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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER	)	
COOPERATIVE, INC. FOR APPROVAL OF THE	)	
ACQUISITION OF EXISTING COMBUSTION TURBINE	)	
FACILITIES FROM BLUEGRASS GENERATION	)	Case No. 2015-00267
COMPANY, LLC AT THE BLUEGRASS GENERATING	)	
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY	)	
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN	)	
EVIDENCES OF INDEBTEDNESS	)	

DIRECT TESTIMONY OF DON MOSIER

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: July 24, 2015

EXHIBIT

4

I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Don Mosier and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Executive Vice President and Chief Operating Officer at EKPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I obtained my Bachelor of Science degree in civil engineering from the University of Virginia and my Master of Business Administration degree from the Kenan-Flagler Business School at the University of North Carolina. My professional experience includes work at Carolina Power & Light (now Duke Energy Progress, Inc.) in Raleigh, North Carolina, developing merchant generation projects and marketing activities, regulatory affairs, and nuclear power plant engineering and operations. I also was an engineering manager of U.S. Operations for Canatom Corp., a Canadian-based engineering firm that provides nuclear plant engineering and construction services. Immediately prior to joining EKPC, I was Vice President of St. Louis-based Ameren Energy Marketing ("AEM'), a subsidiary of Ameren Corp. At AEM, I managed wholesale power trading, plant dispatch, NERC and SERC compliance, transmission and congestion management activities, and customer account management for Ameren Corporation's unregulated merchant generation fleet located in the Midcontinent ISO and PJM Regional Transmission Organization.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AT EKPC.

A. I manage the day-to-day operations of power production and construction, power delivery, power supply, and system operations. I report directly to EKPC's Chief Executive Officer, Mr. Anthony Campbell.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is first to provide a general overview of EKPC's business and existing generation and transmission system. I will discuss EKPC's Strategic Plan, EKPC's current and anticipated needs with respect to capacity, and the actions EKPC has taken and proposes to take to ensure the continued provision of reliable, affordable, and safe energy to its Owner-Members. I will also describe EKPC's proposed acquisition of the existing combustion turbine facilities located in LaGrange, Oldham County, Kentucky (the "Bluegrass Station"), from Bluegrass Generation Company, LLC ("Bluegrass"), as well as the labor requirements of the Bluegrass Station and other operational matters. Finally, I will discuss how the proposed acquisition furthers the goals of EKPC's Strategic Plan and is consistent with prudent utility operations and management.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No.

II. Overview of EKPC

Q. PLEASE GENERALLY DESCRIBE EKPC'S BUSINESS.

A. EKPC is a not-for-profit, member-owned generation and transmission rural electric cooperative corporation with its headquarters in Winchester, Kentucky. EKPC provides wholesale electricity to its sixteen Owner-Member distribution cooperatives, which in turn serve approximately 525,000 Kentucky homes, farms and commercial and industrial establishments in eighty-seven (87) Kentucky counties.

Q. PLEASE DESCRIBE EKPC'S EXISTING GENERATION PORTFOLIO.

A. In total, EKPC owns or purchases a total of approximately 2,794 MW of net summer generating capability and 3,009 MW of net winter generating capability. EKPC owns and operates coal-fired generation at Dale Station in Clark County, Kentucky (149 MW), Cooper Station in Pulaski County, Kentucky (341 MW) and Spurlock Station in Mason County, Kentucky (1,346 MW). EKPC also owns and operates natural-gas fired generation at Smith Station in Clark County, Kentucky (774 MW (summer)/989 MW (winter)), and landfill gas-to-energy facilities in Boone County, Kentucky (3.2 MW), Laurel County, Kentucky (3.2 MW), Greenup County, Kentucky (2.4 MW), Hardin County, Kentucky (2.4 MW) and Pendleton County, Kentucky (3.2 MW). Finally, EKPC purchases hydropower from the Southeastern Power Administration at Laurel Dam in Laurel County, Kentucky (70 MW), and the Cumberland River system of dams in Kentucky and Tennessee (100 MW).

Q. PLEASE GENERALLY DESCRIBE EKPC'S EXISTING TRANSMISSION SYSTEM.

A. EKPC owns 2,938 circuit miles of high voltage transmission lines in various voltages. EKPC also owns the substations necessary to support this transmission line infrastructure. Currently, EKPC has seventy-three (73) free-flowing interconnections with its neighboring utilities. EKPC's transmission system is operated by PJM Interconnection, LLC ("PJM"), of which EKPC has been a fully-integrated member since June 1, 2013. PJM is a regional electric grid and market operator with operational control of over 180,000 MW of regional electric generation. It operates the largest capacity and energy market in North America.

Q. DOES EKPC HAVE A STRATEGIC PLAN CURRENTLY IN PLACE?

A. Yes. Following a Commission-directed management audit, EKPC's Board adopted a Strategic Plan in 2011 that identified pursuing prudent diversity in the fuel mix of its generation portfolio, evaluating new investments using sound financial principles and strengthening the company's balance sheet by increasing its equity-to-assets ratio as three (3) of its core strategies. EKPC has convened Strategic Plan retreats annually since 2011 with the most recent being 2014. Generation diversity and financial stability remain cornerstones of EKPC's current Strategic Plan.

III. Addressing a Need for Capacity

Q. DOES EKPC BELIEVE ITS EXISTING GENERATION PORTFOLIO WILL ADEQUATELY PROVIDE FOR ITS LONG-TERM NEEDS?

A. No. As demonstrated by its 2015 Integrated Resource Plan, EKPC is an electric generation and transmission cooperative with a growing demand for electricity within its service territory.[1] In addition, two consecutive winters with extremely cold temperatures, the ongoing nationwide shift in electric generation fuel sources away from coal and toward natural gas, and the unprecedented, rapid expansion of stringent federal environmental regulation affecting utilities all combine to make

[1] *See In the Matter of The 2014 Integrated Resource Plan of Eastern Kentucky Power Cooperative, Inc.*, Case No. 2015-00134 (filed April 21, 2015).

the ownership of electric generation peaking resources a strategic imperative for EKPC.

Q. PLEASE GENERALLY DESCRIBE THE EFFORTS UNDERTAKEN BY EKPC IN RECENT YEARS TO ADDRESS ITS CAPACITY NEEDS.

A. EKPC has undertaken extensive efforts in recent years to appropriately plan for and satisfy its capacity requirements. In addition to being an active, fully-integrated member of PJM, EKPC has pursued and promoted a robust demand-side management/energy efficiency portfolio and entered into power purchase agreements when necessary. Moreover, EKPC regularly evaluates its generation fleet to ensure availability and compliance; one such evaluation ultimately resulted in the reconfiguration of EKPC's Cooper Station Unit 1 so as to flow its emissions through the existing air quality control system servicing Cooper Unit 2.

Q. DOES THE RECONFIGURATION OF COOPER UNIT 1 RESOLVE THE CAPACITY SHORTFALL EKPC SOUGHT TO ADDRESS THROUGH THE 2012 RFP?

A. No it does not. EKPC still needs to replace the loss of approximately 200 MW of capacity from the retirement of the Dale Station as well as plan for future load growth. The extreme weather occasioned by the 2014 Polar Vortex, combined with new demand peaks in winter 2015 and increased market volatility, confirmed that significant additional capacity is also necessary to mitigate market risk arising from EKPC's capacity shortfall, which totaled nearly 650 MW at the point of EKPC's recent historic winter peak. To address these issues, EKPC engaged The Brattle

Group in the summer of 2014 to undertake a refresh of the competitive bids from the 2012 RFP.

Q. HAS EKPC DETERMINED AND SELECTED THE REASONABLE LEAST-COST OPTION FOR ADDRESSING ITS CURRENT CAPACITY NEEDS?

A. Yes. In light of the RFP Refresh, extensive third-party analyses and its own due diligence, EKPC has concluded that the Bluegrass Station is the reasonable, least-cost power supply option that will enable it to meet a greater amount of its current and future capacity and energy needs without relying upon long-term power purchases.

IV. Bluegrass Station Acquisition

Q. BRIEFLY SUMMARIZE THE PROPOSED ACQUISITION.

A. On June 26, 2015, EKPC and Bluegrass entered into an Asset Purchase Agreement ("Agreement") whereby Bluegrass agreed to sell and assign, and EKPC agreed to purchase and assume, substantially all of the assets and certain specified liabilities of Bluegrass, for the total consideration of $128.75 million, subject to certain terms and conditions set forth in the Agreement.[2] EKPC will realize a total of approximately 500 MW (summer capacity) of additional generation capacity at a cost of $260/kW,[3] which is substantially lower than the estimated $867/kW cost for the new construction of a comparable unit. Stated another way, EKPC stands to recognize a net gain on the transaction so long as the capacity price in PJM remains

[2] A copy of the Asset Purchase Agreement is attached to the Application as Exhibit 3.

[3] These figures reflect the Bluegrass Station's net summer capacity. The Bluegrass Station has a total rating of 594 MW of winter capacity, which equates to a cost of roughly $217/kW.

above $[redacted]/MW-day (2016 dollars), which is considerably below the $120 per MW-day price established in the last PJM incremental capacity auction for planning year 2016/2017. Based on the results of extensive due diligence, EKPC believes it has determined the reasonable least-cost option to addressing its demonstrated need for additional capacity.

Q. DID EKPC CONDUCT APPROPRIATE DUE DILIGENCE PRIOR TO ENTERING INTO THE APA WITH BLUEGRASS?

A. Yes. EKPC conducted extensive due diligence as part of its evaluation of the Bluegrass Station proposal. During the 2012 RFP, EKPC's Power Supply Planning Group retained Burns and McDonnell Engineering Co., Inc. ("B&McD"), to write a Due Diligence Evaluation Report on the Bluegrass Generation Facility. EKPC's Power Production was not involved in this report due to being involved in the self-bid submittal into the RFP. The B&McD report was made available to Power Production staff for review in 2014 after having no further involvement in the RFP process. The report was reviewed by Power Production, whose staff agreed with B&McD's assessment of no material flaws for the facility.

EKPC subsequently engaged the Siemens Corporation, which is the Original Equipment Manufacturer, to perform a detailed borescope inspection of each of the Bluegrass Station Units. The inspection of Unit 1 was performed on April 7-8, 2015, Unit 2's on April 6-7, 2015, and Unit 3's on April 3-5, 2015. Keith McCoy, EKPC's Smith Station Combustion Turbine Supervisor, witnessed each of the inspections, none of which revealed any material flaws.

Following the inspections, EKPC conducted evaluations of the Units while each was in operation. On April 22, 2015, several key staff from EKPC were present to witness the operation of the Units. All three Units were operated for several hours with no material issues observed.

In addition to B&McD's analysis, the borescope inspections, and the review of actual operation, EKPC staff interviewed several companies that have experience with the design and technology of the Bluegrass Station Units. These companies included the Siemens Corporation, Sulzer Turbo, Ethos Energy, and Calpine. All indicated that the Bluegrass Station Units employed mature and reliable technology.

In complement of the operations and engineering due diligence performed, EKPC conducted a thorough review of the transmission and environmental aspects of the proposed transaction and identified how the acquisition is expected to impact EKPC, its Owner-Members, and the end-use consumers. The conclusions of EKPC and its consultants, including those related to value and estimated economic benefits, are detailed in EKPC's Application and supporting testimonies.

Q. IS THE PROPOSED ACQUISITION CONSISTENT WITH EKPC'S STRATEGIC PLAN?

A. Yes. The contemplated transaction is consistent with EKPC's Strategic Plan in many respects. The acquisition of a natural gas-fired facility will result in diversification of EKPC's generation portfolio, and the location of the Bluegrass Station results in greater geographical diversity to EKPC's fleet. Additionally, the purchase price and extensively-studied economics of the contemplated transaction suggest that EKPC will be able to gain significant additional generation capacity without sacrificing financial stability or threatening the Cooperative's improved equity position and credit ratings. Finally, and most fundamentally, the proposed transaction will ensure that EKPC may continue to provide adequate, efficient and safe energy to its Owner-Members at rates that are fair, just and reasonable.

Q. WILL EKPC'S ACQUISITION OF THE BLUEGRASS STATION PROMOTE THE LOCAL ECONOMY THROUGH THE CREATION OF WELL-COMPENSATED POSITIONS?

A. Yes. Upon the completion of the acquisition, EKPC anticipates using the generation assets more frequently than they are currently used and, therefore, an around-the-clock labor presence will be necessary. EKPC believes that it may expand the current workforce of six (6) full-time equivalent ("FTE") positions at the Bluegrass Station to as many as ten (10) FTE positions. Thus, the increased usage of the Bluegrass Station will also provide a local benefit to the Oldham County community by creating up to four (4) new, skilled, well-compensated FTE positions.

Q. HOW WILL EKPC'S EQUITY RATIO BE IMPACTED BY THE PROPOSED ACQUISITION?

A. EKPC remains on track to accomplish its strategic objective of achieving a 15% equity ratio by this year. EKPC has made significant progress towards improving its financial strength over the past six (6) years and has benefitted from a series of credit rating upgrades and favorable guidance from the major credit rating agencies.

Q. HAS THE BLUEGRASS STATION ACQUISITION BEEN APPROVED BY EKPC'S BOARD OF DIRECTORS?

A. Yes. On May 12, 2015, after months of discussion, EKPC's Board approved a resolution authorizing EKPC's President and Chief Executive Officer to enter into the agreements necessary to accomplish the purchase of the Bluegrass Station. Following further negotiations, the Board reaffirmed its prior authorization in the course of a special Board Meeting that occurred on June 24, 2015.[4]

Q. IS THE ACQUISITION OF THE BLUEGRASS STATION THE REASONABLE, LEAST-COST OPTION FOR ADDRESSING EKPC'S CAPACITY NEEDS?

A. Yes. There are many reasons why the proposed acquisition of the Bluegrass Station is the reasonable, least-cost option for addressing EKPC's long-term capacity needs. These reasons include:

- Allowing the acquisition of generation capacity at a cost of $260/kW, which is substantially lower than the estimated $867/kW cost for the new construction of a comparable unit, while at the same time avoiding associated construction risk;
- Diversifying EKPC's generation portfolio by becoming less reliant on coal-fired generation while taking advantage of the dramatic increases in, and lower cost of, natural gas supplies in the region;

[4] A copy of the Resolutions from the May 12, 2015 and June 24, 2015 Board Meetings are attached to the Application as Exhibit 1.

- Providing greater geographical diversity to EKPC's generation fleet;
- Mitigating EKPC's growing winter peak exposure and the increasing market price volatility during those periods;
- Eliminating the need for EKPC to rely upon more costly market-based power purchase agreements to satisfy its load;
- Gaining significant additional generation capacity without sacrificing financial stability or threatening EKPC's improved equity position and credit ratings;
- Keeping EKPC well-positioned to comply with existing and forthcoming environmental regulations and mandates, while mitigating compliance and market locational risks of investing in out-of-state resources;
- Complying with the Commission's stated policy[5] that utilities should seek to have adequate capacity to serve native load;
- Minimizing technology and performance risk by acquiring reliable simple-cycle natural gas combustion turbine technology with proven field experience and a large fleet base;
- Maximizing EKPC's core strengths by acquiring facilities and technology similar to the facilities at its Smith Station in Trapp, Kentucky;
- And supporting the local economy by bringing up to five (5) additional well-paying jobs into the region.

[5] *See In the Matter of the Examination of the Application of the Fuel Adjustment Clause of East Kentucky Power Cooperative, Inc. From November 1, 2013 through April 30, 2014*, Order, Case No. 2014-00226 (Ky. P.S.C. Jan. 30, 2015) ("The Commission believes it is important to maintain the limitation for recovery through the FAC of 'non-economy energy purchases' in order to incentivize utilities to keep outages to a minimum *and to have sufficient capacity to meet load.*") (emphasis added) (rehearing denied July 10, 2015).

V. Conclusions

Q. WHAT IS REQUESTED BY EKPC IN THIS PROCEEDING?

A. EKPC respectfully requests the Commission to issue a Certification of Public Convenience and Necessity for its acquisition of the Bluegrass Station. EKPC also requests that the Commission approve the assumption of certain evidences of indebtedness associated with the proposed transaction.

Q. WHY SHOULD THE COMMISSION GRANT EKPC'S REQUESTED RELIEF?

A. The Bluegrass Station acquisition does not result in an excess of capacity over need, an excessive investment in relation to productivity or efficiency or an unnecessary multiplicity of physical properties. Extensive environmental regulation, growing winter demand, and significant power price volatility has created a need that EKPC seeks to address in a responsible and cost-effective manner. As detailed in the Testimony of Mike McNalley submitted herewith, EKPC's assumption of certain evidences of indebtedness as part of the proposed acquisition is consistent with law and Commission precedent. EKPC has undertaken a thorough review of other alternatives, and, after balancing all factors, the acquisition of the Bluegrass Station is the reasonable, least-cost option.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER)
COOPERATIVE, INC. FOR APPROVAL OF THE)
ACQUISITION OF EXISTING COMBUSTION TURBINE)
FACILITIES FROM BLUEGRASS GENERATION) Case No. 2015-______
COMPANY, LLC AT THE BLUEGRASS GENERATING)
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY)
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN)
EVIDENCES OF INDEBTEDNESS)

VERIFICATION OF DON MOSIER

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Don Mosier, Executive Vice President and Chief Operating Officer of East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Don Mosier

Don Mosier

The foregoing Verification was signed, acknowledged and sworn to before me this 22nd day of July, 2015, by Don Mosier.

NOTARY PUBLIC, Notary # 502993
Commission expiration: 1/27/18

BRENDA BOWEN
Notary Public
State at Large
Kentucky
My Commission Expires Jan 27, 2018

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR APPROVAL OF THE ACQUISITION OF EXISTING COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC AT THE BLUEGRASS GENERATING STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN EVIDENCES OF INDEBTEDNESS	) Case No. 2015-_______

DIRECT TESTIMONY OF DAVID CREWS

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: July 24, 2015

EXHIBIT

5

I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is David Crews and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Senior Vice President of Power Supply at EKPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor's degree in Civil Engineering from North Carolina State University and am a registered professional engineer in North Carolina. Prior to joining EKPC, I served as Manager of Federal Regulatory Affairs at Progress Energy Service Co. I also served as the Director of Coal Marketing and Trading for Progress Fuels, and as Director of Power Trading Operations at Progress. I began working at EKPC in January of 2011; in all, I have more than 32 years of experience in the electric utility industry.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AT EKPC.

A. Generally, I oversee EKPC's Power Supply, which includes the areas of Power Supply Planning, Load Forecasting, PJM Market Operations, Fuel Supply, Renewable Energy Projects, Demand Side Management and Energy Efficiency.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is first to describe EKPC's power supply needs and the efforts it has undertaken in the past four years to address those needs. I will detail the Request for Proposals ("RFP") processes initiated by EKPC in 2012 and

2014 (the "2012 RFP" and "RFP Refresh," respectively), explain EKPC's proposed acquisition of the existing combustion turbine facilities located in LaGrange, Oldham County, Kentucky (the "Bluegrass Station"), from Bluegrass Generation Company, LLC ("Bluegrass"), address the various aspects of the proposed acquisition, and describe the analyses performed by EKPC and its consultants with respect to the proposed acquisition. Finally, I will testify as to the anticipated operation of the Bluegrass Station in PJM Interconnection, LLC ("PJM"), and provide the bases for EKPC's conclusion that the proposed acquisition is the reasonable, least-cost option for satisfying EKPC's needs.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which I ask be incorporated into my testimony by reference:

- Exhibit DC-1, ACES East Kentucky Power Cooperative Bluegrass Valuation Report (January 20, 2015); and
- Exhibit DC-2, a map of the Bluegrass Station.

Each of these exhibits was prepared by me, under my supervision, or at my request.

II. Existing Generation Portfolio and Identification of Need

Q. PLEASE GENERALLY DESCRIBE EKPC'S EXISTING GENERATION PORTFOLIO.

A. In total, EKPC owns or purchases a total of approximately 2,794 MW of net summer generating capability and 3,009 MW of net winter generating capability. EKPC owns and operates coal-fired generation at Dale Station in Clark County, Kentucky (149 MW), Cooper Station in Pulaski County, Kentucky (341 MW) and

Spurlock Station in Mason County, Kentucky (1,346 MW). EKPC also owns and operates natural-gas fired generation at Smith Station in Clark County, Kentucky (774 MW (summer)/989 MW (winter)), and landfill gas-to-energy facilities in Boone County, Kentucky (3.2 MW), Laurel County, Kentucky (3.2 MW), Greenup County, Kentucky (2.4 MW), Hardin County, Kentucky (2.4 MW) and Pendleton County, Kentucky (3.2 MW). Finally, EKPC purchases hydropower from the Southeastern Power Administration at Laurel Dam in Laurel County, Kentucky (70 MW), and the Cumberland River system of dams in Kentucky and Tennessee (100 MW).

Q. IS EKPC A MEMBER OF A REGIONAL TRANSMISSION ORGANIZATION?

A. Yes. EKPC has been a fully-integrated member of PJM since June 1, 2013. PJM is a regional electric grid and market operator with operational control of over 180,000 MW of regional electric generation, and it operates the largest capacity and energy market in North America. Generally, EKPC sells the output of its generation resources into, and purchases its energy needs from, the PJM marketplace.

Q. WILL THERE BE INSTANCES WHEN EKPC'S GENERATION IS INSUFFICIENT TO HEDGE EKPC'S LOAD IN THE PJM MARKET?

A. Yes. It is a common occurrence for EKPC's load to exceed its generation hedge during winter seasons unless additional purchases have been secured. With Dale Units 3 and 4 being unavailable, these occurrences will increase. During times of extreme temperatures such as those associated with the 2014 Polar Vortex and the record cold of 2015, EKPC does not have enough generation or load response to hedge its load from high energy prices that commonly accompany extreme weather. During the winter of 2013/2014, EKPC saw prices over $2000/MWh and EKPC experienced $9.8 million in unrecoverable energy expenses. EKPC's all-time peak demand of 3,507 MW occurred on February 20, 2015, which exceeded its net winter generating capability by nearly 500 MW.

Q. WHY DOES EKPC BELIEVE IT PRUDENT TO CONTINUE TO OWN AND OPERATE GENERATION IF ITS FUTURE POWER SUPPLY NEEDS CAN BE MET THROUGH PURCHASES FROM THE PJM MARKETPLACE?

A. The PJM market is structured such that Load Serving Entities ("LSEs") with no generation can participate. In the PJM market, LSEs must purchase capacity in the Base Residual Auction ("BRA") based on their previous year's peak loads. The purchase of capacity in the BRA allows LSEs to participate in the Day-Ahead and Balancing energy markets. Participating in the PJM markets in this manner does not provide LSEs any protection from price volatility in the energy or capacity markets.

EKPC believes that its Owner-Members are best served by participating in the PJM market with both load and generation. EKPC's generation resources serve as a hedge in both the capacity and energy markets. By netting EKPC's load and generation against one another, EKPC's customers benefit when:

a) EKPC purchases energy at less than the dispatch cost of its plants;

b) EKPC generation is less than the market price of energy and through netting EKPC's generation caps it energy costs; or

c) any excess capacity is monetized in the capacity auctions.

EKPC believes that participation in the PJM market yields vital benefits to its Owner-Members but that relying solely on the market to serve its energy needs would introduce unacceptable price volatility to the systems it serves.

Q. IN WHAT WAYS DOES EKPC PLAN FOR ITS FUTURE POWER SUPPLY NEEDS?

A. Like any prudent utility, EKPC constantly strives to anticipate the challenges it may face over both the near- and long-term. As part of this process, EKPC regularly conducts and reviews load and pricing forecasts, prepares for environmental developments, and evaluates the impact various factors may have on the Cooperative's existing generation portfolio and overall financial stability. EKPC's Board of Directors, through its Strategic Plan, provides particular guidance in identifying and achieving EKPC's future goals.

Q. DOES EKPC HAVE A STRATEGIC PLAN CURRENTLY IN PLACE?

A. Yes. Following a Commission-directed management audit, EKPC's Board adopted a Strategic Plan in 2011 that identified various core strategies, including but not limited to pursuing prudent diversity in the fuel mix of the Cooperative's generation portfolio and evaluating new investments using sound financial principles. EKPC has convened Strategic Plan retreats annually since 2011 with the most recent being 2014. Generation diversity remains a cornerstone of the current Strategic Plan.

Q. DOES EKPC BELIEVE ITS EXISTING GENERATION PORTFOLIO WILL ADEQUATELY PROVIDE FOR ITS LONG-TERM NEEDS?

A. No. EKPC is an electric generation and transmission cooperative with a growing demand for electricity within its service territory. In addition, the increasing integration of the regional electric transmission system, two consecutive winters with extremely cold temperatures, the ongoing nationwide shift in electric generation fuel sources away from coal and toward natural gas, and the unprecedented, rapid expansion of stringent federal environmental regulation affecting utilities all combine to make the ownership of electric generation peaking resources a strategic imperative for EKPC.

Q. PLEASE GENERALLY DESCRIBE EKPC'S ENERGY NEEDS AS REFLECTED IN ITS MOST-RECENT INTEGRATED RESOURCE PLAN.

A. On April 21, 2015, EKPC filed its most recent triennial Integrated Resource Plan ("2015 IRP"), which analyzed EKPC's forecasted load, capacity needs and related issues over a twenty-year period from 2015 through 2034. The 2015 IRP indicates that EKPC's total energy requirement will increase by 1.4% per year over a twenty year period. Reflecting EKPC's status as a winter-peaking utility, the 2015 IRP indicates that EKPC's winter net peak demand will increase 1.0% annually while its summer net peak demand will increase by 1.5% annually. Also, the 2015 IRP predicts that EKPC's annual load factor would increase from 48% to 51%.

Q. HAS FEDERAL ENVIRONMENTAL REGULATION HAD A PARTICULARLY SIGNIFICANT IMPACT ON EKPC'S GENERATION PORTFOLIO AND POWER SUPPLY PLANNING?

A. Yes. Generation and transmission cooperatives such as EKPC are among the most stringently environmentally regulated entities in the United States. The pace of revisions to federal environmental rules has increased substantially over the past decade and significantly impacted EKPC's business as a result. Although the multitude of environmental rules and regulations with which EKPC must comply is more acutely detailed in the testimony of Mr. Jerry Purvis, EKPC's Director of Environmental Affairs, there can be no doubt that the Environmental Protection Agency's Mercury and Air Toxics Standards ("MATS"), Effluent Limitation Guidelines ("ELG"), and Disposal of Coal Combustion Residuals from Electric Utilities Rule ("CCR") have presented numerous challenges to EKPC.

Q. HOW HAS FEDERAL ENVIRONMENTAL REGULATION IMPACTED EKPC'S GENERATION PORTFOLIO IN RECENT YEARS?

A. While EKPC's Spurlock Station, Cooper Station Unit 2 and Smith Station have each been relatively well-positioned for compliance with existing environmental rules, the economic viability of Dale Station and Cooper Station Unit 1 was called into question in light of the investments that would have been required to bring them into compliance with the EPA's new and forthcoming rules (*i.e.*, MATS, CCR, ELG).

III. The 2012 RFP and the RFP Refresh

Q. PLEASE GENERALLY DESCRIBE THE PURPOSE OF THE 2012 RFP.

A. The purpose of the 2012 RFP was to determine if further investments in Dale Station and Cooper Station Unit 1 to comply with MATS were warranted. The 2012 RFP was structured to compare the costs required to bring the Dale Station and Cooper Station Unit 1 into compliance with MATS with the costs of alternative power supply options available in the market. EKPC sought to obtain up to 300 MW of additional generation through the 2012 RFP.

Q. DID EKPC ENGAGE A CONSULTANT TO CONDUCT THE 2012 RFP?

A. Yes. EKPC retained the Brattle Group ("Brattle") in May 2012 to assist with the 2012 RFP and to provide independent and unbiased analysis of the power supply opportunities available. Brattle is widely known for its knowledge and skill set in the generation and transmission industry, and EKPC has successfully worked with Brattle on a number of occasions.

Q. WHAT TYPES OF POWER SUPPLY OPTIONS WAS EKPC WILLING TO CONSIDER AS PART OF THE 2012 RFP?

A. EKPC was willing to consider proposals to purchase new or existing power plants, to enter into intermediate-term or long-term power supply contracts, and to purchase power from renewable or conventional resources. The only strict constraints that EKPC imposed on the supply proposals were that they (a) specify a term of at least five years and (b) specify no less than 50 MW if for power from conventional generation resources and no less than 5 MW if for power from renewable generation sources.

Q. DID EKPC SUBMIT ANY SELF-BUILD PROPOSALS AS PART OF 2012 RFP?

A. Yes. EKPC's Power Production Engineering & Construction group submitted several proposals in response to the 2012 RFP, most notably a proposal to reconfigure Cooper Unit 1 so as to flow its emissions through the existing air quality control system servicing Cooper Unit 2.

Q. DID ANY OF THE RESPONSES TO THE 2012 RFP INVOLVE THE BLUEGRASS STATION?

A. Yes. James Read will discuss this further in his Testimony.

Q. WHAT DID BRATTLE CONCLUDE BASED TO ITS ANALYSIS OF THE RESPONSES TO THE 2012 RFP?

A. Brattle determined that the Cooper Unit 1 retrofit proposed by EKPC was the most attractive of those on the short list. The proposal was designed to return approximately 116 MW of existing generation to service for an investment of $15 million. With respect to Dale Units 3 and 4, however, Brattle found that there were better alternatives than further investment in those Units. Accordingly, EKPC's Board voted to retire Dale Units 1 and 2 and to place Dale Units 3 and 4 in inactive status; moreover, and consistent with Brattle's recommendation, EKPC's Board also voted to pursue the Cooper Unit 1 retrofit, which was the highest value-added option available to EKPC as a result of the 2012 RFP. The Commission approved the Cooper Unit 1 retrofit in February 2014.[1]

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[1] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for Alteration of Certain Equipment at the Cooper Station and Approval of a Compliance Plan Amendment for Environmental Surcharge Cost Recovery*, Case No. 2013-00259 (Ky. P.S.C. Feb. 20, 2014).

Q. DID THE COOPER UNIT 1 RETROFIT RESOLVE THE CAPACITY SHORTFALL EKPC SOUGHT TO ADDRESS THROUGH THE 2012 RFP?

A. No it did not. EKPC still needs to replace the loss of 200 MW of capacity from the retirement of the Dale Station as well as plan for future load growth and increases in load factor. Examining the winter of 2014/2015 provides a good example. EKPC's IRP projected a normalized load of 3201 MW. EKPC had 3076 MW (which included Dale Units 3 & 4) of generation available and made 200 MW of market purchases for a total of 3276 MW to hedge its load. EKPC experienced load in the 2014/2015 winter of 3507 MW. The extreme weather occasioned by the 2013/2014 winter and 2014/2015 winter increased market volatility and confirmed that significant additional capacity is also necessary to mitigate market risk. To address these issues, EKPC engaged Brattle in the summer of 2014 to undertake a refresh of the bids from the 2012 RFP.

