain considerations such as minimizing revenue requirement exposure (i.e., cost to customers) over the planning period while meeting capacity obligations, minimizing the Company's dependency on external energy and its corresponding risk of energy market price volatility, and accelerating renewable energy resources (wind and solar) in a reasonably cost effective manner.

The incremental capacity additions associated with the Preferred Plan are shown below in Table 30. The capacity additions below do not include APCo's planned additions of wind and solar resources discussed in Section 3.2, which are assumed to be in-service in 2018 and 2019. Specifically, the Preferred Plan incorporates the following changes from the optimized Mid and No CO_2 portfolios:

- Advancement of solar resources from 2027 to 2020. Beginning in 2020 20MW (nameplate) of solar is added annually. This allows APCo to gain experience with smaller tranches of solar capacity before embarking on a larger build program.
- Addition of battery storage in 2025. While currently not an economic resource, battery storage may provide benefits which complement the additional renewable sources; and
- Addition of a CHP facility in 2021. This acknowledges that certain customers are interested in CHP initiatives and assumes a suitable host application is identified.

Table 30. Yearly Cumulative PJM Capacity Additions (MW) and Energy Positions (GWh) for Preferred Plan

Preferred Plan		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2031 Net Energy Position (GWh)	Avg Net Energy Position (GWh) (2016-2030)
Mid Commodity, Base Load	Base/Intermediate																4,638	3,152
	Peaking																	
	Solar (Firm)				8	15	23	30	38	46	53	76	99	122	167	190		
	Solar (Nameplate)				20	40	60	80	100	120	140	200	260	320	440	500		
	Wind (Firm)				15	30	45	53	58	53	53	53	53	60	68	68		
	Wind (Nameplate)				300	600	900	1,050	1,050	1,050	1,050	1,050	1,050	1,200	1,350	1,350		
	Battery Storage									5	5	5	5	5	5	5		
	Energy Efficiency			30	52	73	95	117	138	142	145	156	167	180	182	186		
	CHP					14	14	14	14	14	14	14	14	14	14	14		
	VVO											17	17	17	17	17		
	Demand Response																	
	Distr. Gen.	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47		

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

A key facet of the Preferred Plan is that it reduces APCo's need to purchase energy from the PJM market. APCo finds itself short on energy largely because the Company's load profile does not align with that of PJM. APCo experiences its greatest demand during the winter, and hence is a winter-peaking entity. PJM as a whole operates as a summer-peaking RTO. Therefore, when APCo meets its summer demand obligations—per PJM rules—it is not meeting its true peak demand obligations and ultimately the Company is short on energy during the winter months. The Preferred Plan has the potential to minimize the consequences of APCo's energy position by adding renewable resources which can provide significant energy in both the summer and winter months. Similarly, the Plan also calls for DSM programs—EE and VVO—which reduce both demand and energy on a year-round basis.

The Preferred Plan, in conjunction with the Company's five-year action plan (see Section 6.0), offers APCo significant flexibility should future conditions differ considerably from its assumptions. For example, as EE programs progress, APCo will gain insight into customer acceptance and develop additional hard data as to the impact these programs have on load growth. This will assist APCo in determining whether to expand program offerings, change incentive levels for programs, or target specific customer classes for the best results. If current long-term renewable cost assumptions ultimately increase, APCo could consider a more traditional new peaking capacity build, which has a relatively short lead time to implement. Changes to APCo's existing portfolio associated with this Preferred Plan are described in greater detail in Section 6.0 of this Report.

5.3.1 Future CO_2 Emissions Trending – Preferred Plan

The Preferred Plan could be a CPP compliant plan under a Mass-Based Market approach. Figure 35 below shows how the Preferred Plan's CO_2 emissions compare with the CPP targets on a mass basis. Again, the distance between the Preferred Plan emission and the target emission lines represent CO_2 allowances which would need to be purchased from the market.

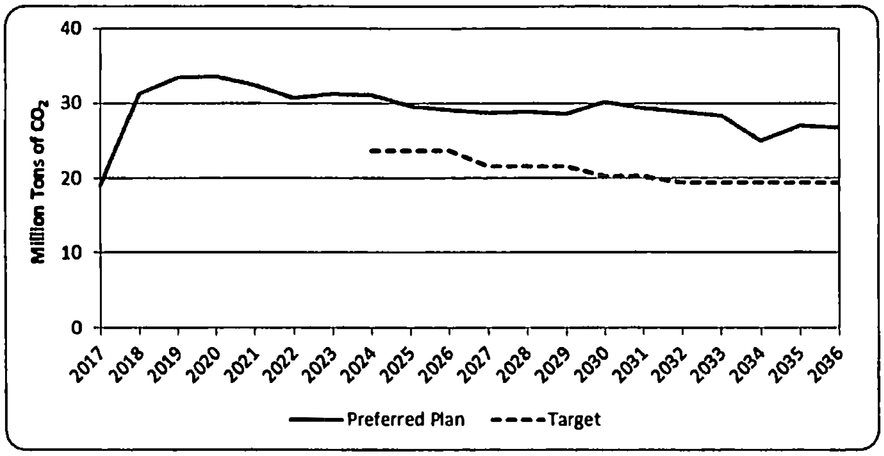

Figure 35. Mass-Based CO_2 Emissions (Million Tons of CO_2) of Preferred Plan vs. Target

5.3.2 Demand-Side Resources

In the Preferred Plan, incremental EE resources were selected beginning in 2019 and throughout the remainder of the planning period. Economic savings are attributable to both Commercial/Industrial and Residential programs, with the majority coming from Commercial/Industrial Lighting programs. By 2031, overall EE savings – consisting of Other Energy Efficiency, Existing DSM Programs, and Incremental DSM Programs – provide a decrease in residential and commercial energy usage of nearly 7% (see Figure 36, below).

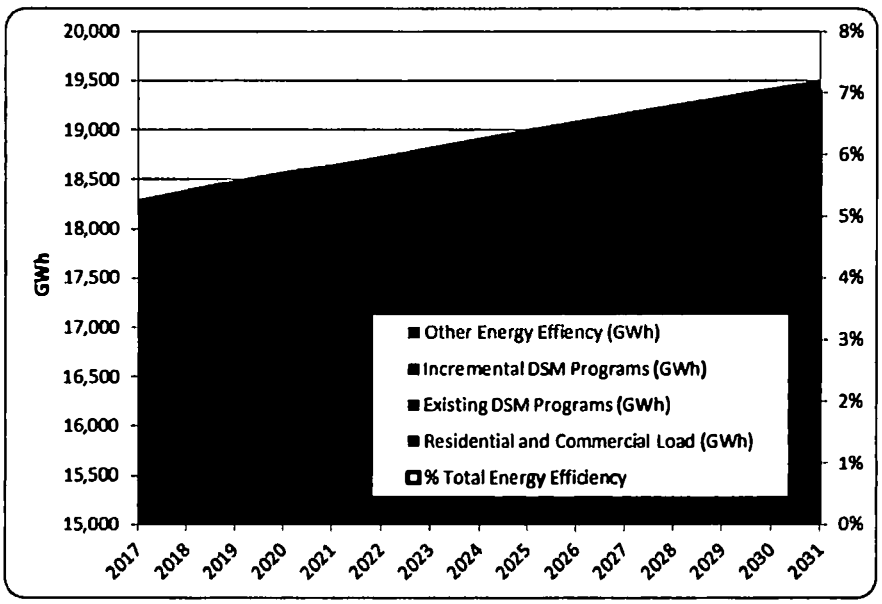

Figure 36. APCo Energy Efficiency Savings According to Preferred Plan

As part of the Preferred Plan, 1 of the 15 available VVO tranches was ultimately selected by the model. When coupled with APCo's existing pilot installation this results in a cumulative capacity reduction of 17MW by 2031. The tranche of circuits (in addition to the pilot program) is added in 2027. The VVO estimates are subject to future revision as more operational information is gained from the pilot installation as well as other tests that are currently underway throughout the AEP system.

DG (i.e. rooftop solar) resources were not selected under any economic scenario during the planning period. DG resources were added incrementally at a CAGR of 22.5% (based on nameplate capacity), resulting in a total of 47MW of PJM capacity credit (123MW nameplate) by 2031.

5.3.3 Comparing the Cost of the Preferred Plan

When comparing plan costs it is important to remember that there are distinct differences between how the rate-based and mass-based plan targets and subsequent optimized portfolios were developed and the inherent assumptions in each. For the mass plans, incremental carbon free energy that is introduced into the portfolio, whether through EE or additional renewable resources, does not allow APCo to achieve its mass goal on its own. The way APCo meets its goal in the mass-based strategy is through the reduction of CO_2 output from its affected sources – its existing fossil units, followed by the purchase of an allowance for each ton of CO_2 emitted in excess of its target. In a rate-based strategy, adding non-carbon energy sources in concert with reduced fossil unit output will contribute to APCo's rate reduction goals. As a result, carbon free resources have more value (and subsequently less net costs) in a rate-based strategy than in a mass-based strategy.

It is appropriate, therefore, to compare the Preferred Plan, which was developed under the assumption of a mass-market strategy, to other mass-market plans. Table 31 below compares the CPW cost of the Preferred plan to the optimized plans under the Low, Mid, and High pricing scenarios. It also includes a calculation of the levelized annual bill impact for a typical customer using 1,000 kWh of energy per month, assuming that cost would apply over the entire study period. Note that the resource selection under the Preferred Plan in the near term is similar to all the optimized plans, and therefore could be easily adjusted if the states in which APCo has affected units follow a rate-based strategy, or if the CPP is further delayed.

Table 31. Comparison of Preferred Plan vs. Optimized Plan based on Cumulative Present Worth ($000), Incremental Cost ($000), and Levelized Annual Bill Impact ($)

Scenario	Low Band CPW ($000)	Mid Band CPW ($000)	High Band CPW ($000)
Optimized Scenarios	$20,704,455	$21,955,105	$23,089,197
Preferred Plan	$20,801,215	$21,964,933	$23,090,076
Incremental Cost	$96,760	$9,828	$879
Levelized Annual Bill Impact ($)	$9.44	$0.96	$0.09

The Preferred Plan presented in this IRP is expected to provide adequate reliability over the planning period. By minimizing CPW, the Company's model produced optimized portfolios with the lowest and most stable rates for customers. Low stable rates benefit customers by attracting new commercial and industrial customers, and retaining and/or expanding existing load. A key aspect of the Preferred Portfolio presented in this IRP is that it would reduce APCo's need to purchase energy from the PJM market, which enhances energy independence. Also, by including renewable resources, the IRP should mitigate volatility in future fuel and purchase power costs.

5.4 Risk Analysis

In addition to comparing the Preferred Plan to the optimized portfolios under a variety of pricing assumptions, the Preferred Plan and an alternative portfolio were also evaluated using a stochastic, or "Monte Carlo" modeling technique where input variables are randomly selected from a universe of possible values, given certain standard deviation constraints and correlative relationships. This offers an additional approach by which to "test" the Preferred Plan over a distributed range of certain key variables. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a higher cost (revenue requirement) relative to the expected outcome.

This study included multiple risk iteration runs performed over the study period with four key price variables (risk factors) being subjected to this stochastic-based risk analysis. The results take the form of a distribution of possible revenue requirement outcomes for each plan. Table 32 and Table 33 below show the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other. Table 32 shows the risk factor details before carbon regulation (2017-2023) and Table 33 shows the risk factor details after carbon regulation.

Table 32. Risk Analysis Factors and Relationships Prior to Carbon Regulation, 2017-2023

	Coal	Gas	Power
Coal	1	0.89	0.87
Gas		1	0.9
Power			1
Standard Deviation	11.1%	9.0%	7.4%

Table 33. Risk Analysis Factors and Relationships After Carbon Regulation, 2024-2036

	Coal	Gas	Power	CO_2
Coal	1	-0.3	0.48	0.53
Gas		1	0.43	0.48
Power			1	0.82
CO_2				1
Standard Deviation	13.9%	11.0%	12.6%	26.7%

Comparing the Preferred Plan to an alternative portfolio which is both plausible yet significantly different, provides a data point that may be used to evaluate the risk associated with the Preferred Plan. The Preferred Plan has a similar resource profile to other "non-island" optimized plans, so there would be little difference in the risk profiles between such portfolios (High Band, Low Band, Rate-Based Market) and the Preferred Plan, and therefore those portfolios were not included in the stochastic analysis. Instead, a portfolio which built a NGCC but no new renewable capacity was used for comparison. All other Preferred Plan resources (existing units, energy efficiency, CHP, battery), are identical in both portfolios. This allows APCo to determine if the renewable resources in the Preferred Plan introduce more risk than relying on traditional fossil generation additions. The range of values associated with the variable inputs is shown in Figure 37.

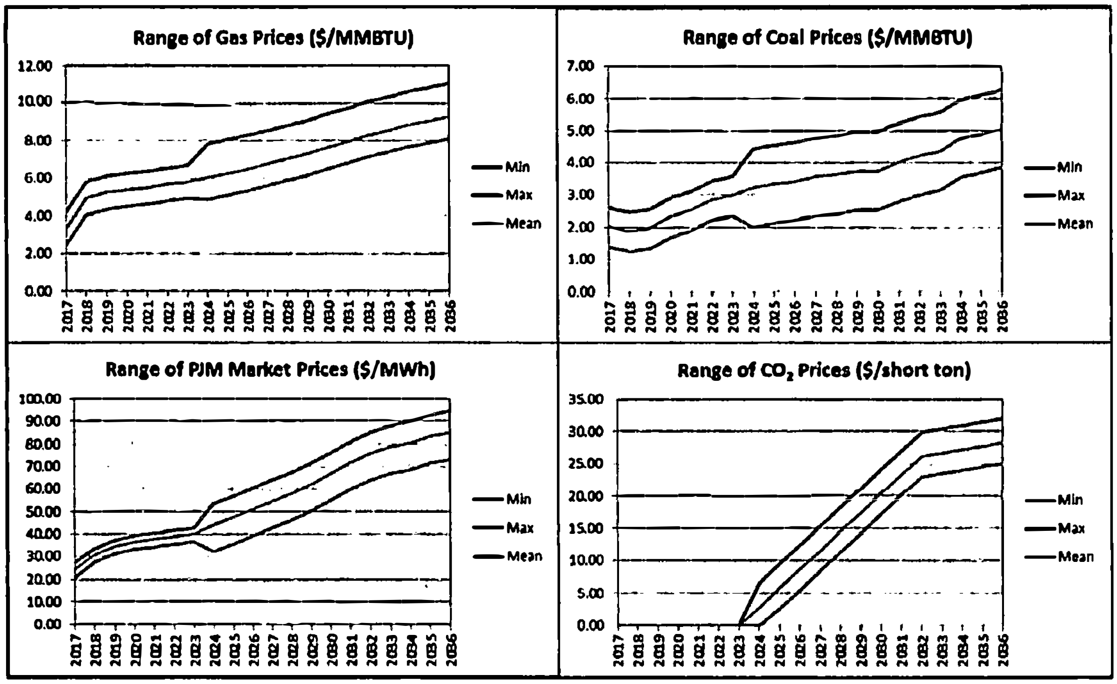

Figure 37. Range of Variable Inputs for Stochastic Analysis

5.4.1 Stochastic Modeling Process and Results

For each portfolio, the results of 100 random iterations are sorted from lowest cost to highest cost, with the differential between the median and higher percentile result from the multiple runs identified as Revenue Requirement at Risk (RRaR). For example, the 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, only five percent of the time. Thus, it is 95 percent likely that those higher-ends of revenue requirements would not be exceeded. The larger the RRaR, the greater the likelihood that customers could be subjected to higher costs relative to the portfolio's mean or expected cost. Conversely, there is equal likelihood costs may be lower than the median value. These higher or lower costs are generally the result of the difference, or spread, between fuel prices and resultant PJM market energy prices. The greater that spread, the more "margin" is enjoyed by the Company and its customers. Figure 38, below, illustrates the RRaR (expressed in terms of incremental cost over the 50th percentile).

