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STATE CORPORATION COMMISSION
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Case No. PUR-2019-00058
Sponsor: ("APPLACHIAN POWER COMPANY")
Exhibit No. 2

Witness: NONE
Bailiff: JABARI T. ROBINSON

NOTICE TO THE PUBLIC OF
A FILING BY APPALACHIAN POWER COMPANY OF ITS
INTEGRATED RESOURCE PLAN
CASE NO. PUR-2019-00058

On May 1, 2019, Appalachian Power Company ("APCo" or "Company") filed with the State Corporation Commission ("Commission") the Company's Integrated Resource Plan ("IRP") pursuant to § 56-599 of the Code of Virginia ("Code").

An IRP, as defined by § 56-597 of the Code, is "a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility." Pursuant to § 56-599 C of the Code, the Commission determines whether an IRP is reasonable and in the public interest.

APCo states that it serves approximately 956,000 customers in Virginia, West Virginia, and Tennessee and that the peak load requirements of APCo's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons.

APCo states that its IRP, based upon various assumptions, provides for adequate capacity resources, at reasonable cost, through a combination of supply-side resources, including renewable supply-side resources and demand-side programs through the forecast period. According to the Company, the IRP encompasses the 15-year planning period from 2019 to 2033 and is based on the Company's current assumptions regarding customer load requirements, commodity price projections, supply-side alternative costs, demand side management program costs and analysis, and the effect of environmental rules and guidelines.

As amended in 2015, § 56-599 of the Code requires, among other things, that an IRP evaluate: (i) the effect of current and pending environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities; and (ii) the most cost-effective means of complying with current and pending environmental regulations. APCo states that, per the Commission's directive in its Final Order in APCo's 2017 IRP case (Case No. PUR-2017-00045), "APCo considered the effect of environmental rules and guidelines, which have the potential to add significant costs and present significant challenges to operations. This IRP considers

EXHIBIT# 2

the potential cost associated with some form of future regulation of carbon emissions, during the planning period, even though there is considerable uncertainty as to the form future carbon regulation may take."

APCo also notes that, in the Commission's Final Orders in Case Nos. PUR-2017-00045 and PUR-2018-00051, the Commission directed APCo to include, in this and future IRPs, plans to implement the mandates contained in the Grid Transformation and Security Act, which became effective July 1, 2018. Accordingly, APCo considered the impact of the resource additions required by the Grid Transformation and Security Act, which include solar, energy storage, and energy efficiency. In addition, the Company's IRP takes into consideration the impacts of the federal Tax Cuts and Jobs Act of 2017.

The Commission entered an Order for Notice and Hearing in this case that, among other things, scheduled a public hearing at ____________________, in the Commission's second floor courtroom located in the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, to receive the testimony of public witnesses. Any person desiring to testify as a public witness should appear at this hearing location fifteen (15) minutes before the starting time of the hearing and contact the Commission's Bailiff. A public hearing will convene at 9:30 a.m. on ________, 2019, in the same location, to receive the testimony and evidence offered by the Company, respondents, and the Staff on the Company's Application.

The public version of the Company's IRP and the Commission's Order for Notice and Hearing are available for public inspection during regular business hours at each of the Company's business offices in the Commonwealth of Virginia. Copies also may be obtained by submitting a written request to counsel for the Company, Noelle J. Coates, Esquire, American Electric Power, 1051 East Cary Street, Suite 1100, Richmond, Virginia 23219. If acceptable to the requesting party, the Company may provide the documents by electronic means.

Copies of the public version of the IRP and other documents filed in this case are also available for interested persons to review in the Commission's Document Control Center, located on the first floor of the Tyler Building, 1300 East Main Street, Richmond, Virginia 23219, between the hours of 8:15 a.m. and 5 p.m., Monday through Friday, excluding holidays. Interested persons also may download unofficial copies from the Commission's website: http://www.scc.virginia.gov/case.

On or before ________, 2019, any interested person wishing to comment on the Company's IRP shall file written comments with Joel H. Peck, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. Any interested person desiring to file comments electronically may do so on or before ________, 2019, by following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. Compact disks or any other form of electronic storage medium may not be filed with the comments. All such comments shall refer to Case No. PUR 2019-00058.

On or before _________, 2019 any person or entity may participate as a respondent in this proceeding by filing a notice of participation. If not filed electronically, an original and fifteen (15) copies of the notice of participation shall be submitted to the Clerk of the Commission at the address above. A copy of the notice of participation as a respondent also must be sent to counsel for the Company at the address set forth above. Pursuant to Rule 5 VAC 5-20-80 B, *Participation as a respondent,* of the Commission's Rules of Practice and Procedure ("Rules of Practice"), any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent then known; and (iii) the factual and legal basis for the action. Any organization, corporation, or government body participating as a respondent must be represented by counsel as required by Rule 5 VAC 5-20-30, *Counsel*, of the Rules of Practice. All filings shall refer to Case No. PUR-2019-00058. For additional information about participation as a respondent, any person or entity should obtain a copy of the Commission's Order for Notice and Hearing.

All documents filed with the Office of the Clerk of the Commission in this docket may use both sides of the paper. In all other respects, all filings shall comply fully with the requirements of 5 VAC 5-20-150, *Copies and format*, of the Commission's Rules of Practice.

The Commission's Rules of Practice may be viewed at http://www.scc.virginia.gov/case. A printed copy of the Commission's Rules of Practice and an official copy of the Commission's Order for Notice and Hearing in this proceeding may be obtained from the Clerk of the Commission at the address set forth above.

APPALACHIAN POWER COMPANY

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APPALACHIAN POWER

An AEP Company

BOUNDLESS ENERGY

INTEGRATED RESOURCE PLANNING REPORT

TO THE

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

CASE NO. PUR-2019-00058

PUBLIC VERSION

May 1, 2019

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Executive Summary

This Integrated Resource Plan (IRP or Report) is submitted by Appalachian Power Company (APCo or Company) based upon the best information available at the time of preparation. This Plan is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. Accordingly, this IRP and the action items described herein are subject to change as new information becomes available or as circumstances warrant.

This IRP addresses the mandates contained in Virginia's recently enacted Grid Transformation and Security Act, which became effective July 1, 2018 (the 2018 Virginia Act), as well as other legal requirements and regulations. 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).

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 planning period (in this filing, 2019-2033). This IRP has been developed using the Company's current long-term assumptions for:

- Customer load requirements – peak demand and hourly energy;
- commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- supply-side alternative costs – including fossil fuel, renewable generation, and storage resources;
- transmission and distribution planning, including projects that meet the definition of grid transformation projects; and
- demand-side management program costs and impacts.

In addition, APCo considered the effect of environmental rules and guidelines, which have the potential to add significant costs and present significant challenges to operations. This IRP considers the potential cost associated with some form of future regulation of carbon emissions, during the planning period, even though there is considerable uncertainty as to the timing and form future carbon regulation may take.

This 2019 IRP addresses the mandates included in the 2018 Virginia Act:

- The construction or acquisition by APCo of at least 200MW of utility-owned solar located in Virginia prior to 2028;
- In future EE-RAC proceedings, APCo is required to request Commission approval of \$140 million in EE programs from July 2018 to July 2027; and
- As part of a five-year battery pilot program deemed to be in the public interest, APCo may invest in up to 10MWs of new battery storage installations.

