Arkansas Electric Cooperative Corporation

Reliable · Affordable · Responsible

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February 18, 2016

Michael Sappington
Secretary of the Commission
Arkansas Public Service Commission
1000 Center Street | P.O. Box 400
Little Rock, AR 72203

RE: APSC Docket No. 07-17-U

Dear Secretary of the Commission:

As directed by Section 6.2 of the Arkansas Public Service Commission's (Commission) Resource Planning Guidelines for Electric Utilities (Guideline), on February 2nd, 2007, Arkansas Electric Cooperative Corporation (AECC) made a compliance filing in Commission Docket No. 07-017-U. In that filing, AECC stated that its proposed timeline for complying with the Guideline would be three (3) years. Accordingly, AECC hereby submits its 2016 Resource Plan (Plan). AECC requests that the Plan be filed in Commission Docket No. 07-01 7-U.

Questions regarding this submission should be directed to Lori Burrows (501-570-2147) or me (501-570-2408).

Sincerely,

Robert Shields

Robert Shields
Manager, Rates and Regulation

Attachment
cc: Duane Highley
Lori Burrows

Arkansas Electric
Cooperative Corporation

2016 Integrated Resource Plan

AECC's mission is to provide electric power to our Member Cooperatives reliably, affordably, and responsibly.

Table of Contents

AECC's Integrated Resource Plan

Integrated Resource Plan Purpose

The purpose of this Integrated Resource Plan (IRP) is to provide an informational report that will meet the planning expectations of the Arkansas Public Service Commission (APSC), based upon the specific circumstances of Arkansas Electric Cooperative Corporation (AECC) and its 17 member distribution cooperatives (Members),[1] in accordance the APSC's *Resource Planning Guidelines for Electric Utilities* (Resource Guidelines).[2]

IRP Executive Summary

AECC and its Members are committed to providing reliable, low cost electricity to our member owner-consumers throughout the state of Arkansas. AECC's primary resource planning goals are to select reliable energy supplies with the lowest life-cycle costs, responsibly. Also, the recognition and evaluation of risks are very important, such as the costs and reputational effect of falling below minimum installed capacity requirements, the uncertainty of future fossil fuel costs, and the possible effect of regulatory dictates, including those anticipated from the U.S. Environmental Protection Agency (EPA).

The boundary within Arkansas between the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) regional transmission organizations (RTOs), often called a "seam," results in a generation-load imbalance between AECC's loads and generating assets between the two RTOs. This seam complicates AECC's planning and operational activities, and requires that AECC separately maintain firm generation resources above the minimum requirements within the footprint of each RTO to serve its loads in each.

[1] AECC's seventeen electric distribution cooperative members are: Arkansas Valley Electric Cooperative Corp. (Ozark, Arkansas); Ashley-Chicot Electric Cooperative, Inc. (Hamburg, Arkansas); C&L Electric Cooperative Corp. (Star City, Arkansas); Carroll Electric Cooperative Corp. (Berryville, Arkansas); Clay County Electric Cooperative Corp. (Corning, Arkansas); Craighead Electric Cooperative Corp. (Jonesboro, Arkansas); Farmers Electric Cooperative Corporation (Newport, Arkansas); First Electric Cooperative Corp. (Jacksonville, Arkansas); Mississippi County Electric Cooperative, Inc. (Blytheville, Arkansas); North Arkansas Electric Cooperative, Inc. (Salem, Arkansas); Ouachita Electric Cooperative Corp. (Camden, Arkansas); Ozarks Electric Cooperative Corp. (Fayetteville, Arkansas); Petit Jean Electric Cooperative Corp. (Clinton, Arkansas); Rich Mountain Electric Cooperative, Inc. (Mena, Arkansas); South Central Arkansas Electric Cooperative, Inc. (Arkadelphia, Arkansas); Southwest Arkansas Electric Cooperative Corp. (Texarkana, Arkansas); and Woodruff Electric Cooperative Corp. (Forrest City, Arkansas).

[2] Approved in APSC Docket No. 06-028-R.

AECC presently owns 3,514 MW of installed generation capacity and has power purchase agreements (PPAs) for an additional 800 MW. This capacity reflects a robust mix of both fossil-fueled resources and a recent doubling of energy supply from non-fossil energy resources. Since AECC's last Integrated Resource Plan filing in 2013, three additional wind resource PPAs have been executed. These wind resources will assist AECC in meeting its Members' energy needs on the SPP side of the RTO seam. AECC does not anticipate retirement of any power plant capacity prior to 2027.

AECC and its Members have a long and successful history of implementing demand-side planning activities to assist in the provision of a reliable and economic supply of electricity including the implementation of 775 MW of demand response resources to reduce peak loads. In addition, as detailed in AECC and the Member Cooperatives' Annual Energy Efficiency Report AECC's Members have many ongoing energy efficiency programs. AECC will continue its robust demand response programs, including supporting Members' demand and energy efficiency programs to reduce Members' future energy needs.

Based on AECC's most recent forecasts of Member demands, and considering the expiration of an existing PPA, AECC will have a need for firm generation capacity within the SPP footprint beginning in 2020. To address this capacity shortage, AECC issued a request for proposals (RFP) to solicit both fossil-fueled and renewable capacity proposals. The proposals that were received were evaluated in direct competition to self-build alternatives and any other identified resource opportunities to determine the least-cost alternative. Based on the responses received in response to the RFP, AECC presented a proposal to extend and existing PPA for five (5) years. A Board vote on that recommendation is expected in March 2016. AECC does not anticipate any additional firm generation needs within the MISO footprint prior to year 2027.

Within AECC's most recent base case long-term indicative economic analysis of firm capacity alternatives to support AECC's resources within the SPP footprint, a portfolio of new fossil capacity combined with additional non-fossil resources showed higher incremental revenue requirements than a fossil-only capacity portfolio. Alternate future scenarios applying lower fossil fuel costs or lower dispatch costs within the SPP energy market increased the cost differential, while a scenario applying an underlying marginal CO_2 emission cost showed approximately equivalent revenue requirement impacts from the two firm capacity portfolios.

AECC's 10-year preferred portfolio of new supply resources includes continuing to pursue an incremental combination of wind and solar resources primarily to stabilize purchased energy costs, and fossil-fueled resources primarily to provide firm capacity.

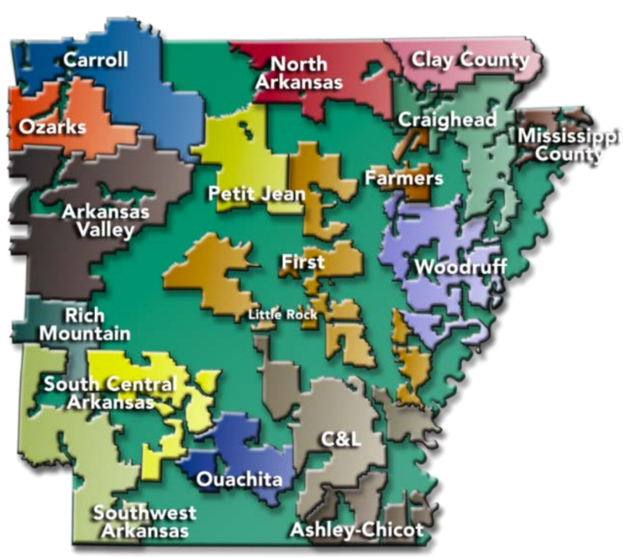
This will allow AECC to achieve an increasingly robust and diverse mix of resources to meet our Members' future needs.

In order to round out AECC's IRP for this reporting period, AECC solicited the feedback of those interested in and affected by AECC's plans. To that end, on August 31, 2015, a draft version of AECC's IRP was sent to the stakeholders in advance of its Stakeholder Committee Meeting (SCM), along with a request that written feedback or concerns be returned to AECC no later than September 23, 2015. On October 7, 2015, AECC hosted its (SCM). The stakeholder report from that meeting is attached to this document as Appendix B.

AECC and Its Members

AECC is an electric generation and transmission cooperative incorporated under Arkansas law with its principal place of business in Little Rock, Arkansas. AECC provides wholesale electricity to its seventeen electric distribution cooperative members (Members). The Members provide electricity, at retail, to approximately 500,000 consumers, primarily in Arkansas. The certified service territories of the Members extend into 74 of the 75 counties in Arkansas and cover approximately 60% of the state's geographic area (see Figure 1).

Figure 1: Service Territory
AECC's Members' Service Territory

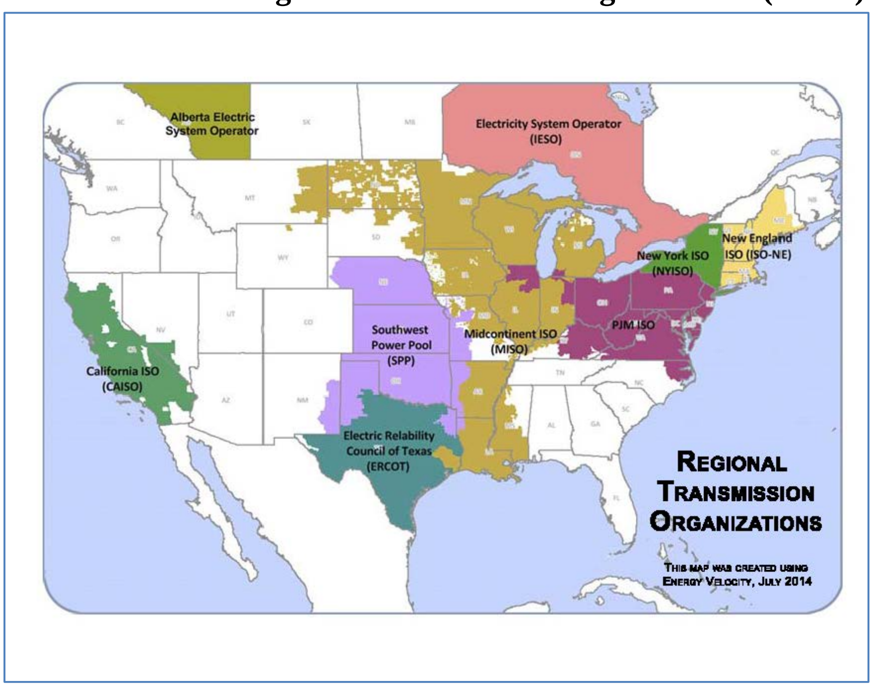


AECC is operated as a not-for-profit cooperative, and designs its rates on a cost-of-service basis that allows recovery of operating and maintenance (O&M) costs, taxes and debt service to maintain reasonable Member equity to achieve required operating margins each fiscal year.

AECC provides the bulk of its Members' power requirements from owned and co-owned generation facilities, supplemented by long-term PPAs. Members receive electric power from AECC under wholesale power contracts, which may be terminated upon 60 months' prior written notice but at this point no earlier than January 1, 2042. With one exception, the wholesale power contracts require Members to purchase 100% of their energy requirements from AECC.

A major change since AECC last filed its IRP in 2013 is that AECC has joined MISO[3] (in addition to being a long-standing Member of SPP) and is now participating in the expanded energy markets of both MISO and SPP. As shown in Figure 2, the interface boundary between the MISO and SPP RTOs crosses through the state of Arkansas.

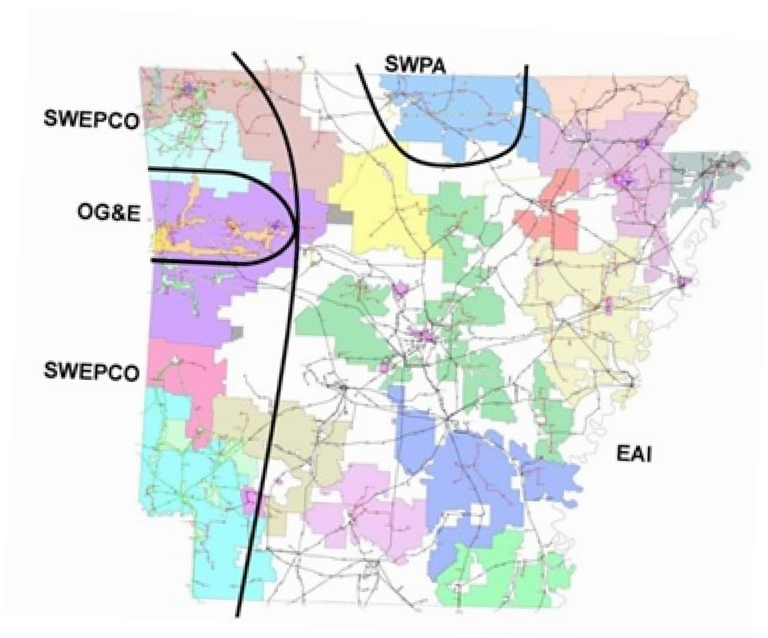
Figure 2
North American Regional Transmission Organizations (RTOs)



[3] EAI's decision to join MISO and the associated formation of the MISO South region necessitated that AECC (as a dependent user of the EAI transmission system) also join MISO's day-ahead and real time energy markets on December 19, 2013. AECC subsequently joined MISO as a transmission-owning member on June 1, 2014.

The generalized boundaries of the transmission owner systems to which AECC Member loads are connected are shown on Figure 3. Approximately 55% of AECC Member cooperative loads are physically connected to the Entergy Arkansas (EAI) transmission system within MISO South, and 45% of AECC Member loads are connected to the Southwestern Electric Power Company (SWEPCO), Oklahoma Gas & Electric (OGE) and Southwestern Power Administration (SWPA) transmission systems within SPP.

Figure 3
Transmission Owner System Boundaries within Arkansas



Integrated Resource Planning Objectives

AECC's primary resource planning objectives are to select reliable resources that responsibly meet AECC's capacity and energy needs with the lowest life-cycle costs. In furtherance of this objective, and consistent with Section 4 of the Resource Guidelines, AECC also considers rate impacts, load growth, financial strength, and environmental stewardship as important considerations. The recognition and evaluation of risks are important within the overall decision making process. Risks that need to be considered and abated include: load growth uncertainty; fuel costs and delivery; regional power market conditions; falling below required minimum installed capacity levels; new legislation and rulemaking; capital cost variability; interest rate volatility; ability to obtain facility permits; long-term resource performance; costs of new technologies; and future RTO requirements.

AECC strives to maintain its currently diverse mix of generation resources in the future. By continuing to evaluate a wide range of resource alternatives at the best identified locations, AECC will pursue a future resource mix that is reliable, cost-effective, and manages risks.

AECC Member Cooperative Loads

This section summarizes recent actual peak electricity demands of AECC's Members, as well as the most recent demand forecasts which were developed within the 2015 AECC Power Requirements Study (PRS).

AECC's Recent Actual Peak Firm Demands

Table 1 summarizes actual peak annual demands of AECC's Members in the most recent five year period. AECC's all-time peak firm load of 2,567 MW was set in August 2011. In both 2013 and 2014, Arkansas experienced below-normal July-August peak temperatures, resulting in less-than-expected peak electric loads. The 2015 AECC peak firm demand was budgeted to be 2,466 MW.[4]

As can be seen in Table 1, AECC has traditionally been a summer-load-peaking electric utility. However, in extremely cold weather conditions, electric heating loads cause AECC's loads to briefly spike in the winter season. This happened during the "polar vortex" event in January of 2014 and again in January of 2015.[5]

[4] This figure includes 31 MW of firm demand at interruptible customer locations.

[5] In addition to firm load customers, AECC's Members also serve several relatively large interruptible load customers. AECC considers only the firm customer loads in determining the amount of generation capacity required to meet mandatory reserve margins of the RTOs.

Table 1
Recent AECC Annual Peak-Hour Firm Loads [6]

Year	Peak Firm Load [7]	Comments
2010	2,171 MW	Occurred on August 3rd
2011	**2,567 MW**	Occurred on August 3rd
2012	2,373 MW	Occurred June 25th (moderate July-August)
2013	2,230 MW	Occurred June 27th (moderate July-August)
2014	2,194 MW (summer) 2,526 MW (winter)	Occurred August 24th (cool summer season) Weather adjusted to 2,441 MW for trending Occurred January 7th
2015	2,466 MW	Forecast value

AECC's Forecasts of Firm Customer Demands

The June 2015 PRS details AECC's most recent forecast of the future electricity needs of AECC's Members. Development of the PRS is managed and conducted primarily by AECC staff, in conjunction with AECC's Members, on an ongoing basis, and is ultimately approved by AECC's Board of Directors. Each PRS update is also submitted for approval to the U.S. Rural Utilities Service (RUS).[8] Each cycle of updating the load forecasts for submittal to RUS takes approximately two years, and the results and supporting documentation contain in excess of 3,000 pages of narrative, data and graphs.

AECC forecasts electric loads by consumer class for each of the 17 Members. The consumer classes are individually modeled to capture the economic and demographic factors that most significantly influence load growth for each particular class. The class forecasts are summed to form Member cooperative load forecasts. Then, each Member cooperative forecast is summed to form an AECC aggregate forecast. Appropriate energy loss factors are applied within the modeling process. Because the impacts of the demand-side programs are embedded within the historical load data applied to develop the PRS econometric models, projections that are developed include the expanding impacts of these demand-side programs.

[6] These figures do not include transmission losses or reserve capacity requirements.
[7] These figures are listed for amounts prior to any adjustment for weather conditions at the time of peak demand.
[8] The RUS is an agency of the U.S. Department of Agriculture (USDA) that provides the capital and leadership to maintain, expand and modernize rural electric infrastructure, as well as funding to support demand-side management, energy efficiency, conservation, and renewable energy systems. AECC is an RUS borrower.

The Member cooperative load classes are:

1. Residential
2. Small Commercial (1000 kVA or less)
3. Large Commercial (over 1000 kVA)
4. Irrigation (for some Members)
5. "Four Other" – a very small aggregated load class (street & highway lighting, other sales to public authorities, Member internal use, and seasonal residential use)

For the residential and small commercial classes, the number of consumers and kilowatt hour (kWh) usage per consumer are separately modeled. Those two components are multiplied to form the forecast for each class. Every third year, AECC conducts an appliance saturation survey for AECC's Members as well. The appliance saturation analysis provides useful information on trends in appliance stock for residential, retail members. Appliance saturation data may play an important role in future AECC end-use modeling efforts. AECC currently believes that energy usage patterns are adequately addressed by the econometric models applied in the current forecast.

For large commercial load, AECC forecasts total load econometrically, and then divides that total among the Members. AECC also addresses specific or likely load additions identified by the Members and applies adjustments to the forecasts.

Irrigation loads are econometrically modeled for each Member cooperative when possible. When econometric modeling data is insufficient, other methods, including judgment, are further employed.

The "Four Other" load class is composed of street & highway lighting, other sales to public authorities, seasonal residential, and each Member's own use. Because this load is relatively small, AECC trends the data for each Member.

The AECC firm load forecast is a banded forecast to address uncertainty of underlying growth, resulting in values for a middle range load growth forecast as well as a "low band" growth forecast and a "high band" growth forecast. The low band forecast incorporates economic and demographic variables that are less conducive to load growth than those applied in the middle range forecast. The high band forecast incorporates economic and demographic variables that are more conducive to load growth than those applied in the middle range forecast. The middle range forecast is generally referred to in this document as the Base Case load growth forecast.

Figure 4 illustrates the projected AECC annual firm peak demands of the base case, growth forecast. The year 2016 base case forecast peak demand is 2,563 MW, which is very close to AECC's overall actual peak firm demand of 2,567 MW in the summer of 2011.

Figure 4

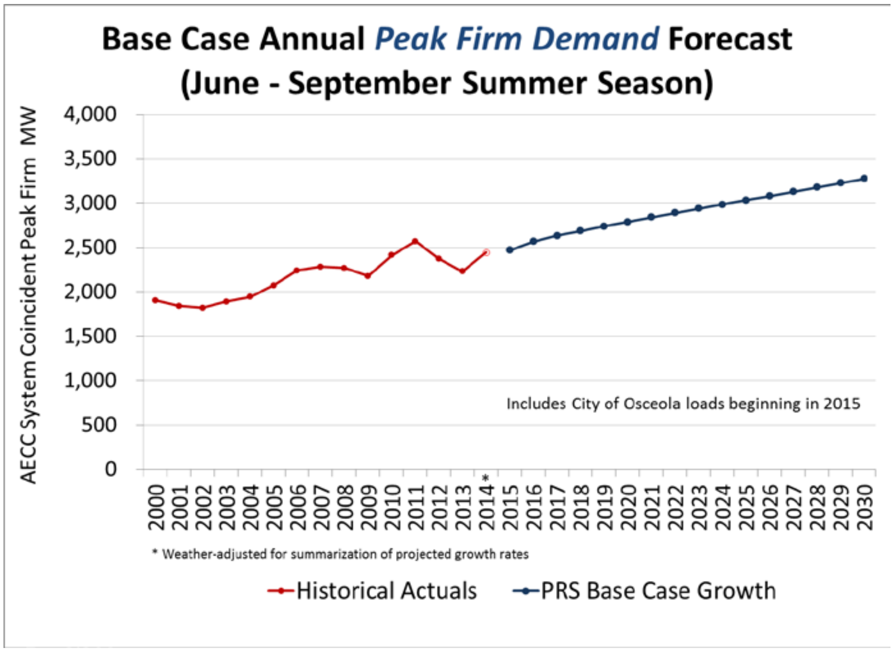


Figure 5 illustrates the comparable annual peak firm demands of the banded forecast range. The year 2016 peak demand value of the low growth forecast is 2,431 MW, which is very close to the 2014 weather adjusted peak for year 2014.

Figure 5

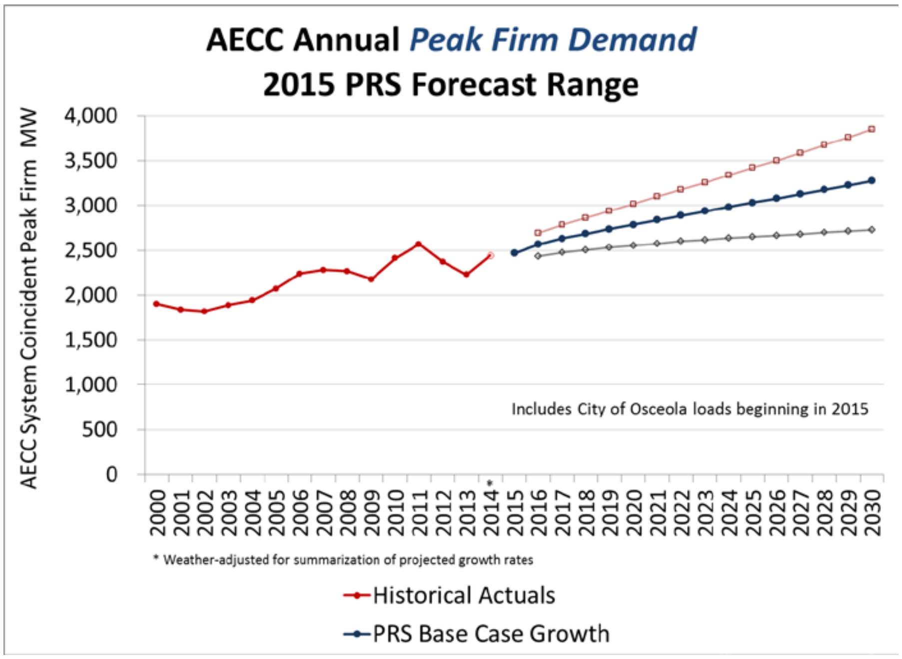


Table 2 summarizes the average annual growth rates for AECC peak demands of the Base case growth forecast, along with values for the low growth forecast and the high growth forecast. For the 11-year time span from 2014 to 2025, the base case forecast reflects an average annual peak demand growth rate of about 1.8 % per year. For this same time span, the low growth forecast and high load growth forecast reflect average annual growth rate of 0.6 % and 3.0 %, respectively.