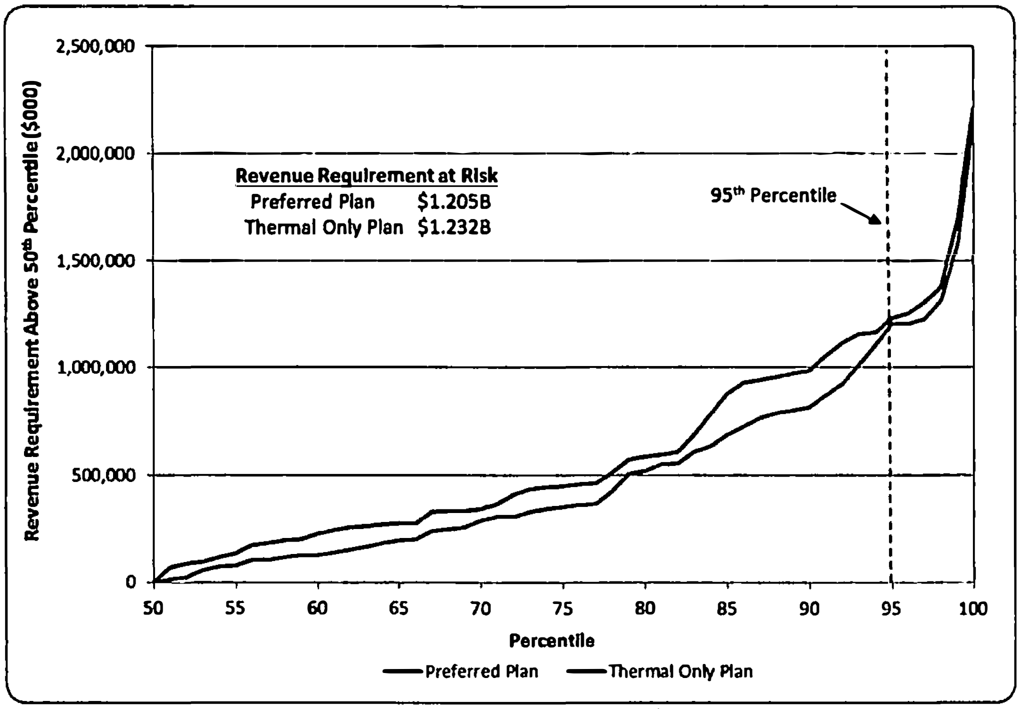

Figure 38. Revenue Requirement at Risk (RRaR) ($000) for Select Portfolios

The difference in RRaR between the two portfolios that were analyzed is relatively small through the 83rd percentile, with the Preferred Plan always being less risky. At the tail end of the analysis (84th through 95th percentiles), the Thermal Only portfolio shows increased risk relative to the Preferred Plan. The additional natural gas generation in this portfolio, in combination with the removal of renewable resources, relative to the Preferred Plan, appears to introduce additional risk.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of the Preferred Plan, which includes renewable resources, is not as great as portfolios which rely on NGCC resources. For this IRP, the risk analysis suggests that the Preferred Plan represents a more reasonable combination of expected costs and risk than a portfolio that relies on gas generation as the primary incremental resource.

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6.0 Conclusions

The optimization results and associated risk modeling of this IRP demonstrate that APCo, as a stand-alone entity in the PJM RTO, can serve customer needs over the prescribed planning period by continuing operation of its existing resources while adding wind and solar renewables, and DSM resources, including EE measures and VVO. The Preferred Plan attempts to balance cost, and the potential risk of a volatile energy market, while allowing APCo the flexibility to adapt to future changes.

The following are summary highlights of the Preferred Plan:

- Assumes 25MW (nameplate) of new large-scale solar energy in 2019, with subsequent additions throughout the planning period, for a total of 525MW (nameplate) by 2031;
- includes 120MW (nameplate) of approved new wind energy in 2018; assumes 225MW (nameplate) of new wind energy in 2019; and adds 300MW (nameplate) of incremental wind energy by 2020, with subsequent additions throughout the planning period, for a total of 1,695MW (nameplate) of incremental wind energy by 2031;
- implements customer and grid EE programs, including VVO, reducing energy requirements by 850GWh annually and summer capacity requirements by 203MW by 2031;
- assumes APCo's customers add distributed generation (DG) (i.e. rooftop solar) capacity totaling over 123MW (nameplate) by 2031. (Note 1);
- adds 10MW (nameplate) of battery storage resources in 2025;
- assumes a host facility is identified such that a Combined Heat and Power (CHP) project can be implemented by 2021;
- addresses expected PJM Capacity Performance rule impacts on APCo's capacity position beginning with the 2020/2021 PJM planning year. Among other things, it assumes that the rule may result in APCo:

- reducing wind resources from prior PJM-recognized capacity levels (i.e. from 13% to 5% of nameplate capacity); and
- reducing run-of-river hydro contributions to 25% of nameplate rating;

- continues operation of APCo's facilities including the Amos Units 1-3 and Mountaineer Unit 1 coal-fired facilities, the Ceredo and Dresden natural gas facilities and operating hydro facilities. Maintains APCo's share of Ohio Valley Electric Company (OVEC) solid-fuel facilities: Clifty Creek Units 1-6 and Kyger Creek Units 1-5; and
- retires gas-steam Clinch River Units 1 and 2 in 2026.

Note 1: APCo does not have control over the amount, location or timing of these additions.

Specific APCo capacity changes over the 15-year planning period associated with the Preferred Plan are shown in Figure 39 and Figure 40, and their relative impacts on APCo's annual energy position are shown in Figure 41 and Figure 42. Figure 39 through Figure 42 indicate that this Preferred Plan would reduce APCo's reliance on coal-based generation and increase reliance on demand-side and renewable resources, further diversifying the portfolio.

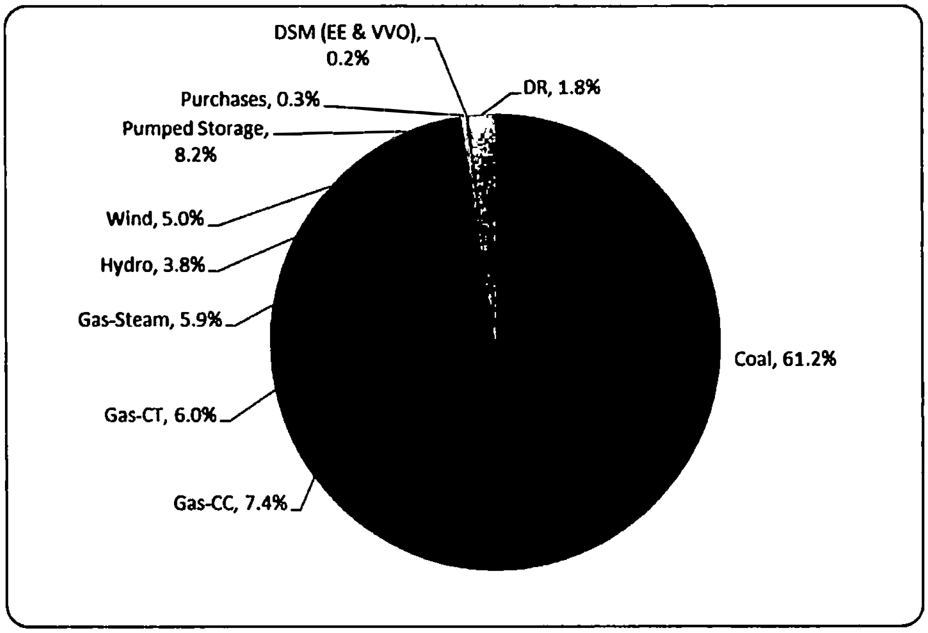

Figure 39. 2017 APCo Nameplate Capacity Mix

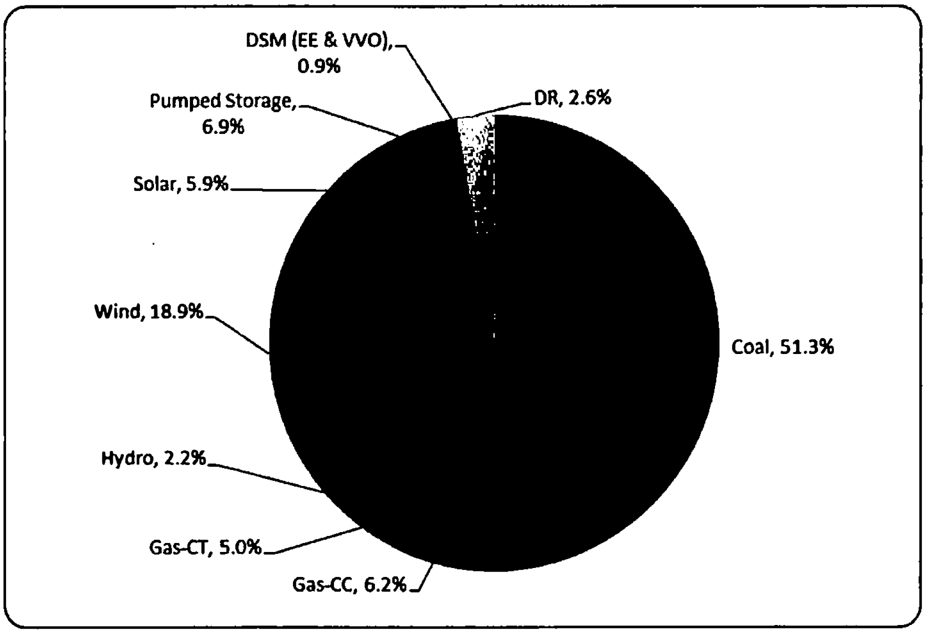

Figure 40. 2031 APCo Nameplate Capacity Mix

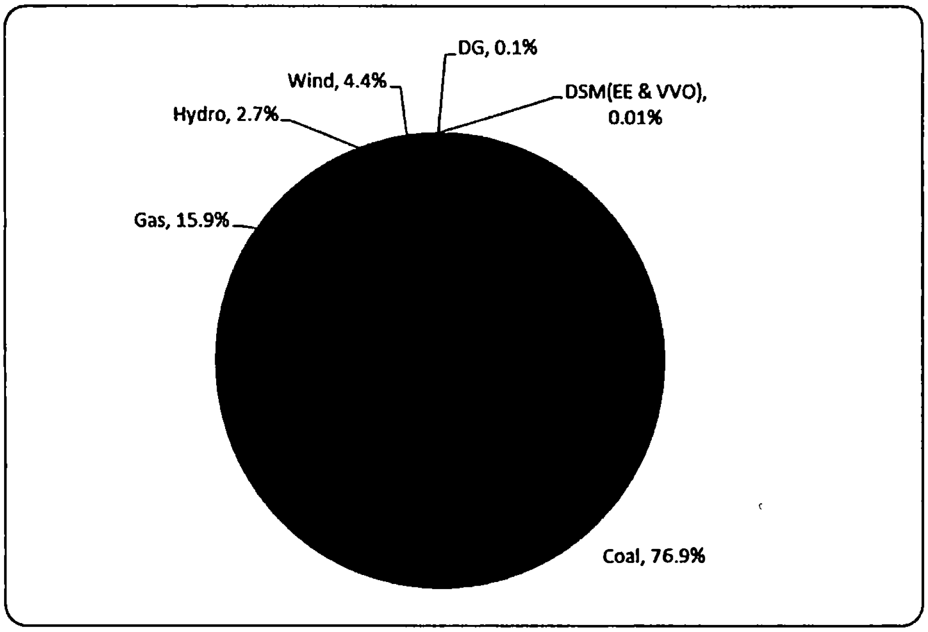

Figure 41. 2017 APCo Energy Mix

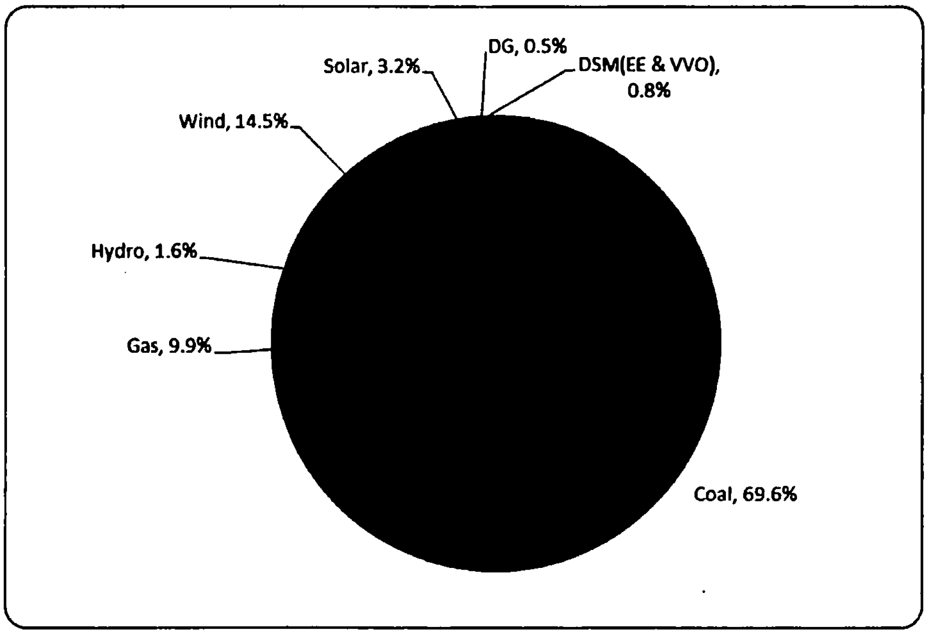

Figure 42. 2031 APCo Energy Mix

Specifically, over the 15-year planning horizon the Company's nameplate capacity mix attributable to coal-fired assets would decline from 61.2% to 51.3%. Wind and solar assets climb from 5% to 24.8%, and demand-side resources (including EE, VVO, DG, Demand Response [DR], and Combined Heat and Power [CHP]) increase from 2.0% to 3.5% over the planning period.

APCo's energy output attributable to coal-fired generation shows a decrease from 76.9% to 69.6% over the period. The Preferred Plan shows a significant increase in renewable energy (wind and solar), from 4.4% to 17.6%. Energy from these renewable resources, combined with EE and VVO energy savings reduce APCo's exposure to energy, fuel and potential carbon prices.

Figure 43 and Figure 44 show annual changes in capacity and energy mix, respectively, that result from the Preferred Plan, relative to capacity and energy requirements. The capacity contribution from renewable resources is fairly modest due to the implications of PJM's Capacity Performance rule reducing the amount of capacity credit for intermittent resources; however, those resources (particularly wind) provide a significant volume of energy. APCo's model selected those wind resources because they were lower cost than alternative energy resources. When comparing the capacity values in Figure 43 with those in Figure 39 and Figure 40, it is important to note that Figure 43 provides an analysis of PJM-recognized capacity, while Figure 39 and Figure 40 depict nameplate capacity.

