**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

| | | |
|---|---|---|
| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | **)<br>)** | **CASE NO.<br>2019-00096** |

**RESPONSES TO ATTORNEY GENERAL'S INITIAL DATA REQUESTS TO EAST KENTUCKY POWER COOPERATIVE, INC.**

**DATED FEBRUARY 21, 2020**

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**ATTORNEY GENERAL'S INITIAL DATA REQUESTS DATED 02/21/2020**

East Kentucky Power Cooperative, Inc. ("EKPC") hereby submits responses to the information requests of Attorney General ("AG") in this case dated February 21, 2020. Each response with its associated supportive reference materials is individually tabbed.

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | **)** **)** | **CASE NO. 2019-00096** |

**CERTIFICATE**

**STATE OF KENTUCKY )**
**)**
**COUNTY OF CLARK )**

Scott Drake, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Scott Drake

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby
Notary Public #590567

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | ) <br> ) | **CASE NO. 2019-00096** |

**CERTIFICATE**

**STATE OF KENTUCKY** )
)
**COUNTY OF CLARK** )

Mark Horn, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Mark Horn

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby
Notary Public #590567

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
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**CERTIFICATE**

**STATE OF KENTUCKY )**
**)**
**COUNTY OF CLARK )**

Craig A. Johnson, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Craig A. Johnson

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby
Notary Public #560567

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | ) ) | **CASE NO. 2019-00096** |

## CERTIFICATE

**STATE OF KENTUCKY** )
)
**COUNTY OF CLARK** )

Jerry Purvis, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Jerry Purvis

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby
Notary Public #596567

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | ) <br> ) | **CASE NO. 2019-00096** |

**CERTIFICATE**

**STATE OF KENTUCKY )**
**)**
**COUNTY OF CLARK )**

Scott Sells, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Scott Sells

Subscribed and sworn before me on this 13 day of March, 2020.

Gwyn M. Willoughby
Notary Public #580867

GWYN M WILLOUGHBY
Notary Public
Kentucky - State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | **)<br>)** | **CASE NO.<br>2019-00096** |

**CERTIFICATE**

**STATE OF KENTUCKY )**
**)**
**COUNTY OF CLARK )**

Tom Stachnik being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Subscribed and sworn before me on this 16th day of March, 2020.

Notary Public #605767

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | ) ) | **CASE NO. 2019-00096** |

**CERTIFICATE**

**STATE OF KENTUCKY** )
)
**COUNTY OF CLARK** )

Julia J. Tucker, being duly sworn, states that she has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Julia J. Tucker

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby
Notary Public #590567

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | )<br>) | **CASE NO. 2019-00096** |

**CERTIFICATE**

**STATE OF KENTUCKY )**
**)**
**COUNTY OF CLARK )**

Mary Jane Warner, being duly sworn, states that she has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Mary Jane Warner

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn M. Willoughby
Notary Public #598507

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
| **2019 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.** | ) ) | **CASE NO. 2019-00096** |

**CERTIFICATE**

**STATE OF KENTUCKY** )
)
**COUNTY OF CLARK** )

Patrick Woods, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Attorney General's Initial Data Requests in the above-referenced case dated February 21, 2020, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Patrick Woods

Subscribed and sworn before me on this 16th day of March, 2020.

Gwyn Willoughby
Notary Public #5,90767

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST REQUEST FOR INFORMATION RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 1**
**RESPONSIBLE PERSON:** **Tom Stachnik**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 1.** According to the articles at the link below,[1] several major insurance companies have issued new directives stating they will cease: (i) issuing new insurance policies to companies that derive more than 30% of their revenues from thermal coal mining; and (ii) making new investments in companies that have a large exposure to thermal coal mining or coal-based energy production. According to the second article ("Energy Transition Prompts More Insurers to Back Away From Coal"), insurance policy premiums and the cost of capital will increase for utilities having significant coal-fired generation resources.

**Request 1a.** Provide a discussion of whether these new directives on behalf of major insurance companies will have any effect on the Company, its production facilities, and fuel sources, and if so, how.

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[1] https://www.latimes.com/business/la-fi-chubb-bans-coal-coverage-20190701-story html; https://www.axios.com/energy-transition-prompts-more-insurers-back-away-from-coal-1e85a50f-ef35-4ce7-b57b-0bec745a376e.html

**<u>Response 1a</u>**. While the insurance markets are moving towards reducing their exposure to coal, EKPC's insurers, FM Global (Property) & AEGIS (Casualty, Workers Comp, Directors & Officers), are standing by their commitment to insuring coal exposure. While we may see some upward pressure in insurance pricing due to general market conditions, the EKPC insurance team has worked diligently with the underwriters to secure agreements that keep price pressure low. EKPC risk management has also negotiated favorable insurance programs for other lines such as unit outage insurance and Capacity Performance Penalty insurance. Overall, the risk exposure over the next 2-3 years is low.

**<u>Request 1b.</u>** State whether these new directives have entered into the Company's planning and decision making regarding the instant IRP. If not, state whether they will or may enter into the Company's planning and decision making regarding future IRP filings.

**<u>Response 1b</u>**. EKPC has developed the current IRP plan on the basis that EKPC will continue to be able to attract reasonable financing for future projects. While the effects noted in item (ii) above may result in slightly higher interest rates, these affects are small compared to overall movements in the interest rate markets, and are considered in EKPC's planning assumptions.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST REQUEST FOR INFORMATION RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 2**

**RESPONSIBLE PERSON:** **Mark Horn and Julia J. Tucker**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 2.** Explain whether the Company's IRP modelling takes into consideration the escalating number of coal mining company bankruptcy filings. If not, why not?

**Response 2.** EKPC's IRP modeling does inherently take into consideration the escalating number of coal mining company bankruptcy filings. The modeling is based on a forecast of fuel prices into the future. The forward price curve for the commodity of coal is based on supply, demand, transportation, fuel sources, and other drivers. The domestic and export market for thermal and metallurgical coal can impact the cost of coal for utilities. The projected supply of coal in the forward cost curve analysis would account for bankruptcies, if the physical coal supply would be deemed to be impacted. A bankruptcy filing does not necessarily mean that less coal is available or that coal prices will experience upward pressure.

**Request 2a.** If the modeling does not take this factor into consideration, explain what would have to be done to do so.

**Response 2a.** Not Applicable.

**Request 2b.** If the Company believes the increasing incidence of coal mining company bankruptcies is of little or no concern, explain fully why not.

**Response 2b.** EKPC is aware and concerned about the rate of coal mining company bankruptcies and continues to monitor the situation with proper attention.

**Request 2c.** Provide the most current forecast of EKPC's member-owners' retail power sales to the mining industry.

**Response 2c.** EKPC does not forecast load by industry. Per 7 C.F.R. §1710.205(a)(3), RUS requires projections of usage by customer class, number of customers by class, annual system peak demand, and season of peak demand for the number of years agreed upon by RUS and the borrower. In accordance with the RUS-approved Work Plan, the classes forecasted are those defined in the RUS Form 7, Part O and include: Residential, Seasonal, Commercial and Industrial 1000 KVA or less (Small

Commercial), Commercial and Industrial greater than 1000 KVA (Large Commercial), Public Street and Highway Lighting, and Other Sales to Public Authorities.

**Request 2d.** For the regions served by EKPC's member-owners, provide any coal price estimates for the next ten (10) years that may have conducted.

**Response 2d.** Coal price estimates specific to the regions served by EKPC's member-owners have not been conducted. EKPC's coal is sourced from two coal basins in multiple states based on the lowest evaluated delivered price. Regional coal forward curves are produced for mark-to-market and informational purposes.

**Request 2e.** Is EKPC aware of any Moody's Investors Service analyses regarding the stability of coal mining companies over the next one (1) to five (5) years? If so, provide copies.

**Response 2e.** EKPC is not aware of any Moody's Investor Service analyses conducted regarding the stability of coal mining companies over the next one (1) to five (5) years.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST REQUEST FOR INFORMATION RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 3**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 3.** In the event the Company decides to pursue more detailed analysis regarding PPAs, explain to what extent transmission costs, including uplift and congestion, enter into the Company's decision-making process.

**Response 3.** Any Power Purchase Agreement ("PPA") that EKPC would enter into would be for the purpose of hedging its owner-members' costs as compared to the PJM market. All alternatives would be compared on a total cost basis. Total costs would include the energy price component, the capacity price component, any additional variable or fixed costs associated with the alternative and the cost to deliver the energy to the EKPC load zone. If the energy source resides within the EKPC load zone, then it would be the cost to interconnect with the transmission system. If the energy source resides elsewhere, then it would be the cost to deliver it to the EKPC system, which would include uplift and congestion costs.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST REQUEST FOR INFORMATION RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 4**

**RESPONSIBLE PERSONS: Mary Jane Warner**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 4.** In the event the Company should decide at some future point in time to construct a new gas-fired combined cycle plant, provide an estimate for the time required from the plan's inception until the date such a plant can become commercially operable.

**Response 4**. EKPC estimates a five-year timeline from identification for the need to construct a new gas-fired combined cycle plant to the plant becoming commercially operable.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST REQUEST FOR INFORMATION RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 5**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 5.** Provide a discussion regarding the extent to which the Company has examined the potential for both: (i) building and owning its own renewable generation sources within its service territory; and/or (ii) entering into PPAs for renewable generation from other sources, whether located inside or outside its service territory. With regard to resources outside its territory, explain how congestion or the risk of congestion could affect the cost and benefits in determining resource decisions.

**Response 5.** EKPC does not currently have a defined need for additional generation of any type, including renewable sources. If a need is defined, each alternative will be compared on a total cost basis.

**Request 5a.** Has the Company, or any entity acting on its behalf, conducted any studies or analyses of the cost impact of congestion with regard to entering into any external PPAs for renewable energy or other resources? If so, provide copies of all such studies.

**<u>Response 5a.</u>** No studies have been conducted.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST REQUEST FOR INFORMATION RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 6**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 6.** With regard to the cost-effectiveness of continuing to use existing coal-fired generation assets as opposed to switching to renewable sources of generation, state whether the IRP modeling examines both a coal plant's marginal cost of energy, and a renewable source's lower, levelized cost of energy.

**Response 6.** EKPC's long-term planning considers both a coal plant's marginal cost of energy and a renewable source's levelized cost of energy. The long-term planning model must consider all costs in total when considering generation alternatives. If an existing facility is retired prematurely, the impact of the stranded fixed costs must also be considered in the analysis.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**COMMISSION STAFF'S FIRST INFORMATION REQUEST DATED 02/21/2020**
**REQUEST 7**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**<u>Request 7.</u>** For purposes of comparing noncombustible renewable energy generation to fossil fuel generation sources, and costs attendant with both forms of generation, explain whether EKPC's modelling compares energy consumption based on the fossil fuel equivalence approach, or the captured energy approach as discussed in more detail in the EIA publication accessible at the below-referenced link.[2]

**<u>Response 7.</u>** EKPC's long-term planning model must consider all costs in total when considering generation alternatives. EKPC is required to demonstrate the least cost alternative for any generation resource that it chosen.

[2] https://www.pressreleasepoint.com/eia-offers-two-approaches-compare-renewable-electricity-generation-other-sources

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 8**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 8.** Explain whether fixed O&M and capital costs are: (i) factored into the calculation of revenue requirements for any of the scenarios modelled in the IRP, and if not, why not; (ii) impacted by the scenarios evaluated; and (iii) considered when assessing whether to retire existing units.

**Response 8.** The long-term planning model must consider all costs in total when considering generation alternatives. These costs include fixed O&M and capital. If an existing facility is retired prematurely, the impact of the stranded fixed costs must also be considered in the analysis.

**Request 8a.** If fixed O&M and capital costs are not taken into consideration, explain whether this is consistent with the Commission's requirement to take into consideration the impact of existing and future environmental regulations.

**Response 8a.** See response to Request 8 above.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 9**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 9.** Explain how the Company's IRP modeling takes into consideration the continuing costs of complying with state and federal environmental regulations for coal-fired generating plants, including but not limited to ash storage and ash pond remediation/reclamation.

**Response 9.** The plans for existing units are defined in Section 7.0 of the IRP and show each project that is expected to cost $100,000 and above. These projects include normal maintenance as well as additions that must be made to meet environmental compliance. The cost for all of these maintenance projects are included in the Financial Planning Section 10.0. Investments made to comply with existing environmental regulations do not necessarily extend the useful service life of a generating asset.

**<u>Request 9a.</u>** Provide any year-over-year inflation factors and discount rates used in estimating costs for environmental compliance with regard to coal-fired generation, including ash storage and ash pond remediation/reclamation.

**<u>Response 9a.</u>** See response to Request 9 above.

**<u>Request 9b.</u>** Provide a discussion of how the year-over-year inflation factors and discount rates for environmental compliance with regard to coal-fired generation, including ash storage and ash pond remediation/reclamation are taken into consideration in considering the costs and benefits of continued operation of coal-fired plants, as opposed to obtaining other power sources.

**<u>Response 9b.</u>** See response to Request 9 above.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 10**
**RESPONSIBLE PERSON:** **Jerry B. Purvis and Craig Johnson**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 10.** Produce the most recent estimate that the Company has prepared or caused to be prepared of the capital and O&M costs to comply with the following regulations:

a. Mercury and Air Toxics Standards;

b. Coal Combustion Residuals rule;

c. Effluent Limitations Guidelines;

d. 316(b) cooling water intake rule;

e. NAAQS, including any new ozone standard, including any standards still in the draft stages or which are still open to public comment;

f. Cross State Air Pollution Rule;

g. Carbon regulations, including the Clean Power Plan and the Affordable Clean Energy Plan;

h. Any applicable state environmental regulations;

i. Any other federal environmental regulation; and

j. Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements.

**Response 10 a-j.** Refer to pages 2 and 3 of this response for the most recent estimate that the Company has prepared or caused to be prepared of the capital and O&M costs to comply with the regulations listed above.

| Number | EPA Rule | Pollutant | Capital and OEM addressed by: | Federally delegated to State | *Capital ($) | *******O&M ($) |
|---|---|---|---|---|---|---|
| a. | Mercury and Air Toxics Standards; | | pollution back in control equipment | via title V program | $2.8 million | |
| b. | Coal Combustion Residuals rule; **AND** | | Clean closure by removal of ash from ponds | via 401 KAR 46 | $162.4 million | |
| c. | ***Effluent Limitations Guidelines; | | Installation of flue gas desulfurization waste water treatment facility | via KPDES program | $100 million | |
| d. | 316(b) cooling water intake rule; | | Spurlock is in compliance. Cooper is pending KDOW determination | via KPDES program | pending State Directors decision in 2023 | TBD |
| e. | NAAQS, including any new ozone standard, including any standards still in the draft stages or which are still open to pubic comment; | | | | | |
| | **NAAQs Standard** | | | | | |
| | Carbon monoxide | CO | good combustion | implemented via Clean Air Act (CAA) Title V program | $ - | $ - |
| | Lead | Pb | pollution back in control equipment | implemented via Clean Air Act (CAA) Title V program | $ - | $ - |
| | Nitrogen Dioxide | NO2 | selective catalytic reactor | implemented via CSAPR and Ozone program | $ - | $ - |
| | Ozone | O3 | selective catalytic reactor | implmented via CSAPR | $ - | $ - |
| | Particulate Matter | PM2.5 | pollution back in control equipment | implemented via BART, MATS and CSAPR | $ - | $ - |
| | Particulate Matter | PM10 | pollution back in control equipment | implemented via BART, MATS and CSAPR | $ - | $ - |
| | Sulfur Dioxide | SO2 | pollution back in control equipment | implemented via BART, MATS and CSAPR | $ - | $ - |
| f. | Cross State Air Pollution Rule; | | *****pollution back in control equipment | | $894.6 million | |
| g. | Carbon regulations, | | No pollution control equipment commercially available | | TBD | TBD |
| | Clean Power Plan | | No pollution control equipment commercially available | | | |
| | The Affordable Clean Energy Plan | | No pollution control equipment commercially available | | | |
| h. | Any applicable state environmental regulations; | | | | | |
| | | most of the federal EPA programs are state adopted by reference: for the purposes of being thorough, here are some others at a high level. | | | | |
| | | ******KY Special Waste / CCR | | implemented now via EPA CCR program | implemented now via EPA CCR program | $ 45,000.00 |
| | | KY Solid Waste | | | $ - | garbage collection fees |
| | | Hazardous Waste | | | $ - | |
| | | Universal Waste | | | $ - | |
| | | Electronic Waste | | | $ - | |
| | | ***KY Water Quality Standards | | implemented via Clean Water Act and KPDES program, existing water permits | | |
| | | KY Pollution Discharge Elimination System (water permitting) | | implemented via Clean Water Act and KPDES program, existing water permits | | |
| | | KY Emergency Response Commission (KERC) - SARA title III | | | | |
| i. | Any other federal environmental regulation; and | | | | | |

| Number | EPA Rule | Pollutant | Capital and OEM addressed by: | Federally delegated to State | *Capital ($) | *******O&M ($) |
|---|---|---|---|---|---|---|
| | | Radiation<br>NSR Federal imposed Consent Decree<br><br>Acid Rain federally imposed Consent Decree<br>Spill Pollution Control and Countermeasure<br><br>Toxic Substances Control Act (TSCA) of 1976<br><br>Emergency Planning and Community Right-to-Know Act (EPCRA)<br><br><br>Superfund Amendments and Reauthorization Act (SARA) Title III<br><br>Department of Homeland Security<br><br><br><br><br>National Environmental Protection Act (NEPA)<br><br><br><br>Comprehensive Environmental Response, Compensation and Liability Act of 1980 | <br><br><br><br><br><br><br>Polychlorinated Biphenyls (PCBs)<br><br><br>Toxic Release Inventory<br>Chemicla Data Reporting<br><br><br>Tier II Reporting<br><br><br>potassium permanganate<br>sulfur trioxide<br><br><br><br>Water of the US<br>Endangered Species Act - Section 7<br>Cultural Resources | delegated to state via Air Quality<br>terminated in 2018<br>completed in November 2009<br><br><br><br><br><br><br><br><br><br><br><br><br>quantity stored reduced below threshold<br>removed<br>implemented via Rural Utilities Service, Corp of Engineers | | |
| j. | Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements. | | | | zero enforcement actions | ****zero $ in penalties |

* Capital ($) - all represented capital dollars are from the EKPC Environmental Surcharge case(s)
that was authorized by The Commission's February 11, 2016 Order in Case No. 2015-00302.

** Environmental department labor budget plus benefits is less than $3 million. With the 27 full time people in the department plus the trained matrixed support from all the facilities, all of the listed EPA, EPA delegated and State environmental regulations, laws and its requirements are covered,. In addition, the department makes all the demineralized water for Smith Station, analyzes the coal, oil, water, mercury in its central laboratory.
Contract labor and consultants help EKPC develop the environmental compliance plan and maintain compliance with several of the listed programs above result in an additional estimated $4 million for a estimated total budget of $7million

*** The KPDES water permit executes all EPA water prorgams such as: ELG, 316(a), and 316(b)

**** Zero enforcement dollars since 2015

***** Wet and dry flue gas desulfurization systems on Spurlock unit1 and 2 and Cooper units 1 and 2

****** KY Division of Waste fees are $15,000 by facility

*******The cost to operate and maintain the environmental pollution control equipment that is in EKPC's approved Environmental Surcharge compliance plan totaled $31,828,466 in 2019.
*The incremental operation and maintenance expense for the new CCR/ELG equipment that is now being constructed at Spurlock Station is estimated to between $3 to $4 million.*

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 11**

**RESPONSIBLE PERSON:** **Mark Horn**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 11.** State whether the IRP modelling takes into consideration estimates for gas transportation, and if so, whether estimates are prepared for both firm and interruptible transportation.