To meet its customers' future capacity and 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) facility, combustion turbine (Ceredo) units, and its two gas-steam units at Clinch River. The Company will also continue to operate its hydroelectric generators, including Smith Mountain Lake. The Company has a portfolio of 575MW of purchase power agreements consisting of five wind farms and one hydro-electric facility. During the planning period, contracts covering 455MW of that amount will expire. In addition, the Company has contracted for the output of the 15MW Depot solar facility in Rustburg, Va., which it expects will be available in 2021. 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

The Commission's April 2, 2018 Order[1] denied APCo's request to acquire two additional Wind Facilities. The Company has consistently modeled resource additions with an eye towards minimizing both capacity and energy costs for its customers over the respective planning periods. The Commission's Wind Facilities Order, by focusing only on capacity "need", suggests that, given the current availability of short-term energy from the PJM market, unless APCo has a need for capacity under PJM requirements, APCo's IRPs should propose adding resources solely on the basis of meeting its capacity obligation. The Company notes that this Report indicates that APCo does not have a capacity need until 2027, and that its projected shortfall can be met with the addition of solar and energy efficiency resources consistent with the mandates of the 2018 Virginia Act and wind resources. In this IRP, the Company continues to model portfolios that not only add resources to meet its capacity obligation, but also provide zero variable cost energy to enhance rate stability and further diversify its generation portfolio.

APCo has analyzed various scenarios that would provide adequate supply and demand resources to meet its projected peak load obligations, and reduce or minimize costs to its customers, including energy costs, for the next fifteen years. The key components of APCo's Preferred Plan, which is presented herein based upon these various analyses, are as follows:

- Adds at least 200MW of large-scale solar resources, consistent with directives in the 2018 Virginia Act.
- Continues to diversify APCo's mix of supply-side resources through the addition of battery storage, wind and large-scale solar;
- Incorporates demand-side resources, including but not limited to additional EE programs and Volt VAR Optimization (VVO) installations; and

[1] Final Order, *Application of Appalachian Power Co. For a rate adjustment clause pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2017-00031, Doc. Con. Cen. No. 180410050 (April 2, 2018).

- Recognizes 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 2018 IRP

This IRP includes the following changes from the Company's 2018 IRP:

- Addresses the Commission's 2018 IRP order.
- Incorporates the most recent load forecast, which shows a reduced need for capacity additions over the forecast period, and a minimal change in energy needs.
- Incorporates the most recent fundamental forecast developed in the first quarter of 2019.
- Incorporates updated renewable cost information primarily based upon Bloomberg New Energy Finance's (BNEF) H2 2018 U.S. Renewable Energy Market Outlook and informed by the Company's 2019 Solar Request for Proposals (RFP).
- Discusses APCo's electric distribution grid transformation (EDGT), as defined by the 2018 Virginia Act, planning and implementation initiatives.

Summary of APCo Resource Plan

APCo's retail sales are projected to remain relatively constant with stronger growth expected from the industrial class (+0.3% per year) while the residential class is projected to decline over the forecast horizon at a compounded annual growth rate (CAGR) of -0.3% per year. APCo's internal energy needs are expected to remain relatively flat and peak demand is expected to change at an average rate of -0.1% per year through 2033. Figure ES-1 below shows APCo's "going-in" (i.e. before resource additions) capacity position over the planning period, which uses the PJM summer peak to determine resource requirements. Through 2026, APCo has capacity resources to meet its forecasted internal demand. In 2027, APCo anticipates experiencing a slight capacity shortfall, 75MW, based upon its assumption regarding the retirement of Clinch River Units 1 and 2 in 2026, and the expiration of wind and hydro contracts totaling 455MWs (nameplate) of renewable generation, during the 2027-2030 timeframe. By 2033, APCo has a capacity deficit of approximately 200MW.

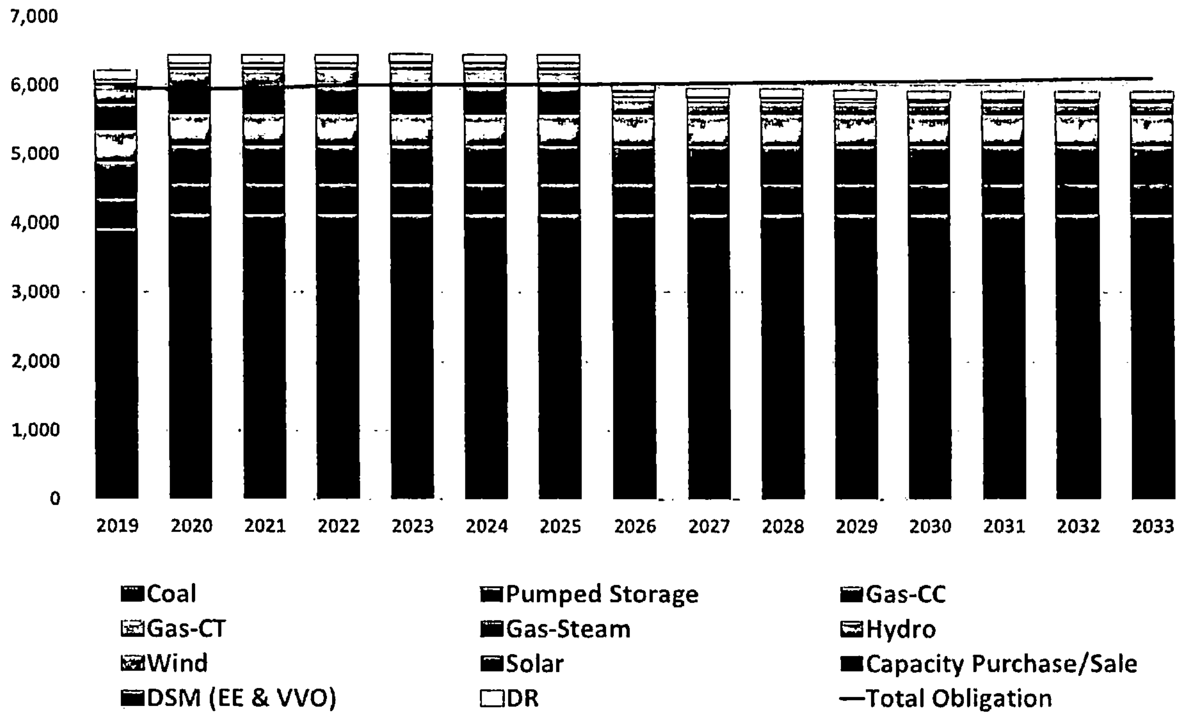

Figure ES - 1. APCo "Going-In" Position

Recognizing its modest capacity deficit position over the planning period, ~200MW in 2033, APCo considered the impact of the resource additions required by the 2018 Virginia Act and resources necessary to satisfy Virginia's voluntary Renewable Portfolio Standard (RPS) goals. These additions, which include solar, energy storage and energy efficiency resources, are expected to eliminate most of the capacity deficit through the planning period. The solar resources are assumed to provide PJM capacity equal to 51.1% of their nameplate rating (or 102MW for 200MW of nameplate solar). Energy storage will provide 10MW, and EE will provide approximately 20MW of planning capacity. Taking these resources into account, a resource plan that meets the 2018 Virginia Act would also be compliant with Virginia's voluntary RPS goals, if the plan adds 300MW of wind resources in 2023.