Q. WHAT DO YOU MEAN WHEN YOU SAY THE RFP REFRESH WAS A "REFRESH" OF THE 2012 RFP?

A. The RFP Refresh was not a "start from scratch" endeavor; because of the proximity in time and similarity in need sought to be remedied by the 2012 RFP and RFP Refresh, EKPC and Brattle believed it prudent to utilize the 2012 RFP as a starting point for the RFP Refresh. Essentially, those firms that submitted conventional power supply proposals in response to the 2012 RFP were invited to submit updated or new proposals as part of the RFP Refresh.

Q. WHAT CHARACTERISTICS DID EKPC SEEK IN PROPOSALS SUBMITTED AS PART OF THE RFP REFRESH?

A. As part of the RFP Refresh, EKPC sought power purchase (*e.g.*, gas tolling) agreements or purchase and sale agreements for new or existing power plants or shares thereof. Consistent with EKPC's Strategic Plan (which promotes the pursuit of diversity in the fuel mix of the Cooperative's generation portfolio) and considerations of existing and future environmental regulation, EKPC sought dispatchable generation with natural gas as the primary generation feedstock. Additionally, EKPC sought proposals with a minimum term of three (3) years, as well as a minimum size of 100 MW and maximum size of 300 MW.

Q. WHY DID EKPC NOT SEEK ANY DEMAND-SIDE MANAGEMENT OR ENERGY EFFICIENCY PROPOSALS AS PART OF THE 2014 RFP?

A. Pursuant to the Commission's mandate in Case No. 2008-00408,[2] EKPC has integrated energy efficiency resources into its long-term energy supply plan and has adopted policies establishing cost-effective energy efficiency resources with equal priority as other resource options. In the situation presented, however, the capacity and energy loss associated with the retirement of the Dale Station is so great that replacing that loss with demand-side management or energy efficiency resources is not practical or efficient.

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[2] *See In the Matter of Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007*, Rehearing Order, Case No. 2008-00408, p. 10 (Ky. P.S.C. July 24, 2012).

Q. WHAT DID BRATTLE CONCLUDE BASED ON ITS ANALYSIS OF THE RESPONSES TO THE RFP REFRESH?

A. Brattle concluded that EKPC's acquisition of the Bluegrass Station was the most attractive option of those on the short list. Brattle determined that EKPC could acquire approximately 500 MW (summer capacity) of existing generation for an initial investment of approximately $128 million.

Q. PLEASE EXPLAIN WHY THE CAPACITY OF THE BLUEGRASS STATION EXCEEDS THE MAXIMUM AMOUNT OF CAPACITY EKPC SOUGHT TO ACQUIRE THROUGH THE RFP REFRESH.

A. As part of the RFP Refresh, EKPC was presented a proposal to purchase the entirety of the Bluegrass Station's capacity. The sale offer for the entire plant's capacity was more operationally and economically attractive than any other offer received. EKPC was initially only seeking to replace its lost Dale Station capacity, but EKPC is already short winter capacity even with Dale Station on line. The purchase of the additional capacity at Bluegrass Station provides an additional, economic hedge for EKPC's winter peak load.

IV. The Bluegrass Station at Present

Q. PLEASE DESCRIBE THE UNITS THAT COMPRISE THE BLUEGRASS STATION.

A. The Bluegrass Station is comprised of three natural gas-fired simple cycle combustion turbine power generation units. Each Unit has a rated capacity of 198 MW, giving the Bluegrass Station a total rating of 594 MW of winter capacity. The Bluegrass Station's net summer capacity is 165 MW per unit, for a total of 495

MW. The Units offer a heat rate of 10,800 MMBtu/MWh and are based upon proven and mature technology. Each of the Units at the Bluegrass Station is projected to have a capacity factor that is consistent with other combustion turbines in EKPC's fleet. While the initial capacity factors are lower in the 2016-2022 timeframe, they are forecasted to increase substantially thereafter as federal carbon policy is implemented.

Q. PLEASE DESCRIBE THE TOLLING AGREEMENT THAT IS IN PLACE WITH RESPECT TO BLUEGRASS STATION UNIT 3.

A. On November 24, 2014, the Commission approved the request of Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E") to enter into a four year Tolling Agreement with Bluegrass.[3] Under the Tolling Agreement, KU and LG&E have access to 165 MW of firm generation capacity and output from Bluegrass Station's Unit 3 from May 1, 2015, through April 30, 2019. In Case No. 2014-00321, KU and LG&E estimated that they would pay approximately $38.5 million in capacity and fixed operations and maintenance costs over the four year term of the Tolling Agreement.

V. The Proposed Transaction

Q. HAS EKPC ENTERED INTO AN AGREEMENT TO ACQUIRE THE BLUEGRASS STATION?

A. Yes. On June 26, 2015, EKPC and Bluegrass entered into an Asset Purchase Agreement ("APA") whereby Bluegrass agreed to sell and assign, and EKPC

[3] *See Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement*, Order, Case No. 2014-00321 (Nov. 24, 2014).

agreed to purchase and assume, substantially all of the assets and certain specified liabilities of Bluegrass, for the total consideration of $128.75 million, subject to certain terms and conditions set forth in the Agreement.

Q. WILL EKPC ASSUME THE RIGHTS AND OBLIGATIONS OF BLUEGRASS UNDER THE TOLLING AGREEMENT WITH KU/LG&E?

A. Yes. EKPC has begun the process of seeking the consent of KU and LG&E to the assignment of the Tolling Agreement. Preliminary discussions suggest that consent to the assignment would be given as part of the closing of the proposed transaction.

Q. WHAT APPROVALS OR CONSENTS ARE NECESSARY IN ORDER FOR THE PROPOSED TRANSACTION TO BE CONSUMMATED?

A. Bluegrass or EKPC must seek consents under the law, or by virtue of the terms of various material contracts, from the following agencies and entities: Federal Trade Commission and U. S. Department of Justice (Hart-Scott-Rodino); Kentucky Department of Water (permit transfer); Kentucky Public Service Commission; Federal Communications Commission (license transfer); KU and LG&E (Tolling Agreement and Interconnection and Operating Agreement assignment); PJM (NITS Agreement assignment); Oldham County Sanitation District (service agreement); and Texas Gas (road access agreement). Additionally, Bluegrass will determine if approval is required by Section 203 of the Federal Power Act from FERC for the transfer of the transmission assets and the Tolling Agreement covered by the transaction, depending upon whether those assets are valued in excess of $10 million. However, EKPC places the proportionate value of the transmission assets to the total plant value established by the total consideration for the acquisition below the FERC Section 203 jurisdictional threshold.

VI. Integration into PJM

Q. WILL EKPC BE ABLE TO UTILIZE THE BLUEGRASS STATION UNITS TO HEDGE ITS LOAD UPON CONSUMMATION OF THE PROPOSED TRANSACTION?

A. Yes. Upon the completion of the contemplated transaction, Bluegrass Station Unit 1 and Unit 2 will be available for use by EKPC in the PJM energy market. Indeed, this is a material aspect of the transaction as it gives EKPC a physical hedge on energy pricing during the coldest portion of the upcoming winter as well as the opportunity to offer the Units, subject to transmission availability, into the PJM day-ahead and real-time energy markets. At the expiration of the KU/LG&E Tolling Agreement, Unit 3 will be available for use by EKPC in the PJM energy market.

Q. WHEN WILL THE BLUEGRASS STATION UNITS BE ABLE TO PARTICIPATE IN THE PJM CAPACITY MARKET?

A. To facilitate the Bluegrass Station's participation in the PJM capacity market, Bluegrass has already executed transmission service agreements with PJM (allowing the output energy from the Bluegrass Units to be delivered) commencing on June 1, 2018, the beginning of the '18-'19 Delivery Year within PJM. Accordingly, Unit 1 and Unit 2 of the Bluegrass Station could be bid into the BRA or any subsequent incremental auctions that apply to the '18-'19 Delivery Year. EKPC is working with PJM to determine whether it will be possible to bid Unit 1 and Unit 2 into the upcoming incremental capacity auctions for the '16-'17 Delivery Year and the '17-'18 Delivery Year. At the expiration of the KU/LG&E Tolling Agreement, Unit 3 can be bid into the BRA.

Q. WHEN IS THE BASE RESIDUAL AUCTION FOR THE '18-'19 DELIVERY YEAR HELD?

A. The BRA for the '18/'19 Delivery Year is scheduled for August 14, 2015.

Q. IS THERE RISK TO EKPC IF IT PARTICIPATES IN THE BASE RESIDUAL AUCTION FOR THE '18-'19 DELIVERY YEAR?

A. EKPC must undertake certain actions to bid capacity equivalent to the capacity offered by Bluegrass Station Unit 1 and Unit 2 into the upcoming '18/'19 BRA. In the event that this Application is not approved, EKPC would have to replace the capacity sold into the BRA by purchasing a corresponding amount of capacity in a subsequent incremental auction ("IA"). The net effect of such a replacement could result in either a gain or loss to EKPC, depending upon the difference in the clearing prices of successive IAs. The BRA typically clears at a higher price than the IAs; for each $20 price differential between the BRA and IA, a loss or gain of $2.4 million in revenue will occur. The historical clearings of the BRA and IAs indicate that generators are best served by participating in the BRA. Accordingly, EKPC is taking all steps necessary during the pendency of this case to keep its options open for maximizing the capacity value of the Bluegrass Station.

Q. **DOES EKPC BELIEVE FUEL FOR THE BLUEGRASS STATION WILL BE AVAILABLE ON A RELIABLE AND ECONOMIC BASIS?**

A. Yes. EKPC, in consultation with Bentek Energy and ACES, has determined that it will have access to fuel for the Bluegrass Station on a reliable and economic basis. The Bluegrass Station is located adjacent to the Texas Gas Transmission, LLC ("Texas Gas") pipeline. Recent developments in the Utica and Marcellus shales in Western Pennsylvania and Eastern Ohio have created a surplus of natural gas production that is expected to result in the reversal of natural gas flows along the Texas Gas and other pipelines. As such, Bluegrass Station is well-situated to benefit from major natural gas producing basins on either end of the Texas Gas pipeline, thereby reducing the risk of interruptions to sustainable sources of natural gas fuel.

Q. **HOW DO PJM'S CAPACITY PERFORMANCE REQUIREMENTS IMPACT THE AVAILABILITY AND PROJECTED COST OF FUEL FOR THE BLUEGRASS STATION UNITS?**

A. ACES's analysis of the proposed transaction took into account the fact that PJM is administering a Capacity Performance requirement in subsequent Base Residual Auctions (and certain Transitional Auctions) on electric generators within its footprint with firm fuel, back up fuel capability and/or onsite storage ability, which may possibly necessitate the purchase by EKPC of No Notice Service from Texas Gas for at least some portion of the winter months. Despite that, the availability and forecasted cost of natural gas indicated that the Bluegrass Station was an excellent investment opportunity for EKPC.

VI. Economic Analyses

Q. IN ADDITION TO THE SCREENING ANALYSIS UNDERTAKEN BY BRATTLE, DID EKPC ENGAGE ANY CONSULTANTS TO ANALYZE THE ECONOMICS OF THE PROPOSED TRANSACTION?

A. Yes. EKPC engaged ACES and Navigant Consulting, Inc. ("Navigant"), to further examine the value of the proposed transaction and provide independent analyses. EKPC also undertook extensive internal analysis of the Bluegrass Station proposal.

Q. PLEASE GENERALLY DESCRIBE THE WORK PERFORMED BY ACES ON BEHALF OF EKPC.

A. ACES was engaged by EKPC to determine the value of the Bluegrass Station to EKPC and to provide a Discounted Cash Flow analysis. A copy of ACES' *East Kentucky Power Cooperative Bluegrass Valuation* (Jan. 20, 2015) is attached to my testimony and incorporated herein as Exhibit DC-1.

Q. PLEASE SUMMARIZE THE CONCLUSIONS REACHED BY ACES.

A. ACES concluded that the Bluegrass Station was worth between $[redacted] and $[redacted] based upon its analysis of the PJM Capacity Market, natural gas pricing and comparable sales. ACES summarized its findings by stating, "Bluegrass [Station] fits perfectly into the EKPC portfolio, significantly reducing [its] winter peak short position. Bluegrass [Station] will also provide excess Reliability Pricing Model (RPM) credits to monetize and allow EKPC to take advantage of [its] peak load diversity in PJM."

Q. PLEASE GENERALLY DESCRIBE THE WORK PERFORMED BY NAVIGANT ON BEHALF OF EKPC.

A. EKPC retained Navigant to conduct an independent analysis of the economic value of the Bluegrass Station within PJM. A Director of Navigant, Ralph L. Luciani, is providing testimony in this case, and a copy of Navigant's *PJM RTO Market Summary and Forecast for the Bluegrass Power Plant* (June 2015) is attached to his testimony as Exhibit RL-2.

Q. PLEASE SUMMARIZE THE CONCLUSIONS REACHED BY NAVIGANT.

A. Navigant's analysis, which was based upon consideration of PJM Capacity and Energy Market forecasts, fuel access and pricing, environmental regulations, and transmission issues, concluded that the net present value of the Bluegrass Station operating margins (excluding capital costs, transaction costs and transmission expenditures for Unit 1 and Unit 2) were $[redacted] over a twenty (20) year period beginning in 2016.

Q. DID NAVIGANT CONDUCT A COMPARISON OF THE RELATIVE VALUES OF THE LG&E/KU TOLLING AGREEMENT AND THE PJM MARKET?

A. Yes. As part of its analysis, Navigant compared: (i) the value of the Tolling Agreement between EKPC and LG&E/KU through April, 2019; and (ii) the value of Bluegrass Unit 3 if the Tolling Agreement did not exist and the Unit was operated in the PJM Capacity and Energy Markets through May 2019. This comparison revealed that the Tolling Agreement provides a net benefit of $[redacted] (undiscounted nominal dollars) relative to the PJM market over the 2016 to 2019 period.

Q. PLEASE SUMMARIZE THE CONCLUSIONS REACHED BY EKPC AS A RESULT OF ITS OWN INTERNAL ECONOMIC ANALYSES.

A. EKPC concluded that the acquisition of the Bluegrass Station would result in a net present value of between $33 million and $49 million. The key assumptions that varied in EKPC's analysis were the amount of future capital expenses and maintenance costs that could arise over time as a result of owning and operating the Bluegrass Station.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE CONCLUSIONS OF NAVIGANT AND THOSE OF EKPC WITH RESPECT TO NPV.

A. Generally speaking, EKPC looked only at the capacity benefits of the transaction and conservatively did not take into account any energy sales benefits. Likewise, EKPC's analysis is considerably lower than the Navigant analysis because utilized a more conservative set of assumptions than did Navigant in conducting its analysis of the capacity benefit.

Q. IN TERMS OF COST OF CAPACITY, HOW DOES ACQUIRING THE BLUEGRASS STATION COMPARE TO INSTALLING A COMPARABLE SIMPLE CYCLE GAS COMBUSTION TURBINE IN PJM?

A. Based on the Bluegrass Station's net summer rating, the purchase price for the Bluegrass Station equates to acquiring capacity at a cost of approximately $260/kW, which is significantly less expensive than the estimated $867/kW cost to install a comparable simple cycle gas combustion turbine in PJM.[4] The levelized operating margins of the Bluegrass Station are projected to be $71/kW-year (real 2015 dollars) over the 2016-2035 period, in comparison to the estimated $97/kW-year (real 2015 dollars) needed to pay for the cost of a new, similarly sized combustion turbine within PJM that is set forth in PJM's most recent Cost of New Entry study. This indicates that the Bluegrass Station operating margins in PJM would support a plant cost significantly more than the Bluegrass Station purchase price of approximately $260/kW based on total summer capacity.

Q. HOW DOES THE PROPOSED PURCHASE PRICE OF $128.75 MILLION COMPARE TO THE PRICE KU/LG&E WERE GOING TO PAY FOR THE BLUEGRASS STATION?

A. The 2010 LG&E/KU purchase agreement for the Bluegrass Station contemplated a purchase price of $110 million. The market for capacity has changed significantly since that time. The winters of 2013/2014 and 2014/2015, closure of generation stations resulting from MATS, and the impending Clean Power Plan have driven capacity prices higher. Stronger capacity prices have been reflected in recent PJM capacity auction clearing prices as well.

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[4] *See PJM's* "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM with June 1, 2018 Online Date." EKPC adjusted the installed $/kW cost of $947/kW for a 2018 online date in the PJM CONE Report to a 2015 online date using a 3% escalation rate. The Bluegrass Station has a total rating of 594 MW of winter capacity, which equates to a cost of roughly $217/kW.

Q. DO EACH OF THE ANALYSES CONDUCTED BY OR ON BEHALF OF EKPC AGREE THAT THE PROPOSED TRANSACTION WILL BE ECONOMICALLY ADVANTAGEOUS FOR EKPC?

A. Yes. The independent analyses of Brattle, ACES and Navigant and EKPC's internal analysis all agree and confirm that the acquisition of the Bluegrass Station will add value to EKPC's system, benefit EKPC's Owner-Members and provide lasting economic value by enhancing capacity revenue and mitigating seasonal energy market volatility risk. In short, the acquisition should more than pay for itself and benefit EKPC's Owner-Members by reducing their exposure to long-term capacity and energy market volatility.

VII. Additional Benefits of the Proposed Acquisition

Q. HOW WILL THE PROPOSED ACQUISITION BENEFIT EKPC AND THE MEMBERS IT SERVES?

A. There are numerous ways the proposed acquisition will benefit EKPC, its Owner-Members, and the end-use customers. Among other things, the proposed acquisition will: (i) provide a replacement for the capacity lost as a result of the retirement of the Dale Station at a deeply discounted price compared to building new generation; (ii) reduce EKPC's significant short position with regard to capacity and energy during winter peaks; (iii) provide a physical hedge against future energy and capacity market volatility; (iv) eliminate the need for EKPC to rely upon more costly market-based power purchase agreements to satisfy its load; (v) keep EKPC well-positioned to comply with existing and forthcoming environmental regulations and mandates while mitigating compliance and market locational risks of investing in out-of-state resources; (vi) minimize technology and performance risk by acquiring relatively new assets that are based upon proven and mature technology; and (vii) assure that a generation asset located in Kentucky remains operational, thereby contributing to the local economy through the payment of skilled-labor wages and property taxes.

Q. WHY DOES EKPC'S 2015 IRP FORECAST POWER PURCHASES INSTEAD OF ACQUISITIONS?

A. When the IRP was submitted, EKPC was in negotiations with regard to the Bluegrass Station, but was not assured that the parties would reach agreeable contract terms. EKPC reflected Power Purchases to show that it would behave in a responsible manner to hedge its energy exposure in the market.

VIII. Conclusions

Q. DOES EKPC HAVE A NEED FOR THE BLUEGRASS STATION?

A. Yes. In light of recent winter load experiences, the retirement of the Dale Station, EKPC's anticipated load growth, the existing and projected volatility of the market in general and other identified reasons, there is an inadequacy of existing service involving a consumer market sufficiently large to make it economically feasible for the Bluegrass Station to be acquired by EKPC and operated as a system resource. The identified inadequacy is due to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business. Likewise, the Bluegrass Station acquisition does not result in an excess of capacity over need, an excessive investment in relation to productivity or efficiency or an unnecessary multiplicity of physical properties.

Q. IS THE PROPOSED ACQUISITION THE REASONABLE LEAST-COST OPTION AVAILABLE TO EKPC?

A. Yes. EKPC, with the assistance of Brattle, thoroughly reviewed other available alternatives to the Bluegrass Station proposal and, after balancing all factors, EKPC determined that the acquisition of the Bluegrass Station is the reasonable least-cost option.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR APPROVAL OF THE ACQUISITION OF EXISTING COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC AT THE BLUEGRASS GENERATING STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN EVIDENCES OF INDEBTEDNESS	)	Case No. 2015-_______

VERIFICATION OF DAVID CREWS

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

David Crews, Senior Vice President of Power Supply at East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

David Crews

The foregoing Verification was signed, acknowledged and sworn to before me this 21st day of July, 2015, by David Crews.

NOTARY PUBLIC, Notary # 502993
Commission expiration: 1/27/18

BRENDA BOWEN
Notary Public
State at Large
Kentucky
My Commission Expires Jan 27, 2018

East Kentucky Power Cooperative

Bluegrass Valuation

January 30, 2015

EXHIBIT

DC-1

ACES
excellence in energy

Table of Contents

1. Executive Summary

East Kentucky Power Cooperative (EKPC) requested ACES provide a portfolio fit assessment and fair market valuation of the Bluegrass Generation Station (Bluegrass) in Oldham County, Kentucky. The unit nameplate capacity of Bluegrass is 576 MW, with a unit installed capacity (ICAP) of 501 MW during the summer period. Bluegrass consists of three simple cycle combustion turbines with a full load heat rate of 10.8 MMBtu/MWh. Bluegrass is currently located in the Louisville Gas and Electric and Kentucky Utilities (LGE/KU) Balancing Authority.

As part of the update to the EKPC 2012 Request for Proposals (RFP), LS Power has offered to sell Bluegrass to EKPC for $132.5 million, inclusive of an existing power purchase agreement (PPA) with LGE/KU for one of the turbines for the next five years. The PPA with LGE/KU will expire in 2019, and EKPC would then own and have rights to 100% of the output of the facility. The RFP was intended to cover a short peak winter position, short energy position, and replace capacity from the pending Dale Station retirement. Bluegrass fits perfectly into the EKPC portfolio, significantly reducing their winter peak short position. Bluegrass will also provide excess Reliability Pricing Model (RPM) credits to monetize and allow EKPC to take advantage of their peak load diversity in PJM. Bluegrass provides minimal expected energy (6% capacity factor), with the majority occurring in summer and winter, and will allow EKPC to continue to make economical purchases from PJM in the spring and fall.

To determine the fair market value of Bluegrass, ACES performed a Discounted Cash Flow (DCF) analysis and an assessment of comparable sales of similar facilities. Combining these valuation techniques results in a plant value range between [redacted] ICAP basis). The majority of value will come from the PJM capacity market. EKPC is in a unique position relative to other potential buyers of Bluegrass with its load in the LGE/KU Balancing Authority, which is part of the PJM market and allows EKPC to qualify the unit for capacity without having to purchase point-to-point transmission service. EKPC has submitted a network transmission request to deliver the resource to the LGE/KU portion of their PJM load. Based on prior studies, it was assumed that EKPC would [redacted] Any other buyers would have to purchase firm point-to-point transmission to deliver to PJM at an incremental cost of almost [redacted]

The revenue stream EKPC will receive from PJM includes selling energy, capacity, and ancillary services. Approximately [redacted] of the expected margins from the facility are tied to capacity payments. The major uncertainty is the structure of the PJM capacity market, as PJM has recently filed with the Federal Energy Regulatory Commission (FERC) to require generators to be 100% available during emergencies or pay significant penalties. As a result, three cases of capacity price forecasts were developed to assess a range of outcomes. The cases include the current capacity market construct and two cases with varying degrees of the proposed Capacity Performance (CP) construct. Under the CP construct, EKPC will have to purchase some form of No Notice Service from the natural gas pipeline for at least the winter months. [redacted]

A secondary risk is the forecasted maintenance costs, which were provided by EKPC. The expenses may increase if the plant operates at a higher frequency in the PJM market. ACES adhered to the Kentucky

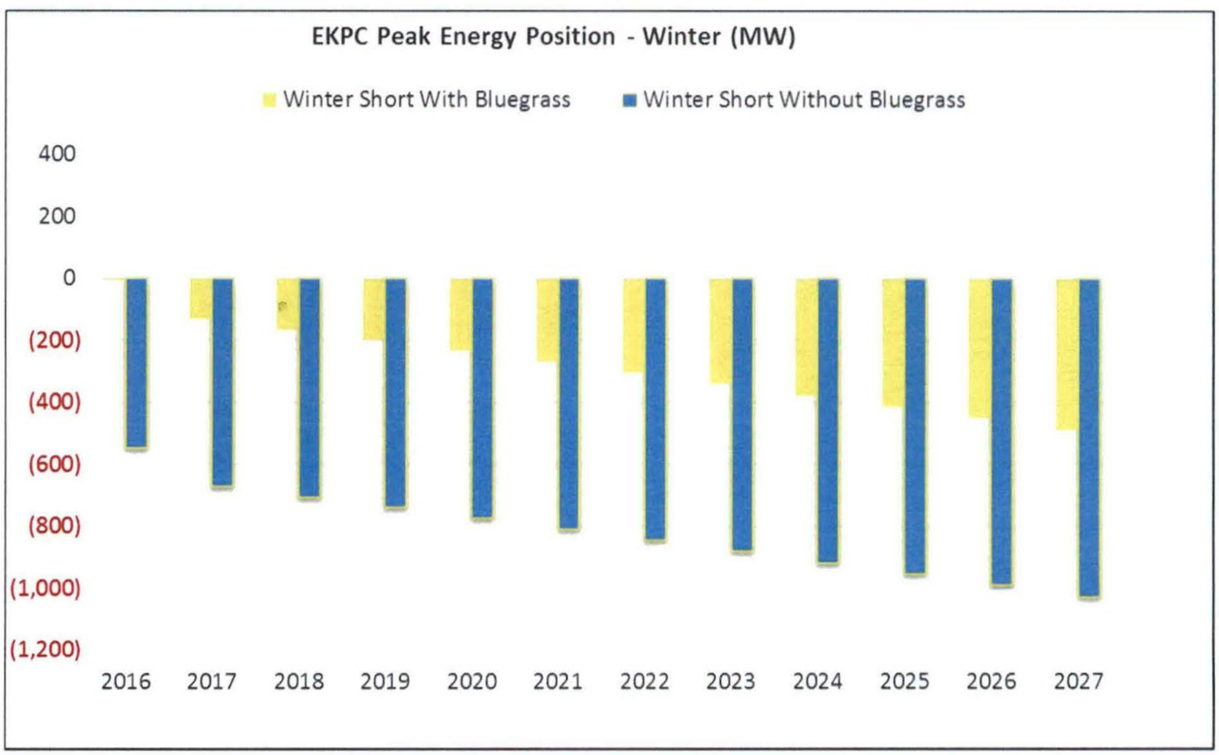
Air Permit limitations of 95 tons of NOx over a rolling 12-month period. This NOx constraint was the limiting factor in generation output and would also likely be limiting if the plant was converted to combined cycle mode in the future without air permit modifications.

In summary, EKPC has several competitive advantages, including [redacted] provides significant value to EKPC and its members.

2. Portfolio Fit

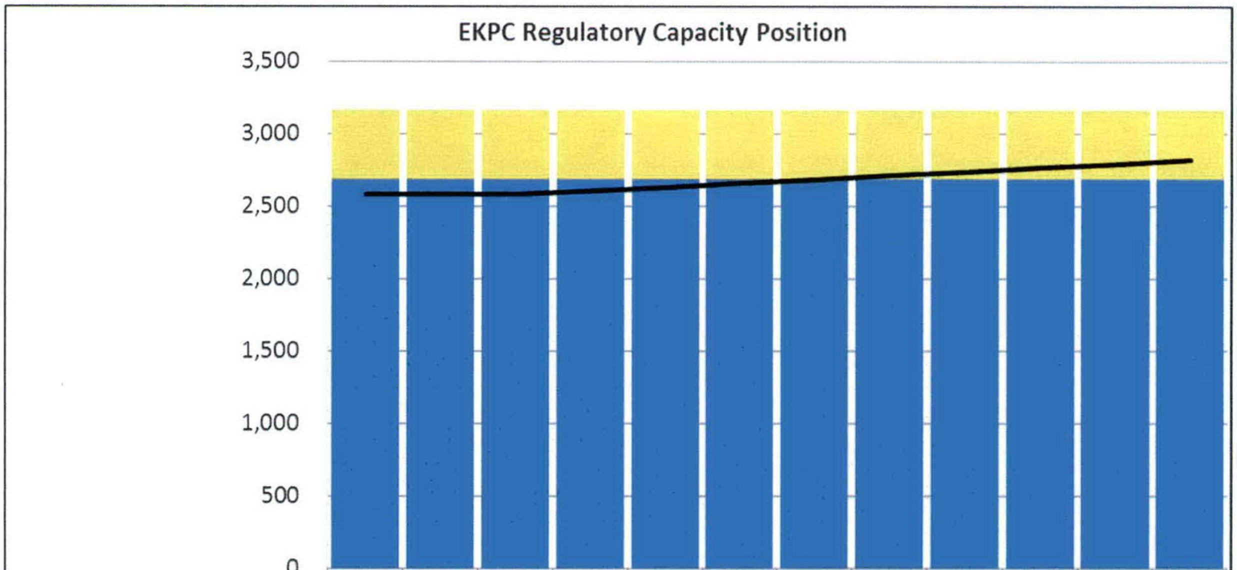
EKPC has a significant short position during the winter peak and relies on short-term purchases to manage this risk. The acquisition of Bluegrass would mitigate that risk completely in the near term and reduce the projected short position to the winter peak by 50% in 10 years. Reserves of 5% were added to the winter peak forecasts to account for load uncertainty. Generator availability uncertainty was already factored in by utilizing the Unforced Capacity (UCAP) values of the generators. Figure 1 displays the portfolio position against the winter peak plus 5% reserves with and without Bluegrass.

Figure 1.



Purchasing Bluegrass would also allow EKPC to take advantage of the peak diversity between the EKPC portfolio and the PJM market. EKPC will be able to monetize the majority of the UCAP value of Bluegrass in the PJM RPM construct. Figure 2 displays the current UCAP generation in blue, the load obligation on the black line, and the Bluegrass UCAP on the yellow bar for the RPM construct.

Figure 2.