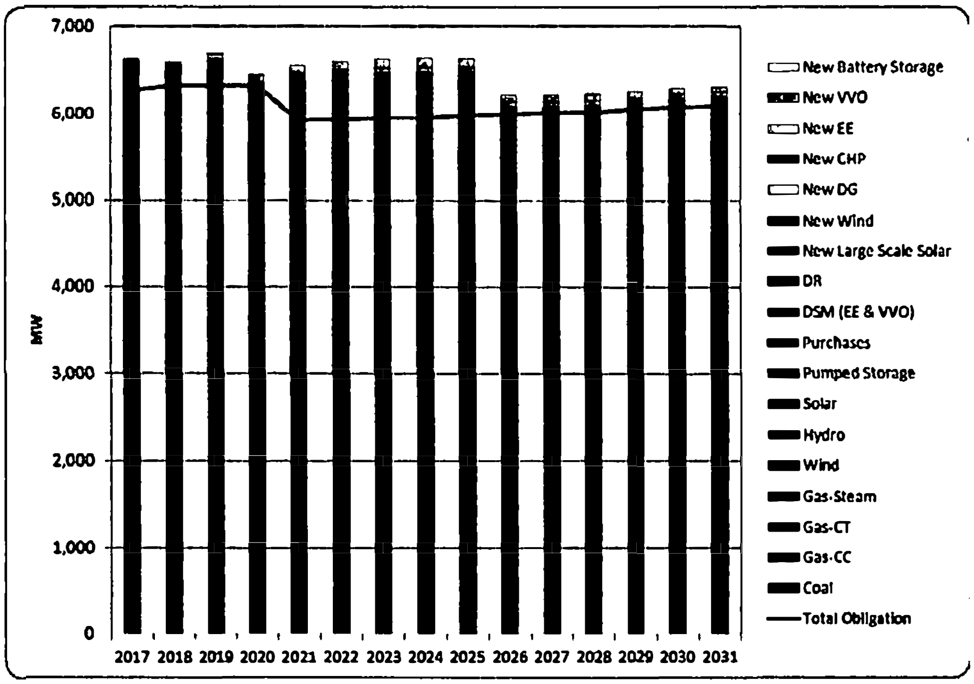

Figure 43. APCo Annual PJM Capacity Position (MW) According to Preferred Plan

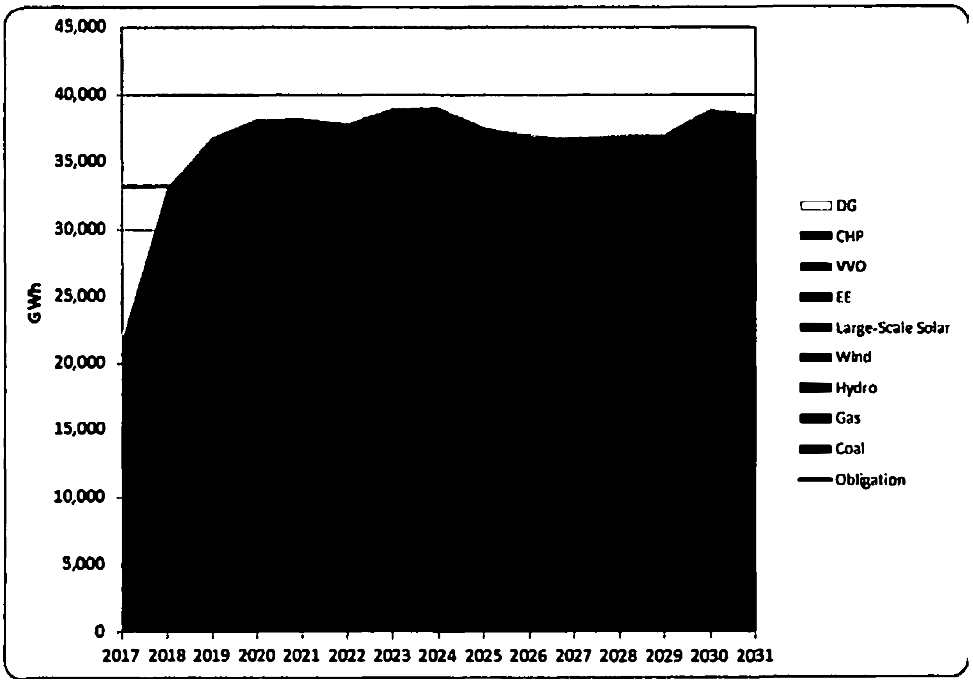

Figure 44. APCo Annual Energy Position (GWh) According to Preferred Plan

While the Preferred Plan improves APCo's annual energy position, it also improves APCo's monthly energy position. Figure 45 shows APCo's monthly energy position for 2017. In each month except December, APCo is energy deficient and its customers are vulnerable to market prices. This situation is most prominent in the Spring and Summer when APCo's existing fleet is dispatched less due to low power prices. Figure 46 shows APCo's monthly energy position for 2031. In 2031 APCo has an energy surplus in each month except January. While APCo's existing fleet is dispatched more in 2031, the energy surplus is largely due to the addition of the renewable resources called for in the Preferred Plan.

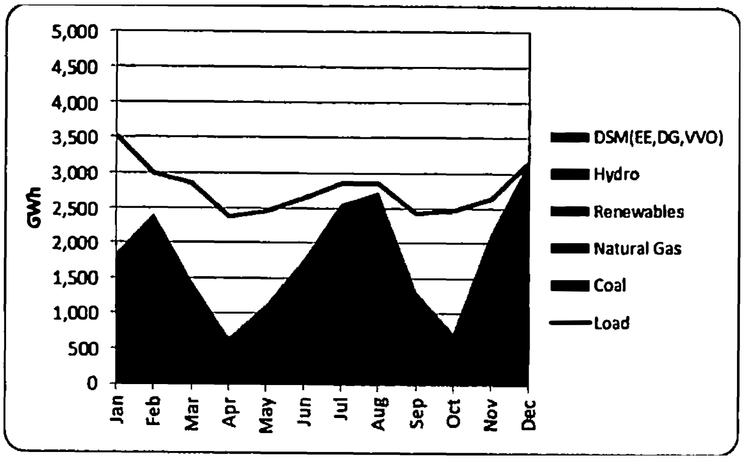

Figure 45. 2017 Energy Position (GWh) by Month

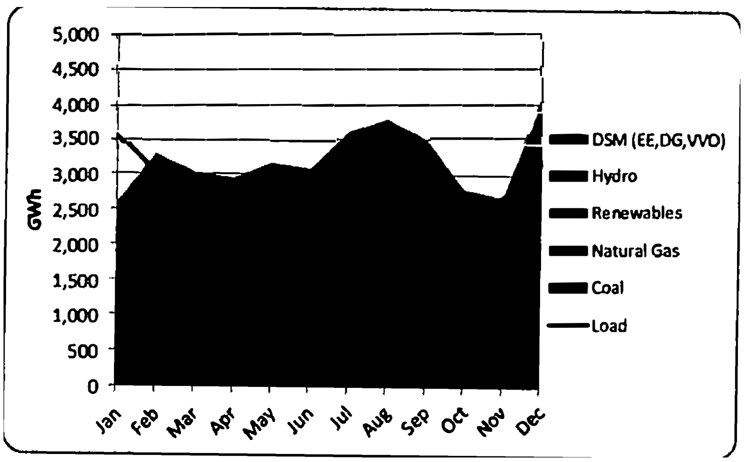

Figure 46. 2031 Energy Position (GWh) by Month

Table 34 provides a summary of the Preferred Plan

Table 34. Preferred Plan Cumulative Capacity Additions throughout Planning Period (2017-2031)

Preferred Plan

IRP Period Yr.	PJM Planning Year[a]	Planning Peak Load MW	(1) (Cumulative) Existing Fleet: Unit Uprates & Derates MW	(2) (Cumulative) Existing Fleet: PJM Capacity Perf. Impact (UCAP Reduction)[c] MW	(3) New-Build: NG CHP MW	(4) New-Build: NG CC MW	(5) Energy Efficiency (EE): "Embedded" Federal EE Regulations (Non-OSM EE)[b] MW	(6) Energy Efficiency (EE): Current OSM Programs[c] MW	(7) Energy Efficiency (EE): New MW	(8) VVO: New MW	(9) DR: Pre-Existing DR Programs[c] MW	(10) Wind[d] MW	(11) Solar[e]: Large Scale MW	(12) Solar[e]: DG MW	(13) Battery[f] MW	(14) (Cumul.) NET "RESOURCE" CHANGE[d] MW	(15) Resulting APCo Reserves Above PJM Minimum Rqmnt[e] MW	(16) PJM Reserve Margin %	(17) (Cumulative) "NAMEPLATE" ADDITIONS: Wind[d] MW	(18) Solar[e]: Large Scale MW	(19) Solar[e]: DG MW	(20) Battery[f] MW
1	2017	5,619	(34)	-	-	-	397	13	0	-	149	-	-	6	-	134	365	6.5%	-	-	16	-
2	2018	5,676	(34)	-	-	-	417	19	0	-	149	6	-	12	-	152	264	4.6%	120	-	31	-
3	2019	5,664	2	-	-	-	444	19	30	-	149	17	10	17	-	245	368	6.5%	345	25	46	-
4	2020	5,668	2	(290)	-	-	471	19	52	-	149	32	17	18	-	1	122	2.1%	645	45	48	-
5	2021	5,207	2	(334)	14	-	496	19	73	-	119	47	25	20	-	(15)	618	11.9%	945	65	53	-
6	2022	5,211	2	(334)	14	-	519	19	95	-	119	62	32	22	-	32	656	12.6%	1,245	85	59	-
7	2023	5,227	2	(334)	14	-	540	19	117	-	119	70	40	24	-	71	670	12.8%	1,395	105	64	-
8	2024	5,233	2	(334)	14	-	560	19	138	-	119	70	48	31	-	106	688	13.2%	1,395	125	81	-
9	2025	5,265	2	(334)	14	-	579	19	142	-	119	70	55	33	5	125	648	12.3%	1,395	145	86	10
10	2026	5,279	(438)	(334)	14	-	598	19	145	-	119	70	63	35	5	(302)	222	4.2%	1,395	165	93	10
11	2027	5,298	(438)	(274)	14	-	613	19	156	17	119	70	86	37	5	(190)	205	3.9%	1,395	225	98	10
12	2028	5,303	(438)	(267)	14	-	622	19	167	17	119	70	108	39	5	(147)	214	4.0%	1,395	285	104	10
13	2029	5,340	(438)	(254)	14	-	633	19	180	17	119	77	131	42	5	(88)	200	3.8%	1,545	345	110	10
14	2030	5,358	(438)	(244)	14	-	649	19	182	17	119	85	177	44	5	(20)	219	4.1%	1,695	465	117	10
15	2031	5,377	(438)	(244)	14	-	[illegible]	19	186	17	119	85	200	47	5	9	216	4.0%	1,695	525	123	10
									222 TOTAL Increm' Energy Efficiency											648 TOTAL Solar		

(14) = (1)+(2)+...+(13)

[a] PJM Planning Year is effective 6/1/XXXX. In 2021, Load Forecast moves from the PJM forecast to APCo's internal forecast.
[b] Represents estimated (post-2005) energy efficiency levels already "embedded" into APCo's long-term load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standards (EPAct 2005; 2007 EISA, 2009 ARRA).
[c] Represents estimated contribution from current/known APCo OSM-EE and Demand Response (Interruptible, DLC/ELM) program activity through 2018; values are backfilled from 2016
[d] Values in 2018 and 2019 represent the 2016 RFP amounts, due to the intermittency of wind resources, APCo assumes 5% of nameplate MW rating are included for capacity resource determination purposes beyond 2020.
[e] Value in 2019 represents the 2017 RFP expected amount, due to the intermittency of solar resources, Utility and Distributed Solar receive 38% of nameplate MW rating for capacity resource determination purposes.
[f] Due to the intermittency of battery/storage resources, APCo assumes 50% of nameplate MW rating for capacity resource determination purposes.

Changes to existing resources Post-January 1, 2017:
[a] Mountaineer turbine upgrade.
[b] Clinch River 1&2 Gas Conversion unit rerate in 2017 and retirement in 2026
[c] Beginning in 2020, assumes removal of 75% Run-of-River Hydro capacity, 50% reduction in Existing DR and a 95% reduction of (Existing) Wind capacity to achieve PJM "Capacity Performance" criteria

[d] Includes changes in existing resources plus plan additions, excluding "embedded" EE and existing DR programs.
[e] PJM minimum criterion @16.6% as a function of peak demand effective with the 2019/20 PY.

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Conclusion

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

Moreover, this IRP also addresses APCo's energy short position. The Preferred 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 long-term exposure of the Company's customers to PJM energy markets.

Recognizing PJM's Capacity Performance construct, the portfolios discussed in this Report attribute limited capacity value for certain intermittent resources (solar, wind and run-of-river hydro). It is possible that intermittent resources can be combined, or "coupled," and offered into the PJM market as Capacity Performance resources. The Company will continue to investigate methods to maximize the utilization of its intermittent resource portfolio within that construct.

This IRP also addresses this Commission's specific 2017 IRP requirements to perform analyses associated with the requirements of the CPP, compared to a least-cost non-compliant analysis. Each of the Commission's requirements has been examined and, despite the uncertainty surrounding the legal status of the CPP and various other uncertainties, the Company has made a good-faith effort to provide both appropriate responses to the Commission's inquiries and reasonable analyses under the circumstances.

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; an IRP is simply a snapshot of the future at a given 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 exacerbate the need for flexibility and adaptability in any ongoing planning activity and resource planning process.