The resource additions required by the 2018 Virginia Act, and needed to meet Virginia's voluntary RPS goals, allow APCo to satisfy most of its PJM load obligations over the planning period. In addition to the required resource additions, the analysis shows that the addition of VVO and additional solar provide benefits to APCo's customers. Additionally, customer owned generation such as rooftop solar, will also improve APCo's capacity position.

APCo's energy requirements vary over the year with APCo customers using more energy in the winter months than APCo can supply with its own resources. Therefore, absent a directive from the Commission to the contrary, APCo will continue to consider the addition of cost-effective energy resources, including wind resources, to reduce its reliance on the volatile PJM energy market, particularly during the winter months.

To determine the appropriate timing of new resources, APCo used the *Plexos®* model to calculate the lowest cost resource addition portfolio under four pricing scenarios, (*i.e.* Base, Upper Band, No Carbon and Low No Carbon) also referred to as the Optimal Plan for a given commodity pricing scenario. APCo also considered the resource additions required to comply with the 2018 Virginia Act and Virginia's voluntary RPS goals. To arrive at the Preferred Plan, APCo considered a resource mix that included attributes of the various Optimal Plans, the 2018 Virginia Act and the RPS goals. APCo then calculated the cost of this Preferred Plan under the three long-term commodity price forecasts to ensure the plan was not significantly costlier under these different futures. The Preferred Plan is presented as an option that balances cost, including energy costs, and other factors, while meeting the 2018 Virginia Act mandates and voluntary RPS goals.

In summary, the Preferred Plan:

- Assumes the 15MW (nameplate) Depot solar facility is available by 2021;
- Adds 300MW (nameplate) of wind energy resources by 2023, but no additional wind before 2033;
- Adds 450MW (nameplate) of utility scale solar by 2028 and 1,500MW by 2033;
- By 2033, implements EE programs reducing energy requirements by 770GWh and summer capacity by 114MW by 2033;
- Adds 1 Tranche of VVO providing 17MW of summer capacity requirements and 67GWh of annual energy savings;

- Meets Virginia's Voluntary Renewable Portfolio Standard (RPS) goals through the planning period;
- Assumes APCo's customers add distributed generation (DG) (i.e. rooftop solar) capacity totaling over 82MW (nameplate) by 2033;
- Adds 10MW (nameplate) of battery storage resources in 2021;
- Continues operation throughout the planning period 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) coal-fired facilities: Clifty Creek Units 1-6 and Kyger Creek Units 1-5;
- Retires the natural gas-steam Clinch River Units 1 and 2 in 2026; and
- Reflects the expiration of 455MWs of wind and hydro purchase power contracts during the 2027-2030 timeframe.

Table ES-1 provides a summary of the Preferred Plan, which resulted from analyses that gave consideration to optimization modeling under various load and commodity pricing

Table ES 1. Preferred Plan Cumulative Additions from 2019 to 2033

Preferred Plan		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base - Compliant with SB-966 and RPS	Base/Intermediate															
	Peaking															
	Solar (Firm)					77	77	77	77	153	230	383	537	613	690	767
	Solar (Nameplate)					150	150	150	150	300	450	750	1,050	1,200	1,350	1,500
	Wind (Firm)					37	37	37	37	37	37	37	37	37	37	37
	Wind (Nameplate)					300	300	300	300	300	300	300	300	300	300	300
	Battery Storage			10	10	10	10	10	10	10	10	10	10	10	10	10
	Energy Efficiency (Degraded)				36	69	98	92	85	78	69	56	47	36	27	20
	Energy Efficiency (Non-Degraded)				36	72	108	114	120	126	132	137	138	140	127	114
	CHP															
	VVO		17	17	17	17	17	17	17	17	17	17	17	17	17	17
	Demand Response															
	Distr. Gen.					18	21	22	23	24	25	27	29	30	32	34
	Total Additions (Firm & Degraded)		17	27	63	228	260	255	249	319	388	530	676	743	813	884
Capacity Reserves Above PJM Requirement without New Additions		242	493	475	439	443	434	428	17	(75)	(104)	(128)	(150)	(164)	(183)	(196)
Capacity Reserves Above PJM Requirement with New Additions		242	510	502	518	671	693	683	266	244	285	401	526	580	630	688

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation scenarios, APCo's modeling of carbon emission regulations, the mandates of the 2018 Virginia Act, and Virginia's voluntary RPS goals.

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

Figure ES-2 indicates that the Preferred Plan would increase APCo's reliance on solar, energy efficiency and wind generation over the planning period, while mostly maintaining its existing fleet of coal-, gas- and hydro-based generation with the exception of the assumed retirement of Clinch River gas plant.

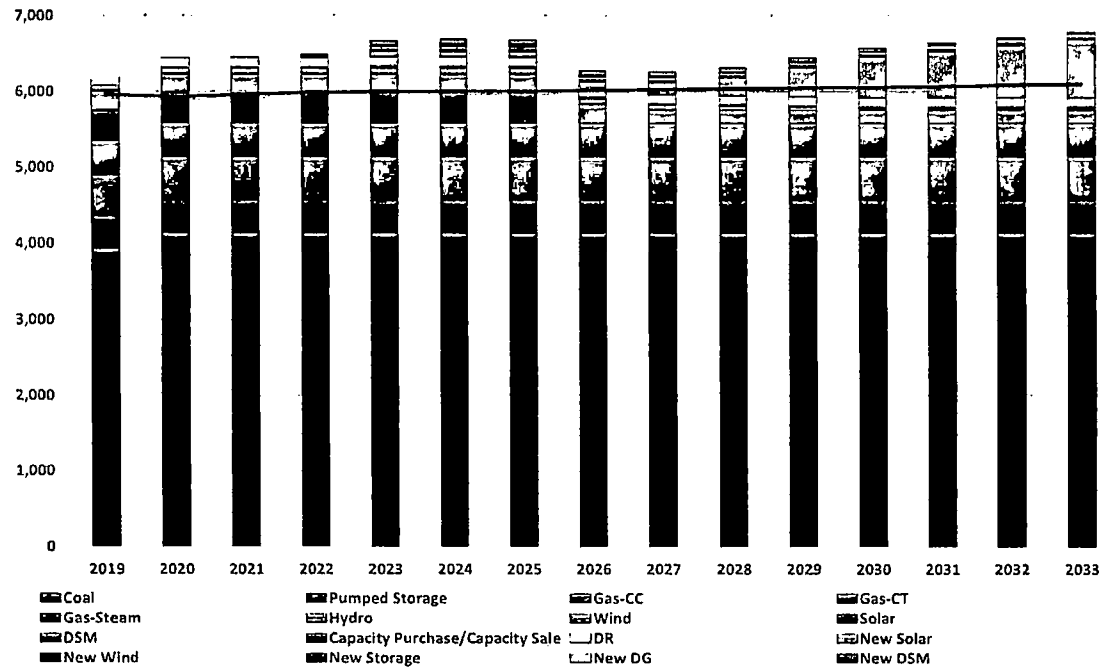

Figure ES - 2. APCo's Preferred Plan Annual Capacity Position (MW)

The capacity contribution from renewable resources is fairly modest due to their intermittent characteristic; however, those resources (particularly wind) provide a significant volume of energy. Wind resources were selected in all of the scenarios because they are a low cost energy resource.