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Bluegrass	476	476	476	476	476	476	476	476	476	476	476	476
Pre-Bluegrass Capacity	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687
Load Obligation	2,576	2,576	2,576	2,601	2,627	2,654	2,680	2,707	2,734	2,761	2,789	2,817

3. Discounted Cash Flow Analysis

The goal of the Discounted Cash Flow Analysis (DCF) is to estimate the price Bluegrass would sell for in the market. The key drivers of the sale price are the capacity and energy revenue forecasts, the fixed cost assumptions for operations and maintenance, and major maintenance costs. EKPC has some unique tax and borrowing advantages, which were not factored into this analysis. The key assumptions for the DCF are:

[redacted]

3.1. Case 1: "As-Is"

Fair Market Purchase Price: [redacted]

This case assumes that the current PJM capacity market continues and the 20-year average nominal price [redacted] The increase in capacity prices over the next 20 years is attributed to:

- Inflation
- FERC approved Variable Resource Requirement (VRR) curve shift
    - This allows PJM to procure more capacity resources for the same level of load, increasing demand
- Uncertainty in the level of participation of Demand Resources (DR) in the capacity markets going forward in light of the recent court decision overturning FERC 745, potentially reducing supply
- Regulatory risk of new market rules incenting generators to not retire
- The Clean Power Plan (CPP) could lead to additional coal-fired plant retirements, further reducing the supply of generation resources

3.2. Case 2: Capacity Performance "Light" is Approved

Fair Market Purchase Price: [redacted]

This case assumes that FERC approves the CP proposal from PJM with some reduction of the gas services required. This case also assumes the buyer could purchase [redacted] The capacity price forecast in this case increases to [redacted].

3.3. Case 3: Capacity Performance "Heavy" is Approved

Fair Market Purchase Price: [redacted]

This case assumes that FERC approves PJM's CP proposal largely as it stands today, requiring, at a minimum, no notice natural gas transportation service [redacted]. The expectation is that generators in eastern PJM, where natural gas pipeline constraints are more prevalent, could set the marginal price in the capacity auction with much higher natural gas service costs than a western PJM CT on Texas Gas Pipeline. The capacity price forecast in this case increases to [redacted].

4. Market Comparables

There have been recent peaking asset sales that can be used as market comparables for the potential acquisition of the Bluegrass peaking asset. The parties involved in the transactions included privately and publicly held independent power producers, a regulated investor-owned utility, and a private equity firm focused on energy infrastructure. These assets are located in their respective RTOs where a significant portion of the value will be derived from the regulatory capacity revenues (i.e., MISO, PJM). The price of these transactions points to an implied valuation near [redacted] incorporate the CT into its rate base. The asset acquisition will help DTE meet its peak demand for energy and will address its current and future resource adequacy requirements in MISO. MISO models its resource adequacy requirements across nine separate zones. The Renaissance Power Plant is located in MISO's Zone 7. The bilateral market for zonal resource credits in Zone 7 has trended higher over 2014. Market participants are anticipating Zone 7 to become capacity constrained over the next few planning years due to the retirement of baseload coal facilities. The projection of capacity shortages in MISO Zone 7 was a leading factor to support this acquisition for DTE.

In August 2014, Dynegy announced the acquisition of the coal and gas generating assets in the Western region of PJM from Duke Energy and Energy Capital Partners[2]. [redacted], respectively for the Duke Energy and Energy Capital Partners assets[3]. UBS took an in depth review of the assets, by fuel type, in each portfolio and assessed an implied valuation to the peaking facilities in PJM. The [redacted].

The market for existing peaking assets continues to be valued at a discount to the cost of new build peaking assets. Current observations in the market show that the discount is beginning to weaken. Many factors are impacting the decrease in cost for new build peaking assets including increased competition from other turbine suppliers (e.g., Siemens, Wartsila, Mitsubishi), availability and supply of new turbines in inventory with developers, and the overall observed weakness in the global economy. The factors increasing the cost of existing peaking assets include the dwindling supply of existing assets (i.e., due to increased participation in acquisitions from load-serving entities and private equity), market changes in the RTOs increasing the capacity value projections, and possible EPA regulations (111d) impacting the overall supply of capacity.

5. Natural Gas Transportation

Natural gas is transported to the plant via the Texas Gas Transmission (TGT) Pipeline through a lateral that is 120-foot long and 12-inches in diameter. The plant is located within Service Zone 4 of the TGT pipeline. [redacted]

[1] Press Release, DTE Energy Newsroom https://dteenergy.mediaroom.com

[2] Press Release, Dynegy News http://dynegy.com/news

[3] "DYN/DUKE: Marrying up the Power Business" *UBS Investment Research*, Electric Utilities Aug. 22, 2014

[redacted]

There are at least three transportation strategies for delivering natural gas to Bluegrass, depending on the type of capacity market that develops in PJM and what the final rules look like:

- [redacted]
  - [redacted]
    - [redacted]
  - [redacted]
  - [redacted]
    - [redacted]
    - [redacted]
- [redacted]
  - [redacted]
  - [redacted]
    - [redacted]
  - [redacted]
    - [redacted]
  - [redacted]
    - [redacted]
    - [redacted]
- [redacted]
  - [redacted]
    - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
    - [redacted]
    - [redacted]

6. Appendix

Figure 3.

CONFIDENTIAL INFORMATION

Figure 4.

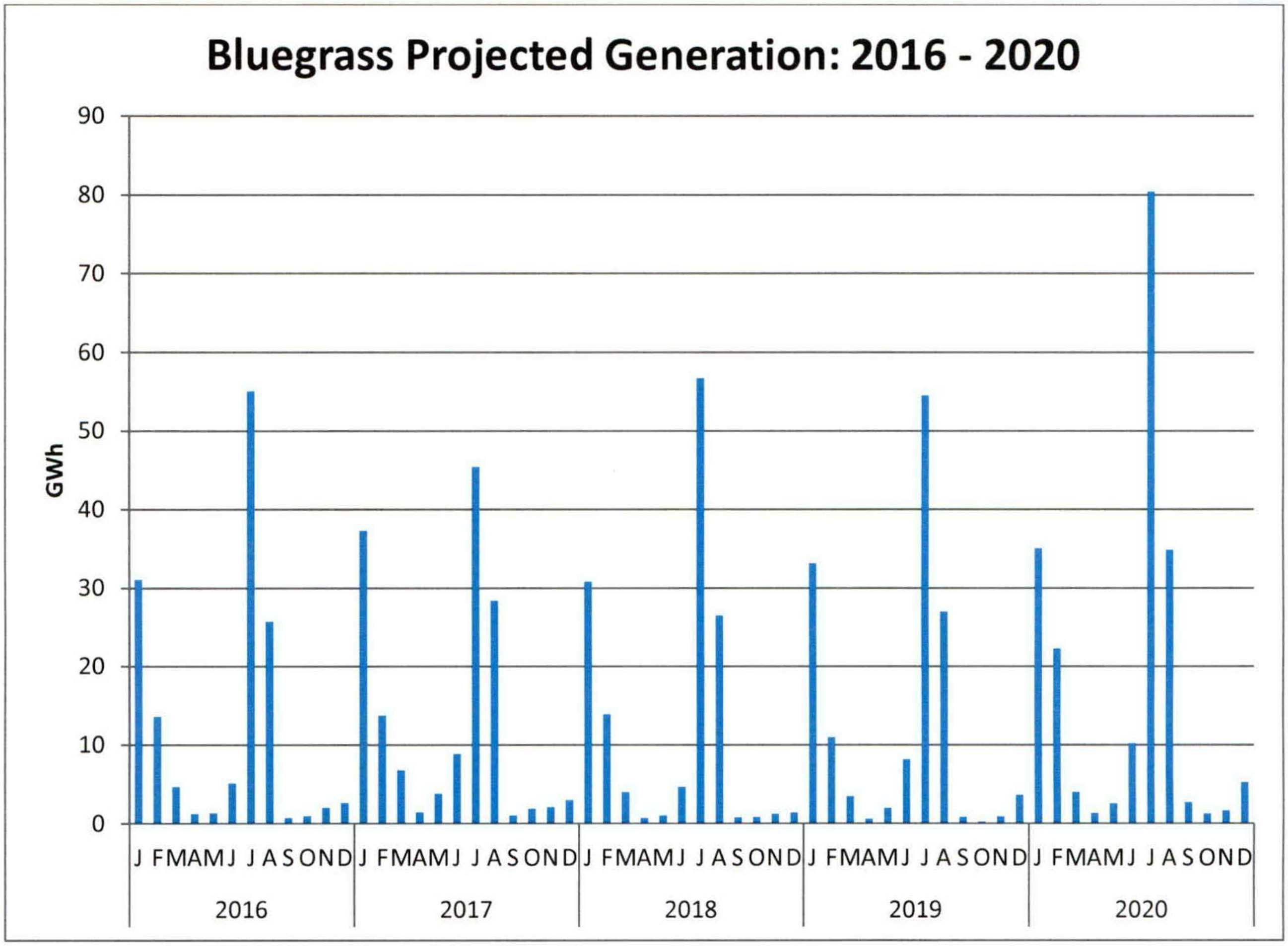

Bluegrass Projected Generation: 2016 - 2020
GWh
90
80
70
60
50
40
30
20
10
0
J F M A M J J A S O N D
2016
2017
2018
2019
2020

Figure 5.

CONFIDENTIAL INFORMATION

Figure 6.

CONFIDENTIAL INFORMATION

CONFIDENTIAL EXHIBIT DC-2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER	)	
COOPERATIVE, INC. FOR APPROVAL OF THE	)	
ACQUISITION OF EXISTING COMBUSTION TURBINE	)	
FACILITIES FROM BLUEGRASS GENERATION	)	Case No. 2015-_______
COMPANY, LLC AT THE BLUEGRASS GENERATING	)	
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY	)	
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN	)	
EVIDENCES OF INDEBTEDNESS	)	

DIRECT TESTIMONY OF JERRY B. PURVIS

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: July 24, 2015

EXHIBIT

6

I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jerry B. Purvis and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Director of Environmental Affairs for EKPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree in Chemistry from Morehead State University and a Bachelor of Science degree in Chemical Engineering from the University of Kentucky. I also received a Master of Business Administration from Morehead State University. I have been employed by EKPC for over twenty-one (21) years serving in various positions. In 2011, I became the Director of Environmental Affairs at EKPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AT EKPC.

A. As Director of Environmental Affairs, I am responsible for compliance with environmental laws, the preparation of applications for all environmental permits required for the construction and operation of generation stations, transmission facilities and landfills, and the preparation of supplemental environmental impact statements and documentation necessary to demonstrate compliance with the National Environmental Policy Act. I have also been responsible for the development of compliance plans for the EKPC New Source Review program for air emissions. I report directly to the Chief Operating Officer/Executive Vice President, Mr. Don Mosier.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to generally describe the environmental rules and regulations currently applicable to EKPC and to provide an overview of additional rules which are forthcoming. I will also discuss the environmental due diligence EKPC performed related to its proposed acquisition of the existing combustion turbine facilities located in LaGrange, Oldham County, Kentucky (the "Bluegrass Station"), from Bluegrass Generation Company, LLC ("Bluegrass"). Finally, I will detail the environmental permits which are necessary for operations at the Bluegrass Station.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No.

II. Regulation Overview and Compliance Generally

Q. IS EKPC SUBJECT TO EXTENSIVE ENVIRONMENTAL REGULATION?

A. Yes. As a generation and transmission utility, EKPC is among the most stringently environmentally-regulated entities in the United States. Environmental oversight of EKPC's operations is maintained by the U.S. Environmental Protection Agency ("EPA"), the U.S. Army Corps of Engineers, the Kentucky Division of Air Quality ("KY DAQ"), the Kentucky Division of Water, and the Kentucky Division of Waste Management, among other authorities. The degree to and manner in which EKPC is regulated continually evolves, and the pace of revisions to federal environmental rules has increased substantially over the past decade.

Q. PLEASE PROVIDE AN OVERVIEW OF THE EXISTING ENVIRONMENTAL RULES AND REGULATIONS WITH WHICH EKPC IS IN COMPLIANCE.

A. The list of environmental rules and regulations applicable to EKPC is extensive. For instance, EKPC currently complies with multiple rules governing air emissions, including: New Source Performance Standards ("NSPS"); New Source Review Rules ("NSR") and the Green House Gas Tailoring Rule ("Tailoring Rule") revisions to the NSR; Title IV of the Clean Air Act ("CAA") and associated rules governing pollutants that contribute to acid rain ("Acid Rain Rules"); CAA Title V operating permit requirements ("Title V Requirements"); Summer ozone trading program requirements based upon Section 126 petitions and the Ozone State Implementation Plan Call ("Summer Ozone Program"); National Ambient Air Quality Standards ("NAAQS") for Sulfur Dioxide ("SO2"), Nitrogen Dioxide ("NO2"), Carbon Monoxide ("CO"), Ozone, Particulate Matter ("PM"), Particulate Matter of 2.5 microns or less ("PM 2.5") and Lead; the Cross State Air Pollution Rule ("CSAPR"); the Clean Air Visibility Regional Haze Rule; National Emissions Standards for Hazardous Air Pollutants ("NESHAPs"); and the Mercury and Air Toxics Standards ("MATS," the current status of which is detailed below). Of course, there are many more rules and regulations with which EKPC must comply other than the foregoing, including those that deal with water quality, soil, and wastes.

Q. DOES EKPC CONTINUALLY REVIEW ITS OPERATIONS AND PRACTICES TO ENSURE COMPLIANCE WITH EXISTING ENVIRONMENTAL LAW?

A. Yes. EKPC regularly monitors and reviews both its operations and applicable law to ensure ongoing compliance.

Q. PLEASE PROVIDE AN OVERVIEW OF ENVIRONMENTAL RULES AND REGULATIONS THAT ARE NOT YET EFFECTIVE, BUT WHICH ARE LIKELY TO IMPACT EKPC'S OPERATIONS IN THE FUTURE.

A. EKPC anticipates that it will be required to comply with numerous new or amended environmental rules in both the near and long term. Such rules include: the Clean Power Plan; the Coal Combustion Residuals Rule ("CCR"); the 316(b) Rule under the Clean Water Act ("316(b) Rule"); the Effluent Limitation Guidelines Rule ("ELG Rule") and a change to the Ozone National Ambient Air Quality Standards. Depending on EPA's designations pursuant to the 2010 SO_2 NAAQS, EKPC may be subject to more stringent obligations. EKPC has already undertaken efforts to comply with many anticipated rules and regulations consistent with prudent utility practices and management.

Q. PLEASE DESCRIBE THE MATS RULE.

A. On March 16, 2011, EPA issued the proposed Electric Generating Unit Maximum Available Control Technology ("EGU MACT") rule, later known as the MATS rule, to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA finalized the MATS rule on December 16, 2011 to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF). The MATS rule allows sources to control surrogate emissions to demonstrate control of HAP metals and HAP acid gases. Non-Hg metallic toxic air pollutants are represented by PM emission limits because these metals travel in particulate form in boiler gas paths. HCL and /or SO_2 are surrogates for all acid gas HAPs since they are controlled by the same mechanisms. Under MATS, mercury emissions are subject to limits and units must measure mercury emissions directly to demonstrate compliance.

Q. IS THE MATS RULE CURRENTLY EFFECTIVE?

A. Yes. On June 29, 2015, the United States Supreme Court determined that the MATS Rule was not properly reviewed and promulgated by the EPA, thereby reversing a decision of the D.C. Circuit Court of Appeals and remanding the case challenging the rule to the lower court. However, the Supreme Court did not vacate the MATS Rule. The Supreme Court determined that the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. Yet the MATS Rule remains in effect unless it is vacated by the D.C. Circuit Court of Appeals or unless EPA vacates the MATS Rule during remand.

Q. DOES EKPC ANTICIPATE THAT THE MATS RULE WILL BE RE-PROMULGATED?

A. Yes. Since the U.S. Supreme Court's decision was directed at the scope of the EPA's rationale and not the agency's authority to promulgate the rule, it is widely anticipated that the MATS Rule will be re-promulgated by the EPA in the near future. Regardless, many utilities, including EKPC, have already been forced to make significant and expensive investment decisions involving the future of their electric generation resources based upon MATS prior to the Supreme Court's ruling.

Q. WHAT EFFORTS HAS EKPC UNDERTAKEN TO ENSURE COMPLIANCE WITH THE MATS RULE?

A. Under the current MATS Rule, EKPC must comply with the mercury, SO_2 or HCL, and PM limits in the MATS beginning in the spring of 2015. However, if units were in the process of installing additional pollution control equipment and could not complete the work by this initial compliance date, an additional year to achieve compliance could be requested from the Kentucky Cabinet. EKPC sought and received a MATS extension from the Kentucky Division of Air Quality ("KDAQ") for Dale Station Units 3 and 4 and Cooper Station Units 1 and 2.

EKPC has conducted emissions testing of its units to determine the best way to achieve compliance with the MATS Rule. This testing was completed as part of an extensive engineering effort to ensure that EKPC's units comply with this rule. Pursuant to authority granted by this Commission, Cooper Unit 1 is being tied-in to Cooper Unit 2's environmental controls this fall in order to comply with MATS by April 2016.[1] With respect to EKPC's Dale Station, PJM requested that, for reliability purposes, KDAQ grant Dale Units 3 and 4 a one-year extension to

[1] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for Alteration of Certain Equipment at the Cooper Station and Approval of a Compliance Plan Amendment for Environmental Surcharge Cost Recovery*, Application, Case No. 2013-00259 (filed Aug. 21, 2013).

comply with MATS. KDAQ granted the extension, thereby temporarily staying the compliance deadline for the Units until April 2016.

Q. HOW HAS THE MATS RULE IMPACTED EKPC'S EXISTING GENERATION PORTFOLIO?

A. The MATS rule, in addition to other existing and anticipated environmental regulations, has required EKPC to evaluate its generation portfolio and determine what actions, if any, it must take to ensure the availability of reliable, affordable capacity. Much of EKPC's generation fleet is well-positioned in terms of environmental compliance. For example, the pollution control upgrades on Spurlock Units 1 and 2 and Cooper Unit 2 place EKPC's units ahead of most electric generating units for MATS compliance, and Spurlock Units 3 and 4, which are equipped with Best Available Control Technology (BACT), will meet the MATS Rule limits without additional controls. However, in and around 2012 EKPC determined that its Dale Station and Cooper Station Unit 1 were unlikely to remain economically viable in light of the substantial investments that would have been required to bring them into compliance with the EPA's new and forthcoming rules (*i.e.*, MATS, CCR, and ELG). To address the compliance issues with respect to Cooper Station Unit 1, EKPC identified and pursued a reconfiguration of that unit's air emissions as a cost-effective and reasonable solution. With respect to Dale Station, EKPC did not and does not believe that reconfiguring or upgrading the Dale Units is an economically viable alternative for ongoing future environmental compliance, and thus those Units are not part of EKPC's long-term power supply plan.[2]

Q. PLEASE DESCRIBE THE CROSS-STATE AIR POLLUTION RULE AND WHAT EFFORTS EKPC HAS UNDERTAKEN TO ENSURE COMPLIANCE.

A. On July 6, 2011, the EPA finalized CSAPR to require 27 states (Kentucky included) and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. This rule replaces EPA's 2005 CAIR rule that was remanded to EPA by a U.S. Court of Appeals. CSAPR requires significant reductions in SO_2 and nitrogen oxides (NO_X) emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to achieve the National Ambient Air Quality Standards (NAAQS). The rule called for the first phase emission reduction compliance to begin January 1, 2012, for annual SO_2 and NO_X and May 1, 2012 for ozone season NO_X. The second phase of SO_2 reductions was to begin January 1, 2014. On December 30, 2011, CSAPR was stayed by the United States Court of Appeals for the District of Columbia in response to industry petitions challenging the rule. On August 21, 2012, CSAPR was vacated and remanded back to EPA. EPA appealed this decision and on April 29, 2014, the Supreme Court reversed the United States Court of Appeals for the D.C. Circuit (D.C. Circuit) and reinstated

[2] EKPC anticipates that Dale Units 3 and 4 will remain unavailable beginning in 2016 because environmental regulation (including CCR, ELG, and a likely re-promulgated MATS Rule) renders those Units uneconomical.

CSAPR and remanded the rule back to the D.C. Circuit to determine next steps and resolve the many pending appeals of the rule that have not been acted on.

On June 26, 2014, the United States moved the D.C. Circuit to lift the stay on CSAPR but to toll the original compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted the motion and as a result, CSAPR was reinstated with Phase 1 beginning January 1, 2015, and Phase 2 starting on January 1, 2017. At this point, only the dates have changed from the original program.

Q. PLEASE DESCRIBE THE GHG TAILORING RULE AND HOW EKPC IS COMPLYING WITH THIS RULE.

A. On May 13, 2010, the EPA issued a final rule that established emission thresholds for addressing GHG emissions from stationary sources under the CAA permitting programs. The GHG Tailoring rule set GHG thresholds for applicability under the NSR rules and Title V program. GHGs are considered one pollutant for NSR, which is composed of the weighted aggregate of CO_2, N_2O, SF_6, HFCs, PFCs, and methane (CH_4) into a combined CO_2 equivalent (CO_{2e}).

Under the original GHG Tailoring rule, if any of the stations made a physical or operational change that would result in a net increase of 75,000 tons per year or more of CO_2 equivalents (CO_{2e}), EKPC must have obtained an NSR permit for the modification including the installation of Best Available Control Technology (BACT) for GHGs on the modified unit.

On June 23, 2014, the U.S. Supreme Court struck part of the GHG Tailoring Rule and held that a significant net emissions increase in GHGs alone cannot trigger NSR. NSR permitting requirements for GHGs can be triggered, but only if the physical or operational change also results in a significant net emissions increase of another PSD pollutant and that EPA has not yet set a significant emissions increase threshold for GHGs.

EKPC routinely analyzes all capital projects for the potential need to undergo pre-construction NSR permitting. This NSR review process has been expanded to include an analysis of GHG emissions. EKPC's NSR Consent Decree also includes a future covenant from EPA that allows EKPC some flexibility with respect to the NSR rules until December 31, 2015.

Q. PLEASE DESCRIBE THE NATIONAL AMBIENT AIR QUALITY STANDARDS RULE.

A. The Clean Air Act requires EPA to set NAAQS for wide-spread pollutants. EPA has set NAAQS for six pollutants, called "criteria" pollutants. These pollutants are carbon monoxide (CO), lead, nitrogen oxides (NO_x), ozone, particulate matter (PM), and sulfur dioxide (SO_2). The Clean Air Act established two types of NAAQS. Primary standards set limits to protect public health and secondary standards set limits to protect public welfare.

If a county or counties are designated to be in nonattainment for a NAAQS, the Cabinet will work with major sources contributing to nonattainment to implement Reasonably Available Control Technology (RACT) retrofits to bring the areas into attainment.

A. <u>Carbon Monoxide (CO)</u>

In January 2011, EPA proposed to retain the current primary CO NAAQS of 9 ppm (8-hour) and 35 ppm (1-hour). This rule was finalized in August 2011. *See* 76 Fed.

Reg. 54294 (Aug. 31, 2011). As of September 27, 2010, all areas in Kentucky have been designated as maintenance areas for CO. *See* 56 Fed. Reg. 56694 (Nov. 6, 1991).On April 11, 2014, the D.C. Circuit deferred to EPA's authority to set NAAQS, maintain the primary standard from 1971 and not set a secondary standard.

B. <u>Sulfur Dioxide (SO2)</u>

EPA revised the primary SO_2 NAAQS in June 2010 to a one-hour standard of 75 ppb. 75 Fed. Reg. 35520 (June 22, 2010). On October 4, 2013, EPA designated part of Campbell County, Kentucky (together with part of Clermont County, Ohio) as non-attainment and part of Jefferson County, Kentucky as non-attainment. 78 Fed. Reg. 47191. The current secondary 3-hour SO_2 standard is 0.5 ppm. EPA proposed to retain this SO_2 secondary standard in a final rule was published on April 3, 2012 (77 Fed. Reg. 20218).

In 2013, Sierra Club sued EPA over EPA's 2010 SO_2 NAAQS area designations. EPA promulgated designations for 29 areas and Sierra Club alleged that EPA acted illegally and arbitrarily, and failed to undertake a non-discretionary duty, by not promulgating designations for the remainder of the county. Sierra Club and EPA resolved this matter in a Consent Decree that was entered by the Northern District of California on March 2, 2015. The Consent Decree sets milestones for EPA to issue the remaining SO_2 NAAQS designations.

EPA's first milestone is that it must promulgate designations by July 2, 2016 for the following areas: (1) areas that were not previously shown to be non-attainment, but for which new monitoring data exceeds the SO_2 NAAQS; and (2) areas containing sources that either emitted more than 16,000 tons of SO_2 in 2012, or emitted more than 2,600 tons of SO_2 and had an annual average emission rate of at least 0.45 lbs SO_2/mmBTU in 2012, and those sources were not scheduled for retirement as of March 2, 2015.

C. Nitrogen Dioxide (NO2)

EPA revised the primary NO_2 NAAQS in January 2010. *See* 75 Fed. Reg. 6474 (Feb. 9, 2010). The new primary NAAQS for NO_2 is a one-hour standard of 100 ppb. EPA retained the existing primary and secondary annual standard of 53 ppb. On January 11, 2011, Kentucky made area designation recommendations for the new NO_2 standard and recommended that areas with monitors showing compliance be designated as in attainment and that the remainder of the Commonwealth be designated as unclassifiable. On June 28, 2011, EPA responded indicating its intent to designate the entire country as unclassifiable/attainment due to the limited availability of monitoring data. On August 3, 2011, the Commonwealth responded to EPA's proposed revision requesting that the areas that show compliance with area monitors be designated as attainment and that the remainder of the Commonwealth be designated as unclassifiable/attainment. Final designation of the entire United States as unclassified/attainment was made on February 17, 2012 (77 Fed. Reg. 9532). EPA finalized a rule implementing a nation-wide monitoring system on March 7, 2013 in two phases (2014 and 2017). 78 Fed. Reg. 16184 (March 14, 2013). Three years after the new monitoring system is implemented, EPA will re-evaluate the existing data and re-designate areas as necessary (2020).

In a final rule published on April 3, 2012, EPA retained the secondary NO_2 NAAQS of 0.053ppm averaged over a year (77 Fed. Reg. 20218).

D. Ozone

Currently, the primary 8-hour Ozone NAAQS is 75 ppb and the secondary 8-hour Ozone NAAQS is 75 ppb. Boone, Campbell and Kenton counties have been designated as non-attainment and the remainder of the Commonwealth as unclassifiable/attainment.

On November 25, 2014, EPA issued a proposed rule to revise both the primary and secondary standards to within a range of 65 to 70 ppb. 79 Fed. Reg. 75233 (Dec. 17, 2014). EPA solicited comment on the appropriate primary and secondary limits, including what the limit should be, whether the existing limit should be retained and whether the primary (health) standard should be as low as 60 ppb. EPA expects to issue a final rule by October 1, 2015.[3]

E. Particulate Matter (PM2.5)

In 1997, EPA adopted the 24-hour fine particulate NAAQS ($PM_{2.5}$) of 65 $\mu g/m^3$ and an annual standard of 15 $\mu g/m^3$. 62 Fed. Reg. 38652 (July 18, 1997). In 2006, EPA revised this standard to 35 $\mu g/m^3$, and retained the existing annual standard. 71 Fed. Reg. 61144 (Oc. 17, 2006).

EPA proposed tighter $PM_{2.5}$ NAAQS on June 29, 2012 and finalized the revised primary $PM_{2.5}$ NAAQS to 12 $\mu g/m^3$ on January 15, 2013 (78 Fed. Reg. 3086). On January 15, 2015 EPA issued final 2012 $PM_{2.5}$ designations and designated part of

[3] On January 21, 2014, the Sierra Club, American Lung Association, Environmental Defense Fund and Natural Resources Defense Council sued EPA for not completing its review of the ozone standard by March 2013 (five years from the March 2008 update). The October 1, 2015 deadline resulted from that lawsuit.

Bullitt County and all of Jefferson County as unclassifiable and the rest of the state as unclassifiable/attainment with the 2012 standard.

F. Lead

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 $\mu g/m^3$ to 0.15 $\mu g/m^3$. *See* 73 Fed. Reg. 66964 (Nov. 12, 2008). EPA has designated the Commonwealth of Kentucky as unclassifiable/attainment for the lead NAAQS.

Currently, EKPC's units are not located in any areas that are in nonattainment. EPA designated all of Kentucky as unclassifiable/attainment. EKPC anticipates that existing controls on its coal generation and new controls and compliance strategies adopted to comply with the MATS rule and CSAPR will ensure that the fleet will also comply with any future NAAQS requirements.

Q. PLEASE DESCRIBE THE REGIONAL HAZE RULE.

A. The Regional Haze Rule triggered the first in a series of once-per-decade reviews of impacts on visibility at pristine areas such as national parks, with a focus in the first review on large emission sources put into operation between 1962 and 1977. These sources were targeted for addition of Best Available Retrofit Technology (BART) controls for SO_2, NO_x, and PM emissions. The threshold for being exempt from BART review is very stringent, such that coal-fired electrical generating stations are almost universally subject to BART.

A BART assessment includes an evaluation of SO_2 controls and post-combustion NO_x controls. EKPC has submitted its Regional Haze compliance plans to the Cabinet and the Cabinet submitted the plan for the Commonwealth to EPA who has proposed to adopt it formally into Kentucky's State Implementation Plan (SIP).

EKPC installed SO_2, NOx and PM controls on Spurlock Unit 1, 2 and Cooper Unit 2 to comply with the NSR Consent Decree, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. EKPC committed in the Regional Haze compliance plan to install parallel controls on Cooper Unit 1, which was ultimately resulted in Cooper Unit 1 being tied into Cooper Unit 2 environmental controls.

Q. PLEASE DESCRIBE THE CLEAN POWER PLAN.

A. EPA released the proposed Clean Power Plan (CPP) for existing EGUs on June 2, 2014, consistent with the President's Climate Action Plan. The proposal ultimately sets out CO_2 emissions rate goals (lbs/netMWhr) that each state must meet. These goals begin with an interim state lbs/netMWHr rate for EGUs that must be met over a ten year averaging period (glide path) from 2020-2029 and a final rate beginning 2030. EKPC notes that EPA is diverging from its practice in other air regulations (e.g., MATS) of using gross generation instead of net generation for the calculation of emissions rates. The net CO_2 emissions rate goals are not only more difficult to meet, but are also punitive for stations like the Spurlock station which has 154 MWs of auxiliary power, 45 percent of which is used for pollution controls.