Table 2
Peak Demand Growth of the Base Case & Low/High Band Forecasts

Time Span *	**Average Annual Peak Firm Demand Growth Rate**		
	Base Case Forecast	Low Band Forecast	High Band Forecast
2014 to 2020	1.96 %	0.49 %	3.31 %
2014 to 2025	1.84 %	0.61 %	2.96 %
* 39 MW added to the 2014 weather-adjusted peak demand to consistently reflect inclusion of loads for the City of Osceola beginning in 2015 (also included after 2018 for consistency)			

AECC Supply Resources

The following paragraphs, tables and figures summarize AECC's current generation resources.

Owned and Leased Generation Resources

AECC currently has ownership in a mix of coal-fueled, natural gas-fueled, hydroelectric, and wind-powered resources. Six generating units at four plant locations burn low-sulfur Wyoming coal. Nineteen generating units at seven plant locations are powered by natural gas, with three of those plants being able to also burn fuel oil as backup. AECC owns nine hydroelectric generating units at three plant locations. Table 3 provides specifics on the AECC-owned and leased generation resources.

Although about 300 MW of AECC's owned capacity is now aged 44 years or more,[9] each of the plants has undergone refurbishment over the years. With the exception of the White Bluff plant, discussed below, none of this capacity is currently projected to be retired in the near future.

[9] This capacity includes the Fitzhugh steam turbine, the Bailey steam plant, and the McClellan steam plant.

Table 3
AECC Owned/Leased Generation Resources as of June 2015

Name	Type of Fuel	Percent Owned or Leased	Operator/ Dispatcher	Year Declared in Commercial Operation	AECC's Rated [10] Generation Capacity (MW)
Flint Creek	Coal	50	SWEPCO	1978	264 [11]
White Bluff 1	Coal	35	EAI	1980	285 [12]
White Bluff 2	Coal	35	EAI	1981	295 [13]
Independence 1	Coal	35	EAI	1983	293 [14]
Independence 2	Coal	35	EAI	1984	295 [15]
Turk	Coal	11.667	SWEPCO	2012	73 [16]
Bailey	Gas/Oil	100	AECC	1966	122
McClellan	Gas/Oil	100	AECC	1972	134
Fitzhugh	Gas/Oil	100	AECC	2003	165
Fulton CT1	Gas	100	AECC	2001	153
Oswald	Gas	100	AECC	2002	548
Magnet Cove	Gas	100	AECC	2006	660 [17]
Elkins	Gas	100	AECC	2010	60
Ellis (Dam 13)	Water	100	AECC	1988	17 [18]
Whillock (Dam 9)	Water	100	AECC	1993	14 [19]
ECA Hydro (Dam 2)	Water	100	AECC	1999	44 [20]
Total Owned & Leased					3,422 MW

[10] Generally, based on formal capacity ratings procedures of the MISO and SPP RTOs; all generators are shown on the basis of installed capacity (ICAP).
[11] AECC owns a 50% undivided interest in Flint Creek, which has a net generation capacity of 528 MW. Under normal conditions, AECC schedules approximately 240 MW from the plant.
[12] AECC owns a 35% undivided interest in each unit of White Bluff. White Bluff 1 has a net generation capacity of 815 MW, and White Bluff 2 has a net generating capacity of 844 MW.
[13] *Id*.
[14] AECC owns a 35% undivided interest in each unit of Independence. Independence 1 has a net generating capacity of 836 MW, and Independence 2 has a net generation capacity of 842 MW.
[15] Id.
[16] AECC owns an 11.667% undivided interest in Turk, which has a net generation capacity of 626 MW.
[17] AECC, as lessee, has certain leasehold interests in the fee interest in the real property and right, title, and interest in the personal property of Magnet Cove owned by Hot Spring County, Arkansas, as lessor, under a certain lease agreement related to an existing agreement for payment in lieu of taxes.
[18] Ellis hydro has a nameplate capacity of 32.4 MW. Net generating capacity is dependent on river conditions.
[19] Electric Cooperatives of Arkansas Hydroelectric Generating Station (ECA Hydro) has a nameplate capacity of 102.6 MW. Net generation capacity is dependent on river conditions.
[20] Electric Cooperatives of Arkansas Hydroelectric Generating Station (ECA Hydro) has a nameplate capacity of 102.6 MW. Net generation capacity is dependent on river conditions.

Power Purchase Agreements (PPAs)

In addition to the owned/leased resources, AECC has eleven PPAs in place for fossil-fueled and non-fossil energy resources.

1. AECC has a contract with the Southwestern Power Administration (SWPA) for the purchase of **189 MW** of firm capacity and associated energy from SWPA's hydroelectric plants. This is a system firm contract and is considered to carry its own reserves. The power provided comes primarily from United States Army Corps of Engineers-owned hydroelectric facilities in Arkansas, Missouri and Oklahoma. The current contract is through June 30, 2020.
2. AECC has an agreement with the City of Augusta, Arkansas, (Augusta) whereby AECC acquired **3.7 MW** of firm hydroelectric capacity and associated energy that Augusta earlier acquired from SWPA under an agreement with terms that are similar, except for size, to the agreement between SWPA and AECC described above. This contract expires on the earlier of the date Augusta ceases to purchase from AECC's Member cooperative or termination of Augusta's underlying SWPA contract.
3. AECC has an agreement for the purchase of energy from a facility in Springdale, Arkansas, fueled by landfill gas from the Eco-Vista Landfill. AECC only pays for energy delivered, and all energy produced by the facility in excess of the energy required to operate the facility and prepare the landfill gas for fuel will be sold to AECC. The facility currently produces a maximum of **4 MW**. The current contract expires on November 22, 2020.
4. AECC has an agreement for capacity and associated energy from a natural gas fueled plant in Texas. This PPA provides **170 MW of firm capacity** and is for a five-year term, June 2015, through May 31, 2020.
5. AECC has four agreements for the purchase of energy from wind-powered facilities as listed in Table 4, with a combined **installed capacity of 373 MW**. Each of the first three agreements listed on the table is a 20-year commitment, and the fourth contract is a 25-year commitment. Each PPA commences on the associated facility's commercial operational date, to purchase 100% of the net electric power generated at the associated facility. All of these wind facilities are within the SPP regional footprint.
6. AECC has an agreement with the City of Osceola relating to the City's leased capacity shares at the Independence plant and the Plum Point coal-fueled plant, together totaling **28 MW**, for a three-year period beginning January 2015.

7. AECC has an agreement to purchase **excess energy from a 12 MW** solar photovoltaic (PV) facility in Camden Arkansas. This agreement will expire in the year 2040.

8. In addition, AECC and its Members have an agreement under which each cooperative has the option to build a 1 MW community solar facility. To date, AECC has an agreement with one Member, Ozarks Electric Cooperative Corporation (OECC), to purchase energy from a 1 MW solar facility to be constructed in northwest Arkansas. This agreement will expire in the year 2041.

Table 4
AECC PPAs for Wind-Powered and Solar Resources

Name	State Located	Capacity Type	Commercial Operation and Contract Expiration	Installed Capacity (MW)	Estimated Firm Capacity (MW)
Flat Ridge	Kansas	Wind	2012 / 2032	51	8
Origin	Oklahoma	Wind	2014 / 2034	150	22
Drift Sand	Oklahoma	Wind	2016 / 2036	108	16
Chisholm View II	Oklahoma	Wind	2017 / 2042	64	10
E Camden PV	Arkansas	PV	2015 / 2040	12	2
Ozarks ECC Solar PV	Arkansas	PV	2016 / 2041	1	<1
Total				386	58

SPP and MISO establish the rules and processes that determine the amounts of firm capacity that resources required within each RTO. For intermittent (non-dispatchable) resources, the RTO methodologies are primarily based on historical energy production patterns for each resource, and as such, AECC is not yet certain how much firm capacity the wind and solar PV PPAs will be credited in the future. AECC is presently estimating that the RTOs will accredit approximately 15 to 25 % of the installed capacity at the wind facilities, and possibly similar percentages of the installed capacity at solar PV facilities. The solar PV facilities which AECC and the Members are developing and purchasing from will provide valuable information regarding the operating and performance characteristics of this technology.

Recent and Potential Modifications at Existing Resources

SWEPCO is undertaking a major project to install emission control equipment at the Flint Creek coal-fueled plant, which is expected to be completed in the summer of 2016.[21] With Arkansas Public Service Commission approval through Docket No. 12-008-U, this project includes installation of a dry flue gas desulfurization system (commonly referred to as a "dry scrubber"), low-NO_X burners and overfire air to comply with the EPA Regional Haze Rule, as well as an activated carbon injection system to comply with the EPA Mercury and Air Toxics Standards (MATS) rule. The increased ancillary plant load associated with the scrubber system is expected to reduce AECC's share of Flint Creek's net capacity by about 5 MW in 2016.

AECC recently undertook various projects to improve the performance of its wholly-owned power plants, including the upgrading of controls and equipment at several plants. At the Magnet Cove plant, for example, AECC implemented a "low load turndown" project to allow the plant to operate at lower output levels overnight and to support more efficient overall dispatch of on-line resources.

Entergy is discussing with the EPA, and other parties, modifications to the White Bluff and Independence coal-fueled plants to meet requirements of the Regional Haze rule and the MATS rule.[22] In August of 2015, Entergy announced its intention to retire one White Bluff generating unit in 2027 and the second White Bluff generating unit in 2028.

The EPA issued a proposed "Clean Power Plan" (CPP) rule in June of 2014, which would have required drastic reductions of carbon dioxide (CO_2) at Arkansas power plants and nationwide. After AECC and other commented, the EPA issued the final CPP rule on August 3, 2015,[23] which states that specified CO_2 emission reductions occur beginning in the year 2022, with further annual emission reductions required through year 2030.

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[21] AECC owns 50% of the Flint Creek plant.

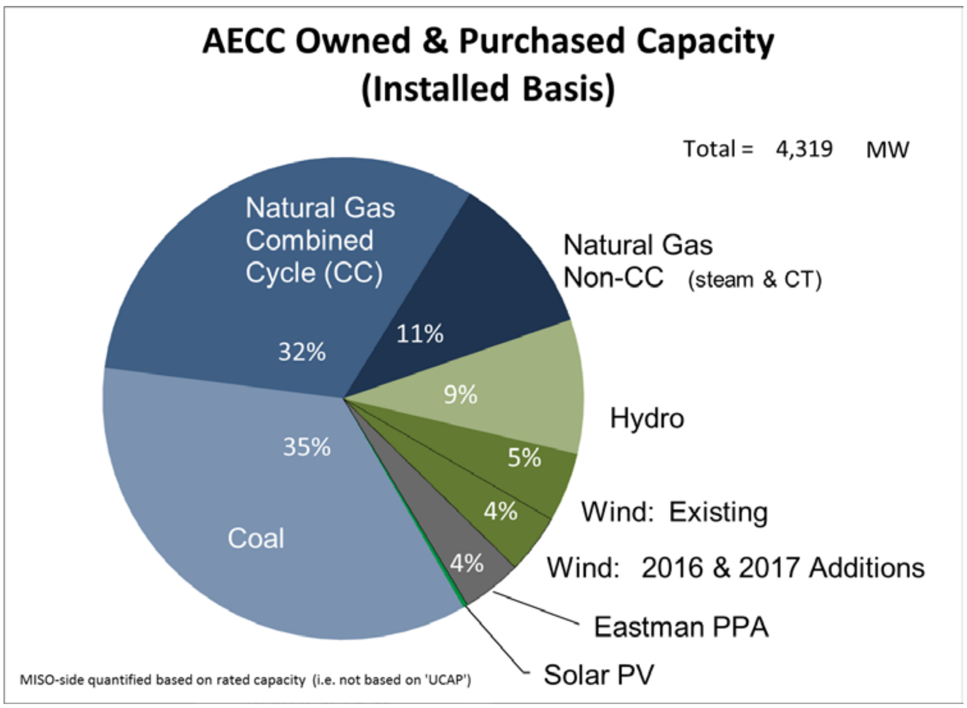
[22] AECC owns 35 % of both generating units at the White Bluff plant.

[23] More formally designated as the revisions to 40 CFR Part 60: *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*

AECC's Generation Resource Mix

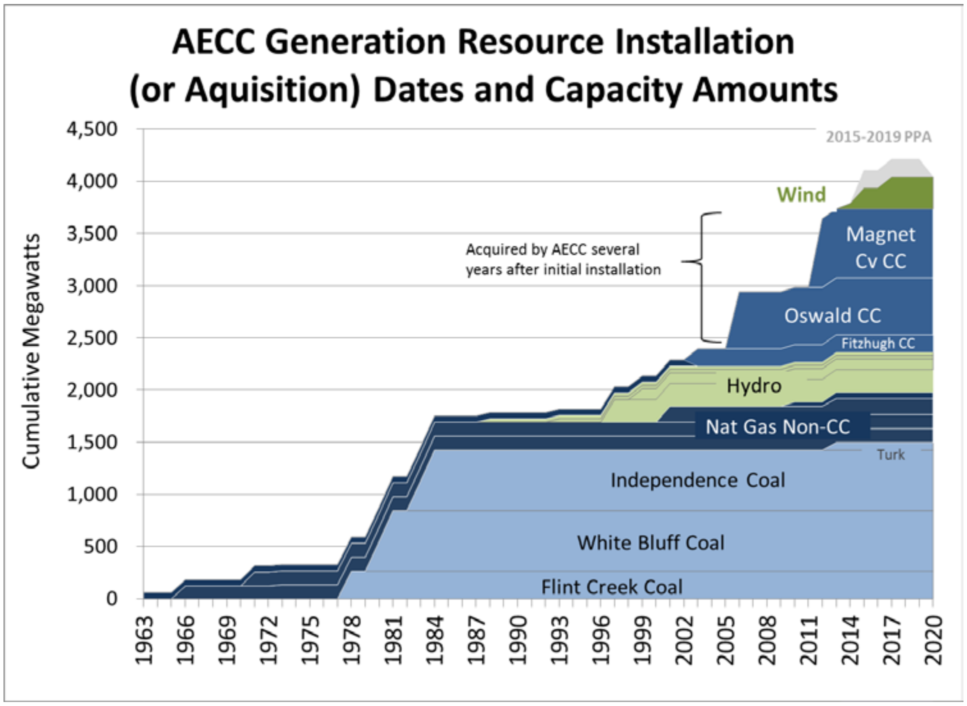
Figure 6 shows the present fuel mix of AECC's owned generation capacity and long-term PPA capacity. The chart shows the data for year 2018, which is the year AECC's most recent PPA becomes fully effective. AECC's natural gas combined-cycle (NGCC) and other NG-fueled capacity will represent 43% of AECC's total capacity; coal-fueled capacity will represent 35% of the total, and the installed non-fossil capacity (hydroelectric, wind-powered and solar PV capacity) will represent 18% of the total installed capacity. The PPA which is expiring in year 2020 presently provides the remaining 4 % of installed capacity.

Figure 6



As shown on Figure 7, all of AECC's wind-powered PPA capacity has been added since year 2012, and almost all of the NGCC capacity has been added since 2006.[24] The NGCC capacity represents the highest efficiency thermal capacity that AECC owns.

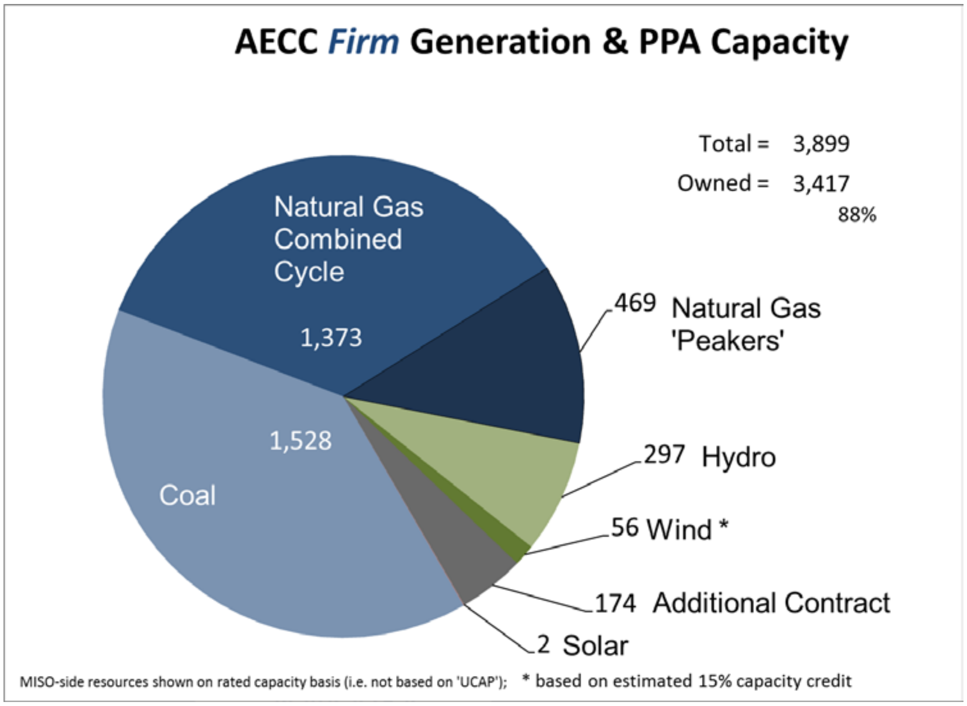
Figure 7



Due to the intermittent nature of the production from the hydroelectric, wind and solar resources, only a portion of the installed capacity for these facilities qualifies for firm capacity credit by the RTOs. Figure 8 summarizes AECC's total firm capacity for year 2018. It is presently estimated that about 15% of the installed wind capacity will be accredited as firm capacity by SPP. This results in a firm capacity estimate of 56 MW for AECC's contracted wind plants. The AECC hydroelectric plants are presently rated at a combined value of 75 MWs, which represents 45% of their installed capacity. Approximately 90% of AECC's overall installed generation capacity and PPA capacity is credited as firm capacity that can contribute to the reserve margins, which is the amount of capacity AECC is expected have greater than its peak load and available MW to serve that load as required by the RTOs.

[24] The Fitzhugh plant was converted from NG steam-turbine (NGST) configuration to NGCC in 2003.

Figure 8

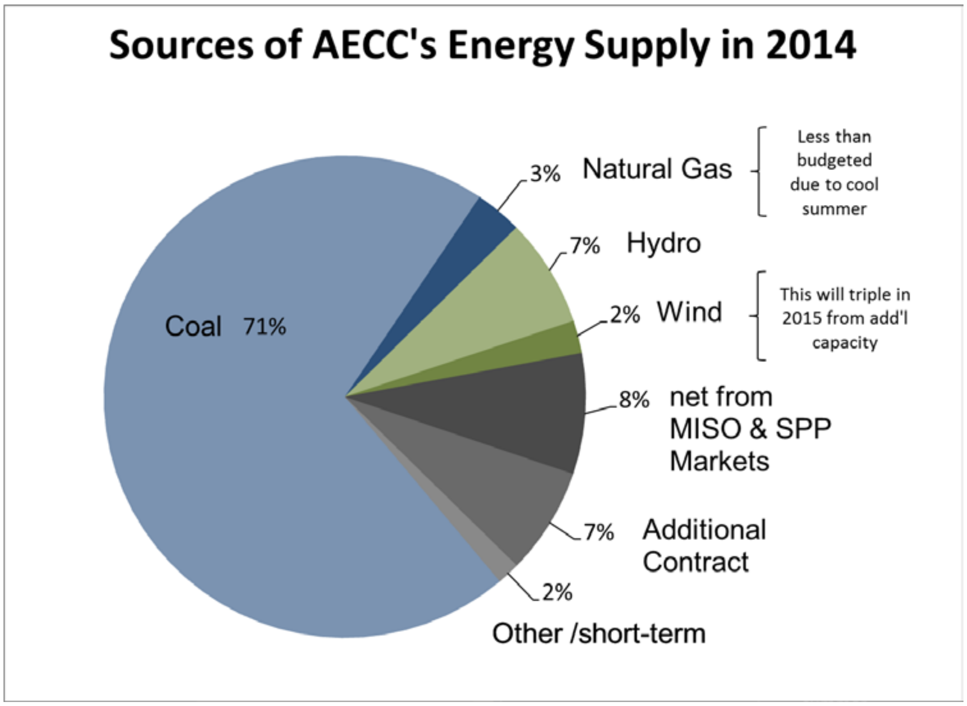


Energy Supply

AECC's actual sources of energy supply to meet its Members' energy needs in calendar year 2014 are summarized on Figure 9. Coal-fueled generation met 71% of the overall energy requirements of AECC's Members, and natural gas provided 3 % of the energy requirements. The combined output of AECC's non-fossil resources in year 2014 was 9 %, up from 6 % just two years earlier.

Figure 9 also shows that 8% of AECC's energy requirements in year 2014 were purchased, rather than generated by AECC's own units, from the MISO and SPP RTO energy markets.[25] While these markets provide opportunities for economic transactions within their respective footprints, the future availability and prices of energy in these markets is uncertain.

Figure 9



With the completion of a new wind plant in late 2014 and two additional wind PPAs providing energy beginning in late 2016 and 2017, the percentage of total AECC Member energy needs served by wind resources will increase to approximately 10 % in year 2018. Combined with AECC's hydroelectric and biomass resources, non-fossil resources will provide approximately 17% of AECC Member energy requirements in the year 2018, as summarized on Table 5.

[25] The MISO South market began operation in December of 2013, and the SPP "Integrated Marketplace" began operation in March of 2014.

Table 5
AECC Non-Fossil Energy Sources in Years 2012 and 2018

Type	2012 Actual		2018 Projection[26]	
	Energy GWH	Percent of Member Energy	Energy GWH	Percent of Member Energy
Hydroelectric	950	7.3 %	950	6.2 %
Wind Powered		--	1,585	10.3 %
Solar		--	20	0.1 %
Biomass		--	35	0.2 %
Total	950	7.3 %	2,590	16.9 %

Need for Additional Resources

Capacity Needs

One of the unique aspects of AECC's statewide service territory being divided by the seam between the MISO and SPP RTOs is that AECC must concurrently meet the firm capacity requirements within each RTO.[27] In other words, AECC does not receive "credit" for a capacity surplus in MISO from SPP and vice versa. Because generation capacity must be added in finite increments, this results in AECC experiencing a somewhat higher average reserve margin than would be the case if this seam did not exist. This section of the Resource Plan shows projections for both the overall AECC system and for the portions within the boundary of each RTO.