Figure ES-3 and Figure ES-4 show annual changes in energy mix that result from the Preferred Plan over the planning period. APCo's energy output attributable to coal-fired generation shows a slight decrease over the period, while the energy output attributable to renewable generation (wind and solar) grows. Energy from these renewable resources, combined with EE and VVO energy savings reduce APCo's exposure to PJM energy, fuel and potential carbon emission prices.

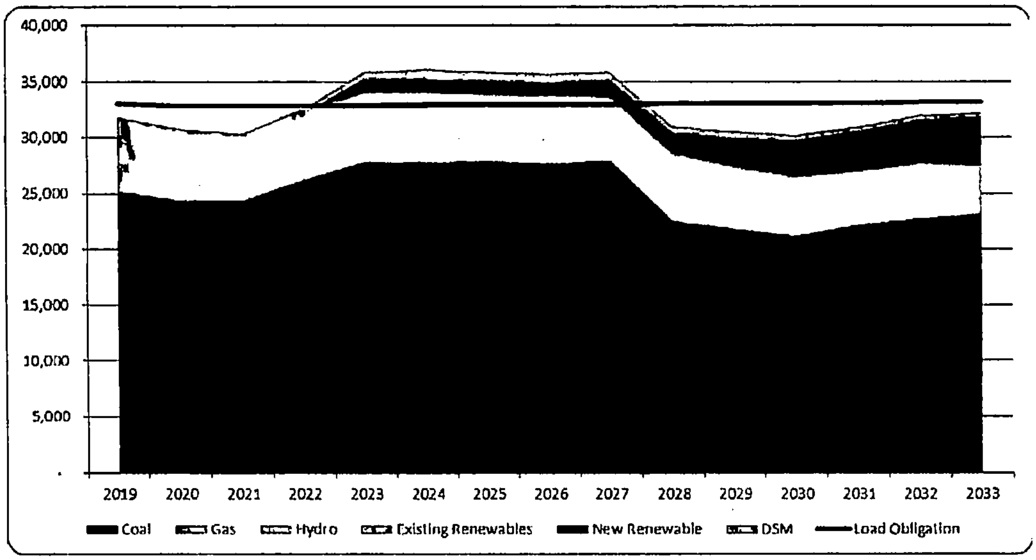

Figure ES - 4. APCo's Preferred Plan Annual Energy Position (GWh)

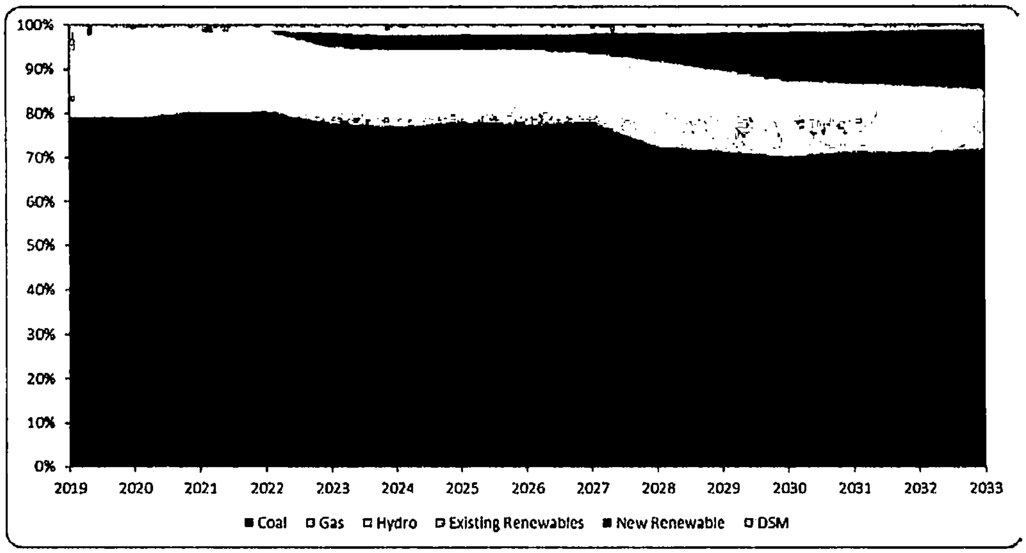

Figure ES - 3. APCo's Preferred Plan Percentage of Annual Energy by Supply Type (%)

Conclusion

This IRP presents various plans, including the Preferred Plan, that would provide adequate capacity resources at reasonable cost, through a combination of supply-side resources (exclusively renewable supply-side resources) and demand-side programs throughout the planning period.

The Preferred Plan includes incremental resources that will provide—in addition to the needed PJM installed capacity to achieve mandatory PJM (summer) peak demand requirements—modest amounts of 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 and wind). It is possible that intermittent resources can be combined, or "coupled," and offered into the PJM market as Capacity Performance resources. The Company continues to investigate methods to maximize the utilization of its intermittent resource portfolio within that construct, which becomes effective in the 2020/2021 PJM planning year.

This IRP also addresses the 2018 Virginia Act mandates regarding solar, energy storage and energy efficiency; APCo's plans to satisfy Virginia's voluntary RPS goals throughout the planning period; and the effects of potential carbon emission regulations.

The resource portfolios developed 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. The resource planning process continues to be complex, especially with regard to such things as 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. Continue the evaluation of the Company's Solar RFP and determine if any projects will be brought forward for regulatory consideration.
2. Implement a battery pilot program with up to 10MW of energy storage.
3. Continue the planning and regulatory actions necessary to implement additional economic EE programs in Virginia and West Virginia, as well as programs that target low-income, disabled and elderly customers provided for in the 2018 Virginia Act.
4. Complete its deployment of AMI meters and associated infrastructure, add Distribution Automation Circuit Reconfiguration schemes to 60 circuits, widen certain distribution rights-of-way, and relocate or underground certain lines.
5. Plan to meet Virginia's Voluntary Renewable Portfolio Standard goals.
6. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, or if needed to meet escalating voluntary RPS goals, pursue competitive solicitations that would include self-build or acquisition options.
7. Pursue opportunities to identify a suitable host facility for a CHP installation.
8. Monitor developments associated with PJM's Capacity Performance rule.
9. Monitor the status of, and participate in formulating any proposed carbon emissions regulations. Once established, assess the implications of such regulations on APCo's resource profile.
10. 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 2019 Integrated Resource Plan (IRP or Plan) 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 supply capacity and energy to customers consistent with maintaining and enhancing rate stability, energy independence, economic development, and service reliability at reasonable prices over the long –term.*

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 such things as determining capital expenditure requirements, regulatory planning, environmental compliance, and other planning processes.

1.2 Integrated Resource Plan (IRP) Process

This Report covers the processes, assumptions, results and recommendations required to develop the Company's 2019 IRP. As required by Virginia Code § 56-599, APCo's IRP considers options for maintaining and enhancing rate stability, energy independence, economic development, including retention and expansion of energy-intensive industries, and service reliability. The Company files this IRP on May 1, 2019 in compliance with Section 56-599.

This IRP is based upon the best available information at the time of preparation, but changes that may impact its results can, and do, occur without notice. Therefore, this IRP is not a commitment to a specific course of action, and all the resource actions are subject to change.