**Response 11.** EKPC's IRP modeling does take into consideration estimates for natural gas transportation. Due to the capacity factor as it relates to the nature of EKPC's simple cycle combustion turbine generating assets, only estimates for interruptible transportation and the appropriate services are included.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 12**
**RESPONSIBLE PERSON:** **Tom Stachnik/Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 12.** Demonstrate where in the IRP filing the Company addressed affordability of electricity rates, and if so, how.

**Response 12**. EKPC is a wholesale provider of electricity to its owner-members, and the wholesale rates charged to our owner-members are just one component of the retail rates eventually charged to our owner-members' end-use retail members. Therefore, EKPC cannot comment on whether or not the rates its owner-members charge their retail members are affordable.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 13**

**RESPONSIBLE PERSON: Julia J. Tucker**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 13.** Identify any counties in the service territories of EKPC's members which are projected to lose population, and provide the projected losses over the next ten (10) years.

**Response 13**. Based upon population forecasts retrieved from IHS Global Insights on March 1, 2018, there are 31 counties identified with projected decreases in population. Refer to page 2 of 2 of this response for county level data with no Geographic Information System shape file or share modifications.

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**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 14**

**RESPONSIBLE PERSON:** **Julia J. Tucker**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 14.** Reference IRP § 3.0, p. 36, wherein it is stated that "Factors considered when preparing the [load] forecast include population and housing trends " Discuss how the IRP takes into consideration projections that most of the Commonwealth's population growth through 2025 will occur in the Lexington and Louisville metropolitan areas.[3]

**Response 14.** Economic forecasts are retrieved at the county level from IHS. Geographic Information System shape files of EKPC owner-members' service territories are used to proportion county level data to represent each owner-member. The shape files remove growth that is outside of the owner-member's service territory, as is the case with Fayette County and Jefferson County. For example, while Blue Grass Energy does serve part of Fayette County, only growth occurring within its service boundaries would be accounted for in the customer forecast.

[3] See, e.g., "Kentucky Demographics: Present and Future," Kentucky State Data Center, University of Louisville Dept. of Urban and Public Affairs, in particular p. 25, accessible at: http://www ksdc.louisville.edu/wp-content/uploads/2015/08/kysu.pdf

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 15**

**RESPONSIBLE PERSON:** **Julia J. Tucker**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 15.** Reference the 2015 IRP (Case No. 2015-00134) Staff Report, p. 6. Confirm that in that prior IRP, the residential customer count was forecasted to increase by nearly 70,000 during the 15-year period 2015-2029. Confirm also that the current IRP, § 6.3, Table 6-2, forecasts residential customer count to grow by approximately 55,700 over the same timeframe.

**Response 15.** The 2015 IRP reported residential customer growth of 66,864 customers between 2015 and 2029. The current 2018 IRP reports residential customer growth of 55,721 customers over that same period.

**Residential Customers**

| Year | IRP 2015 | | IRP 2019 | |
|---|---|---|---|---|
| **2015** | 495,084 | projected | 494,297 | actual |
| **2029** | 561,948 | | 550,018 | |
| | **66,864** | | **55,721** | |

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 16**

**RESPONSIBLE PERSON: Julia J. Tucker**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**<u>Request 16.</u>** Explain how the Company determined the anticipated capacity factor for each generating unit in each year analyzed.

**<u>Response 16.</u>** **Generating Unit Capacity Factors**

The monthly capacity factors of individual generating units follows the NERC definition:

Net Capacity Factor = [NAG/(PH x NMC)]

Where:

NAG is the Net Actual Generation which is the net electrical megawatthours (MWh) produced by the unit during the period being considered.

PH is the Period Hours which is number of hours a unit was in the active state. A unit generally enters the active state on its commercial date.

NMC is the Net Maximum Capacity which is the capacity a unit can sustain over a specified period when not restricted by ambient conditions or equipment deratings, minus the losses associated with station service or auxiliary loads.

EKPC uses the RTSim model, as described in Section 8.4, to develop future expectations of how much Net Actual Generation (MWh) will be produced by each unit and those expectations are then used to develop the anticipated capacity factor for each generating unit in each year analyzed.

**REDACTED**



**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 17**

**RESPONSIBLE PERSON:** **Patrick Woods**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 17.** Explain whether any of the Company's generating and/or transmission facilities are required to meet any North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standards. If so:

**Response 17.** NERC Reliability Standards are mandatory for all electric utilities in North America, and as such, the Standards, including the Critical Information Protection (CIP) Standards, are applicable to all EKPC generation and transmission facilities.

**Request 17a.** Explain whether the Company's generating facilities have been designated as low, medium or high impact;

**Response 17a.** EKPC has designated all its generating facilities connected to the Bulk Electric System as [redacted].

**Request 17b.** Provide the costs of meeting such standards (both initial and on-going costs), and how they are calculated into the overall costs of these facilities;

**Response 17b.** Because of the specialized nature of the CIP Standards, EKPC has a dedicated team focused on maintaining compliance with those standards. In addition, some EKPC employees not part of the CIP Compliance team may be involved in assisting the CIP Compliance team on as-needed basis, taking direction from, and reporting back to, the CIP Compliance team when such assistance is needed. As such, cost of compliance with the NERC Critical Infrastructure Protection standards is the cost of the manpower – both of the CIP Compliance Team and of those required to assist it when needed - to manage the policies, procedures, and processes needed to ensure compliance, as well as the cost of tools and equipment necessary to comply. These costs are simply the costs of doing business, are not calculated into the costs of EKPC's facilities, and are not material to any decisions made for future planning purposes.

**Request 17c.** Explain whether those costs are significant enough for them to be taken into consideration in the IRP modeling, and if so, how.

**Response 17c.** The costs of compliance with the NERC Critical Infrastructure Protection standards are not material to decisions made for future planning purposes and are not taken into consideration in EKPC's IRP modeling.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 18**

**RESPONSIBLE PERSONS:** **Julia J. Tucker**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**<u>Request 18.</u>** Provide the projected peak load forecast for each year since the date of the Company's last IRP filing. Provide also the actual peak load for each of the last three (3) years.

**<u>Request 18.</u>** EKPC has not completed a new long-term load forecast since it filed the IRP in April 2019. EKPC develops a new forecast every two years and is currently in the process of starting this year's update.

| Peak Day | Actual | Temperature | Forecasted |
|---|---|---|---|
| Monday, January 18, 2016 | 2,890 | 7 | 3,176 |
| Sunday, January 8, 2017 | 2,871 | 6 | 3,199 |
| Tuesday, January 2, 2018 | 3,437 | -2 | 3,217 |
| Thursday, January 31, 2019 | 3,073 | 5 | 3,251 |

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 19**

**RESPONSIBLE PERSON: Julia J. Tucker**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 19.** Provide the following historical annual data by generating unit, from 2010 to present:

**Requests 19a-d.** a. Fixed O&M cost;

b. Variable O&M cost (without fuel);

c. Fuel costs; and

d. Capital costs

**Responses 19a-d.** The following tables detail the requested information for the current fleet of fossil generating units. The costs are available by plant via the Financial and Operating Report prepared annually for the Rural Utilities Service (RUS) Form 12 data submission. Data for 2019 is currently validated through October 2019. The cost elements, presented in dollars per megawatt-hour ($/MWh) available on the RUS Form 12 include:

- Maintenance
- Non-Fuel Operations
- Fuel Cost
- Total Fixed Cost – this is composed of depreciation and interest

**COOPER STATION**

| $/MWh | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Maintenance | 3.95 | 4.87 | 8.12 | 7.69 | 9.53 | 10.97 | 12.92 | 22.64 | 19.36 | 41.08 |
| Non-Fuel Operations | 5.51 | 5.52 | 7.96 | 11.83 | 11.2 | 14.4 | 20.49 | 25.23 | 20.5 | 58.18 |
| Fuel Cost | 33.46 | 32.49 | 32.56 | 36.76 | 33.29 | 31.49 | 31.18 | 30.31 | 31.35 | 43.41 |
| Total Fixed Cost | 3.66 | 4.42 | 9.37 | 25.82 | 26.05 | 34.15 | 43.31 | 63.71 | 50.82 | 158.96 |

**SPURLOCK STATION**

| $/MWh | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Maintenance | 3.63 | 4.16 | 5.24 | 5.78 | 6.38 | 8.15 | 6.05 | 9.63 | 7.89 | 10.29 |
| Non-Fuel Operations | 4.19 | 4.66 | 4.93 | 4.89 | 4.83 | 5.8 | 5.1 | 6.41 | 5.67 | 6.97 |
| Fuel Cost | 23.55 | 26.8 | 26.38 | 27.15 | 25.97 | 25.56 | 24.77 | 22.86 | 21.04 | 22.58 |
| Total Fixed Cost | 11.93 | 11.98 | 12.82 | 12.48 | 12.28 | 14.6 | 11.99 | 15.94 | 13.67 | 17.7 |

**SMITH STATION**

| $/MWh | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Maintenance | 3.80 | 3.1 | 3.81 | 13.03 | 7.66 | 16.09 | 26.9 | 26.46 | 25.68 | 10.09 |
| Non-Fuel Operations | 9.67 | 8.48 | 5.38 | 13.2 | 12.03 | 14.73 | 25.08 | 40.22 | 16.52 | 19.89 |
| Fuel Cost | 71.14 | 53.4 | 34.01 | 48.25 | 67.2 | 37.45 | 35.85 | 45.37 | 52.51 | 34.03 |
| Total Fixed Cost | 50.27 | 47.18 | 24.84 | 61.52 | 47.25 | 60.18 | 100.21 | 139.15 | 57.67 | 58.99 |

**BLUEGRASS STATION**

| $/MWh | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Maintenance | | | | | | | 24.57 | 34.03 | 22.39 | 16.14 |
| Non-Fuel Operations | | | | | | | 110.38 | 62.24 | 53.21 | 27.56 |
| Fuel Cost | | | | | | | 39.41 | 43.84 | 42.87 | 34.03 |
| Total Fixed Cost | | | | | | | 344.29 | 165.06 | 136.26 | 61.48 |

**Requests 19e-f.** e. Capacity factor; and

f. Generation in kWh.

**Response 19e-f.** The generation and capacity factor are available by unit.

| **Cooper 1** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor | 74.21 | 76.91 | 70.83 | 54.15 | 47.78 | 32.66 | 29.75 | 12.55 | 19.87 | 5.60 |
| Generation (kWh) | 610,659,000 | 714,903,000 | 586,816,000 | 428,078,900 | 380687000 | 249762000 | 238679000 | 102,834,000 | 163,467,000 | 42,559,000 |
| **Cooper 2** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 69.96 | 70.16 | 72.64 | 32.76 | 37.92 | 32.59 | 22.86 | 20.54 | 23.18 | 7.00 |
| Generation (kWh) | 1,334,237,000 | 1,077,461,000 | 875,887,000 | 569,296,000 | 648,752,998 | 533,229,000 | 405,977,000 | 343,924,000 | 398,620,000 | 126,051,000 |
| **Spurlock 1** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 76.55 | 73.39 | 69.65 | 65.26 | 66.47 | 43.97 | 70.79 | 57.15 | 63.05 | 50.34 |
| Generation (kWh) | 2,020,393,000 | 1,872,656,000 | 1,858,079,000 | 1,664,066,000 | 1,785,173,000 | 1,160,856,000 | 1,869,799,000 | 1,440,977,000 | 1,562,826,000 | 1,255,230,000 |
| **Spurlock 2** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 79.83 | 80.73 | 74.37 | 77.71 | 81.46 | 70.31 | 75.15 | 73.66 | 76.55 | 64.52 |
| Generation (kWh) | 3,364,690,108 | 3,502,986,000 | 2,599,677,000 | 3,372,551,000 | 3,353,232,000 | 2,963,302,000 | 3,084,841,000 | 2,217,620,000 | 3,115,811,000 | 2,220,498,000 |
| **Spurlock 3** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 83.49 | 79.10 | 77.45 | 76.34 | 80.18 | 64.81 | 78.68 | 75.16 | 71.87 | 50.90 |
| Generation (kWh) | 1,903,443,000 | 1,669,507,000 | 1,677,214,000 | 1,589,464,000 | 2,005,137,000 | 1,359,099,000 | 1,743,725,000 | 1,560,167,000 | 1,634,072,000 | 1,161,395,000 |
| **Spurlock 4** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 86.01 | 84.76 | 83.15 | 81.13 | 79.45 | 71.63 | 79.75 | 66.80 | 66.84 | 59.41 |
| Generation (kWh) | 2,005,856,000 | 1,975,364,000 | 1,971,075,000 | 1,777,781,000 | 1,767,884,000 | 1,607,515,000 | 1,862,623,000 | 1,365,492,000 | 1,459,418,000 | 1,252,473,000 |

| **Smith CT 1** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor | 3.11 | 0.43 | 2.72 | 1.86 | 3.03 | 2.77 | 1.45 | 0.94 | 3.03 | 2.78 |
| Generation (kWh) | 28,636,000 | 4,078,000 | 25,654,000 | 16,506,000 | 24,076,000 | 24,769,000 | 12,166,000 | 8,881,000 | 27,885,000 | 25,865,000 |
| **Smith CT 2** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 0.43 | 0.66 | 1.38 | 1.77 | 5.90 | 3.47 | 1.60 | 1.05 | 3.31 | 2.67 |
| Generation (kWh) | 4,054,000 | 6,260,000 | 13,160,000 | 15,798,000 | 56,067,000 | 31,798,000 | 15,058,000 | 9,851,000 | 30,240,000 | 24,892,000 |
| **Smith CT 3** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 5.11 | 1.98 | 3.68 | 2.41 | 5.89 | 2.96 | 1.26 | 1.05 | 3.76 | 2.52 |
| Generation (kWh) | 46,482,000 | 18,779,000 | 23,740,000 | 19,701,000 | 56,520,000 | 27,966,000 | 11,597,000 | 9,834,000 | 27,891,000 | 23,102,000 |
| **Smith CT 4** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 6.03 | 6.32 | 18.25 | 5.68 | 8.63 | 5.02 | 4.60 | 3.35 | 7.81 | 6.35 |
| Generation (kWh) | 38,934,000 | 40,155,000 | 109,910,000 | 36,554,000 | 52,009,000 | 31,850,000 | 28,491,000 | 21,158,000 | 48,744,000 | 38,917,000 |
| **Smith CT 5** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 5.88 | 8.11 | 15.52 | 9.12 | 7.79 | 5.61 | 4.99 | 3.42 | 8.26 | 6.72 |
| Generation (kWh) | 36,602,000 | 52,296,000 | 95,602,000 | 58,879,000 | 46,944,000 | 32,546,000 | 30,660,000 | 21,641,000 | 47,007,000 | 40,930,000 |
| **Smith CT 6** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 9.87 | 8.41 | 18.10 | 9.65 | 7.90 | 6.80 | 5.41 | 3.39 | 7.86 | 6.17 |
| Generation (kWh) | 63,994,000 | 48,502,000 | 16,393,000 | 58,200,000 | 47,777,000 | 40,234,000 | 31,525,000 | 19,797,000 | 48,707,000 | 37,901,000 |

| **Smith CT 7** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor | 5.65 | 12.59 | 22.45 | 4.91 | 8.02 | 6.39 | 5.03 | 3.39 | 8.00 | 6.59 |
| Generation (kWh) | 36,511,000 | 80,553,000 | 144,849,000 | 28,037,000 | 51,056,000 | 40,703,000 | 31,215,000 | 20,186,000 | 50,209,000 | 40,419,000 |
| **Smith CT 9** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 19.19 | 21.19 | 27.05 | 12.06 | 10.06 | 10.17 | 4.92 | 3.76 | 8.21 | 9.77 |
| Generation (kWh) | 92,943,000 | 143,636,000 | 193,377,000 | 67,505,000 | 68,173,000 | 70,167,000 | 33,759,000 | 25,998,000 | 56,279,000 | 63,248,000 |
| **Smith CT 10** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | 20.12 | 18.64 | 27.67 | 17.22 | 11.30 | 10.52 | 4.25 | 3.79 | 8.32 | 9.79 |
| Generation (kWh) | 83,127,000 | 120,436,000 | 186,019,000 | 67,769,000 | 69,427,000 | 67,231,000 | 28,952,000 | 26,086,000 | 57,509,000 | 60,376,000 |
| **Bluegrass CT 1** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | | | | | | | 0.86 | 1.48 | 1.65 | 4.56 |
| Generation (kWh) | | | | | | | 11,727,000 | 19,715,000 | 22,178,000 | 57,130,000 |
| **Bluegrass CT 2** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | | | | | | | 0.63 | 1.43 | 1.89 | 4.99 |
| Generation (kWh) | | | | | | | 8,609,000 | 19,042,000 | 25,506,000 | 62,580,000 |
| **Bluegrass CT 3** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
| Capacity Factor | | | | | | | 2.28 | 2.90 | 4.47 | 2.05 |
| Generation (kWh) | | | | | | | 32,629,000 | 41,394,000 | 64,082,000 | 26,119,000 |

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 20**

**RESPONSIBLE PERSON:** **Julia J. Tucker**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 20.** Provide the Company's off-system sales for each of the past three (3) years.

**Response 20.** The following table shows EKPC's off-system sales in both MWh and total fuel costs associated with the sales, which were excluded from the Fuel Adjustment Clause (FAC).

| Year | Off System Sales (MWh) | Fuel Credited to FAC |
|---|---|---|
| 2017 | 37,157.00 | $ 986,028.44 |
| 2018 | 74,669.00 | $ 2,106,535.60 |

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 21**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 21.** Provide the Company's current order of economic dispatch, and the dispatch rate for each generating unit, including the Clark County solar generation facility.

**Response 21.** The economic dispatch order and rate is provided in the following table. The dispatch rate is based on the cost-based energy offer submitted to PJM on January 1, 2020. The cost-based energy offer is developed using the stockpile fuel costs, which are referenced in the monthly Fuel Adjustment Clause filings. The Clark County solar generation facility, Cooperative Solar Farm 1, is not offered into PJM as a generation resource. This resource is a non-retail behind-the-meter generator (NRBTMG) which reduces EKPC's purchased demand from PJM. The levelized cost of energy from Cooperative Solar Farm 1 is valued at [redacted].

**REDACTED**



| EKPC Resource | Average of Cost Segments ($/MWh)* |
|---|---|
| EKPC LAUREL DAM | [redacted] |
| EKPC SPURLOCK 4 F | [redacted] |
| EKPC SPURLOCK 2 F | [redacted] |
| EKPC SPURLOCK 1 F | [redacted] |
| EKPC SPURLOCK 3 F | [redacted] |
| EKPC BLUEGRASS 1 CT | [redacted] |
| EKPC BLUEGRASS 2 CT | [redacted] |
| EKPC BLUEGRASS 3 CT | [redacted] |
| EKPC SMITH 10 CT | [redacted] |
| EKPC SMITH 9 CT | [redacted] |
| EKPC COOPER 2 F | [redacted] |
| EKPC SMITH 6 CT | [redacted] |
| EKPC SMITH 4 CT | [redacted] |
| EKPC SMITH 5 CT | [redacted] |
| EKPC SMITH 7 CT | [redacted] |
| EKPC COOPER 1 F | [redacted] |
| EKPC SMITH 3 CT | [redacted] |
| EKPC SMITH 1 CT | [redacted] |
| EKPC SMITH 2 CT | [redacted] |
| EKPC SMITH 6 CT OIL | [redacted] |
| EKPC SMITH 4 CT OIL | [redacted] |
| EKPC SMITH 5 CT OIL | [redacted] |
| EKPC SMITH 7 CT OIL | [redacted] |
| EKPC SMITH 3 CT OIL | [redacted] |
| EKPC SMITH 1 CT OIL | [redacted] |
| EKPC SMITH 2 CT OIL | [redacted] |

*Stockpile fuel costs, plus variable O&M, plus variable environmental cost as of 1/1/2020

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 22**

**RESPONSIBLE PERSONS: Mary Jane Warner**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 22.** Explain when the Bluegrass combustion turbines will have dual-fuel capability.