For many years, AECC has utilized high capacity factor coal-fueled generation at co-owned power plants connected to the Entergy-owned transmission system (which is now part of the MISO South region) to serve a portion of loads on the SPP side of the seam. Upon transition to the MISO South RTO region in late 2013, many of the costs of transmission service that were governed by a negotiated agreement between AECC and EAI were replaced with more expensive and more expansive transmission service charges, via multiple rate schedules, under the Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). In addition to potentially being responsible for

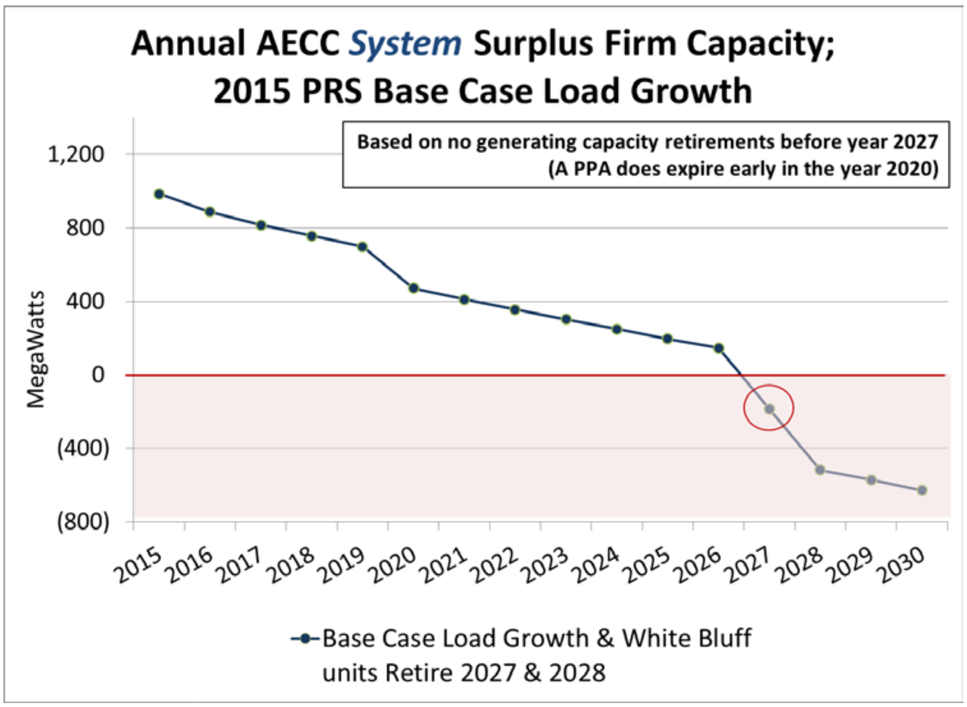
[26] Based on all executed contracts at time of this Resource Plan
[27] The boundary between MISO and SPP RTO footprints is sometimes referred to as a 'seam'

paying the "regional through-and-out rate" (RTOR) to deliver power across the MISO/SPP, for its non-MISO load, AECC faced the potential to pay the much higher point-to-point (PTP) rate for nearly 300 MW of its load, which would have cost AECC millions of dollars annually.

The need to mitigate these increased costs, which result directly from the seam, resulted in AECC (working with EAI, MISO, SPP and SWEPCO) to restructure a portion of its transmission transactions via a "pseudo-tie", which is now in place pursuant to a MISO Tariff waiver approved by FERC in Docket No. ER14-684, through which certain AECC loads that are physically located within SPP are served as network loads (rather than PTP transmission service) within MISO South. At present, about 250 MW of AECC Member peak load is transferred in this manner. The loads at these specified delivery points are expected to grow to almost 300 MW by year 2020. The charts within this section assumed the present pseudo-tie arrangements will remain in place indefinitely, an option that was afforded AECC (and similarly-situated parties) by a FERC decision that converted the one-off solution afforded to AECC in its pseudo-tie docket to a more global solution. *See* FERC Docket No. ER15-1745.

To maintain an adequate level of generation reliability, AECC plans for an installed reserve margin of 15 %, and secures firm capacity to meet the load plus transmission losses and required reserves.[28] [29] Applying the AECC base case load growth forecast while assuming no capacity retirements or significant capacity impairments prior to year 2027, Figure 10 shows the resultant AECC *overall* annual firm capacity balance. An existing PPA expires in May of year 2020, creating the downward step observed in that year. The two generating units at White Bluff are tentatively assumed to be retired in 2027 and 2028, respectively, resulting in the overall AECC capacity deficiency shown in year 2028. The annual numerical values associated with this projection are shown within Appendix A.

Figure 10



[28] SPP requires a 12 % Capacity Margin, which mathematically translates to an equivalent reserve margin of 13.64 %; Because SPP measures achievement of the Capacity Margin requirement based on *actual* peak load (i.e., 'after the fact'), it is considered prudent to be able to cover peak load at least 1.5 % higher than projected for normal summer conditions, which translates to a 15% planning reserve margin.
MISO employs a somewhat different methodology, which translates to a reserve margin of between 14 % and 15 %.

[29] The costs of *falling below* a required minimum installed reserve margin, including direct costs such as replacement power costs and possible punitive costs, as well as the reputational and possible further regulatory impacts, are generally much higher than the incurred costs of experiencing or maintaining a comparable MW *above* the minimum reserve margin.

Figure 11 adds the high load growth forecast and low load growth forecast to this perspective. Under the *high band load growth forecast*, AECC would have no *overall* remaining surplus as early as year 2022. Under the *low band load growth forecast*, AECC would have an *overall* capacity surplus until significant capacity retirement(s) were to occur. Assuming both White Bluff units are fully retired by 2028, an overall AECC capacity shortage would occur in that year even under the low band load growth forecast.

Figure 11

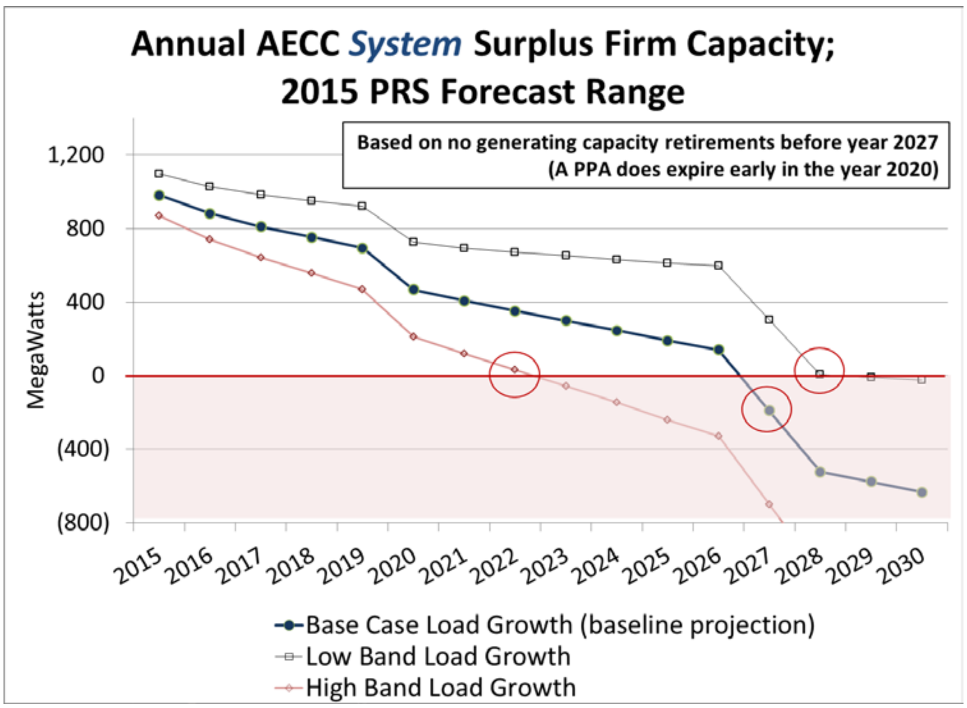
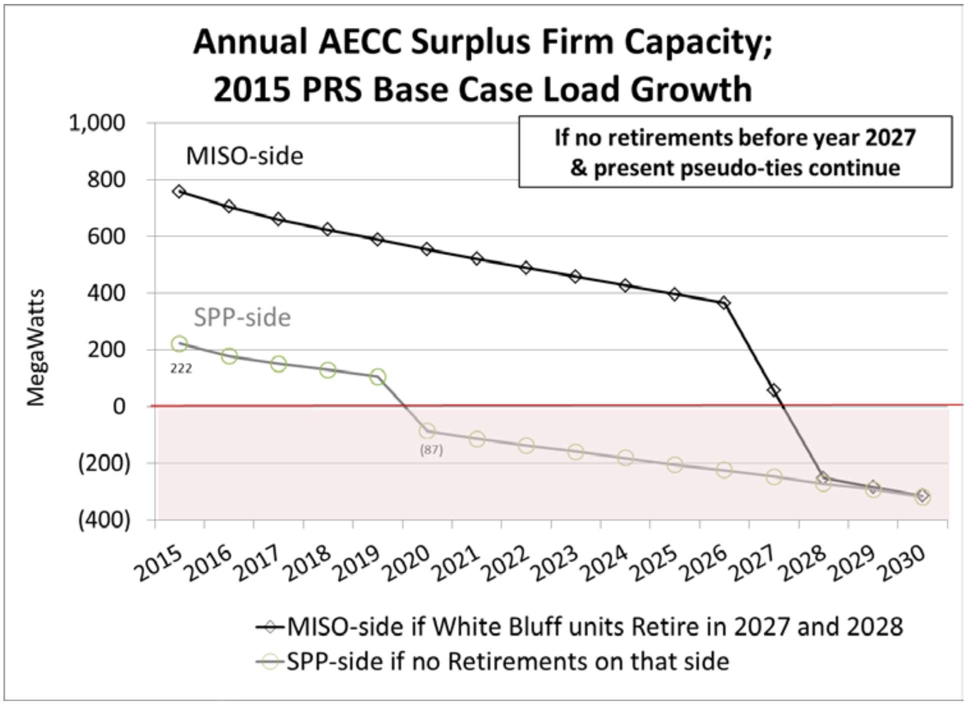


Figure 12 shows the annual AECC firm capacity situation within each RTO footprint for the baseline projection. In the year 2020, the MISO-side of the AECC system shows a 554 MW surplus, while the SPP-side shows an 87 MW capacity deficit.

Figure 12



Prior to elimination of the seam—which is AECC's preference, focus and desired long-term result—one possibility to address the imbalance between MISO and SPP for AECC's load and generation would be to increase the amount of SPP-side load pseudo-tied into MISO. However, the following considerations must also be weighed:

1) This would increase the amount of load for which AECC would be required to purchase network transmission service from both the SPP and MISO RTOs
2) In order to support the pseudo-tie, whether additional transmission facilities might have to be constructed, which—if required to be funded by AECC—would increase the overall cost to AECC's Members;
3) At the future point in time when AECC has no remaining surplus as a system, the economic value of the pseudo-tie load is diminished, since AECC would need to obtain firm capacity regardless, and pseudo-tied load will no longer defer that cost

4) The perpetuation of forcing AECC, to a very large degree, to serve its Members on an RTO-specific basis, rather than a statewide basis, which would affect AECC's ability to achieve an overall least-cost dispatch of AECC resources; the resources for which all of AECC's Members paid.

Figure 13 shows the AECC SPP-side capacity situation for the banded load growth range. Under the low band load growth forecast, a miniscule surplus would exist on the SPP-side in year 2020, while under the high band growth forecast, the SPP-side capacity deficiency in 2020 would be about 187 MW.

Figure 13

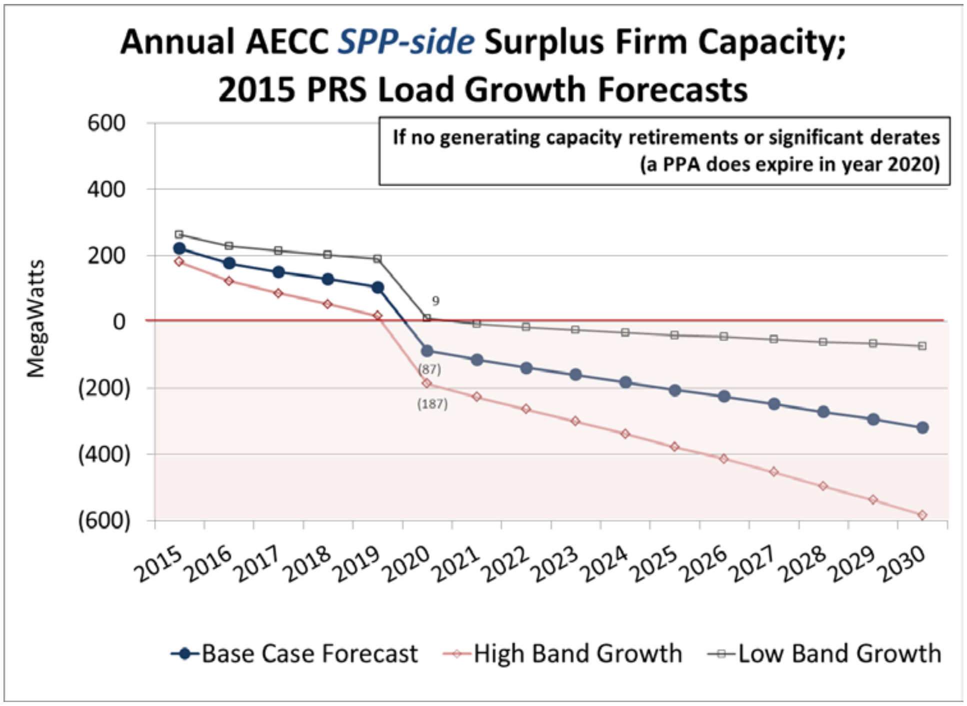
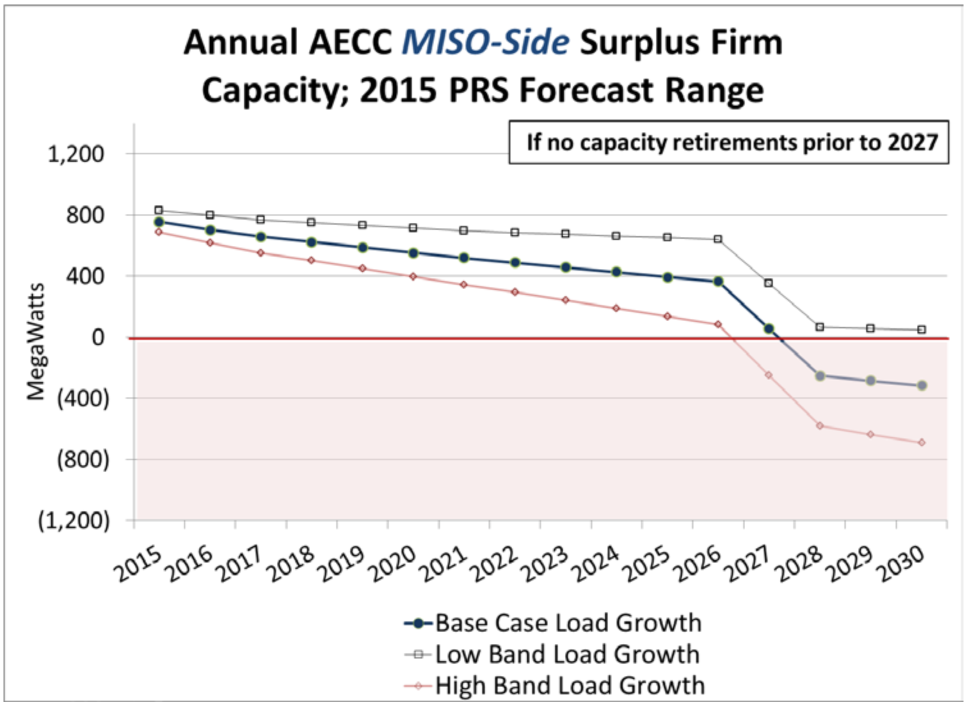


Figure 14 shows the MISO-side capacity situation across the banded load growth range. Across virtually the entire load forecast growth range, AECC would experience a capacity deficiency on the MISO side (which is the side that includes the White Bluff units) by the year 2028. This would be in addition to the earlier-projected AECC capacity deficiencies on the SPP side.

Figure 14



Energy Needs[30]

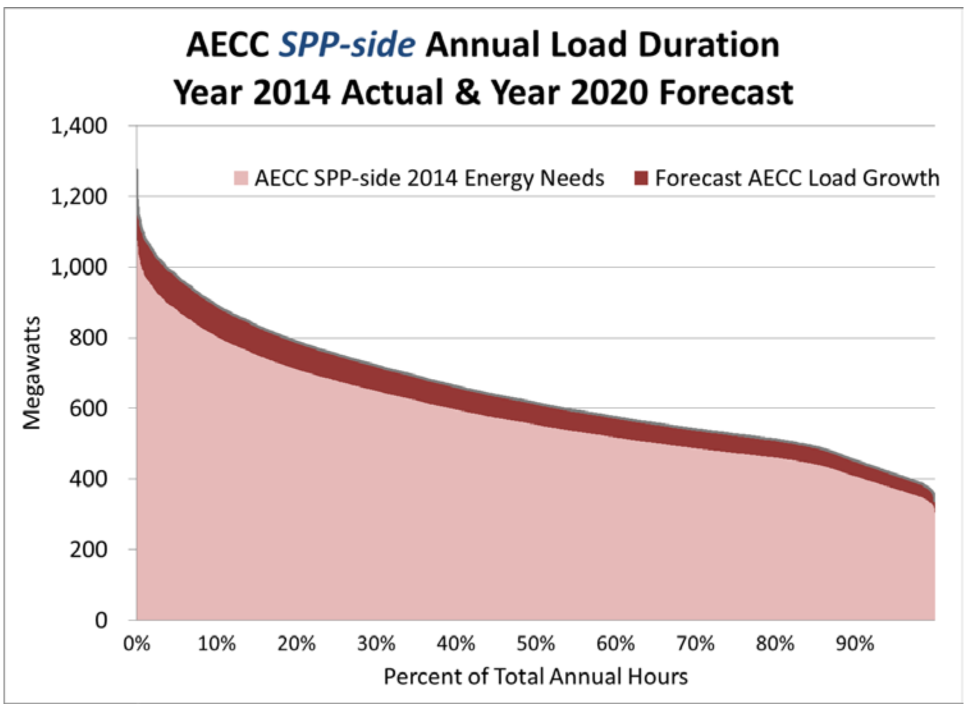
One of the limitations presented by the RTO seam within Arkansas is that the MISO and SPP energy markets are largely independent of one another on a daily and hourly basis. The RTOs are gradually implementing market-to-market processes, although these processes will not directly involve transactions by market participants. For the foreseeable future, a market participant such as AECC intending to serve load on one side of the seam

[30] The energy growth rates for firm load are forecast to be similar to the demand growth for these loads. AECC's load forecast includes no new AECC-managed interruptible loads. Under AECC's interruptible customer (IC) tariff, the number of hours required of a new customer wishing to use the IC tariff would be 993 hours. It is uncertain whether there are customers willing to accept such a high number of hours of interruption for the same rate that other customers experience far fewer interruptions.

with generation on the other side of the seam will be required to purchase transmission capacity, which is not practical in real-time or on a one day-ahead basis. As a result, in practical terms, AECC must serve its Members on each side of the RTO seam separately, for the foreseeable future.

Looking first at AECC Member cooperative loads and resources within the SPP RTO footprint, Figure 15 shows Member loads for a recent 12-month period arranged in order from highest to lowest hourly values.[31] AECC Member SPP-side loads exceeded 800 MW during about 15 % of the annual hours. Also shown on the figure is an approximation of the AECC year 2020 loads. In this depiction, the year 2020 hourly loads are about 12 % greater than the recent 12 month actual values.

Figure 15



[31] The actual data was for the 12 month period of March 2014 through February of 2015.

To provide a perspective on the ability of AECC's generating resources and PPAs to serve Member loads on the SPP side of the Arkansas seam, Figure 16 presents a visual "stacking" of generation resources against the approximate year 2020 load duration curve (from Figure 15). Shown at the bottom of the stack are the Member loads which are pseudo-tied from the SPP to MISO (shown in grey), which represent about 28 % of AECC's SPP-side loads. The next resources of the stack are the existing intermittent hydroelectric and wind resources (including the new 2016 and 2017 wind plants), which will collectively serve approximately 35 % of the SPP-side energy needs in the year 2020. Next, the coal-fueled plants at Flint Creek and Turk are shown to meet about 32 % of the overall energy need, and the NG fueled plants at could potentially serve much of the remaining AECC SPP-side energy need.

Figure 16

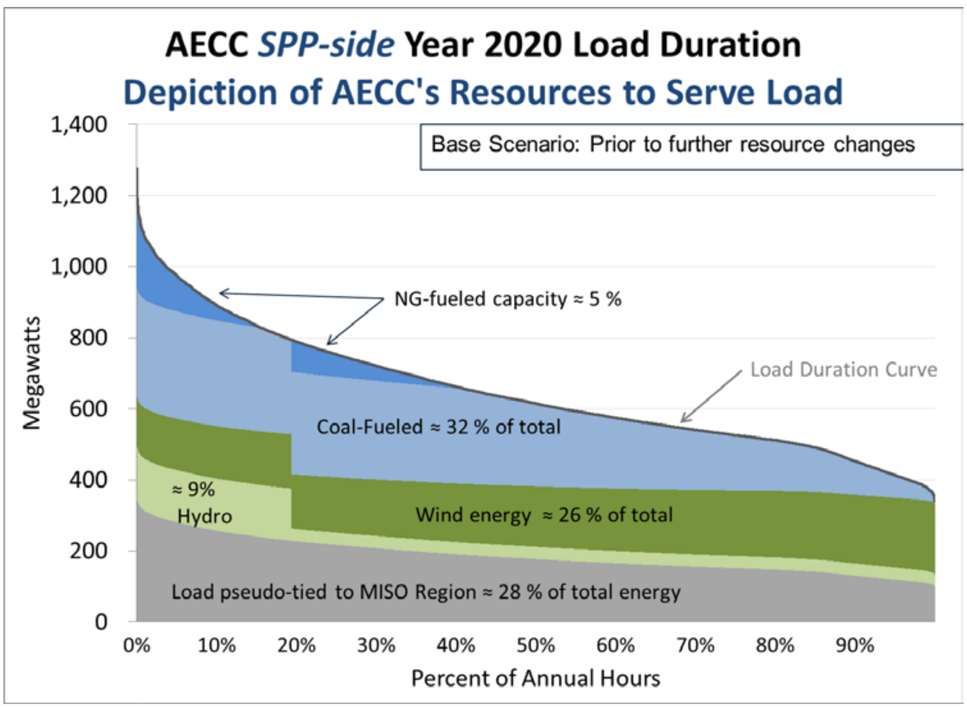
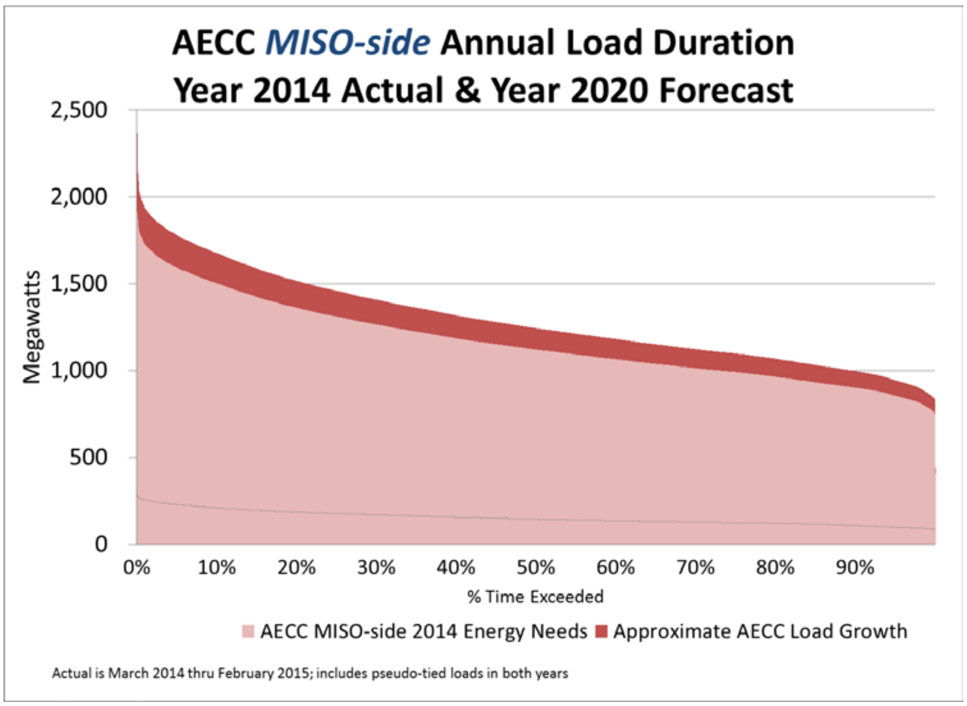


Figure 17 shows the MISO-side load duration format for a recent 12 month time period.[32] It can be observed, for example, that AECC Member MISO-side loads exceeded 1,500 MW during about 15 % of the annual hours. Also shown on Figure 17 is an approximation of the AECC year 2020 loads. In this depiction, the year 2020 hourly loads are about 10 % greater than the recent actual values.