APCo's IRP process includes the following components/steps:

- Describes the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning;

- provides projected growth in demand and energy which serves as the underpinning of the Plan;
- identifies and evaluates demand-side options such as Energy Efficiency (EE) measures, Demand Response (DR) and Distributed Generation (DG);
- describes how the IRP ties to underlying PJM reserve margin requirements;
- identifies and evaluates supply-side resource options; and
- performs resource modeling, including modeling various portfolios using a carbon emissions cost beginning in 2028 as a surrogate for potential future carbon emission regulation.

As indicated throughout this Report, APCo's IRP process seeks to strike a reasonable balance among the various factors in its development of the Preferred Resource Plan, which provides a road map to inform future resource decisions, including the following specific resource actions required by the 2018 Virginia Act:

- construct or acquire at least 200MW of solar power located in the Commonwealth by 2028;
- propose $140 million in Energy Efficiency programs over 10 years; and
- invest in a five-year battery pilot program of up to 10 MW.

1.3 Compliance with 2018 IRP Order

APCo's 2019 IRP addresses each of the requirements of the Commission's final order in the Company's 2018 IRP (the 2018 IRP Order), which include the following:

- 2018 IRP Order Requirement #1: Implement the mandates in the 2018 Virginia Act, including the mandate to propose $140 million in EE programs[2] APCo addressed this requirement in Section 5.2.2.3 and 5.3.

[2] Commonwealth of Virginia, State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing, Case No. PUr-2018-00051, Final Order at 3 (December 18, 2019).

- 2018 IRP Order Requirement #2: Propose a least-cost plan to provide a benchmark against which to measure the costs of other alternative plans.[3] APCo addressed this requirement in Section 5.2.2 and 5.3.
- 2018 IRP Order Requirement #3: Model EE programs as reduction to load and as a supply resource.[4] APCo addressed this requirement in Section 5.3.1.
- 2018 IRP Order Requirement #4: Consider PJM peak load forecast.[5] APCo addressed this requirement in Section 5.2.2.2.

For an index of all requirements and their location in the report, please see Exhibit D in the Appendix.

1.4 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

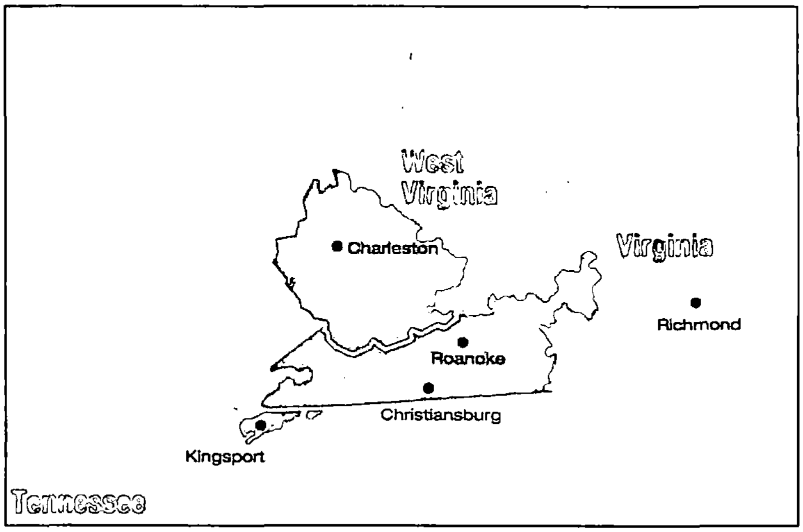

Figure 1. APCo Service Territory

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[3] Id. at 3-4.

[4] Id. at 4

[5] Id. at 4.

approximately 532,000 and 424,000 retail customers 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 2018 and winter 2018/19) actual APCo summer and winter peak demands were 5,618MW and 7,319MW, occurring on June 18, 2018 and January 21, 2019, respectively.

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 2018.[6] The 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 (2019-2033)[7], APCo's service territory is expected to see population and non-farm employment growth 0.4% per year. 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 remain relatively constant with stronger growth expected from the industrial class (+0.3% per year) while the residential class is projected to decline over the forecast horizon

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[6] The load forecasts (as well as the historical loads) integral to this Resource Plan 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.

[7] 15 year forecast periods begin with the first full forecast year, 2019.

at a compounded annual growth rate (CAGR) of -0.3% per year. Finally, APCo's internal energy is expected to remain relatively flat and peak demand is expected to change at an average rate of -0.1% per year through 2033.

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 2017. Moody's Analytics projects moderate growth in the U.S. economy during the 2019-2033 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 2.0% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.6% per year during the same period. Moody's projects regional employment growth of 0.4% per year during the forecast period and real regional income per-capita annual growth of 1.6% for the APCo service area.

2.2.2 Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and 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.

Some customers have opted to purchase generation resources from an alternative supplier. The load for these customers is included in the peak and energy forecasts within this IRP, as they remain part of the Company's capacity obligation in PJM.

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 DSM programs, which either have been previously approved by or are pending currently before the Commission, at the time the load forecast is created to adjust the forecast for the impact of these programs. For this IRP, DSM programs through 2021 have been embedded into the load forecast.

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.

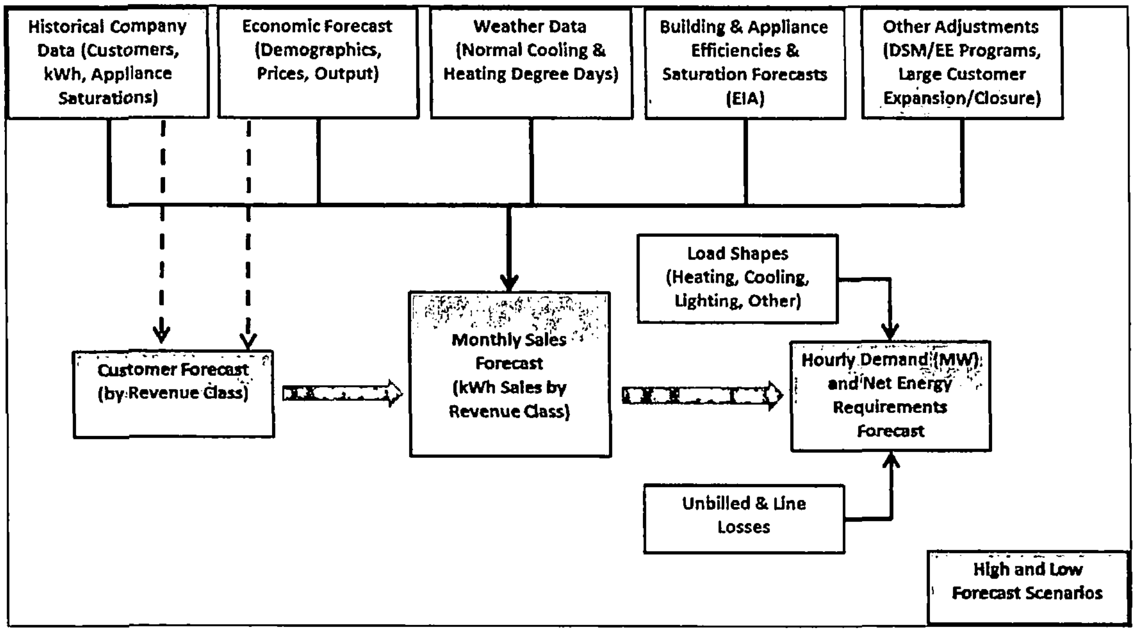

Figure 2. APCo Internal Energy Requirements and Peak Demand Forecasting Method

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 may include gross regional product, employment, population, real personal income and households 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.