**Request 22a.** Explain if a cost-benefit analysis for constructing dual-fuel capability at Bluegrass has been, or will be performed. If one has been performed, provide a copy. If one has yet to be performed, provide an estimate for when it will be completed.

**Response 22a**. In 2018, EKPC partnered with Navigant Consulting, Inc. to evaluate the present value of various options considered for mitigating risk associated with PJM's Capacity Performance construct at Bluegrass Station. Navigant's methodologies and conclusions were fully detailed in the Bluegrass Capacity Penalty Risk Analysis and provided in EKPC's response to the Commission Staff's First Request for Information Request No. 46. EKPC did seek and was issued an Order from the Public

Service Commission (Case No. 2018-00292) on February 28, 2019 granting a CPCN for EKPC to construct a fuel oil system at Bluegrass Station. As part of the CPCN application, the Bluegrass Capacity Penalty Risk Analysis was referenced in testimony and included as an exhibit.

**Request 22b.** State whether the Company will seek a CPCN for installing such dual fuel capability.

**Response 22b**. As stated previously, EKPC did seek and was issued an Order from the Public Service Commission (Case No. 2018-00292) on February 28, 2019 granting a CPCN for EKPC to construct a fuel oil system at Bluegrass Station. The current schedule for the Project is to achieve commercial operation of Bluegrass Station in a dual fuel configuration by the end of 2020.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 23**

**RESPONSIBLE PERSONS:** **Mary Jane Warner**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 23.** Explain if the Company has any plans to construct dual-fuel capability for Smith units 9 and 10.

**Response 23.** EKPC has no plans on making units 9 and 10 dual fuel capable.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 24**
**RESPONSIBLE PERSON:** **Scott Drake**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 24.** State whether EKPC is able to demonstrate any energy conservation resulting from the use of AMI meters by those member cooperatives that have initiated system-wide AMI deployments. Provide a discussion of whether the members' increased deployments of AMI systems have proved useful to EKPC in relation to its PJM membership, and if so, how.

**Response 24.** EKPC has not evaluated energy conservation from AMI meters. Since all of EKPC's owner-members deployed AMI systems years ago and at different times, there is no way now to evaluate a "before AMI deployment" energy usage compared to an "after AMI deployment" energy usage to obtain an energy conservation impact.

EKPC's owner-members have several large industrial members taking advantage of the interruptible rider and are subject to the PJM capacity performance market requirements. One market requirement is for the participating industrial members to reduce their load to their contracted firm load when PJM issues an event requiring their reduction. If PJM hasn't issued an event requiring a reduction in a PJM calendar year, PJM requires a test event near the end of the PJM calendar year. The test event requires each participating industrial member to prove they can reduce their load to the contracted firm load. EKPC utilizes AMI data to prove that the interruptible members reduced load and performed per the PJM capacity performance market rules.

Each year EKPC installs special meters at a small sample of member's homes that participates in the Direct Load Control ("DLC") program. Special meters are installed at those homes to capture energy usage data and compressor run times for the air conditioner units and energy usage data for water heaters. A contractor physically gathers the meter readings monthly. From that information, the contractor evaluates the kw load reduction results for the DLC switches installed on air conditioners and water heaters.

EKPC is working to replace the need for the special meter installations by utilizing AMI data from the owner-members. In doing so, costs associated with the special meter installations and data collection each month will be eliminated. However, the load reduction evaluation from the AMI data has proven to be less reliable for this type of evaluation. EKPC continues to improve this process in the hopes of eliminating the need for and cost associated with the special DLC meters.

Due to the PJM capacity performance market rules, the DLC switches on air conditioners and water heater no longer are offered into the PJM market. Therefore, to monetize the switch kw drop capabilities in PJM, EKPC now manages the switches during peak summer days to lower EKPC's load requirements in PJM and the associated load requirement payments to PJM. Having the special meters, and AMI data when we perfect the evaluation process, provides EKPC an understanding of the total MW load impact the switches provide and the associated cost savings.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 25**

**RESPONSIBLE PERSON: Julia J. Tucker**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 25.** Provide a copy of EKPC's RUS-approved Work Plan, as identified in IRP § 1.2.

**Response 25.** The Work Plan is provided on pages 2 through 26 of this response.

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

# 2018-2019
# Load Forecast
# Work Plan

Prepared by
Load Forecasting Department

December 2017

**Table of Contents**

| | Page |
|---|---|
| Section 1.0: Executive Summary | 3 |
| Section 2.0: Description of the Cooperative | 4 |
| Section 3.0: Description of the Load Forecast Methodology | 4 |
| Section 3.1: Software | 4 |
| Section 3.2: Data | 5 |
| Section 3.3: Models and Calculations | 5 |
| Section 3.3.1: Economic Forecasts by Owner Member | 6 |
| Section 3.3.2: Forecasts by Consumer Class | 7 |
| Section 3.3.3: Forecasts of Own Use and Losses | 11 |
| Section 3.3.4: Peak Model | 11 |
| Section 3.3.5: Scenario Analyses | 12 |
| Section 4.0: Description of the Load Forecast Process | 13 |
| Section 4.1: Personnel | 13 |
| Section 4.2: Report | 14 |
| Section 4.3: Timeline | 14 |
| Appendix A: Federal Regulations Related to Load Forecasts | 15 |
| Appendix B: Board of Directors' Approval | 24 |

**Section 1.0: Executive Summary**

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative headquartered in Winchester, Kentucky. EKPC is owned by 16 electric distribution cooperatives (owner members), which serve more than 533,000 retail consumer accounts.

The purpose of the *2018-2019 Load Forecast Work Plan* is to:

1) Comply with RUS 7 CFR §1710.209 regulation which requires EKPC to maintain a load forecast work plan approved by the EKPC Board of Directors ("Board") and RUS. The Board approved the last such plan in February 2016 for use in 2016.
2) Ensure EKPC and its owner members comply with federal regulations related to load forecasts (7 CFR §1710 Subpart E).
3) Provide a detailed scope of the methodology and processes to be followed in preparing the load forecasts that will be used to satisfy business needs for long-term planning.

EKPC is electing the filing option specified in 7 CFR §1710.204(a)(2), therefore, the entire process described herein will repeat on a 2-year cycle. This ensures the owner members and EKPC have up-to-date, approved load forecasts for their planning purposes. EKPC and the owner members will use the resulting forecasts for long-term planning, including construction work plans, financial forecasts, transmission, generation, and demand-side management planning.

There is close collaboration between EKPC and its owner members. EKPC will prepare a preliminary load forecast for each owner member. EKPC will meet with each to discuss the assumptions and the resulting forecast. Owner member personnel present at the meetings include the President/CEO and other key staff. Based on the discussions, revisions will be made if needed. Owner members often have access to information not available to EKPC or may elect to use assumptions different from preliminary forecast assumptions. Input from owner members includes industrial development, subdivision growth, and other specific service area information.

Consumers and energy will be modeled for each class reported on the RUS Form 7. EKPC's sales to owner members are the sum of total retail sales and distribution losses. EKPC's total requirements are estimated by adding transmission losses to sales to members. Seasonal peak demands are determined by summing individual appliance and class load shapes based on normal EKPC peak day weather.

Both parties have significant input into the load forecast process and both use the results for planning and decision making. The forecasts resulting from this partnership reflect a combination of a structured forecast methodology combined with judgment and experience of owner member staff.

**Section 2.0: Description of the Cooperative**

EKPC's owner members include:

- Big Sandy RECC
- Blue Grass Energy Cooperative
- Clark Energy Cooperative
- Cumberland Valley Electric
- Farmers RECC
- Fleming-Mason Energy Cooperative
- Grayson RECC
- Inter-County Energy Cooperative
- Jackson Energy Cooperative
- Licking Valley RECC
- Nolin RECC
- Owen Electric Cooperative
- Salt River Electric Cooperative
- Shelby Energy Cooperative
- South Kentucky RECC
- Taylor County RECC

EKPC's owner members serve more than 533,000 consumers in 87 counties in Kentucky and 3 counties in Tennessee. The service territories encompass mainly the rural areas, while investor-owned and municipal utilities serve most of the cities and towns. The fixed service-area boundaries are available from the Kentucky Public Service Commission via http://psc.ky.gov/Home/Maps.

EKPC owns or purchases nearly 3,243 MW, including coal, natural gas and oil, 16 MW of landfill gas, 8.5 MW of solar, and purchases up to 170 MW of hydro power from the Southeastern Power Administration. EKPC also owns and operates more than 2,800 miles of transmission line and related substations. In 2013, EKPC became a member of PJM, a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. EKPC's all-time peak demand of 3,507 MW occurred on February 20, 2015.

**Section 3.0: Description of the Load Forecast Methodology**

This section explains the software, data, and models and calculations used to develop the load forecasts.

**Section 3.1: Software**

EKPC will use the following for data manipulation and modeling:

- Itron MetrixND will be used for regression analyses of consumers, energy and demand for each RUS class. MetrixND enables the use of a set of models, including linear regression and artificial neural networks, within a framework specifically built for load forecasting. The input datasets will reside in Microsoft Excel.

- Itron MetrixLT will be used to develop hourly data based upon the monthly forecasts from MetrixND and calibrated to historical hourly data.
- SAS, a statistical software package, will be used for data manipulation and analyses.
- Microsoft Office will be used for the creation of reports and presentations.

**Section 3.2: Data**

EKPC maintains SAS and Excel datasets containing information from a multitude of sources:

- EKPC Itron MV-90 database: hourly load data for each owner member and wholesale rate
- EKPC EMS database: hourly EKPC system load data
- End-Use Survey data: a survey conducted every 2-3 years since 1981, designed to satisfy the requirements of 7 CFR §1710.209(g) by collecting data from a representative sample of residential consumers from each owner member
- RUS Financial and Operating Report – Electric Distribution (formerly RUS Form 7): annual consumer class-level and aggregate data by owner member; monthly data provided by owner members
- IHS Global Insight: observed and forecasted annual economic data for all counties in the state of Kentucky, as well as the aggregate
- EIA Annual Energy Outlook: observed and forecasted electricity usage by end use, consumer class, and Census Division, for a variety of economic and public policy scenarios, obtained via http://www.eia.gov/forecasts/aeo/
- EIA Short-Term Energy Outlook: observed and forecasted monthly electricity usage by consumer class and Census Division, obtained http://www.eia.gov/forecasts/steo/
- NOAA National Climatic Data Center: climate normal for weather stations in or near the service areas of EKPC's owner members
- DTN: observed and forecasted hourly weather for weather stations in or near the service areas of EKPC's owner members.

**Section 3.3: Models and Calculations**

The load forecast is developed using a series of models and calculations to create appropriate economic indices for each owner member and forecast load by RUS classification within a statistically-adjusted end-use modeling framework. These forecasts in aggregate, along with own use and losses, determine the EKPC load forecast.

**Section 3.3.1: Economic Forecasts by Owner-Member**

An important part of the load forecast is the regional economic outlook. EKPC has divided its owner-members' service area into seven economic regions based on service territorial boundaries and natural regions that exist within the EKPC territory. For example, the Central region defined by EKPC fits closely within the Lexington Metropolitan Statistical Area (MSA). The Bureau of Economic Analysis defines MSAs as areas of interrelated economic activity that go beyond a single county's boundaries. The coal mining industry, albeit declining, has dominated EKPC's eastern region historically. The Northern region includes Kentucky counties that border Cincinnati. The Southern region is influenced by tourism. The Louisville metropolitan area influences the West Central region. Finally, services and retail trade dominate the northeastern region. Models for these regions provide EKPC with a way of linking the electricity needs of a service area to the rest of the economy in a consistent and reasonable manner.

IHS Global Insight collects county-level historical data, models the data, and provides forecasts for key variables including: population, income, employment levels, wages, labor force, and unemployment rate. Population forecasts are used to project residential class consumers; regional household income is used to project residential energy sales; and regional economic activity is used to project small commercial energy sales.

Relating the regional data to the individual owner member is a challenge due to the fact that service area boundaries do not correspond exactly to county boundaries used by IHS to produce the forecasts. To address this issue, EKPC uses the following method for each owner member:

1. Aggregate the IHS Global Insight forecasts for the counties in a region. The most populous counties, such as Jefferson and Fayette, will be removed as these counties are served predominantly by investor-owned utilities. This will prevent these counties' economic conditions from unduly influencing the weighted aggregate economic indices.
2. Based upon analysis from the End-Use Survey, determine the appropriate portion of residential accounts that are actual residences versus those that are barns, seasonal buildings or other non-residence type accounts.
3. Create a weighted aggregate of the IHS Global Insight forecasts for the counties each owner member serves using the share of the county's land area.
4. Calculate the ratio of population density of each owner member relative to the population density of its weighted aggregate.
5. Forecast this relative population density ratio with a regression model using population density and time among the explanatory variables.
6. Apply the forecasted relative population density ratio to the weighted aggregate data to obtain adjusted economic indices.

**Section 3.3.2: Forecasts by Consumer Class**

To serve the needs of the owner members and to comply with the requirements of 7 CFR §1710.205(b)(3), EKPC must forecast the number of consumers and usage by consumer class on an annual basis.

*Residential Class*

Residential consumers are analyzed by means of regression analysis with resulting coefficients used to prepare consumer projections. Regressions for residential consumers are typically a function of regional economic and demographic variables. Different explanatory variables are used for owner members in order to account for regional differences in local economies.

Two variables that are very significant for these regressions are the numbers of households by county in each economic region and the percent of total households served by the owner member.

| **Model Inputs** | **Source** |
|---|---|
| *Population* | IHS Global Insight database |
| *Households* - The number of households by county | IHS Global Insight database |
| *Share* – The percent of the region's households served by owner member | RUS Form 7 |
| *Employment* - Regional employment levels by SIC Code | IHS Global Insight database |
| *Income* – Regional income levels | IHS Global Insight database |
| **Model Outputs** | **Use of** |
| *Residential Consumers* | Residential consumers are input into the residential sales model. |

The sales are forecasted using a statistically adjusted end-use (SAE) model. This method of modeling incorporates end-use forecasts and can be used to separate the monthly and annual forecasts into end-use components. SAE models offer the structure of end-use models while also taking advantage of the strength of time-series analysis.

This method requires detailed information about appliance saturation, appliance use, appliance efficiencies, household characteristics, weather characteristics, and demographic and economic information. The SAE approach segments the average household use into end-use components as follows:

$$Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Water\ Heat_{y,m} + Other_{y,m}$$

Where, y=year, m=month

Each component is defined in terms of its end-use structure. For example, the cool index may be defined as a function of appliance saturation, efficiency of the appliance, and usage of the appliance. Annual end-use indices and a usage variable are constructed and used to develop a variable to be used in least squares regression in the model. These variables are constructed for heating, cooling, water heating, and an 'Other' variable, which includes lighting and other miscellaneous usages.

$$CoolIndex_y = \sum_{Type} Wgt^{Type} * \frac{\left( CoolShare_y^{Type} / Eff_y^{Type} \right)}{\left( CoolShare_{98}^{Type} / Eff_{98}^{Type} \right)}$$

$$CoolUse_{y,m} = \left( \frac{CDD_{y,m}}{NormCDD} \right) * \left( \frac{HHSize_y}{HHSize_{by}} \right) * \left( \frac{Income_y}{Income_{by}} \right) * \left( \frac{Price_{y,m}}{Price_{by}} \right)^{-.30}$$

Where, by=base year

$$Cool_{y,m} = CoolIndex_y * CoolUse_{y,m}$$

The Cool, Heat, Water Heat, and Other variables are then used in a least squares regression which results in estimates for annual and monthly use per household.

Features of EKPC's SAE model are as follows:

1. Over 20 years of End-Use Survey historical data are used to forecast saturation of appliances.

2. Appliance efficiencies due to government regulation have been accounted for using a standard roll-in method, where new households and existing households in the market for new appliances encounter more efficient units. Indices pertaining to appliance efficiency trends and usage are used to construct energy models based on heating, cooling, water heating and other energy for the residential class. Source: Energy Information Administration Annual Energy Outlook, East South Central region representing Kentucky.

3. Forecasted demand response, distributed generation and energy efficiency impacts due to owner-member programs are accounted for using owner member insight as well as planned budget funds.

4. Various demographic and socioeconomic factors that affect appliance choice and appliance use are present in the methodology. These include the changing shares of urban and rural consumers relative to total consumers, number of people living in the household, as well as square footage of the house and the thermal integrity of the house.

Every two to three years since 1981, EKPC has surveyed the member systems' residential consumers. The survey will be conducted first quarter of 2018. Appliance ownership of survey respondents are analyzed in order to project future appliance saturations and to better understand electricity consumption.

*Small Commercial Class*

This class is analyzed by means of regression analysis, and the resulting coefficients are used to prepare sales and consumer forecasts. The sales regression consists of total small commercial sales as a function of price, weather, and some measure of the local or national economy. The consumer regression consists of small commercial consumers as a function of residential consumers, the unemployment rate, and time. Different explanatory variables are used for member systems in order to account for regional differences in local area economies. For example, small commercial sales in some territories are heavily influenced by the oil and gas industry, while other areas are more affected by retail stores.

This class is a challenge to forecast due to the relative heterogeneity of the consumers. Consumers in this class include consumers with a wide range of electric use such as small mines, quarries, churches, schools, retail stores, large farm operations, and others. Additionally, this class has numerous reclassifications in the historical data which complicates the analysis.

*Large Commercial Sales Model*

Unlike the small commercial class, no regression equations are used in the analysis and forecast of large commercial sales. Since there are so few large commercial consumers, use of regression to study the past history would reflect individual plant production or expansion decisions and not necessarily responses to economic conditions. EKPC and its owner members have a two-part method for making projections in this class: existing consumer forecasts and forecasts of new consumers.

<u>Forecasts of Existing Consumers</u>: These projections are made directly by owner members since they are in regular contact with the consumers. Each owner member prepares a three-year projection of each consumer whose monthly demand exceeds 1 MW. Load forecasts beyond the three-year horizon for existing large commercial consumers are either fixed at the third year level or are adjusted based on information shared at the load forecast meeting.

<u>Forecasts of New Consumers</u>: In the short-term, two to three years, owner members have been informed by individual consumers of planned large load additions. Due to normal construction lead times, the ability to predict additions in the near term is strong. Beyond the three year horizon, a regression technique is used to forecast new large commercial consumers. Because there are so few consumers in this class, analysis is initially done at the EKPC level to forecast total new consumers. These new consumers are then allocated to the member systems using a probabilistic model which provides an analytical basis for locating large loads on the EKPC system. The model is spreadsheet based using @RISK. The model distributes new large commercial consumers to owner members based on their regional economic outlook, share of county served and historical growth.

Once the number of new large commercial consumers is determined, energy projections are based on the assumption that new large commercial consumers have the same characteristics as the average of existing large commercial consumers, a peak load of 1.8 MW with a 70 percent load factor. This methodology for forecasting new large commercial consumers and energy provides a defensible projection at the member system level.

*Residential Seasonal, Public Street and Highway Lighting, Other Public Authorities Classes*

Some owner members report seasonal sales, street light sales and sales to public authorities as separate classes while others include these consumers in the residential or small commercial classes. EKPC's approach to modeling these classes is the same for each owner member. Consumer and energy equations are developed using the related economic and member specific variables.

**Section 3.3.3: Forecasts of Own Use and Losses**

For EKPC and each owner member, future own use is assumed to be the average of recent historical own use, unless there is a specific reason to assume otherwise, such as a renovation or expansion.