Figure 17

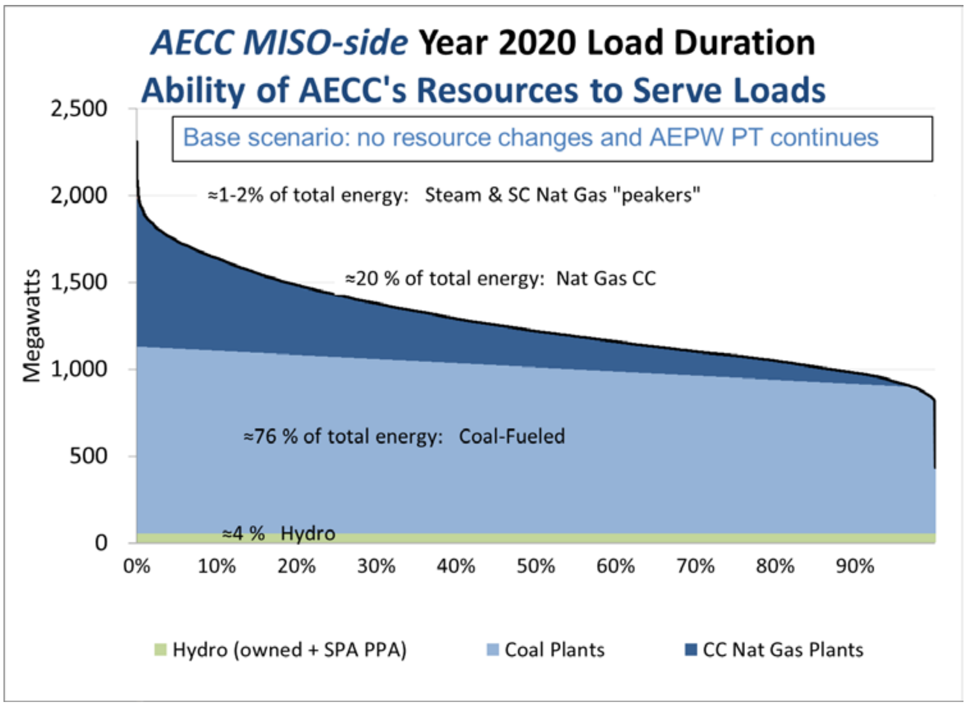


To illustrate the ability of AECC's firm resources to serve Member loads within

[32] The actual data was for the 12 month period of March 2014 through February of 2015;

the MISO footprint, Figure 18 presents a stacking of generation resources against the approximate year 2020 load duration curve. This figure depicts that AECC could meet virtually all of the depicted year 2020 MISO-side energy needs with the existing hydroelectric, coal-fueled and NGCC resources situated on that side of the RTO seam. This analysis assumes a maximum annual capacity factor of 80 % at the coal-fueled plants, and virtually all of this energy would be needed to serve AECC loads in year 2020. [33]

Figure 18



Energy Efficiency and Demand Response Programs

AECC and its 17 Members have a long and successful history of including a demand side planning philosophy to assist in the provision of a reliable and economic supply of electricity. AECC's demand-side programs are included in all of AECC's and

[33] Numerous other methods exist to define baseload capacity. The 80 % applied to AECC's coal-fueled capacity is intended to reflect an average capacity factor that could be expected from the coal-fueled generation units.

its Members' planning, and will continue to provide additional energy efficiency and capacity savings in future years. [34]

Energy Efficiency Programs

AECC and its Members presently undertake a broad range of ongoing programs and projects to improve end-use energy efficiency. The following discussion summarizes active energy efficiency programs, services and educational resources available to member consumers in 2014.

New HELP Program Launched in 2014 In 2014, former employees of the Clinton Foundation Climate Initiative and energy efficiency leaders from several Members created an on-bill finance and repayment program called Home Energy Lending Program or HELP. Electric cooperative members who own inefficient homes with high utility bills may qualify for HELP assistance from participating distribution cooperatives. Energy efficiency retrofit work will be performed through an approved contractor network managed by an Arkansas-based residential energy efficiency company.

Residential Energy Audits AECC and its Members offer varying energy audit programs. Some offer walk-through and checklist inspections. Others offer comprehensive programs that include blower-door tests and duct-blaster leakage tests to quantify air infiltration. Many incorporate infrared thermography for visual thermal analysis and air infiltration confirmation. For additional visual reference, some may incorporate a theatrical fog device that is used in conjunction with the duct-blaster. Audit results and a prescriptive list of retrofit or repairs are provided to each participating homeowner.

Comprehensive Training and Certification AECC is committed to training, education and information. Staying on the cutting edge of building science technology and providing the proper training to electric distribution cooperative representatives remains an annual goal.

Commercial & Industrial Energy Efficiency and Audits The AECC Economic Development department facilitates third-party audits on behalf of the electric distribution cooperatives.
These third-party audits are designed to take a comprehensive look at the facility and make recommendations for improved energy efficiency measures.

[34] A more detailed description of AECC and the Members' energy efficiency and demand response activities is publicly-available online at www.arkansas.gov/PSC using the Docket No. 08-061-RP. The most recent document in that matter is AECC and the Members' Annual Energy Efficiency Report, which was submitted to the Commission on April 15, 2015.

Energy Efficiency Information & Communications *Arkansas Living* magazine and the Electric Cooperatives of Arkansas continued social media efforts in 2014 with energy efficiency messages being a focal point for messaging. Also, a wide array of energy efficiency tools, tips and resources are available online.

Marathon Energy Efficient Water Heaters All of the AECC electric distribution cooperatives promote use of a product line of energy efficient electric water heaters. Some Arkansas electric distribution cooperatives install a load control device as part of their ongoing demand response program.

General Electric Geo-Spring Hybrid Heat Pump Water Heater The Members promote a line of high efficiency hybrid electric water heaters. The units are designed to provide the same hot water homeowners are accustomed to, but requires only about half the energy to produce it.

Air Source & Geothermal Heat Pump Information All of the AECC Members promote use of air-source and geothermal heat pumps. Cooperatives offer information with brochure marketing collateral and personal one-on-one consultation with members.

Compact Fluorescent Lamp Programs All of the AECC Members promote the use of compact fluorescent lighting. Some offer sale of the product from their local and district offices. Some Members have implemented creative promotional and distribution campaigns.

LED Lamp Technology All of the AECC distribution cooperatives are promoting the emergence of LED lighting technology. Many have LEDs installed in test applications.

Building Guidelines for Energy Efficiency Booklet The Electric Cooperatives of Arkansas have published revised editions of this booklet in 1997 and over 30,000 copies have been distributed thus far.

Arkansas Living Magazine The Electric Cooperatives of Arkansas promote energy efficiency practices, measures, components and appliances via the cooperatives' statewide magazine, *Arkansas Living*, which is distributed to approximately 383,000 readers each month.

Smart Energy Tips Podcasts The Smart Energy Tips podcast provides fact-based building science to assist cooperative members with comfort and high bill problems.

ERC Loan Programs Energy Resource Conservation (ERC) loans are available from participating electric distribution cooperatives at low interest rates. ERC loans can be used to finance energy-saving devices and heating, ventilation and air-conditioning systems. Loans are available for a wide variety of energy efficiency improvements.

The Magic of Energy Efficiency Educational Magic Show The Electric Cooperatives of Arkansas offer a very successful Making Accidents Disappear program to school age children. The program has stressed electrical safety to millions of children in Arkansas and across the United States since 2003.

Energy Efficient Home Makeover Project AECC has customized a television program format to create an ongoing effort to promote home energy efficiency "makeovers."

Energy Efficiency Educational Trailer In 2013, AECC developed a mobile energy efficiency educational medium. The creative interior parallels the *Building Guidelines for Energy Efficiency* booklet.

Energy Efficiency Arkansas Program In Order No. 12 issued in Docket No. 06-004-R, the Arkansas Public Service Commission (the "Commission") called for utilities to take actions jointly with the Arkansas Economic Development Commission-Energy Office to design, construct, and fund a statewide education program that has a consistent message promoting the efficient use of electricity and natural gas. AECC has actively participated in this program since 2007.

Demand Response Programs

AECC and the 17 Members cooperatives are national leaders in demand response programs, having achieved approximately 775 MW of savings from demand response. This represents approximately 33 % of AECC's potential on-peak demand (firm load plus interruptible load). Based on a 2009 report, AECC and the Member Cooperatives' demand response efforts provide approximately one half of the total demand response within the entire SPP RTO footprint.[35]

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[35] A January 2009 publication titled *Retail Demand Response in Southwest Power Pool* determined that the 30 load-serving entities within SPP have a potential demand response of 1,552 MW. The SPP Report further states that: *"Arkansas accounts for ~50% of the DR [demand response] resources in the SPP footprint; these DR resources are primarily managed by [AECC and the Members]*." From: Bharvirkar, Ranjit; Heffner, Grayson; and Goldman, Charles, *Retail Demand Response in Southwest Power Pool*, Ernest Orlando Lawrence Berkeley National Laboratory, prepared for the Office of Electricity Delivery and Energy Reliability, Permitting, Siting, and Analysis, U.S. Department of Energy, 2009, (v)

Successful demand response programs have been achieved through many years of steady effort by AECC and its Members. Initially, certain Members used clock switches to control water heaters and irrigation loads. Advanced System Control and Data Acquisition (SCADA) systems were installed to provide the Members with more sophisticated and timely load data. Participating commercial and industrial (C&I) retail consumers are now provided with current, minute-by-minute, AECC load data via the internet.

To encourage demand response, the Electric Cooperatives have maintained rates and charges that closely adhere to their cost of service. These rates and charges provide the economic incentives for retail consumers to voluntarily participate in demand response.[36]

All of the Electric Cooperatives' demand response programs fall within three basic categories. These categories are summarized on Table 6.

Table 6
Demand Response Impact of AECCs Existing Programs in 2015

D.R. Category	**Demand Response Program**	**Achieved Demand Response**
1	Member Coop Direct Control	135 MW
2	Member Coop C&I Voluntary Peak Avoidance	110 MW
3	Member Coop Voltage Reduction	10 MW
4	AECC Controlled Industrial Loads	520 MW
	Total	**775 MW**

Category 1 - Member Cooperative Direct Control: In Category 1 demand response (member cooperative direct control), each participating member cooperative receives current AECC system load data. This load data allows the Members to evaluate and determine when AECC summer peaks are imminent. Using this data, the Members control participating retail loads, thus reducing the member cooperative's contribution to AECC's summer peaks. The economic benefit to the Members is a reduced wholesale electric bill, allowing the Member to reduce rates to participating retail customer members. Through various surveys, AECC has identified approximately 135 MW of Member direct demand

[36] The report mentioned within the previous footnote stated: *"The very high penetration levels of demand response in Arkansas cooperatives can be traced to three factors: (i) long-term stability in the type of price signals sent; and (ii) sufficient bill savings potential to gain active customer participation and interest; and (iii) avoiding over-payment of incentives, so there is sufficient savings for participants, non-participants, and utility management."*

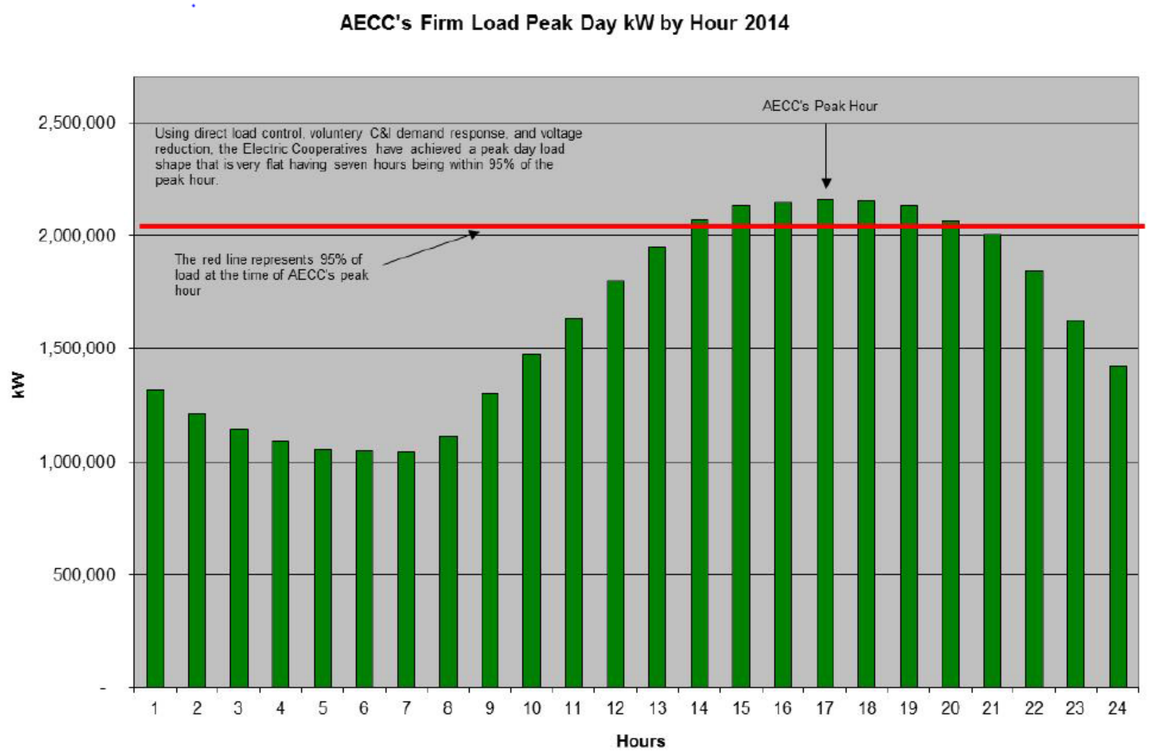
response within Category 1. This is achieved through the installation of approximately 40,000 load control switches by nine Members. These switches are primarily installed on irrigation water pumping, air-conditioning, and water heating loads. AECC believes that these switches effectively remove approximately 135 MW from AECC's summer peaks.

Category 2 - C&I Voluntary Peak Avoidance: In Category 2 demand response (C&I Voluntary Peak Avoidance), each participating member cooperative offers a rate incentive to participating C&I consumers. This incentive encourages the consumer to voluntarily reduce its demand during periods when AECC summer peaks are imminent.

Category 3 - Voltage Reduction: In Category 3 demand response (Voltage Reduction), over the past few years, AECC's Members have used the method of voltage reduction as a means to further reduce peak demand. In a simple resistive circuit, a reduction in the voltage across the resistance will result in a reduction in the power dissipated by the circuit. Several Members have had success with this technique and have effectively reduced their demand at the time of AECC's firm peak by approximately 10 MW when applied to a portion of their systems.

Effect of Combining Category 1, 2 & 3 Demand Response on AECC's Summer Peak Day Load Shape: The Category 1, 2 & 3 demand response programs (switch, voluntary C&I peak avoidance, and voltage reduction) have greatly flattened AECC's summer peak day load shape(s). As shown on Figure 19, during AECC's 2014 summer peak day, there were seven hours that fell within 95% of its firm peak hour. AECC estimates that without Category 1, 2 & 3 demand responses, only three hours would be within 95 % of its peak hour.

Figure 19



The estimated effect that Category 1, 2 & 3 demand response had on AECC's 2014 peak day load shape may be observed on Figure 20. The green bars in this figure represent AECC's actual 2014 peak day hourly load shapes, and the red line represents an estimated peak day load shape if Category 1, 2 & 3 demand response were not present.

Figure 20

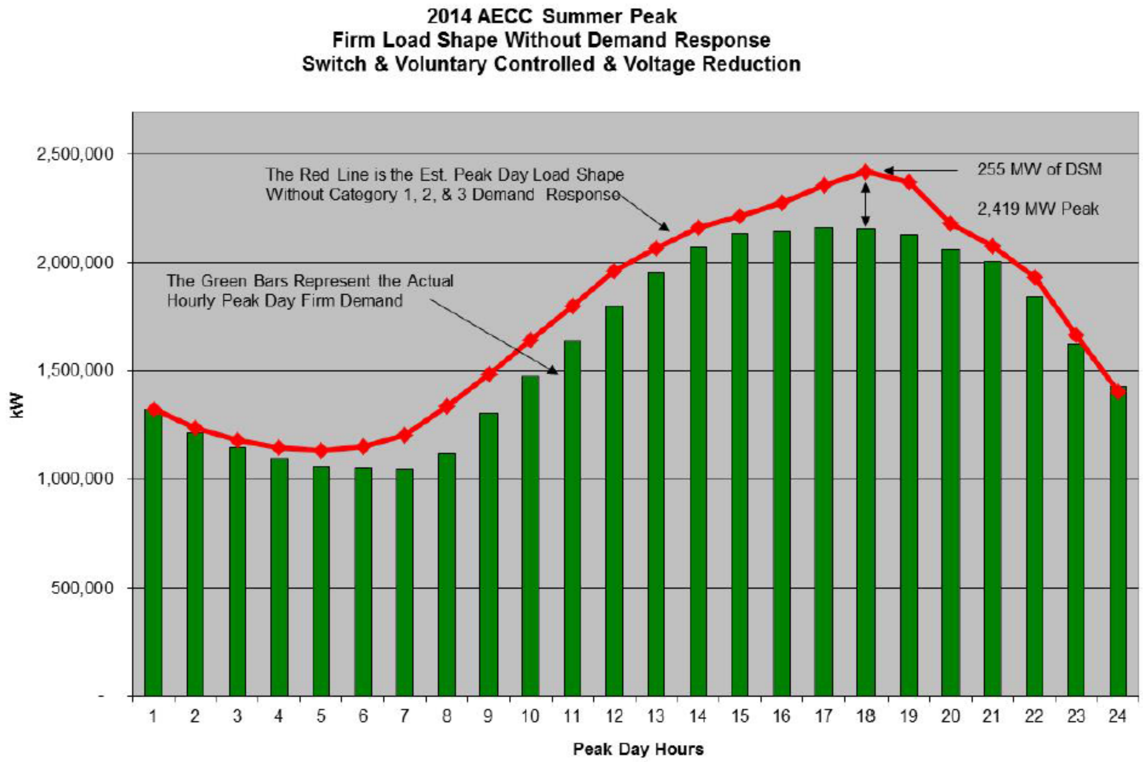
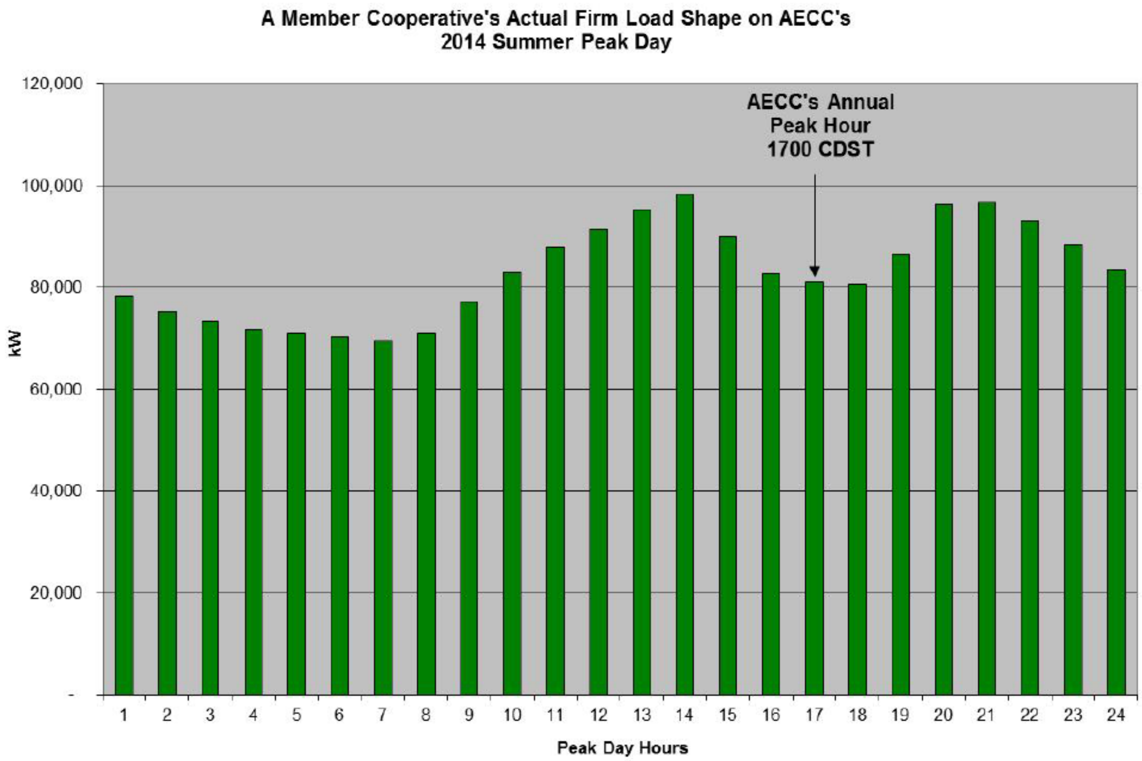


Figure 21 illustrates the typical effect of Category 1 and 2 demand response on one Member's actual twenty-four hour load shape. Using Category 1 and 2 demand response, this Member dramatically reduced its load during the hours 1500 through 1900 CDST. These hours normally represent AECC's summer peak period.