To that end, APCo intends to pursue the following five-year action plan:

1. Complete implementation activities necessary to purchase renewable energy from approved 120MW wind resource beginning in 2018.
2. Obtain regulatory approval of 225MW of additional wind energy, and have these resources in-service beginning in 2019.
3. Continue evaluation, due diligence, and regulatory activities necessary to select a 25MW solar resource, obtain regulatory approval, and have the resource in-service beginning in 2019.
4. Continue the planning and regulatory actions necessary to implement economic EE programs in Virginia and West Virginia.
5. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, pursue competitive solicitations that would include self-build or acquisition options.
6. Pursue opportunities to identify a suitable host facility for a CHP installation.
7. Monitor developments associated with PJM's Capacity Performance rule; continue to investigate opportunities to couple/hedge traditional hydro and renewable resources (wind and solar) as reasonable Capacity Performance products.
8. Monitor the status of, and participate in formulating, Virginia (as well as West Virginia, Ohio and Indiana) state plans pertaining to the CPP. Once established, perform specific assessments as to the implications of the CPP on APCo's resource profile.
9. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

Appendix

Exhibit A **Load Forecast Tables**

Exhibit B **Non-Renewable New Generation Technologies**

Exhibit C **Schedules**

Exhibit D **Cross Reference Table**

Exhibit A Load Forecast Tables

EXHIBIT A-1
Appalachian Power Company
Annual Internal Energy Requirements and Growth Rates
2013-2031

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual										
2013	11,914	---	6,828	---	10,393	---	6,855	---	35,990	---
2014	12,183	2.3	6,829	0.0	10,314	-0.8	6,904	0.7	36,230	0.7
2015	11,495	-5.6	6,721	-1.6	9,866	-4.3	6,890	-0.2	34,972	-3.5
2016	11,421	-0.6	6,751	0.4	9,410	-4.6	6,591	-4.3	34,172	-2.3
Forecast										
2017	11,391	-0.3	6,708	-0.6	9,489	0.8	6,459	-2.0	34,048	-0.4
2018	11,282	-1.0	6,689	-0.3	9,558	0.7	6,576	1.8	34,106	0.2
2019	11,116	-1.5	6,688	0.0	9,614	0.6	6,630	0.8	34,048	-0.2
2020	11,017	-0.9	6,694	0.1	9,653	0.4	6,654	0.4	34,017	-0.1
2021	10,958	-0.5	6,702	0.1	9,686	0.3	6,659	0.1	34,005	0.0
2022	10,930	-0.3	6,724	0.3	9,725	0.4	6,652	-0.1	34,031	0.1
2023	10,899	-0.3	6,747	0.3	9,757	0.3	6,670	0.3	34,073	0.1
2024	10,878	-0.2	6,775	0.4	9,783	0.3	6,684	0.2	34,120	0.1
2025	10,870	-0.1	6,797	0.3	9,810	0.3	6,690	0.1	34,167	0.1
2026	10,849	-0.2	6,821	0.4	9,837	0.3	6,697	0.1	34,204	0.1
2027	10,849	0.0	6,846	0.4	9,864	0.3	6,707	0.2	34,266	0.2
2028	10,860	0.1	6,872	0.4	9,893	0.3	6,721	0.2	34,346	0.2
2029	10,875	0.1	6,899	0.4	9,921	0.3	6,737	0.2	34,431	0.2
2030	10,863	-0.1	6,918	0.3	9,946	0.3	6,747	0.1	34,475	0.1
2031	10,859	0.0	6,941	0.3	9,975	0.3	6,757	0.2	34,532	0.2
Average Annual Growth Rates										
2013-2016		-1.4		-0.4		-3.3		-1.3		-1.7
2017-2031		-0.3		0.2		0.4		0.3		0.1

EXHIBIT A-2A
Appalachian Power Company-Virginia
Annual Internal Energy Requirements and Growth Rates
2013-2031

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual										
2013	6,297	---	3,208	---	5,474	---	3,190	---	18,170	---
2014	6,461	2.6	3,223	0.5	5,488	0.2	3,233	1.3	18,405	1.3
2015	6,138	-5.0	3,199	-0.7	5,356	-2.4	3,241	0.2	17,934	-2.6
2016	6,153	0.2	3,233	1.1	5,270	-1.6	3,191	-1.5	17,847	-0.5
Forecast										
2017	6,057	-1.6	3,216	-0.5	5,251	-0.4	3,285	2.9	17,810	-0.2
2018	6,008	-0.8	3,202	-0.4	5,248	-0.1	3,350	2.0	17,808	0.0
2019	5,954	-0.9	3,200	-0.1	5,276	0.5	3,383	1.0	17,813	0.0
2020	5,924	-0.5	3,199	-0.1	5,286	0.2	3,400	0.5	17,809	0.0
2021	5,909	-0.3	3,202	0.1	5,296	0.2	3,406	0.2	17,814	0.0
2022	5,907	0.0	3,214	0.4	5,311	0.3	3,405	0.0	17,837	0.1
2023	5,907	0.0	3,227	0.4	5,321	0.2	3,417	0.3	17,872	0.2
2024	5,912	0.1	3,242	0.5	5,328	0.1	3,425	0.2	17,908	0.2
2025	5,922	0.2	3,256	0.4	5,335	0.1	3,430	0.1	17,943	0.2
2026	5,920	0.0	3,271	0.4	5,342	0.1	3,434	0.1	17,967	0.1
2027	5,930	0.2	3,286	0.5	5,350	0.2	3,440	0.2	18,006	0.2
2028	5,945	0.3	3,301	0.5	5,360	0.2	3,448	0.2	18,055	0.3
2029	5,962	0.3	3,317	0.5	5,369	0.2	3,457	0.3	18,106	0.3
2030	5,966	0.1	3,329	0.3	5,378	0.2	3,463	0.2	18,136	0.2
2031	5,973	0.1	3,341	0.4	5,387	0.2	3,470	0.2	18,172	0.2
Average Annual Growth Rates										
2013-2016		-0.8		0.3		-1.3		0.0		-0.6
2017-2031		-0.1		0.3		0.2		0.4		0.1

EXHIBIT A-2B
Appalachian Power Company-West Virginia
Annual Internal Energy Requirements and Growth Rates
2013-2031

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Total Internal Energy Requirements	
Year	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**
Actual										
2013	5,617	---	3,620	---	4,919	---	1,556	---	15,712	---
2014	5,722	1.9	3,606	-0.4	4,826	-1.9	1,488	-4.4	15,643	-0.4
2015	5,357	-6.4	3,522	-2.3	4,510	-6.6	1,503	1.0	14,892	-4.8
2016	5,268	-1.7	3,518	-0.1	4,140	-8.2	1,303	-13.3	14,228	-4.5
Forecast										
2017	5,334	1.2	3,492	-0.7	4,238	2.4	1,075	-17.5	14,139	-0.6
2018	5,274	-1.1	3,487	-0.2	4,311	1.7	1,130	5.1	14,202	0.4
2019	5,162	-2.1	3,488	0.0	4,338	0.6	1,152	1.9	14,140	-0.4
2020	5,093	-1.3	3,495	0.2	4,367	0.7	1,160	0.7	14,115	-0.2
2021	5,050	-0.8	3,500	0.1	4,389	0.5	1,160	0.0	14,098	-0.1
2022	5,023	-0.5	3,510	0.3	4,414	0.6	1,152	-0.7	14,099	0.0
2023	4,992	-0.6	3,521	0.3	4,435	0.5	1,155	0.3	14,103	0.0
2024	4,965	-0.5	3,533	0.3	4,455	0.4	1,156	0.1	14,109	0.0
2025	4,948	-0.3	3,541	0.2	4,475	0.5	1,154	-0.2	14,118	0.1
2026	4,928	-0.4	3,550	0.3	4,495	0.4	1,153	0.0	14,127	0.1
2027	4,919	-0.2	3,560	0.3	4,514	0.4	1,154	0.1	14,147	0.1
2028	4,915	-0.1	3,571	0.3	4,532	0.4	1,155	0.1	14,173	0.2
2029	4,913	0.0	3,581	0.3	4,551	0.4	1,157	0.2	14,202	0.2
2030	4,897	-0.3	3,590	0.2	4,568	0.4	1,158	0.0	14,213	0.1
2031	4,886	-0.2	3,600	0.3	4,588	0.4	1,158	0.0	14,232	0.1
Average Annual Growth Rates										
2013-2016		-2.1		-0.9		-5.6		-5.8		-3.3
2017-2031		-0.6		0.2		0.6		0.5		0.0

EXHIBIT A-3
Appalachian Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2013-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2013	07/18/13	5,902	---	01/23/13	6,839	---	6,839	---	35,990	---	59.9
2014	07/02/14	5,649	-4.3	01/30/14	8,460	23.7	8,460	23.7	36,230	0.7	48.9
2015	06/23/15	5,744	1.7	02/20/15	8,708	2.9	8,708	2.9	34,972	-3.5	45.8
2016	07/25/16	5,885	2.5	01/19/16	7,379	-15.3	7,379	-15.3	34,172	-2.3	52.9
Forecast											
2017		5,686	-3.4		7,158	-3.0	7,158	-3.0	34,048	-0.4	54.1
2018		5,692	0.1		7,171	0.2	7,171	0.2	34,106	0.2	54.3
2019		5,703	0.2		7,152	-0.3	7,152	-0.3	34,048	-0.2	54.3
2020		5,696	-0.1		7,110	-0.6	7,110	-0.6	34,017	-0.1	54.6
2021		5,717	0.4		7,121	0.2	7,121	0.2	34,005	0.0	54.4
2022		5,730	0.2		7,116	-0.1	7,116	-0.1	34,031	0.1	54.6
2023		5,748	0.3		7,117	0.0	7,117	0.0	34,073	0.1	54.6
2024		5,750	0.0		7,095	-0.3	7,095	-0.3	34,120	0.1	54.9
2025		5,780	0.5		7,118	0.3	7,118	0.3	34,167	0.1	54.6
2026		5,791	0.2		7,108	-0.1	7,108	-0.1	34,204	0.1	54.9
2027		5,806	0.3		7,105	-0.1	7,105	-0.1	34,266	0.2	55.1
2028		5,810	0.1		7,079	-0.4	7,079	-0.4	34,346	0.2	55.4
2029		5,845	0.6		7,108	0.4	7,108	0.4	34,431	0.2	55.3
2030		5,859	0.3		7,102	-0.1	7,102	-0.1	34,475	0.1	55.4
2031		5,875	0.3		7,098	-0.1	7,098	-0.1	34,532	0.2	55.5

EXHIBIT A-4
Appalachian Power and Virginia and West Virginia Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	APCo DSM/EE			APCo - Viginia DSM/EE			APCo - West Virginia DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2017	83.0	12.9	15.5	47.4	6.7	9.3	35.7	6.2	6.3
2018	125.0	19.5	23.8	75.2	10.8	14.8	49.9	8.7	9.0
2019	224.3	23.9	34.5	105.5	12.3	18.0	118.8	11.6	16.5
2020	241.5	20.8	33.9	113.1	11.2	17.4	128.4	9.6	16.5
2021	244.8	19.3	33.7	114.5	10.7	17.3	130.3	8.7	16.4
2022	245.7	17.7	33.1	114.8	10.1	16.9	130.9	7.7	16.2
2023	244.6	15.9	32.4	114.2	9.3	16.5	130.5	6.6	15.9
2024	243.3	14.7	32.0	113.2	8.6	16.2	130.1	6.0	15.8
2025	240.8	15.1	34.5	112.1	8.6	17.7	128.7	6.5	16.8
2026	236.8	16.6	39.6	111.0	9.2	20.8	125.8	7.4	18.8
2027	233.2	18.4	45.2	110.0	9.9	23.9	123.2	8.5	21.3
2028	230.5	20.4	50.8	109.5	10.6	26.7	121.0	9.8	24.1
2029	229.0	22.5	56.6	109.4	11.2	29.4	119.6	11.3	27.3
2030	227.3	25.2	62.3	109.4	12.1	31.6	117.9	13.1	30.6
2031	223.9	28.1	68.2	108.3	12.9	33.4	115.5	15.2	34.9

***Demand coincident with Company's seasonal peak demand.**

EXHIBIT A-5
Appalachian Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results

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

EXHIBIT A-6
Blending Illustration

Month	Short-term Forecast	Weight	Long-term Forecast	Weight	Blended Forecast
1	1,000	100%	1,150	0%	1,000
2	1,010	100%	1,160	0%	1,010
3	1,020	100%	1,170	0%	1,020
4	1,030	100%	1,180	0%	1,030
5	1,040	83%	1,190	17%	1,065
6	1,050	67%	1,200	33%	1,100
7	1,060	50%	1,210	50%	1,135
8	1,070	33%	1,220	67%	1,170
9	1,080	17%	1,230	83%	1,205
10	1,090	0%	1,240	100%	1,240
11	1,100	0%	1,250	100%	1,250
12	1,110	0%	1,260	100%	1,260

EXHIBIT A-7
Appalachian Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
2017	6,991	7,158	7,294	5,553	5,686	5,793	33,253	34,048	34,693
2018	6,969	7,171	7,359	5,531	5,692	5,840	33,145	34,106	34,998
2019	6,896	7,152	7,372	5,499	5,703	5,879	32,830	34,048	35,097
2020	6,814	7,110	7,383	5,459	5,696	5,914	32,602	34,017	35,325
2021	6,790	7,121	7,459	5,451	5,717	5,989	32,424	34,005	35,620
2022	6,751	7,116	7,507	5,437	5,730	6,045	32,289	34,031	35,904
2023	6,716	7,117	7,556	5,424	5,748	6,102	32,150	34,073	36,171
2024	6,662	7,095	7,581	5,400	5,750	6,145	32,039	34,120	36,459
2025	6,648	7,118	7,639	5,398	5,780	6,203	31,910	34,167	36,668
2026	6,606	7,108	7,669	5,382	5,791	6,248	31,787	34,204	36,900
2027	6,574	7,105	7,681	5,373	5,806	6,277	31,709	34,266	37,048
2028	6,527	7,079	7,662	5,357	5,810	6,289	31,671	34,346	37,177
2029	6,537	7,108	7,706	5,375	5,845	6,337	31,665	34,431	37,329
2030	6,518	7,102	7,717	5,377	5,859	6,366	31,639	34,475	37,458
2031	6,506	7,098	7,736	5,385	5,875	6,403	31,649	34,532	37,637
Average Annual Growth Rate % - 2016-2025									
	-0.5	-0.1	0.4	-0.2	0.2	0.7	-0.4	0.1	0.6

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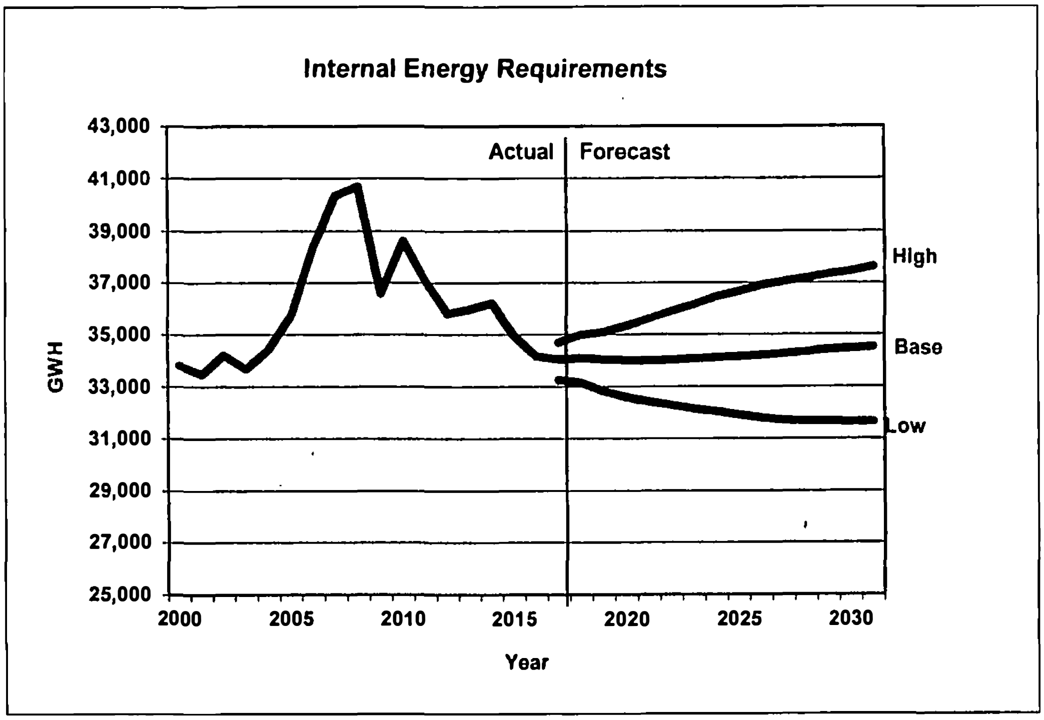
EXHIBIT A-8