While there is no formal modeling process in loss analysis, owner members provide input into the projected distribution loss assumption such as any right-of-way programs, which may reduce losses, and details concerning direct-served large commercial consumers, consumers with no distribution line. Using the average of recent years as a starting point, the owner member will account for any planned upgrades for the projection. Transmission losses are projected similarly using recent history as a proxy.

**Section 3.3.4: Peak Model**

EKPC's peak demand forecast is a bottom-up approach. The owner members' peaks are summed to determine the EKPC peak. Model inputs include annual energy by end-use for the residential class and total energy use for small and large commercial. Model outputs are hourly demand for winter peak day and summer peak day. Weather sensitive appliance demands reflect typical peak day temperature profiles. The resulting peaks are explicitly linked to energy projections. Load factor is an input to the forecast. The load factors used are derived from data collected in the EKPC Load Research Program, as well as historical data.

**Section 3.3.5: Uncertainty Analyses**

For the system base load forecast, high and low scenarios are developed using the same tools and methodology previously described. The assumptions for each case include:

Low Case – Pessimistic economic assumptions with mild weather resulting in lower loads
Base Case - Most probable economics assumptions with normal weather (Base Case pre DSM)
High Case – Optimistic economic assumptions with extreme weather resulting in higher loads

Adjusting the following assumptions leads to different consumer forecasts which in turn results in different energy forecasts:

*Weather*: based on historical heating and cooling degree day data, alternate weather projections are developed based upon the $90^{th}$ and $10^{th}$ percentile to reflect extreme and mild weather, respectively.

*Electric price*: The general approach is to use price forecasts that are available and use the growth rates from those forecasts to prepare the high and low growth rates around the growth patterns for the base case residential price forecast. The manner in which the price of electricity will change in the future is primarily a function of how prices change for the underlying fixed and variable components of electricity rates.

*Residential consumers*: The basic approach to preparing high and low case scenarios for the future number of residential consumers is to determine the magnitude of variation in the past between long term average growth rates and higher or lower growth rates during shorter periods of time. First, the data on the historic monthly household counts for the previous 20 year period is prepared. Next, the compound annual growth rate in households is calculated for each rolling ten year. This produced a set of twelve compound annual growth rate values each representing a unique ten year span. Maximum and minimum values are determined. The highest growth is used to prepare the high case scenario, while the 10 year period that experienced the lowest growth is used to prepare the low case scenario.

These resulting adjustments are applied to the 20 year compound annual growth rate in the base case consumer count forecast to produce the high case and low case compound annual growth rate forecast scenarios. This relationship is preserved when preparing the monthly consumer counts for the high and low case scenarios.

**Section 4.0: Description of the Load Forecast Process**

This section explains the personnel responsible for the load forecast, the organization of the load forecast report, and the timeline for the development of the load forecast.

**Section 4.1: Personnel**

The load forecasting function is in EKPC's Load Forecasting Department in the Power Supply Business Unit. Key contributors include:

- David Crews is the Senior Vice President of Power Supply and will maintain executive authority and direction for the load forecast.
- Julia Tucker is the Director of Power Supply Planning, and will provide strategic oversight as well as management support of load forecast development.
- Sally Witt, Manager of Load Forecasting, will direct and support all aspects of the 2018 Load Forecast.
- Jacob Watson, Load Forecasting Analyst, will participate in the data development, modeling, and reporting of the forecasts.
- Sandy Mollenkopf, Load Forecasting Analyst, will provide support for the load forecast process in areas of data collection, specifically, saturation survey data, load research data, and RUS Form 7 data.
- Scott Drake, Manager of Corporate Technical Services, will provide demand side management programs' impact on energy and peak demands for inclusion into the system forecast.

The owner member personnel involved may include:

- President and Chief Executive Officer,
- Vice President of Finance,
- Vice President of Engineering and Operations, and
- other key staff as selected by each owner member.

**Section 4.2: Report**

The load forecast report will be organized as follows:

- Table of Contents
- Section 1.0: Executive Summary
- Section 2.0: Description of the Cooperative
- Section 3.0: Description of the Load Forecast Methodology and Assumptions
- Section 4.0: Regional Economic Model
- Section 5.0: Analyses and Results by Class
- Section 6.0: Scenarios
- Appendix A: Owner Member Load Forecast Reports (CD)
- Appendix B: Board of Directors Resolutions (CD)
- Appendix C: Data, Models, Assumptions, and Results (CD)

**Section 4.3: Timeline**

- Winter 2017 / Spring 2018: The 2018 Membership Energy Use Survey will be conducted.
- Spring 2018: Other input data specified in Section 3.2 will be updated, and the models specified in Section 3.3 will be run to produce a draft load forecast using the software specified in Section 3.1.
- Summer / Fall 2018: EKPC staff will develop a draft load forecast report and visit with owner member staff specified in Section 4.1 to present the report, which will be discussed and revised as needed to achieve the coordination required in 7 CFR §1710.205(g). Owner member staff may also elect to seek review and approval by the RUS General Field Representative, but this is no longer required by regulation.
- Fall / Winter 2018: The management and boards of directors of the owner members and EKPC will review and approve the load forecast report specified in Section 4.2 as required in 7 CFR §1710.205(a)(2-3).
- December 2018: EKPC will submit the load forecast report to the RUS Energy Forecasting Branch Chief for approval under 7 CFR §1710.206.
- Ongoing: EKPC staff will update the models periodically in order to identify any material changes that may warrant an update to the approved load forecast.
- December 2019: EKPC will submit an updated load forecast work plan to RUS for approval.

## Appendix A: Federal Regulations Related to Load Forecasts

Title 7: Agriculture

PART 1710—GENERAL AND PRE-LOAN POLICIES AND PROCEDURES COMMON TO ELECTRIC LOANS AND GUARANTEES

Subpart E—Load Forecasts

Source: 65 FR 14786, Mar. 20, 2000, unless otherwise noted.

### §1710.200 Purpose.

This subpart contains RUS policies for the preparation, review, approval and use of load forecasts and load forecast work plans. A load forecast is a thorough study of a borrower's electric loads and the factors that affect those loads in order to estimate, as accurately as practicable, the borrower's future requirements for energy and capacity. The load forecast of a power supply borrower includes and integrates the load forecasts of its member systems. An approved load forecast, if required by this subpart, is one of the primary documents that a borrower is required to submit to support a loan application.

### §1710.201 General.

(a) The policies, procedures and requirements in this subpart are intended to implement provisions of the loan documents between RUS and the electric borrowers and are also necessary to support approval by RUS of requests for financial assistance.

(b) Notwithstanding any other provisions of this subpart, RUS may require any power supply or distribution borrower to prepare a new or updated load forecast for RUS approval or to maintain an approved load forecast on an ongoing basis, if such documentation is necessary for RUS to determine loan feasibility, or to ensure compliance under the loan documents.

### §1710.202 Requirement to prepare a load forecast—power supply borrowers.

(a) A power supply borrower with a total utility plant of $500 million or more must maintain an approved load forecast that meets the requirements of this subpart on an ongoing basis and provide an approved load forecast in support of any request for RUS financial assistance. The borrower must also maintain an approved load forecast work plan. The borrower's approved load forecast must be prepared pursuant to the approved load forecast work plan.

(b) A power supply borrower that is a member of another power supply borrower that has a total utility plant of $500 million or more must maintain an approved load forecast that meets the requirements of this subpart on an ongoing basis and provide an approved load forecast in support of any request for RUS financial assistance. The member power supply borrower may comply with this requirement by participation in and inclusion of its load forecasting information in the approved load forecast of its power supply borrower. The approved load forecasts must be prepared pursuant to the RUS approved load forecast work plan.

(c) A power supply borrower that has total utility plant of less than $500 million and that is not a member of another power supply borrower with a total utility plant of $500 million or more must provide an approved load forecast that meets the requirements of this subpart in support of an application for any RUS loan or loan guarantee which exceeds $50 million. The borrower is not required to maintain on an ongoing basis either an approved load forecast or an approved load forecast work plan.

**§1710.203 Requirement to prepare a load forecast—distribution borrowers.**

(a) A distribution borrower that is a member of a power supply borrower with a total utility plant of $500 million or more must maintain an approved load forecast that meets the requirements of this subpart on an ongoing basis and provide an approved load forecast in support of any request for RUS financial assistance. The distribution borrower may comply with this requirement by participation in and inclusion of its load forecasting information in the approved load forecast of its power supply borrower. The distribution borrower's load forecast must be prepared pursuant to the approved load forecast work plan of its power supply borrower.

(b) A distribution borrower that is a member of a power supply borrower which is itself a member of another power supply borrower that has a total utility plant of $500 million or more must maintain an approved load forecast that meets the requirements of this subpart on an ongoing basis and provide an approved load forecast in support of any request for RUS financial assistance. The distribution borrower may comply with this requirement by participation in and inclusion of its load forecasting information in the approved load forecast of its power supply borrower. The distribution borrower's approved load forecast must be prepared pursuant to the approved load forecast work plan of the power supply borrower with total utility plant in excess of $500 million.

(c) A distribution borrower that is a member of a power supply borrower with a total utility plant of less than $500 million must provide an approved load forecast that meets the requirements of this subpart in support of an application for any RUS loan or loan guarantee that exceeds $3 million or 5 percent of total utility plant, whichever is greater. The distribution borrower may comply with this requirement by participation in and inclusion of its load forecasting information in the approved load forecast of its power supply borrower. The borrower is not required to maintain on an ongoing basis either an approved load forecast or an approved load forecast work plan.

(d) A distribution borrower with a total utility plant of less than $500 million and that is unaffiliated with a power supply borrower must provide an approved load forecast that meets the requirements of this subpart in support of an application for any RUS loan or loan guarantee which exceeds $3 million or 5 percent of total utility plant, whichever is greater. The borrower is not required to maintain on an ongoing basis either an approved load forecast or an approved load forecast work plan.

(e) A distribution borrower with a total utility plant of $500 million or more must maintain an approved load forecast that meets the requirements of this subpart on an ongoing basis and provide an approved load forecast in support of any request for RUS financing assistance. The borrower must also maintain an approved load forecast work plan. The distribution borrower may comply with this requirement by participation in and inclusion of its load forecasting information in the approved load forecast of its power supply borrower.

**§1710.204 Filing requirements for borrowers that must maintain an approved load forecast on an ongoing basis.**

(a) Filing of load forecasts and updates. A power supply or distribution borrower required to maintain an approved load forecast on an ongoing basis under §1710.202 or §1710.203 may elect either of the following two methods of compliance:

(1) Submitting a new load forecast to RUS for review and approval at least every 36 months, and then submitting updates to the load forecast to RUS for review and approval in each intervening year; or

(2) Submitting a new load forecast to RUS for review and approval not less frequently than every 24 months.

(b) Extensions. RUS may extend any time period required under this section for up to 3 months at the written request of the borrower's general manager. A request to extend a time period beyond 3 months must be accompanied by a written request from the borrower's general manager, an amendment to the borrower's approved load forecast work plan incorporating the extension, a board resolution approving the extension request and any amendment to the approved load forecast work plan, and any other relevant supporting information. RUS may extend the time periods contained in this section for up to 24 months.

**§1710.205 Minimum approval requirements for all load forecasts.**

(a) Documents required for RUS approval of a borrower's load forecast. The borrower must provide the following documents to obtain RUS approval for a load forecast:

(1) The load forecast and supporting documentation;

(2) A memorandum from the borrower's general manager to the board of directors recommending that the board approve the load forecast and its uses; and

(3) A board resolution from the borrower's board of directors approving the load forecast and its uses.

(b) Contents of Load Forecast. All load forecasts submitted by borrowers for approval must include:

(1) A narrative describing the borrower's system, service territory, and consumers;

(2) A narrative description of the borrower's load forecast including future load projections, forecast assumptions, and the methods and procedures used to develop the forecast;

(3) Projections of usage by consumer class, number of consumers by class, annual system peak demand, and season of peak demand for the number of years agreed upon by RUS and the borrower;

(4) A summary of the year-by-year results of the load forecast in a format that allows efficient transfer of the information to other borrower planning or loan support documents;

(5) The load impacts of a borrower's demand side management activities, if applicable;

(6) Graphic representations of the variables specifically identified by management as influencing a borrower's loads; and

(7) A database that tracks all relevant variables that might influence a borrower's loads.

(c) Formats. RUS does not require a specific format for the narrative, documentation, data, and other information in the load forecast, provided that all required information is included and available. All data must be in a tabular form that can be transferred electronically to RUS computer software applications. RUS will evaluate borrower load forecasts for readability, understanding, filing, and electronic access. If a borrower's load forecast is submitted in a format that is not readily usable by RUS or is incomplete, RUS will require the borrower to submit the load forecast in a format acceptable to RUS.

(d) Document retention. The borrower must retain its latest approved load forecasts, and supporting documentation until RUS approval of its next load forecast. Any approved load forecast work plan must be retained as part of the approved load forecast.

(e) Consultation with RUS. The borrower must designate and make appropriate staff and consultants available for consultation with RUS to facilitate RUS review of the load forecast work plan and the load forecast when requested by RUS.

(f) Correlation and consistency with other RUS loan support documents. If a borrower relies on an approved load forecast or an update of an approved load forecast as loan support, the borrower must demonstrate that the approved load forecast and the other primary support documentation for the loan were reconciled. For example, both the load forecast and the financial forecast require input assumptions for wholesale power costs, distribution costs, other systems costs, average revenue per kWh, and inflation. Also, a borrower's engineering planning documents, such as the construction work plan, incorporate consumer and usage per consumer projections from the load forecast to develop system design criteria. The assumptions and data common to all the documents must be consistent.

(g) Coordination. Power supply borrowers and their members that are subject to the requirement to maintain an approved load forecast on an ongoing basis are required to coordinate preparation of their respective load forecasts, updates of load forecasts, and approved load forecast work plan. A load forecast of a power supply borrower must consider the load forecasts of all its member systems.

**§1710.206 Approval requirements for load forecasts prepared pursuant to approved load forecast work plans.**

(a) Contents of load forecasts prepared under an approved load forecast work plan. In addition to the minimum requirements for load forecasts under §1710.205, load forecasts developed and submitted by borrowers required to have an approved load forecast work plan shall include the following:

(1) Scope of the load forecast. The narrative shall address the overall approach, time periods, and expected internal and external uses of the forecast. Examples of internal uses include providing information for developing or monitoring demand side management programs, supply resource planning, load flow studies, wholesale power marketing, retail marketing, cost of service studies, rate policy and development, financial planning, and evaluating the potential effects on electric revenues caused by competition from alternative energy sources or other electric suppliers. Examples of external uses include meeting state and Federal regulatory requirements, obtaining financial ratings, and participation in reliability council, power pool, regional transmission group, power supplier or member system forecasting and planning activities.

(2) Resources used to develop the load forecast. The discussion shall identify and discuss the borrower personnel, consultants, data processing, methods and other resources used in the preparation of the load forecast. The borrower shall identify the borrower's member and, as applicable, member personnel that will serve as project leaders or liaisons with the authority to make decisions and commit resources within the scope of the current and future work plans.

(3) A comprehensive description of the database used in the study. The narrative shall describe the procedures used to collect, develop, verify, validate, update, and maintain the data. A data

dictionary thoroughly defining the database shall be included. The borrower shall make all or parts of the database available or otherwise accessible to RUS in electronic format, if requested.

(4) A narrative for each new load forecast or update of a load forecast discussing the methods and procedures used in the analysis and modeling of the borrower's electric system loads as provided for in the load forecast work plan.

(5) A narrative discussing the borrower's past, existing, and forecast of future electric system loads. The narrative must identify and explain substantive assumptions and other pertinent information used to support the estimates presented in the load forecast.

(6) A narrative discussing load forecast uncertainty or alternative futures that may determine the borrower's actual loads. Examples of economic scenarios, weather conditions, and other uncertainties that borrowers may decide to address in their analysis include:

(i) Most-probable assumptions, with normal weather;

(ii) Pessimistic assumptions, with normal weather;

(iii) Optimistic assumptions, with normal weather;

(iv) Most-probable assumptions, with severe weather;

(v) Most-probable assumptions, with mild weather;

(vi) Impacts of wholesale or retail competition; or

(vii) new environmental requirements.

(7) A summary of the forecast's results on an annual basis. Include alternative futures, as applicable. This summary shall be designed to accommodate the transfer of load forecast information to a borrower's other planning or loan support documents. Computer-generated forms or electronic submissions of data are acceptable. Graphs, tables, spreadsheets or other exhibits shall be included throughout the forecast as appropriate.

(8) A narrative discussing the coordination activities conducted between a power supply borrower and its members, as applicable, and between the borrower and RUS.

(b) Compliance with an approved load forecast work plan. A borrower required to maintain an approved load forecast work plan must also be able to demonstrate that both it and its RUS borrower members are in compliance with its approved load forecast work plan for the next load forecast or update of a load forecast.

**§1710.207 RUS criteria for approval of load forecasts by distribution borrowers not required to maintain an approved load forecast on an ongoing basis.**

Load forecasts submitted by distribution borrowers that are unaffiliated with a power supply borrower, or by distribution borrowers that are members of a power supply borrower that has a total utility plant less than $500 million and that is not itself a member of another power supply borrower with a total utility plant of $500 million or more must satisfy the following minimum criteria:

(a) The borrower considered all known relevant factors that influence the consumption of electricity and the known number of consumers served at the time the study was developed;

(b) The borrower considered and identified all loads on its system of RE Act beneficiaries and non-RE Act beneficiaries;

(c) The borrower developed an adequate supporting data base and considered a range of relevant assumptions; and

(d) The borrower provided RUS with adequate documentation and assistance to allow for a thorough and independent review.

**§1710.208 RUS criteria for approval of all load forecasts by power supply borrowers and by distribution borrowers required to maintain an approved load forecast on an ongoing basis.**

All load forecasts submitted by power supply borrowers and by distribution borrowers required to maintain an approved load forecast must satisfy the following criteria:

(a) The borrower objectively analyzed all known relevant factors that influence the consumption of electricity and the known number of customers served at the time the study was developed;

(b) The borrower considered and identified all loads on its system of RE Act beneficiaries and non-RE Act beneficiaries;

(c) The borrower developed an adequate supporting database and analyzed a reasonable range of relevant assumptions and alternative futures;

(d) The borrower adopted methods and procedures in general use by the electric utility industry to develop its load forecast;

(e) The borrower used valid and verifiable analytical techniques and models;

(f) The borrower provided RUS with adequate documentation and assistance to allow for a thorough and independent review; and

(g) In the case of a power supply borrower required to maintain an approved load forecast on an ongoing basis, the borrower adequately coordinated the preparation of the load forecast work plan and load forecast with its member systems.

**§1710.209 Approval requirements for load forecast work plans.**

(a) In addition to the approved load forecast required under §§1710.202 and 1710.203, any power supply borrower with a total utility plant of $500 million or more and any distribution borrower with a total utility plant of $500 million or more must maintain an approved load forecast work plan. RUS borrowers that are members of a power supply borrower with a total utility plant of $500 million or more must cooperate in the preparation of and submittal of the load forecast work plan of their power supply borrower.

(b) An approved load forecast work plan establishes the process for the preparation and maintenance of a comprehensive database for the development of the borrower's load forecast, and load forecast updates. The approved load forecast work plan is intended to develop and maintain a process that will result in load forecasts that will meet the borrowers' own needs and the requirements of this subpart. An approved work plan represents a commitment by a power supply borrower and its members, or by a large unaffiliated distribution borrower, that all parties concerned will prepare their load forecasts in a timely manner pursuant to the approved load forecast work plan and they will modify the approved load forecast work plan as needed with RUS approval to address changing circumstances or enhance the usefulness of the approved load forecast work plan.