The estimation period for the short-term models was January 2008 through January 2018. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 20 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 1995-2018 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 Model

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 Census region's sectoral prices, with the forecast being obtained from EIA's "2018 Annual Energy Outlook." The natural gas price model is based upon 1980-2017 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 "2018 Annual Energy Outlook." The estimation period for the model was 1998-2017.

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 West South 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 model is estimated using linear regression models. These monthly models are typically for the period January 1995 through December 2017. 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.

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 December 2017.

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 December 2017.

2.4.4.5 All Other Energy Sales

The forecast of other retail sales, which is comprised of public-street and highway lighting and other sales to public authorities, relates energy sales to service area population and binary variables.

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

2.4.4.6 Blending Short and Long-Term Sales

Forecast values for 2018 and 2019 are taken from the short-term process. Forecast values for 2020 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 2020 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.

2.4.4.7 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all 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.

2.4.5 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 2015-2018 and on a forecast basis for the years 2019-2033. 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. Figure 3 provides a graphical depiction of weather normal and forecast Company residential, commercial and industrial sales for 2002 through 2033.

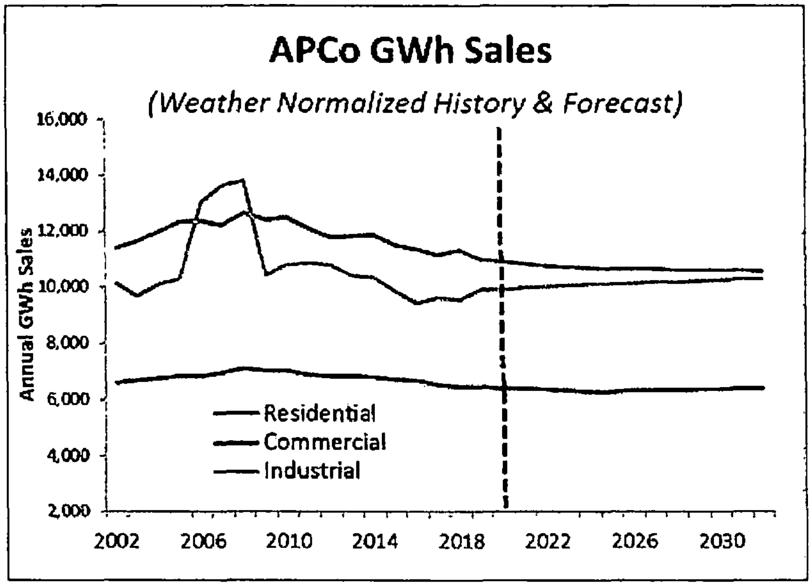

Figure 3. APCo GWh Retail Sales

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 2015-2018 and on a forecast basis for the years 2019-2033. The table also shows annual growth rates for both the historical and forecast periods.

Figure 4 presents actual, weather normal and forecast APCo peak demand for the period 2000 through 2033. Figure 4 depicts the Company's annual peak demand, which occurs in the winter season. The Company's capacity planning in PJM is concerned with the Company's peak coincident with the PJM summer peak. This peak demand forecast is discussed in section 2.8.

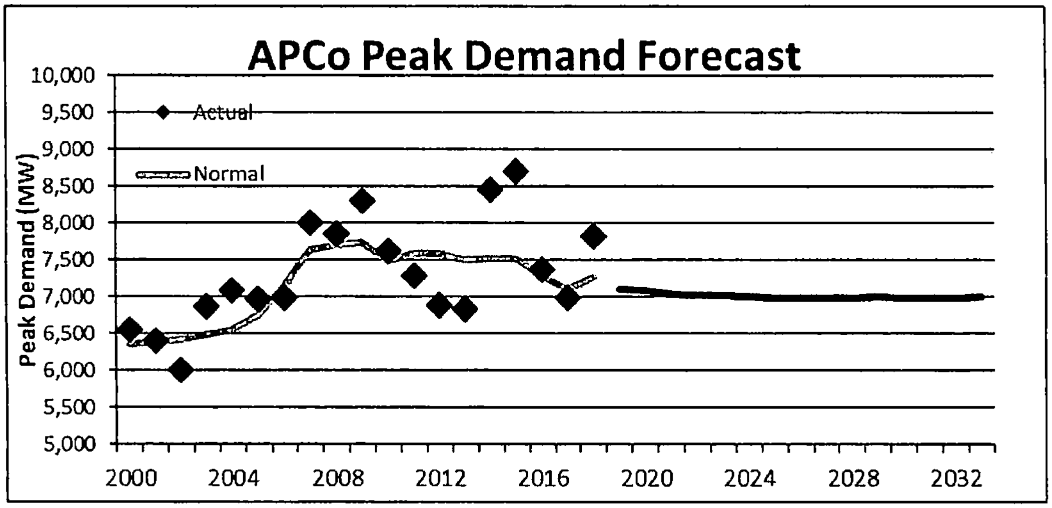

Figure 4. APCo Peak Demand Forecast

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 5 presents APCo's historical and forecasted residential and commercial usage per customer between 1991 and 2025. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 1.2% per year, while the commercial usage grew by 0.6% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.7% per year while the commercial class usage decreased by 0.5% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 1.01% per year while the commercial usage decreases by an average of 0.9% per year. It is worth noting that the decline in residential and commercial usage accelerated between 2008 and 2018, with usage declining at average annual rates of 1.1% and 1.3% for residential and commercial sectors, respectively, over that period. For the forecast period 2020 through 2025, residential and commercial usage per customer are project to decline at average annual rates of 0.4% and 0.7%, respectively.