Appalachian Power Company
Range of Forecasts



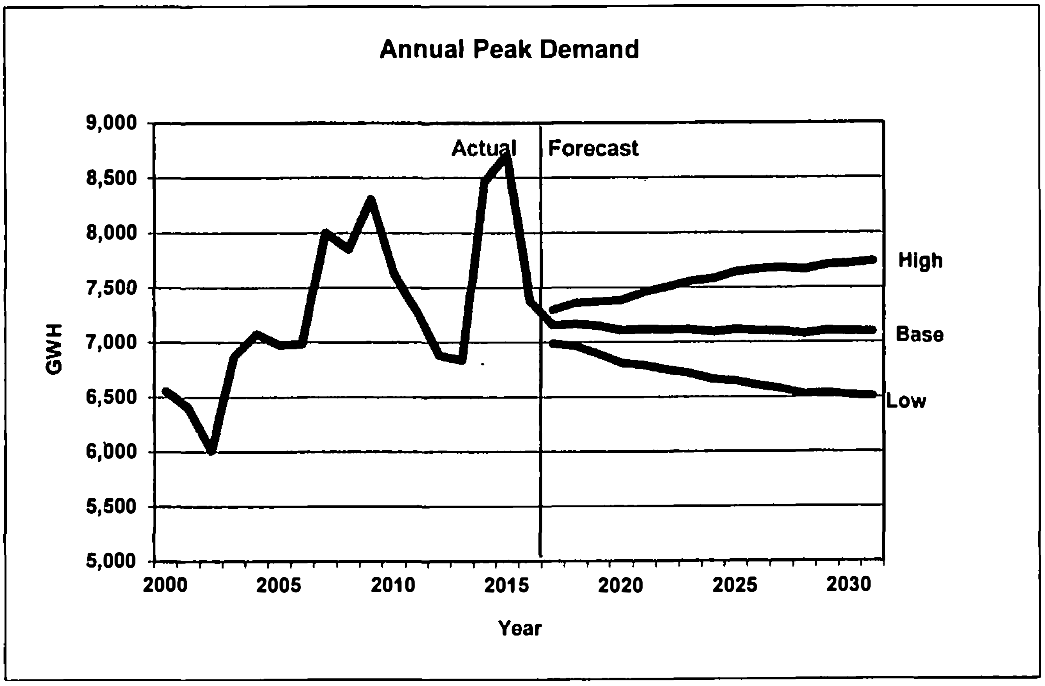


Exhibit A-9

Appalachian Power Company

Forecasted DSM, Adjusted for IRP Modeling [1]

		Total APCo	
Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2017	83,034	12.9	15.5
2018	125,041	19.5	23.8
2019	125,311	19.5	24.6
2020	87,318	13.5	18.6
2021	69,923	10.7	14.9
2022	54,934	8.3	11.6
2023	42,086	6.3	9.1
2024	32,383	4.9	7.2
2025	23,869	3.7	5.5
2026	16,838	2.7	4.1
2027	11,517	1.9	2.9
2028	7,651	1.2	1.9
2029	4,664	0.8	1.2
2030	2,472	0.4	0.6
2031	1,050	0.2	0.3

(1) DSM values shown here reflect the most recent information for APCo available at the time of the IRP. These values may differ from the DSM values shown in Exhibit A-4, which are the APCo DSM values at the time of the overall APCo load forecast.

Exhibit B Non-Renewable New Generation Technologies

EXHIBIT B

AEP System-East Zone
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (g) Std. ISO	Capability (MW) (g) Winter	Capability (MW) (g) Summer	Installed Cost (c,d) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost (f) ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emission Rates SO2 (Lb/mmBtu)	Emission Rates NOx (Lb/mmBtu)	Emission Rates CO2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)	LCOE (k) ($/MWh)
Base Load														
Nuclear	1,610	1,690	1,560	7,400	10,500	1.1	6.2	143.5	0.0000	0.000	0.0	90	94	176.2
Base Load (90% CO2 Capture New Unit)														
Pulv. Coal (Ultra-Supercritical) (PRB)	540	570	520	8,700	12,500	3.2	13.0	95.8	0.1000	0.070	21.3	85	90	252.6
IGCC "F" Class (PRB)	490	510	470	8,200	10,300	3.2	5.6	76.3	0.0638	0.062	21.3	85	88	227.5
Base / Intermediate														
Combined Cycle (1X1 "F" Class)	376	400	510	1,200	6,600	7.4	3.7	7.5	0.0007	0.009	117.1	60	89	91.9
Combined Cycle (1X1 "J" Class)	484	510	620	1,400	6,300	7.4	3.7	8.1	0.0007	0.007	117.1	60	89	94.6
Combined Cycle (2X1 "J" Class)	1,066	1,120	1,370	1,000	6,300	7.4	3.7	4.9	0.0007	0.007	117.1	60	89	82.5
Combined Cycle (2X1 "H" Class)	1,020	1,080	1,320	900	6,400	7.4	3.7	4.9	0.0007	0.007	117.1	60	89	83.3
Peaking														
Combustion Turbine (2 - "E" Class) (h)	175	180	180	1,200	11,700	7.4	15.6	9.8	0.0007	0.009	117.1	25	93	196.9
Combustion Turbine (2 - "F" Class, w/evap coolers) (h)	466	490	470	700	10,000	7.4	15.6	5.2	0.0007	0.009	117.1	25	93	151.3
Aero-Derivative (1 - Large Machine) (h)	110	110	110	1,500	9,200	7.4	15.6	13.7	0.0007	0.007	117.1	25	97	180.8
Aero-Derivative (2 - Large Machines) (h,i)	200	210	210	1,300	9,200	7.4	15.6	10.1	0.0007	0.007	117.1	25	97	180.7
Aero-Derivative (2 - Small Machines) (h,i)	100	100	100	1,700	9,800	7.4	15.6	43.7	0.0007	0.007	117.1	25	97	206.6
Recip Engine Farm (3 - Engines) (h)	50	50	50	1,800	8,400	7.4	6.2	27.2	0.0007	0.018	117.1	25	98	198.5
Battery Storage (Lithium-Ion)	10	10	10	2,300	87% (j)	–	–	15.9	–	–	–	25	94	209.9

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2017 dollars. Assume 2.13% escalation rate for 2017 and beyond.
(c) $/kW costs are based on nominal capability.
(d) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.4%,site rating $/kW).
(f) Levelized Fuel Cost (40-Yr. Period 2018-2057)
(g) All Capabilities are at 1,000 feet above sea level
(h) Includes Dual Fuel capability and SCR environmental installation.
(i) Includes Black Start capability .
(j) Denotes efficiency, (w/ power electronics).
(k) Levelized cost of energy based on assumed capacity factors shown in table.

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Exhibit C Schedules

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) — Schedule 1

PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)			(PROJECTED)														
1. Peak Load (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PJM Coincident Internal Load [4,5]	n/a	n/a	n/a	5,710	5,813	5,801	5,804	5,438	5,449	5,465	5,465	5,494	5,506	5,522	5,527	5,562	5,579	5,597
A. Summer																		
1. Base Forecast [1]	-	-	-	5,699	5,712	5,727	5,717	5,736	5,748	5,764	5,765	5,795	5,808	5,824	5,830	5,868	5,884	5,903
2. Conservation, Efficiency [2,6]	-	-	-	(13)	(20)	(24)	(21)	(19)	(18)	(16)	(15)	(15)	(17)	(18)	(20)	(23)	(25)	(28)
3. Demand-side and Response [2,6]	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Adjusted Load	5,649	5,744	5,885	5,686	5,692	5,703	5,696	5,717	5,730	5,748	5,750	5,780	5,791	5,806	5,810	5,845	5,859	5,875
5. % Increase in Adjusted Load (from previous year)	(12)	2	2	(3)	0	0	(0)	0	0	0	0	1	0	0	0	1	0	0
B. Winter [3]																		
1. Base Forecast [1]	-	-	-	7,174	7,195	7,187	7,144	7,155	7,149	7,149	7,127	7,153	7,148	7,150	7,130	7,165	7,164	7,166
2. Conservation, Efficiency [2,6]	-	-	-	(16)	(24)	(35)	(34)	(34)	(33)	(32)	(32)	(35)	(40)	(45)	(51)	(57)	(62)	(68)
3. Demand-side and Response [2,6]	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Adjusted Load	8,460	8,708	7,379	7,158	7,171	7,152	7,110	7,121	7,116	7,117	7,095	7,118	7,108	7,105	7,079	7,108	7,102	7,098
5. % Increase in Adjusted Load (from previous year)	23	3	(15)	(3)	0	(0)	(1)	0	(0)	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)
2. Energy (GWh)																		
A. Base Forecast [1]	-	-	-	34,084	34,156	34,167	34,145	34,135	34,162	34,204	34,250	34,296	34,330	34,389	34,467	34,551	34,593	34,648
B. Conservation, Efficiency [2,6]	-	-	-	(36)	(50)	(119)	(128)	(130)	(131)	(131)	(130)	(129)	(126)	(123)	(121)	(120)	(118)	(116)
C. Demand-side and Response [2,6]	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D. Adjusted Energy	36,230	34,972	34,172	34,048	34,106	34,048	34,017	34,005	34,031	34,073	34,120	34,167	34,204	34,266	34,346	34,431	34,475	34,532
E. % Increase in Adjusted Energy (from previous year)	1	(3)	(2)	(0)	0	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0	0

(1) Reflects the impact of past and on-going conservation and load management and approved or proposed new programs.
(2) Estimated aggregate impact of projected expanded demand-side management and energy efficiency programs.
(3) 2014 data refer to winter of 2013/2014, 2014 data refer to winter of 2014/2015, etc
(4) Through 2019, the values shown represent an estimate of APCo's share of the final and forecasted PJM load that is the basis for AEP's capacity obligation
The remaining years represent an estimate of APCo's share of the internal AEP forecast that has been adjusted to the PJM peak.
(5) APCo is not an independent PJM member and therefore does not have actual PJM specific data.
(6) Tables reflect DSM levels consistent with June 2016 forecast and do not include DSM incremental to the forecast associated with Plexos portfolios.
-= not available

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)

Schedule 2

GENERATION

I. SYSTEM OUTPUT(GWh)	(ACTUAL)			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	24,760	23,511	22,121	15,584	27,583	29,786	29,836	28,691	26,751	27,208	26,970	25,637	25,066	24,658	24,792	24,416	25,919	24,978
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	4,105	4,251	4,364	3,445	1,956	2,205	2,249	2,254	2,607	2,621	2,854	2,739	2,865	2,964	3,074	3,207	3,275	3,792
F. Hydro-Conventional[1]	713	811	848	815	765	823	849	848	848	848	849	848	848	756	629	629	629	629
G. Hydro-Pumped Storage	365	294	509	551	687	660	641	641	646	659	669	639	616	597	585	578	574	559
H. Renewable Resources[2]	1,003	1,024	967	944	1,339	2,085	3,139	4,176	5,222	5,768	5,829	5,862	5,909	6,049	6,018	6,371	6,823	6,807
I. Total Generation (sum of A through H)[3]	30,581	29,596	28,299	20,788	31,643	34,899	36,073	35,969	35,428	36,445	36,502	35,086	34,688	34,427	34,513	34,623	36,646	36,206
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total DSM[6]	-	-	-	26	47	295	495	624	755	865	958	824	689	664	627	621	536	481
3. Other[4]	1,710	1,303	1,486	1,093	1,791	1,919	1,906	1,910	1,962	1,955	1,928	1,930	1,903	1,894	1,884	1,893	1,885	1,859
K. Pumping Energy	(379)	(229)	(544)	(641)	(835)	(797)	(768)	(771)	(777)	(795)	(808)	(766)	(733)	(708)	(688)	(679)	(675)	(651)
L. Net Market Purchase/(Sale)[5]	3,939	4,073	4,386	12,177	675	(2,946)	(4,329)	(4,368)	(3,983)	(5,062)	(5,138)	(3,544)	(2,950)	(2,596)	(2,557)	(2,586)	(4,474)	(3,899)
M. Total System Firm Energy Requirements	36,230	34,972	34,172	34,084	34,156	34,167	34,145	34,135	34,162	34,204	34,250	34,296	34,330	34,389	34,467	34,551	34,593	34,648

II. ENERGY SUPPLIED BY:
COMPETITIVE SERVICE PROVIDERS

(1) Includes purchases from Summersville Hydro
(2) Includes purchases from Grand Ridge, Beech Ridge, Fowler Ridge and Camp Grove wind facilities
(3) Excludes Hydro Pumped Storage since the net of pump load energy and generation is accounted for in the load forecast
(4) Includes purchases from OVEC 2014-2031.
(5) Includes net sales or purchases with other electric utilities 2014-2031.
(6) Includes Embedded EE, Incremental EE, and DG

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)

Schedule 3

GENERATION

III. SYSTEM OUTPUT MIX (%) [1]	2014 (ACTUAL)	2015	2016	2017 (PROJECTED)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	68	67	65	46	81	87	87	84	78	80	79	75	73	72	72	71	75	72
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	11	12	13	10	6	6	7	7	8	8	8	8	8	9	9	9	9	11
F. Hydro-Conventional	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
G. Hydro-Pumped Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H. Renewable Resources	3	3	3	3	4	6	9	12	15	17	17	17	17	18	17	18	20	20
I. Total Generation (sum of A through H)	84	85	83	61	93	102	106	105	104	107	107	102	101	100	100	100	106	104
J. Purchased and Interchange Received																		
1. Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Total DSM [3]	-	-	-	0	0	1	1	2	2	3	3	2	2	2	2	2	2	1
3. Other	5	4	-	3	5	6	6	6	6	6	6	6	6	6	5	5	5	5
K. Energy for Pumping	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
L. Other Sales	11	12	13	36	2	(9)	(13)	(13)	(12)	(15)	(15)	(10)	(9)	(8)	(7)	(7)	(13)	(11)
IV. SYSTEM LOAD FACTOR (%) [2]	60	47	45	53	52	52	52	52	52	52	52	52	52	51	51	52	51	51

(1) Expressed as a percent of Total System Firm Energy Requirements (Schedule 2, line M).
(2) Based on Total System Firm Energy Requirements (internal load) and annual peak demand.
(3) Includes Embedded EE, Incremental EE, and DG
(4) Excludes Hydro Pumped Storage since the net of pump load energy and generation is accounted for in the load forecast

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 4

POWER SUPPLY DATA[7]

I. CAPABILITY (MW)	(ACTUAL)[1] 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1. Summer PJM Capacity (ICAP)[5]																		
A. Installed Dependable Capability[1,2]	8,185	6,984	6,998	6,958	6,966	7,023	7,022	7,022	7,022	7,022	7,022	7,022	6,582	6,490	6,477	6,460	6,445	6,445
B. Total Positive Interchange Commitments[3]	4	25	26	24	22	22	22	4	4	4	4	4	4	4	4	4	4	4
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	8,189	7,009	7,024	6,982	6,988	7,045	7,044	7,026	7,026	7,026	7,026	7,026	6,586	6,494	6,481	6,464	6,449	6,449
E. Total Unforced Capacity UCAP[4]	7,544	6,365	6,573	6,619	6,584	6,638	6,348	6,391	6,399	6,399	6,392	6,389	5,986	5,960	5,953	5,947	5,941	5,940
2. Winter PJM Capacity (ICAP)[5,6]																		
A. Installed Net Dependable Capability[1,2]	8,185	6,984	6,998	6,958	6,966	7,023	7,022	7,022	7,022	7,022	7,022	7,022	6,582	6,490	6,477	6,460	6,445	6,445
B. Total Positive Interchange Commitments 3	4	25	26	24	22	22	22	4	4	4	4	4	4	4	4	4	4	4
C. Capability in Cold Reserve Status	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Total Installed Capacity (ICAP)	8,189	7,009	7,024	6,982	6,988	7,045	7,044	7,026	7,026	7,026	7,026	7,026	6,586	6,494	6,481	6,464	6,449	6,449
E. Total Unforced Capacity UCAP[4]	7,544	6,365	6,573	6,619	6,584	6,638	6,348	6,391	6,399	6,399	6,392	6,389	5,986	5,960	5,953	5,947	5,941	5,940