EPA recognizes in the proposal that there is no technological option to reduce CO_2 emissions from power plants. Instead, EPA determines that the best system of emissions reduction (BSER) for CO_2 emissions from EGUs consists of two basic approaches that are made up of four "Building Blocks." The basic approaches are (1) reducing carbon intensity from individual fuel burning EGUs and (2) reducing state CO_2 emissions rates by reducing utilization levels of coal, and forcing increased use of natural gas, nuclear and renewable sources through a series of unprecedented requirements clearly outside of EPA's authority under the Clean Air Act (CAA) or otherwise. Shifting generation away from coal, in the way that the CPP proposes, falls under the jurisdiction of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), state legislatures, state public utility commissions and state environmental agencies, not EPA. The four Building Blocks are:

- Improving boiler efficiency by six percent (Building Block 1);
- Shifting electricity generation from existing baseload coal to existing natural gas combined cycle (NGCC) with a target of a 70 percent capacity factor from existing NGCC (Building Block 2);
- Shifting generation to low-or zero-carbon generation by completing all nuclear generation currently under construction and preventing the planned retirement of existing nuclear generation and increasing renewable energy (RE) generation (Building Block 3); and
- Increasing demand-side energy efficiency (EE) measures with a target of 1.5 percent in annual energy savings (Building Block 4).

EPA applies these four factors to 2012 state-level data to calculate the interim and final lbs/netMWHr CO_2 emissions rate goals. Almost all of the CO_2 emissions rate goal reductions are calculated by assuming that the CPP will shift generation from existing coal plants to existing natural gas combined-cycle units, new RE generation and through aggressive demand-side EE projects. For Kentucky these calculations yielded

Interim Goal (2020-2029) 1,844 lbs/netMWh

Final Goal (2030) 1,763 lbs/netMWh

Q. PLEASE DESCRIBE THE NEW NON-CAA EPA RULES.

A. <u>New CWA 316(b) Rule</u>

EPA published its final rule to regulate cooling water intake structures (CWIS) at existing facilities on August 15, 2014. The rule sets requirements that establish Best Technology Available (BTA) for minimizing adverse environmental impact from impingement mortality and entrainment mortality due to operation of CWIS. The rule became effective on October 14, 2014 and has been challenged in court by various parties. Unless the rule is stayed, EKPC must move forward with proposing to the Kentucky Division of Water how it will comply with BTA at its facilities with CWIS.

Impingement mortality (IM) results from impingement of aquatic organisms on the cooling water intake structure, typically traveling water screens used to prevent debris from entering the cooling water circulating pumps and the steam condenser tubes. Entrainment mortality (EM) results when organisms that are entrained through the cooling water intake structure die due to the combined effects of mechanical stress from the pumps, thermal stresses from the heat transferred from the condensers, and application of any biocides.

Spurlock Station, Cooper Station, and Dale Station are subject to requirements of Section 316(b) of the Clean Water Act (CWA) to minimize adverse environmental impact due to IM and EM at the respective cooling water intakes because each: (1) holds a Kentucky Pollutant Discharge Elimination System (KPDES) permit, (2) has a design intake capacity that withdraws more than 2 million gallons per day

(MGD) from waters of the United States, and (3) withdraws at least 25 percent of the intake water for dedicated cooling purposes. EKPC's Smith Station is not subject to regulation under Section 316(b) as the combustion turbine generation does not use cooling water.

The IM performance standard established in the final rule is based on modified traveling screens with fish returns, and includes a compliance option based on survival rates after impingement as well as several alternative compliance approaches. In its rulemaking, EPA determined that there is no single technology that is BTA for EM. The final rule therefore contains a national BTA standard for EM that establishes a process by which the permitting authority (in Kentucky, the Division of Water) determines EM mitigation requirements on a site-specific basis.

<u>Impingement Mortality</u>

As stated above, the final rule's IM performance standard is based on modified traveling screens with fish returns, but 40 CFR 125.94(c) includes several compliance alternatives. The alternatives are:

a. Closed-cycle recirculating system.
b. Design through-screen velocity $\leq$ 0.5 fps.
c. Actual through-screen velocity $\leq$ 0.5 fps.
d. Existing offshore velocity cap > 800 feet offshore.
e. Modified traveling screens with fish return.
f. A system of technologies and/or operational measures.
g. Compliance with numeric impingement mortality performance standard.

EPA described options a., b., and d. as "essentially" pre-approved technologies that require little if any demonstration for compliance. Options c., e., and f. were described as "streamlined" technologies that require monitoring and reporting requirements that ensure proper operation of the installed control technology. Option g. requires compliance with a numeric performance standard for IM. EPA does not anticipate that retrofit to closed-cycle cooling will be justified to mitigate IM alone. Each of these compliance alternatives has specific information submittal and monitoring requirements.

Entrainment Mortality

The rule requires the Director of the Division of Water to establish BTA for EM for EKPC's facilities on a site-specific basis that reflects the Director's determination of "the maximum reduction in entrainment warranted after consideration of the relevant factors..." (§125.94(d)). For facilities with actual intake flows (AIF[4]) greater than 125 MGD, the rule requires the submission of a number of reports that provide information to be used as the basis of the Director's decision on BTA for EM. Facilities with AIF less than 125 MGD are not required to perform these studies but are still subject to a BTA determination by the Director under §125.98(f).

EPA stated in the preamble to the final rule that "EPA is not implying or concluding that the 125 MGD threshold is an indicator that facilities withdrawing less than 125 MGD are (1) not causing any adverse impacts or (2) automatically qualify as

[4] AIF is the defined as the average rate of pumping by the facility over the last three years. AIF may account for days with zero flow. Five years after the effective date of the rule, the previous five years of record is used in calculating AIF.

meeting BTA". The Director has the discretion to still require some or all of these studies for facilities with an AIF less than 125 MGD "if there is reasonable concern regarding entrainment impacts."

As listed in §125.98(f)(2), a number of factors must be considered in the Director's determination, including:

- The number and types of organisms entrained, including federally-listed T&E species and/or critical habitat.
- Impact of particulate emissions and other pollutants.
- Land availability for entrainment technology.
- Remaining useful life of the plant.
- Quantified and qualitative social costs and benefits.

Further, §125.98(f)(3) states that the Director may base the decision on the following factors "to the extent the applicant submitted information under 40 CFR 122.21(r):"

- Entrainment impacts on the waterbody.
- Thermal discharge impacts.
- Credit for flow reduction with unit retirement in the preceding 10 years.
- Impacts on reliability of energy delivery.
- Impacts on water consumption.
- Availability of water for reuse.

Information and Data Submittals

Section 122.21(r)(1)(ii) requires that all existing facilities with design intake flows of greater than 2 MGD submit to the Director information required under paragraphs (r)(2) and (3) and applicable provisions of paragraphs (4) through (8) Section 122.21 (r). For facilities with AIF greater than 125 MGD, the required additional studies include five additional reports described at §122.21(r)(9-13). The first is an entrainment characterization study (§122.21(r)(9)) with a minimum duration of two years. The entrainment study will support additional studies including a technical feasibility and cost study of entrainment mitigation measures (§122.21(r)(10)) which at minimum is to include closed-cycle cooling, fine mesh screens with a mesh size of 2 millimeters or smaller, and water reuse or alternate sources of cooling water. The Director may require evaluation of additional measures for entrainment mitigation. Additional studies include a Benefits Valuation Study (§122.21(r)(11)) and a Non-water Quality Environmental and Other Impacts Study (§122.21(r)(12)). Reports (10) through (12) require external peer review as provided by §122.21(r)(13). The reviewers are selected by the applicant and approved by the Director, and must have "appropriate qualifications". The applicant must provide an explanation for any "significant" reviewer comments that are not accepted.

The Director may reduce or waive some or all of the information required under paragraphs (r)(9) to (13) if the facility intends to comply with the BTA standards for entrainment using a closed-cycle recirculating system. The Director also has discretion to waive some of the submittal requirements under §122.21(r) if the intake is located in a manmade lake or reservoir and the fisheries are stocked and managed by a State or Federal natural resources agency or equivalent. Finally, existing facilities are required to submit any additional information deemed necessary by the NPDES director to determine permit conditions and requirements, potentially including information requested by the U.S. Fish & Wildlife Service (USFWS) and/or the National Marine Fisheries Service under §125.98(h).

As to the timing of the information submittals and determinations of IM and EM requirements, for facilities with pending NPDES renewal applications as of the rule's effective date that will result in a renewal permit being issued before July 2018, the information and studies required by §122.21(r) should not be due until the next NPDES Permit application is submitted (*i.e.*, the next 5-year permitting cycle). However, the permitting authority has discretion to establish a schedule for submitting the information in the next renewal permit. Additional IM and EM controls, if any, would be generally determined by the agency in the next permitting cycle along with any necessary compliance schedule for designing and installing any necessary controls.

Potential Spurlock Station 316(b) Requirements

The Spurlock Station Cooling Water System consists of four evaporative mechanical draft cooling towers with a combined makeup water requirement of 21.6 MGD. Spurlock Station withdraws water for cooling tower makeup and other purposes from the Ohio River. The station's CWIS consists of two submerged passive wedgewire intake screens, an intake sump, and three vertical makeup water pumps. The screens consist of welded Type 304 stainless steel wedgewire strainer elements with circumferential 1/8 inch slot construction. They each have a design capacity of 14,050 gallons per minute (gpm) and a maximum through-slot velocity 0.5 fps at design flow. The calculated velocity through the strainer elements is

0.466 fps. Debris collected in the screen is periodically cleaned by a compressed air backwash system which is capable of producing a backwash pressure of 150 pounds per square inch (psi).

Makeup water is withdrawn through the two submerged intake screens by gravity and flows into the intake sump. Each pump is rated for 5,000 gpm at 141.5 feet of head and is driven by a 250 hp/1.15 service factor, 1,180 rpm motor manufactured by General Electric. The cooling water intake structure does not employ traveling water screens.

Spurlock Station's passive wedgewire screens have a maximum design through-screen velocity of 0.5 fps; therefore, the intake screens should be considered BTA for IM under §125.94(c)(2). Spurlock Station's closed-cycle cooling system should also be considered BTA for IM under §125.94(c)(1).

Spurlock Station utilizes a closed-cycle recirculating cooling system with maximum makeup water demand of 21.6 MGD, which is substantially under the rule's AIF threshold of 125 MGD that would subject it to the rule's requirement for comprehensive entrainment studies. As discussed above, facilities with AIF less than 125 MGD are not required to perform the entrainment studies required under §§122.21(r)(9) through (13) but are still subject to a BTA determination by the Director under §125.98(f).

An additional factor that could impact the expectation that no additional controls will be required for IM or EM at Spurlock Station is whether there are potential issues with federally-listed threatened or endangered (T&E) species or designated critical habitat. A recent review of listed species in the vicinity of the Spurlock

Station intake indicated two federally-listed endangered mussel species that may be present in the source waterbody, the fanshell (Cyprogenia stegaria) and the sheepnose (Plethobasus cyphyus). Of the two, the sheepnose is more likely to be present as it is known to occur within the Ohio River. There are no critical habitat designations in the adjacent segment of the Ohio River near Spurlock Station. With regard to T&E species, the Director, in consultation with the Services, determines additional control measures that may be required "to minimize incidental take, reduce or remove more than minor detrimental effects to federally-listed species and designated critical habitat, or avoid jeopardizing federally-listed species or destroying or adversely modifying designated critical habitat" under §125.94(g). At this point in time, EKPC is unaware of any potential impacts to T&E species. Spurlock Station's KPDES permit has been administratively continued and a renewal application has been pending since prior to the rule's effective date. It is uncertain when the permit will be reissued, but it is anticipated it will be issued within the next 12 to 15 months. Submittals required under sections 122.21(r)(2)-(8) will therefore need to be included with the next KPDES renewal application per §125.95(a)(1) in approximately 5 years. The final rule contains no explicit supplemental information requirements for administratively continued permits; however, §125.98(g) allows the Director of the Division of Water to ask for additional information to support the current renewal application. The final BTA determinations for IM and EM should be confirmed by the Division of Water in the KPDES renewal permit issued at that time (approximately 2021). Alternatively, §125.98(g) authorizes the Division of Water to make those determinations in the upcoming renewal permit if it finds the record supports findings that the cooling tower use meets IM and EM standards.

Q. PLEASE DESCRIBE THE EFFLUENT LIMITATION GUIDELINES AND STANDARDS FOR THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY.

A. On June 7, 2013, EPA published its proposed effluent limitation guidelines (ELGs) for the steam electric power generating point source category. The ELGs, when final, will establish revised technology-based effluent limitations and standards for various wastewater streams generated by fossil fuel-fired steam electric generating stations. The ELGs will establish the best available technology economically achievable (BAT) requirements for existing facilities, including Spurlock Station, Cooper Station, and Dale Station.

In the proposed rule, EPA set forth the wastewater treatment options that were under consideration for various wastewater streams generated by coal-fired power plants. That includes flue gas desulfurization (FGD) wastewater, fly ash transport water, bottom ash transport water, coal combustion residual (CCR) landfill leachate, non-chemical metal cleaning wastes, and wastewater from flue gas mercury control systems. EPA has proposed effluent limitation standards based upon four combinations of treatment options for existing sources. Some of the treatment options for specific wastestreams (e.g., landfill leachate) are the same under several or all preferred options.

EPA expects to promulgate the final ELGs in September 2015. In the proposal, EPA expected that NPDES Permits issued in the next permitting cycle beginning three years from the effective date of the rule would contain a compliance schedule for any newly established ELGs. The compliance schedules would be set by the state NPDES permitting authority *(e.g.*, Division of Water in Kentucky). At the time of the proposed rule, EPA anticipated that the rule would be finalized in June 2014, but issuance of the final rule has been delayed a year and is now expected by September 2015. Accordingly, it is anticipated that any new wastewater controls required to be installed to meet the new ELGs would need to be constructed and operational within no more than eight years from the effective date of the final rule, depending on circumstances. EPA determined that compliance schedules are necessary to accommodate studies of available technologies and operational measures, and subsequent design and installation of the wastewater control technologies at each facility.

Q. PLEASE DESCRIBE THE NEW CCR RULE.

A. On June 21, 2010, EPA published the Proposed Rule for Disposal of Coal Combustion Residuals (CCRs) from Electric Utilities. EPA provided two co-proposals for public comment: regulation of CCRs as a hazardous, or "special," waste under RCRA subtitle C and regulation of CCRs as a solid waste under RCRA subtitle D. EPA stated that it supports and has endeavored to maintain beneficial reuse of CCRs under both proposed rules. The Subtitle C alternative has extensive repercussions and there are serious questions as to whether the industry could comply with these requirements.

EPA issued the final CCR rule on December 19, 2014. In its final rule, EPA determined that CCR is a solid waste, not a hazardous waste. The final rule applies to owners and operators of new and existing landfills and new and existing surface impoundments, including all lateral expansions of landfills and surface impoundments where CCR is disposed (together, CCR units). The rule also applies to some inactive CCR surface impoundments (units no longer receiving CCR after the rule is effective) at active electric utilities, if the unit still contains CCR and liquids. CCR includes fly ash, bottom ash, boiler slag and flue gas desulfurization materials.

The requirements in the final rule do not apply to (1) CCR landfills that ceased receiving CCR prior to the effective date of the rule; (2) CCR units at facilities that have ceased producing electricity prior to the rule being effective; (3) CCR generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities and hospitals; (4) fly ash, bottom ash, boiler slag, and flue gas desulfurization generated primarily from the combustion of fuels other than coal (unless the fuel burned consists of more than fifty percent coal on a total heat input or mass input basis, whichever results in the greater mass feed rate of coal; (5) CCR that is beneficially used; (6) CCR placement at active or abandoned underground or surface coal mines; or (7) municipal solid waste landfills that receive CCR.

The rule will be effective on October 19, 2015. Certain requirements that need additional time to implement have later deadlines. The key components of the final rule are outlined below.

- Reducing Risk of Catastrophic Failure through Structural Integrity Requirements
- Protecting Groundwater through Groundwater Monitoring and Corrective Action; Location Restrictions and Liner Design Criteria
- Operating Criteria
- Record Keeping, Notification, and Internet Posting
- Inactive Units
- State Programs
- Closure
- Beneficial Use.

EKPC is actively developing legal and technical analysis in order to produce an environmental compliance plan for the new CCR rule.

III. Environmental Compliance at the Bluegrass Station

Q. PLEASE DESCRIBE THE ENVIRONMENTAL DUE DILIGENCE CONDUCTED BY EKPC WITH RESPECT TO ITS PROPOSED ACQUISITION OF THE BLUEGRASS STATION.

A. EKPC performed a robust legal and technical review of permit documents, correspondence, records, and reports obtained from agency files as well as extensive due diligence materials and environmental compliance information supplied by the Bluegrass Station's current operator. EKPC also witnessed emission tests of the Bluegrass Station Units and held several on-site reviews and meetings. Additionally, EKPC hired Linebach Funkhouser, Inc., to conduct a Phase I Environmental Site Assessment of the property in accordance with ASTM

E1527-1; the Assessment Report revealed no evidence of recognized environmental conditions in connection with the subject property and recommended that no further assessment was necessary. Finally, EKPC's due diligence confirmed that the Bluegrass Station's current operator is complying with the Title V and KPDES permits, applicable requirements for Aboveground Storage Tanks, and noise limits established by existing real property agreements, among other environmental obligations.

Q. DOES EKPC BELIEVE THE BLUEGRASS STATION IS IN COMPLIANCE WITH ALL EXISTING ENVIRONMENTAL PERMITTING REQUIREMENTS?

A. Yes. As part of EKPC's proposed acquisition of the Bluegrass Station, Bluegrass will assign to EKPC the various environmental permits necessary to operate the Bluegrass Station. A list of the Environmental Permits to be transferred to EKPC as part of the transaction is set forth in the Asset Purchase Agreement's Disclosure Schedule 4.16(b)(i) (*see* Exhibit 3 to EKPC's Application).

Q. DOES EKPC ANTICIPATE THAT IT WILL REQUIRE ADDITIONAL PERMITS OR APPROVALS FOR ENVIRONMENTAL COMPLIANCE UPON ITS ACQUISITION OF THE BLUEGRASS STATION?

A. EKPC does not anticipate seeking any additional permits or approvals for this existing facility. If a need for modifications to the operations arises in the future, EKPC will evaluate any implications for existing permits and approvals at that time.

Q. IS THE BLUEGRASS STATION WELL-POSITIONED FOR FUTURE ENVIRONMENTAL COMPLIANCE?

A. Yes. As a relatively new, natural gas-fired generation facility, the Bluegrass Station is well-positioned for compliance with the myriad upcoming environmental requirements identified above. Because coal-fired generation has been the focus of the vast majority of EPA's increased regulatory requirements, the Bluegrass Station faces fewer environmental compliance challenges and a more favorable regulatory outlook. Moreover, certain otherwise-impactful federal regulations, such as CCR and MATS, do not concern natural gas-fired generation resources. Of course, as coal and associated carbon emissions become more heavily regulated, natural gas-fired generation increases in value. Based on these considerations and others, EKPC has made pursuing prudent diversity in the fuel mix of its generation portfolio a core component of its Strategic Plan. The Bluegrass Station is an environmentally-sound investment that will help EKPC achieve its strategic objectives in both the near and long term.

IV. Conclusions

Q. IS EKPC'S PROPOSED ACQUISITION OF THE BLUEGRASS STATION CONSISTENT WITH PRUDENT ENVIRONMENTAL COMPLIANCE PLANNING?

A. Yes. The proposed acquisition keeps EKPC in a good position vis-a-vis the promulgation of new environmental rules. For instance, since the proposed federal Clean Power Plan looks at carbon emissions on a state-by-state basis, the fact that the Bluegrass Station is located in Kentucky means that EKPC's future compliance with the Clean Power Plan will be less complicated than if it acquired an out-of-state facility. Additionally, natural gas-fired generation has a more favorable regulatory outlook than generation fueled with coal, and extensive due diligence performed by EKPC and its consultants confirms that the Bluegrass Station is a sound investment from an environmental compliance perspective.

Q. DID EKPC CONDUCT A THOROUGH AND APPROPRIATE REVIEW OF THE ENVIRONMENTAL ASPECTS OF THE PROPOSED BLUEGRASS STATION ACQUISITION?

A. Yes. As described herein, EKPC conducted extensive due diligence prior to pursuing the proposed acquisition. Based on the results of this review and EKPC's broad knowledge of existing and anticipated environmental regulations, EKPC has determined that the Bluegrass Station is a prudent investment from an environmental perspective.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER)
COOPERATIVE, INC. FOR APPROVAL OF THE)
ACQUISITION OF EXISTING COMBUSTION TURBINE)
FACILITIES FROM BLUEGRASS GENERATION) Case No. 2015-_______
COMPANY, LLC AT THE BLUEGRASS GENERATING)
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY)
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN)
EVIDENCES OF INDEBTEDNESS)

VERIFICATION OF JERRY PURVIS

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Jerry Purvis, Director of Environmental Affairs for East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Jerry Purvis
Jerry Purvis

The foregoing Verification was signed, acknowledged and sworn to before me this 21st day of July, 2015, by Jerry Purvis.

Gwyn M. Willoughby
NOTARY PUBLIC, Notary # 500144
Commission expiration: 11/30/17

GWYN M. WILLOUGHBY
Notary Public
State at Large
Kentucky
My Commission Expires Nov 30, 2017

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER	)
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STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY	)
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EVIDENCES OF INDEBTEDNESS	)

DIRECT TESTIMONY OF DARRIN ADAMS

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: July 24, 2015

I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Darrin Adams and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Director of Power Delivery Planning, Design, & Construction at EKPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of Transylvania University with a Bachelor of Arts degree in Liberal Studies, and a graduate of the University of Kentucky with a Bachelor of Science degree in Electrical Engineering. I am a Licensed Professional Engineer in the Commonwealth of Kentucky and have more than 20 years of experience in the electric utility industry. From May 1991 to August 1996, I was employed by Kentucky Utilities Company ("KU") as an engineer responsible for planning of the KU transmission system. From March 1999 to October 2001, I was employed by LG&E Energy as an engineer within the Operations Department, primarily responsible for transmission system operational analysis. From October 2001 through June 2004, I was employed as the Group Leader of Transmission Planning at LG&E Energy. I began my employment at EKPC in 2004. Prior to my current position at EKPC, I served the cooperative as an engineer, as the Supervisor of Transmission Planning, and as Manager of Transmission Planning for EKPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AT EKPC.

A. As EKPC's Director of Power Delivery Planning, Design, & Construction, I am responsible for overseeing the planning of the electric transmission facilities necessary to reliably and economically deliver EKPC's power supply resources to its Owner-Member systems. This includes not only the planning of EKPC-owned facilities, but coordination with other electric utilities regarding system modifications that may be needed within their external systems. In addition to overseeing EKPC's transmission planning activities, I am responsible for the design and construction activities necessary to implement modifications for the EKPC transmission system.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the various transmission-related considerations that accompany EKPC's proposed acquisition of the existing combustion turbine facilities located in LaGrange, Oldham County, Kentucky (the "Bluegrass Station"), from Bluegrass Generation Company, LLC ("Bluegrass"). I will discuss the transmission assets to be acquired by EKPC as part of the proposed transaction, certain transmission studies that have been undertaken by EKPC and others in association with the contemplated transaction, the anticipated actions that will be taken as a result of those studies, and the deliverability of the output of the Bluegrass Station Units to EKPC load within PJM Interconnection, LLC ("PJM").

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibit, which was prepared by me or under my supervision and which I ask be incorporated into my testimony by reference:

- Exhibit DA-1, a map showing the location of the transmission lines to be upgraded as a result of the acquisition.

II. Transmission Overview and Operation

Q. PLEASE BRIEFLY DESCRIBE THE TRANSMISSION ASSETS THAT EKPC WILL ACQUIRE AS PART OF THE CONTEMPLATED TRANSACTION.

A. As part of the transaction, EKPC will acquire [redacted]. Additionally, EKPC will acquire [redacted]

Q. DOES EKPC INTEND TO UPGRADE OR OTHERWISE ALTER ANY TRANSMISSION FACILITIES AS A RESULT OF THE PROPOSED TRANSACTION?

A. EKPC has not identified, nor does it anticipate, the need to upgrade or modify either its existing transmission facilities or the existing facilities within the Bluegrass and [redacted] switchyards as a result of this proposed acquisition.

Q. HOW WILL THE OUTPUT OF THE BLUEGRASS STATION REACH EKPC LOAD IN THE PJM MARKET?

A. The [redacted] are owned and operated by KU/LG&E. Thus, in order to successfully flow the output of the Bluegrass Station to EKPC load in the PJM market, firm transmission service must be available within the KU/LG&E transmission system.

Q. HAS EKPC REQUESTED TRANSMISSION SERVICE THROUGH KU/LG&E FOR THE OUTPUT OF THE BLUEGRASS STATION?

A. Yes. Transmission service requests have been made by EKPC to designate each of the Bluegrass Station Units as Network Resources for EKPC load. In light of a Tolling Agreement in place between KU/LG&E and Bluegrass with respect to Bluegrass Station Unit 3, the transmission service request made by EKPC with respect to that Unit was separate from EKPC's request with respect to Bluegrass Station Units 1 and 2.

Q. HAS TRANSMISSION SERVICE BEEN FINALIZED WITH RESPECT TO BLUEGRASS STATION UNITS 1 AND 2?

A. Yes. TranServ International, Inc. ("TranServ"), as KU/LG&E's Independent Transmission Operator, accepted EKPC's transmission service request and, upon EKPC's confirmation of the request on June 26, 2015, the service was finalized.

Q. WILL THE FINALIZED TRANSMISSION SERVICE WITH RESPECT TO BLUEGRASS STATION UNITS 1 AND 2 NECESSITATE THE REVISION OF THE NETWORK INTEGRATED TRANSMISSION SERVICE AGREEMENT IN PLACE BETWEEN EKPC AND KU/LG&E?

A. Yes. The Network Integrated Transmission Service ("NITS") Agreement that exists between EKPC and KU/LG&E will be revised to incorporate the finalized transmission service with respect to Bluegrass Station Units 1 and 2. Pursuant to the revised NITS Agreement, Bluegrass Station Unit 1 and Unit 2 will become Designated Network Resources of EKPC upon the consummation of the contemplated transaction.

Q. DOES THE REVISED NITS AGREEMENT REQUIRE APPROVAL FROM ANY REGULATORY BODY?

A. Yes. The NITS Agreement between EKPC and KU/LG&E is governed by the Federal Energy Regulatory Commission ("FERC"), and KU and LG&E will file the revised NITS Agreement for approval. This is expected to be a filing that is strictly ministerial in nature.

Q. HAS TRANSMISSION SERVICE BEEN FINALIZED WITH RESPECT TO BLUEGRASS STATION UNIT 3?

A. No. TranServ and KU/LG&E are still evaluating EKPC's request for transmission service with respect to Bluegrass Station Unit 3. However, EKPC anticipates finalization of the service in the coming months. Notably, due to the KU/LG&E Tolling Agreement in effect for Unit 3 through April 2019, this requested service would not commence until May 1, 2019, and thus there is no particular urgency.

III. Transmission Due Diligence

Q. DID EKPC EVALUATE OR INVESTIGATE THE TRANSMISSION ASSETS IT WILL ACQUIRE AS PART OF THE CONTEMPLATED TRANSACTION?

A. Yes. EKPC retained a third-party firm, CE Power, to perform complete testing on the three (3) Generator Step-up and four (4) auxiliary transformers at the Bluegrass Station. These tests were witnessed by EKPC Power Delivery staff. The testing included Doble power factor, winding excitation, turns ratio, bushing, winding resistance, oil, acoustic, and CT saturation tests. Although some minor anomalies were observed, all tested transmission equipment was shown to be in acceptable condition. In addition, EKPC reviewed available documentation and performed a visual inspection of all transmission assets it would acquire as part of the proposed transaction to ensure their condition is acceptable.

Q. HAS A SYSTEM IMPACT STUDY BEEN PERFORMED RELATED TO TRANSMISSION SERVICE FOR BLUEGRASS STATION UNITS 1 AND 2?

A. Yes. Following EKPC's transmission service request to designate Bluegrass Station Units 1 and 2 as Network Resources for EKPC load, TranServ conducted a System Impact Study ("SIS"), the results of which were released in March 2015. This study identified likely loading constraints, foremost of which is a constraint on the [redacted].

Q. IS THE [redacted] CONSTRAINT A RESULT OF EKPC'S PROPOSED ACQUISITION OF THE BLUEGRASS STATION?

A. No. The [redacted] has been a limiting constraint in real-time operations historically during certain periods. As a result, the three NERC Reliability Coordinators (MISO, PJM, and TVA) responsible for the systems in the vicinity of this facility have jointly developed an operating guide to manage congestion on this facility. Notably, the [redacted] constraint was determined to be a constraint only in the near-term years of the SIS.

Q. HAS A STUDY BEEN PERFORMED TO DETERMINE WHAT ACTIONS MAY BE NECESSARY TO ALLEVIATE THE CONSTRAINTS IDENTIFIED BY THE AFOREMENTIONED SIS?

A. Yes. The constraints identified in the SIS led to the preparation of a Facilities Study by TranServ and KU/LG&E. This Facilities Study identified the system upgrades and operating procedures which would be necessary to alleviate the identified constraints.

Q. **HOW DOES THE AFOREMENTIONED FACILITIES STUDY PROPOSE THAT THE [redacted] CONSTRAINT BE ADDRESSED?**

A. Because the [redacted] constraint was identified as a short-term constraint, an operating procedure was specified to mitigate the constraint during real-time operating conditions. The Bluegrass Station will operate subject to an operating guideline under the direction of the three NERC Reliability Coordinators involved in the event an actual constraint develops in the course of operations. Essentially, the operating guide that is currently in effect to manage congestion on the [redacted] will be modified to recognize the transmission service granted to EKPC in response to its transmission service request for Bluegrass Station Units 1 and 2.

Q. **HOW DOES THE AFOREMENTIONED FACILITIES STUDY PROPOSE THAT THE OTHER CONSTRAINTS IDENTIFIED BY THE SIS BE ADDRESSED?**

A. The remaining constraints identified on the KU/LG&E transmission system will be addressed through timely system upgrades by KU/LG&E that will provide sufficient capacity to transmit the output of the Bluegrass Station Units so that EKPC will be able to serve its load that resides on the KU/LG&E system as it currently does.

Q. WILL EKPC BE RESPONSIBLE, FINANCIALLY OR OTHERWISE, FOR ANY NECESSARY SYSTEM UPGRADES?

A. No costs identified for system upgrades on the KU/LG&E system due to EKPC's transmission service request will be directly assigned to EKPC. EKPC will only be responsible financially to the extent that KU/LG&E will ultimately incorporate the costs of these upgrades into its transmission rates for network service as described in Attachment O of its Open Access Transmission Tariff, and EKPC will be responsible for its pro rata share of those incremental costs based on its use of the KU/LG&E transmission system relative to other transmission customers. KU/LG&E will be responsible for the design, construction, operation, and maintenance of the system upgrades, and those entities will maintain ownership.