(c) An approved load forecast work plan for a power supply borrower and its members must cover all member systems, including those that are not borrowers. However, only members that are borrowers, including the power supply borrower, are required to follow the approved load forecast work plan in preparing their respective load forecasts. Each borrower is individually responsible for forecasting all its RE Act beneficiary and non-RE Act beneficiary loads.

(d) An approved load forecast work plan must outline the coordination and preparation requirements for both the power supply borrower and its members.

(e) An approved load forecast work plan must cover a period of 2 or 3 years depending on the applicable compliance filing schedule elected under §1710.204.

(f) An approved load forecast work plan must describe the borrower's process and methods to be used in producing the load forecast and maintaining current load forecasts on an ongoing basis.

(g) Approved load forecast work plans for borrowers with residential demand of 50 percent or more of total kWh must provide for a residential consumer survey at least every 5 years to obtain data on appliance and equipment saturation and electricity demand. Any such borrower that is experiencing or anticipates changes in usage patterns shall consider surveys on a more frequent schedule. Power supply borrowers shall coordinate such surveys with their members. Residential consumer surveys may be based on the aggregation of member-based samples or on a system-wide sample, provided that the latter provides for relevant regional breakdowns as appropriate.

(h) Approved load forecast work plans must provide for RUS review of the load forecasts as the load forecast is being developed.

(i) A power supply borrower's work plan must have the concurrence of the majority of the members that are borrowers.

(j) The borrower's board of directors must approve the load forecast work plan.

(k) A borrower may amend its approved load forecast work plan subject to RUS approval. If RUS concludes that the existing approved load forecast work plan will not result in a satisfactory load forecast, RUS may require a new or revised load forecast work plan.

**§1710.210 Waiver of requirements or approval criteria.**

For good cause shown by the borrower, the Administrator may waive any of the requirements applicable to borrowers in this subpart if the Administrator determines that waiving the requirement will not significantly affect accomplishment of RUS' objectives and if the requirement imposes a substantial burden on the borrower. The borrower's general manager must request the waiver in writing.

**Appendix B: Board of Directors' Approval**

Please see the following page.

**FROM THE MINUTE BOOK OF PROCEEDINGS
OF THE BOARD OF DIRECTORS OF
EAST KENTUCKY POWER COOPERATIVE, INC.**

At a regular meeting of the Board of Directors of East Kentucky Power Cooperative, Inc. held at the Headquarters Building, 4775 Lexington Road, located in Winchester, Kentucky, on Tuesday, December 12, 2017, at 9:30 a.m., EST, the following business was transacted:

Approval of the 2018 Load Forecast Work Plan

After review of the applicable information, a motion to approve the 2018 Load Forecast Work Plan was made by Strategic Issues Committee Chairman Tim Eldridge, seconded by Landis Cornett, and passed by the Board to approve the following:

**Whereas,** The Rural Utilities Service ("RUS") requires East Kentucky Power Cooperative, Inc., ("EKPC") to maintain a Load Forecast Work Plan ("Plan") approved by the EKPC Board of Directors ("Board") and RUS;

**Whereas,** EKPC has prepared a Plan which describes the methodology to be used in the preparation of a 20-year load forecast and corresponding reports for EKPC and its 16 Owner Members during the year 2018; and;

**Whereas,** EKPC Management and the Strategic Issues Committee have recommended approval of this Plan by the Board; now, therefore, be it

**Resolved,** That the Board of Directors hereby approves the 2018 Load Forecast Work Plan.

The foregoing is a true and exact copy of a resolution passed at a meeting called pursuant to proper notice at which a quorum was present and which now appears in the Minute Book of Proceedings of the Board of Directors of the Cooperative, and said resolution has not been rescinded or modified.

Witness my hand and seal this 12th day of December 2017.

Jody E. Hughes, Secretary

Corporate Seal

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 26**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 26.** Reference IRP § 1.2, Load Forecast. Provide a breakdown by customer class of the projected 1.4% annual load growth.

**Response 26.** Table 3-10 on page 49 shows the following average growth rate by customer class.

| **2019 2033 Average Growth Rates By Class** | |
|---|---|
| Residential | 0.7% |
| Small Commercial | 0.8% |
| Large Commercial and Industrial | 2.9% |
| Seasonal | 4.5% |
| Public Building | 0.9% |
| Public Street and Highway Lighting | 0.6% |

**Request 26a.** Given that the winter and summer net peak annual demand will increase by 0.6% and 0.9% respectively, explain whether the fact that the summer peak is growing approximately 30% faster than the winter peak will have any implications on the Company's planning processes.

**Response 26a.** Table 8-6 on page 142 of the IRP shows both summer and winter expected peak demands and the implications for capacity needs. Those needs were incorporated into the Projected Major Capacity Additions shown in Table 8-7 on page 143.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 27**

**RESPONSIBLE PERSON: Scott Drake**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 27.** Reference IRP § 1.3, Demand Side Management. Provide a copy of the GDS Associates, Inc. report, if not already included within the IRP filing.

**Response 27.** The GDS Associates, Inc. report is included in EKPC's initial IRP filing under Technical Appendix Volume 2 Exhibit DSM-1.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 28**

**RESPONSIBLE PERSON: Julia J. Tucker**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 28.** Reference IRP § 1.6, third paragraph regarding winter peak energy and capacity needs, in which the Company states that in the 2024 timeframe, it will either have to enter into a PPA or pursue other economic power supply alternatives to be identified in an RFP process. EKPC further states that PJM provides enough capacity to cover EKPC's winter peak load, but the prices for that energy are not hedged. Explain whether the RFP process will include obtaining bids for a financial hedge against PJM market prices in lieu of entering into a PPA for capacity.

**Response 28.** EKPC will entertain all viable options for supplying its energy and capacity requirements. For a hedge to adequately cover EKPC's winter energy exposure, it needs to be a physical product and not a financial hedge. EKPC can entertain an energy-only physical product without requiring capacity if that is the most economic alternative.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 29**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 29.** Provide a discussion regarding the risk of fuel source with regard to EKPC's landfill gas to energy generation facilities.

a. In the event methane should no longer be available on a reliable basis to one or more of these facilities, explain whether EKPC could replace the lost energy production with existing resources.

**Response 29.** The landfill gas plants provide a value to EKPC owner-members by reducing the amount of energy that is purchased from the PJM system since they provide behind-the-meter generation. Landfill gas plants provide less than 1% of EKPC's total energy requirements; therefore, the loss of those facilities is a relatively small risk. The energy would be replaced by the PJM market. EKPC's hedge on the energy price would be lost for the amount of generation that is no longer available.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 30**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 30.** Confirm that power output from neither the landfill gas generating stations, nor the Company's Solar Farm One generating facility, are dispatched into PJM.

**Response 30.** The Clark County solar generation facility, Cooperative Solar Farm 1, along with the Landfill Gas generation stations are not offered into PJM as generation resources. These resources are NRBTMG which reduce EKPC's purchased demand from PJM.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 31**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 31.** Explain whether EKPC's 100 MW hydropower allocation from the Cumberland System remains on track to return to normal in the fall of 2020. If not, explain why not.

**Response 31.** The anticipated completion of the major rehabilitation of Center Hill, in the fall of 2020, is expected to return the necessary megawatts to the Cumberland System to provide the full allocation to the program participants. As major rehabilitation continues with the aging fleet of hydroelectric generation facilities, the total amount of capacity available will continue to fluctuate over the next twenty to thirty years, and EKPC's allocation will fluctuate with these necessary outages.

**Request 31a.** If EKPC has prepared any projections regarding where the hydropower will be placed in the order of economic dispatch, provide this data.

**Response 31a.** The hydropower provided by the Cumberland River system is a low-cost resource and continues to be scheduled over the anticipated daily peak periods. The table below details the current and expected energy and capacity costs for the next five (5) years:

| CAPACITY $/kW/Month | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
| 2020 | 1.0808 | 1.0808 | 1.0808 | 1.8380 | 1.8380 | 1.8380 | 1.8380 | 1.8380 | 1.8380 | 1.8821 | 1.8821 | 1.8821 |
| 2021 | 1.8821 | 1.8821 | 1.8821 | 1.9273 | 1.9273 | 1.9273 | 1.9273 | 1.9273 | 1.9273 | 1.9273 | 1.9273 | 1.9273 |
| 2022 | 1.9273 | 1.9273 | 1.9273 | 1.9736 | 1.9736 | 1.9736 | 1.9736 | 1.9736 | 1.9736 | 1.9736 | 1.9736 | 1.9736 |
| 2023 | 1.9736 | 1.9736 | 1.9736 | 2.0209 | 2.0209 | 2.0209 | 2.0209 | 2.0209 | 2.0209 | 2.0209 | 2.0209 | 2.0209 |
| 2024 | 2.0209 | 2.0209 | 2.0209 | 2.0694 | 2.0694 | 2.0694 | 2.0694 | 2.0694 | 2.0694 | 2.0694 | 2.0694 | 2.0694 |
| ENERGY $/MWh | | | | | | | | | | | | |
| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
| 2020 | 12.188 | 12.188 | 12.188 | 12.308 | 12.308 | 12.308 | 12.308 | 12.308 | 12.308 | 12.603 | 12.603 | 12.603 |
| 2021 | 12.603 | 12.603 | 12.603 | 12.905 | 12.905 | 12.905 | 12.905 | 12.905 | 12.905 | 12.905 | 12.905 | 12.905 |
| 2022 | 12.905 | 12.905 | 12.905 | 13.215 | 13.215 | 13.215 | 13.215 | 13.215 | 13.215 | 13.215 | 13.215 | 13.215 |
| 2023 | 13.215 | 13.215 | 13.215 | 13.532 | 13.532 | 13.532 | 13.532 | 13.532 | 13.532 | 13.532 | 13.532 | 13.532 |
| 2024 | 13.532 | 13.532 | 13.532 | 13.857 | 13.857 | 13.857 | 13.857 | 13.857 | 13.857 | 13.857 | 13.857 | 13.857 |
| (Estimated: October 2020 - December 2024) | | | | | | | | | | | | |

**Request 31b.** Explain how much of EKPC's allocation is available for scheduling during summer, and how much during winter.

**Response 31b.** The following table lists the maximum MW allocation per month over the previous five (5) years. This details the seasonality of this resource and general trend that is expected to continue:

| | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 64 | 64 | 62 | 71 | 71 | 61 | 66 | 64 | 51 | 42 | 54 | 79 |
| 2016 | 78 | 77 | 77 | 70 | 66 | 67 | 67 | 72 | 58 | 37 | 20 | 64 |
| 2017 | 74 | 76 | 76 | 76 | 74 | 72 | 72 | 70 | 52 | 53 | 64 | 76 |
| 2018 | 76 | 71 | 72 | 73 | 67 | 64 | 64 | 64 | 51 | 59 | 65 | 62 |
| 2019 | 61 | 56 | 61 | 65 | 56 | 59 | 69 | 66 | 49 | 49 | 67 | 77 |

**Request 31c.** Explain whether the hydropower is, and/or will be available for dispatch into one or more PJM auctions.

**Response 31c.** EKPC's 100 MW hydropower allocation from the Cumberland System has been offered into, and has cleared, the PJM RPM capacity market auctions for delivery years 2016/2017 through 2021/2022. PJM has not held an RPM auction for delivery years past the 2021/2022 auction. In addition to PJM RPM capacity market participation, EKPC schedules energy from the Cumberland System resource into the PJM day-ahead energy market.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 32**

**RESPONSIBLE PERSON:** **Jerry B. Purvis**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 32.** Reference IRP § 2.0, p. 29, the discussion of the CPP and the Affordable Clean Energy Rule (ACE). Explain whether the final ACE Rule has been published in the Federal Register. If so: (i) provide the Federal Register citation; and (ii) provide a discussion on whether EKPC's power supply plan as submitted in the IRP will be compliant with the ACE Rule.

**Response 32.** **A. Affordable Clean Energy Rule**

EPA published and issued the Proposed Rule to replace the Clean Power Plan (CPP) on August 21, 2018, entitled the Affordable Clean Energy (ACE) rule under the EPA link https://www.regulations.gov/docket?D=EPA-HQ-OAR-2017-0355, Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units: Emission Guideline Implementing Regulations; New Source Review Program, Proposed Rule EPA-HQ-OAR-2017-0355-21117 (Affordable Clean Energy Rule) 40 CFR Parts 51,52 and 60.

EPA's general approach to the rule is to clarify the Federal and state roles in rulemaking, with particular emphasis on granting states more authority to make decisions about how to implement the ACE. EPA clarified that the CPP exceeded the EPA's statutory authority and that the ACE rule would follow EPA's historic application of the Clean Air Act (CAA) section 111, and cooperative federalism, by focusing on seven (7) candidate technologies that could be cost-effective measures implemented at coal-fired facilities, unit-by-unit. EPA also proposed revisions to the New Source Review program to clearly allow for projects to improve unit efficiency, which may be required under the ACE rule.

EPA published the Final ACE Rule on July 8, 2019, EPA-HQ-OAR-2017-0355-26699 or 40 CFR Part 60. The ACE Final Rule repealed and replaced the Clean Power Plan. EPA sets Best System of Emission Reduction (BSER) and provides guidance to the states on how to apply BSER. States apply BSER on a unit-by-unit basis to set standards of performance in short-term $CO_2$ emissions rate limits ($CO_2$ lbs./MWh). States are charged with examining the seven (7) potential candidate technologies and operation and maintenance practices that could potentially improve the heat rate efficiency of individual coal units which may result in a reduction of $CO_2$ emissions. In theory, the units will combust less coal but generate the same amount of electricity. All resulting limits must be set based on the $CO_2$ emissions rate from a unit (pounds of CO2 emitted per megawatt hour generated). The Proposed Rule included a revised NSR emissions test, but the Final Rule removed this test.

States have three years to prepare a plan implementing the Rule. Kentucky has already begun collecting information from Electric Generating Units (EGUs) for this process. In accordance with the federal ACE rule, the States' Plan is due July 8, 2022. Within 60 days, but no later than six months after EPA's receipt of the state plan, EPA shall make a completeness determination. If EPA does not act within the six-month period, the plan is deemed to meet the minimum criteria for completeness. The latest date for completeness determination would be January 8, 2023. Within 12 months of finding the state plan complete, EPA must approve or disapprove the plan. The latest date for the EPA approval or disapproval would be January 8, 2024. If EPA disapproves the state plan, EPA must issue a federal plan within two years. The latest date of the federal plan issuance would be January 8, 2026.

The Final ACE Rule has been challenged by numerous environmental non-governmental organizations and public health organizations, with states and industry participation in *amicus curiae* briefing. The cases have been consolidated in the D.C. Circuit Court with oral argument likely to take place in the fall of 2020.

EKPC is participating in the state ACE implementation process with the Kentucky Energy and Environmental Cabinet (KY Cabinet) for ACE and tracking judicial developments. EKPC provided ACE submittals to the KY Cabinet last Fall and awaits further requests, guidance and direction. EKPC works very closely with the KY Cabinet and the Division of Air Quality. We support and plan to be in compliance with the state ACE plan.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 33**

**RESPONSIBLE PERSON:** **Julia J. Tucker**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 33.** Reference IRP § 2.0, p. 30, the discussion on the ongoing SEPA construction. Provide an update on the Center Hill project, and a description of this project.

**Response 33.** Center Hill has three (3) 45MW units. A contract for complete rehabilitation of the units was awarded in 2014. The Unit 2 project was completed on August 23, 2017. Due to manufacturing defects, the Unit 1 and Unit 3 projects were delayed. Unit 3 is scheduled for completion in May 2020. Unit 1 will be completed in September 2020. The dam safety projects, including remediation of the earthen dam and an additional saddle dam, were completed in 2019.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 34**

**RESPONSIBLE PERSON:** **Mary Jane Warner**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**<u>Request 34.</u>** Reference IRP § 6.0, Transmission and Distribution Planning. Provide a description of all on-going supplemental transmission expansion plans[4] the Company has, as well as those for the next three (3) years, together with cost projections for each project.

**<u>Response 34.</u>** The following Table 34-1 provides information regarding EKPC's current on-going (i.e., either in the preliminary engineering, engineering and procurement, or construction phase) supplemental transmission expansion projects, including the status of the project, whether the project results in new infrastructure or is replacement of existing infrastructure, and the current projections of in-service date and cost for each project.

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[4] For purposes of this question, the term "supplemental transmission project" is defined as a transmission expansion or enhancement that is not required for compliance with PJM criteria for system reliability, operational performance, or economic criteria, and is not a state public policy project according to the PJM Operating Agreement.

**Table 34-1**

**EKPC Currently On-Going Supplemental Transmission Projects**

| Project Description | Project Status | Infrastructure Classification (New or Replacement of Existing) | Forecasted In-Service Date | Estimated Cost |
|---|---|---|---|---|
| Construct a new North Sharkey 138-25 kV, 18/24/30 MVA distribution substation and associated 138 kV tap line (0.5 mile) from the existing Sharkey substation | Under Construction | New | 6/15/2020 | $3,575,000 |
| Rebuild the KU Elizabethtown-Kargle/Tharp 69 kV double-circuit line section (1.4 miles) using 954 MCM ACSR conductor. | Engineering & Procurement | Replacement | 7/1/2020 | $2,350,000 |
| Construct a new South Marion County Industrial 161-13.8 kV, 30/40/50 MVA distribution substation and associated 161 kV tap line (0.25 mile) from the existing Marion County Industrial substation | Engineering & Procurement | New | 11/2/2020 | $6,000,000 |
| Rebuild and upgrade the existing Lancaster 69-12.5 kV, 11.2/14 MVA distribution substation to 12/16/20 MVA, including a rebuild of the 69 kV tap line (1.8 miles) | Engineering & Procurement | Both | 11/17/2020 | $3,500,000 |
| Construct a new 69 kV line section from the Bekaert distribution substation to a new 69 kV LGE/KU switching station (West Shelby) using 556 MCM ACSR/TW (2.0 miles) | Engineering & Procurement | New | 11/27/2020 | $8,990,000 |
| Install a 161 kV circuit switcher on the 161-69 kV autotransformer and install a 161 kV breaker on the TVA tie line at Summer Shade substation | Under Construction | New | 12/1/2020 | $3,980,000 |
| Rebuild the existing Hope-Hillsboro 69 kV line sections (20.6 miles) using 556.5 MCM ACSR/TW conductor. | Under Construction | Replacement | 12/18/2020 | $10,580,000 |
| Construct a new Monticello 69 kV switching station. Rebuild the existing 3/0 ACSR Monticello-Homestead 69 kV line section (1.3 miles) using 556.5 MCM ACSR/TW conductor | Engineering & Procurement | Both | 1/7/2021 | $5,980,000 |
| Rebuild the existing Grants Lick-Griffin Junction 69 kV line sections (5.8 miles) using 556.5 MCM ACSR/TW conductor. | Preliminary Engineering | Replacement | 6/17/2021 | $2,490,000 |
| Rebuild the existing 2/0 ACSR Elizabethtown-Nelson County 69 kV line sections (14.5 miles) using 556.5 MCM ACSR/TW conductor. | Under Construction | Replacement | 11/2/2021 | $7,240,000 |
| Construct a new Broughtontown 69-25 kV, 12/16/20 MVA distribution substation and associated 69 kV tap line (7.4 miles) tapping the EKPC Highland-Tommy Gooch 69 kV line section | Engineering & Procurement | New | 12/1/2021 | $9,245,000 |
| Construct a new Patriot Parkway (Rineyville Junction) 69 kV switching station | Preliminary Engineering | New | 12/30/2021 | $3,105,000 |

**<u>Table 34-1</u>**

**<u>EKPC Currently On-Going Supplemental Transmission Projects</u>**

| Project Description | Project Status | Infrastructure Classification (New or Replacement of Existing) | Forecasted In-Service Date | Estimated Cost |
|---|---|---|---|---|
| Reconductor the existing 4/0 ACSR Boone-Williamstown 69 kV line sections (28.5 miles) using 556.5 MCM ACSR/TW conductor. | Preliminary Engineering | Replacement | 9/22/2022 | $6,950,000 |
| Construct a new Mineola Pike 138-12.5 kV, 12/16/20 MVA substation and associated 138 kV tap line (0.9 mile) to connect to the DEOK 138 kV Constance substation. | Preliminary Engineering | New | 11/28/2022 | $10,565,000 |
| Construct a new Griffin 138-12.5 kV, 12/16/20 MVA distribution substation and associated 138 kV tap line (3.6 miles), tapping the Stanley Parker-Spurlock 138 kV line. Retire the existing Griffin 69 kV tap line and distribution substation. | Preliminary Engineering | Both | 6/29/2023 | $7,425,000 |
| Rebuild the existing 3/0 ACSR McCreary County Junction-KU Wofford 69 kV line sections (20.7 miles) using 556.5 MCM ACSR/TW conductor. | Preliminary Engineering | Replacement | 1/29/2024 | $14,300,000 |

The following Table 34-2 provides information for the 2021-2023 period regarding EKPC's currently identified (i.e., either in a conceptual or early project development phase) supplemental transmission expansion projects, including whether the project results in new infrastructure or is replacement of existing infrastructure, and the current planning-level projections of in-service date and cost for each project.