(1) PJM Installed Capacity (ICAP) Rating
(2) Changes in unit capability are reflected on schedule 13
(3) Capacity sales/purchases, positive values are sales, negative values are purchases
(4) UCAP value; includes EE, VVO, and DR; includes the impacts of $EFOR_D$
(5) Value represent PJM planning year 20XX/20XX+1
(6) Difference in Summer and Winter capacity ratings is negligible
(7) Values shown are exclusive of resource additions

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)

Schedule 5

POWER SUPPLY DATA (continued)[4]

	(ACTUAL)			(PROJECTED)														
II. LOAD (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1. Summer																		
A. Adjusted Summer Peak [1]	5,649	5,744	5,885	5,686	5,692	5,703	5,696	5,717	5,730	5,748	5,750	5,780	5,791	5,806	5,810	5,845	5,859	5,875
B. Total Negative Power Commitments [2]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Total Summer Peak	5,649	5,744	5,885	5,686	5,692	5,703	5,696	5,717	5,730	5,748	5,750	5,780	5,791	5,806	5,810	5,845	5,859	5,875
D. Percent Increase In Total Summer Peak	(4)	2	2	(3)	0	0	(0)	0	0	0	0	1	0	0	0	1	0	0
2. Winter [3]																		
A. Adjusted Winter Peak [1]	8,460	8,708	7,379	7,158	7,171	7,152	7,110	7,121	7,116	7,117	7,095	7,118	7,108	7,105	7,079	7,108	7,102	7,098
B. Total Negative Power Commitments [2]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C. Total Winter Peak	8,460	8,708	7,379	7,158	7,171	7,152	7,110	7,121	7,116	7,117	7,095	7,118	7,108	7,105	7,079	7,108	7,102	7,098
D. Percent Increase In Total Winter Peak	6	3	(15)	(3)	0	(0)	(1)	0	(0)	0	(0)	0	(0)	(0)	(0)	0	(0)	(0)

(1) Peak after energy efficiency and demand-side programs, see Schedule 1.
(2) Includes firm commitments for the delivery of specified blocks of power (i.e., unit power, diversity exchange).
(3) 2013 data refers to winter of 2012/2013, 2014 data refers to winter of 2013/2014, etc.
(4) Values shown are exclusive of resource additions

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 6

POWER SUPPLY DATA (continued)[5]

	(ACTUAL)			(PROJECTED)														
I. Reserve Margin (Including Cold Reserve Capability)[1]	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1. Summer Reserve Margin																		
A. MW	2,540	1,265	1,139	1,296	1,296	1,342	1,348	1,309	1,296	1,278	1,276	1,246	795	688	671	619	590	574
B. Percent of Load	45	22	19	23	23	24	24	23	23	22	22	22	14	12	12	11	10	10
2. Winter Reserve Margin[2]																		
A. MW	(271)	(1,699)	(355)	(176)	(183)	(107)	(66)	(95)	(90)	(91)	(69)	(92)	(522)	(611)	(598)	(644)	(653)	(649)
B. Percent of Load	(3)	(20)	(5)	(2)	(3)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(7)	(9)	(8)	(9)	(9)	(9)
II. Reserve Margin (Excluding Cold Reserve Capability)[3]																		
1. Summer Reserve Margin																		
A. MW	2,540	1,265	1,139	1,296	1,296	1,342	1,348	1,309	1,296	1,278	1,276	1,246	795	688	671	619	590	574
B. Percent of Load	45	22	19	23	23	24	24	23	23	22	22	22	14	12	12	11	10	10
2. Winter Reserve Margin[2]																		
A. MW	(271)	(1,699)	(355)	(176)	(183)	(107)	(66)	(95)	(90)	(91)	(69)	(92)	(522)	(611)	(598)	(644)	(653)	(649)
B. Percent of Load	(3)	(20)	(5)	(2)	(3)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(7)	(9)	(8)	(9)	(9)	(9)
III. Annual Loss-of-Load Hours[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Calculated based on Total Net Capability for summer and winter.
(2) 2013 data refers to winter of 2012/2013, 2014 data refers to winter of 2013/2014, etc.
(3) Same as footnote 1 above less capability in cold reserve.
(4) The loss of load calculation is carried out by PJM and reserve targets are set with the intention of maintaining a loss of load expectation of no more than 1 day in 10 years.
(5) Values shown are exclusive of resource additions
-= not available

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)

Schedule 7

CAPACITY DATA

I. Nameplate Capacity (MW) [1,3]	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	(ACTUAL)			(PROJECTED)														
A. Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
B. Coal	6,264	5,027	4,573	4,567	4,563	4,599	4,599	4,599	4,599	4,599	4,599	4,599	4,599	4,599	4,599	4,599	4,599	4,599
C. Heavy Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
D. Light Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Natural Gas	1,005	1,005	1,479	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,005	1,005	1,005	1,005	1,005	1,005
F. Hydro-Conventional	277	281	281	281	281	281	281	281	281	281	281	281	281	201	201	201	201	201
G. Pumped Storage	586	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615
H. Wind	376	376	376	376	496	721	1,021	1,321	1,621	1,771	1,771	1,771	1,771	1,771	1,596	1,747	1,695	1,695
I. Solar	-	-	-	-	-	25	45	65	85	105	125	145	165	225	285	345	465	525
J. Demand-Side [4]	188	219	147	152	158	193	314	329	345	357	367	347	328	333	329	330	320	316
K. Purchases	4	25	26	24	22	22	22	4	4	4	4	4	4	4	4	4	4	4
L. Total (sum of A through H)	7,337	8,186	6,984	7,460	7,580	7,901	8,342	8,659	8,995	9,177	9,207	9,207	8,768	8,753	8,634	8,846	8,904	8,960
II. Installed Capacity Mix (%) [2,3]																		
A. Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
B. Coal	85.37	61.41	65.48	61.22	60.20	58.21	55.13	53.11	51.13	50.11	49.95	49.95	52.45	52.54	53.27	51.99	51.65	51.33
C. Heavy Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D. Light Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E. Natural Gas	13.70	12.28	21.18	19.37	19.06	18.29	17.32	16.69	16.06	15.75	15.69	15.69	11.46	11.48	11.64	11.36	11.29	11.22
F. Hydro-Conventional	3.78	3.43	4.02	3.77	3.71	3.56	3.37	3.25	3.12	3.06	3.05	3.05	3.20	2.30	2.33	2.27	2.26	2.24
G. Pumped Storage	7.99	7.51	8.81	8.24	8.11	7.78	7.37	7.10	6.84	6.70	6.68	6.68	7.01	7.03	7.12	6.95	6.91	6.86
H. Wind	5.12	4.59	5.38	5.04	6.54	9.13	12.24	15.26	18.02	19.30	19.24	19.24	20.20	20.23	18.49	19.75	19.04	18.92
I. Solar	0.00	0.00	0.00	0.00	0.00	0.32	0.54	0.75	0.94	1.14	1.36	1.57	1.88	2.57	3.30	3.90	5.22	5.86
J. Demand-Side [4]	2.56	2.68	2.10	2.04	2.08	2.44	3.76	3.80	3.84	3.89	3.99	3.77	3.74	3.80	3.81	3.73	3.59	3.53
K. Purchases	0.05	0.31	0.37	0.32	0.29	0.28	0.26	0.05	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.04	0.04

(1) Nameplate capacities by fuel types for supply-side resources
(2) Each item in lines A-I of Section II. as a percent of line J above in Section I.
(3) Reflects resource additions of the Preferred Plan
(4) Includes EE, VVO, DR, and DG Resources

COMPANY NAME: AEP SYSTEM - EAST ZONE
UNIT PERFORMANCE DATA
Equivalent Availability Factor (%) [1]

Schedule 8
CONFIDENTIAL

Unit Name	2014 (ACTUAL)	2015	2016	2017 (PROJECTED)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Amos 1	[redacted]																	
Amos 2																		
Amos 3																		
Ceredo 1																		
Ceredo 2																		
Ceredo 3																		
Ceredo 4																		
Ceredo 5																		
Ceredo 6																		
Clinch River 1																		
Clinch River 2																		
Mountaineer 1																		
Dresden																		
Clinch River 1 Gas Conversion																		
Clinch River 2 Gas Conversion																		
14 MW CHP																		

(1) Does not inlcude renewable generation, or power purchases

- = not available

COMPANY NAME: AEP SYSTEM - EAST ZONE
UNIT PERFORMANCE DATA
Net Capacity Factor (%)[1]

Schedule 9
CONFIDENTIAL

	(ACTUAL)			(PROJECTED)														
Unit Name	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Amos 1	[redacted]																	
Amos 2																		
Amos 3																		
Ceredo 1																		
Ceredo 2																		
Ceredo 3																		
Ceredo 4																		
Ceredo 5																		
Ceredo 6																		
Clinch River 1																		
Clinch River 2																		
Mountaineer 1																		
Dresden																		
Clinch River 1 Gas Conversion																		
Clinch River 2 Gas Conversion																		
14 MW CHP																		

(1) Does not inlcude renewable generation, or power purchases
- = not available

COMPANY NAME: AEP SYSTEM - EAST ZONE
UNIT PERFORMANCE DATA
Average Heat Rate - (Btu/kWh)[1]

Schedule 10
CONFIDENTIAL

Unit Name	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	(ACTUAL)			(PROJECTED)														
Amos 1	[redacted]																	
Amos 2																		
Amos 3																		
Ceredo 1																		
Ceredo 2																		
Ceredo 3																		
Ceredo 4																		
Ceredo 5																		
Ceredo 6																		
Clinch River 1																		
Clinch River 2																		
Mountaineer 1																		
Dresden																		
Clinch River 1 Gas Conversion																		
Clinch River 2 Gas Conversion																		

(1) Does not include renewable generation, or power purchases
- = not available

170510078

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)
RENEWABLE RESOURCES (MWh)

Schedule 11

Resource Type [1]	Unit Name	C.O.D [2]	Built/ Purchase [3]	Life/ Duration [4]	Size (MW) Nameplate	Size (MW) NDC [5]	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022
Wind	Camp Grove	Jan/2008	Purchase	20 years	75	13	209,727	222,278	202,649	209,843	209,843	209,843	210,570	209,843	209,843
	Fowler Ridge 3	Feb/2009	Purchase	20 years	100	13	243,629	262,350	238,278	245,403	245,403	245,403	246,065	245,403	245,403
	Grand Ridge 2	Dec/2009	Purchase	20 years	51	9	135,149	135,629	128,633	130,656	130,655	130,655	131,088	130,655	130,655
	Grand Ridge 3	Dec/2009	Purchase	20 years	50	8	130,303	127,697	122,382	126,812	126,812	126,812	127,233	126,812	126,812
	Beech Ridge	Jun/2010	Purchase	20 years	101	15	283,747	276,044	274,621	231,045	231,045	231,045	231,658	231,045	231,045
	2018 Wind Project	Jan/2018	Purchase	20 years	120	-	-	-	-	-	395,273	395,273	396,419	395,273	395,273
	2019 Wind Project Part 1	Jan/2019	Owned	-	50	-	-	-	-	-	-	157,761	158,562	157,761	157,761
	2019 Wind Project Part 2	Jan/2019	Owned	-	175	-	-	-	-	-	-	529,812	531,110	529,812	529,812
	New	Varies	-	20 years	Varies	Varies	-	-	-			-	1,000,585	1,997,280	2,995,920
Wind Subtotal					721	58	1,002,555	1,023,998	966,563	943,758	1,339,031	2,026,604	3,033,289	4,023,884	5,022,524
Solar	Distributed	-	-	-	-	-	-	-	-	24,264	45,292	67,938	71,454	79,261	87,349
	2019 Solar Project	-	-	-	25	-	-	-	-	-	-	58,588	58,824	58,588	58,588
	New Large-Scale	Varies	-	25 years	Varies	Varies	-	-	-	-	-	-	47,059	93,741	140,612
Solar Subtotal					-	-	-	-	-	24,264	45,292	126,526	177,337	231,591	286,549
Total Renewables					721	58	1,002,555	1,023,998	966,563	968,021	1,384,323	2,153,131	3,210,625	4,255,475	5,309,074

Resource Type	Unit Name	2023	2024	2025	2026	2027	2028	2029	2030	2031
Wind	Camp Grove	209,843	210,570	209,843	209,843	209,843	22,940	-	-	-
	Fowler Ridge 3	245,403	246,065	245,403	245,403	245,403	246,065	51,961	-	-
	Grand Ridge 2	130,655	131,088	130,655	130,655	130,655	131,088	102,744	-	-
	Grand Ridge 3	126,812	127,233	126,812	126,812	126,812	127,233	99,772	-	-
	Beech Ridge	231,045	231,658	231,045	231,045	231,045	231,658	231,045	156,504	-
	2018 Wind Project	395,273	396,419	395,273	395,273	395,273	396,419	395,273	395,273	395,273
	2019 Wind Project Part 1	157,761	158,562	157,761	157,761	157,761	158,562	157,761	157,761	157,761
	2019 Wind Project Part 2	529,812	531,110	529,812	529,812	529,812	531,110	529,812	529,812	529,812
	New	3,495,240	3,502,048	3,495,240	3,495,240	3,495,240	3,502,048	3,994,560	4,493,880	4,493,880
Wind Subtotal		5,521,844	5,534,751	5,521,844	5,521,844	5,521,844	5,347,122	5,562,878	5,733,231	5,576,727
Solar	Distributed	95,436	120,172	127,788	137,493	145,581	154,275	163,374	173,080	182,785
	2019 Solar Project	58,588	58,824	58,588	58,588	58,588	58,824	58,588	58,588	58,588
	New Large-Scale	187,483	235,295	281,224	328,095	468,707	611,767	749,932	1,031,156	1,171,768
Solar Subtotal		341,508	414,291	467,601	524,177	672,877	824,866	971,894	1,262,824	1,413,147
Total Renewables		5,863,352	5,949,042	5,989,445	6,046,021	6,194,721	6,171,988	6,534,773	6,996,055	6,989,869

(1) Per definition of 56-576 of the code of Virginia.
(2) Commercial operation date.
(3) Describe as Company built or purchase.
(4) State expected life of facility or duration of purchase contract.
(5) Net dependable capacity (summer)(as of 6-1-2016).
- = not available

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)

Energy Efficiency/Conservation/Demand Side Management/Demand Response (MWh)

Program Type	Program Name	Date (3)	Life/ Duration (4)	Size (MW) (5)	(ACTUAL) (6)			(PROJECTED) (6)															
					2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EE (1)	Current Programs	06/12/2016	10	19.5	49,227	39,196	34,566	83,034	125,041	125,311	87,318	69,923	54,934	42,086	32,383	23,869	16,838	11,517	7,651	4,664	2,472	1,050
EE (2)	Residential Lighting	01/01/2019	30	27				-	-	95,000	183,635	231,645	275,410	314,435	340,522	291,827	241,678	195,772	170,344	158,411	122,358	93,251
EE (2)	Residential Water Heating	01/01/2019	10	12				-	-	13,000	24,700	23,034	20,194	16,964	12,443	9,125	6,693	15,178	21,889	24,202	18,075	17,920
EE (2)	Residential Appliances	01/01/2019	16	8				-	-	13,000	12,129	11,271	10,400	9,529	7,579	8,616	6,491	8,487	7,186	6,171	11,770	19,340
EE (2)	Commercial/Ind. Lighting - Screw-In	01/01/2019	6	64				-	-	37,000	71,521	103,920	139,709	183,921	233,408	193,471	153,083	114,968	95,068	85,835	61,387	43,843
EE (2)	Commercial/Ind. Lighting - Fluorescent	01/01/2019	10	45				-	-	37,000	71,521	104,853	140,576	149,521	133,720	106,183	79,403	68,541	69,772	77,306	55,920	38,535
EE (2)	Commercial/Ind. Lighting - Outdoor	01/01/2019	11	30				-	-	30,000	57,990	67,995	79,488	93,190	108,382	85,252	62,088	46,865	40,324	37,118	25,010	17,147
EE (1)	VVO Pilot	12/14/2016	15	0.6				2,171	2,161	2,149	2,143	2,139	2,138	2,141	2,143	2,147	2,152	2,158	2,164	2,172	2,181	2,180
EE (2)	VVO	01/01/2016	15	16.7				-	-	-	-	-	-	-	-	-	-	66,329	66,329	66,329	66,329	66,329
Subtotal				223	49,227	39,196	34,566	85,206	127,202	352,460	510,956	614,779	722,850	811,786	870,580	720,491	568,425	529,814	480,728	462,208	365,501	299,595
DR	PSEDR	06/12/2015	15	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	Interruptible	06/12/2015	15	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	ATOD	06/12/2015	15	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal				119	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Demand Side Management				342	49,227	39,196	34,566	85,206	127,202	352,460	510,956	614,779	722,850	811,786	870,580	720,491	568,425	529,814	480,728	462,208	365,501	299,595

Notes:

1) Current Program Descriptions
   C&I Rebates - Program includes lighting, motor, and refrigeration measures
   Residential Low & Moderate Income - Program includes insulation, thermostat, duct sealing, CFL, low flow fixtures, and water heater blanket measures
   Residential Rebates - Primarily CFL, also Energy Star appliance measures
   Residential Whole House - Program primarily includes CFL, low flow, with some insulation, thermostat, duct sealing, and A/C measures
   PSEDR - Peak Shaving and Emergency Demand Response
   Interruptible - Special contracts
   ATOD Pricing - Tariff, tiered pricing
2) Incremental Proxy EE Programs modeled in the IRP.
3) Date indicates year program starts.
4) Average life of measures that constitute programs.
5) Demand impacts for EE programs reflect 2031 undegraded value. Values are coincendent peak impacts. Demand impacts for DR programs are for PJM (summer) peak.
6) Energy values shown are degraded.