Q. HAS A SYSTEM IMPACT STUDY BEEN PERFORMED RELATED TO TRANSMISSION SERVICE FOR BLUEGRASS STATION UNIT 3?

A. Yes. Following EKPC's transmission service request to designate Bluegrass Station Unit 3 as a Network Resource for EKPC load, TranServ conducted a second SIS (the "Unit 3 SIS"), the results of which were released in July 2015. The [redacted] constraint was again identified as a potential short-term constraint in the Unit 3 SIS, but not as a long-term constraint.

Q. HAS TRANSERV INDICATED HOW THE [redacted] CONSTRAINT WILL BE ADDRESSED WITH REGARD TO SERVICE TO BLUEGRASS STATION UNIT 3?

A. Yes. TransServ has indicated that this constraint will be addressed through an operating procedure similar to the manner in which the constraint will be managed with regard to the service for Units 1 and 2.

Q. WILL A STUDY BE PERFORMED TO DETERMINE WHAT ACTIONS MAY BE NECESSARY TO ALLEVIATE THE CONSTRAINTS IDENTIFIED BY THE UNIT 3 SIS?

A. Yes. A Facilities Study will be conducted by TranServ and KU/LG&E to determine the specific mitigation required for each constraint identified. The preliminary indication in the Unit 3 SIS is that all constraints other than the [redacted] will be addressed through system upgrades that will be in place when needed to provide sufficient capacity to transmit the entire output of the three Bluegrass Station Units to EKPC's load.

Q. WILL EKPC BE RESPONSIBLE, FINANCIALLY OR OTHERWISE, FOR ANY NECESSARY SYSTEM UPGRADES?

A. As described above for the system upgrades identified to allow the requested service for Bluegrass Station Units 1 and 2, EKPC anticipates only being responsible financially to the extent that its pro rata share for the relative use of the KU/LG&E transmission system increases as a result of KU/LG&E incorporating the upgrade costs associated with service for Unit 3 into its transmission rate base. EKPC does not expect to be responsible otherwise for the upgrades.

IV. Conclusions

Q. DOES EKPC ANTICIPATE FACING ANY SIGNIFICANT HURDLES WITH RESPECT TO THE TRANSMISSION OF THE OUTPUT OF THE BLUEGRASS STATION?

A. No. EKPC anticipates that the combination of the operating guide to address the [redacted] constraint and the planned system upgrades by KU/LG&E will provide an adequate transmission system to allow delivery of the Bluegrass Station output to EKPC's load when desired.

Q. WILL THE TRANSMISSION ASSETS AND AGREEMENTS YOU HAVE DESCRIBED HEREIN PROVIDE VALUE TO EKPC AS A RESULT OF THE CONTEMPLATED TRANSACTION?

A. Yes. The transmission assets that are being acquired are well-priced and of good quality. These assets, along with the transmission service arrangements EKPC has put in place will allow EKPC to reliably and affordably deliver the output of the Bluegrass Station Units to EKPC load within the PJM market when it is advantageous to do so, will ultimately benefit EKPC's Owner-Member cooperatives and their end-use members.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. As a result of the proposed transaction, EKPC will become the owner of certain transmission assets necessary to deliver the output of the Bluegrass Station Units into the KU/LG&E transmission system. EKPC has performed its due diligence to ensure that these assets are in acceptable condition to ensure continued reliable delivery. In order to deliver the output to EKPC load in the PJM market, transmission service requests have been submitted to KU/LG&E. This service has been finalized for Units 1 and 2 and is being incorporated into the NITS agreement that exists between EKPC and KU/LG&E. The SIS for EKPC's request for transmission service for Unit 3 has been completed and the Facilities Study will be completed in the coming months. Based on the SIS results, EKPC expects that the service will be granted. No significant incremental transmission costs are anticipated as a result of the asset ownership and contractual transmission arrangements EKPC would enter into as a result of this transaction. Furthermore, EKPC expects these transmission arrangements to allow EKPC to reliably and affordably deliver the output of the Bluegrass Units to EKPC load in the PJM market when desired.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR APPROVAL OF THE ACQUISITION OF EXISTING COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC AT THE BLUEGRASS GENERATING STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN EVIDENCES OF INDEBTEDNESS	) Case No. 2015-_______

VERIFICATION OF DARRIN ADAMS

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Darrin Adams, Director of Power Delivery Planning, Design, & Construction at East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Darrin Adams

Darrin Adams

The foregoing Verification was signed, acknowledged and sworn to before me this 21st day of July, 2015, by Darrin Adams.

Gwyn M Willoughby

NOTARY PUBLIC, Notary # 508144

Commission expiration: 11/30/17

GWYN M. WILLOUGHBY
Notary Public
State at Large
Kentucky
My Commission Expires Nov 30, 2017

CONFIDENTIAL EXHIBIT DA-1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER	)	
COOPERATIVE, INC. FOR APPROVAL OF THE	)	
ACQUISITION OF EXISTING COMBUSTION TURBINE	)	
FACILITIES FROM BLUEGRASS GENERATION	)	Case No. 2015-_______
COMPANY, LLC AT THE BLUEGRASS GENERATING	)	
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY	)	
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN	)	
EVIDENCES OF INDEBTEDNESS	)	

DIRECT TESTIMONY OF JAMES READ

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: July 24, 2015

EXHIBIT

8

I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is James Read and I am a Principal with The Brattle Group ("Brattle"). My office is located at 44 Brattle Street in Cambridge, Massachusetts 02138.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I have been consulting in the areas of energy and financial economics for over thirty years. My consulting practice has focused on the electric power and natural gas industries, including the valuation of energy resources and contracts, investment decision-making, portfolio risk management, market analysis and modeling, energy trading, and supply procurement. I have worked for many years with the Electric Power Research Institute to apply modern financial economics to decision-making in the electric power industry, to develop tools and methods for valuation and risk management, and to teach principles and methods of value and risk to industry participants. I hold a Bachelor's degree in economics from Princeton University and a Master's degree in finance from the Sloan School of Management at the Massachusetts Institute of Technology. My education and professional experience is more fully described in my *curriculum vitae*, a copy of which is attached to this testimony as Exhibit JR-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe Brattle's engagement by East Kentucky Power Cooperative, Inc. ("EKPC"), to function as an independent procurement manager ("IPM") with respect to EKPC's efforts to secure adequate capacity to serve its Member-Owners and meet its power supply needs. I will describe the Request for Proposals ("RFP") processes undertaken in this regard in 2012 and 2014 (the "2012 RFP" and "RFP Refresh," respectively) and Brattle's role in those processes.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. In addition to my *curriculum vitae* (attached hereto as Exhibit JR-1), I am also sponsoring the letter report dated June 19, 2015 (the "Brattle Screening Analysis"), which is attached hereto as Exhibit JR-2. The Brattle Screening Analysis details the proposals received as part of the RFP Refresh and reflects the analyses conducted and conclusions reached by Brattle as part of the RFP process. Both my *curriculum vitae* and the Brattle Screening Analysis were either prepared directly by me or by someone working under my supervision and direction, and I ask that each be incorporated into my testimony by reference.

II. Background

Q. HAVE YOU PREVIOUSLY OFFERED TESTIMONY BEFORE THIS COMMISSION AND/OR OTHER REGULATORY BODIES?

A. Yes. I have offered testimony before the Federal Energy Regulatory Commission and the Public Service Commission of the State of New York. I also submitted testimony on behalf of EKPC in Case No. 2013-00259.[1]

[1] *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for Alteration of Certain Equipment at the Cooper Station and Approval of a Compliance Plan Amendment for Environmental Surcharge Cost Recovery*, Case No. 2013-00259 (filed Aug. 21, 2013).

Q. WHAT IS THE ROLE OF AN INDEPENDENT PROCUREMENT MANAGER?

A. The issuer of an RFP may engage an IPM for various reasons. For example, if an issuer anticipates that an affiliate will participate in the RFP process as a bidder, it may engage an IPM to ensure that the process is fair, open, and non-discriminatory. It is my understanding that, with respect to the 2012 RFP, EKPC decided to engage an IPM because it expected to submit one or more self-build options in response to the 2012 RFP. Brattle was engaged as an IPM by EKPC for the RFP Refresh due to Brattle's familiarity with the relevant parties, expressed needs, and available alternatives.

Q. PLEASE DESCRIBE BRATTLE'S EXPERIENCE SERVING AS AN IPM FOR OTHER UTILITIES.

A. Brattle has served as an IPM for purchases or sales of long-term energy, renewable power, and electric power transmission rights. These include an RFP process for Northern Illinois Municipal Power Agency to solicit offers for a power purchase agreement or outright sale of an entitlement share of a coal-fired power plant; several auction processes for First Energy to procure solar renewable energy credits (subject to approval by the Pennsylvania Public Utility Commission); and open season processes for the sale of transmission rights between PJM Interconnection, LLC ("PJM") and the New York ISO (subject to approval by the Federal Energy Regulatory Commission).

Q. PLEASE BRIEFLY DESCRIBE THE EXPERTISE AND CONTRIBUTIONS OF THE OTHER MEMBERS OF YOUR BRATTLE TEAM WHO PARTICIPATED IN THE PREPARATION OF THE BRATTLE SCREENING ANALYSIS.

A. I was assisted by several research analysts at Brattle. Brattle research analysts have expertise in economic analysis and proficiency with various software tools, such as Microsoft Excel. In this case, research analysts prepared and applied an Excel spreadsheet model to analyze proposals received in response to the RFPs.

II. The 2012 RFP

Q. WHY DID EKPC UNDERTAKE THE 2012 RFP?

A. It is my understanding that EKPC's decision to pursue the 2012 RFP was based on its anticipated loss of approximately 300 megawatts ("MW") of capacity as a result of federal environmental regulation, most notably the Mercury and Air Toxics Standards ("MATS") rule.

Q. WHAT WAS BRATTLE'S ROLE IN THE 2012 RFP?

A. Brattle was retained in May 2012 to assist EKPC in a solicitation process to address the projected capacity shortfall. Specifically, Brattle was engaged to develop and market the RFP, select a short list, and report on a recommended course of action. This was a collaborative effort in which Brattle leveraged EKPC's Power Supply planning staff, analytical resources, and data.

Q. WERE YOU PERSONALLY INVOLVED IN THE 2012 RFP?

A. Yes. I served as the project manager at Brattle for the 2012 RFP. In addition to me, two other principals at Brattle, Joseph Wharton and James Reitzes, were involved in the project. We were assisted by several research analysts and administrative assistants.

Q. HOW MUCH GENERATION DID EKPC SEEK TO ACQUIRE THROUGH THE 2012 RFP?

A. EKPC sought to obtain up to 300 MW of additional generation through the 2012 RFP.

Q. WHAT TYPES OF POWER SUPPLY OPTIONS WERE EKPC WILLING TO CONSIDER AS PART OF THE 2012 RFP?

A. EKPC was willing to consider proposals to purchase new or existing power plants, to enter into intermediate-term or long-term power supply contracts, and to purchase power from renewable or conventional resources. EKPC identified a target start date of October 2015 for new resources but said it would consider proposals that specified earlier or later dates. The only strict constraints that EKPC imposed on the supply proposals were that they (a) specify a term of at least five years and (b) specify no less than 50 MW if for power from conventional generation resources and no less than 5 MW if for power from renewable generation sources.

Q. HOW DID BRATTLE GO ABOUT MARKETING THE 2012 RFP?

A. EKPC and Brattle assembled a list of potentially-interested parties. Among others this list included firms that had expressed interest after EKPC announced its intention to issue an RFP in a press release on April 23, 2012. Brattle simultaneously built a web site through which interested parties could obtain the RFP documents, register to receive RFP updates, submit questions, obtain required forms, and submit their proposals. The web site was also used to post answers to questions thought to be of general interest.

Q. PLEASE SUMMARIZE THE RESPONSES RECEIVED TO THE 2012 RFP.

A. EKPC received a large and diverse set of proposals in response to the 2012 RFP. These included proposals for new natural-gas fired power plants, some at existing EKPC sites, others outside of EKPC; proposals to sell EKPC existing gas or coal-fired plants, or ownership shares thereof; natural gas tolling agreements, with rights to the associated capacity as well as energy; power purchase agreements with contract price terms linked to the owner's operating costs ("cost-based PPAs"); energy-only contracts for "block" products, with liquidated damages provisions; capacity-only contracts; PPAs for power from renewable energy resources, including wind, solar, biomass, landfill gas, and waste; and proposals for energy from coal waste and mine mouth methane.

Q. DID EKPC SUBMIT ANY SELF-BUILD PROPOSALS AS PART OF 2012 RFP?

A. Yes. In addition to the proposals received from third parties, EKPC's Power Production Engineering & Construction ("PPE&C") group submitted several proposals in response to the 2012 RFP.

Q. DID THE 2012 RFP TAKE INTO ACCOUNT EKPC'S PENDING INTEGRATION INTO PJM?

A. Yes. Although EKPC was not then integrated into PJM, the proposals received in response to the 2012 RFP were evaluated under the assumption that EKPC would be integrated into PJM by the beginning of the planning period. EKPC was, in fact, integrated into PJM in June of 2013. As a PJM member, EKPC's load obligations and power supply portfolio are effectively separated—EKPC schedules its load with PJM on a daily basis and it bids it generation into PJM on a daily basis. EKPC pays PJM for the energy, capacity, and ancillary services its Owner-Members consume. EKPC receives payments from PJM for the energy, capacity, and ancillary services is produces.

Q. WHY IS EKPC'S INTEGRATION INTO PJM RELEVANT TO THE EVALUATION OF PROPOSALS RECEIVED IN RESPONSE TO THE 2012 RFP?

A. Prior to its integration into PJM, EKPC's ability to buy power from and sell power to third parties was limited. As a result, it had to plan to meet the power supply needs of its Owner-Members largely from its own generation resources. Now, in contrast, PJM is both the supplier to EKPC's Owner-Members and the market for the production of EKPC's generation fleet. Therefore, constructing or acquiring additional generation resources is an option for EKPC, not a requirement.

Q. WHAT CRITERIA DID YOU APPLY TO EVALUATE PROPOSALS?

A. The principal criterion we applied to evaluate power supply proposals as part of the 2012 RFP was net present value ("NPV"). The NPV of a power supply resource is equal to the difference between (a) the present value of the energy and capacity it is expected to provide and (b) the present value of the costs that EKPC would incur to obtain that energy and capacity. Essentially, NPV is a proposal's *value added.* Because EKPC is a member of PJM, it purchases from PJM the energy and capacity its Members consume and PJM purchases from EKPC the energy and capacity

EKPC's generation resources produce. Therefore, one can also think of NPV as the expected reduction in net power supply costs to EKPC's Member-Owners conditional on a proposal's acceptance.

Q. DID YOUR EVALUATION OF THE RESPONSES TO THE 2012 RFP TAKE INTO ACCOUNT THE SIZE AND DURATION OF THE PROPOSALS?

A. Yes. In addition to calculating NPVs, we calculated NPVs normalized for the size and duration of the proposals, that is, the NPV per megawatt-year.

Q. DID YOUR ANALYSIS OF FACILITY PURCHASES AND RETROFIT PROPOSALS TAKE INTO ACCOUNT THE REQUIRED CAPITAL INVESTMENTS?

A. Yes. Like fuel and operating and maintenance costs, the purchase prices and investments associated with proposed facility purchases and retrofits were deducted from the present value of the energy and capacity a proposal was projected to provide. In addition, we calculated the benefit-cost ratio for facility purchase and retrofit proposals. The benefit-cost ratio is the ratio of the NPV of the proposal to the purchase price or required capital investment.

Q. AS PART OF YOUR CONSIDERATION OF THE RESPONSES TO THE 2012 RFP, DID YOU TAKE INTO ACCOUNT EKPC'S STRATEGIC OBJECTIVES?

A. Yes. One of EKPC's strategic objectives is to rebuild its equity-to-assets ratio. Another strategic objective is to diversify its supply mix.

Q. WHAT OTHER FACTORS DID YOU TAKE INTO ACCOUNT AS PART OF YOUR EVALUATION OF THE RESPONSES TO THE 2012 RFP?

A. As previously stated, EKPC received a diverse set of proposals in response to the 2012 RFP. The proposals included facility acquisitions, which would entail substantial up-front investments, as well as power purchase agreements, which do not. Some were for renewable generation resources, others for conventional resources. Some were for dispatchable resources, some for baseload resources, and others for intermittent resources. The heat (energy conversion) rates of the proposed dispatchable resources vary as well. Therefore, comparing the proposals strictly on the basis of NPVs—even when normalized for size and duration—does not provide a sufficiently clear picture to make an appropriate recommendation.

Q. HOW DID YOU TAKE INTO ACCOUNT THE DIVERSITY OF THE RESPONSES RECEIVED TO THE 2012 RFP?

A. We compared proposals with similar characteristics. Specifically, we identified several categories of proposals and assigned each proposal to one of the categories. The categories were:

- PPAs for power from conventional (or unspecified) energy resources—most of the power purchase agreements offered were structured as tolling agreements or call options or provide some degree of dispatch flexibility. The energy output tends to be greater under contracts with high heat (*i.e.*, energy conversion) rates than those with low heat rates. Proposals for high heat rate resources were put in a separate category from proposals with low heat rates.

- Ownership of generation resources—as distinct from the contractual obligations of a PPA—entails an up-front investment of funds and thus associated financing requirements. Ownership also entails management responsibilities (*e.g.*, operation and maintenance).
- PPAs for power from solar and wind generation resources are intermittent supplies—when available, they provide a flow of energy subject to ambient weather conditions (*e.g.*, wind speed and sunshine).
- PPAs for power from other renewable energy resources (landfill gas, waste, biomass) have the character of baseload resources—they typically produce energy approximately equally over the diurnal and seasonal cycles.
- Self-build proposals were a separate category. The self-build options were qualitatively distinct from the other proposals EKPC considered. If EKPC were to enter into a contract with a third party, it would be able to negotiate performance provisions to protect itself in the event of a cost overrun, delay, etc. Under a self-build option, EKPC does not have the ability to obtain comparable assurances.

Q. DO THE FOREGOING CATEGORIES CAPTURE ALL OF THE RELEVANT DISTINCTIONS AMONG THE POWER SUPPLY PROPOSALS RECEIVED AS PART OF THE 2012 RFP?

A. Even within categories, proposals varied in terms of fuel type, contract duration, heat rate, and new build versus retrofit, among other distinctions. However, we were aware of these differences when considering the proposals.

Q. AFTER CATEGORIZING EACH OF THE PROPOSALS RECEIVED AS PART OF THE 2012 RFP, HOW DID YOU PROCEED?

A. We created a short list of bidders by selecting the most attractive proposal in each category. The project team then held further discussions with each of the short list bidders, either by telephone or in person, to review and clarify proposal terms.

Q. WHAT DID YOU CONCLUDE BASED ON YOUR ANALYSIS OF THE RESPONSES TO THE 2012 RFP?

A. We concluded that one of the self-build proposals, a proposal to remediate Cooper Unit 1, was the most attractive of those on the short list. The proposal was to reconfigure Cooper Unit 1 so as to flow its emissions through the existing air quality control system servicing Cooper Unit 2, and thereby to return approximately 116 MW of existing generation to service for an investment of $15 million. This was the highest value-added option available to EKPC and, consistent with our recommendation, it ultimately did pursue this option.[2]

Q. DID THE RECONFIGURATION OF COOPER UNIT 1 RESOLVE THE CAPACITY SHORTFALL EKPC SOUGHT TO ADDRESS THROUGH THE 2012 RFP?

A. Only in part. EKPC still needs to replace the loss of 200 MW of capacity from the retirement of its Dale Station, plan for future load growth, and provide a physical hedge for its winter peak demand. As noted by this Commission in its Order entered February 20, 2014, in Case No. 2013-00253, EKPC is still several hundred

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[2] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for Alteration of Certain Equipment at the Cooper Station and Approval of a Compliance Plan Amendment for Environmental Surcharge Cost Recovery*, Case No. 2013-00259 (Ky. P.S.C. Feb. 20, 2014).

MW short on capacity in winter.[3] To address these issues, EKPC engaged Brattle in 2014 to undertake a refresh of the bids from the 2012 RFP.

III. The RFP Refresh

Q. WHAT WAS BRATTLE'S ROLE IN THE RFP REFRESH?

A. Like with the 2012 RFP, Brattle was engaged to provide an independent and unbiased analysis of the various options available to EKPC to meet its capacity needs.

Q. WHAT DO YOU MEAN WHEN YOU SAY THE RFP REFRESH WAS A "REFRESH" OF THE 2012 RFP?

A. EKPC and Brattle believed it prudent to utilize the 2012 RFP as a starting point for the RFP Refresh, so firms that submitted conventional power supply proposals in response to the 2012 RFP were invited to submit updated or new proposals as part of the RFP Refresh.

Q. HOW MUCH GENERATION DID EKPC SEEK TO ACQUIRE THROUGH THE RFP REFRESH?

A. EKPC sought proposals with a minimum size of 100 MW and maximum of 300 MW as part of the RFP Refresh.

Q. WHAT OTHER CHARACTERISTICS DID EKPC SEEK IN PROPOSALS SUBMITTED AS PART OF THE RFP REFRESH?

A. The RFP Refresh stated that EKPC would consider proposals for PPAs as well as proposals for the purchase and sale of new or existing power plants ("P&SAs"). It also stated that EKPC was seeking dispatchable generation with natural gas as the

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[3] *Id.*, at p. 16.

primary generation feedstock; a preferred start date of November 2014; a minimum term of three years; and a requirement that energy and capacity must be deliverable in PJM, with a preference for delivery to the EKPC load zone and locational delivery area.

Q. WITH RESPECT TO THE TYPES OF POWER SUPPLY OPTIONS EKPC WAS WILLING TO CONSIDER, WERE THERE ANY NOTABLE DIFFERENCES BETWEEN THE 2012 RFP AND THE RFP REFRESH?

A. Yes. EKPC specifically sought natural gas-fired generation in the RFP Refresh, whereas the 2012 RFP was open to other types of conventional generation resources and to renewable generation.

Q. AS PART OF THE RFP REFRESH, DID BRATTLE SEEK PROPOSALS FROM BIDDERS THAT WERE NOT INVOLVED WITH THE 2012 RFP?

A. No. Due to the proximity in time between and similarity in need sought to be addressed by the 2012 RFP and the RFP Refresh, each of the firms and companies invited to participate in the RFP Refresh was involved in the 2012 RFP.

Q. PLEASE SUMMARIZE THE RESPONSES RECEIVED TO THE RFP REFRESH.

A. EKPC received proposals for PPAs, for the construction of new gas-fired generating units, and for the purchase of existing gas-fired generation. The power purchase proposals had terms as short as three (3) years and as long as thirty (30) years. Start dates for proposed PPAs were generally the requested November 1, 2014 date, whereas start dates for proposals to build new generating units were in 2017 or 2018.

Q. DID EKPC SUBMIT ANY SELF-BUILD PROPOSALS AS PART OF RFP REFRESH?

A. No.

Q. HOW DID BRATTLE GO ABOUT EVALUATING PROPOSALS FROM QUALIFIED BIDDERS AS PART OF RFP REFRESH?

A. As in the 2012 RFP, Brattle used the NPV of the proposals as our primary economic criterion for screening. Generation resources create value in the PJM markets chiefly through the production and sale of electric energy and capacity. Therefore, the NPV of each proposal is the present value of the energy and capacity it is projected to produce minus the present value of the associated costs. In the case of PPA proposals, the NPV is the present value of energy margins plus the present value of capacity revenues less the present value of fixed contract charges. (The term "energy margin" refers to net energy revenues—energy revenues less fuel and other variable production costs.) In the case of P&SA proposals, the NPV is the present value of energy margins plus the present value of capacity revenues less the present value of fixed operating and maintenance costs and the purchase price.

Q. WHAT DID YOU CONCLUDE BASED ON YOUR ANALYSIS OF THE RESPONSES TO THE RFP REFRESH?

A. We concluded that EKPC's acquisition of the existing combustion turbine facilities from Bluegrass Generation Company, LLC ("Bluegrass"), in LaGrange, Oldham County, Kentucky (the "Bluegrass Station Proposal"), was the most attractive option of those on the short list. Each Unit has a rated capacity of 198 MW, giving the Bluegrass Station a total rating of 594 MW of winter capacity. The Bluegrass

Station's net summer capacity is 165 MW per unit, for a total of 495 MW. The Units offer a heat rate of 10,800 MMBtu/MWh, and thus they provide peaking capacity. The proposed purchase price was approximately $128 million, equivalent to roughly $260/kW (based on summer capacity) or $217/kW (based on winter capacity).

Q. HOW DID THE BLUEGRASS STATION PROPOSAL COMPARE TO OTHER LEADING PROPOSALS RECEIVED AS PART OF THE RFP REFRESH?

A. Our analysis indicated that the proposed purchase of the Bluegrass Station was the most attractive proposal. The Bluegrass Station has an NPV of $[redacted] under our assumptions, which is far greater than the other proposals. Additionally, its NPV per kW-month is greater than or comparable to the other proposals.

Q. WAS THE BLUEGRASS STATION PROPOSAL CONSIDERED AS PART OF THE 2012 RFP?

A. A proposal to purchase the generating units at the Bluegrass Station was not considered in the 2012 RFP. However, a proposal for a tolling agreement tied to the Bluegrass Station was submitted in the 2012 RFP. This tolling agreement was on the short list for the 2012 RFP, and EKPC entered into negotiations for a tolling agreement tied to Bluegrass Station in 2013.

Q. DID BRATTLE COMPARE THE BLUEGRASS STATION PROPOSAL TO THE ALTERNATIVE OF PURCHASING ENERGY AND CAPACITY IN THE PJM WHOLESALE MARKETS?

A. Yes. In fact, the NPVs we calculated are based on the alternative of purchasing energy and capacity in the PJM markets.

IV. Conclusions

Q. IS IT YOUR PROFESSIONAL OPINION THAT THE BLUEGRASS STATION PROPOSAL IS THE SINGLE BEST PROPOSAL FROM AMONG THOSE SUBMITTED TO EKPC THROUGH THE RFP REFRESH?

A. Yes. Based on our economic analysis and our understanding of EKPC's objectives, constraints, and opportunities, the Bluegrass Station Proposal is the best proposal among those submitted in response to the RFP Refresh.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR APPROVAL OF THE ACQUISITION OF EXISTING COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC AT THE BLUEGRASS GENERATING STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN EVIDENCES OF INDEBTEDNESS	) Case No. 2015-_______

VERIFICATION OF JAMES READ

COMMONWEALTH OF MASSACHUSETTS)
MIDDLESEX COUNTY)

James Read, a Principal with The Brattle Group, being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

____
James Read

The foregoing Verification was signed, acknowledged and sworn to before me this 15th day of July, 2015, by James Read.

JENNIFER M. OSSEN
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 11, 2016

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NOTARY PUBLIC, Notary #
Commission expiration: February 11, 2016

JAMES A. READ, JR.
Principal

Cambridge, MA | +1.617.864.7900 | James.Read@brattle.com

James Read is an expert in valuation, risk management, and capital budgeting. He specializes in the application of option pricing methods to analyze the value and risk of securities, derivatives, non-financial contracts, and real assets. His consulting practice is focused on the energy industry, especially electric power and natural gas.

Mr. Read's consulting engagements have involved, among other topics, energy trading and contract valuation; market and credit risk measurement and management; power and fuel procurement; hedging retail electric and gas service obligations; valuation of generation, storage and transmission assets; analysis, modeling and forecasting energy market prices and volatility; and investment decision making. He has developed analytical methods and software tools for valuation and risk management of energy contracts and portfolios. He has also developed and taught professional training courses on these topics. In addition to his management consulting, Mr. Read has served as a consulting and testifying expert in litigation and regulatory matters involving cost of capital, valuation, commercial damages, securities, taxes, and energy trading.

Prior to joining The Brattle Group, Mr. Read was a Principal with Incentives Research Inc., and before that Director of Financial Consulting with Charles River Associates. He holds a B.A. in economics from Princeton University and an M.S. in finance from the Sloan School of Management at the Massachusetts Institute of Technology.

AREAS OF EXPERTISE

- Electric Power
- Natural Gas
- Risk Management
- Securities
- Valuation

EXPERIENCE

Management Consulting

- Mr. Read has conducted independent reviews of risk management policies, procedures, and compliance for electric power companies in the United States and Canada.
- Advised numerous companies in the electric power industry regarding portfolio risk assessment and management, including forward curve building, volatility modeling and estimation, valuation of energy contracts and generation assets, calculation of risk exposures, and measurement of portfolio risk.

- Analyzed historical data on availability and outages of generating units to develop a model for describing and forecasting generation fleet reliability.
- Worked with a major electric utility to develop a custom methodology for measuring the risk of its power supply portfolio. This was used for regulatory reporting as well as internal management purposes.
- Developed economic theory for allocating capital to lines of business in multiple-line insurance companies.
- For the Electric Power Research Institute (EPRI), directed development of the *Energy Book System* (EBS) software for valuation and management of energy resources. EBS includes tools for portfolio risk management, valuation and pricing of wholesale and retail energy contracts, and management of generation resources.
- Developed and taught professional training courses for EPRI on the application of derivatives methods for understanding the value and risk of commodity contracts and physical assets. Courses include *Value & Risk in Energy Markets*, *Applied Valuation & Risk Management*, and *Generation Asset Valuation*.
- Advised many clients in connection with the valuation of power generation assets for purchase or sale. Projects entailed development and use of options-based valuation tools as well as estimation of long-term forward price curves and volatility term structures.
- Developed a derivatives-based methodology for estimating the cost of capital for investments in merchant power generation.
- Designed methodology for pricing a new product in the gas pipeline industry that would allow shippers to purchase options on pipeline capacity expansion.
- Developed a valuation algorithm for a retail electric service that allows the supplier to buy back electric energy when wholesale market conditions are tight.
- Developed an options-based valuation and decision-making model of nuclear power plants. The model explicitly incorporates the flexibility to shut down prior to operating license expiration and the flexibility to extend the operating license.
- Advised Tennessee Valley Authority and other companies in connection with their evaluations of bids received in response to power purchase option RFPs. Engagements involved development of models for evaluating option-type bids and development of forward price and volatility curves.
- Mr. Read is a principal author of the *Utility Capital Budgeting Notebook*, which integrates previous EPRI studies in finance and project evaluation into a single text.