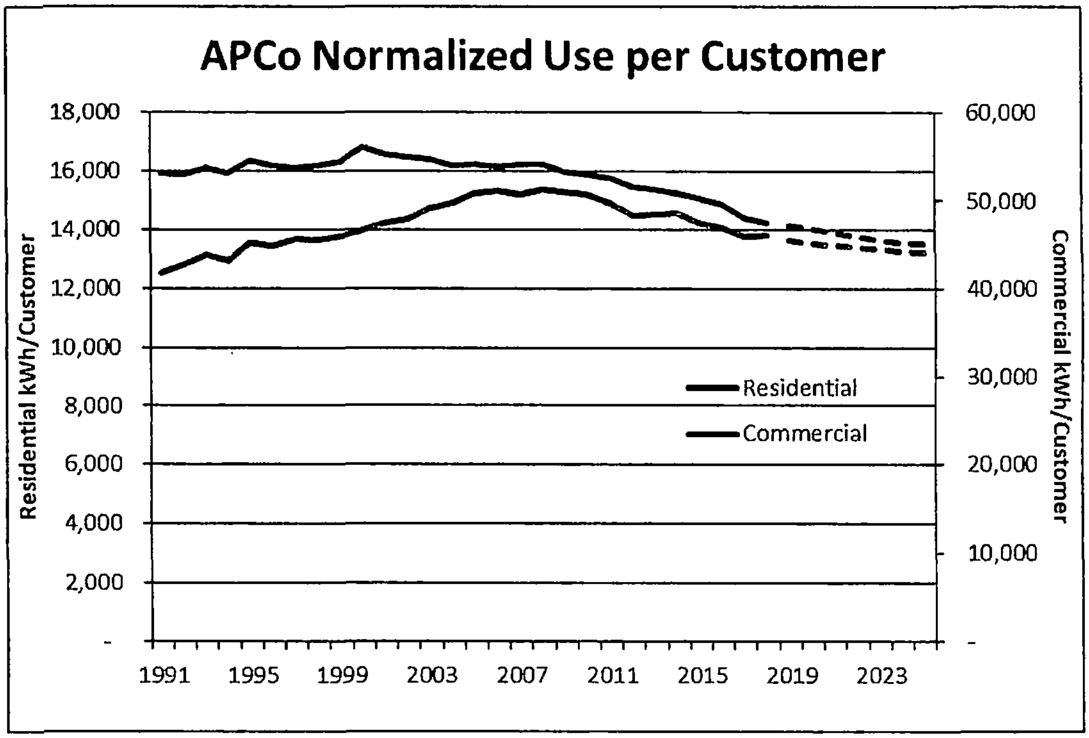

Figure 5. APCo Normalized Use per Customer (kWh)

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 6 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 nearly 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 7 shows similar improvements in the efficiencies of lighting and clothes washers over the same period.

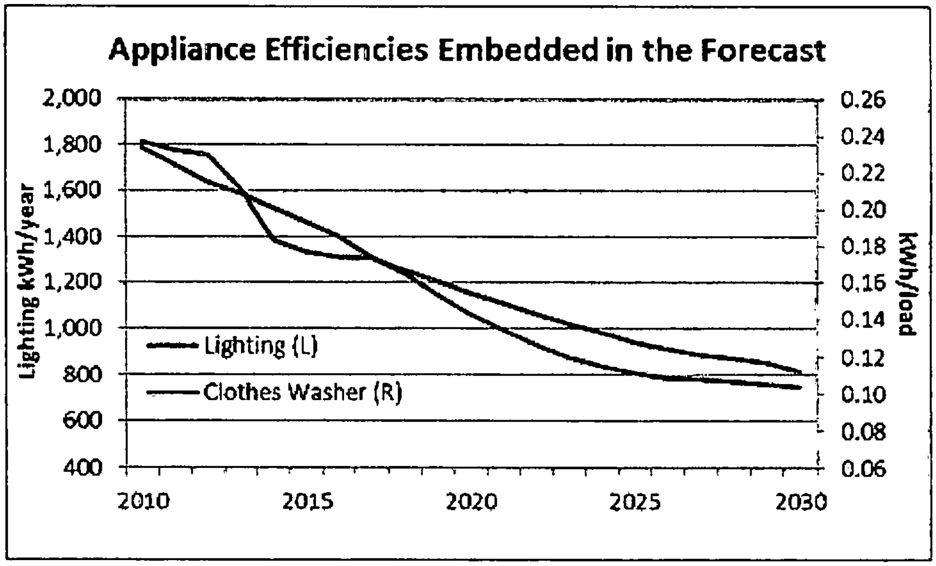

Figure 6. Projected Changes in Cooling Efficiencies, 2010-2030

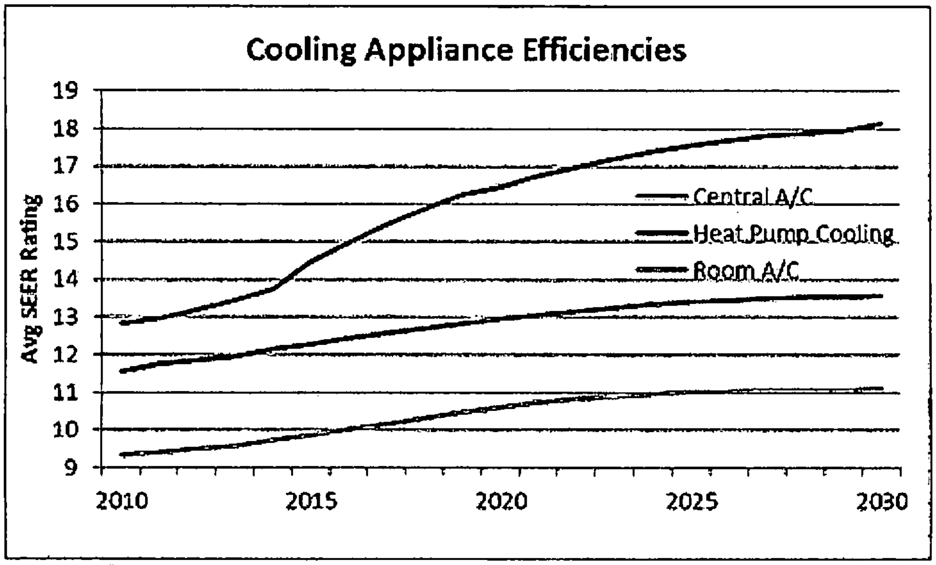

Figure 7. Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2030

Figure 8 shows the impact of appliance, equipment and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast APCo residential customers are provided.

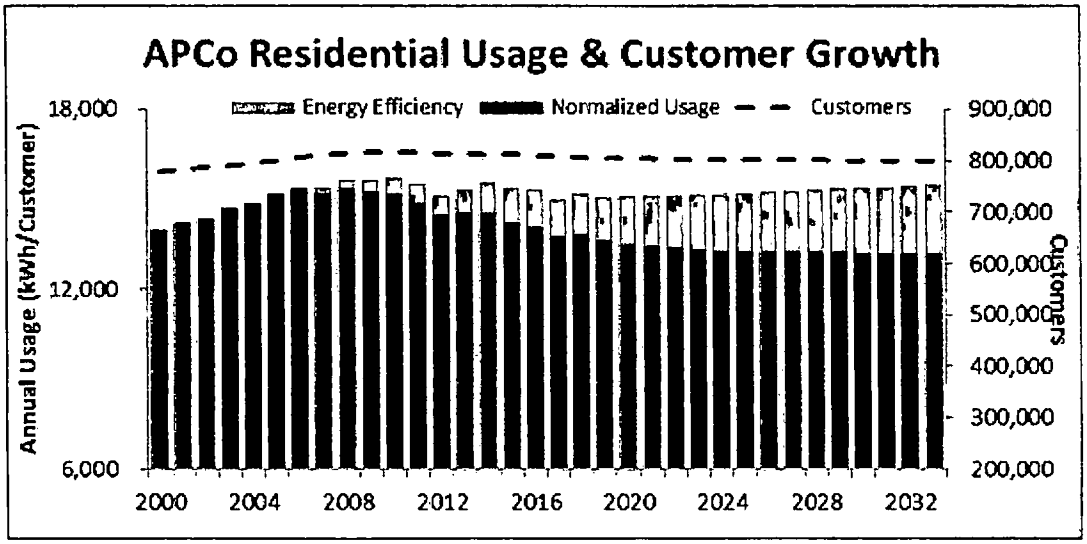

Figure 8. Residential Usage & Customer Growth, 2000-2033

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 2021), the load forecast uses assumptions from the DSM programs currently pending approval before the Commission. For the years beyond 2021, 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 135MW and 153MW available for interruption at the time of the winter and summer peaks, respectively. An additional customer has 14MW 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 2019 were typically taken from the short-term process. Forecast values for 2020 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 2020 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 9 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.