Figure 21

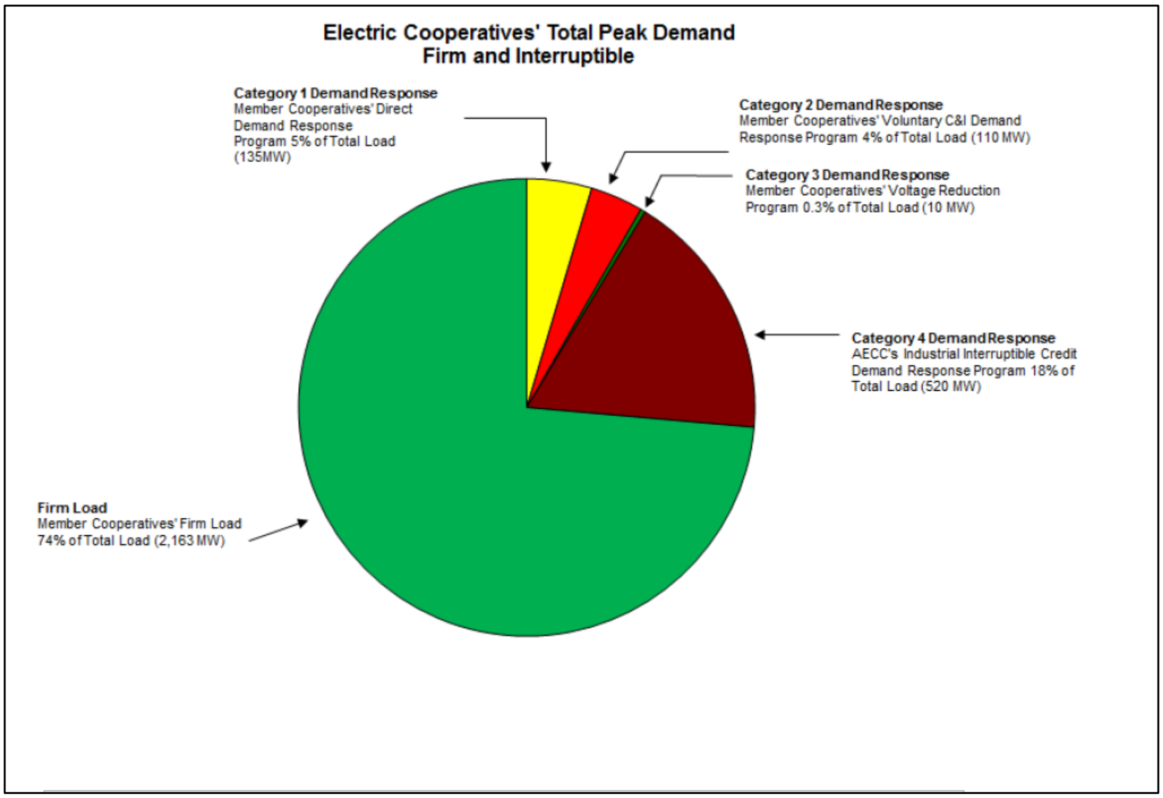


Category 4 - AECC-Controlled Industrial Loads: Category 4 demand response represents the direct control by AECC of participating retail industrial consumers whose loads are 5 MW or greater. Under Category 4 demand response, eight retail industrial consumers have voluntarily agreed to receive service under a member cooperative's extension of AECC's Interruptible Credit Rider. These eight industrial consumers have a combined potential maximum demand of approximately 520 MW. When interrupting participating industrial consumers, AECC attempts to lessen the impact of the interruption by locating and offering any "buy-through" energy that is available on the wholesale market.

Total Impact of Category 1, 2, 3 & 4 Demand Response: Figure 22 demonstrates Categories 1, 2, 3 & 4 demand response, as a ratio of total system potential demand (the AECC Members' potential demand, both firm and interruptible).

Impact on Long Term Capacity Needs and Reductions in Fixed Costs: The AECC and Members' demand response programs currently allow AECC to avoid approximately 890 MW of generation peaking capacity. This number is derived from 775 MW of demand response plus an additional 115 MW of capacity reserves (based on a 15% reserve margin). AECC's generation planning department estimates that the investment cost of newly constructed peaking capacity would be approximately $800 per kW.[37] If AECC were to acquire 890 MW on additional peaking capacity at $800 per kW it would result in approximately $710 million of new investment along with its associated cost of ownership, operation, and maintenance. This number would not include any necessary transmission investment to interconnect the capacity.

Figure 22



Impact on the Cost of Energy: With Category 4 demand response, AECC may interrupt up to one-half of the number of hours stated in the interruptible blocks for any reason. Reducing AECC's load during times when the cost of fuel and purchased energy is greatest, AECC has avoided several million dollars in incremental fuel and purchased energy costs, which has directly reduced the necessary collection of these costs under AECC's Fuel and Purchased Energy Rider.

[37] Based on what the U.S. EIA refers to as 'advanced technology' combustion turbine (CT) generation unit

Industrial Expansion and Growth: Demand response is essential in attracting and maintaining industry in the Electric Cooperatives' service territory. Of the eight industries currently participating in Category 4 demand response, six were established after Category 4 demand response was initially made available.

Future Innovation - Automated Metering Infrastructure: Currently, certain Members are exploring the advantages of Advanced Metering Infrastructure (AMI) systems and how these systems might be used to achieve additional efficient demand response.

Supply Side Alternatives

Methodologies and Tools for Analysis

Consistent with AECC's mission to maintain an affordable supply of electricity for our Members AECC evaluates supply alternatives by comparing the revenue requirements of each alternative. The phrase "revenue requirements" is a ratemaking term that refers to a calculation of the revenues needed from AECC's Members to recover all of the operating costs and capital-related costs of providing power supply in both the near-term and the long-term horizon. These costs include the repayment of principal and interest on loans to support capital investment, as well as fuel and non-fuel operating expenses. AECC compares the resulting revenue requirements for each alternative to ascertain the least-cost opportunities.

In considering supply alternatives AECC primarily conducts three types of analysis: 1) indicative comparative analysis, which is later typically followed up with 2) detailed comparative analysis and 3) corporate-level financial analysis on an as-needed basis for decision-making purposes. The process is on one hand sequential as described here, but in a broader ongoing context is continually iterative as specific opportunities and new information is identified and included within the evaluations.

Comparative analysis applies worksheet-based tools to quantify and compare the incremental revenue requirements [38] and other impacts of the resource alternatives, with line items for the affected items, and includes comparisons on a per kW and per MWh basis. This process differentiates resource alternatives based on both annualized revenue

[38] In contrast to 'embedded costs' which are not impacted by future decisions. An example of embedded costs are those deriving from a previous capital investment, since these costs need to be recovered once the investment is made, and are not impacted by future decisions.

requirements and the overall net present value (NPV) for the life of the each resource alternative. The annualized analysis often applies a levelized value for the capital-related costs. The operational capacity factors and O&M costs are approximated for each resource alternative.

As part of the comparative analysis, summary formats and charts are applied, such as break-even points for the resource alternatives across a range of capacity factors, or based on which year the alternatives are placed in service. The results can be applied to illustrate the sensitivity of the incremental revenue requirements to key input assumptions such as fuel prices. The indicative comparative analysis is often applied as a screening tool to determine which options merit a more detailed review. In some situations, this will involve a multi-step screening process.

When AECC conducts corporate modeling, a forecast of aggregated economic and financial metrics is developed, including a detailed simulation of generation dispatch to meet loads. Various resource alternatives or portfolios can be compared to check the financial results and further refine which are the lowest cost alternatives. One good reason to rely on the corporate modeling approach is to carefully consider potential cost differences based on the consideration of a plant that being relied on for its long-term capacity, even when the capacity in the initial years is greater than is needed at that time.

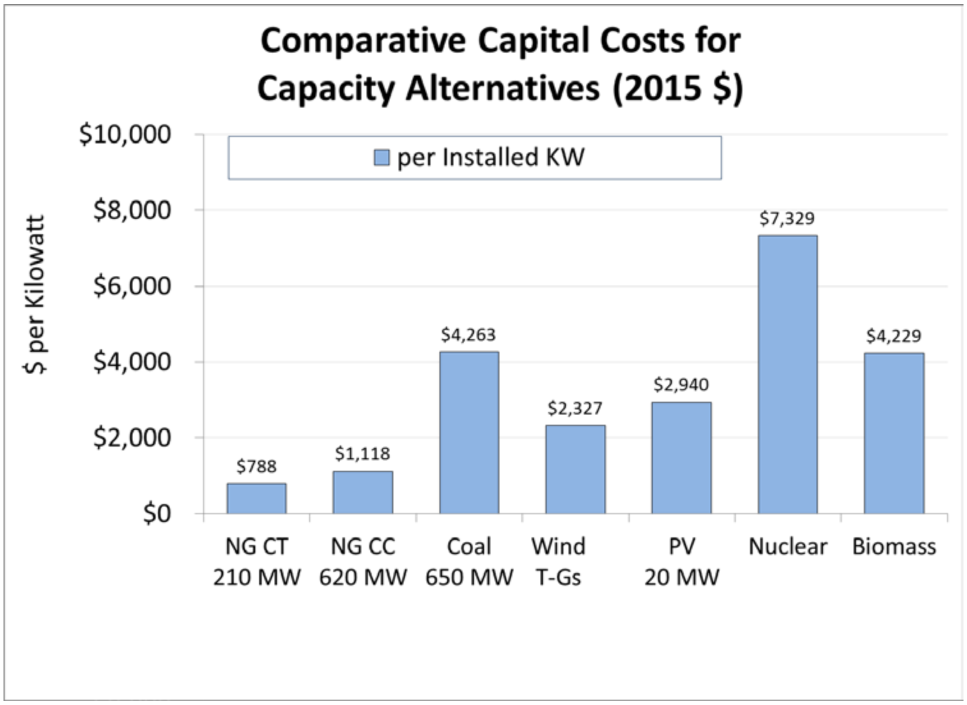
AECC also works with a consultant, when needed, to apply stochastic (“Monte Carlo”) resource dispatch analysis, which can help further refine the economic evaluation of resource alternatives. The stochastic analysis is applied to properly vet the potential for variations in load patterns, fuel prices, plant outages and possibly other parameters, such as variable generation output, to more fully and accurately evaluate and compare alternatives.

<u>Capital Costs and Operational Characteristics</u>

The electric utility industry is capital intensive, both from the perspective of traditional energy supply sources and the expanding development of non-fossil supply sources. Traditionally, the firm capacity alternatives have been divided into those exhibiting either: a) relatively high capital costs and low operating costs (with these alternatives typically considered for baseload operation); or b) those with comparatively lower capital costs and higher operating costs, typically considered for intermediate or “peaking”” capacity factor operation.

Estimates for capital costs, as well as fixed and variable operation and maintenance (O&M) costs and heat rate efficiencies for the technologies applied within the indicative analysis described above were obtained from a collection of U.S. EIA publications.[39] The EIA reports represent a data source which applies a consistent methodology and underlying technical and costs assumptions for the various alternatives. The estimated installed capital cost of various resource alternatives are shown in Figure 23. For comparative purposes, this graphic shows the estimated capital cost per kilowatt of installed capacity, prior to consideration of firm capacity as further discussed below.

Figure 23



A driving factor in the underlying economics of the capacity alternatives is the amount of firm capacity credit that the RTOs will give AECC, per installed kilowatt. The fossil-fueled resource alternatives will generally be credited approximately 95 % of the tested or nominal capacity, based on RTO-specified test criteria, outage history, and any possibly specific fuel limitations. [40] Similar to run-of-river hydroelectric alternatives, the solar photovoltaic (PV) and wind-powered resources are credited lower percentages of the nominal installed capacity by the RTOs, due to the intermittent output of these resources.[41]

[39] Either the *Annual Energy Outlook* (dated April 2015), or the *Updated Capital Cost Estimates for Utility Scale Electricity* (dated April 2013)

[40] For example, within MISO, despite the relatively advanced age of AECC's fossil-fueled fleet, AECC presently receives firm capacity credit for 93 % of the tested fossil capability.

[41] For example, SPP requires for wind and solar facilities that the firm capacity reflect the hourly net power output value that can be expected from the facility 60% of the time during the top 3% of load hours for each

AECC is tracking and participating in discussion and working groups focused on these topics within both RTOs' stakeholder processes, and elsewhere, in order to be continually aware of changes that might occur, particularly as those might result from increased operational history at facilities being placed in service.

When additional firm capacity is needed to meet RTO reserve requirements, as will be the case for AECC in the year 2020, it is important to compare all resource alternatives that could meet the need based on economics. One approach would be to compare the costs of obtaining a specific amount of firm MW from each of several technologies. For the intermittent resources, it can be necessary to install between 3 and 7 MW of capacity for each firm MW achieved.[42] [43]

Another approach regarding the intermittent resources is to include battery storage (or other possible storage technologies) as needed to achieve a needed amount of firm capacity. An estimation of overall capital costs using this approach is shown within the middle bars of Figure 24, based on a recent publicized price for a lithium-ion battery system.[44]

One additional approach is to pair or supplement the intermittent resources with conventional capacity to achieve a comparable amount of firm capacity. Approximate comparable capital costs per KW of firm capacity are included on Figure 24 when pairing wind or solar PV resources with NGCT capacity.[45] Pairing or supplementing intermittent

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month of each year for the evaluation period (paraphrasing from SPP Criteria section 12.5.1.5.g); MISO applies an analytical approach which computes the collective Effective Load Carrying Capability (ELCC) of all the installed wind-powered plants (defined as "the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served"), and then allocating that amount across all the individual facilities based on the top 8 daily peak hours for each of the previous 7 years" (Appendix A of MISO Business Practice Manual 011)

[42] Based on a range of between 15 % and 35% of each installed MW being credited by the RTO as firm, and would be dependent on locational factors as impacting the energy production patterns

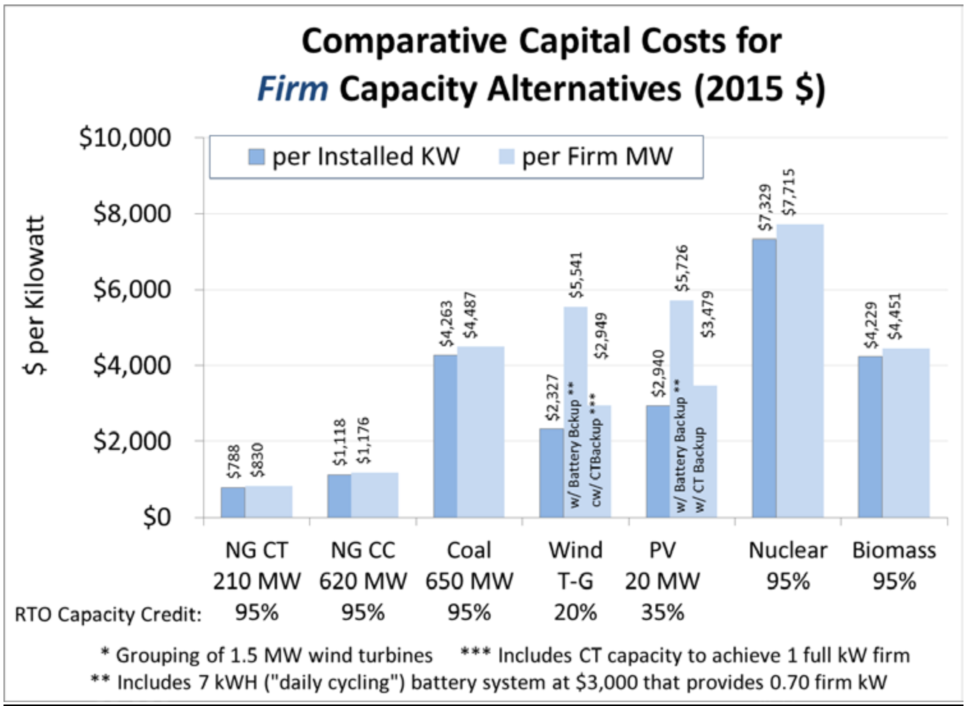
[43] Levelized costs for the firm and intermittent resources were not directly compared, as AECC agrees with the following comment within the *EIA Annual Energy Outlook 2015*: "The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE [levelized cost of energy] values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the [*Energy Outlook*] tables."

[44] *NRECA Tesla Energy Powerwall Technical Advisory (May 2015)* quotes a capital cost of $3,000 for a 7 KWH 'daily cycling' battery system from Tesla (does not include inverter or installation costs; it is implicitly assumed here that future reduction of the quoted cost would offset these costs)

[45] NGCT capacity is often studied for this purpose because it represents a relatively low $ per KW capital cost as typically pursued for "peaking duty" operation.

capacity such as wind-powered and solar PV with batteries, conventional CT capacity or other firm capacity reflects that the intermittent resources are inherently non-firm energy sources rather than firm capacity sources. AECC has added PPAs for 369 MW of installed wind-powered resources to our resource portfolio on the SPP side since 2012. How AECC has made this work in the RTO context is by adding low-investment cost peaking capacity to supplement or "firm up" the wind resources as a means of maintaining the required RTO reserve margins.

Figure 24

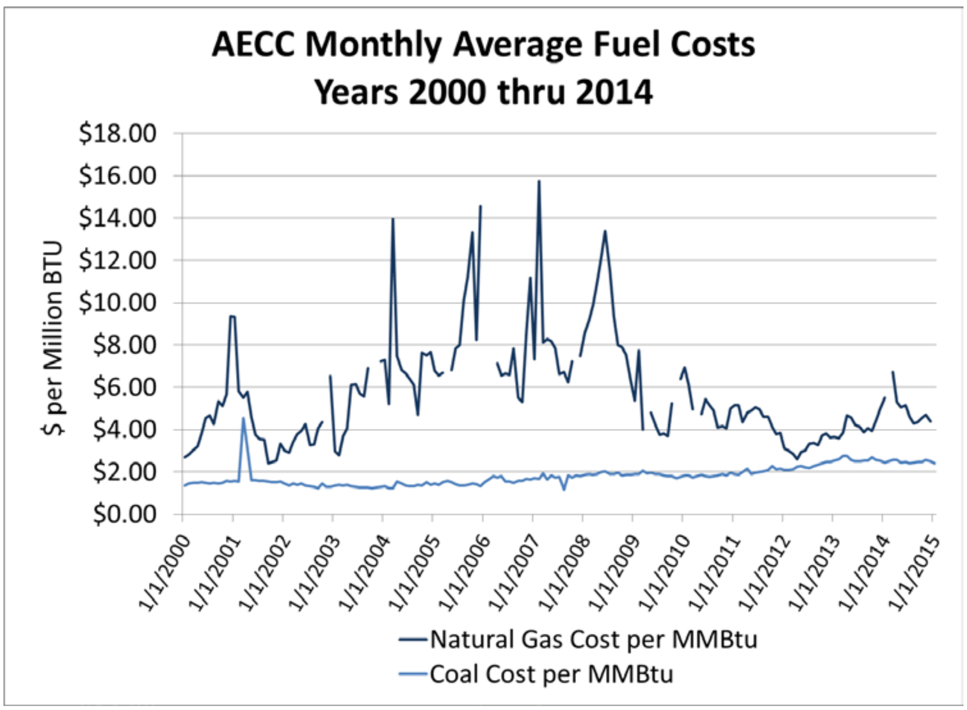


AECC is keeping abreast of the advancement of technologies that could cost-effectively improve the performance of future resources, as well as reduce emissions. For example, it is possible that cost-effective technology will be available to capture CO_2 emissions at new or existing fossil-fueled power plants within the 10 to 15 year upcoming timeframe. If so, AECC will be actively engaged in reviewing those options for cost-effectiveness.

Fuel Costs

Historical delivered costs for coal and natural gas for use in AECC's generation plants in years 2000 through 2014 are summarized on Figure 25. During this 15 year time period, the cost of AECC's purchased natural gas averaged $5.25 per Million BTU, and cost of AECC's purchased coal averaged $1.80 per Million BTU. Thus, AECC's natural gas cost averaged 190 % higher than coal cost per million BTU across the 15 year period (an average ratio of 2.9:1). Within the most recent five year period, natural gas costs moderated somewhat, such that AECC's natural gas costs averaged 1.9 times coal costs per Million BTU. As the graph depicts, natural gas costs are more volatile than coal costs, in several instances changing greatly from one month to the next.

Figure 25



Looking to future fuel costs, the U.S. EIA *Annual Energy Outlook* report includes projections of future energy prices. Figure 26 summarizes the US EIA April 2015 *Reference Case* (essentially base case) forecast for natural gas prices in future years, along with 15 years of historical prices, both reflecting the benchmark Henry Hub spot price. In constant 2013 dollars (before factoring in an underlying inflation rate), the 15 year average price for forecast for years 2016 through 2030 is $5.03 per Million BTU, which is lower than the 15 year historical average price of $5.85 (again, expressed in constant 2013 dollars). When including a future general inflation rate of 2.5 % per year, the US EIA average natural gas price for the upcoming 15 year period (2016-2030) is $6.48 per million Btu.

Figure 26

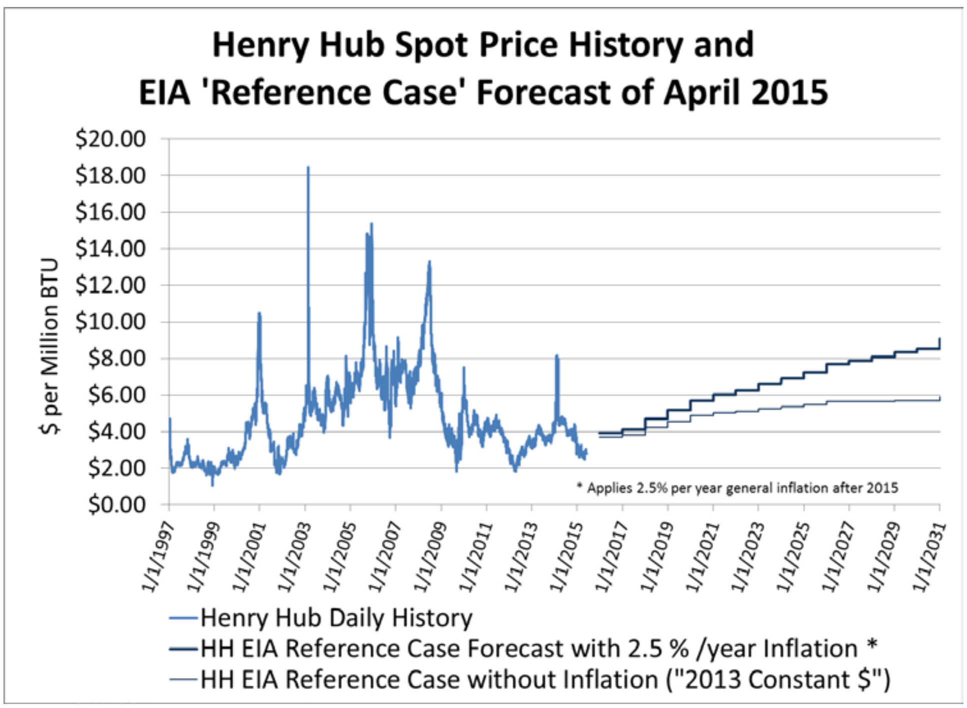
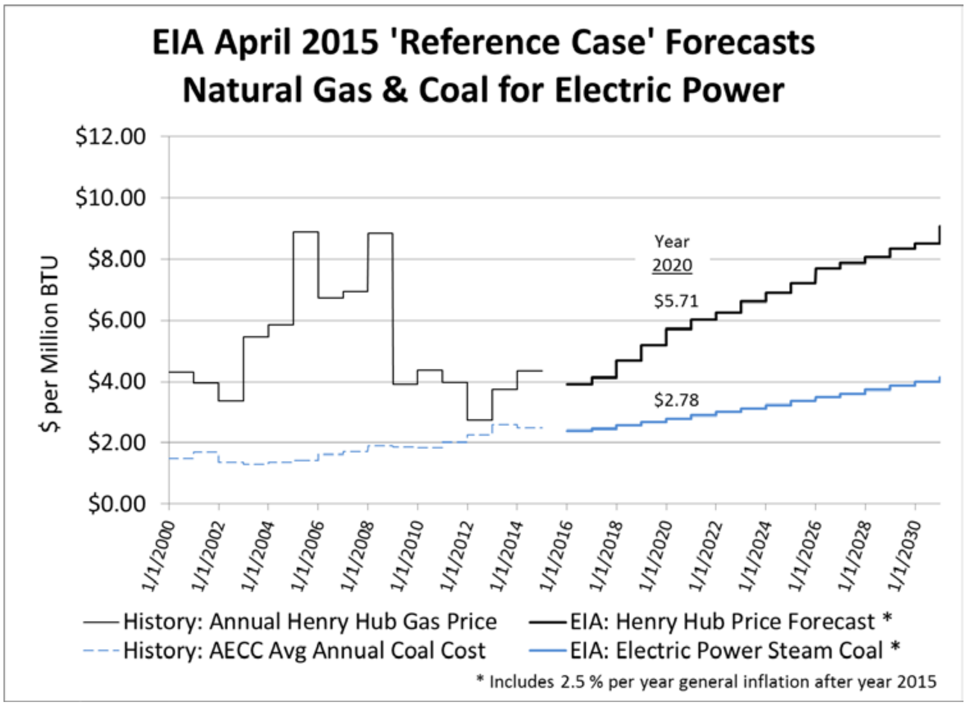


Figure 27 compares the EIA Reference Case forecasts for the Henry Hub natural gas price index and for price of coal for electric power production, along with the above described historical prices. The EIA Reference forecast predicts that coal prices will continue to be well below natural gas prices. For example, in the year 2020, the EIA Reference Case predicts the Natural Gas daily price index will be slightly more than double the U.S. average delivered coal price.