**Table 34-2**

**EKPC Currently Identified Supplemental Transmission Projects for 2021-2023**

| Project Description | Infrastructure Classification (New or Replacement of Existing) | Planned In-Service Date | Planning Cost Estimate |
|---|---|---|---|
| Install a new 69 kV breaker at Baker Lane for protection of the Holloway line exit | New | 6/1/2021 | $128,000 |
| Construct a new White Oak 69-13.2 kV, 12/16/20 MVA distribution substation and associated 69 kV tap line (0.1 mile). Retire the existing South Fork distribution substation and tap line. | Both | 12/30/2021 | $1,605,000 |
| Construct a new Pekin Pike 69-13.2 kV, 12/16/20 MVA distribution substation and associated 69 kV tap line (6.4 miles) tapping the Baker Lane-Holloway Junction 69 kV line section | New | 5/1/2022 | $7,170,000 |
| Rebuild the existing Boone-Bullittsville 69 kV line sections (6.5 miles) using 556.5 MCM ACSR/TW conductor. | Replacement | 5/31/2022 | $4,680,000 |
| Rebuild the existing Hodgenville-Magnolia 69 kV line section (8.5 miles) using 556.5 MCM ACSR/TW conductor. | Replacement | 5/31/2022 | $4,915,000 |
| Rebuild the Penn distribution substation and install a 69 kV transmission switching station. | Both | 11/30/2022 | $4,255,000 |
| Rebuild the existing Summersville-Magnolia 69 kV line section (15.0 miles) using 556.5 MCM ACSR/TW conductor. | Replacement | 12/31/2023 | $8,550,000 |

**Request 34a.** Provide a description of all supplemental transmission expansion projects the Company has had for the last three (3) years, together with: (i) costs for each project; and (ii) any cost performance studies.

**Response 34a.** The following Table 34a-1 provides information regarding EKPC's completed supplemental transmission expansion projects for the 2017-2020 period, including the in-service date and actual cost for each project. These projects were implemented due to various drivers, including serving new and existing customers; addressing distribution load growth, customer outage exposure, degraded equipment condition, equipment failure, or outage history; optimizing system configuration; improving system restoration capability; and addressing safety concerns. Cost performance studies have not been performed for these projects. In many cases, the implemented project was identified through engineering judgment to be the most cost-efficient solution to address the drivers. In some cases, alternatives were identified and the final project was selected holistically, considering cost, improvement in system performance, flexibility, future expansion needs, etc.

| **Table 34a-1**<br>**EKPC Completed Supplemental Transmission Projects for 2017-2020 Period** | | |
|---|---|---|
| **Project Description** | **In-Service Date** | **Actual Cost** |
| Construct a new Long Lick 69-25 kV, 12/16/20 MVA substation and associated 69 kV tap line (0.1 mile) | 1/30/2017 | $2,153,470 |
| Increase the maximum conductor operating temperature of the Arkland Tap-Oven Fork 69 kV line section to 167° F | 2/16/2017 | $94,757 |
| Increase the maximum conductor operating temperature of the Rowan County-Elliottville 69 kV line section to 167° F | 2/16/2017 | $92,467 |
| Increase the maximum conductor operating temperature of the Mount Sterling-Fogg Pike-Reid Village 69 kV line section to 167° F | 2/16/2017 | $78,453 |
| Install a 69 kV circuit breaker adjacent to the existing Shelby County substation with a 69 kV line added to connect this breaker to both the Shelby County-LGE/KU 69 kV tie line and the Logan-Budd 69 kV line. | 3/30/2017 | $157,762 |
| Construct a new Big Woods 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.2 mile) | 5/30/2017 | $2,155,958 |
| Rebuild the South Bardstown-West Bardstown 69 kV line section (3.0 miles) using 556.5 MCM ACSR conductor. | 8/23/2017 | $1,107,664 |
| Replace 69 kV switches, bus, and jumpers at the Boone County substation | 9/22/2017 | $509,494 |
| Replace all 69 kV switches, bus, jumpers, and circuit breaker 614 at the Falcon substation. | 10/24/2017 | $411,716 |
| Replace 69 kV bus jumpers at the Cooper substation. | 11/17/2017 | $139,570 |
| Rebuild the Campbellsburg 69 kV tap line (0.1 mile) using 266.8 MCM ACSR conductor. | 12/12/2017 | $77,892 |
| Replace the 3/0 ACSR conductor in the Pine Knot-Whitley City 69 kV line section (0.2 mile) using 795 MCM ACSR conductor. | 12/13/2017 | $21,640 |
| Relocate the Hilda 18.37 MVAR capacitor bank to Plummers Landing. | 1/5/2018 | $231,493 |
| Reconfigure the Avon substation 138 kV bus from a ring-bus configuration to a breaker-and-a-half configuration. | 11/16/2018 | $2,460,209 |
| Construct a new 69 KV line from Beattyville Distribution-Oakdale using 556 ACSR (11.66 miles). Retire the existing Oakdale Jct.-Oakdale line. | 12/8/2018 | $6,465,161 |
| Rebuild the Hope transmission substation and install a new 69 kV breaker for protection of the line to Powell County. | 2/4/2019 | $2,009,442 |
| Rebuild the existing 3/0 ACSR Airport Road-Mazie 69 kV line sections (19.4 miles) using 556.5 MCM ACSR/TW conductor. | 8/4/2019 | $8,882,371 |
| Replace the Skaggs 138-69 kV, 100 MVA transformer with a 150 MVA transformer. | 10/31/2019 | $285,009 |
| Construct a new Contown 69-12.5 kV, 12/16/20 MVA substation between Phil and Liberty Junction and an associated 69 kV tap line (0.2 miles) | 11/13/2019 | $1,567,598 |
| Rebuild the existing 1/0 ACSR Stephensburg-Hodgenville 69 kV line sections (17.8 miles) using 556.5 MCM ACSR/TW conductor. | 11/14/2019 | $9,669,738 |
| Construct a new Hunt 138-69 kV transmission substation including the addition of a 138-69 kV, 100 MVA autotransformer. Loop the existing Dale-JK Smith 138 kV line section into the new Hunt 138-69 kV transmission substation via two new 138 kV line additions (0.55 miles). Retire the Dale-Hunt 69 kV lines. | 11/22/2019 | $5,782,587 |
| Construct a new Duncannon Lane 69-13.2 kV, 12/16/20 MVA substation between KU Fawkes-Crooksville (tap point 7.5 miles from KU Fawkes towards Crooksville and an associated 69 kV tap line (0.8 mile) | 1/10/2020 | $1,991,222 |

**Request 34b.** Provide an asset management plan that includes a forecast of the expected costs for each supplemental transmission project over the next five (5) years.

**Response 34b.** Tables 34-1 and 34-2 provided above provide information for EKPC's currently in-progress and future projects for the 2020-2023 period. The following Table 34b-1 provides information for EKPC's currently identified (i.e., either in a conceptual or early project development phase) supplemental transmission expansion projects for 2024, including the current planning-level projections of in-service date and cost for each project.

**Table 34b-1**

**EKPC Currently Identified Supplemental Transmission Projects for 2024**

| Project Description | Infrastructure Classification (New or Replacement of Existing) | Planned In-Service Date | Planning Cost Estimate |
|---|---|---|---|
| Rebuild the existing Three Links Junction-Three Links 69 kV line section (9.6 miles) using 556.5 MCM ACSR/TW conductor. | Replacement | 7/31/2024 | $5,485,000 |
| Rebuild the existing Goddard-Charters 69 kV line sections (16.7 miles) using 556.5 MCM ACSR/TW conductor. | Replacement | 9/30/2024 | $9,945,690 |

**Request 34c.** Provide an estimate of the transmission capital investment over the next five (5) years.

**Response 34c.** EKPC's current projections for capital investment for all transmission and distribution substation project types (baseline, supplemental, maintenance, system protection improvements, etc.) for the 2020-2024 period are as follows:

| | |
|---|---|
| 2020 | $62,090,678 |
| 2021 | $59,259,269 |
| 2022 | $69,783,360 |
| 2023 | $70,643,960 |
| 2024 | $72,062,242 |

**Request 34d.** For each supplemental transmission project scheduled for the next five (5) years, provide a description of whether the investment is for new infrastructure, or for maintenance of existing facilities.

**Response 34d.** Tables 34-1, 34-2, and 34b-1 provided above include information regarding whether each project results in new infrastructure or replaces existing infrastructure. In some cases, the project results in both. For example, some projects involve construction of a new facility to enable retirement of an existing facility.

**Request 34e.** Provide cost-benefit analyses for each supplemental transmission project scheduled for the next five (5) years.

**Response 34e.** The supplemental projects identified for the 2020-2024 period are due to various drivers, including serving new and existing customers; addressing distribution load growth, customer outage exposure, degraded equipment condition, equipment failure, or outage history; optimizing system configuration; improving system restoration capability; and addressing safety concerns. These drivers typically cannot be translated into an economic value. The projects are undertaken to provide a higher level of service rather than to gain economic benefits that offset the costs of the projects. Cost/benefit analyses have not been performed for these projects. In many cases, the identified project has been identified through engineering judgment to be the most cost efficient solution to address the drivers. In some cases, alternatives were identified and the final project was selected holistically, considering cost, improvement in system performance, flexibility, future expansion needs, etc.

**Request 34f.** For each supplemental transmission project scheduled for the next five (5) years, identify the quantifiable benefits expected to be achieved.

**Response 34f.** See the response to 34e.

**Request 34g.** Explain whether each supplemental transmission project scheduled for the next five (5) years will be competitively bid. If not, explain fully why not.

**<u>Response 34g.</u>** The decision to competitively bid any or all aspects of these projects is made on a case-by-case basis, considering a variety of factors, including availability of EKPC's internal labor resources and the needed in-service date for the project. EKPC has chosen to competitively bid certain aspects of almost all of the projects presently in progress (for example, construction labor for transmission line rebuilds and steel pole purchases for transmission line projects.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 35**
**RESPONSIBLE PERSON:** **Scott Sells**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 35.** Explain whether EKPC utilizes, or has considered utilizing, dynamic transmission line ratings as opposed to static transmission line ratings.

**Response 35.** EKPC does not currently use Dynamic Transmission Line Ratings. EKPC uses seasonal static ratings in long-term transmission planning and a form of Ambient Adjusted Ratings (AAR) for transmission operations. This approach is consistent with PJM, which also uses seasonal static ratings in long-term transmission planning and AAR for transmission operations.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 36**

**RESPONSIBLE PERSON: Mary Jane Warner**

**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 36.** Reference the IRP filing, § 6, p. 92, wherein EKPC states it is planning two new interconnections. Explain whether these projects will or may be RTEP projects, supplemental transmission projects. Provide a full explanation.

**Response 36.** These two new interconnection projects have been included in the PJM RTEP. Information is provided on each project below:

- *New EKPC 161 kV Interconnection to TVA's East Glasgow Tap-East Glasgow 161 kV line section (~1 mile due west of EKPC's Fox Hollow substation). Add Fox Hollow 161/69 kV, 150 MVA transformer. Construct a new Fox Hollow-Fox Hollow Junction 161 kV line section using 795 MCM ACSR conductor (PJM project ID b2921)* -- This is a PJM baseline project that was identified as the preferred solution to violations of both PJM regional planning criteria and

EKPC local planning criteria. The PJM Board of Managers approved inclusion of this project in the PJM RTEP in October 2017.

- *Build approximately 1 mile of 69 kV line from near Bekaert to the LGE/KU Simpsonville-Shelbyville 69 kV line and a 69 kV switching station at the connection point (PJM project ID s1250)* -- This is a PJM supplemental project that was identified by EKPC as the recommended solution to address the loss-of-load impacts of either a 69 kV bus outage at the Shelby County substation or an outage of the Shelby County-Logan Tap 69 kV line section. EKPC presented this supplemental project to PJM stakeholders during the PJM Western Sub-regional RTEP Committee meeting on January 24, 2017, and EKPC then added the project to the EKPC local plan, which has been incorporated into the PJM RTEP.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 37**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 37.** Explain whether SERC provided any reports, or conducted any studies and/or analyses on EKPC's behalf with regard to the instant IRP. If so, provide copies.

**Response 37.** SERC did not provide any reports or studies for the IRP.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 38**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 38.** Reference the IRP generally, and in particular § 8.5 and Table 8.6. Confirm that the IRP's preferred plan indicates the Company will likely need to enter into a PPA.

**Response 38.** A capacity resource may be necessary to meet capacity needs in the winter. If the load forecast continues to indicate a deficiency in this time period, EKPC will issue an RFP to determine if a PPA is an appropriate and economical option.

**Request 38a.** Confirm further that based on Table 8.6, the Company in 2024 is projected to have excess winter capacity of 40.6 MW and excess summer capacity of 582.6 MW.

**Response 38a.** Based on the load forecast utilized in the preparation of this integrated resource plan, those are the anticipated amounts of capacity that will be in excess in those periods.

**<u>Request 38b.</u>** Provide the level of reserves that PJM and SERC require for both winter and summer.

**<u>Response 38b.</u>** Taking into account EKPC's load diversity within the PJM system, the equivalent amount of reserves that EKPC must maintain on its system as compared to its summer peak load is approximately 3%. PJM develops its system coincident peak demand plus an adequate amount of reserves, approximately 16%, then assigns a load ratio share of that value to each of its owner-members. EKPC's share has historically been approximately its expected summer peak load plus an additional 3%. PJM does not have a winter reserve requirement for each of its members. SERC does not have summer or winter reserve requirements. SERC monitors the availability of generation and the reserves available to serve load. SERC documents the expected reliability of the system, but does not have generation reserve requirements. The reserve requirements are a function of the Balancing Authority and PJM is the Balancing Authority for EKPC.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 39**
**RESPONSIBLE PERSON: Julia J. Tucker**
**COMPANY: East Kentucky Power Cooperative, Inc.**

**Request 39.** Reference Table 8.5. Confirm that the IRP under Plan 2 projects a resource need in 2030 for 300 MW of intermediate power.

a. Explain whether the Company has analyzed the cost effectiveness of either acquiring or building a resource with a capacity in the range of 200 MW - 300 MW, as opposed to entering into the two PPAs identified in Table 8-7 over the period 2024 - 2030.

**Response 39.** EKPC has not compared acquiring or building a larger resource as compared to purchasing two smaller PPAs. As the need for additional capacity gets closer, EKPC will issue an RFP for capacity resources and will compare alternatives in more detail at that time. This IRP plan is a general guideline to know when the timing will be right to look at additional generation resources. As stated in the third bullet of the Recommended Plan of Action on page 4, EKPC will "continue to evaluate winter peak energy and capacity needs and review against market and owned generation options".

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 40**
**RESPONSIBLE PERSON:** **Jerry B. Purvis**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 40.** Reference IRP § 9.1 generally. Provide any applicable updates since the date the application was filed.

**Response 40.** Several EPA actions have taken place since the original filing in March 2018. If it pleases the Commission, 9.1 introduction contains each section that we re-assessed and updated by each EPA final rule or action.

**9.1 Introduction**

Actions to be undertaken during the last 15 years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990 (CAA), and how these actions affect the utility's resources assessment.

EKPC is currently in compliance with the following CAA rules:

- New Source Performance Standards (NSPS);
    - NSPS GHG for New, Modified and Reconstructed Fossil Fueled Units

- New Source Review (NSR);
- Title IV of the CAA and the rules governing pollutants that contribute to Acid Deposition (Acid Rain program);
- Title V operating permit requirements (Title V);
- Summer ozone trading program requirements promulgated after EPA action on Section 126 petitions and the Ozone SIP Call (Summer Ozone program);
- Clean Air Interstate Rule (CAIR) (Phased Out 12/31/15);
- Cross State Air Pollution Rule (CSAPR);
- National Ambient Air Quality Standards (NAAQS) for Sulfur Dioxide ($SO_2$), Nitrogen Dioxide (NO2), Carbon Monoxide (CO), Ozone, Particulate Matter (PM), Particulate Matter 2.5 microns or less (PM 2.5) and Lead;
- Mercury Air Toxics Standards (MATS); and
- EPA Affordable Clean Energy Rule (ACE), formerly known as the Clean Power Plan**.**

EKPC is currently in compliance with the following other environmental rules affecting the power generation sector:

- Clean Water Act
  - Section 316(a) and (b)**;**
  - Effluent Limitations Guidance (ELG)**;** and
  - Waters of the US (WOTUS)**.**
- Resource Conservation and Recovery Act (RCRA) – Coal Combustion Rule**.**

East Kentucky Power Cooperative is in compliance with the existing EPA rules. As a prudent utility, we survey the environmental landscape for future rules, in draft, proposed and final form. EPA puts forth an annual report that describes their strategic plan going forward called "Working Together", FY 2018-2022 U.S. EPA Strategic Plan, published February 2018 and updated in September 2019 and a "Year in Review 2019" from EPA Administrator Andrew Wheeler.

EPA's updated strategic plan for 2018-2022 indicates its core mission has three goals: (1) deliver a cleaner, safer, and healthier environment for all Americans and future generations by carrying out the Agency's core mission; (2) provide certainty to states, localities, tribal nations, and the regulated community in carrying out shared responsibilities and communicating results to all Americans; and (3) increase certainty, compliance, and effectiveness by applying the rule of law to achieve more efficient and effective agency operations, service delivery, and regulatory relief.

EKPC is complying with the rules of environmental law and is in alignment with the EPA strategic plan's core mission and the KY Cabinet. The rules identified above are what EKPC expects to see coming over the next 4 years that will have an impact to the utility industry over the next 15 years. A description of each rule appears below and lays out what impacts are expected.

**New Source Review**

On January 28, 2004, the United States filed a complaint alleging that EKPC was out of compliance with the Prevention of Significant Deterioration provisions in Part C of

Subchapter I of the Act, 42 U.S.C. §§ 7470-92 (NSR); NSPS, Title V and the federally-enforceable State Implementation Plan (SIP) developed by the Commonwealth of Kentucky. EKPC and the United States settled this action and entered into a Consent Decree memorializing the terms of the settlement, which was entered by the Court on September 27, 2007 (NSR CD).