- For EPRI, prepared a report that describes how the theory and methods of option pricing can be exploited to help evaluate investment projects and contracts.
- In a study for EPRI, developed a methodology for selecting project-specific discount rates. The methodology is based on the idea that cash flows can be partitioned into risk classes, and hence that the value of an investment project can be found by adding up the values of the parts.
- In a study for EPRI, identified a conceptual problem that arises in applications of the revenue requirements method when utility ratemaking procedures are inflexible. The study pointed out that there is feedback between demand and rates, which may undermine the logic for cost-based evaluation of projects.
- In a study for EPRI, developed a rigorous procedure for calculating the cost of holding fuel and other commodity inventories. The procedure exploits information in commodity futures and money markets.
- In a study for EPRI, was part of study team that developed theoretical and empirical analyses of a bias that exists in conventional measures of market risk when applied to the shares of public utility companies. It explained why a bias is likely to arise, provided empirical confirmation of the bias, and devised corrected measures of market risk.
- In a study for EPRI, prepared an exposition of the revenue requirements method. Among other findings, the report concluded that the appropriate risk-adjusted discount rate for calculating the present value of revenue requirements may differ from the discount rate used to calculate net present value. It also identified the logical errors involved in the use of customer discount rates for calculating the present value of revenue requirements.
- Project manager in a study for the U.S. Department of Energy to assess the cost of capital for public and private investments in petroleum stockpiles. The objective of the research was to assess the investment value of private oil stocks and thereby determine the effectiveness of government policies aimed at stimulating private stockpile formation.

Litigation and Regulatory Support

- In a class action matter, Mr. Read prepared an expert report on the cost of capital acquired through the merger of a public company with a special purpose acquisition company (SPAC). The merger involved a complex exchange of warrants and shares.
- In a federal tax matter, Mr. Read was an expert witness on the economic substance of foreign exchange transactions ostensibly facilitated by a credit agreement with a major financial institution.

- Advised legal counsel in several matters involving allegations of manipulation of natural gas and electricity markets in the United States.
- Served as a consulting expert in an international arbitration matter involving two companies in a joint venture to market beverages in Central America. The dispute centered on an option held by one of the parties to buy certain assets from the other, in particular, implementation of the formula set out in the shareholders' agreement for the option exercise price.
- Mr. Read served as a consulting expert in several tax matters that involved complex transaction structures utilizing exotic options and other derivatives.
- Served as a consulting expert in a number of litigation matters that involved option backdating. This work included assessing the odds that options were backdated as well as valuing executive and employee stock options.
- Advised counsel regarding energy trading and risk management practices in an arbitration between participants in a major energy marketing and trading joint venture.
- Provided legal counsel with economic analysis of a series of structured finance transactions in a litigation matter involving companies in the energy and financial services industries.
- Prepared an expert report on the determination of settlement prices for certain commodity futures contracts.
- Advised legal counsel in an arbitration that concerned the termination value of power supply contracts written under the WSPP master agreement.
- On behalf of an industry trade group, conducted a preliminary investigation of whether certain commodity futures prices had been manipulated.
- Analyzed gaming practices in the Western power markets during the energy crisis of 2000-2001. Prepared expert testimony for hearings before the Federal Energy Regulatory Commission.
- Assisted in the development of expert testimony in connection with regulatory hearings about the sale of a nuclear power station by a public utility to an unregulated energy company.
- Advised several clients in the electric utility industry in connection with the design, pricing, and risk management of "provider of last resort" and similar retail transition services created as part of industry restructuring.
- Analyzed the impact of credit risk on the pricing of energy contracts. Analysis was performed in the context of a regulatory review of energy procurement decisions.

- Used option pricing methods to estimate the premium over cost required to compensate investors for the long-term nature of investments in railroad assets. Analysis was used in a revenue adequacy proceeding before the Surface Transportation Board.

Other Experience

- Financial Analyst, Corporate Financial Staff, General Motors Corporation. Mr. Read worked in forward product programs and corporate transfer pricing.
- Staff Economist, Mail Classification Research Division, United States Postal Service. Mr. Read's responsibilities included writing statements of work, technical evaluation of analytical study proposals, and directing contractors in the Postal Service's Long Range Classification Research Program.
- Staff Economist, Office of Rates, United States Postal Service. Mr. Read was engaged in the preparation of testimony filed with the Postal Rate Commission in support of requests for changes in rates. His responsibilities included cost analysis, revenue forecasting, econometric analysis of postal markets, and rate design.

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THE **Brattle** GROUP

Confidential
Contains Information Subject to Non-Disclosure Agreements between EKPC and Bidders

June 19, 2015

Mr. David Crews
Senior Vice President of Power Supply
East Kentucky Power Cooperative
4775 Lexington Road
Winchester, Kentucky 40392

Dear David:

The purpose of this letter is to summarize the second phase of the Request for Proposals ("RFP") process initiated in 2012 to obtain additional long-term power supplies for East Kentucky Power Cooperative, Inc. ("EKPC"). The first phase of that effort was summarized in my letter to you dated January 28, 2013. The second phase, like the first, has been a collaborative process in which The Brattle Group has leveraged EKPC's power planning staff, analytical resources, and data. This letter summarizes The Brattle Group's work on this project and documents the findings we have previously discussed.

Recap of the 2012 RFP

The Brattle Group was engaged by EKPC in 2012 to assist in the development and marketing of an RFP for long-term power supplies. The purpose of the RFP was to solicit proposals for an additional 300 megawatts of generating capacity, a requirement created by the anticipated retirement of approximately 300 MW of coal-fired generating capacity at EKPC's Dale and Cooper Stations. The RFP was issued on June 8, 2012 and responses were due on or before August 30, 2012.

The least-cost option from among the proposals submitted in response to the RFP was a proposal to remediate Cooper Unit No. 1. Remediating Cooper 1 filled approximately 115 MW of the 300 MW RFP capacity target, so EKPC also entered into negotiations for a natural gas tolling agreement—another proposal received through the RFP. The tolling agreement was tied to the Bluegrass Generating Station located in Oldham County, Kentucky.

In August 2013 EKPC filed an application with the Kentucky Public Service Commission for a certificate of public convenience and necessity in connection with the Cooper 1 remediation. Hearings were held in January 2014 and the Commission approved the application in February 2014. In April 2014 EKPC

EXHIBIT
JR-2

announced that it would deactivate Dale Station by April 15, 2015. The deactivation date for Unit 3 and Unit 4 at Dale Station has since been delayed for one year, until April 15, 2016.

The RFP Refresh

In April 2014 EKPC also decided to resume its pursuit of additional power supplies. In light of the fact that almost two years had passed since the original RFP was issued, EKPC asked The Brattle Group to conduct a refresh of the RFP (the "RFP Refresh" or "Refresh RFP"). Specifically, EKPC asked Brattle to invite firms that had proposed conventional power supply resources in the original RFP to submit updated or new proposals. The Refresh RFP stated that EKPC sought proposals with the following characteristics:

- Power purchase (e.g., gas tolling) agreements ("PPAs") or purchase and sale agreements ("P&SAs") for new or existing power plants or shares thereof;
- Dispatchable generation, with natural gas being the primary generation feedstock;
- A minimum size of 100 MW and maximum of 300 MW;
- A preferred start date of November 1, 2014;
- A minimum term of three years; and
- Energy and capacity delivered to PJM, with a preference for energy and capacity delivered to the EKPC load zone and locational deliverability area (LDA).

The Refresh RFP stated that EKPC's J. K. Smith site would be available for the construction of a gas-fired generating unit to be transferred to EKPC. It also emphasized that EKPC viewed transmission and fuel supply reliability as high priorities.

The Refresh RFP was sent via email to the invitees on May 12, 2014. Proposals in response to the RFP were due on June 13, 2014. Invitees were asked to submit a non-binding letter of intent if they wished to participate. They were also required to execute a confidentiality and nondisclosure agreement (NDA).

Proposals Received

Twelve firms submitted proposals in response to the Refresh RFP. Some firms submitted more than one proposal. In contrast to the original RFP, EKPC did not submit any self-build proposals in the Refresh.

There was considerable diversity to the proposals. EKPC received proposals for power purchase agreements, for the construction of new gas-fired generating units, and for the purchase of existing gas-fired generation. The power purchase proposals had terms as short as three years and as long as 30 years.

Start dates for proposed PPAs were generally the requested November 1, 2014 date, whereas start dates for proposals to build new generating units were in 2017 or 2018.

A number of proposals were not fully responsive to the RFP. For example, some firms proposed PPAs tied to coal-fired generation resources. Some others proposed PPAs that did not provide dispatch flexibility.

Screening and Preliminary Evaluation

We first verified that the proposals received in response to the RFP Refresh were submitted by firms that had executed a letter of intent, signed a confidentiality agreement, and submitted the other required forms. The proposal submitted by one respondent was not considered further because the respondent was unwilling to execute the required NDA.

We then turned to an economic evaluation of proposals. The goal of the economic evaluation was to identify the most promising proposals for further consideration and possible negotiation.

Generation resources create value in the PJM markets chiefly by providing electric energy and capacity, so our principal economic criterion for screening proposals was the net present value (NPV) of the incremental energy and capacity each proposal offered. In the case of PPA proposals, the NPV is the present value of energy margins plus the present value of capacity revenues less the present value of fixed contract charges. In the case of P&SA proposals, the NPV is the present value of energy margins plus the present value of capacity revenues less the present value of fixed operating and maintenance costs and the purchase price. (Energy margins are net energy revenues—energy revenues less fuel and other variable production costs.)

We took the engineering, performance, and cost data provided by the respondents as good faith estimates of the corresponding parameters for purposes of this evaluation. These data included capacity, unit availability, fixed and variable operating costs, and heat rates, among other parameters. Whereas the delivery period of a power purchase agreement is an explicit contractual term, the remaining economic life of a power plant is uncertain. Our analysis assumed that the service life of new power plants would be 25 years and the remaining economic life of existing power plants would be 20 years.

The energy margins associated with the proposals were calculated using the RTSim production simulation and optimization model. RTSim is a commercial software product developed and supported by Simtec, Inc. and licensed by EKPC.

Future market prices of electric energy and natural gas are important inputs for calculating energy margins. Forward price curves for electric energy and natural gas were obtained from ACES, a vendor of information and consulting services to the energy marketing and trading industry. Our understanding is that ACES builds its forward price curves by combining forward prices observed in over-the-counter

(OTC) and exchange markets with long-term price forecasts it obtains from Wood Mackenzie, a well-known vendor of energy market information and forecasts. We used electric energy prices for delivery to the AEP Dayton Hub, the electricity trading point closest to the EKPC service territory. We used natural gas prices for delivery to the Henry Hub, the most liquid natural gas trading point in North America. (Forward prices for delivery of natural gas differ to other points differ from Henry Hub prices. I will return to this point below.) All of the market price observations were dated as of June 12, 2014, the day before the due date for the proposals.

Capacity revenues were calculated based on the forward capacity prices determined in the PJM Base Residual Actions for the 2015/16, 2016/17, and 2017/18 capacity delivery years. (The PJM capacity delivery year begins on June 1 and ends May 31.) Capacity prices for delivery years beyond 2017/18 were forecast by escalating the 2017/18 result at a rate of 2.5 percent per annum.

Results

We divided the proposals EKPC received into three categories: intermediate-term PPAs (up to six-year delivery period), longer-term PPAs (greater than six years), and purchase and sale of gas fired generating units. Because they varied in terms of size and duration, we compared the proposals within each category based on a normalized NPV: the NPV per kW of capacity per month. The most attractive proposal in the intermediate-term PPA category by this criterion was one submitted by [redacted] The most attractive in the long-term PPA category was a tolling agreement proposed by LS Power. We identified two proposals in the P&SA category, one by [redacted] to build a new generating unit and one by LS Power to sell an existing generating station.

- [redacted]

- [redacted]

[redacted]

- [redacted]

- [redacted]

All of these proposals have positive NPVs according to our calculations, indicating that they represent opportunities to acquire energy and capacity at an expected cost below forward market prices and price projections. Each has the highest normalized NPV in its category. The following table summarizes our main results.

Proposal	NPV ($millions)	NPV ($/kW-month
[redacted]	[redacted]	[redacted]

[redacted]

Conclusion

The acquisition of additional power supply resources is an option for EKPC, not a requirement. Now that EKPC is integrated into PJM, it has the flexibility to acquire additional resources *if* they are attractive in relation to purchasing energy and capacity in the PJM markets.

Several of the proposals EKPC received look attractive from this perspective. Our analysis indicates that the proposed purchase of Bluegrass Station is the most attractive proposal. It has an NPV of [redacted] under our assumptions, which is far greater than the other proposals. And its NPV per kW-month is greater than or comparable to the other proposals.

Of course, the NPVs are conditional on the inputs—especially the power and fuel market prices. Market prices of electric energy and natural gas are subject to substantial uncertainty, and the uncertainty increases the further into the future one looks. Future capacity market prices, too, are uncertain. But our analysis is relatively conservative in that we have incorporated only 20 years of projected energy margins and capacity revenues, whereas Bluegrass may operate a number of years more. Also, the benefit-cost ratio for the Bluegrass purchase is well in excess of two, so there is considerable "headroom" for energy margins and/or capacity revenues to fall short. Therefore, the proposed purchase of Bluegrass looks like a very attractive opportunity for EKPC.

Sincerely yours,

James Read
Principal

JAR:jr

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER	)	
COOPERATIVE, INC. FOR APPROVAL OF THE	)	
ACQUISITION OF EXISTING COMBUSTION TURBINE	)	
FACILITIES FROM BLUEGRASS GENERATION	)	Case No. 2015-_______
COMPANY, LLC AT THE BLUEGRASS GENERATING	)	
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY	)	
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN	)	
EVIDENCES OF INDEBTEDNESS	)	

DIRECT TESTIMONY OF RALPH L. LUCIANI

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: July 24, 2015

EXHIBIT

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9

I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Ralph L. Luciani. I am a Director with Navigant Consulting, Inc. ("Navigant"), and my business address is 1200 19th Street, NW, Suite 700, Washington, DC 20036.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree in Electrical Engineering and Economics from Carnegie Mellon University, as well as a Master of Science degree from the Graduate School of Industrial Administration at Carnegie Mellon University. I have more than twenty years of consulting experience analyzing economic and financial issues affecting the electric industry, including those related to costing, ratemaking, generation and transmission planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, asset valuation, wholesale power solicitations, power marketing, and Regional Transmission Organization costs and benefits. Prior to joining Navigant, I was a Vice President at Charles River Associates, a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes and Bartlett, Inc. My education and professional experience is more fully described in my *curriculum vitae*, a copy of which is attached to this testimony as Exhibit RL-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe Navigant's engagement by East Kentucky Power Cooperative, Inc. ("EKPC"), to prepare a 20-year (2016-2035) nodal energy price forecast and Independent Market Consultant Report with respect to the existing combustion turbine facilities located in LaGrange, Oldham County, Kentucky (the "Bluegrass Station"), if operated in the western market of PJM Interconnection, LLC ("PJM").

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. In addition to my *curriculum vitae* (attached hereto as Exhibit RL-1), I am also sponsoring Navigant's *PJM RTO Market Summary and Forecast for the Bluegrass Power Plant, June 2015* (the "Navigant Report"), which is attached hereto as Exhibit RL-2. Both of these exhibits were either prepared directly by me or by someone working under my supervision and direction, and I ask that each be incorporated into my testimony by reference.

II. Background

Q. HAVE YOU PREVIOUSLY OFFERED TESTIMONY BEFORE THIS COMMISSION AND/OR OTHER REGULATORY BODIES?

A. Yes. I have previously offered testimony before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Missouri, Ohio, and Pennsylvania state regulatory commissions, the Federal Energy Regulatory Commission, and the Ontario Energy

Board. In Case No. 2012-00169[1] before this Commission, I offered testimony describing the costs and benefits of EKPC's proposed membership in PJM.

Q. HAVE YOU PREVIOUSLY BEEN ENGAGED ON OTHER MATTERS INVOLVING ENERGY PRICE FORECASTS AND ECONOMIC ANALYSES RELATED TO GENERATION RESOURCES OPERATING WITHIN PJM?

A. Yes. Navigant has performed numerous market summaries and price forecasts on behalf of utilities and merchant operators, and I have personally been involved in such undertakings many times throughout my career. For example, in 2013 on behalf of the Staff of the Public Utilities Commission of Ohio, I analyzed a proposed cost-based capacity rate for Duke Energy Ohio's generating units. This analysis included an assessment of the margins on sales of energy from these units.

Q. PLEASE IDENTIFY AND BRIEFLY DESCRIBE THE EXPERTISE AND CONTRIBUTIONS OF THE OTHER MEMBERS OF YOUR NAVIGANT TEAM WHO PARTICIPATED IN THE PREPARATION OF THE NAVIGANT REPORT.

A. Other key members of the Navigant team included:

- Tim McClive, Director, manages the Navigant power markets modeling team and is a resource economist with thirty (30) years' experience in government, utilities, and consulting. At Navigant, Mr. McClive has been actively engaged in over forty (40) power sector analyses, spanning areas

[1] *In the Matter of the Application of East Kentucky Power Cooperative, Inc., to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC*, Case No. 2012-00169 (Ky. P.S.C. Dec. 20, 2012).

across the U.S. and Canada. He holds Bachelor's and Master's degrees in Economics from Trinity College and the State University of New York, and completed all requirements but the dissertation for a Ph.D. from Cornell University.

- Matt Tanner, Associate Director, is responsible for designing, implementing, and updating Navigant's suite of power market models, including the model for forecasting capacity market clearing prices in PJM. Prior to joining Navigant, Dr. Tanner worked as an energy modeler for the U.S. Energy Information Administration. He received his Ph.D. from Texas A&M in Industrial and Systems Engineering and his B.S.E. from Princeton University in Operations Research and Financial Engineering.
- Stan Lee, Managing Consultant, has over twenty-five (25) years of experience in power system planning and computer application development. At Navigant, he uses the integrated generation and transmission simulation software PROMOD IV to analyze the value of generating plants or portfolios, the location of transmission bottlenecks, and congestion costs. Dr. Lee holds a Ph.D. in Operations Research from the University of California, and a B.S. in Electrical Engineering from Seoul National University
- Maggie Shober, Managing Consultant, coordinates Navigant's regional energy market overview reports as well as the integration of environmental regulations into Navigant's energy market models. Ms. Shober holds a Master's in Energy and Environmental Policy from the University of

Delaware and a B.S. in Physics and Environmental Studies from Allegheny College.

- Matt Drews, Senior Consultant, models electric system production cost and generator market performance, with particular focus on the economics of retrofitting and retiring coal units, the performance of gas units in organized markets, and modeling frequency regulation markets. He holds a B.S. in Applied Mathematics and B.A. in Economics and History from the University of Texas at Austin.

III. Summary of the Navigant Report

Q. PLEASE BRIEFLY DESCRIBE THE METHODOLOGIES EMPLOYED AND ANALYSES CONDUCTED AS PART OF THE NAVIGANT REPORT.

A. Navigant uses PROMOD, a commercially-available software, to develop its wholesale energy market price and plant performance forecasts. PROMOD is a detailed energy production cost model that simulates hourly chronological operation of generation and transmission resources on a nodal basis in wholesale electric markets. Navigant maintains and continually develops and updates inputs into PROMOD, such as unit operating parameters, fuel price projections, unit additions and retirements, and load forecasts for PJM and other markets across North America. When conducting dispatch and revenue analyses for individual power plants such as for the Bluegrass Station, Navigant first forecasts a fundamental hourly energy price series for the applicable node or zone using PROMOD. Using the plant operating parameters and projected energy prices from PROMOD for the Bluegrass Station in the western PJM market, the Bluegrass

Station was then dispatched through Navigant's extrinsic value modeling (EVM) software to calculate individual unit operating margins (energy revenues net of plant operating costs) over the 2016 to 2035 period. EVM explicitly accounts for the additional volatility in market prices that is generally absent from simulated prices, including the effect of intra-month volatility in fuel and emissions prices, stochastic variations in demand, and deviations of market bidding away from marginal cost bidding. Finally, using the forecasted peak load, unit additions and retirements contained in our PROMOD input database, Navigant used its capacity model to project capacity revenues in PJM for the Bluegrass Station over the 2016 to 2035 period.

Q. ARE YOU AWARE OF THE COMMISSION'S EXPECTATIONS WITH RESPECT TO SENSITIVITY ANALYSES AS EXPRESSED IN THE ORDER ENTERED FEBRUARY 20, 2014, IN CASE NO. 2013-00259?[2]

A. Yes. In the referenced Order, the Commission stated that it expects EKPC to perform sensitivity analyses with regard to anticipated future environmental rules and regulations "as part of a utility's prudent evaluation of alternatives to any environmental compliance plan." Although the present matter does not directly pertain to environmental compliance, EKPC and Navigant believed it prudent to consider the impact anticipated future environmental rules and regulations may have on generation within PJM generally and the Bluegrass Station in particular.

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[2] *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for Alteration of Certain Equipment at the Cooper Station and Approval of a Compliance Plan Amendment for Environmental Surcharge Cost Recovery*, Order at p. 19, Case No. 2013-00259 (Ky. P.S.C. Feb. 20, 2014).

Q. IN WHAT WAYS DOES THE NAVIGANT REPORT REFLECT CONSIDERATION OF ANTICIPATED FUTURE ENVIRONMENTAL RULES AND REGULATIONS?

A. As discussed in the Navigant Report, anticipated future environmental rules and regulations are considered in detail by Navigant to develop key inputs into PROMOD, including an assessment of future unit retirements and unit environmental retrofits, and projections of emission prices. As part of this process, Navigant evaluates a number of EPA proposed or finalized regulations that will affect generation resources in PJM, including those related to carbon dioxide, mercury and air toxics emissions, nitrogen oxide and sulfur dioxide emissions that cross state lines, pollution contributing to smog in national parks, cooling water intake structures, and coal combustion residuals.

Q. DOES THE NAVIGANT REPORT REFLECT CONSIDERATION OF THE RISK ASSOCIATED WITH PJM'S CAPACITY PERFORMANCE PROPOSAL AND THE BLUEGRASS STATION'S RELATIVELY LOW CAPACITY FACTORS?

A. Yes, the risks and uncertainties associated with PJM's capacity performance proposal and the impact on the Bluegrass Station are discussed and analyzed in the Navigant report. Similarly, the projected capacity factors of the Bluegrass Station and the associated impact on Bluegrass Station energy revenues are analyzed and evaluated in the Navigant report.

Q. DOES THE NAVIGANT REPORT ATTEMPT TO COMPARE THE COSTS AND BENEFITS OF EKPC'S PROPOSED ACQUISITION OF THE BLUEGRASS STATION WITH OTHER OPTIONS FOR CAPACITY THAT MAY BE AVAILABLE TO EKPC?

A. Generally speaking, no it does not. The overarching purpose of the Navigant Report is to evaluate and forecast the revenues and costs that EKPC may realize if it operates the Bluegrass Station in the western market of PJM through 2035. In light of this purpose, the Navigant Report does not include consideration of acquisition/transaction/financing costs or include a comparison or evaluation of alternative proposals for capacity, and it is my understanding that EKPC engaged other professionals to undertake such analyses. However, the Navigant Report does include a comparison of: (i) the value of a tolling agreement between EKPC and Louisville Gas & Electric Company/Kentucky Utilities Company with respect to Bluegrass Unit 3 through April, 2019 (the "Tolling Agreement"); and (ii) the value of Bluegrass Unit 3 if the Tolling Agreement did not exist and the unit was operated in the PJM Capacity and Energy Markets through May 2019. This comparison revealed that the value of the Tolling Agreement relative to the PJM market is $[redacted] (undiscounted nominal dollars) over the 2016 to 2019 period.

Q. PLEASE SUMMARIZE THE PRIMARY CONCLUSIONS OF THE NAVIGANT REPORT.

A. The levelized operating margins (revenues net of operating costs) of the Bluegrass Station are projected to be $71/kW-year (real 2015 dollars) over the 2016 to 2035 period. As a point of comparison, according to the most recent PJM Cost of New

Entry (CONE) study, operating margins of $97/kW-year are needed to cover the $867/kW (2015 dollars) capital cost of a new CT in the PJM region encompassing EKPC. Using a [redacted] percent discount rate as provided by EKPC, the net present value of the operating margins for the Bluegrass Station over the forecast period of 2016 to 2035 is $[redacted] in January 1, 2016 dollars.

IV. Conclusion

Q. IS IT YOUR PROFESSIONAL OPINION THAT THE NAVIGANT REPORT REPRESENTS A REASONABLE ESTIMATION OF THE REVENUES THAT EKPC MAY REALIZE IF IT ACQUIRES THE BLUEGRASS STATION AND OPERATES SAME IN THE WESTERN PJM MARKET?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER)
COOPERATIVE, INC. FOR APPROVAL OF THE)
ACQUISITION OF EXISTING COMBUSTION TURBINE)
FACILITIES FROM BLUEGRASS GENERATION) Case No. 2015-_______
COMPANY, LLC AT THE BLUEGRASS GENERATING)
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY)
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN)
EVIDENCES OF INDEBTEDNESS)

VERIFICATION OF RALPH L. LUCIANI

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF FAIRFAX)

Ralph L. Luciani, Director with Navigant Consulting, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Ralph L. Luciani
Ralph L. Luciani

The foregoing Verification was signed, acknowledged and sworn to before me this 7th day of July, 2015, by Ralph L. Luciani.

Sharon Denise Williams
NOTARY PUBLIC, Notary # 7587134
Commission expiration: 09-30-2018

SHARON DENISE WILLIAMS
NOTARY PUBLIC
REG # 7587134
COMMISSION EXPIRES 9/30/2018
COMMONWEALTH OF VIRGINIA

NAVIGANT

Ralph Luciani

Ralph Luciani
Director

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ralph.luciani@navigant.com

Professional History

- Director, Navigant Consulting, Inc.
- Vice President, Charles River Associates
- Senior Vice President, PHB Hagler Bailly
- Director, Putnam, Hayes & Bartlett, Inc.
- Edison Engineer, General Electric Company (GE)
- Financial Analyst, IBM Corporation

Education

- M.S., Industrial Administration, Carnegie Mellon University
- B.S., Electrical Engineering and Economics, Carnegie Mellon University

Ralph Luciani is a Director in the Energy Practice in Navigant's Washington, D.C. office. Mr. Luciani works in the Power Systems, Markets, and Pricing group. He has more than 20 years of consulting experience analyzing economic and financial issues affecting regulated industries.

Mr. Luciani focuses on the electricity industry, where he has assisted electric utilities and generating companies with business planning, resource planning, power solicitations, ratemaking, transmission cost-benefit studies, fuel and power supply contract negotiations, and environmental compliance strategy.

He recently led the economic evaluation performed by the Eastern Interconnection Planning Collaborative (EIPC) in a two-year study of the expansion of the transmission system in the eastern U.S. needed to support future generation under uncertainty with respect to climate change, renewable portfolio standards, and fuel prices. Mr. Luciani has also recently performed cost-benefit studies for four different electric utilities considering joining a Regional Transmission Organization (RTO), and authored a white paper on transmission planning.

Mr. Luciani has assisted clients and their legal counsel in the management of numerous complex litigation matters, including electric utility prudence and rate cases, and assessments of economic damages in commercial disputes. He has assisted many clients in reaching agreements in settlement processes administered by the Federal Energy Regulatory Commission (FERC). He has appeared as an expert witness in a number of regulatory proceedings.

Professional Experience

RTOs and Transmission

» **RTO Cost-Benefit Studies.** Performed a number of major cost-benefit studies of RTOs over the last ten years, and provided related testimony in state regulatory proceedings.

» **Transmission Planning**. On behalf of EIPC, led the economic evaluation in a two-year study of the potential build-out of the transmission system in the eastern U.S. needed through 2030.

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- **Competitive Transmission.** Assisted a transmission owner in developing transmission proposals in a RTO competitive bidding process to pass cost-benefit and reliability screens.
- **RTO Administrative Costs and Rates**. Served as the lead consultant in a FERC settlement process in which PJM establishing stated rates for the recovery of its administrative costs.
- **Transmission Ratemaking.** On a number of occasions, filed testimony which developed OATT transmission, ancillary service, and reactive power.
- **Transmission Costing**. Provided testimony and negotiated settlement agreements in a FERC settlement process regarding the assignment of costs for through and out transmission charges.

Generation and Power Marketing

- **Nuclear Power.** Assisted a utility in negotiating the sale of a nuclear plant, developed the financial model used in a utility's application for DOE-supported financing of a new nuclear facility, and provided testimony on CWIP financing in rates to support new nuclear plants.
- **Wind/Transmission Studies.** Performed a number of wind/transmission cost-benefit studies, including analyzing the economics of installing 765 kV transmission lines to support new wind power in the Southwest Power Pool.
- **Power Solicitations.** Assisted electric utilities in a number of solicitations for power, including formulating the RFP, conducting bidder's conferences, negotiating term sheets and definitive agreements, and obtaining regulatory approval for the final agreements.
- **Generation Valuation Lecturer.** Over a five-year period, served as the lead lecturer and instructor of an advanced training course on generation valuation under cost-of-service rates and under market-based pricing offered annually at a large U.S. investor-owned utility.
- **Power Marketing.** Prepared several affidavits at FERC analyzing wholesale trading activities of power marketers, developed utility cost-based rates for wholesale sales of capacity and energy, and assisted counsel in reaching an arbitration settlement regarding standby power charges.
- **Stranded Cost Derivation.** Presented testimony before four state utility commissions on the quantification of the stranded cost associated with the deregulation of generation.

Financial Evaluation

- **Cost of Capital.** Testified before the U.S. Bankruptcy Court and assisted counsel in arbitration proceedings regarding the proper discount rate to apply in assessing termination payments for wholesale power contracts, and assessed capital structure and rates for use in FERC proceedings.
- **Municipalization.** Assisted an electric utility in deriving the exit charges to be assessed for a proposed municipalization of a portion of the electric utility's service territory.

» **Mergers and Acquisitions.** Analyzed the potential acquisition of electric utilities and formulated transmission and distribution pro forma financials.

» **Organizational Restructuring.** Lead facilitator in a 12-month project that functionally unbundled the operation of an integrated electric utility into stand-alone profit centers.

Distribution and Retail

» **Distribution Performance-Based Rates.** Formulated a performance-based ratemaking (PBR) plan, for an electric utility, and presented the plan to the state public utility commission.

» **Distribution Benchmarking.** Formulated a benchmarking analysis to compare the costs and rates for the distribution system of an electric utility to the systems of neighboring utilities.

» **Efficiency Programs.** Developed a financial and rate incentive model for an electric utility to evaluate the impact on rates and earnings of adopting energy efficiency programs.

» **Distribution Cost Allocation.** Filed an affidavit in Ontario regarding allocation of distribution costs and derivation of stand-by rates for load displacement generation.

» **Retail Market Strategy.** Formulated models to assess the profitability of new retail loads in a competitive market and a product to reduce on-peak demand in residences.