Figure 27



Indicative Comparison of Supply Alternatives

AECC recently conducted an indicative economic analysis comparing several resource alternatives on the SPP side of the AECC system. This analysis did not include the MISO side since AECC does not have an identified capacity need on the MISO side within the next 10 years.

The indicative analysis included a base case set of assumptions, supplemented by three sensitivity cases for which a specific assumption was altered to demonstrate the potential impact of that assumption. The indicative analysis approximated both the annualized and 30 year NPV revenue requirement impacts of obtaining 1 MW of firm capacity from each resource alternative.

Because this Resource Plan covers the reporting period of 2016 – 2019, it does not include new coal-fueled or nuclear alternatives so they were excluded from the indicative analysis. Given AECC is not presently aware of any opportunities for a "generic" biomass facility, this alternative was also excluded from the indicative analysis. Many of the technical and cost assumptions applied for the alternatives within the indicative analysis were obtained from the earlier-mentioned EIA cost reports. [46]

The following summaries of the resource alternatives were drawn from descriptions within the EIA reports:

> NGCC: The NGCC facility utilizes two natural gas-fueled F5-class CTs and associated electric generators, two supplemental-fired heat recovery steam generators (HRSG), and one condensing ST and associated electric generator operating in combined-cycle mode. Each CT includes a dry-low NOX (DLN) combustion system and a hydrogen-cooled electric generator.

> NGCT: The Advanced CT Facility produces 210 MW of electricity using a single natural gas-fueled, state of the art (as of 2012) F-class CT and associated electric generator. The CT facility would be equipped with the DLN combustion hardware to mitigate emissions.

> Wind: The Onshore Wind Facility is based on 67 wind turbine-generators, each with a rated capacity of 1.5 MW. The total design capacity is 100 MW. The nacelle contains the variable-speed generator, transmission, and yaw drive.

> Solar PV: The PV Facility uses numerous arrays of ground-mounted, single-axis tracking PV modules which directly convert incident solar radiation into DC electricity, which can then be inverted to AC. Additional BOP components include DC-to-AC inverters, AC wiring, various switchgear and step-up transformers, and a control system.

Table 7 lists the approximate annual capacity factors of the non-dispatchable alternatives. For the dispatchable resource alternatives, the analysis estimated the capacity factors at which those resources would dispatch to reduce the overall AECC annual cost of dispatch. The base case analysis assumed the SPP daily energy market would reduce AECC's marginal dispatch costs by approximately 10 % in year 2020. The base case analysis did not include an assumed marginal cost impact directly related to CO_2 emissions.

[46] Ibid footnote 42

Table 7
A Listing of the Capacity Alternatives Analyzed

Capacity Alternative	MW Size and Configuration	Approx Annual Capacity Factor	Portion of Total Energy	
			On-Peak *	Off-Peak *
NGCC	620 MW "2x1" F-class CTs with emission equipment; 2 HSRGs and steam turbine-generators	Dispatchable		
NGCT	210 MW "1x0" F-class CT with emission equipment	Dispatchable		
Wind	A cluster of 1.5 MW-class wind turbine-generators	45 %	40 %	60 %
Solar PV	A 20 MW scale PV plant	20 %	90 %	10 %
* On-peak refers to the highest 50 % of annual marginal cost hours, and off-peak refers to the lowest 50 % of annual marginal cost hours				

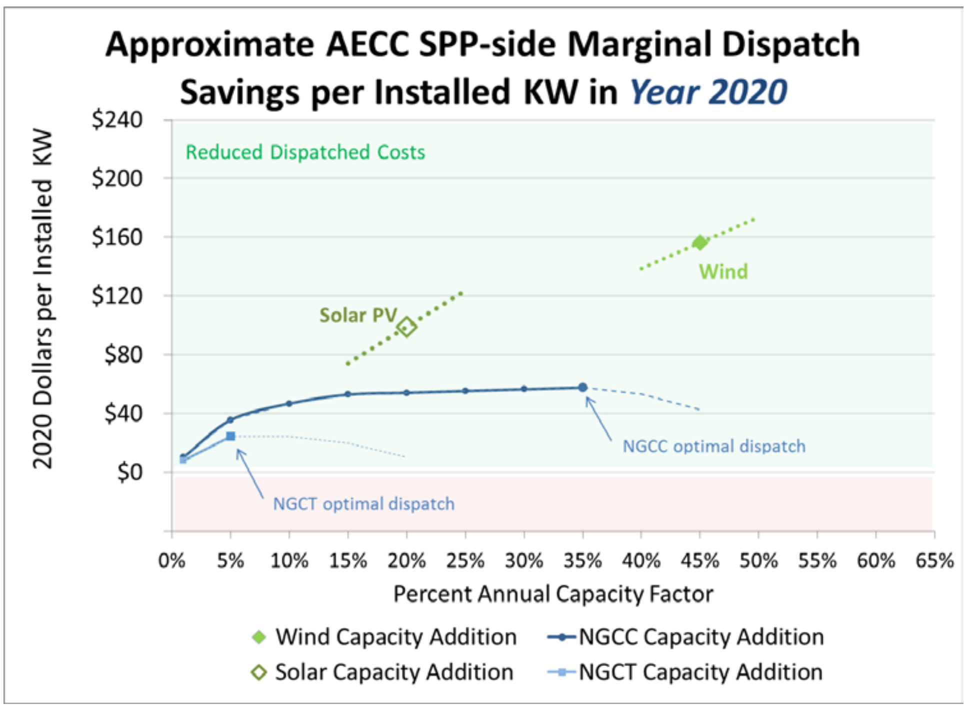
The analysis quantified capital-related costs, fuel costs, and non-fuel O&M costs for each resource alternative. For the base case analysis, the EIA Reference fuel forecasts were applied to estimate AECC's natural gas and coal fuel costs in year 2020. For each of the resource alternatives, non-fuel O&M costs from the EIA reports were applied. The EIA reports reflect all O&M at the wind-powered and solar PV as fixed ($0 variable cost per MWH), and this was assumed within the indicative analysis.

Within the base case, all capital costs per KW were assumed to increase at inflationary rates after the year 2015. Because there is a general consensus that solar PV capital costs will continue to decrease in the coming years, a parallel alternative was applied in which the capital costs (per KW) of solar PV were assumed to decrease 35 % by the year 2020.[47]

[47] This was applied as a reduction of the 'constant dollar' cost, and the same inflationary impact was applied as for the other capacity alternatives.

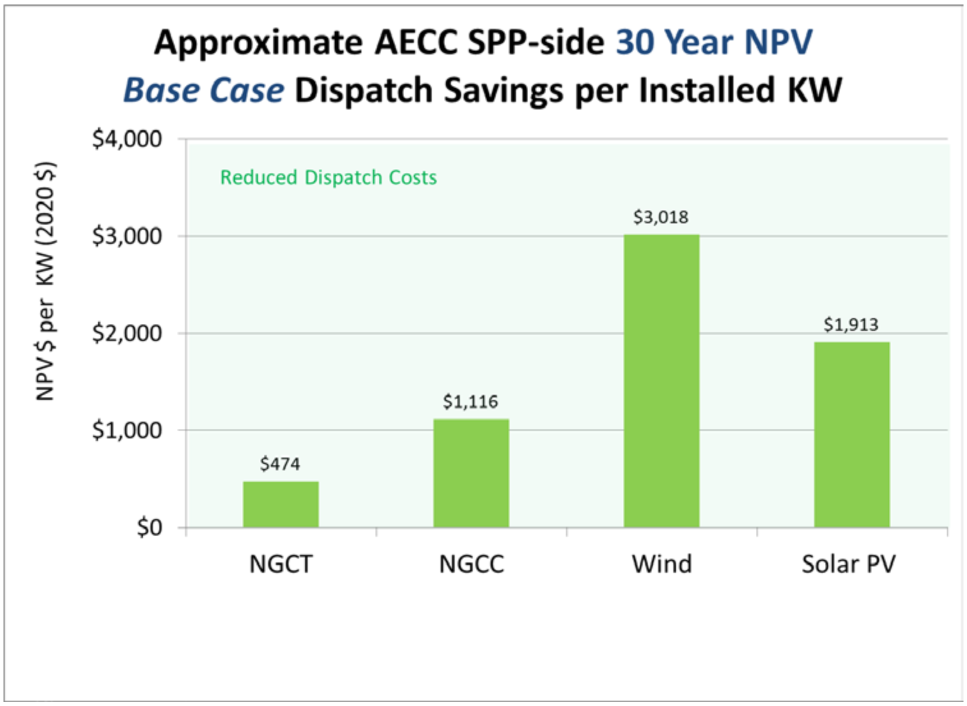
Figure 28 summarizes the approximate effect of each resource alternative on AECC's year 2020 cost of dispatch. The NGCT and NGCC alternatives are shown across a relatively broad range of capacity factors on the figure, given these resources are dispatchable. For these resources, the approximate optimal dispatch capacity factor would be the highest point on the curve, which was approximately a 5 % annual capacity factor for the NGCT and a 35 % capacity factor for the NGCC. The base case capacity factors for the wind-powered and solar PV were applied as presented on Table 7, although sensitivity was conducted for somewhat higher and lower capacity factors for these alternatives, as also shown in Figure 28.

Figure 28



As expected, the wind-powered and solar PV alternatives showed much greater dispatch cost savings than the NGCT and NGCC alternatives, given they have no fuel cost. The resultant 30 year NPV dispatch savings of each resource per installed KW are shown on Figure 29. [48]

Figure 29



[48] Essentially all cost parameters within the analysis were assumed to increase at an inflationary rate of 2.5% per year after year 2020. The annual discount rate applied within the analysis was 5.5 %.

Figure 30 presents the 30 year NPV effect of combining the fixed costs and the dispatch savings for each installed kW. The fixed costs included the capital-related costs and the fixed O&M costs for each alternative. The bold red bars on the figure show the resultant net incremental revenue requirement per installed kW for the base case analysis. On this comparative basis, the resource alternatives show a relatively similar impact per installed KW, with the NPV revenue impact ranging from $561 per installed kW for the NGCC to $2,154 per installed kW for the solar PV alternative. The relatively small difference between NGCT and NGCC results as shown on the figure (and typically also on the upcoming figures) would be within the range of accuracy inherent to the indicative analysis. The NGCT alternative exhibits the lowest fixed per kW and as such would inherently pose the lowest investment-related risks.

Figure 30

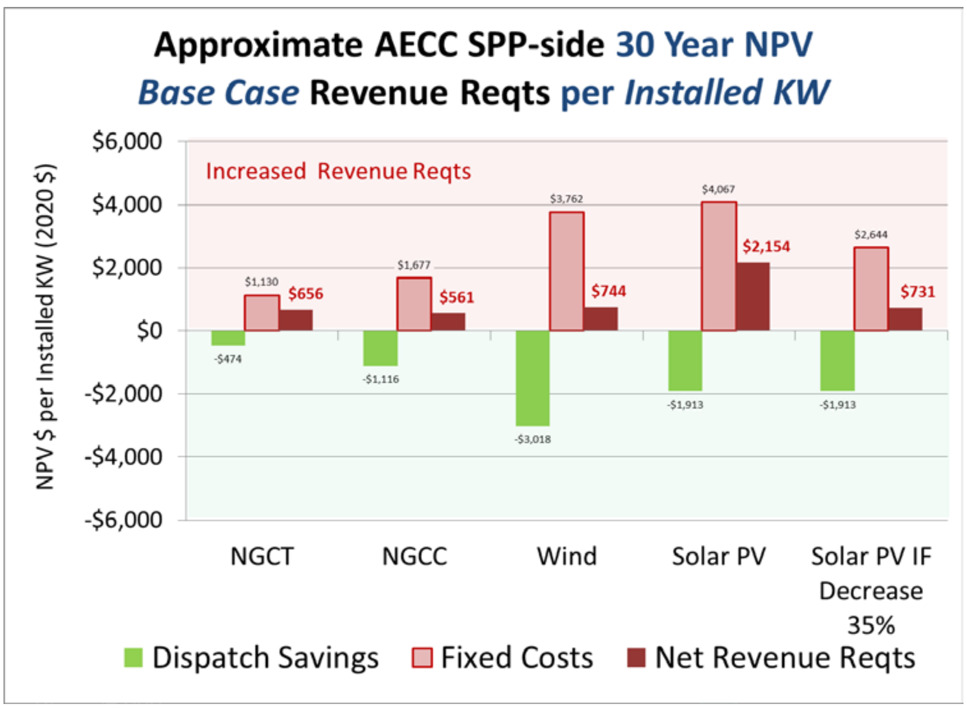
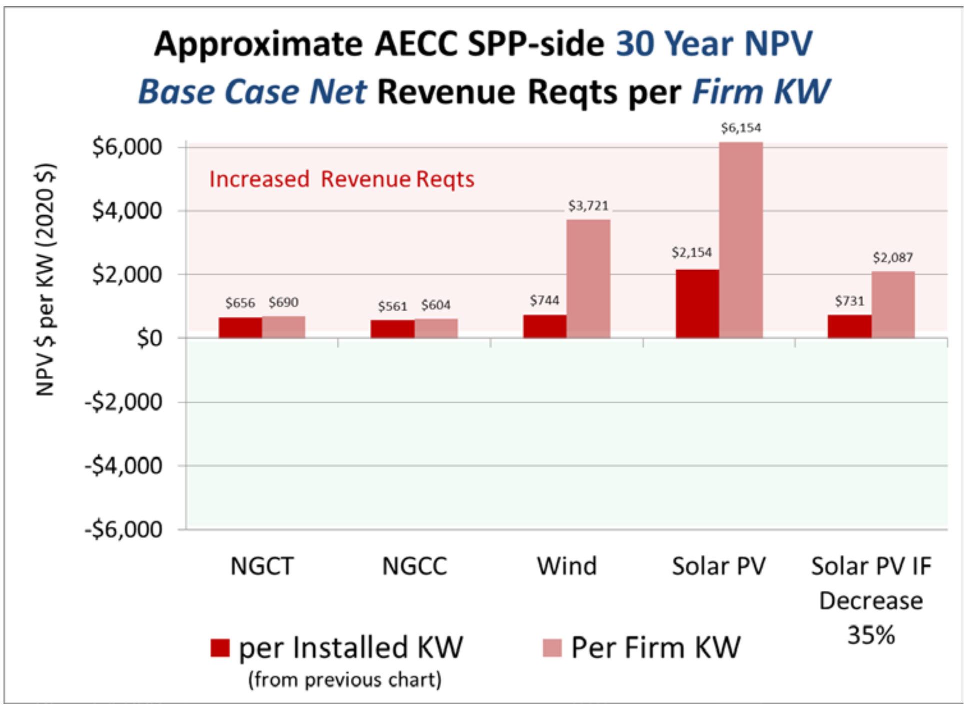


Figure 31 presents the NPV impact per firm KW achieved for the individual resource alternatives. Following from the earlier discussion of firm capacity, the indicative analysis quantified that for the NGCT and NGCC alternatives, 1.05 MW of capacity would need to be installed to achieve 1 MW of firm capacity, and the revenue requirement impacts (of the lighter shaded bar) would be multiplicative of the installed capacity requirements on that basis.[49] For the wind-powered and solar PV capacity alternatives, the amount of installed capacity that would be necessary to achieve 1 MW of firm capacity were 5 MW and 2.86 MW, respectively, [50] and the revenue requirements of acquiring firm capacity would again be multiplicative on that basis as shown on the figure.

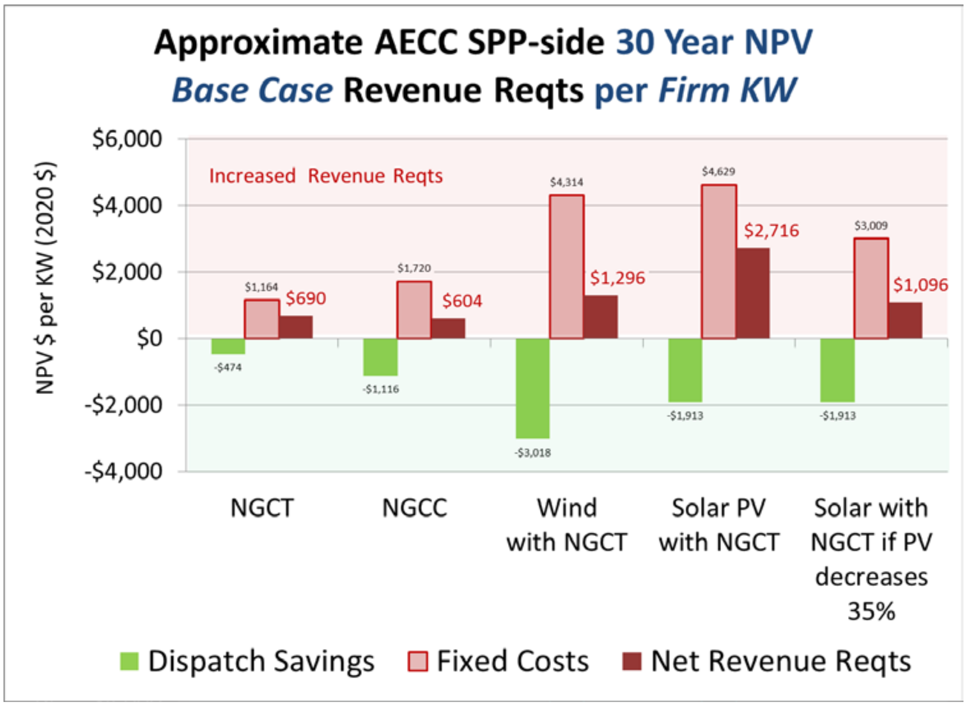
Figure 31



[49] Based on 95 % capacity credit per installed kW: (1/.95) = 1.053
[50] Based on 20 % (multiplier = 1/0.2) and 35 % (multiplier = 1/0.35) capacity credit per installed kW, respectively

The indicative analysis also approximated the comparable revenue requirement effects of potential "paired" resource portfolios, where each installed MW of renewable capacity has added to it sufficient NGCT (peaking) capacity to achieve 1 full MW of firm capacity. While this is only one approach to implementing a portfolio mix, it provides additional perspective within the indicative analysis. Figure 32 presents the comparable base case 30 year NPV and annualized revenue requirement impacts of this portfolio approach. For the base case analysis, the incremental revenue requirements per firm kW for the wind-powered and solar PV portfolios with NGCT backup were significantly higher than those for the individual NGCT or NGCC capacity alternatives.

Figure 32



Finally, three sensitivity cases were conducted for the indicative analysis:

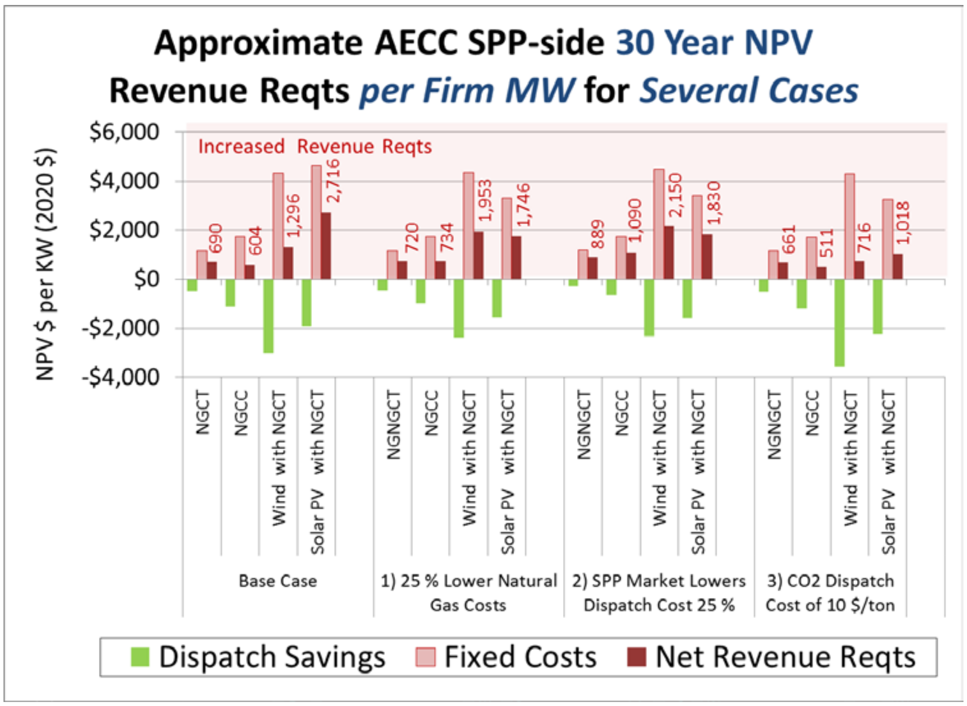
Case 1: Natural gas costs 25% lower than the base case value, along with coal prices being 12.5% lower than the base case value.

Case 2: The SPP energy market lowers AECC's marginal dispatch costs by 25% (versus 10% in the base case).

Case 3: A marginal cost impact of $10 /ton assumed for CO_2 emissions in year 2020.