On June 30, 2006, the United States and the Commonwealth of Kentucky filed a complaint alleging that EKPC was in violation of the Acid Rain Program and Title V. This matter was also settled, and the Consent Decree capturing the terms of the settlement was entered by the Court on November 30, 2007 (Acid Rain CD).

EKPC, in partnership with the EPA and KY Cabinet worked diligently to implement and comply with the requirements of these two Consent Decrees. On February 14, 2014, the United States filed a Joint Stipulation to terminate the Acid Rain CD. The court entered an Order terminating that consent decree on February 20, 2014. With respect to the NSR CD, the United States determined that EKPC met all the requirements for Conditional Termination. Upon EKPC's filing of a Certificate with the court on June 16, 2017, the Conditional Termination was effective 45 days later. EKPC remains in compliance with the conditions of the consent decrees that were designed to survive termination through EKPC's air permits.

In addition to these settlement costs, EKPC dedicates ongoing legal, operations, engineering and environmental resources to the review of outage projects under its NSR compliance program. If EKPC had the benefit of a clearly defined set of NSR regulations, EKPC could have avoided settlement costs and could have reduced its ongoing NSR compliance costs.

Congress is considering reforms to the NSR rules, and EPA considered reforms in conjunction with the ACE rule and in guidance, although efforts appear to have stagnated with the 2019 departure of Bill Wehrum as the EPA's Assistant Administrator of Air. A bright line emissions test would assuage the shifting EPA NSR enforcement interpretations, which are costly to industry to defend. EKPC supports a historical hourly maximum emissions test in lieu of the current actual-to-projected-actual emissions test. The historical hourly maximum emissions test, which is used for the New Source Performance Standard (NSPS), evaluates increases in maximum hourly emissions, based on a five-year lookback. 40 CFR § 60.14(h). The maximum hourly emissions test would capture projects that allow the boiler to combust more fuel, thereby increasing the emissions from the boiler. It would promote certainty by removing the demand growth variable from the present NSR analysis. The hourly approach is consistent with the CAA definition of "construction," which is a statutory justification for the NSR program.[5]

[5] 42 U.S.C. § 7475 (defining pre-construction requirements in the PSD program). The term "construction" when used in connection with any source or facility, includes the modification (as defined in section 7411(a) of this title) of any source or facility). *Id.* The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. 40 CFR § 52.21(b)(2).

In addition, EKPC also supports a bright line definition of the exclusion for "routine maintenance, repair and replacement"[6] so that EKPC can easily delineate which outage projects fall under this exception to modification. That exclusion should allow EKPC to perform outage projects that improve plant efficiency and enable EKPC to repair components in its electric generating units with like-kind equipment. Rather, at present, the exclusion is defined by a murky set of judicial opinions that provide little guidance to industry on which outage projects qualify for the exclusion.

EKPC also supports EPA's recent efforts to make reforms in the interpretation of "ambient air." EPA's December 2, 2019 guidance entitled, "Revised Policy on Exclusions from "Ambient Air" penned by Administrator Wheeler, adds a commonsense element to defining the fence-line for NSR permitting. As long as a source employs measures to control land, the land area is excluded from ambient air, even absent physical barriers.

**EGU Mercury Air Toxics Standards**

On March 16, 2011, EPA issued the proposed Electric Generating Unit (EGU) MACT rule to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA finalized the Mercury Air Toxic Standards (MATS) as the EGU MACT rule on December 16, 2011, to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen

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[6] 40 CFR 52.21(b)(2)(iii)(a): "Routine maintenance, repair and replacement. Routine maintenance, repair and replacement shall include, but not be limited to, any activity(s) that meets the requirements of the equipment replacement provisions contained in paragraph (cc) of this section."

chloride (HCl) and hydrogen fluoride (HF). MATS allows sources to control surrogate emissions to demonstrate control of hazardous air pollutants (HAP) metals and HAP acid gases. Non-Hg metallic toxic air pollutants are captured 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. EGUs began compliance with the mercury, $SO_2$ or HCl, and PM limits for MATS beginning in the spring of 2015. On December 27, 2018, EPA proposed to revise the Supplemental Cost Finding for MATS, as well as the CAA required risk and technology review (RTR). However, if this Proposed Rule became a Final Rule, the requirements of MATS would not be changed. The MATS RTR Final Rule is undergoing review by the Office of Budget and Management (OMB) and should be issued in 2020.

Prior to the MATS initial compliance date, EKPC conducted emissions testing of its units to determine the best way to achieve compliance with the MATS rule. This testing was conducted as part of an extensive engineering effort to ensure that EKPC's units complied with the rule. The pollution control upgrades on Spurlock 1 and 2 and Cooper 2 as part of NSR CD, placed EKPC's units ahead of most EGU units for MATS compliance with minimal additional capital investment. Likewise, Cooper, Spurlock 3 and 4 are equipped with Best Available Control Technology (BACT) and met the MATS lowest emissions (LEE) limits without additional controls. EKPC is currently in compliance with MATS requirements and monitors its units to assure ongoing compliance.

**Cross-State Air Pollution Rule**

On July 6, 2011, 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 replaced EPA's 2005 CAIR that was remanded to EPA by the U.S. District Court of Appeals for the D.C. Circuit (D.C. Circuit). CSAPR required 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 $NO_X$. On December 30, 2011, CSAPR was stayed by the D.C. Circuit 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 D.C. Circuit and reinstated CSAPR. The Court remanded the rule back to the D.C. Circuit to determine next steps and resolve the many pending appeals of the Rule.

On June 26, 2014, the United States moved the D.C. Circuit to lift the stay on CSAPR but 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 January 1, 2017.

In November 2016, EPA proposed the CSAPR Update Rule (CSAPR II), addressing earlier court concerns and interstate transport of air pollution under the 2008 ozone NAAQS. CSAPR became effective on December 27, 2016 and does not affect the $SO_2$ allocations or the $NO_x$ allocations for 2015 and 2016. CSAPR $NO_x$ emissions allowances will likely be reduced further in the next couple of years to achieve compliance with the new 2015 ozone NAAQS (70 ppb). Future reductions in $NO_x$ allowances to comply with the 2015 ozone NAAQS is generally referred to as CSAPR III.

CSAPR III has not been issued, but is expected to follow the same methodology as CASPR II, with some reductions in allowances for units that are in non-attainment areas or that have a significant contribution to non-attainment areas.

EKPC Bluegrass Station (Bluegrass) is located in Oldham County, which EPA recently designated as marginal nonattainment for the 2015 Ozone NAAQS. Bluegrass may lose some of the allowances once CSAPR incorporates the 2015 Ozone NAAQS. The rest of the fleet is in areas that are in attainment for ozone. The number of these allowances for Bluegrass is a small fraction of the allowances assigned to the EKPC fleet. The four Dale units will continue to have allowances assigned through 2020. After that, some of the Dale unit allowances (Dale Unit 1 and Unit 2) will go to the new unit set aside account. The EKPC fleet has roughly twice the number of allowances it needs to operate in 2020. Based on the allowances assigned under CASPR II, EKPC should have sufficient allowances to operate normally under CSAPR III for the foreseeable future.

**GHG Tailoring Rule**

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 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 both a significant net-emissions increase of GHGs and another PSD pollutant. On October 3, 2016, EPA responded to the Court's action by issuing a Proposed Rule that sets the GHG significant emissions rate at 75,000 tons per year or more of $CO_{2e}$. But until EPA issues a Final Rule, the GHG threshold will not be set. EKPC is tracking these developments.

**National Ambient Air Quality Standards (NAAQS)**

If a county or counties are designated to be in nonattainment for a NAAQS, the KY Cabinet will work with major sources contributing to nonattainment to implement Reasonably Achievable Control Technology (RACT) retrofits to bring the areas into attainment. Further, no permits can be approved by the KY Cabinet without a NAAQS compliance demonstration, which involves submitting computer modeling of emissions that shows that the Commonwealth will stay in attainment despite the permitted activity.

**A. CO**

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. As of September 27, 2010, all CO areas have been designated as maintenance areas. 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. $SO_2$**

EPA strengthened the primary $SO_2$ NAAQS in June 2010 to a one-hour standard of 75 ppb. On June 2, 2011, Kentucky made area designation recommendations for the new $SO_2$ standard. The Commonwealth recommended that Jefferson County be designated as a non-attainment area and that the remainder of the Commonwealth be designated as unclassifiable or attainment. On July 25, 2013 EPA designated 29 areas in 16 states as nonattainment, but did not at that time designate other areas. Pursuant to a March 2, 2015, a court-ordered schedule, the EPA had completed the remaining

$SO_2$ designations by three specific deadlines: July 2, 2016, December 31, 2017, and December 31, 2020. On February 6, 2013, EPA, in Round 1, responded to Kentucky's staff recommendations dated June 2, 2011, updates in December 20, 2011, and January 15, 2013, on air quality designations for the Commonwealth and designated part of Campbell County, KY (together with part of Clermont County, OH) as non-attainment and part of Jefferson County, KY as non-attainment. On March 6, 2013, Secretary Peters responded to EPA by providing that upgraded $SO_2$ controls on LGE Mill Creek Station should bring Jefferson County back into attainment, something under its control. However, the KY Cabinet strongly opposed the nonattainment status for Campbell County since, a coal-fired plant upwind in Ohio contributed to its nonattainment 10 miles away. Ultimately EPA agreed and in Round 2, neither counties remained in nonattainment. The remaining KY counties are in attainment/ unclassifiable at this time. The attainment demonstration deadline for both non-attainment areas is April 6, 2015. The current secondary 3-hour $SO_2$ standard is 0.5 ppm. EPA proposed to retain both the $SO_2$ and $NO_2$ secondary standards in July 2011 and this final rule was published on April 3, 2012. After weighing potential changes to its implementation of the NAAQS, including altering the formula for how the agency determines whether an area is attaining or violating the NAAQS, EPA Administrator issued a Final Rule on March 18, 2019 to keep the existing one-hour standard of 75 parts ppb of $SO_2$. EKPC facilities are in attainment / unclassifiable areas. No further action is required by EKPC at this time.

**C. <u>$NO_2$</u>**

EPA revised the primary $NO_2$ NAAQS in January 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 are 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. A new monitoring system was implemented to measure $NO_2$ concentrations. EPA finalized a rule establishing a nation-wide monitoring on March 7, 2013 in two phases (2014 and 2017). Three years after the new monitoring system was implemented, EPA will re-evaluate the existing data and re-designate areas as necessary (2020). An initial compliance deadline of 2025 is contemplated. On April 18, 2018, EPA finalized its periodic review of the $NO_2$ NAAQS one-hour standard of 100 ppb and the annual standard of 53 ppb to determine if these existing standards are protective of public health and welfare. EPA retained both standards without revision.

**D. <u>Ozone</u>**

On December 20, 2017, EPA provided notice to Kentucky concerning the air quality designations for the revised 2015 NAAQS Ozone Standards throughout Kentucky. The 2015 Ozone NAAQS Ozone Standard lowered the 8-hour ozone standard from 0.075 parts per million (ppm) to 0.070 ppm.

EPA published a notification of availability and public comment period on January 5, 2018, concerning the state's designation recommendations for the 2015 NAAQS Ozone Standard. The Notification identified EPA's responses sent to the states, including the Kentucky Nonattainment Designation Letter, technical support information for designations, and opened the comment period for the 2015 NAAQS Ozone Standard designations. The Kentucky Nonattainment Designation Letter identified certain counties in Kentucky that EPA determined violate the 2015 NAAQS Ozone Standard and nearby areas that contribute to the violating areas.

The 2015 NAAQS Ozone Standard designations affect Bluegrass Station in Oldham County, which is designated nonattainment as an area contributing to a 2015 NAAQS Ozone Standard violation. EKPC filed comments on this designation on February 5, 2018. All other EKPC generation facilities are located in areas in attainment with the standard. Kentucky is in the process of developing an attainment plan to submit to EPA. EKPC will follow developments and assess any impacts on Bluegrass Station.

**E. <u>Particulate Matter ($PM_{2.5}$)</u>**

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 ug/m3. In 2006, EPA revised this standard to 35 $\mu g/m^3$, and retained the existing annual standard. In December 2004, the following counties were designated as nonattainment under the 1997 standard: Boone, Campbell, Kenton, Boyd, Lawrence (partial), Bullitt, and Jefferson. This was modified in April 2005 and in October of 2009, the entire Commonwealth was designated as unclassifiable/attainment under the 2006 standard.

EPA tightened the primary $PM_{2.5}$ NAAQS to 12 $\mu g/m^3$ on January 15, 2013. On January 15, 2015, EPA issued final $PM_{2.5}$ designations. EPA designated Boone, Campbell, Kenton, Bullitt and Jefferson counties as non-attainment. EKPC does not have generation facilities in these counties.

**F. <u>Lead</u>**

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 $\mu g/m^3$ to 0.15 $\mu g/m^3$ in a three month period averaging time. EPA has designated the Commonwealth as unclassifiable/attainment for the lead NAAQS. EPA retained this standard on October 18, 2016 in a Final Rule.

**<u>Regional Haze Rule</u>**

The Regional Haze Rule has 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. This first review, just now being completed, targets 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. Spurlock and Cooper Stations are subject to BART. EKPC submitted its Regional Haze compliance plans to the KY Cabinet, and the KY Cabinet submitted the plan for the Commonwealth to EPA who adopted it formally into Kentucky's State Implementation Plan (SIP). EKPC installed $SO_2$, NOx and PM controls on Spurlock 1 and 2 and Cooper 2 to comply with the NSR CD, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. At this point, Spurlock and Cooper Stations' compliance with CSAPR means that it is also in compliance with the Regional Haze Rule. EKPC's coal-fired fleet has remained in compliance with BART since its compliance date of April 2017 and is in compliance with the BART provisions in its Title V permits.

**II. Clean Power Plan**

See Response 32.

**A. Reconsideration of $CO_2$ NSPS for New Utility Coal and Natural Gas Units (111(b) Rule)**

EPA released proposed revisions to the 111(b) $CO_2$ rule (Proposed Rule) on December 6, 2018. The current 111(b) $CO_2$ rule applies, as do all 111(b) rules, to new EGUs. The primary goal of the Proposed Rule is to revise EPA's former finding that partial Carbon Capture and Sequestration (CCS) was the best system of emissions reduction (BSER) for

$CO_2$ emissions from EGUs. The Proposed Rule determines that CCS is too costly, technically infeasible and geographically limited. Instead, EPA proposes to set BSER as units with the most efficient demonstrated steam cycle in combination with best operating practices.

Supercritical units (which includes ultra-supercritical units) are BSER for units with a heat input larger than 2,000 MMBtu/h. For units with a heat input equal to or less than 2,000 MMBtu/h highly efficient subcritical units. The resulting emissions limits (Table 1) apply to new and reconstructed EGU and are a floor for modified EGUs. Coal refuse EGUs have a slightly higher limit.

**Table 1. Summary of BSER and Proposed Standards for Affected Sources**

| **Affected Source** | **BSER** | **Emissions Standard** |
|---|---|---|
| New and Reconstructed Steam Generating Units and IGCC Units | Most efficient generating technology in combination with best operating practices | 1. 1,900 lb CO2/MWh-gross for sources with heat input > 2,000 MMBtu/h<br>2. 2,000 lb CO2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h or<br>3. 2,200 lb CO2/MWh-gross for coal refuse-fired sources |
| Modified Steam Generating Units and IGCC Units | Best demonstrated performance | A unit-specific emission limit determined by the unit's best historical annual CO2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than<br>1. 1,900 lb CO2/MWh-gross for sources with heat input > 2,000 MMBtu/h<br>2. 2,000 lb CO2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h or<br>2,200 lb CO2/MWh-gross for coal refuse-fired sources |

There is no change to new unit limits for combustion turbines, including NGCC units. These limits are:

1. 1,000 lb. CO2/MWh-g or 1,030 lb CO2/MWh-n for base-load natural gas-fired units.
2. 120 lb CO2/MMBtu for non-base load natural gas-fired units.
3. 120 to 160 lb CO2/MMBtu for multi-fuel-fired units.

The Proposed Rule uses a modification test that contemplates determining whether a modification triggers the 111(b) Rule by comparing hourly $CO_2$ emissions rates after change with the highest hourly emissions rate in the five years before. This test is contrary to the traditional NSPS modification test under 60.14(h), which looks at the maximum achievable hourly emissions rates in the five years before the project compared to hourly rates going forward. However, it is more consistent with the proposed NSR hourly emissions rate alternatives in the ACE proposal.

The Proposed Rule very briefly discusses the 2009 endangerment finding and the lack of an additional endangerment finding when the 111(b) Rule was promulgated in 2015, but makes clear that EPA is not re-opening these issues or inviting comment on them. EPA seems unlikely to change the legal basis for the 111(d) Rule. No Final Rule has been issued.

## NON-CAA RULES WITH REGULATORY CHANGES

For completeness EKPC is providing a summary of new Clean Water Act (CWA) rules and Proposed Rules to change portions of the Coal Combustion Residuals (CCR) rule.

### I. CWA 316(b) Rule

**Background**

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.

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 and Cooper Stations are subject to requirements of Section 316(b) of the 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 and Bluegrass Stations are 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 (Kentucky Division of Water) determines EM mitigation requirements on a site-specific basis

**Impingement Mortality**

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:

Closed-cycle recirculating system.

Design through-screen velocity ≤ 0.5 fps.

Actual through-screen velocity ≤ 0.5 fps.

Existing offshore velocity cap > 800 feet offshore.

Modified traveling screens with fish return.

A system of technologies and/or operational measures.

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[7]) 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

[7] 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.

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 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 <u>must</u> 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) of 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 man-made 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.

**Spurlock Station**

**Spurlock Station Cooling Water System Description**

The cooling 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 wedge-wire intake screens, an intake sump, and three vertical makeup water pumps. The screens consist of welded Type 304 stainless steel wedge-wire 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 Compliance Options**

Spurlock Station's passive wedge-wire 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 was issued by the Kentucky Division of Water on 10/23/2018 with a compliance date of January 1, 2019. The KPDES permit confirms that Spurlock Station's existing closed-cycle recirculating cooling water system is BTA for both impingement and entrainment under the final Section 316(b) existing facilities rule. In addition, the Division allowed EKPC to submit existing data from other facilities on the well-studied Ohio River in lieu of an entrainment sampling requirement in that permit. EKPC is currently in compliance with this rule and permit.

**Cooper Station**

**Cooper Station Cooling Water System Description**

The cooling system at the Cooper Station consists of two condensers equipped with once-through cooling systems. The permanent intake structures are located in Lake Cumberland approximately 25 feet from the shoreline and withdraw water at an elevation of 671 feet mean sea level (MSL), which under full pool conditions (723 feet MSL) is approximately 52 feet below the water surface.

The once-through cooling water system at Cooper Station has a design intake flow of approximately 208 MGD. Unit 1's intake has a design capacity of 89.2 MGD and consists of two 42-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 32,000 gpm circulating water pumps, and a fish return system. The conventional traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of

30 feet. The estimated through-screen velocity at design flow is 0.34 fps. The estimated velocity at the two 42-inch intakes located in the lake at design flow is 7.2 fps.

Unit 2's intake has a design capacity of 118.9 MGD and consists of two 48-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 40,000 gpm circulating water pumps, and a fish return system. The traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.45 fps. The estimated through-pipe velocity at the two 48-inch intakes located in the lake at design flow is 7.3 fps.

An 8-cell cooling tower was also retrofitted to Unit 2 in 2007 and brought online in 2009, and was operated during warm water months to offset the elevated intake temperatures at the surface due to the lower lake levels that existed while Wolf Creek Dam was being repaired. When operating, the cooling tower has an average makeup water demand of 3.25 MGD, substantially reducing the cooling water supply requirement for Unit 2 and the overall demand for the station. The estimated through-pipe velocity at the Unit 2 intakes drops to 0.2 fps during cooling tower operation and the through-screen velocity drops to an estimated 0.012 fps.