Environmental and Fuel

» **Environmental Regulations.** Assisted utilities in formulating strategies for Clean Air Act provisions regarding SO_2 and NO_x, and in assessing potential climate change regulations.

» **Fuel Supply.** Assisted an electric utility in negotiating the terms of a buyout and replacement of a long-term coal supply contract, and in obtaining approval for the rate treatment.

» **Nuclear.** Assisted counsel in litigation involving the responsibility for costs incurred in nuclear spent fuel storage and the estimation of damages related to steam generator replacement

» **Natural Gas.** Assisted counsel in obtaining state and federal approval for the merger of natural gas distribution companies, and in evaluating natural gas market manipulation in California.

Expert Testimony Experience

» Testified before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Mississippi, Missouri, Ohio, Pennsylvania, and Texas public utility commissions, the Ontario Energy Board, the U.S. Bankruptcy Court, the U.S. Postal Service Commission, and the Federal Energy Regulatory Commission (FERC).

Testimony or Expert Report Experience, 2003 - 2015

Date	Case	Venue
2013	Westar Generating, Inc., Supplemental Filing, Purchase Power Agreement, Analysis of the Affiliate Transaction under the Commission's *Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991) ("*Edgar*") Precedent, Docket No. ER13-1210-002	Federal Energy Regulatory Commission
2013	In the Matter of the Application of Duke Energy Ohio, Inc. For the Establishment of a Charge Pursuant to Revised Code Section 4909.18. Case No. 12-2400-EL-UNC	Public Utilities Commission of Ohio
2012	Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Its Transmission Assets to the PJM Interconnection, L.L.C., PSC Case No. 2012-00169	Kentucky Public Service Commission
2012	Show Cause Order Directed to Entergy Arkansas, Inc. Regarding Its Continued Membership in the Current Entergy System Agreement, or Any Successor Agreement Thereto, and Regarding the Future Operation and Control of Its Transmission Assets, Docket No. 10-011-U	Arkansas Public Service Commission
2012	Application of Entergy Texas, Inc. for Approval to Transfer Operational Control of Its Transmission Assets to the MISO RTO, Docket No. 40346	Texas State Office of Administrative Hearings
2012	Joint Application of Entergy Mississippi, Inc., and the Midwest Independent Transmission System Operator, Inc., for Transfer of Functional Control of Entergy Mississippi's Transmission Facilities to MISO, Docket No. 2011-UA-376	Mississippi Public Service Commission
2012	Joint Application of Entergy New Orleans, Inc. and Entergy Louisiana, L.L.C. Regarding Transfer of Functional Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Docket No. UD-11-01	New Orleans City Council
2010	Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Operator, Inc., Case No. 2010-00043	Kentucky Public Service Commission
2010	Cost-based Revenue Requirement for the Provision of Reactive Supply and Voltage Control from Generation Sources under Schedule 2 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff, Docket No. ER10-865-000	Federal Energy Regulatory Commission
2010	Application by Ontario Power Generation Inc., Payment Amounts for Prescribed Facilities for 2011 and 2012, Docket No. EB-2010-0008	Ontario Energy Board
2008	Application of Ameren Energy Marketing Company under Section 205 of the Federal Power Act, Docket No. ER09-398-000	Federal Energy Regulatory Commission

Date	Case	Venue
2008	Application of Aquila, Inc. for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest ISO, Docket No. EO-2008-0046	Missouri Public Service Commission
2008	Arizona Public Service Company, Docket No. ER08-514-000	Federal Energy Regulatory Commission
2007-8	TransCanada Pipelines Ltd. vs. USGen New England, Inc., Case Number 03-30465	U.S. Bankruptcy Court for the District of Maryland
2007	Application of Big Rivers Electric Corporation for Approval of Wholesale Tariff Additions, Case No. 2007-00455	Kentucky Public Service Commission
2006	Postal Rate and Fee Changes, Docket No. R2006-1	U.S. Postal Rate Commission
2006	Arizona Public Service Company, Docket No. ER07-23-000	Federal Energy Regulatory Commission
2006	Midwest Independent Transmission System Operator, Docket No. ER-05-6-001	Federal Energy Regulatory Commission
2006	Generic Issues, RP-2005-0020/EB-2005-0529, 2006 Distribution Rates	Ontario Energy Board
2005	Investigation of Practices of the California Independent System Operator, and the California Power Exchange, Docket No. EL-00-95-000	Federal Energy Regulatory Commission
2005	Investigation of Practices of the California Independent System Operator, and the California Power Exchange, Docket No. EL-00-95-000	Federal Energy Regulatory Commission
2005	Application of Southwest Power Pool for a Certificate of Public Convenience and Necessity, Docket No. 04-137-U	Arkansas Public Service Commission
2005	Application of Southwest Power Pool for a Certificate of Convenience, Docket No. 06-SPPE-202	Kansas State Corporation Commission
2005	Policy Issues Related to Southwest Power Pool, Case No. EO-2006-0142	Missouri Public Service Commission
2003	Investigation of Practices of the California Independent System Operator, and the California Power Exchange, Docket No. EL-00-95-000	Federal Energy Regulatory Commission
2003	Midwest Independent Transmission System Operator, Docket No. EL02-111-000	Federal Energy Regulatory Commission

CONFIDENTIAL EXHIBIT RL-2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER	)	
COOPERATIVE, INC. FOR APPROVAL OF THE	)	
ACQUISITION OF EXISTING COMBUSTION TURBINE	)	
FACILITIES FROM BLUEGRASS GENERATION	)	Case No. 2015-_______
COMPANY, LLC AT THE BLUEGRASS GENERATING	)	
STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY	)	
AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN	)	
EVIDENCES OF INDEBTEDNESS	)	

DIRECT TESTIMONY OF MIKE MCNALLEY

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: July 24, 2015

EXHIBIT

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I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Mike McNalley and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Executive Vice President and Chief Financial Officer for EKPC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I obtained my undergraduate degree in economics from Reed College in Portland, Oregon, and my Masters of Business Administration from Dartmouth College. Prior to joining EKPC, I held various positions with DTE Energy ("DTE"), including Chief Financial Officer and Chief Operating Officer of one of DTE's subsidiaries, DTE Energy Technologies. Prior to joining DTE, I served as the corporate leader of finance or as a senior executive at various companies including Corrillian Corp., System2, Inc., and Oliver & Thompson, Inc., all located in Portland, Oregon. I have been employed by EKPC since July 2010.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AT EKPC.

A. I am responsible for accounting, finance, performance measures, pricing and regulatory services, risk management, marketing, information technology, and supply chain at EKPC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is first to describe EKPC's Strategic Plan as it pertains to building and maintaining financial strength and how EKPC's proposed acquisition of the existing combustion turbine facilities located in LaGrange, Oldham County, Kentucky (the "Bluegrass Station"), from Bluegrass Generation Company, LLC ("Bluegrass") furthers EKPC's financial goals. I will also discuss how EKPC intends to finance the proposed acquisition and EKPC's assumption of certain evidences of indebtedness.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my supervision and which I ask be incorporated into my testimony by reference:

- Exhibit MM-1, Schedule of Property Value and Property Cost;
- Exhibit MM-2, Financial Exhibit required by 807 KAR 5:001 Section 12; and
- Exhibit MM-3, Estimate of Costs under the Uniform System of Accounts.

II. EKPC Financial Overview and Description of Proposed Transaction

Q. PLEASE GENERALLY DESCRIBE EKPC'S FINANCIAL PERFORMANCE DURING THE MOST RECENT YEAR.

A. EKPC has enjoyed several years of excellent performance as a result of weather patterns, cost control, and benefits from its membership in PJM Interconnection, LLC ("PJM"). For the year ended December 31, 2014, EKPC had sales of 13,119,594 MWh resulting in total revenue of $952,771,000. EKPC earned a net margin of $64,845,000 and ended the year with $482,553,000 in Members' Equities. EKPC's equity-to-assets ratio was 14.2%, well on the way to achieving the Board of Directors' goal of a 15% equity-to-assets ratio by the end of 2015.

EKPC's Debt Service Coverage (DSC) ratio was a healthy 1.30 and its Times Interest Earned Ratio (TIER) was 1.56. Additional detail concerning EKPC's financial performance for the most recent twelve (12) months ending June 30, 2015, is contained in the Financial Exhibit attached hereto as Exhibit MM-2.

Q. DOES EKPC HAVE A STRATEGIC PLAN CURRENTLY IN PLACE?

A. Yes. Following a Commission-directed management audit, EKPC's Board adopted a Strategic Plan in 2011 that identified various core strategies, including but not limited to pursuing prudent diversity in the fuel mix of the Cooperative's generation portfolio and evaluating new investments using sound financial principles. EKPC's Strategic Plan also includes the ongoing goal of building and maintaining financial strength, with a specific emphasis on increasing its equity ratio. EKPC has convened Strategic Planning retreats annually since 2011 with the most recent being 2014. Generation diversity and financial stability remain cornerstones of EKPC's current Strategic Plan.

Q. IN TERMS OF FINANCIAL STRENGTH, IS EKPC FULFILLING ITS STRATEGIC PLAN?

A. Although it is a continuing process, EKPC has made significant progress towards improving its financial strength over the past six (6) years. It is on track to accomplish its strategic objective of achieving a 15% equity-to-assets ratio this year. EKPC also obtained its initial investment-grade credit ratings from Fitch Ratings and Standard & Poor's and has benefitted from a series of credit rating upgrades and favorable guidance from the major credit rating agencies. Following the initial credit ratings, EKPC replaced its RUS Mortgage with a Trust Indenture, enabling ready access to capital markets in addition to RUS financing. A private placement financing was completed in early 2014. Each of these actions is a milestone in EKPC's strategic plan to improve financial strength and market access.

Q. HAS EKPC ENTERED INTO AN AGREEMENT TO ACQUIRE THE BLUEGRASS STATION?

A. Yes. On June 26, 2015, EKPC and Bluegrass entered into an Asset Purchase Agreement ("Agreement") whereby Bluegrass agreed to sell and assign, and EKPC agreed to purchase and assume, substantially all of the assets and certain specified liabilities of Bluegrass, for the total consideration of $128.75 million, subject to certain terms and conditions set forth in the Agreement.

Q. DOES BLUEGRASS OWN THE BLUEGRASS STATION?

A. No. Currently, the Bluegrass Station and the land upon which it is located is owned by Oldham County, a political subdivision of the Commonwealth of Kentucky. Bluegrass leases and operates the Bluegrass Station pursuant to a Lease Agreement dated November 1, 2000, as amended on December 27, 2001, December 27, 2002, and January 19, 2006 (the "Lease").

Q. PLEASE BRIEFLY EXPLAIN HOW OLDHAM COUNTY CAME TO OWN THE BLUEGRASS STATION.

A. In and around the year 2000, Oldham County assisted Bluegrass in funding the acquisition, construction, installation and equipping of the Bluegrass Station through the issuance of certain revenue bonds ("Bonds") under the provisions of KRS Chapter 103. These Bonds, which were issued in three separate series totaling approximately $192 million, were purchased and are currently held by Bluegrass.

In connection with these bond issuances, Bluegrass conveyed the Bluegrass Station to Oldham County and Oldham County then leased the Bluegrass Station to Bluegrass.

Q. WHO IS RESPONSIBLE FOR MAKING PAYMENTS ON THE BONDS ISSUED BY OLDHAM COUNTY?

A. As issuer of the Bonds, Oldham County is directly and technically responsible for making payments due on the Bonds to the Bonds' holder, namely Bluegrass. However, under the terms of the Lease, Bluegrass is obligated to make a monthly Lease payment to Oldham County that matches the amount of the monthly Bond payment due to Bluegrass from Oldham County. Pursuant to a series of Home Office Payment agreements between Oldham County and Bluegrass, no cash is actually transferred between Bluegrass and Oldham County as part of the financing arrangement.

Q. IS BLUEGRASS OBLIGATED TO MAKE ANY OTHER PAYMENTS TO OLDHAM COUNTY UNDER THEIR ARRANGEMENT?

A. Yes. By conveying the Bluegrass Station to Oldham County, Bluegrass avoided having to pay real and personal property taxes on the subject property. In lieu of the taxes that would have otherwise been collected by Oldham County, Bluegrass makes an annual payment of $565,000 to Oldham County pursuant to an In-Lieu of Tax Payments Agreement dated November 1, 2000 ("PILOT Agreement").

Q. PURSUANT TO THE AGREEMENT, WILL EKPC TAKE AN ASSIGNMENT OF THE RIGHTS AND OBLIGATIONS OF BLUEGRASS UNDER THE LEASE WITH OLDHAM COUNTY?

A. Yes. EKPC will acquire all of Bluegrass' interest in the Lease pursuant to Section 2.01(b) of the Agreement. Accordingly, EKPC will "step into the shoes" of Bluegrass with regard to owing the monthly Lease payment. Because EKPC will also take an assignment of the bonds held by Bluegrass, however, EKPC's Lease payment obligation will be entirely offset by Oldham County's bond repayment obligation.

Q. PURSUANT TO THE AGREEMENT, WILL EKPC ASSUME THE RIGHTS AND OBLIGATIONS OF BLUEGRASS UNDER THE PILOT AGREEMENT WITH OLDHAM COUNTY?

A. Yes. EKPC will assume the PILOT Agreement upon the closing of the transaction and will continue to make the annual payments required thereby to Oldham County for the remaining seven (7) years of the contract's term. Following the closing of the proposed transaction between EKPC and Bluegrass, the Bonds, Lease and/or PILOT Agreement may be modified or replaced subject to negotiations with Oldham County.

III. Financing of the Contemplated Transaction

Q. HOW DOES EKPC INTEND TO FINANCE THE CLOSING OF THE PROPOSED ACQUISITION?

A. EKPC intends to finance the closing of the acquisition through funds currently available from its $500 million unsecured Credit Facility established with the

National Rural Utilities Cooperative Finance Corporation and other banks.[1] EKPC's currently available credit under the Credit Facility exceeds the amount necessary to complete the transaction and will allow the closing to occur as quickly as circumstances allow.

Q. DOES EKPC INTEND TO RELY UPON ITS CREDIT FACILITY FOR THE LONG-TERM FINANCING OF THE BLUEGRASS STATION?

A. No. EKPC does not believe that it is prudent to keep such a large amount of its Credit Facility tied up by the capital costs of the proposed acquisition because the Credit Facility is short-term while the Bluegrass Station is a long-lived asset. A more appropriate financing would match as closely as possible the life and depreciation of the Bluegrass Station. Accordingly, EKPC intends to secure long-term financing for up to 100% of the Bluegrass Station's capital cost under the Indenture of Mortgage, Security Agreement and Financing Statement, dated October 11, 2012, between EKPC and the U.S. Bank National Association.[2]

Q. WHAT FORM DOES EKPC ENVISION THE LONG-TERM FINANCING WILL TAKE?

A. EKPC's plans for the long-term financing of the Bluegrass Station to take the form of a loan with the Rural Utilities Service ("RUS"). However, in the event that RUS

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[1] The Credit Facility was approved by the Commission on September 27, 2013. *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval of the Issuance of up to $200,000,000 of Secured Private Placement Debt, for the Amendment and Extension of an Unsecured Revolving Credit Agreement in an Amount up to $500,000,000, and for the use of Interest-Rate Management Instruments*, Order, Case No. 2013-00306 (Ky. P.S.C., Sept. 27, 2013).

[2] The Trust Indenture was approved by the Commission on August 9, 2012. *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval to Obtain a Trust Indenture*, Order, Case No. 2012-00249 (Ky. P.S.C., Aug. 9, 2012).

financing is not timely available or is otherwise unacceptable, EKPC anticipates offering the debt through a private placement.

Q. AS PART OF ITS APPLICATION IN THIS MATTER, DOES EKPC SEEK COMMISSION APPROVAL OR AUTHORIZATION UNDER KRS 278.300 OF THE FINANCING ASPECTS OF THE PROPOSED ACQUISITION?

A. No. Because EKPC intends to fund the closing of the contemplated transaction utilizing its previously-approved Credit Facility, EKPC will not immediately issue any new evidences of indebtedness as part of its proposed acquisition of the Bluegrass Station. If, following the closing of the contemplated transaction, EKPC pursues a private placement as part of its long-term financing plan, EKPC will seek the approval of the Commission via a separate application filed pursuant to KRS 278.300. It is likely that this separate financing application will also include financing for unrelated items that would otherwise be too small to qualify for the most favorable loan terms. By aggregating the long-term financing of the Bluegrass Station with other, smaller projects, EKPC should be able to secure more favorable terms for a greater amount of its debt offering.

Q. WHAT COMMISSION APPROVAL OR AUTHORIZATION UNDER KRS 278.300 DOES EKPC SEEK IN THIS MATTER?

A. EKPC requests Commission approval and authorization to assume two (2) evidences of indebtedness as part of the contemplated transaction, specifically the Lease and the PILOT Agreement. Both of these agreements are currently in effect between Bluegrass and Oldham County and are to be assigned to EKPC under the terms of the Agreement. Neither the assumption of the Lease nor the PILOT

Agreement will result in the discharge or refund of any existing obligations of EKPC.

IV. Financial Impact of the Proposed Transaction

Q. WHAT DOES EKPC ESTIMATE WILL BE THE ANNUAL OPERATIONS AND MAINTENANCE EXPENSES ASSOCIATED WITH THE BLUEGRASS STATION?

A. EKPC anticipates that the annual operations and maintenance expense (excluding fuel expense) for the Bluegrass Station will be approximately $[redacted]. EKPC also anticipates that the annual fuel costs for each of the Bluegrass Station Units will be approximately $[redacted].

Q. PLEASE GENERALLY DESCRIBE THE FINANCIAL IMPACT OF THE PROPOSED ACQUISITION ON EKPC'S OWNER-MEMBERS.

A. EKPC's ability to maximize the energy and capacity value of the Bluegrass Station through its involvement in PJM means that EKPC's customers will benefit from both excess energy sales to non-native load and revenues realized from participation in the PJM capacity market. These benefits will be reflected in lower costs than would otherwise be incurred, resulting in increasing margins and capital patronage for EKPC's Owner-Members. EKPC acknowledges that recovery through base rates of the capital and fixed and variable operating and maintenance costs of the Bluegrass Station would not commence until after EKPC's base rates are re-established in a rate case or any incurred fuel costs are passed through the company's fuel adjustment clause.

Q. DOES EKPC BELIEVE ITS PROPOSED ACQUISITION OF THE BLUEGRASS STATION IS A FINANCIALLY SOUND AND PRUDENT INVESTMENT?

A. Yes. EKPC's internal analysis, as well as the independent analyses of EKPC's third-party consultants (*e.g.*, The Brattle Group, ACES and Navigant Consulting, Inc.), confirm that the acquisition of the Bluegrass Station will add significant value to EKPC's system, benefit EKPC's Owner-Members and provide lasting economic value by generating capacity revenue and mitigating seasonal market volatility risk. EKPC will realize a total of 495 MW of additional generation capacity at a cost of \$260/kW,[3] which is substantially lower than the estimated \$867/kW cost for the new construction of a comparable unit. Stated another way, EKPC stands to recognize a net gain on the transaction so long as the capacity price in PJM remains above \$[redacted]/MW-day (2016 dollars), which is considerably below the \$120 per MW-day price established in the last PJM incremental capacity auction for planning year 2016/2017. In short, the proposed acquisition should pay for itself and benefit EKPC's Owner-Members by reducing their exposure to long-term capacity and energy market volatility.

Q. HOW WILL THE PROPOSED ACQUISITION IMPACT EKPC'S EQUITY RATIO?

A. In the short term on a stand-alone basis, the addition of the Bluegrass Station to EKPC's assets will lower the equity ratio about six tenths of a percent (*e.g.*, from 15.6% to 15.0%). Over time the margin earned and costs avoided will build equity

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[3] These figures reflect the Bluegrass Station's net summer capacity. The Bluegrass Station has a total rating of 594 MW of winter capacity, which equates to a cost of roughly \$217/kW.

and restore the equity ratio (*e.g.*, to restore the equity ratio to 15.6% would require margin of $20.1 million). Long term, EKPC expects the Bluegrass Station will continue to build equity, further improving EKPC's equity ratio.

If the Bluegrass Station is compared to alternative generation options, such as new construction, the immediate impact on EKPC's equity ratio is less and the long-term impact is more favorable with the Bluegrass Station, largely due to its low acquisition cost.

V. Conclusions

Q. IS THE PROPOSED ACQUISITION OF THE BLUEGRASS STATION CONSISTENT WITH THE FINANCIAL ELEMENTS OF EKPC'S STRATEGIC PLAN?

A. Yes. EKPC's proposed acquisition of the Bluegrass Station furthers EKPC's efforts to build and maintain financial strength and flexibility while also allowing EKPC to mitigate risk from exposure to volatility in capacity and energy markets during seasonal peaks. The purchase price and extensively studied economics of the contemplated transaction suggest that EKPC will be able to gain significant additional generation capacity without sacrificing financial stability or threatening the Cooperative's improved equity position and credit ratings. Finally, and most fundamentally, the proposed transaction will ensure that EKPC may continue to provide adequate, efficient and safe energy to its Members at rates that are fair, just and reasonable.

Q. WHY SHOULD THE COMMISSION GRANT THE RELIEF EKPC REQUESTS PURSUANT TO KRS 278.300?

A. The Lease and PILOT Agreement EKPC proposes to assume are integral aspects of a transaction that EKPC believes will add significant value to its operations and finances. The assumption of these evidences of indebtedness is for a lawful object within the corporate purposes of EKPC, is necessary and appropriate for and consistent with the proper performance by EKPC of its service to the public and will not impair EKPC's ability to perform that service, and is reasonably necessary and appropriate for such purpose.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR APPROVAL OF THE ACQUISITION OF EXISTING COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC AT THE BLUEGRASS GENERATING STATION IN LAGRANGE, OLDHAM COUNTY, KENTUCKY AND FOR APPROVAL OF THE ASSUMPTION OF CERTAIN EVIDENCES OF INDEBTEDNESS	) Case No. 2015-_______

VERIFICATION OF MIKE MCNALLEY

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Mike McNalley, Executive Vice President and Chief Financial Officer of East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Mike McNalley

The foregoing Verification was signed, acknowledged and sworn to before me this 20th day of July, 2015, by Mike McNalley.

NOTARY PUBLIC, Notary # 502993
Commission expiration: 1/27/18

BRENDA BOWEN
Notary Public
State at Large
Kentucky
My Commission Expires Jan 27, 2018

Exhibit MM-1

Original Cost of Property
807 KAR 5:001, Section 18

EXHIBIT
tabbies
MM-1

Pursuant to 807 KAR 5:001, Section 18(1)(b), a general description of EKPC's property and the field of its operation is set forth in the Application. A schedule showing: (a) the original cost of EKPC's property; and (b) the cost of said property to EKPC, is presented below. The original cost of the property is as of June 30, 2015.

Power Production Utility Plant	$2,951,179,107
Transmission Utility Plant	571,630,947
Distribution Utility Plant	209,012,756
General Utility Plant	110,700,499
Subtotal	$3,842,523,309
Construction Work in Progress	$46,550,851
Total Utility Plant	$3,889,074,160

The original cost of EKPC's property and the cost of that property to EKPC are the same.

Exhibit MM-2

Financial Exhibit
807 KAR 5:001, Section 12

EXHIBIT
tabbies
MM-2

Pursuant to 807 KAR 5:001, Section 12(1) and (2), a financial exhibit is attached. Unless otherwise specified, the attached schedules cover operations for the twelve (12) month period ending June 30, 2015, which is not more than ninety (90) days prior to the date this Application is filed.

Section 12(2)(a). The amount and kinds of stock authorized.
Section 12(2)(b). The amount and kinds of stock issued and outstanding.
Section 12(2)(c). Terms of preference of preferred stock, cumulative or participating, or on dividends or assets or otherwise.

EKPC is a not-for-profit rural electric cooperative which has no stock authorized, issued or outstanding.

Section 12(2)(d). A brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with sinking fund provisions, if applicable.

EKPC has an "Indenture of Mortgage, Security Agreement and Financing Statement" ("Trust Indenture"). The Trust Indenture was executed on October 11, 2012 with the U.S. Bank National Association as trustee. The amount of indebtedness secured is up to and including $5,000,000,000. There are no sinking fund provisions associated with the Trust Indenture. The Commission approved the Trust Indenture in Case No. 2012-00249 and an executed copy of the Trust Indenture was filed with the Commission on October 19, 2012.

Section 12(2)(e). The amount of bonds authorized and amount issued, giving the name of the public utility that issued the same, describing each class separately and giving the date of issue, face value, rate of interest, date of maturity, and how secured, together with amount of interest paid during the last fiscal year.
Section 12(2)(f). Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid during the last fiscal year.
Section 12(2)(g). Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of a portion of the indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid during the last fiscal year.

A description of the Bonds and Notes Outstanding is included on pages 3 through 9 of 12 of this Exhibit. EKPC has no other forms of indebtedness.

Section 12(2)(h). The rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.

EKPC has no capital stock and has paid no dividends at any time during the five previous fiscal years.

Section 12(2)(i). A detailed income statement and balance sheet.

A detailed income statement and balance sheet are provided on pages 10 through 12 of 12 of this Exhibit.

Bonds

Type of Debt Issue	Amount Outstanding 6/30/2015	Amount Issued	Issuer	Date Issued	Face Value	Coupon Interest Rate	Date of Maturity	Interest 2014
Spurlock Pollution Control Bonds	-	141,300,000.00	County of Mason	11/15/1984	-	Variable	10-15-2014	27,132.87
Private Placement Bonds	199,000,000.00	200,000,000.00	US Bank	2/6/2014	199,000,000.00	4.610%	02-06-2044	8,323,611.10
Cooper Solid Waste Disposal Bonds	5,500,000.00	11,800,000.00	County of Pulaski	12/15/1993	5,500,000.00	Variable	08-15-2023	34,687.51
Total Bonds	**204,500,000.00**							8,385,431.48

Type of Debt Issue	Date of Issue	Date of Maturity	Amount Outstanding 6/30/2015	Amount Issued	Coupon Interest Rate	Interest 2014
Rural Utilities Service Notes						
T62-1-B650	03-02-1998	12-31-2024	3,229,403.85	6,125,500.00	5.125%	180,898.54
T62-1-B655	03-02-1998	12-31-2024	3,229,403.85	6,125,500.00	5.125%	180,898.54
		Total RUS	6,458,807.70			361,797.08
Federal Financing Bank Notes						
H0080	08-24-1978	12-31-2015	297,473.09	5,782,000.00	10.372%	94,446.92
H0150	11-15-1979	12-31-2015	348,869.65	6,790,000.00	10.144%	108,465.53
H0160	12-26-1979	12-31-2015	294,584.40	6,237,000.00	9.352%	84,802.79
H0165	01-15-1980	12-31-2015	355,832.76	8,746,000.00	7.690%	85,005.66
H0210	04-29-1981	12-31-2015	143,395.78	3,676,542.00	6.248%	28,056.69
H0215	05-15-1981	12-31-2015	265,320.08	6,805,000.00	6.248%	51,912.30
H0220	05-15-1981	12-31-2015	192,683.48	4,942,000.00	6.248%	37,700.29
H0235	06-16-1981	12-31-2015	292,853.56	7,484,000.00	6.248%	57,299.41
H0245	07-20-1981	12-31-2015	63,332.92	1,193,000.00	10.572%	20,473.49
H0255	09-15-1981	12-31-2015	251,158.02	4,700,000.00	10.657%	81,806.98
H0265	10-15-1981	12-31-2015	146,020.03	3,700,000.00	6.248%	28,570.20
H0275	10-19-1981	12-31-2015	39,449.09	1,000,000.00	6.248%	7,718.65
H0285	11-17-1981	12-31-2015	129,065.12	2,500,000.00	10.204%	40,350.97
H0295	01-18-1982	12-31-2016	476,075.50	3,732,000.00	7.991%	63,649.80
H0300	01-20-1982	12-31-2015	12,205.72	300,000.00	7.690%	2,915.82
H0305	01-22-1982	12-31-2016	45,950.56	360,000.00	7.991%	6,143.45
H0310	02-17-1982	12-31-2016	58,114.75	506,000.00	6.591%	6,456.48
H0315	02-18-1982	12-31-2016	709,615.52	6,181,000.00	6.591%	78,837.86
H0320	02-19-1982	12-31-2015	20,341.60	500,000.00	7.690%	4,859.61
H0325	03-15-1982	12-31-2016	1,056,248.58	9,307,000.00	6.591%	117,348.55
H0330	03-22-1982	12-31-2016	60,180.66	530,000.00	6.591%	6,686.02
H0335	04-19-1982	12-31-2016	71,587.19	560,000.00	7.991%	9,571.03
H0340	05-17-1982	12-31-2016	38,351.13	300,000.00	7.991%	5,127.39
H0345	05-24-1982	12-31-2016	513,975.96	4,000,000.00	7.991%	68,716.86
H0350	06-14-1982	12-31-2016	899,256.28	7,000,000.00	7.991%	120,227.70
H0355	06-15-1982	12-31-2016	202,137.18	1,570,000.00	7.991%	27,025.09
H0360	07-14-1982	12-31-2016	790,758.75	6,131,000.00	7.991%	105,721.86
H0365	07-16-1982	12-31-2016	116,079.60	900,000.00	7.991%	15,519.45
H0370	08-16-1982	12-31-2016	55,564.48	430,000.00	7.991%	7,428.73
H0375	08-16-1982	12-31-2016	525,784.41	4,069,000.00	7.991%	70,295.69
H0380	09-15-1982	12-31-2015	24,880.81	500,000.00	10.381%	7,906.19
H0385	09-13-1982	12-31-2016	1,050,018.53	8,126,000.00	7.991%	140,384.10
H0390	09-14-1982	12-31-2016	77,531.01	600,000.00	7.991%	10,365.61
H0395	10-14-1982	12-31-2016	259,142.68	2,000,000.00	7.991%	34,646.56
H0400	10-14-1982	12-31-2016	155,485.99	1,200,000.00	7.991%	20,787.96
H0405	10-14-1982	12-31-2016	580,351.71	4,479,000.00	7.991%	77,591.08
H0410	11-10-1982	12-31-2016	116,439.15	900,000.00	7.991%	15,567.49
H0415	11-10-1982	12-31-2016	77,625.33	600,000.00	7.991%	10,378.25
H0420	11-10-1982	12-31-2016	711,567.28	5,500,000.00	7.991%	95,134.22