COMPANY NAME: AEP SYSTEM - APCo

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate[2]

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Unit Name	(ACTUAL) 2014	2015	2016	(PROJECTED) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Amos 1	[redacted]																	
Amos 2																		
Amos 3																		
Ceredo 1-6																		
Clinch River 1 [3]																		
Clinch River 2 [3]																		
Clinch River 3 [4]																		
Glen Lyn 5 [4]																		
Glen Lyn 6 [4]																		
Kanawha River 1 [4]																		
Kanawha River 2 [4]																		
Mountaineer 1																		
Sporn 1 [4]																		
Sporn 3 [4]																		
Buck 1 - 3																		
Byllesby 1 - 4																		
Claytor 1 - 4																		
Leesville 1 - 2																		
London 1 - 3																		
Marmet 1 - 3																		
Niagara 1 - 2																		
Winfield 1 - 3																		
Smith Mountain 1																		
Smith Mountain 2																		
Smith Mountain 3																		
Smith Mountain 4																		
Smith Mountain 5																		
Dresden																		

(1) Reflects owned, active units. Combustion turbines, combined cycles and hydro plants reported as composite facilities.
(2) PJM capability as of filing. Incremental Uprates shown as positive + and decremental Derates shown as negative (-).
(3) Inlcudes conversion from coal to natural gas fuel in 2016, unit retirement in 2026
(4) Reflects unit retirement

COMPANY NAME: AEP SYSTEM - APCo **Schedule 14**

UNIT PERFORMANCE DATA

Existing Owned Supply-Side Resources (MW) as of April 1, 2017 [1]

Unit Name	Company	Location	UnitType	PrimaryFuel Type	C.O.D. [2]	Net Capability - MW [3] Winter		Summer	
Amos 1	APCo	St. Albans, WV	Steam	Coal - Bit.	1971	800		800	
Amos 2	APCo	St. Albans, WV	Steam	Coal - Bit.	1972	800		800	
Amos 3	APCo	St. Albans, WV	Steam	Coal - Bit.	1973	1,330		1,330	
Ceredo 1	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 2	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 3	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 4	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 5	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Ceredo 6	APCo	Ceredo, WV	Combustion Turbine	Gas	2001	86		75	
Clinch River 1	APCo	Carbo, VA	Steam	Gas	1958	237		237	
Clinch River 2	APCo	Carbo, VA	Steam	Gas	1958	237		237	
Dresden	APCo	Dresden, OH	Combined Cycle	Gas	2012	613		555	
Mountaineer 1	APCo	New Haven, WV	Steam	Coal - Bit.	1980	1,320		1,305	
Buck 1 - 3	APCo	Ivanhoe, VA	Hydro	--	1912	5		3	(A)
Byllesby 1 - 4	APCo	Byllesby, VA	Hydro	--	1912	8		4	(A)
Claytor 1 - 4	APCo	Radford, VA	Hydro	--	1939	28		15	(A)
Leesville 1 - 2	APCo	Leesville, VA	Hydro	--	1964	9		5	(A)
London 1 - 3	APCo	Montgomery, WV	Hydro	--	1935	12		7	(A)
Marmet 1 - 3	APCo	Marmet, WV	Hydro	--	1935	11		6	(A)
Niagara 1 - 2	APCO	Roanoke, VA	Hydro	--	1924	1		1	(A)
Reusens 1 - 5	APCo	Lynchburg, VA	Hydro	--	1903	0		0	(A)
Winfield 1 - 3	APCo	Winfield, WV	Hydro	--	1938	15		9	(A)
Smith Mountain 1	APCo	Penhook, VA	Pump. Stor.	--	1965	70	(B)	70	(B)
Smith Mountain 2	APCo	Penhook, VA	Pump. Stor.	--	1965	185	(B)	185	(B)
Smith Mountain 3	APCo	Penhook, VA	Pump. Stor.	--	1980	105	(B)	105	(B)
Smith Mountain 4	APCo	Penhook, VA	Pump. Stor.	--	1966	185	(B)	185	(B)
Smith Mountain 5	APCo	Penhook, VA	Pump. Stor.	--	1966	70	(B)	70	(B)
						6,558		6,379	

Notes:

(1) Power Purchase Agreements (PPAs) are not included

(2) Commercial operation date.

(3) Peak net dependable capability as of filing.

(A) Estimated summer net capability.

(B) Units 1, 3 & 5 have pump-back capability, units 2 & 4 are generation only.

COMPANY NAME: AEP SYSTEM - APCo **Schedule 15**
UNIT PERFORMANCE DATA
Planned Supply Side Resources (MW) [1]

Unit Name	Company	Location	UnitType	PrimaryFuel Type	C.O.D. [2]	Nameplate Capacity [3]	Installed Capacity [4]
2021 APCO CHP	APCO	TBD	Combined Heat and Power	Gas	Jan/2020	15	14
2019 Solar Project	APCo	TBD	Solar	Solar	Jan/2019	25	10
2018 Wind Project	APCo	Indiana	Wind	Wind	Jan/2018	120	6
2019 Wind Project Part 1	APCo	TBD	Wind	Wind	Jan/2019	50	3
2019 Wind Project Part 2	APCo	TBD	Wind	Wind	Jan/2019	175	9
2020 APCo Solar	APCo	TBD	Solar	Solar	Jan/2020	20	8
2021 APCo Solar	APCo	TBD	Solar	Solar	Jan/2021	20	8
2022 APCo Solar	APCo	TBD	Solar	Solar	Jan/2022	20	8
2023 APCo Solar	APCo	TBD	Solar	Solar	Jan/2023	20	8
2024 APCo Solar	APCo	TBD	Solar	Solar	Jan/2024	20	8
2025 APCo Solar	APCo	TBD	Solar	Solar	Jan/2025	20	8
2026 APCo Solar	APCo	TBD	Solar	Solar	Jan/2026	20	8
2027 APCo Solar	APCo	TBD	Solar	Solar	Jan/2027	60	23
2028 APCo Solar	APCo	TBD	Solar	Solar	Jan/2028	60	23
2029 APCo Solar	APCo	TBD	Solar	Solar	Jan/2029	60	23
2030 APCo Solar	APCo	TBD	Solar	Solar	Jan/2030	120	46
2031 APCo Solar	APCo	TBD	Solar	Solar	Jan/2031	60	23
2020 APCo Wind	APCo	TBD	Wind	Wind	Jan/2020	300	15
2021 APCo Wind	APCo	TBD	Wind	Wind	Jan/2021	300	15
2022 APCo Wind	APCo	TBD	Wind	Wind	Jan/2022	300	15
2023 APCo Wind	APCo	TBD	Wind	Wind	Jan/2023	300	15
2029 APCo Wind	APCo	TBD	Wind	Wind	Jan/2029	150	8
2030 APCo Wind	APCo	TBD	Wind	Wind	Jan/2030	150	8

Notes:

(1) In view of the current economic conditions, potential federal and state requirement for renewable energy and energy efficiency, and the potential for federal CO_2 legislation the timing of future generation resource additions are highly uncertain.
(2) Commercial operation date.
(3) Standard ISO rating at 1000' elevation
(4) Net Dependable Rating of unit as determined in accordance with PJM's Rules and Procedures.
Wind Resources are assumed to have a installed capacity rating of 5% of nameplate and solar is assumed to have 38%.

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View) Schedule 16

UTILITY CAPACITY POSITION (MW) [1]

	(ACTUAL) [2]			(PROJECTED)														
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Existing Capacity (ICAP)																		
Conventional	-	-	-	6,006	6,006	6,042	6,042	6,042	6,042	6,042	6,042	6,042	5,602	5,602	5,602	5,602	5,602	5,602
Renewable [7]	-	-	-	952	960	981	980	980	980	980	980	980	980	888	875	858	843	843
Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	24	22	22	22	4	4	4	4	4	4	4	4	4	4	4
Total Existing Capacity	-	-	-	6,982	6,988	7,045	7,044	7,026	7,026	7,026	7,026	7,026	6,586	6,494	6,481	6,464	6,449	6,449
Planned Capacity Changes (ICAP)																		
Conventional	-	-	-	0	0	36	36	36	36	36	36	36	(404)	(404)	(404)	(404)	(404)	(404)
Renewable	-	-	-	0	8	29	28	28	28	28	28	28	28	(64)	(77)	(94)	(109)	(109)
Total Planned Capacity Changes	-	-	-	0	8	65	64	64	64	64	64	64	(376)	(468)	(481)	(498)	(513)	(513)
Capacity Performance Changes (UCAP)	-	-	-	0	0	0	(290)	(334)	(334)	(334)	(334)	(334)	(334)	(274)	(267)	(254)	(244)	(244)
Expected New Capacity (UCAP)																		
Conventional	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	-	-	-	0	0	0	23	45	68	83	91	98	106	129	151	182	235	258
Battery Storage	-	-	-	0	0	0	0	0	0	0	0	5	5	5	5	5	5	5
Total Expected New Capacity	-	-	-	0	0	0	23	45	68	83	91	103	111	134	156	187	240	263
Unforced Availability (Factor)	-	-	-	7.25%	7.93%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.82%	7.80%	7.82%	7.84%	7.86%	7.86%
Net Generation Capacity (UCAP)	-	-	-	6,476	6,434	6,488	6,221	6,182	6,205	6,220	6,228	6,240	5,848	5,847	5,863	5,890	5,938	5,961
Existing DSM Reductions (ICAP) [3,6]																		
Demand response	-	-	-	137	137	137	137	219	219	219	219	219	219	219	219	219	219	219
Conservation/Efficiency	-	-	-	0	0	0	0	13	20	20	14	11	8	6	5	4	3	2
Total Existing DSM Reductions	-	-	-	137	137	137	137	232	239	239	233	230	227	225	224	223	222	221
Expected New DSM Reductions (ICAP) [3,6]																		
Demand Response	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation/Efficiency/VVO	-	-	-	0	0	30	52	73	95	117	138	142	145	173	184	197	199	203
Distributed Generation	-	-	-	6	12	17	18	20	22	24	31	33	35	37	39	42	44	47
Combined Heat and Power	-	-	-	0	0	0	0	14	14	14	14	14	14	14	14	14	14	14
Total Expected New DSM Reductions	-	-	-	7	13	48	73	106	125	141	159	141	122	128	124	126	115	111
Total Demand-side Reductions (ICAP)	-	-	-	144	150	185	210	338	364	380	392	371	349	353	348	349	337	332
Net Generation & Demand-side (UCAP)	-	-	-	6,625	6,596	6,685	6,443	6,541	6,590	6,621	6,641	6,631	6,217	6,220	6,231	6,259	6,295	6,313
PJM Capacity Obligation (UCAP) [4]	-	-	-	6,264	6,330	6,317	6,321	5,922	5,934	5,951	5,951	5,983	5,996	6,013	6,019	6,057	6,076	6,095
Additional Obligation	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Obligation	-	-	-	6,264	6,330	6,317	6,321	5,922	5,934	5,951	5,951	5,983	5,996	6,013	6,019	6,057	6,076	6,095
Net Utility Capacity Position [5]				365	264	368	122	618	656	670	688	648	222	205	214	200	219	216

(1) Net dependable installed capability during peak season (summer); unit capabilities are classified by primary fuel type.
(2) Not Applicable - APCo is not an independent PJM member and therefore does not have actual PJM specific data.
(3) The impact of new Conservation/Efficiency is delayed three years to represent its impact on actual load feeding through the PJM load forecast process.
(4) Through 2017, the values shown represent an estimate of APCo's share of the final and forecasted PJM load that is the basis for AEP's capacity obligation. The remaining years represent an estimate of APCo's share of the internal AEP forecast that has been adjusted to the PJM peak.
(5) Through 2017, reflects APCo's contribution as part of a 4-Company (through 2015) or 3-Company (through 2017) FRR entity.
(6) Tables reflect DSM levels consistent with July 2015 forecast and DSM incremental to the forecast associated with Plexos portfolios.
(7) Renewable represents conventional hydro, pumped storage, solar and wind

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CONFIDENTIAL

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)

CONSTRUCTION FORECAST (Million Dollars)

	ACTUAL EXPENDITURES			PROJECTED EXPENDITURES		
	2014	2015	2016	2017	2018	2019
I. New Traditional Generating Facilities	[redacted]					
a. Capital Investment (Exclusive of AFUDC)						
b. AFUDC						
c. Annual Total						
d. Cumulative Total						
II. New Renewable Generating Facilities[1]						
III. Other Facilities						
a. Existing Generation						
b. Transmission						
c. Distribution						
d. Energy conservation/efficiency & demand response						
e. gridSMART						
f. Other						
g. AFUDC						
h. Annual Total						
i. Cumulative Total						
IV. Total Construction Expenditures						
a. Annual Total						
b. Cumulative Total						
V. Percent of Funds for Total Construction Provided from External Financing						

1 APCo has signed contracts to purchase renewable energy under power purchase agreements with third parties.

COMPANY NAME: APPALACHIAN POWER COMPANY (APCo)(Stand Alone View)
FUEL DATA

Schedule 18
CONFIDENTIAL

	(ACTUAL)			(PROJECTED)[1]															
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
I. Delivered Fuel Price (cents/MBtu)																		
a. Nuclear	[redacted]																	
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable *																		
II. Primary Fuel Expenses (cents/kWh)																		
a. Nuclear																		
b. Coal																		
c. Heavy Fuel Oil																		
d. Light Fuel Oil																		
e. Natural Gas																		
f. Renewable *																		
g. Purchases Energy Charges only																		
h. Purchases Energy and Capacity Charges																		

* Per definition of 56-576 of the Code of Virginia.
(1) As consumed.