The traveling screens are typically manually operated twice per day but may operate more frequently when the debris loads are high and increased differential pressure across the screens triggers automatic operation. Fish and debris are washed into a trough below the traveling screens and then conveyed through a pipe, which releases fish back into the lake.

**Cooper Station 316(b) Compliance Requirements**

The final KPDES permit for Cooper Station was issued with an effective date of July 1, 2018. The permit includes a condition to prepare and submit a 316(b) demonstration for the Division "to establish impingement mortality and entrainment BTA requirements as applicable under 40 CFR 125.94(c) and (d)." This demonstration is to be included with the next KPDES permit renewal application due 180 days prior to permit expiration (approximately December 31, 2022). EKPC met with the Kentucky Division of Water (KDOW) in January 2020 to review the plan for the demonstration due with the next renewal application. KDOW agreed that EKPC is required to submit site-specific entrainment information pursuant to 40 CFR 122.21(r)(2)-(r)(8). The actual intake flow at Cooper is <125 MGD, less than the Section 316(b) Rule's threshold requiring an entrainment characterization study. KDOW confirmed that the entrainment characterization study and supporting BTA information required by 40 CFR 122.21 (r)(9) through (13) is not required.

When Cooper Station submits this information to KDOW, the Division will be charged with making an entrainment BTA determination under §125.98(f) where the Director must determine "the maximum reduction in entrainment warranted after consideration of factors relevant for determining the best technology available for minimizing adverse environmental impact at each facility."

The factors which the Director must/may consider in the best professional judgment (BPJ) decision are listed in the Rule. The Director has the discretion as to the relative weighting of each factor. First and foremost amongst the factors is consideration of the numbers and types of organisms entrained (including federally-listed T&E species and designated critical habitat). There are no federal- or state-listed T&E fish species in the watershed, although the USFWS is evaluating a potential listing of Lake Sturgeon within the range, pursuant to 84 Fed. Reg. 41691 (Aug. 15, 2019). Several federally-listed mussel species exist in the watershed, although the deep lake is not a preferred habitat. With the unlikely potential for impacts to T&E species, EKPC believes the Director would focus most on the numbers and types of organisms entrained and the other factors listed in the Rule and since this is a managed Lake by the KY Division of Wildlife Resources. These include consideration of the remaining useful life of the plant, the relative costs to society compared with the benefits of retrofitting entrainment reduction technologies, and the impacts on the reliability of energy delivery within the immediate area. EKPC will provide the Director with the relevant information to support the BTA decision with its Section 316(b) information submittal.

Existing site-specific entrainment data are not currently available, but this information will be developed pursuant to the requirement in 40 CFR §122.21(r)(4) using available biological data from the lake and other similar water bodies. Using available biological data, EKPC plans to evaluate whether the location of the submerged intake at a depth of 52 feet minimizes the potential for entrainment of these early life stages, and in combination with the seasonal generation patterns anticipated for Cooper Station, supports a determination by the Director that additional measures to reduce EM (such as use of the existing Unit 2 cooling towers) are not warranted. EKPC will discuss the basis of its selected IM compliance approach, accounting for the intake location, documented historical de minimis impingement rates, seasonal generation, and the low anticipated capacity factor in the submittal for §122.21(r)(6). Compliance based on these factors will potentially eliminate the need for IM monitoring requirements following the Director's decision on IM BTA.

EKPC believes that its current system is BTA for impingement and entrainment. As described above, a key component in the analysis is that Cooper Station's operational patterns have changed to a peaking operation, drawing water when biological productivity is low (winter/summer). Further, EKPC projects reduced utilization of Cooper Station in the coming years. Cooper Station's deep water intake further mitigates impingement and entrainment concerns.

## II. <u>Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category</u>

### A. <u>Background</u>

The EPA published the Effluent Limitations Guidelines (ELG) final rule on November 3, 2015. The ELG governs the quality of the wastewater that can be discharged from power plants. The rule phases in more stringent effluent limits for arsenic, mercury, selenium, and nitrogen discharged from wet scrubber systems and zero discharge of pollutants in ash transport water. As initially issued, power plants must comply between 2018 and 2023, depending upon when new CWA) permits are required for each respective plant.

EPA issued a final rule, September 18, 2017, postponing the compliance dates for FGD wastewater and bottom ash transport water ELG requirements. In the United States Court of Appeals for the Fifth Circuit, environmental non-governmental organizations (eNGOs) challenged the ELG postponement as well as the ELG rule's "best available technology" (BAT) determinations as to legacy wastewater and combustion residual leachate. On April 12, 2019, the Fifth Circuit vacated and remanded EPA's decision not to impose stricter ELG standards on legacy wastewater or landfill leachate.

On November 4, 2019, EPA issued a Proposed Rule to revise the ELG Rule for FGD wastewater and bottom ash transport water. EPA proposed two sets of BAT limitations for FGD wastewater, and two sets of BAT limitations for bottom ash transport water. The Proposed Rule also provides separate requirements for high flow facilities, low utilization boilers, and boilers retiring by 2028. The Proposed Rule puts forward BAT limitations that are more stringent than Best Practicable Control Technology limitations but extends compliance as far out as December 31, 2023 (BA Transport Water) or December 31, 2025 (FGD Wastewater), depending on NPDES renewal dates. Comments were due on January 21, 2020. No Final Rule has been promulgated, but EPA projects the Final Rule to be promulgated by the end of 2020. EPA stated that it intends to address the vacatur by the Fifth Circuit in a separate rulemaking.

B. Potential ELG Requirements for Spurlock Station

Wastewaters at Spurlock Station are generated from several sources, including ash transport waters, ash pond overflow, low volume waste, coal pile runoff, cooling tower blowdown, FGD scrubber blowdown, metal cleaning wastes, and storm water. The ash pond receives clarifier solids and other wastewaters from the pretreatment area and boiler bottom ash water in addition to effluent from the material handling storage pond. Flows from the primary lagoon and ash pond are directed to the secondary lagoon, along with FGD scrubber blowdown from FGD Units 1 and 2. Cooling tower blowdown can be directed to either the primary or secondary lagoons. Chemical precipitation is used to treat chemical metal cleaning wastes.

EKPC is committed to timely compliance with ELG and has commissioned a project that will result in enhanced treatment of effluent prior to discharge. EKPC is installing a wastewater treatment system to handle wastewater prior to solid clarification and discharge (the Wastewater Treatment Project). The resulting effluent will be compliant with ELG BAT limitations. EKPC has obtained the necessary state approvals and permits for this Project. The project completion date is estimated to be prior to expiration of the Spurlock KPDES permit (September 2023). Spurlock will be in compliance with ELG prior to the deadlines articulated in the Proposed Rule.

**Potential ELG Requirements for Cooper Station**

Wastewaters at Cooper Station are generated from several sources and include once-through cooling water, cooling tower blowdown, metal cleaning wastes, coal pile runoff, CCR landfill leachate, and storm water. Cooper Station already utilizes dry handling for fly ash and bottom ash and, therefore, there are no impacts from these activities. Similarly, Cooper Station already employs sedimentation through an impoundment for treatment of CCR leachate from the landfill. Cooper Station does not operate a wet FGD, so there is no FGD wastewater flow to address. In addition, non-chemical metal cleaning wastes are discharged to the coal pile runoff pond and are treated in a physical chemical wastewater treatment plant prior to being discharged. EKPC is currently in compliance with the provisions in its current KPDES Permit.

**III. Waters of the United States (WOTUS)**

On February 28, 2017, the President issued an Executive Order directing EPA and the Department of the Army to review and rescind or revise EPA's definition of "Waters of the United States" (WOTUS) from a 2015 Final rulemaking (2015 Rule). The 2015 Rule more broadly construed WOTUS than the prior Regulatory Definition of "Waters of the United States" from 1986/1988.

On January 23, 2020, EPA and the Department of Army issued the Final Navigable Waters Protection Rule (the Navigable Waters Rule), which completed the two steps involved to rescind the 2015 Rule and revise the regulatory definition of WOTUS. The first step in this process involved rescission of the 2015 Rule amendments and a temporary reversion to the 1986/1988 WOTUS definition. EPA promulgated a Final Rule that made rescission of the 2015 Rule effective on December 23, 2019. Step two, the Navigable Waters Rule, provided a replacement WOTUS definition. These two rulemakings clarify the patchwork of CWA applicability among states, which had resulted from various legal challenges.

The Navigable Waters Rule identifies four categories of waters subject to federal regulation:

- Territorial seas and traditional navigable waters;
- Perennial and intermittent tributaries to those waters;
- Certain lakes, ponds and impoundments; and
- Wetlands adjacent to jurisdictional waters.

The Navigable Waters Rule outlines exclusions to WOTUS such as groundwater, certain ditches, wastewater treatment systems, and prior converted cropland. The Navigable Waters Rule includes clarifications to the scope of WOTUS jurisdiction. Once this rule becomes effective (60 days after publication in the Federal Register), it will apply in Kentucky.

Kentucky previously utilized the pre-2015 definition for the Waters of the United States and of the Commonwealth. Since EKPC borrows money from RUS, the National Environmental Policy Act is applicable to all EKPC capital projects. All the capital projects are vetted and go through RUS NEPA process for RUS Environmental and Engineering permitting and approval. Should any capital projects impact WOTUS, the NEPA process resultant report is reviewed and approved by RUS via the NEPA process, which includes public participation. As a cooperating regulatory federal agency the USACE reviews the environmental report or environmental assessment for their permit purposes and issues a Finding of No Significant Impact (FONSI), or an Environmental Assessment (EA) as authorization of the project. Should the USACE identify impacts to the waters of the United States, the permit applicant must submit a mitigation plan and / or pay the mitigation fees, bank or self-mitigate the project.

## IV. Coal Combustion Residual Rule

On April 17, 2015, the EPA published a final rule regulating management of CCR under the Resource Conservation and Recovery Act. The CCR rule became effective on October 14, 2015. The final rule applies to landfills and surface impoundments that contain CCRs. The CCR rule establishes minimum national criteria for the safe disposal of CCR. The criteria address a wide spectrum of activities related to CCR. Areas addressed include location restrictions, structural integrity requirements, liner design criteria, operations, groundwater monitoring, closure and post-closure requirements. 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 final CCR Rule applies to owners and operators of landfills and surface impoundments and establishes minimum national criteria for the safe disposal of solid waste CCR. The criteria address a wide spectrum of activities related to CCR solid waste disposal. Areas addressed include location restrictions, structural integrity requirements, liner design criteria, operations, groundwater monitoring, closure and post-closure requirements. The closure and post-closure requirements resulted in the Cooperative revising its asset retirement obligations. Additionally, the CCR Rule sets out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly-accessible website. In 2016, EKPC established a website for CCR postings, as required by the CCR Rule.

The Water Infrastructure Improvements for the Nation (WIIN) Act became effective law on December 16, 2016. Overall, the WIIN Act is comprehensive legislation that aims to improve the United States' water resources infrastructure. The WIIN Act also includes an amendment to the CCR Rule. Specifically, the WIIN Act allows for a state permit program for CCR management that is at least as protective as the federal coal combustion residual rule. The WIIN Act also granted the EPA authority to directly enforce the implementation of the CCR Rule and an approved state permit program. In the absence of an approved state program, the WIIN Act requires EPA to put its own program in place.

Certain provisions of the CCR rule were remanded back to EPA by the D.C. Circuit of Appeals for further action on June 14, 2016. On March 15, 2018, EPA proposed a rule to address these remanded issues. The key issue for the remand rule is for EPA to delay future CCR compliance deadlines. EPA published a final rule extending certain CCR compliance deadlines on July 30, 2018. The final rule provides for the following:

- Delayed the deadlines for CCR Units that have detected a statistically significant increase in a covered pollutant or cannot comply with aquifer requirements to close from six months to until October 31, 2020.
- Allows the suspension of groundwater monitoring for up to ten years where there is no potential for migration of CCR constituents to groundwater.
- Adds limits for cobalt, lithium, molybdenum, and lead.
- Allows State Directors of approved programs to approve compliance measures instead of a third-party professional engineer.

On August 22, 2018, the United States District Court for the District of Columbia issued an opinion in *USWAG v. EPA.* The court found that unlined impoundments are likely to leak, that contamination is likely to create an unacceptable risk to human health and the environment, and that only twice-yearly monitoring would allow leaks to go undetected. The court found that clay-lined impoundments are similarly insufficiently protective. The court further found that RCRA provides authority to regulate both active and inactive units and rejected the exemption for legacy ponds (described as a subset of inactive impoundments) as arbitrary and capricious.

In 2019, EPA published additional rules that propose substantial changes to the CCR federal regulatory scheme, many of which were in response to the *USWAG* decision. These 2019 proposed rules include:

- Proposed Rule: Enhancing Public Access to Information; Reconsideration of Beneficial Use Criteria and Piles, 84 Fed. Reg. 403 53 (Oct. 15, 2019).
- Proposed Rule: Federal CCR Permit Program.
- Proposed Rule: Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part A: Deadline to Initiate Closure (Closure Part A Rule).
- Proposed Rule: Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part B: Alternate Demonstration for Unlined Surface Impoundments; Implementation of Closure; Legacy Units (Closure Part B Rule).

Although in each of these rulemakings EPA has suggested significant changes and additions to the CCR Rule provisions for beneficial use, reporting, website posting, and impoundment liners, the Proposed Rules concerning closure have the most impact on EKPC's CCR compliance strategy. The Closure Part A Rule confirms, consistent with the *USWAG* decision, that unlined or clay-lined impoundments (per the CCR liner definitions) must commence closure by ceasing the placement of CCR materials in those CCR Units. The Closure Part A Rule also proposes to move the closure commencement deadline from October 2020 to August 2020. The Rule also provides for short-term and long-term extensions for facilities that must commence closure by August 2020 but cannot secure capacity for CCR storage by that deadline. The Closure Part B Rule gives facilities an alternative liner demonstration off-ramp to closure. That Rule also proposes additional regulations that would apply to the closure process itself, including additional regulations for facilities choosing closure by removal.

The EKPC facilities are in compliance with the CCR Rule. Spurlock Station has three regulated CCR units (1 surface impoundment and 2 landfills); Cooper Station has a regulated CCR unit (landfill); and Smith Station has a regulated CCR unit (landfill). The Dale Station ash ponds are not subject to the CCR Rule because the facility did not generate electricity after October 19, 2015. The ponds have been closed by removal in accordance with a closure plan approved by the Kentucky Division of Waste Management. Therefore, the Spurlock surface impoundment is EKPC's only surface impoundment regulated by the CCR Rule.

EKPC's CCR units are presently in detection monitoring, except for the Spurlock Station surface impoundment, which is in assessment monitoring. None of the constituents in the CCR units have been detected at statistically significant levels above the groundwater protection standards established under the CCR rule. Therefore, no corrective action is required. However, the Spurlock surface impoundment is unlined per the CCR Rule. The Proposed Closure Part A Rule dictates that EKPC cease placement of CCR material in the impoundment by August 2020 due solely to the lack of a compliant liner or be self-certification by November 2020 or to seek EPA approval under the alternative closure plan by June 2020. EKPC is planning to seek EPA approval under the alternative closure plan by June 2020.

EKPC has proactively pursued a CCR compliance plan, which has been under development for more than three years. In 2018, EKPC obtained approval by the Public Service Commission for its Clean Closure Plan to close the Spurlock Station surface impoundment by removal. To achieve this clean closure, the Wastewater Treatment Project will divert the handling of certain CCR streams (FGD waste waters) away from the impoundment and, instead, to solids clarification, evaporation, and finally to a permitted CCR landfill. As previously mentioned in the ELG discussion, EKPC estimates that the Wastewater Treatment Project will be complete by 2023, the timing depending on a number of factors, such as construction timing, equipment availability, weather, Acts of God, and possible discovery of additional ash in the Spurlock ash pond. EKPC has no other alternative capacity options for CCR storage in the interim. EKPC anticipates applying for the long-term extension proposed in the Closure Part A Rule. Based on information from utility groups and NRECA, EKPC expects that many facilities will not be able to meet the August 2020 deadline or November 2020 deadline and will be utilizing and requesting this extension. However, EKPC has placed itself in a favorable compliance position by pursuing its CCR compliance strategy much earlier than many of its utility counterparts and gained the KY Cabinet approval for this plan.

**<u>OTHER NON-CAA RULES WITH COMPLIANCE DEVELOPMENTS</u>**

The CWA, Section 316(a) applies to point sources with thermal discharges. It authorizes the NPDES permitting authority (KDOW) to impose alternative thermal effluent limitations in lieu of the requirements that would be required under Sections 301 and 306 of the CWA. To obtain an alternative effluent thermal limitation, the permittee must demonstrate that the thermal limit is stringent enough to assure protection and propagation of a balanced, indigenous population (BIP) in and on the body of water into which the discharge is made every five years to renew the KPDES permit.

Cooper Station currently has an alternative thermal effluent limit (daily maximum limit of 100 degrees F) under Section 316(a) at Outfall 003, which handles once-through cooling water. Condition 5.7 of Cooper Station's KPDES permit requires that EKPC request continuation of this limitation in its next KPDES permit renewal application (due by December 31, 2022). EKPC plans to request that KDOW renew this alternative limit.

EKPC is in the process of developing a thermal plan study to support the renewal of this alternative thermal limit. The demonstration will include consideration of the following key elements, which is consistent with EPA Region 4 guidance:

- biotic community typically characterized by diversity;
- the capacity to sustain itself through cyclic seasonable changes;
- presence of necessary food chain species; and
- lack of domination of pollution-tolerant species.

In addition, EKPC will follow the KDOW guidance issued in 2019 for permittees seeking thermal variances under Section 316(a). EKPC met with KDOW in June 2019 to discuss EKPC's demonstration plan. KDOW concurred with EKPC's plan. EKPC is preparing the demonstration to apply for renewal of the alternative thermal limitation.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2019-00096**
**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**
**REQUEST 41**
**RESPONSIBLE PERSON:** **Scott Drake**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 41.** Reference the Technical Appendix, vol. 2.

**Request 41a.** Confirm that at p. DSM-3, the report states that all of the proffered DSM programs pass the Total Resource Cost test. If not already provided, provide the results of the TRC evaluation for each program.

**Response 41a.** All of the programs selected, with the exception of the EKPC Community Assistance Resources for Energy Savings (CARES) low-income program and the energy audit program, were shown to be cost-effective using the TRC test.

Low income programs are historically difficult to pass the TRC, and Commissions including the Kentucky Public Service Commission have allowed utilities to offer them to serve this disadvantaged community. The energy audit program is an owner-member tool for high bill complaints; it also saves electricity.

The results of the TRC evaluation for each program are presented in Table DSM-1 on page DSM-4.

**Request 41b.** If EKPC has performed any other California tests regarding the proffered programs, provide those.

**Response 41b.** EKPC performed the California tests for each of the proffered programs. The results can be found in Exhibit DSM-4 of Technical Appendix vol. 2.

**EAST KENTUCKY POWER COOPERATIVE, INC.**

**PSC CASE NO. 2019-00096**

**FIRST INFORMATION REQUEST RESPONSE**

**ATTORNEY GENERAL'S INITIAL DATA REQUEST DATED 02/21/2020**

**REQUEST 42**

**RESPONSIBLE PERSON:** **Scott Drake**

**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 42.** Reference the Technical Appendix, vol. 2, at p. DSM-4. Explain whether the $81 million in benefits refers to current year dollars.

**Response 42.** Yes, the $81 million in benefits refers to current year (2019) dollars.

**Request 42a.** Provide the lifetime period of the cost-effectiveness study.

**Response 42a.** The lifetime period of the cost-effectiveness study is 2019-2033 (15 years).