As summarized on Figure 33, both sensitivity case 1 and sensitivity case 2 resulted in somewhat higher revenue requirements for the wind-powered with NGCT renewable portfolio and the solar PV with NGCT renewable portfolio, due to reduced dispatch savings. In these cases, the incremental revenue requirements of the renewable portfolios were approximately twice those of the conventional NGCT and NGCC alternatives. Sensitivity case 3 showed a generalized equivalence of revenue requirements for the renewable portfolios and the conventional alternatives.

Figure 33



Additional Discussion of Future Uncertainty

AECC believes there is a uniquely high level of uncertainty at this time regarding future power industry conditions, both regionally and within Arkansas, and particularly regarding EPA rules including the EPA CPP.[51] Due to reliability effects of closing baseload plants, the MISO and SPP RTOs have recently expressed concerns regarding the proposed CPP.[52] Even if the proposed CPP year 2020 impacts are deferred, regional

[51] Subsequent to the issuance of the draft version of this Resource Plan, the EPA on October 23, 2015 published in the Federal Register its final rule on the CPP.
[52] A MISO news release on November 24, 2014 addressing the CPP stated: "MISO has identified electric system reliability concerns related to the proposed rule's 2020-2029 interim performance requirements. The

capacity reserve margins will likely be narrow in the post-2020 time period. MISO has recently expressed additional concerns in this regard.[53]

The potentially accelerated decline of regional and national reserve margins makes it likely that increased demand for power plant components and construction activities will significantly elevate the associated costs in the coming years. This could be particularly true for combustion turbines, resulting in manufacturers reaching production limits and associated elevated prices similar to those that occurred in the late 1990s. These considerations further emphasize the need for AECC to offset the reduction of firm PPA capacity that AECC will experience in the year 2020.

The risk of retiring a portion of AECC's capacity is presently considered low prior to year 2025, but increases afterward due to both of the age of some of the facilities and the proposed phased implementation of EPA's CPP rule.

Specific Resource Portfolios

Under all future scenarios, AECC will continue its initiatives regarding energy efficiency improvements, energy conservation, and demand-side management. Also, AECC will continue to evaluate and possibly pursue additional non-fossil resources as underlying costs change and cost-effective alternatives become available. If legislation related to CO_2 is implemented, assumptions related to the cost of CO_2 may more affect the economic evaluation of future generation capacity.

Potential AECC firm capacity portfolios based on the banded load growth forecast range are summarized in Table 8. The need for additional firm capacity on the SPP side of the RTO seam in year 2020 is driven more by the expiration of a PPA contract than by the load growth forecast. Even under the low growth load forecast, firm capacity would be needed on the SPP side in year 2021.

MISO region faces declining power reserve margins due to EPA's Mercury and Air Toxics Standards and other factors. The Clean Power Plan will drive further changes to the energy resources used across our footprint. Building new generation, natural gas infrastructure and transmission facilities necessary to support electric system reliability will take more time than the interim performance period allows."

An SPP news release on October 9, 2014 stated: "SPP staff incorporated the EPA's assumptions into power-grid models that assessed how compliance with the proposed CPP would impact reliability within the SPP region. … The impact assessment indicates SPP's anticipated reserve margin would be 4.7 %, a reserve-margin deficiency of about 4,600 megawatts by 2020."

[53] A MISO news release on June 17, 2015 included the statement: "While there are sufficient resources available in 2016, the [MISO and OMS] survey forecasts the potential for resources to fall below the regional reserve margin requirement beginning in 2020. Lowered reserve margins present a new operating reality for MISO members."

Table 8
Firm Capacity Resource Portfolios Based on Load Growth

Year	Low Band Growth	Base Case Growth	High Band Growth
2020		200 MW firm capacity on SPP side OR 200 MW additional load transfer to MISO side	300 MW firm capacity on SPP side OR 300 MW additional load transfer to MISO side
2021	100 MW firm capacity on SPP side OR 100 MW additional load transfer to MISO side		
Beyond a decision point which is prior to the next Resource Plan (due 2019)			
2025		200 MW capacity on the SPP side	300 MW on the SPP side
2028	500 MW MISO side *	500 MW MISO side *	500 MW MISO side *
* If White Bluff plant is fully retired in year 2028			

An additional consideration for the future portfolios is the possible eventual termination of the existing pseudo-tie arrangement, as discussed earlier. Given that the pseudo-tie necessitates AECC purchase network transmission service within both RTOs for the transferred megawatts, the economics of continuing this arrangement beyond when AECC has an overall need for firm capacity will need to be further considered. Under the base case load growth forecast, this situation would not occur before year 2028, and as such, it should not alter any capacity decisions prior to the next AECC Resource Plan to be developed in year 2018 for filing in early 2019.

Preferred Resource Plan

As mentioned earlier, AECC does not expect to need additional capacity on the MISO side within the next 10 years. The expiration of an existing PPA in year 2020 drives the underlying need for firm capacity in the SPP region that year more so than does the load growth forecasts. However, the quantity of capacity needed on the SPP side in year 2020 is affected by the load growth forecasts. Under the low growth forecast, and assuming no SPP-side capacity retirements or significant impairments, 100 MW would suffice for approximately 10 years.

However, AECC believes it is best to primarily apply the base case load growth in order to reduce the risk of AECC experiencing a capacity deficiency in the 2020-2025 time frame. The annual capacity and energy replacement costs of an AECC deficiency in that time frame could be especially high due to the likely continued downward trending of regional reserve margins and uncertainty regarding impacts of the final EPA CPP rule.

As shown in Table 9, under the base case load growth forecasts, approximately 200 MW in year 2020 would suffice until year 2025, and an additional 200 MW in that year would meet growth on the SPP side beyond the year 2030. After year 2025, AECC's additional need for firm capacity will most likely be driven by potential capacity retirements. If the White Bluff plant is fully retired in year 2028, additional capacity would be needed in that year.

Table 9
Preferred Plan for Firm Capacity in Years 2016-2030

Year	SPP-side	MISO-side	Total
2020	150-200 MW firm capacity mix	--	150-200 MW firm capacity
2025	150-200 MW firm Capacity mix	--	150-200 MW firm capacity
(If no capacity is retired or significantly degraded in the interim)			
2028		500 MW firm capacity replacement *	500 MW firm capacity replacement *
* Assuming, as AECC does, that the White Bluff plant is retired by year 2028			

Action Plan

Capacity Resources

AECC issued a request for proposals (RFP) to solicit both fossil-fueled and renewable capacity proposals. The proposals that were received were evaluated in direct competition to self-build alternatives and any other identified resource opportunities to determine the least-cost alternative. Based on the responses received in response to the RFP, AECC presented a proposal to extend and existing PPA for five (5) years. s. A Board vote on that recommendation is expected in March 2016. AECC does not anticipate any additional firm generation needs within the MISO footprint prior to year 2027.

AECC also expects that extensive internal corporate, state-wide and regional evaluations of impacts and ultimate strategies related to the EPA CPP will be undertaken in year 2016, continuing into 2017 and 2018,[54] which will be incorporated within AECC's next Resource Plan in 2018 and within related planning activities.

Transmission Facilities

Both SPP and MISO have robust transmission planning processes in which AECC actively participates. AECC does not develop a transmission plan apart from those of MISO and SPP. Both RTOs coordinate various working groups and committees, in particular the SPP Transmission Working Group (TWG) and the MISO Planning Subcommittee. AECC has voting rights in these and other working groups as a member of both RTOs. Driven by MISO's multi-regional footprint, the MISO transmission process includes multiple "sub-regions" for planning coordination. AECC is located within the MISO South sub-region, and participates in the ongoing South Technical Study Task Force.

The culmination of the annual planning processes within each RTO is the publication of an updated transmission plan, which is ultimately voted upon by the respective RTOs' Boards of Directors. The MISO plan is referred to as the MTEP (MISO Transmission Expansion Plan) and the SPP plan is referred to as the STEP (Southwest Power Pool Transmission Expansion Plan).

As a firm hydroelectric customer of SWPA, AECC also participates in forums and other discussions to provide input to the SWPA transmission planning process.

[54] Each State is required to complete an initial plan in September of year 2016 and a Final Plan by September of 2018.

Stakeholder Process

AECC distributed a draft of this Resource Plan to a group of stakeholders referred to as the Stakeholder Committee on August 31, 2015. The stakeholders were encouraged to submit comments and questions to AECC by September 23, 2015, and a Stakeholder Committee Meeting was hosted by AECC on October 7, 2015. A summary of the meeting was drafted by AECC and submitted to the Stakeholder Committee designees for review and input. The Stakeholder Committee Report is included within this Resource Plan as Appendix B.

Appendix A
Annual Load and Capacity for the Base Case Growth Forecast

AECC Load & Capacity Summary -- April 2015 Base Case Growth

	(note that values round to the nearest MW)	Budget 2015	2016	2017	2018	2019	2020	2021	2022
1	MISO-side Rate 1 Customer Loads	1,649	1,699	1,744	1,777	1,810	1,842	1,873	1,903
2	SPP-side Rate 1 Customer Loads	786	834	856	874	895	913	933	953
3	Total AECC Rate 1 Peak Loads	2,435	2,532	2,599	2,651	2,704	2,755	2,806	2,856
4	MISO IC Rider Firm Loads	31	31	31	31	31	31	31	31
5	SPP IC Rider Firm Loads								
6	Total AECC Firm Loads	2,466	2,563	2,630	2,682	2,735	2,786	2,837	2,887
7	Diversity Impacts	(50)	(52)	(53)	(54)	(55)	(56)	(57)	(58)
8	AECC 'RTO coincident' Firm Peak	2,415	2,511	2,577	2,628	2,680	2,730	2,780	2,829
9	Firm Load Losses	61	64	66	67	68	70	71	72
10	Reserve Requirements	243	254	261	266	272	277	282	287
11	Firm Peak + Losses & Reserves	2,720	2,829	2,903	2,961	3,020	3,076	3,133	3,188
12	MISO-side Firm Capacity (UCAP)	2,546	2,546	2,548	2,548	2,548	2,548	2,548	2,548
13	SPP-side Firm Capacity (ICAP)	1,154	1,165	1,165	1,165	1,165	995	991	991
14	Total Firm Capacity	3,700	3,711	3,713	3,713	3,713	3,543	3,539	3,539
15	Surplus in MISO	758	705	659	623	588	554	521	489
16	Surplus in SPP	222	177	151	129	105	(87)	(114)	(138)
17	AECC Surplus	980	882	810	752	693	467	406	351

AECC Load & Capacity Summary -- April 2015 Base Case Growth

	(note that values round to the nearest MW)	2023	2024	2025	2026	2027	2028	2029	2030
1	MISO-side Rate 1 Customer Loads	1,933	1,962	1,991	2,020	2,049	2,079	2,109	2,138
2	SPP-side Rate 1 Customer Loads	971	990	1,010	1,026	1,045	1,066	1,084	1,105
3	Total AECC Rate 1 Peak Loads	2,904	2,952	3,001	3,046	3,094	3,144	3,193	3,244
4	MISO IC Rider Firm Loads	31	31	31	31	31	31	31	31
5	SPP IC Rider Firm Loads								
6	Total AECC Firm Loads	2,935	2,983	3,032	3,077	3,125	3,175	3,224	3,275
7	Diversity Impacts	(59)	(60)	(61)	(62)	(62)	(63)	(64)	(65)
8	AECC 'RTO coincident' Firm Peak	2,876	2,923	2,971	3,016	3,063	3,112	3,159	3,209
9	Firm Load Losses	73	75	76	77	78	80	81	82
10	Reserve Requirements	292	297	303	307	312	318	322	328
11	Firm Peak + Losses & Reserves	3,241	3,295	3,350	3,399	3,453	3,509	3,562	3,619
12	MISO-side Firm Capacity (UCAP)	2,548	2,548	2,548	2,548	2,271	1,994	1,994	1,994
13	SPP-side Firm Capacity (ICAP)	991	991	991	991	991	991	991	991
14	Total Firm Capacity	3,539	3,539	3,539	3,539	3,262	2,985	2,985	2,985
15	Surplus in MISO	457	426	395	365	56	(252)	(284)	(315)
16	Surplus in SPP	(160)	(182)	(206)	(225)	(248)	(272)	(293)	(319)
17	AECC Surplus	298	244	189	140	(192)	(524)	(578)	(634)

Appendix B

2016 Integrated Resource Plan
Stakeholder Committee Report

Arkansas Electric Cooperative Corporation
Integrated Resource Plan
Stakeholders' Committee Report

Meeting Held
October 7, 2015
AECC
1 Cooperative Way
Little Rock, Arkansas 72209

Table of Contents

I. Executive Summary

On July 7, 2015,[1] notice of AECC's intention to host its Integrated Resource Plan (IRP) Stakeholder Committee Meeting (SCM) on October 7, 2015 was sent to a list of approximately 89 individuals and entities who previously identified their interest to AECC concerning its IRP. Along with this notice, AECC provided a proposed timeline, agenda, and a promise to provide a draft version of its proposed prior to the SCM. The stakeholders invited represented a diverse group of wholesale consumers, independent power producers, renewable energy advocates, economic development interests, industrial consumers, biomass suppliers, investor-owned utilities, the Attorney General's office, the Arkansas Energy Office, members of the Arkansas Public Service Commission's General Staff in addition to members of the Commissioners' Staff, the Arkansas Department of Environmental Quality as well as AECC's Member Cooperatives. A list of the stakeholders invited is attached as Appendix A, Section I.

As promised in AECC's notice, on August 31, 2015, a draft of AECC's proposed IRP was sent to the stakeholders for their review. Along with the draft was a request that written feedback or concerns be returned to AECC no later than September 23, 2015. AECC received 1 response, which is attached as Appendix B.

On October 7, 2015, AECC hosted its SCM meeting at its offices located in southwest Little Rock. A list of those in attendance is attached as Appendix A, Section II, and the agenda for the SCM is attached as Appendix A, Section III. During the SCM, AECC presented information on the goals and objectives of the IRP SCM process, a description of the unique characteristics of the cooperative business model, a discussion of economic dispatch and fuel comparisons, the methodology for the development of the AECC load forecast, demand response and energy efficiency program overview, and a description of AECC's generation planning process. A subject-matter expert panel was presented and time was given for an interactive session with questions and answers. Stakeholders were also given and encouraged to provide input as to their issues of concern via a Stakeholders Resource Planning Issue form, which is attached as Appendix C.

Following the interactive session, AECC personnel left the room to provide the assembled group the chance to privately discuss any concerns they had about AECC's IRP and generation plans. The group elected Brad Harrison, President and CEO of Mississippi County Electric Cooperative, Incorporated to lead that private discussion and report back to AECC Staff regarding those topics of concern. Following the confidential discussion, AECC was advised that no further issues were identified for AECC to address, and Mr. Harrison committed to assisting AECC in finalizing this Stakeholder Committee Report, a draft of which was presented and approved by the stakeholders. AECC reconvened its personnel, thanked the stakeholders, and the SCM concluded.

[1] Throughout the course of the IRP, AECC sent the following in advance of the SCM: emails, calendar invitations, and a proposed agenda (July 7 and 10, 2015); a proposed IRP Report (August 31, 2015); and presentation materials and a proposed Stakeholder Report (October 6, 2015).

II. Stakeholders' Initial Statement

The stakeholders appreciate the opportunity to participate in AECC's SCM and the process of drafting this report. The stakeholders would like to make it clear, however, that although their participation in this stakeholder advisory process was important and necessary, the views expressed in this Stakeholder Report (SR) do not represent the views of any single party with regard to the subjects addressed herein. Each of the individual stakeholders intends to continue to fully participate in AECC's IRP process as allowed under the Commission's *Resource Planning Guidelines* and in any and all specific docketed proceedings which will follow the filing of this SR and the filing of AECC's IRP. Accordingly, the stakeholders hereby reserve the right to participate fully in any future proceeding(s) associated with AECC's IRP and any future resource acquisition that may spring from that IRP process and raise any appropriate argument therein.

III. Stakeholders' Issues

During the interactive SCM, the following stakeholders asked several questions generally relating to AECC's perception of the accuracy of Energy Information Association data and the capturing of costs; seams issues and the need for transmission upgrades; AECC's outstanding RFP and addressing the 2020 capacity gap; AECC's opinion of the shale play options and long-term contracts to lock in Arkansas prices; the levelized cost of gas prices and the delivery risk of gas; the Resource Plan timeline; market assurances and the effect of the CPP on demand for gas; and storage costs for developing technologies and bottom storage. AECC personnel present for the SCM addressed each answer in turn.

IV. Conclusion

The stakeholders appreciate the opportunity to provide input and feedback on key issues central to the business of AECC as evidenced in the IRP, and this report reflects the views shared with AECC for inclusion in the planning process.

Appendix A

Section I. Stakeholders Invited to Attend (in alphabetical order by last name)

Name	Company	E-mail
Rose Adams	Arkansas Community Action Agencies Assn.	acaaa@aristotle.net
John Ahlen	Arkansas Science and Technology Authority	John.ahlen@arkansas.gov
Chad Allen	MISO Energy	callen@misoenergy.org
John Askegaard	Tyson Foods	John.akegaard@tyson.com
Stacy Bankston	AEP Southwestern Electric Power Company	slbankston@aep.com
Billy Joe Bartholomew	Ozarks Electric Cooperative Corporation	b.j.bart@p.d.com
John Bethel	Arkansas Public Service Commission	johnbethel@psc.state.ar.us
Rob Boaz	Carroll Electric Cooperative Corp	rboaz@carrollecc.com
Jerry Bolinger	Ozarks Electric Cooperative Corporation	
Valerie Boyce	Arkansas Public Service Commission	Valerie_boyce@psc.state.ar.us
Brandon Bradford	AEP - Southwestern Electric Power Co.	bcbradford@aep.com
Diana Brenske	Arkansas Public Service Commission General Staff	dbrenske@psc.state.ar.us
Larry Bright	Farmers Electric Cooperative Corporation	lbright@farmersecc.com
Jerel Brown	Petit Jean Electric Cooperative Corporation	peggy.kathleen@gmail.com
Nick Brown	Southwest Power Pool	nbrown@spp.org
Kevin Brownlee	South Central Arkansas Electric Cooperative, Inc.	k.brownlee@scaec.com
Lori L. Burrows	Arkansas Electric Cooperative Corp	Lori.burrows@aecc.com
Lynn Carlisle	Midwest Independent Transmission System Operator, Inc.	vcarlisle@misoenergy.org
Kurt Castleberry	Energy Arkansas	kcastle@entergy.com
Mark Cayce	Ozarks Electric Cooperative Corporation	mcayce@oecc.com
Rodney Chapman	Ashley-Chicot Electric Cooperative, Inc.	rchapman@ashley-chicot.com

Digaunto Chatterjee	Midwest Independent Transmission System Operator, Inc.	dichatterjee@misoenergy.org
Mel Coleman	North Arkansas Electric Cooperative, Incorporated	mcoleman@naeci.com
Sam Commella	Nucor	Sam.commella@nucor.com
Bill Conine	Petit Jean Electric Cooperative Corporation	bconine@pjecc.com
Clark Cotton	Arkansas Public Service Commission	Clark_Cotton@psc.state.ar.us
Brad Cox	Tenaska	bcox@tnsk.com
Don Crabbe	First Electric Cooperative Corporation	don.crabbe@firstelectric.coop
John M. Dalton	Clay County Electric Cooperative Corporation	
Robert Earl Davis	Mississippi County Electric Cooperative, Inc.	
Mark DiGirolamo	Nucor Steel	mark.digirolamo@nucor.com
Brian Duncan	Craighead Electric Cooperative Corporation	bduncan@craigheadelectric.coop
Kandice Fielder	Entergy Corporation	kfielder@entergy.com
W. H. Frizzell	C & L Electric Cooperative Corp.	whfrizzell@clelectric.com
Steve Gaw	Wind Coalition	steve@windadvocacy.org
Mark Goodman	UALR College of Business	msgoodman@ualr.edu
Brad Harrison	Mississippi County Electric Cooperative, Inc.	bharrison@mceci.com
Duane Highley	Arkansas Electric Cooperative Corp	Duane.highley@aecc.com
Robert M. Hill	First Electric Cooperative Corporation	robcpa1@yahoo.com
John Hillman	Remington Arms	john.hillman@remington.com
Jody Holland	GridLiance	jholland@gridliance.com
Rachel Hulett	Southwest Power Pool	rhulett@spp.org
Alan Hunnicutt	Carroll Electric Cooperative Corporation	
Jerry Jacobs	Rich Mountain Electric Cooperative	jerryandruthjacobs@gmail.com
Mitchell Johnson	Ozarks Electric Cooperative Corp	mjohnson@ozarksecc.com
Rene Johnson	C & L Electric Cooperative	rjohnson@clectric.com
Steve Jones	Arkansas Economic Development Commission	sjones@arkansasedc.com

Karen Kirkpatrick	South Central Arkansas Electric Cooperative, Inc.	dkkirkpatrick@sbcglobal.net
Ludwik Kozlowski, Jr.	Arkansas Community Action Agency Assn.	lkozlowski@acaaa.org
Andrew Lachowsky	Arkansas Electric Cooperative Corp	Andrew.lachowsky@aecc.com
Victoria Lamb	Arkansas Electric Cooperative Corp	Victoria.lamb@aecc.com
Sarah Lane	Tenaska	slane@tnsk.com
Simon Mahan	Southern Wind Energy Association	simon@cleanenergy.org
Emon Mahony	Office of the Attorney General	emon.mahony@arkansasag.gov
Sandy Manning	South Central Arkansas Electric Cooperative	s.manning@scaec.com
Shawn McMurray	Arkansas Attorney General's Office	Shawn.mcmurray@arkansasag.gov
Charles Miller	Arkansas Environmental Federation	cmiller@environmentark.org
Walter Nixon III	Arkansas Public Service Commission	wnixon@psc.state.ar.us
Michael Odom	Southwestern Power Pool	modom@spp.org
Jerry Pahal	Ashley-Chicot Electric Cooperative, Incorporated	
Bill Peters	Arkansas Valley Electric Cooperative	Bill_peters@avecc.com
Leon Philpot	Rich Mountain Electric Cooperative Corp	Lphilpot@rmec.com
Mike Porta	Arkansas Department of Environmental Quality	porta@adeq.state.ar.us
Mike Preston	Arkansas Economic Development Comm.	mpreston@arkansasedc.com
Keith Prevost	Nucor-Yamato Steel	keith.prevost@nucor-yamato.com
Michael Riley	Southwest Power Pool	mriley@spp.org
Robert Robinette	Arkansas State University	rrobinette@astate.edu
Rick Running	Arkansas Electric Cooperative Corp	Rick.running@aecc.com
Robert Shields	Arkansas Electric Cooperative Corp	Robert.shields@aecc.com
Mitchell Simpson	Arkansas Economic Development Comm.	msimpson@arkansasedc.com
D. David Slaton		ddavidslaton@gmail.com
Tom Sloan	Craighead Electric Cooperative Corporation	
David Smith	Clay County Electric Cooperative Corporation	dsmith@claycountyelectric.com

Greg Smith	C & L Electric Cooperative Corporation	gsmith@clelectric.com
Jameson T. Smith	Midwest Independent Transmission System Operator, Inc.	jtsmith@misoenergy.org
Kevin Smith	Tenaska	ksmith@tnsk.com
Elizabeth Solano	MISO Energy	esolano@misoenergy.org
Don Stemple	Southwest Arkansas Electric Cooperative Corp.	dpstemple@alltel.net,
Elizabeth D. Stephens	AEP-Southwestern Electric Power Company	edstephens@aep.com
Michael Swan	Woodruff Electric Cooperative Corporation	mswan@woodruffelectric.com
Judith Thorne	Tyson Foods	Judith.thorne@tyson.com
Randy Thurman	Government Solutions	rthurman@arkansaslobbying.com
Rebecca Turner	Entegra Power Group LLC	rturner@entegrapower.com
Chad Utermark	Nucor	Chad.utermark@nucor.com
J. A. Wampler	Woodruff Electric Cooperative Corporation	
Bary Warren	Gridliance	bwarren@gridliance.com
Wayne Whitaker	Southwest Arkansas Electric Cooperative Corp	wwhitaker@swrea.com
Matt Wolf	Energy Arkansas	hwolf1@entergy.com
Jim Youngquist	Institute for Economic Advancement	jlyoungquist@ualr.edu

Section II. Stakeholders in Attendance (in alphabetical order by last name)

Name	Company
John Bethel	Arkansas Public Service Commission
Rob Boaz	Carroll Electric Cooperative Corp
Jerry Bolinger	Ozarks Electric Cooperative Corporation
Valerie Boyce	Arkansas Public Service Commission
Brandon Bradford	AEP - Southwestern Electric Power Co.
Carrol Dee Bradford	Petit Jean Electric Cooperative
Larry Bright	Farmers Electric Cooperative Corporation
Kevin Brownlee	South Central Arkansas Electric Cooperative, Inc.
Neil M. Burge	Mississippi County Electric Cooperative
Lori L. Burrows	Arkansas Electric Cooperative Corp
Mark Cayce	Ozarks Electric Cooperative Corporation
Rodney Chapman	Ashley-Chicot Electric Cooperative, Inc.
Bill Conine	Petit Jean Electric Cooperative Corporation
Clark Cotton	Arkansas Public Service Commission
John M. Dalton	Clay County Electric Cooperative Corporation
Robert Earl Davis	Mississippi County Electric Cooperative, Inc.
Mark DiGirolamo	Nucor Steel
Brian Duncan	Craighead Electric Cooperative Corporation
Chris Hardy	Clean Line Energy
Duane Highley	Arkansas Electric Cooperative Corporation
Brad Harrison	Mississippi County Electric Cooperative, Inc.
Michael Henderson	Arkansas Electric Cooperative Corporation
John Hillman	Remington Arms
Sam Houston	Farmers Electric Cooperative Corporation
Alan Hunnicutt	Carroll Electric Cooperative Corporation
Mario Hurtado	Clean Line Energy
Mike Hutchinson	Ouachita Electric Cooperative
Mitchell Johnson	Ozarks Electric Cooperative Corp
Steve Jones	Arkansas Economic Development Commission
Brian Kirksey	South Central Arkansas Electric Cooperative, Inc.