Type of Debt Issue	Date of Issue	Date of Maturity	Amount Outstanding 6/30/2015	Amount Issued	Coupon Interest Rate	Interest 2014
Federal Financing Bank Notes (cont.)						
H0425	12-13-1982	12-31-2016	181,368.17	1,400,000.00	7.991%	24,248.29
H0430	12-13-1982	12-31-2016	893,881.99	6,900,000.00	7.991%	119,509.16
H0435	01-17-1983	12-31-2017	214,311.67	1,200,000.00	5.913%	17,777.72
H0440	02-14-1983	12-31-2017	860,368.27	4,800,000.00	5.913%	71,369.78
H0445	03-16-1983	12-31-2017	89,397.73	500,000.00	5.913%	7,415.79
H0450	03-16-1983	12-31-2017	1,162,175.79	6,500,000.00	5.913%	96,405.50
H0455	04-14-1983	12-31-2017	447,439.31	2,500,000.00	5.913%	37,116.26
H0460	04-14-1983	12-31-2017	841,186.43	4,700,000.00	5.913%	69,778.60
H0465	05-16-1983	12-31-2017	169,901.10	950,000.00	5.913%	14,093.76
H0470	06-15-1983	12-31-2017	125,715.12	700,000.00	5.913%	10,428.38
H0475	06-15-1983	12-31-2017	1,257,146.96	7,000,000.00	5.913%	104,283.60
H0480	07-14-1983	12-31-2017	806,677.29	4,500,000.00	5.913%	66,915.98
H0485	08-16-1983	12-31-2017	179,507.72	1,000,000.00	5.913%	14,890.62
H0490	09-27-1983	12-31-2017	143,480.02	800,000.00	5.913%	11,902.02
H0495	09-27-1983	12-31-2017	358,698.90	2,000,000.00	5.913%	29,755.00
H0500	10-24-1983	12-31-2017	180,884.98	1,000,000.00	5.913%	15,004.86
H0505	10-24-1983	12-31-2017	180,884.98	1,000,000.00	5.913%	15,004.86
H0510	05-09-1984	12-31-2018	4,185,330.62	16,500,000.00	6.665%	355,484.79
H0515	01-17-1985	12-31-2019	1,799,921.83	5,900,000.00	5.991%	130,502.10
H0520	04-16-1985	12-31-2015	30,890.90	600,000.00	10.377%	9,812.10
H0525	05-20-1985	12-31-2019	345,323.46	1,130,000.00	5.991%	25,037.43
H0530	06-24-1985	12-31-2019	220,442.78	720,000.00	5.991%	15,983.05
H0535	06-24-1985	12-31-2015	11,433.69	215,000.00	10.590%	3,701.16
H0540	12-23-1985	12-31-2015	153,113.45	3,165,291.00	9.385%	44,224.77
H0545	03-18-1986	12-31-2020	638,559.10	1,897,000.00	5.177%	38,725.38
H0550	03-18-1986	12-31-2015	32,414.14	751,000.00	8.058%	8,097.48
H0555	04-16-1986	12-31-2020	62,965.10	188,000.00	5.177%	3,818.51
H0560	04-16-1986	12-31-2015	28,753.58	706,000.00	7.413%	6,631.50
H0565	10-14-1986	12-31-2020	837,546.37	2,480,000.00	5.177%	50,792.95
H0570	10-30-1986	12-31-2020	1,701,389.05	5,035,000.00	5.177%	103,180.62
H0575	11-06-1995	12-31-2023	7,358,881.26	14,895,000.00	6.301%	508,466.19
H0580	11-06-1995	12-31-2024	15,278,238.42	28,812,000.00	6.306%	1,043,896.82
H0585	11-06-1995	12-31-2024	15,278,238.42	28,812,000.00	6.306%	1,043,896.82
H0590	11-06-1995	12-31-2024	15,278,238.42	28,812,000.00	6.306%	1,043,896.82
H0595	01-26-1996	12-31-2024	3,098,684.06	5,836,000.00	6.123%	205,741.13
H0600	06-25-1997	12-31-2023	1,836,636.67	3,607,000.00	6.297%	126,825.21
H0605	09-14-2000	12-31-2024	3,427,069.60	6,082,000.00	6.005%	223,400.17
H0610	09-15-2000	12-31-2024	3,767,879.08	6,626,000.00	6.067%	247,946.47
H0615	04-10-2001	12-31-2024	5,373,125.06	9,681,000.00	5.451%	318,739.49
H0620	06-05-2001	12-31-2024	4,614,190.32	8,119,000.00	5.726%	287,007.66
H0625	07-10-2001	12-31-2024	4,619,408.85	8,119,000.00	5.729%	287,478.92
H0630	08-10-2001	12-31-2024	4,566,518.19	8,119,000.00	5.488%	272,528.58
H0635	09-06-2001	12-31-2024	4,569,556.60	8,119,000.00	5.426%	269,704.90
H0640	10-03-2001	12-31-2024	6,106,738.70	11,000,000.00	5.104%	339,543.03
H0645	11-08-2001	12-31-2024	7,271,830.80	13,357,000.00	4.709%	373,718.01

Type of Debt Issue	Date of Issue	Date of Maturity	Amount Outstanding 6/30/2015	Amount Issued	Coupon Interest Rate	Interest 2014
Federal Financing Bank Notes (cont.)						
H0650	12-10-2001	12-31-2024	4,554,964.42	7,970,000.00	5.644%	279,369.30
H0655	01-15-2002	12-31-2030	14,315,572.74	20,000,000.00	5.447%	815,189.44
H0660	06-04-2002	12-31-2030	4,366,889.16	6,000,000.00	5.678%	258,977.73
H0665	07-02-2002	12-31-2030	4,343,048.88	6,000,000.00	5.538%	251,352.20
H0670	08-15-2002	12-31-2024	8,550,618.85	15,000,000.00	4.695%	438,417.86
H0675	08-22-2002	12-31-2024	5,727,166.62	10,000,000.00	4.802%	300,191.70
H0680	09-24-2002	12-31-2024	8,426,690.16	15,000,000.00	4.366%	402,414.33
H0685	10-03-2002	12-31-2024	5,620,060.62	10,000,000.00	4.375%	268,926.18
H0690	11-05-2002	12-31-2024	8,558,876.98	15,000,000.00	4.717%	440,851.97
H0695	12-10-2002	12-31-2024	5,687,639.80	10,000,000.00	4.644%	288,525.25
H0700	01-23-2003	12-31-2024	1,953,251.11	3,500,000.00	4.557%	97,211.76
H0705	01-23-2003	12-31-2030	4,603,397.48	6,500,000.00	4.790%	231,139.10
H0710	02-27-2003	12-31-2030	2,250,792.96	3,200,000.00	4.624%	109,173.24
H0715	05-06-2003	12-31-2024	2,423,877.81	4,300,000.00	4.442%	117,723.89
H0720	07-03-2003	12-31-2032	18,883,788.18	25,000,000.00	4.460%	877,558.82
H0725	07-17-2003	12-31-2032	19,120,782.25	25,000,000.00	4.819%	958,694.52
H0730	07-24-2003	12-31-2032	19,052,160.62	24,800,000.00	4.950%	980,708.64
H0735	08-26-2003	12-31-2024	2,277,438.54	3,938,000.00	5.055%	125,441.35
H0740	10-02-2003	12-31-2030	1,827,752.15	2,550,000.00	4.753%	91,077.67
H0745	10-02-2003	12-31-2024	1,503,367.84	2,660,000.00	4.501%	73,965.27
H0750	10-23-2003	12-31-2032	19,296,442.46	25,000,000.00	5.091%	1,021,008.02
H0755	11-04-2003	12-31-2032	19,333,459.28	25,000,000.00	5.149%	1,034,385.94
H0760	11-14-2003	12-31-2032	19,279,798.31	25,000,000.00	5.065%	1,015,021.21
H0765	11-25-2003	12-31-2032	19,245,130.39	25,000,000.00	5.011%	1,002,607.40
H0770	12-04-2003	12-31-2032	20,880,135.81	27,000,000.00	5.149%	1,117,136.81
H0775	02-05-2004	12-31-2030	4,699,237.69	6,500,000.00	4.854%	239,040.00
H0780	05-06-2004	12-31-2030	1,664,926.80	2,260,000.00	5.240%	91,281.07
H0785	05-06-2004	12-31-2024	2,421,618.43	4,130,000.00	5.020%	132,557.46
H0790	08-26-2004	12-31-2030	12,364,544.61	16,900,000.00	4.921%	637,461.43
H0795	11-01-2004	12-31-2030	4,879,829.42	6,700,000.00	4.672%	239,101.47
H0800	11-16-2004	12-31-2030	2,370,223.53	3,240,000.00	4.795%	119,131.96
H0805	11-16-2004	12-31-2024	3,296,748.98	5,644,000.00	4.577%	164,878.44
H0810	12-16-2004	12-31-2038	42,276,384.47	50,000,000.00	4.744%	2,057,569.77
H0815	12-22-2004	12-31-2038	42,370,583.07	50,000,000.00	4.825%	2,096,760.57
H0820	12-29-2004	12-31-2038	42,509,752.87	50,000,000.00	4.946%	2,155,486.04
H0825	02-02-2005	12-31-2038	21,087,731.37	25,000,000.00	4.658%	1,008,034.33
H0830	02-08-2005	12-31-2038	20,992,005.29	25,000,000.00	4.497%	969,341.92
H0835	05-10-2005	12-31-2038	21,115,366.57	25,000,000.00	4.705%	1,019,367.72
H0840	06-02-2005	12-31-2038	20,892,200.62	25,000,000.00	4.332%	929,903.96
H0845	06-07-2005	12-31-2038	15,874,361.57	19,000,000.00	4.324%	705,278.10
H0850	06-09-2005	12-31-2030	7,464,103.40	13,192,000.00	4.353%	359,761.41
H0855	08-26-2005	12-31-2038	25,169,506.41	30,000,000.00	4.468%	1,154,873.26
H0860	08-30-2005	12-31-2038	25,170,949.69	30,000,000.00	4.470%	1,155,447.96
H0865	08-19-2005	12-31-2030	2,702,471.80	3,675,000.00	4.485%	127,216.45
H0870	10-14-2005	12-31-2038	25,383,328.17	30,000,000.00	4.769%	1,241,793.11

Type of Debt Issue	Date of Issue	Date of Maturity	Amount Outstanding 6/30/2015	Amount Issued	Coupon Interest Rate	Interest 2014
Federal Financing Bank Notes (cont.)						
H0875	11-09-2005	12-31-2030	1,552,552.60	2,075,000.00	4.858%	79,038.74
H0880	11-09-2005	12-31-2024	344,143.78	566,000.00	4.789%	17,990.70
H0885	03-27-2006	12-31-2032	5,101,178.03	6,500,000.00	4.890%	259,461.92
H0890	05-03-2006	12-31-2038	12,970,028.20	15,000,000.00	5.345%	709,741.67
H0895	05-09-2006	12-31-2038	8,644,156.82	10,000,000.00	5.333%	471,979.65
H0900	08-23-2006	12-31-2034	12,473,191.34	15,000,000.00	5.070%	653,534.35
H0905	08-25-2006	12-31-2034	12,470,394.46	15,000,000.00	5.061%	652,250.06
H0910	08-29-2006	12-31-2034	19,117,456.39	23,000,000.00	5.053%	998,366.73
H0915	03-14-2007	12-31-2038	19,844,387.19	23,000,000.00	4.776%	972,220.01
H0920	03-16-2007	12-31-2038	20,073,718.05	23,251,000.00	4.812%	990,741.83
H0925	11-01-2007	12-31-2040	45,019,978.09	50,000,000.00	4.821%	2,218,950.19
H0930	11-08-2007	12-31-2040	22,475,570.25	25,000,000.00	4.736%	1,088,562.12
H0935	11-14-2007	12-31-2040	44,896,382.76	50,000,000.00	4.669%	2,144,203.60
H0940	12-05-2007	12-31-2040	22,329,269.96	25,000,000.00	4.384%	1,002,329.54
H0945	12-11-2007	12-31-2040	44,879,129.56	50,000,000.00	4.648%	2,133,894.05
H0950	12-12-2007	12-31-2040	22,220,642.95	25,000,000.00	4.511%	1,025,886.54
H0955	12-19-2007	12-31-2040	44,843,666.74	50,000,000.00	4.605%	2,112,797.30
H0960	01-03-2008	12-31-2032	8,854,679.52	11,000,000.00	4.338%	400,437.20
H0965	01-03-2008	12-31-2040	7,146,994.57	8,000,000.00	4.396%	321,682.92
H0970	01-09-2008	12-31-2040	9,752,202.29	11,000,000.00	4.385%	437,860.95
H0975	02-05-2008	12-31-2040	17,853,556.26	20,000,000.00	4.355%	796,202.31
H0980	02-12-2008	12-31-2040	17,857,980.10	20,000,000.00	4.368%	798,739.71
H0985	05-22-2008	12-31-2040	22,389,437.99	25,000,000.00	4.527%	1,037,287.52
H0990	05-30-2008	12-31-2040	22,482,888.27	25,000,000.00	4.754%	1,092,987.93
H0995	06-04-2008	12-31-2040	22,429,266.83	25,000,000.00	4.623%	1,060,813.16
H1000	10-14-2008	12-31-2040	7,044,461.68	7,900,000.00	4.298%	310,108.64
H1005	10-14-2008	12-31-2032	3,438,474.24	4,200,000.00	4.306%	154,372.46
H1010	11-07-2008	12-31-2040	22,313,537.98	25,000,000.00	4.347%	993,301.46
H1015	11-10-2008	12-31-2040	22,338,169.07	25,000,000.00	4.405%	1,007,456.72
H1020	12-18-2008	12-31-2040	6,398,942.55	7,400,000.00	2.846%	187,596.62
H1025	03-17-2009	12-31-2038	3,145,183.58	3,612,000.00	3.801%	123,082.46
H1030	04-16-2009	12-31-2040	21,971,259.85	25,000,000.00	3.651%	823,609.10
H1035	05-15-2009	12-31-2040	31,673,952.19	35,000,000.00	3.988%	1,295,246.08
H1040	05-27-2009	12-31-2040	22,762,745.58	25,000,000.00	4.374%	1,019,493.38
H1045	06-04-2009	12-31-2040	22,768,705.00	25,000,000.00	4.391%	1,023,661.50
H1055	06-08-2009	12-31-2040	36,548,355.64	40,000,000.00	4.605%	1,721,965.96
H1050	06-08-2009	12-31-2040	22,842,722.28	25,000,000.00	4.605%	1,076,228.73
H1060	06-15-2009	12-31-2040	22,841,014.11	25,000,000.00	4.600%	1,074,998.49
H1065	06-29-2009	12-31-2040	13,055,833.09	14,596,000.00	4.252%	568,682.40
H1070	06-30-2009	12-31-2040	22,723,188.09	25,000,000.00	4.262%	992,062.18
H1075	07-09-2009	12-31-2040	22,665,064.66	25,000,000.00	4.100%	952,477.33
H1080	07-17-2009	12-31-2040	11,608,422.22	12,900,000.00	4.382%	520,851.76
H1085	07-20-2009	12-31-2040	22,794,162.58	25,000,000.00	4.464%	1,041,573.06
H1090	08-05-2009	12-31-2039	9,054,013.29	10,000,000.00	4.396%	408,152.38
H1100	08-10-2009	12-31-2040	22,768,354.90	25,000,000.00	4.569%	1,067,373.15

Type of Debt Issue	Date of Issue	Date of Maturity	Amount Outstanding 6/30/2015	Amount Issued	Coupon Interest Rate	Interest 2014
Federal Financing Bank Notes (cont.)						
H1095	08-12-2009	12-31-2040	22,830,400.62	25,000,000.00	4.390%	1,023,416.28
H1105	09-15-2009	12-31-2040	18,144,189.44	20,000,000.00	4.142%	770,183.51
H1110	09-16-2009	12-31-2040	18,159,137.02	20,000,000.00	4.194%	780,346.24
H1115	09-22-2009	12-31-2040	18,153,685.63	20,000,000.00	4.175%	776,631.88
H1120	09-23-2009	12-31-2039	18,033,449.05	20,000,000.00	4.137%	765,778.69
H1125	10-01-2009	12-31-2039	17,087,291.52	19,000,000.00	3.978%	698,132.97
H1130	10-01-2009	12-31-2040	5,429,996.30	6,000,000.00	3.990%	222,159.07
H1135	11-18-2009	12-31-2039	22,534,503.15	25,000,000.00	4.117%	952,358.37
H1140	11-18-2009	12-31-2039	22,534,503.15	25,000,000.00	4.117%	952,358.37
H1145	11-19-2009	12-31-2039	22,548,739.37	25,000,000.00	4.156%	961,846.71
H1150	11-19-2009	12-31-2039	22,548,739.37	25,000,000.00	4.156%	961,846.71
H1155	01-27-2010	12-31-2039	18,102,626.79	20,000,000.00	4.377%	812,590.46
H1160	01-28-2010	12-31-2040	6,350,452.01	7,000,000.00	4.398%	285,958.90
H1165	02-03-2010	12-31-2039	8,145,669.97	9,000,000.00	4.373%	365,313.90
H1170	02-12-2010	12-31-2040	17,335,145.85	19,000,000.00	4.508%	799,808.27
H1175	06-04-2010	12-31-2023	1,841,909.36	2,714,000.00	3.224%	66,121.51
H1180	06-04-2010	12-31-2034	283,243.45	327,000.00	3.943%	11,593.33
H1185	06-08-2010	12-31-2040	590,742.98	652,000.00	3.922%	23,763.42
H1190	06-08-2010	12-31-2040	824,503.43	910,000.00	3.922%	33,166.73
H1195	06-08-2010	12-31-2039	1,124,282.04	1,249,000.00	3.897%	45,013.28
H1200	06-10-2010	12-31-2039	389,790.66	433,000.00	3.913%	15,669.30
H1205	03-25-2011	12-31-2039	11,372,602.12	12,424,000.00	4.197%	489,824.40
H1210	05-24-2011	12-31-2044	22,501,784.03	24,000,000.00	4.067%	933,267.28
H1215	05-24-2011	12-31-2040	1,669,315.48	1,813,000.00	3.954%	67,690.13
H1220	05-24-2011	12-31-2040	11,664,030.84	12,668,000.00	3.954%	472,972.24
H1225	09-07-2011	12-31-2040	5,908,996.64	6,471,000.00	2.852%	173,593.74
H1230	09-07-2011	12-31-2039	33,419,771.38	36,804,000.00	2.811%	969,458.02
H1235	12-15-2011	12-31-2040	24,774,022.40	27,091,000.00	2.590%	661,697.83
H1240	12-28-2011	12-31-2040	19,219,140.31	21,000,000.00	2.713%	537,420.39
H1245	02-28-2012	12-31-2044	28,043,533.45	30,000,000.00	2.791%	802,047.43
H1250	03-13-2012	12-31-2044	28,126,799.31	30,000,000.00	2.916%	840,028.67
H1255	03-27-2012	12-31-2044	28,154,767.09	30,000,000.00	3.094%	891,558.24
H1260	04-10-2012	12-31-2040	10,228,378.03	11,038,000.00	2.800%	295,074.88
H1265	04-10-2012	12-31-2044	17,837,774.45	18,962,000.00	2.928%	534,905.38
H1270	06-25-2012	12-31-2044	27,714,638.21	29,588,000.00	2.495%	709,456.17
H1275	06-25-2012	12-31-2040	1,548,751.52	1,679,000.00	2.369%	37,873.61
H1280	08-29-2012	12-31-2039	23,091,042.99	25,000,000.00	2.302%	549,791.06
H1285	10-01-2012	12-31-2039	22,326,685.67	24,000,000.00	2.338%	539,816.62
H1290	10-19-2012	12-31-2044	25,597,846.41	27,000,000.00	2.724%	714,723.54
H1295	12-19-2012	12-31-2040	1,139,426.00	1,217,000.00	2.549%	29,956.96
H1300	12-19-2012	12-31-2040	9,362,579.72	10,000,000.00	2.549%	246,154.14
H1305	12-19-2012	12-31-2039	12,123,790.82	13,000,000.00	2.510%	314,450.69
H1310	04-19-2013	12-31-2039	6,615,376.26	7,011,000.00	2.393%	163,668.95
H1315	04-19-2013	12-31-2044	13,090,559.03	13,683,000.00	2.573%	345,461.74
H1320	04-19-2013	12-31-2040	3,011,088.40	3,181,000.00	2.432%	75,570.87

Type of Debt Issue	Date of Issue	Date of Maturity	Amount Outstanding 6/30/2015	Amount Issued	Coupon Interest Rate	Interest 2014
Federal Financing Bank Notes (cont.)						
H1325	08-30-2013	12-31-2039	11,270,463.11	11,787,000.00	3.338%	387,371.70
H1330	10-28-2013	12-31-2040	34,931,478.88	11,315,000.00	3.202%	1,138,137.75
H1335	10-28-2013	12-31-2039	10,900,168.98	36,347,000.00	3.162%	358,995.57
H1340	11-19-2013	12-31-2039	20,649,402.80	21,468,000.00	3.316%	705,116.71
H1345	12-20-2013	12-31-2039	16,304,755.64	16,916,000.00	3.513%	589,215.85
H1350	12-19-2014	12-31-2040	20,723,033.11	21,000,000.00	2.563%	18,880.47
H1355	12-19-2014	12-31-2044	21,394,871.94	21,622,000.00	2.656%	17,695.21
H1360	03-27-2015	12-31-2040	660,370.01	665,000.00	2.253%	-
		Total FFB	2,366,050,293.24			104,948,129.70
Other Debt						
National Rural Utilities Cooperative Finance Corporation ("CFC")						
CFC # 9033 P-12	08-29-1984	05-31-2019	1,876,936.75	8,530,000.00	3.300%	73,803.61
CFC # 9034 R-12	06-12-1995	11-30-2024	3,466,565.81	6,734,000.00	3.300%	120,125.94
CFC # 9038 T-62	03-02-1998	02-28-2024	2,634,016.69	5,251,000.00	3.300%	92,039.29
CFC - Unsecured Credit Facility - #5106002	08-09-2011	10-03-2018	75,000,000.00	75,000,000.00	1.190%	1,441,347.24
Clean Renewable Energy Bonds	02-06-2008	12/1/2023	4,575,681.30	8,613,048.00	0.400%	19,179.63
NCSC						
NCSC Unsecured -#9061004	12-30-2010	11-30-2014	-	1,962,147.00	3.250%	34,615.85
NCSC Unsecured -#9061005	12-30-2010	11-30-2015	789,833.77	1,565,448.00	3.650%	57,138.84
NCSC Unsecured -#9061006	12-30-2010	11-30-2016	1,707,115.00	1,707,115.00	4.050%	69,138.16
NCSC Unsecured -#9061007	12-30-2010	11-30-2017	1,795,642.00	1,795,642.00	4.350%	78,110.44
NCSC Unsecured -#9061008	12-30-2010	11-30-2018	1,886,964.00	1,886,964.00	4.650%	87,743.84
NCSC Unsecured -#9061009	12-30-2010	11-30-2019	1,836,229.00	1,836,229.00	4.850%	89,057.12
NCSC Unsecured -#9061010	12-30-2010	11-30-2020	1,335,822.00	1,335,822.00	5.050%	67,459.00
NCSC Unsecured -#9061011	12-30-2010	11-30-2021	1,544,167.00	1,544,167.00	5.150%	79,524.60
NCSC Unsecured -#9061012	12-30-2010	11-30-2022	1,389,610.00	1,389,610.00	5.250%	72,954.52
NCSC Unsecured -#9061013	12-30-2010	11-30-2023	980,127.00	980,127.00	5.400%	52,926.84
NCSC Unsecured -#9061014	12-30-2010	11-30-2024	325,315.00	325,315.00	5.500%	17,892.32
		Total Other	101,144,025.32			2,453,057.24
		Total Long-term Debt exclusive of Bonds	**2,473,653,126.26**			**107,762,984.02**
		Less Current Maturities-Long-term Debt	**(93,493,843.91)**			
		Less Payments-Unapplied	**(153,067,783.46)**			
		Total Bonds	**204,500,000.00**			**8,385,431.48**
		Long-term Debt Per Financial Statements	**2,431,591,498.89**			**116,148,415.50**

EAST KENTUCKY POWER COOPERATIVE, INC.
STATEMENT OF OPERATIONS
807 KAR 5:001, Section 12(2)(i)

	12 Months Ending June 30, 2015
Electric Energy Revenues	877,597,675
Other Operating Revenue and Income	17,184,711
TOTAL OPERATING REVENUE & PATRONAGE CAPITAL	894,782,386
Operation Expense-Production-Excluding Fuel	62,797,011
Operation Expense-Production-Fuel	247,963,922
Operation Expense-Other Power Supply	157,368,691
Operation Expense-Transmission	35,043,319
Operation Expense-Regional Market Expenses	4,434,749
Operation Expense-Distribution	1,705,166
Operation Expense-Consumer Service & Information	7,776,576
Operation Expense-Sales	93,428
Operation Expense-Administrative & General	36,705,733
TOTAL OPERATION EXPENSE	553,888,595
Maintenance Expense-Production	76,457,554
Maintenance Expense-Transmission	7,249,191
Maintenance Expense-Distribution	2,742,769
Maintenance Expense-General Plant	1,964,346
TOTAL MAINTENANCE EXPENSE	88,413,860
Depreciation & Amortization Expense	95,517,853
Taxes	34,563
Interest on Long-Term Debt	115,056,495
Other Interest Expense	0
Asset Retirement Obligations	(69,318)
Other Deductions	828,366
TOTAL OPERATING EXPENSES	211,367,959
TOTAL COST OF ELECTRIC SERVICE	853,670,414
OPERATING MARGINS	41,111,972
Interest Income	10,388,505
Allowance for Funds Used During Construction	0
Other Non-operating Income - Net	(914,576)
Other Capital Credits & Patronage Dividends	260,146
NET PATRONAGE CAPITAL OR MARGINS	50,846,047

EAST KENTUCKY POWER COOPERATIVE, INC.
BALANCE SHEET - ASSETS
807 KAR 5:001, Section 12(2)(i)

		June 30, 2015
UTILITY PLANT		
Total Utility Plant in Service	$	3,842,523,309
Construction Work in Progress		46,550,851
TOTAL UTILITY PLANT	$	3,889,074,160
Accumulated Depreciation & Amortization		1,268,860,330
NET UTILITY PLANT	$	2,620,213,830
OTHER PROPERTY & INVESTMENTS		
Non-Utility Property - Net	$	820
Investments in Associated Organizations - Patronage Capital		1,859,665
Investments in Associated Organizations - Other General Funds		11,618,072
Other Investments		1,163,871
Special Funds		35,138,605
TOTAL OTHER PROPERTY & INVESTMENTS	$	49,781,033
CURRENT ASSETS		
Cash - General Funds	$	27,765,984
Cash - Construction Funds		580
Special Deposits		3,127,716
Temporary Investments		150,000,000
Accounts Receivable - Sale of Energy (Net)		70,775,049
Accounts Receivable - Other (Net)		322,427
Fuel Stock		65,130,832
Materials and Supplies - Electric & Other		56,358,978
Prepayments		6,681,287
Other Current & Accrued Assets		734,405
TOTAL CURRENT & ACCRUED ASSETS	$	380,897,258
Unamortized Debt Discount & Extraordinary Property Losses	$	2,607,256
Regulatory Assets		159,316,955
Other Deferred Debits		2,293,434
TOTAL ASSETS	$	3,215,109,766

EAST KENTUCKY POWER COOPERATIVE, INC.
BALANCE SHEET - LIABILITIES & EQUITY
807 KAR 5:001, Section 12(2)(i)

		June 30, 2015
MEMBERS EQUITY		
Memberships	$	1,600
Patronage Capital		469,528,297
Operating Margins - Current Year		41,372,118
Non-Operating Margins		9,473,929
Other Margins & Equity		(329,740)
TOTAL MARGINS & EQUITY	$	520,046,204
LONG-TERM DEBT		
RUS	$	5,850,006
Long-term Debt - FFB RUS Guaranteed		2,281,864,917
Long-term Debt - Other		296,944,359
Payments - Unapplied		(153,067,783)
TOTAL LONG-TERM DEBT	$	2,431,591,499
ACCUMULATED OPERATING PROVISIONS	$	109,767,792
CURRENT & ACCRUED LIABILITIES		
Accounts Payable	$	42,591,555
Current Maturities Long-term Debt		93,493,844
Taxes Accrued		5,179,498
Interest Accrued		3,786,281
Other Current & Accrued Liabilities		3,764,930
TOTAL CURRENT & ACCRUED LIABILITIES	$	148,816,108
DEFERRED CREDITS	$	4,888,163
TOTAL LIABILITIES & OTHER CREDITS	$	3,215,109,766

Exhibit MM-3

Estimated Cost of Acquired Property
807 KAR 5:001, Section 18(2)(c)

EXHIBIT

MM-3

Pursuant to 807 KAR 5:001, Section 18(2)(c), an estimate of the Bluegrass Station's acquisition costs, using the uniform system of accounts prescribed for EKPC by the Commission, is shown below.

The estimated acquisition cost of Bluegrass Station's assets is $128,750,000 and consists of the following types of assets:

Prime Movers	$120,013,607
Transmission Station Equipment	7,040,393
Land and Land Rights	350,000
Miscellaneous Intangible Plant	146,000
Plant Materials and Operating Supplies	1,200,000
Total Acquisition Cost	$128,750,000

The plant acquisition cost will be debited to Account 102 – Electric Plant Purchased. The original cost of the plant (estimated if not known) will then be credited to this account and debited to the following plant accounts:

Account 343 – Prime Movers
Account 353 – Station Equipment
Account 340 – Land and Land Rights
Account 303 – Miscellaneous Intangible Plant

Any accumulated depreciation associated with these assets would then be debited to Account 102 and credited to the respective accumulated depreciation or amortization accounts:

Account 108.4 – Accumulated Provision for Depreciation of Other Production Plant
Account 108.5 – Accumulated Provision for Depreciation of Transmission Plant
Account 111 – Accumulated Provision for Amortization of Electric Utility Plant

The net balance remaining in Account 102 will then be closed to Account 114 – Electric Plant Acquisition Adjustments. The balance in Account 114 will then be amortized over the life of the plant.[1]

EKPC would stress that these are only estimates and the specific amounts and accounts utilized to record the acquired utility plant will be determined once final detailed accounting information from the seller is available.

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[1] The accounting entries noted above represent the expected final entries for the purchase of the plant assets, assuming the lease agreement with Oldham County is terminated. Should the lease agreement with Oldham County be assumed by EKPC for a period of time or for the duration of the lease, the transaction will follow RUS System of Accounts requirements for capital leases.