- =not available

Exhibit D Cross Reference Table

EXHIBIT D

Appalachian Power Company
For the 15 Year Forecast Period Beginning 2017

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
A. Purpose The purpose of these guidelines is to implement the provisions of §§ 56-597, 56-598 and 56-599 of the Code of Virginia with respect to integrated resource planning ("IRP") by the electric utilities in the Commonwealth. In order to understand the basis for the utility's plan, the IRP filing shall include a narrative summary detailing the underlying assumptions reflected in its forecast as further described in the guidelines. To better follow the utility's planning process, the narrative shall include a description of the utility's rationale for the selection of any particular generation addition or demand-side management program to fulfill its forecasted need. Such description should include the utility's evaluation of its purchase options and cost/benefit analyses for each resource option to confirm and justify each resource option it has chosen.	
Such narrative shall also describe the planning process including timelines and appropriate reviews and/or approvals of the utility's plan. For members of PJM Interconnection, LLC ("PJM"), the narrative should describe how the IRP incorporates the PJM planning and implementation processes and how it will satisfy PJM load obligations.	
These guidelines also include sample schedules to supplement this narrative discussion and assist the utilities in developing a tabulation of the utility's forecast for at least a 15-year period and identify the projected supply-side or demand-side resource additions and solutions to adequately and reliably meet the electricity needs of the Commonwealth. This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the same period. These guidelines also direct that all IRP filings include information to comparably evaluate various supply-side technologies and demand-side programs and technologies on an equivalent basis as more fully described below in Section F (7). The Commission may revise or supplement the sample schedules as needed or warranted.	
B. Applicability These guidelines are applicable to all investor-owned utilities responsible for procurement of any or all of its individual power supply resources.	
C. Integated Resource Plan Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:	
C.1. Forecast A three-year historical record and a 15-year forecast of the utility's native load requirements, the utility's PJM load obligations if appropriate, and other system capacity or firm energy obligations for each peak season along with the supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced.	Schedule 1, Exhibits A-1, A-2A, A-2B, A-3, Section 5.3
C.2. Option Analyses A comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks, uncertainties, reliabiltiy, and customer acceptance where appropriate, considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period.	Sections 5.3
C.2.a. Purchased Power Assess the potential costs and benefits of purchasing power from wholesale power suppliers and power marketers to supply it with needed capacity and describe in detail any decision to purchase electricity from the wholesale power market.	Sections 4.7, 5.3
C.2.b. Supply-side Energy Resources Assess the potential costs and benefits of reasonably available traditional and alternative supply-side energy resource options, including, but not limited to technologies such as, nuclear, pulverized coal, clean coal, circulating fluidized bed, wood, combined cycle, integrated gasification combined cycle, and combustion turbine, as well as renewable energy resources such as those derived from sunlight, wind, falling water, sustainable biomass, energy from waste, municipal solid waste, wave motion, tides, and geothermal power.	Section 4.5, Exhibit B
C.2.c. Demand-side Options Assess the potential costs and benefits of programs that promote demand-side management. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options.	Section 4.4
C.2.d. Evaluation of Resource Options Analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs.	Sections 5.2, 5.3
C.3. Data Availability To the extent the information requested is not currently available or is not applicable, the utility will clearly note and explain this in the appropriate location in the plan, narrative, or schedule.	

EXHIBIT D

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
D. Narrative Summary Each utility shall provide a narrative summary detailing the major trends, events, and/or conditions reflected in the forecasted data submitted in response to these guidelines. Examples of items which should be highlighted in the summary include:	Sections 1, 2, 3
D.1. Discussion regarding the forecasted peak load obligation and energy requirements. PJM members should also discuss the relationship of the utility's expected non-coincident peak and its expected PJM related load obligations.	Section 2.5
D.2. Discussion regarding company goals and plans in response to directives of Chapters 23 and 24 of Title 56 of the Code of Virginia, including compliance with energy efficiency, energy conservation, demand-side and response programs, and the provision of electricity from renewable energy resources.	Sections 3,4
D.3. Discussion regarding the complete planning process, including timelines, assumptions, reviews, approvals, etc., of the company's plans. For PJM members, the discussion should also describe how the IRP integrates into the complete planning process of PJM.	Executive Summary, Section 1.2
D.4. Discussion of the critical input assumptions to determine the load forecast and expected changes in load growth including factors such as energy conservation, efficiency, load management, demand response, variations in customer class sizes, expected levels of economic activity, variations in fuel prices and appliance inventories, etc.	Section 2
D.5. Discussion regarding cost/benefit analyses and the results of such factors on this plan, including the methodology used to consider equal or comparable treatment afforded both the demand-side options and supply-side resources.	Section 5
D.6. Planned changes in operating characteristics such as unit retirements, unit uprates or derates, changes in unit availabilities, changes in capacity resource mix, changes in fuel supplies or transport, emissions compliance, unit performance, etc.	Section 6; Schedules 8, 9, 10 and 13
D.7. Discussion regarding the effectiveness of the utility's IRP to meet its load obligations with supply-side and demand-side resources to enable the utility to provide reliable service at reasonable prices over the long term.	Section 5
E. Filing By September 1, 2009, and every two years thereafter, each utility shall file with the Commission its then current integrated resource plan, which shall include all information required by these guidelines for the ensuing 15-year planning period along with the prior three-year historical period. The process and analyses shall be described in a narrative discussion and the results presented in tabular format using an EXCEL spreadsheet format, similar to the attached sample schedules, and be provided in both printed and electronic media. For those utilities that operate as part of a multi-state integrated power system, the schedules should be submitted for both the individual company and the generation planning pool of which the utility is a member. The top line stating the company name should indicate that the data reflects the individual utility company or the total system. For partial ownership of any facility, please provide the percent ownership and footnote accordingly.	
Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP.	Executive Summary, Section 6
If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.	Confidential Schedules will be labeled as such and will be included in a separate Confidential Supplement
Additionally, by September 1 of each year in which a plan is not required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified. If the utility provides a total system IRP in another jurisdiction by September 1 of the year in which a plan is not required, filing the total system IRP from the other jurisdiction will suffice for purposes of this section.	
As § 56-599 E requires the giving of notice and an opportunity to be heard, each utility shall also include a copy of its proposed notice to be used to afford such an opportunity.	
F. Contents of the Filing The IRP shall include the following data:	
F.1. Forecast of Load The forecast shall include descriptions of the methods, models, and assumptions used by the utility to prepare its forecasts of its loads, requirements associated with the utility's PJM load obligation (MW) if appropriate, the utility's peak load (MW) and energy sales (MWh) and the variables used in the models and shall include, at a minimum, the following:	Section 2; Schedule 1
F.1.a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class,	Section 2; Exhibits A-1, A-2A, A-2B
F.1.b. The most recent three-year history and 15-year forecast of the utility's peak load and the expected load obligation to satisfy PJM's coincident peak forecast if appropriate, and the utility's coincident peak load and associated non-coincident peak loads for summer and winter seasons of each year (prior to any DSM), annual energy forecasts, and resultant reserve margins. During the forecast period, the tabulation shall also indicate the projected effects of incremental demand-side options on the forecasted annual energy and peak loads, and	Section 2; Schedule 1
F.1.c. Where future resources are required, a description and associated characteristics of the option that the utility proposes to use to address the forecasted need.	Sections 5; Schedule 15
F.2. Supply-side Resources The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production) and a narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc:	Sections 3; Schedules 13, 14

EXHIBIT D

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
F.2.a. Existing Generation. For existing units in service:	
i. Type of fuel(s) used;	Schedule 14
ii. Type of unit (e.g., base, intermediate, or peaking);	Schedule 14
iii. Location of each existing unit;	Schedule 14
iv. Commercial Operation Date;	Schedule 14
v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW));	Schedules 13 and 14
vi. Units to be placed in reserve shutdown or retired from service with expected date of shutdown or retirement and an economic analysis supporting the planned retirement or shutdown dates;	Schedules 13 and 14
vii. Units with specific plans for life extension, refurbishment, fuel conversion, modification or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, expected return to service date, capacity rating upon return to service, a general description of work to be performed as well as an economic analysis supporting such plans for existing units;	Schedules 13 and 14
viii. Major capital improvements such as the addition of scrubbers, shall be evaluated through the IRP analysis to assess whether such improvements are cost justified when compared to other alternatives, including retirement and replacement of such resources; and	Section 3
ix. Other changes to existing generating units that are expected to increase or decrease generation capability of such units.	Schedule 14
F.2.b. Assessment of Supply-side Resources. Include the current overall assessment of existing and potential traditional and alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent IRP or annual report.	Sections 3.1, 3.2, and 4.5
F.2.b.i. For the currently operational or potential future supply-side energy resources included, provide information on the capacity and energy available or projected to be available from the resource and associated costs. The utility shall also provide this information for any actual or potential supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.	Schedules 9, 13 and 15
F.2.b.ii. For supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; estimated costs and the reasons for the rejection of the resource.	Section 5
F.2.c. Planned Generation Additions. A list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:	Section 5.3 ; Schedule 15
i. Type of conventional or alternative facility and fuel(s) used;	Schedule 15
ii. Type of unit (e.g. baseload, intermediate, peaking);	Schedule 15
iii. Location of each planned unit, including description of locational benefits identified by PJM and/or the utility;	Schedule 15
iv. Expected Commercial Operation Date;	Schedule 15
v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW));	Schedule 15
vi. Summaries of the analyses supporting such new generation additions, including its type of fuel and designation as base, intermediate, or peaking capacity.	Section 5.3, Schedule 15
vii. Estimated cost of planned unit additions to compare with demand-side options.	Schedule 15
F.2.d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the IRP, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and contractual capacity (including any contract dispatch conditions or limitations), and the contractual start and expiration dates. The utility shall also indicate which facilities are included in their total supply of resources.	Schedule 11
<u>F.3. Capacity Position</u> Provide a narrative discussion and tabulation reflecting the capacity position of the utility in relation to satisfying PJM' s load obligation, similar to Schedule 16 of the attached schedules.	Section 6
<u>F.4. Wholesale Contracts for the Purchase and Sale of Power</u> A list of firm wholesale purchased power and sales contracts reflected in the plan, including the primary fuel type, designation as base, intermediate, or peaking capacity, contract capacity, location, commencement and expiration dates, and volume.	Schedule 11
<u>F.5. Demand-side Options</u> Provide the results of its overall assessment of existing and potential demand-side option programs, including a descriptive summary of each analysis performed or used by the utility in its assessment and any changes to the methods and assumptions employed since its last IRP. Such descriptive summary, and corresponding schedules, shall clearly identify the total impact of each DSM program.	Section 4.4; Schedules 12 and 16
<u>F.6. Evaluation of Resource Options</u> Provide a description and a summary of the results of the utility's analyses of potential resource options and combinations of resource options performed by it pursuant to these guidelines to determine its integrated resource plan. IRP filings should identify and include forecasted transmission interconnection and enhancement costs associated with specific resources evaluated in conjunction with the analysis of resource options.	Sections 5 and 6
<u>F.7. Comparative Costs of Options</u> Provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side options and demand-side options to permit comparison of such resources on equitable footing. Such data should be tabulated and at a minimum, reflect the resource's heat rate, variable and fixed operating maintenance costs, expected service. life, overnight construction costs, fixed charged rate, and the basis of escalation for each component.	Section 4, Exhibit B

EXHIBIT D

Virginia - Integrated Resource Planning Guidelines Cross Reference Table	Section/Page Reference
Required Schedules not Specifcally Addressed Above	Schedules 2, 3, 4, 5, 6, 7,17 and 18
Chapter 476 of the 2008 Virginia Acts of Assembly ("Senate Bill 311")	
2. That as part of its 2009 integrated resource plan developed pursuant to this act, each electric utility shall assess govermental, nonprofit, and utility programs in its service territory to assist low income residential customers with energy costs and shall examine, in cooperation with relevant governmental, nonprofit, and private sector stakeholders, options for making any needed changes to such programs.	
2015 Virginia Acts of Assembly ("Senate Bill 1349") *	
Provide a copy of integrated resource plan to the Chairmen of the House and Senate Committees on Commerce and Labor and to the Chairman of the Commission on Electric Utility Regulation	
Integrated resource plan shall consider options for maintaining and enhancing rate stability	Sections 1.3, 5.2.3.3, and 5.3.3
Integrated resource plan shall consider options for maintaining and enhancing energy independence	Sections 1.3, and 6.0
Integrated resource plan shall consider options for maintaining and enhancing economic development including retention and expansion of energy-intensive industries	Sections 1.3 and 2.8
Integrated resource plan shall consider options for maintaining and enhancing service reliability	Sections 5 and 6
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	Section 3.3
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	Section 5
Final Order from 2015 Virginia IRP (Case No. PUE-2015-00036)	
Clean Power Plan	
Model and provide an optimal (least-cost, base plan) for meeting the electricity needs of its service territory over the IRP planning timeframes	Sections 5.2.2.1, 5.3
Model and provide multiple plans compliant with the CPP under a mass-based approach and an intensity-based approach (including a least-cost compliant plan where the Plexos model is allowed to choose the least-cost path given emission constraints imposed by the CPP), providing a detailed analysis of the impacts of each (in terms of total cost, including capital, programmatic and financing costs) as well as the impact on rates and identification of whether any aspect of the plan would require a change in existing Virginia law	Sections 3.3.8, 3.3.8.8, 5.2.3
Analyze the final federal implementation plan (should the final federal plan be published by May 1, 2016 or, if not, analyzing any proposed federal plan), providing a detailed analysis of the impact of a federal plan in terms of all costs, as well as the impact on rates and identification of whether any aspect of the federal plan would require a change in existing Virginia law;	Section 5.2.3.4
Provide a detailed description of leakage and treatment of new units under differing compliance regimes;	Section 3.3.8.3
Examine the differing impacts of the Virginia-specific targets verses source subcategory-specific rates under an intensity-based approach;	Section 3.3.8.2
Examine the potential for early action emission rate credits/allowances that may be available for qualified renewable energy or demand-side energy efficiency measures;	Section 3.3.8.4
Examine the cost benefits of trading emissions allowances or emissions reductions credits, or acquiring renewable resources from inside and outside of Virginia;	Section 3.3.8.5
Provide a detailed discussion of the development of state compliance plans in Indiana, Ohio, and West Virginia, as well as the potential for differing compliance approaches in each and how such differing approaches may impact APCo's ability to comply with the CPP	Section 3.3.8.6
Identify a long-term recommendation that reflects EPA's final version of the CPP	Section 3.3.8.7
Rate Design	
Analyze whether maintaining the existing rate structure is in the best interest of residential customers	Commission's Order for 2016 IRP provided respite of these requirements
Evaluate options for variable pricing models that would incent customers to shift consumption away from peak times to reduce costs and emissions	
Market Alternatives	
Include a detailed analysis of market alternatives, especially third-party purchases, that may provide long-term price stability and which includes wind and solar resources	Section 4.7
Examine wind and solar purchases at prices (including prices available through long-term purchase power agreements) and in quantities that are seen in the market at the time that the Company prepares its IRP filings	Section 4.7
Solar Photovoltaic Generation	
Examine the impact of higher levels of distributed generation and identify any barriers to increased reliance by the Company on solar voltaic generation	Section 3.4.5
Include a detailed analysis of the load characteristics of net metering customers and the generation-related impacts of customer generation	Section 3.4.5