Ludwik Kozlowski, Jr.	Arkansas Community Action Agency Assn.
Andrew Lachowsky	Arkansas Electric Cooperative Corporation
Victoria Lamb	Arkansas Electric Cooperative Corporation
Kevin Lemley	Arkansas Attorney General's Office
Shawn McMurray	Arkansas Attorney General's Office
Charles Miller	Arkansas Environmental Federation
Gary Moody	Audubon
Eddy Moore	Arkansas Public Service Commission
Wally Nixon	Arkansas Public Service Commission
Jerry Pahal	Ashley-Chicot Electric Cooperative, Incorporated
John F. Pendergrass	Arkansas Valley Electric Cooperative
Bill Peters	Arkansas Valley Electric Cooperative
Keith Prevost	Nucor-Yamato Steel
Mark Robbins	Rich Mountain Electric Cooperative
Terry Rorex	Craighead County Electric Cooperative
Rick Running	Arkansas Electric Cooperative Corp
Robert Shields	Arkansas Electric Cooperative Corp
Mitchell Simpson	Arkansas Economic Development Comm.
David Smith	Clay County Electric Cooperative Corporation
Michael Swan	Woodruff Electric Cooperative Corporation
Wayne Turney	Nucor Steel
J. A. Wampler	Woodruff Electric Cooperative Corporation
Wayne Whitaker	Southwest Arkansas Electric Cooperative Corp
Matt Wolf	Energy Arkansas
Randall Wright	IEA

Section III. Stakeholder Committee Meeting Agenda

October 7, 2015
Arkansas Electric Cooperative Corporation Headquarters
1 Cooperative Way, Little Rock, Arkansas

Welcome

Duane Highley, President/CEO

RP Background

Lori L. Burrows, Vice President and General Counsel

Meeting AECC's Future Capacity & Energy Needs

Andrew Lachowsky, Vice President – Planning and Market Operations

AECC's Long-Term Forecast

Victoria Lamb, Manager – Load Forecasting

Panel Discussion

Andrew Lachowsky, Vice President – Planning and Market Operations

Victoria Lamb, Manager – Load Forecasting

Rick Running, Manager – Generation Planning

Stakeholder Report Discussion (AECC Staff not present)

Conclusion

Lori L. Burrows, Vice President and General Counsel

Appendix B

Written Feedback

swea
southernwind.org

Southern Wind Energy Association
P.O. Box 1842, Knoxville, TN 37901

September 23, 2015

John T. Elkins
Legal Division
Arkansas Electric Cooperative Corporation
1 Cooperative Way
Little Rock, AR 72209

Re: Draft 2016 Integrated Resource Plan for Arkansas Electric Cooperative Corporation as of August 31, 2015

Dear Mr. Elkins,

The Southern Wind Energy Association (SWEA) is an industry-led initiative that promotes the use and development of wind energy in the south. We appreciate the opportunity to provide comments on the Draft Integrated Resource Plan (IRP) for 2016 for Arkansas Electric Cooperative Corporation (AECC) as of August 31, 2015. AECC has been a leader in voluntarily purchasing wind energy resources in the southeast and a robust IRP process can help identify additional opportunities for wind energy procurement.

SWEA respectfully submits the following comments and recommendations.

- Include feasible energy options, including out-of-state wind energy from a new HVDC transmission project, SPP and Local resources and adjust cost and performance accordingly.
- Use the data submissions SWEA provided for the IRP inputs (see Figure 1), including installed costs, capacity factors, levelized cost of energy as well as cost and performance improvements over the IRP study timeframe.
- Apply the Production Tax Credit as a sensitivity analysis for wind energy resources.
- Apply carbon emission reductions in all modeling cases, as best aligned with compliance with the federal Clean Power Plan as possible.
- Do not attempt to "firm" wind energy resources.

Diversify Wind Energy Resources for Evaluation

The Draft IRP currently evaluates one type of wind energy resource: wind energy imported from the Southwest Power Pool (SPP). There are several other resources available to AECC that should be assessed as a part of the IRP process- local wind resources, and wind resources imported via High-Voltage Direct Current (HVDC) transmission. The wind resources imported via HVDC transmission avoid delivery via the AC transmission system, and can be delivered at a fixed cost with no congestion risk.

Evaluating multiple wind resource opportunities has become common practice in recent IRP processes. The Tennessee Valley Authority (TVA) in its 2015 IRP evaluated wind energy resources from local resources, imports from SPP and the Midcontinent Independent System Operator (MISO), and imports via new-build High-Voltage Direct Current (HVDC) transmission designed to transmit large quantities of low-cost, high-capacity wind energy resources.[1] TVA's various wind energy resources were modeled with differing installed costs as well as capacity factors.

Additionally, the Southwestern Electric Power Company (SWEPCO) has evaluated three separate wind energy resource "tranches" in its 2015 IRP.[2] SWEPCO's Tranche 1 wind energy resources evaluated wind energy with a levelized cost of energy (LCOE) of $47/MWh, without the federal Production Tax Credit (PTC) and a 56% capacity factor. SWEPCO's Tranche 2 wind energy resources evaluated wind energy with a levelized cost of energy (LCOE) of $55/MWh, without the federal Production Tax Credit (PTC) and a 50% capacity factor. SWEPCO's Tranche 3 wind energy resources evaluated wind energy with a levelized cost of energy (LCOE) of $60/MWh, without the federal Production Tax Credit (PTC) and a 45% capacity factor. SWEA recommends that AECC model several wind energy resources, at various LCOE's and capacity factors.

To ensure that AECC accurately assesses the full value of each separate wind resource available to AECC, SWEA recommends the use of the following model inputs in Figure 1, below, for its IRP.

Figure 1. Recommended Wind Energy Model Inputs for AECC's 2016 IRP

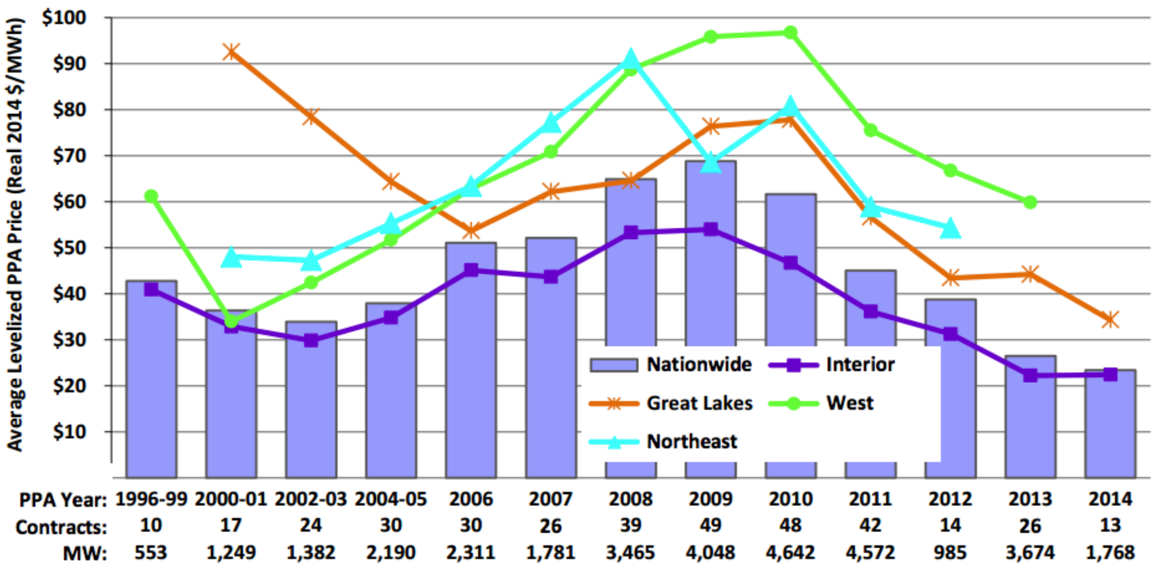
	SPP Wind Imports	HVDC Wind	Local Wind
LCOE 2014$/MWh w/PTC (all-in, busbar)	$23.43	$23.43	$58
w/o PTC (adds $15/MWh)	$38.43	$38.43	$73
Installed Cost 2014$/kW (all-in)	$1,638	$1,638	$1,877
in 2020	$1,568	$1,568	$1,856
in 2030	$1,515	$1,515	$1,840
2014 Capacity Factor	51%	51%	38%
in 2020	54%	54%	41%
in 2030	57%	57%	44%
Capacity Value	15%	28%	15%

SPP/HVDC wind energy resource LCOE and Installed costs for 2014 are based on Lawrence Berkeley National Laboratory's *2014 Wind Technologies Market Report*[3]. The PTC cost savings of $15/MWh is also reported by LBNL. All costs (excluding the PTC) and learning curves for Local wind energy resources are based off the Department of Energy's *Wind Vision* report Table H–3 and Table H–4 for Land4/TRG4 resources.[4] All net capacity factors and learning curves are based off DOE's Table H-4 for TRG1 and TRG4 resources. SPP and Local wind resource capacity values are based on AECC's assigned values. HVDC's wind energy resource capacity values are based on analysis performed for the Tennessee Valley Authority.[5] At AECC's request, SWEA will provide additional information regarding additional inputs if necessary for IRP modeling purposes.

Use Updated Capital Costs for Wind Energy Resources

According to Draft IRP Figure 24, the capital cost of wind energy is reported as $2,327/kW installed. Alternatively, SWEA recommends AECC use data from the most recent Lawrence Berkeley National Laboratory (LBNL) wind energy market assessment, which is widely recognized by wind industry experts as most representative of actual costs. In its *2014 Wind Technologies Market Report*, LBNL found that The nationwide capacity-weighted average installed project cost was $1,710/kW. The capacity-weighted average installed project cost represents an all-in cost; additionally, LBNL notes that the PTC does not affect the installed cost directly.[6] This report also found that the average power purchase agreement (PPA) for wind energy contracts in 2014 reached an all-time low price of $23.43 per megawatt hour (MWh), including the PTC.[7]

Figure 2. Generation-weighted average levelized wind PPA prices by PPA execution date and region



Source: LBNL 2015[8]

AECC also has a direct and up-to-date insight to the price of wind energy through its existing PPA's. Specifically, news reports state that the recently completed Origin wind farm represents a nameplate capacity of 150 MW at a total cost of $250 million, or an installed project cost of roughly $1,667/kW.[9] The LBNL report corroborates this figure and reports that average installed project costs in the interior region of the country (including Texas, Oklahoma and Kansas), reached $1,638/kW in 2014.[10] According to a recent Electronic Quarterly Report (EQR) filing with the Federal Energy Regulatory Commission (FERC), Origin Wind Energy LLC transmitted 156,459 MWh of energy to AECC at a rate of $25.6/MWh, during the second quarter of 2015.[11]

As such, the use of a $2,327/kW installed cost for wind energy, as done in the Draft IRP, is significantly higher than national average installed costs, as well as costs from AECC's existing wind energy PPA's. SWEA recommends using market-based installed cost information, or AECC's existing wind PPA's as price points for modeling purposes. Additionally, because renewable energy costs are frequently reported as all-in PPA's (not necessarily on a $/kW installed cost basis), SWEA also recommends that AECC publish LCOE figures associated with the generation technologies evaluated in the IRP. At a minimum, AECC should strive to ensure the wind energy LCOE figures used in IRP modeling are similar to its existing PPA's.

Use Updated Capacity Factors for Wind Energy Resources

According to Draft IRP Table 7, wind energy was assigned a capacity factor of 45%. However, according to Draft IRP Table 5, wind energy generation from the 309 MW PPA's is expected to reach 1,332 GWh in 2017. As such, AECC's existing wind PPAs represent an average net capacity factor of 49.2%. Additionally, AECC should ensure that each wind resource evaluated in the IRP is analyzed individually and assigned a distinct capacity factor. SWEA has provided capacity factors for SPP wind, HVDC wind, and local wind resources in Figure 1.

Evaluate the Production Tax Credit (PTC) for Near-Term PPA's

The federal Production Tax Credit (PTC) is the primary federal incentive for wind energy resources. The PTC is benchmarked as a tax credit of $23/MWh of wind energy generated, and is available for the first ten years of a wind project.

The current Production Tax Credit expired in late 2014, however wind farms completed by the end of 2016 may still qualify for the PTC. The PTC has been extended numerous times with broad bipartisan support in the past and in July 2015, a key senate committee approved a bill that could extend the PTC to the end of 2016.[12] If Internal Revenue Service (IRS) guidelines remain similar, wind farm developments could qualify if development begins prior to the end of 2016 with operations beginning as late as 2018. Of course, at that time the PTC may be extended again. SWEA recommends that the PTC be evaluated through 2020, as a sensitivity, to best capture the likely near-term opportunities that will occur if the PTC extension occurs.

Apply Cost and Performance Learning Curves

As shown by the LBNL market report, wind energy PPA's have consistently declined since 2008 (See Figure 2).[13] Price declines are a factor of both improved performance and reduced all-in installed costs and highlight a need to apply a learning curve to wind energy resources, similar to solar energy resources. As part of the DOE *Wind Vision* report, the National Renewable Energy Laboratory (NREL) conducted an extensive literature review to deduce future cost reduction potential, as well as capacity factor improvements. The DOE noted that, "…the High Cost case represents no future cost reduction or performance improvement through 2050 for land-based wind, and the Low Cost case represents a land-based wind LCOE reduction of 37% by 2050."[14] In its "mid-cost" learning curves, the DOE reduced the 2014 installed capital cost assumptions between 1.1% to 4.3% by 2020, and a full 1.9% to 7.5% by 2030 (over 2014 cost assumptions). These figures varied depending on wind resource quality, with the lower cost reductions (1.1% by 2020 and 1.9% by 2030 over 2014 cost estimates) occurring in lower quality wind resource areas and the higher cost reductions (4.3% by 2020 and 7.5% by 2030 over 2014 cost estimates) in higher quality wind resource areas.

In addition to a reduction in installed costs, the DOE assigned performance improvements to turbine capacity factors. In its "mid-cost" learning curves, the DOE increased 2014 estimated capacity factors by 4.3% to 9.4% by 2020 and 10.6% to 15.8% by 2030. These figures varied depending on wind resource quality, with the lower capacity factor improvements (4.3% by 2020 and 10.6% by 2030 over 2014 capacity factors) occurring in higher quality wind resource areas and the higher capacity factor improvements (9.4% by 2020 and 15.8% by 2030 over 2014 cost estimates) in lower quality wind resource areas. SWEA recommends that the cost and performance learning curves be applied in AECC's base case as a standard input.

Apply Carbon Emission Reductions in All Modeling Cases

As noted in the Draft IRP, "Case 3: A marginal cost impact of $10/ton assumed for CO2 emissions in year 2020." It is unclear if AECC modeled some sort of carbon emission constraint or regulatory cost in all portfolio cases evaluated. AECC should use the current IRP to evaluate carbon emission reduction requirements based on the final federal Clean Power Plan (CPP).

Arkansas regulators have scheduled a meeting on October 9th, 2015, to begin discussing compliance options for the CPP.[15] State implementation plans (SIPs) are required to be submitted to the Environmental Protection Agency by September 6, 2018 or earlier[16]; thus waiting until the next IRP iteration (potentially late 2018) would limit AECC's ability to evaluate near-term CPP compliance options. For example, even though the official compliance period for the federal Clean Power Plan (CPP) has been delayed to 2022, the CPP contains a newly proposed Clean Energy Implementation Plan (CEIP) that would allow state to incorporate and receive credit for renewable energy purchases and low-income energy efficiency programs in place beginning in 2020. In order to qualify for those early compliance credits, the SIP must include the proposed CEIP projects by the time of submittal in 2018.

SWEA recommends that AECC include carbon emission constraints or regulatory costs in all portfolio cases evaluated, preferably as close of a resemblance of the CPP (with possible CEIP project inclusion) as possible. SWEA also recommends that AECC report its 2012 baseline carbon emissions and forward projections for each modeling case.

Use Wind Energy's Capacity Value as Firm Capacity

As the Draft IRP noted, wind energy is primarily viewed as an energy resource, not necessarily a capacity resource. To further "firm" wind energy resources, AECC provides cost estimates of coupling wind energy resources with a natural gas combustion turbine (CT) or with battery storage. According to Draft IRP Figure 24, the "firm" installed capital cost of wind energy, including CT backup, is reported as $2,949/kW; or $5,541/kW including battery backup.

However, a CT or battery "backup" are not strictly required for wind energy resources to provide capacity value, and the capacity value provided by wind resources should be analyzed as a benefit of wind during the IRP process. AECC estimates that about 15% of the installed wind capacity will be accredited as firm capacity. The Draft IRP notes that the SPP-side of AECC needs an additional 87 MW of firm capacity by 2020; by using AECC's 15% capacity value for wind energy, 580 MW of new wind energy resources could provide 87 MW of "firm" capacity by 2020.

New wind turbine and transmission technology (including wind energy delivered via new-build HVDC transmission) could also increase capacity values of wind energy resources. An HVDC converter station is planned for northern Arkansas (within MISO) and a previous study completed for TVA has calculated a 28% capacity value for that resource.[17] Also, firm capacity purchases may be available through market purchases in SPP to supplement wind energy capacity and those market purchases may be lower cost than new-build CT generation. In fact, contractual negotiations may be available whereby wind farm development companies provide "block scheduled" energy resources that could have higher capacity values precisely by supplementing wind energy generation with SPP market purchases and guaranteeing energy delivery at specific peak periods. SWEA recommends that wind energy's capacity value alone be used as AECC's evaluation of firm capacity. Or, if AECC prefers to evaluate wind energy resources at higher capacity values, to also incorporate market capacity procurement as an option.

SWEA does not currently recommend modeling battery storage to "firm" wind energy capacity in the IRP. According to Draft IRP Footnote #41, the price-point for battery storage technology was set based on the Tesla Powerwall, a 7 kWh daily cycling system for an installed cost of $3,000 (or $428/kWh of storage capacity). The Powerwall is only meant as a residential battery storage system. For the utility-scale market, Tesla is marketing the Powerpack battery system, which is designed to scale up to many megawatts worth of capacity with improved economies of scale (and reduced price). Elon Musk (Tesla's CEO) noted that the Powerpack price point is roughly $250/kWh of storage capacity.[18] However, and most importantly, these figures do not reflect continuous or peak power output. For the residential Powerpack of either 7 kWh or 10 kWh storage capacity, the continuous power output is rated at 2 kW while peak power output is rated at 3.3 kW.[19] SWEA is not aware of similar specifications published for the Powerwall, but such information is necessary to assign an actual capacity output value to battery storage. If the Powerwall specifications are the same as the Powerpack, but scaled to megawatt level, a 7 MWh Powerwall would have a continuous power output of 2 MW or peak output of 3.3 MW for a total cost of $1.75 million (at $250/kWh, multiplied by 7,000 kWh for storage capacity), or $825/kW capacity (continuous power output). Even this calculation is too simplistic because this system would only provide full generation over the course of roughly 3.5 hours. If AECC is interested in procuring battery storage, SWEA recommends additional research on utility-scale battery storage capital cost and performance assumptions. SWEA also recommends AECC more fully explain its modeling methodology and use dispatch modeling such as the PLEXOS Integrated Energy Model.

Recommendations for the Draft IRP

- Include feasible energy options, including out-of-state wind energy from a new HVDC transmission project, SPP and Local resources and adjust cost and performance accordingly.
- Use the data submissions SWEA provided for the IRP inputs (see Figure 1), including installed costs, capacity factors, levelized cost of energy as well as cost and performance improvements over the IRP study timeframe.
- Apply the Production Tax Credit as a sensitivity analysis for wind energy resources.
- Apply carbon emission reductions in all modeling cases, as best aligned with compliance with the federal Clean Power Plan as possible.
- Do not attempt to "firm" wind energy resources.

SWEA appreciates the opportunity to provide these comments. We are eager and willing to assist AECC and the Public Service Commission and staff in any way possible regarding this IRP process.

Sincerely,

Simon Mahan
Director
Southern Wind Energy Association

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Appendix C

Stakeholders Resource Planning Issue Form

Stakeholder Resource Planning Issue Submitted by: ___________________________

Representing (name of company or organization): _____________________________

This worksheet is designed to identify and develop key resource planning issues which should be discussed by the Stakeholders.

1. Key issue to be addressed by the Stakeholders:
2. Description of the planning issue:
3. Why is the issue important?
5. What are the benefits of the issue?
6. What are the risks associated with the issue?
7. What obstacles may exist to a possible implementation of the issue?