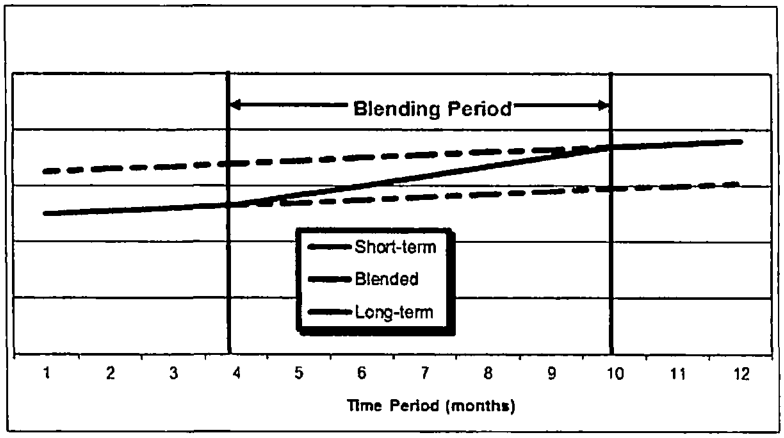

Figure 9. Load Forecast Blending Illustration

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 2018 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.

For APCo, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2033, represent deviations of about 10.5% below and 8.4% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios.

Figure 10 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

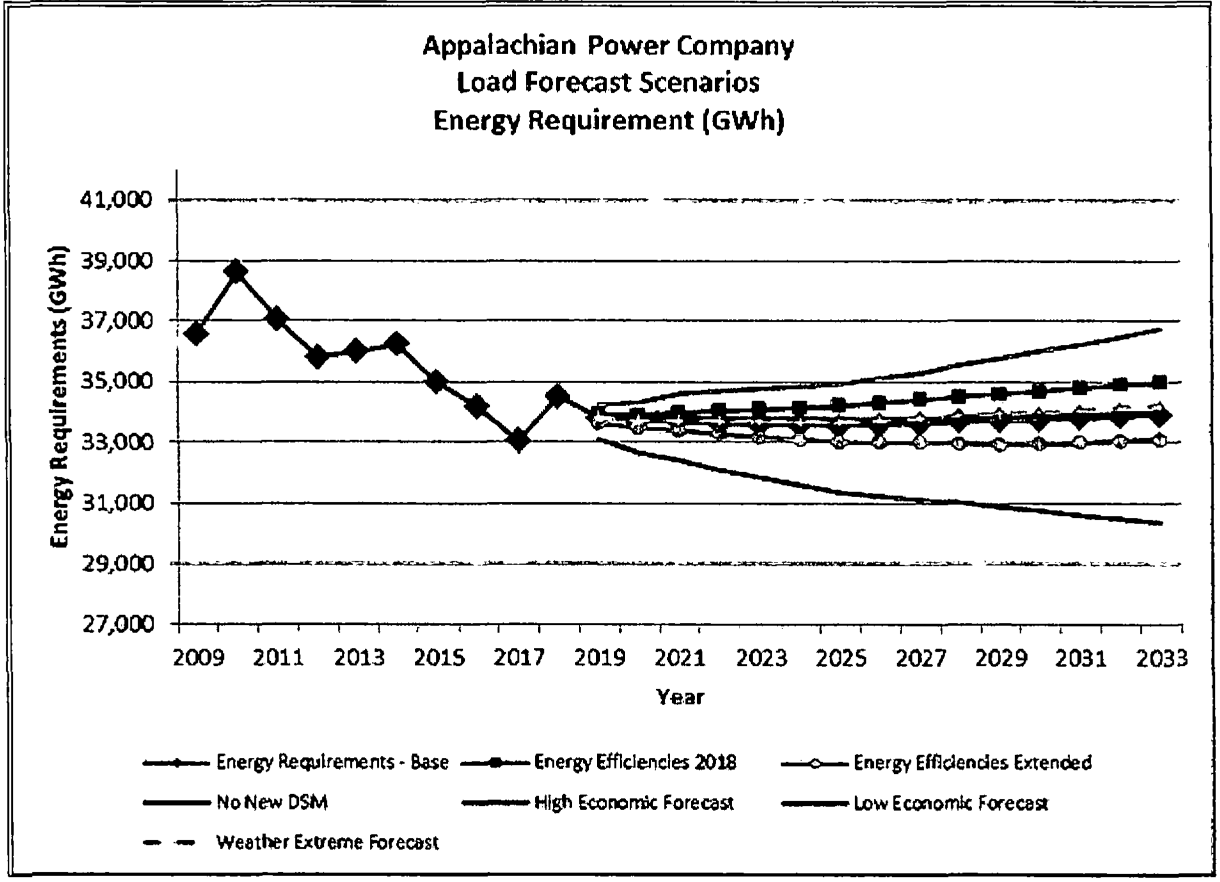

Figure 10. Load Forecast Scenarios

The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2018 scenario keeps energy efficiencies at 2018 levels for the residential and commercial equipment. Both of these scenarios result in a load forecast greater than the base forecast.

The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial equipment.

The weather extreme forecast assumes increased degree-days for both the winter and summer seasons. This analysis is based on a potential impact of climate change developed by

Purdue University. This scenario results in increased load in the summer and diminished load in the winter, with the net result being a higher energy requirements forecast. Exhibit A-8 provides graphical displays of the range of forecasts of summer and winter peak demand for APCo along with the impacts of the weather scenario for each season.

All of these alternative scenarios fall within the boundary of the Company's high and low economic scenario forecasts. The Company's expectations are that any reasonable scenario developed will fall within this range of forecasts.

2.8 Long-Term PJM Load Forecast

In its order related to APCo's 2018 IRP, the Commission stated "We further direct APCo to include in all future IRPs modelling that includes, but need not be limited to, the AEP Zone PJM coincident peak load forecast produced by PJM Interconnection, LLC, scaled down to the APCo load serving entity level."

The Company utilized the PJM 2019 Load Forecast to develop a forecast for the APCo load serving entity (LSE) coincident with the PJM RTO. The APCo LSE is comprised of retail load and FERC wholesale load, which includes Kingsport Power, an affiliated company that purchases all of its power needs from the Company. In PJM, the Company is required to include those customers that have chosen alternative energy suppliers in its capacity obligation for Fixed Resource Requirement (FRR) planning. The forecasts provided in this report include choice customers in all analyses.

Exhibit A-9 provides the forecast of the APCo LSE load based on the PJM forecast for the AEP Zone. These forecasts are for the summer season and are coincident with PJM RTO. The summer season is used as it is the critical season for the RTO and it is used for capacity planning. The APCo forecast diversified to be coincident with PJM RTO is also provided, as well as the Company's high forecast diversified to be coincident with the PJM RTO. The Company's forecast tends to be lower than APCo's share of the PJM forecast for the AEP Zone. However, the Company's high forecast is above the PJM forecast. As discussed in the forecast scenario section, any reasonable scenario is expected fall within the boundaries of the high and low economic scenario forecasts.