COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC TARIFF FILING OF EAST	**)**	
KENTUCKY POWER COOPERATIVE, INC.	**)**	
AND ITS MEMBER DISTRIBUTION	**)**	**CASE NO.**
COOPERATIVES FOR APPROVAL OF	**)**	**2021-00198**
PROPOSED CHANGES TO THEIR QUALIFIED	**)**	
COGENERATION AND SMALL POWER	**)**	
PRODUCTION FACILITES TARIFFS	**)**	

RESPONSES TO COMMISSION STAFF'S FIRST REQUEST

FOR INFORMATION TO EAST KENTUCKY POWER COOPERATIVE, INC.

DATED JUNE 14, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC TARIFF FILING OF EAST KENTUCKY POWER COOPERATIVE, INC. AND ITS MEMBER DISTRIBUTION COOPERATIVES FOR APPROVAL OF PROPOSED CHANGES TO THEIR QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITES TARIFFS	)))))))	**CASE NO. 2021-00198**

CERTIFICATE

COMMONWEALTH 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 Commission Staff's First Request for Information in the above-referenced case dated June 14, 2021, 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 28th day of June 2021.

Gwyn M. Willoughby

Notary Public - #590567
Commission expires - 11/30/2021

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

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2021-00198

FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S REQUEST FOR INFORMATION DATED 06/14/21

REQUEST 1

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 1. Provide, in narrative form, a detailed explanation of how EKPC determines its avoided energy and avoided capacity rates under its Cogeneration and Small Power Production Tariff.

Response 1. The avoided energy and avoided capacity are directly related to market activity in PJM. The avoided energy is the forecasted PJM Hourly LMP. The AEP Dayton Hub ("ADHub") is the market point that EKPC uses due to the proximity of this liquid hub to the EKPC zone within the PJM footprint.

The avoided capacity is based on the PJM Reliability Pricing Model ("RPM") auction results. The RPM auction has a base auction and three subsequent incremental auctions. The expectation for a potential cogeneration or small power producer is that the resource will be available within the next 6 to 12 months. Thus, the Third Incremental Auction provides the most recent value for a capacity resource that would be available in this 6- to 12-month window and is a reasonable measure of capacity value.

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REQUEST 2
RESPONSIBLE PERSON: Julia J. Tucker
COMPANY: East Kentucky Power Cooperative, Inc.

Request 2. Refer to the Application, Proposed Fifth Revised Tariff Sheets 39 and 42.

Request 2a. Provide the supporting calculations that detail how the new capacity rate of $7.86 per kW is derived.

Response 2a. The PJM capacity auction is composed of a base auction and three incremental auctions. The value of capacity in the third auction results is used as the price of capacity for the referenced Tariff Sheets and is stated in Dollars per Megawatt-Day. This price is converted to Dollars per kilowatt-year by multiplying the $/MW-Day value by 365 days per year to get $/MW-Year and dividing by 1,000 to convert from a Megawatt rate to a kilowatt rate. The forced outage rate, as specified by the PJM auction results, is used to calculate the adjusted capacity rate:

2021/22 3rd IA RTO

Average EFORd: 4.835%

Auction Clearing Price: $20.55/MW-Day

Conversion to $/kW-yr: ($20.55/MW-Day*365days/yr)/1000=$7.501/kW-yr

Adjusted Capacity Rate: $7.501 * 1.04835 = $7.86/kW-yr

<u>Request 2b.</u> Explain why the proposed Winter and Summer peak and off-peak rates are different from the rates derived in Exhibit 03-Supporting_Data_-_SPP-COGEN-Energy-PJM_Market-DST_2021-2025_-_12MAR21.xlsx (Exhibit 03).

<u>Response 2b.</u> The values in Exhibit 3 are energy only, while the proposed rates reflect the impact of the administrative fees.

<u>Request 2c.</u> Confirm in the strikethrough copy of the proposed tariff that the 2024 Non-Time Differentiated Rate is $0.2609 instead of $0.02609.

<u>Response 2c.</u> The value of $0.02609 is correct.

<u>Request 2d.</u> In Exhibit 03, explain what each of the columns represent for tabs 2021-2025.

Response 2d. Columns in support file 3:

Sequence - consecutive numbering of rows for identification purposes

Year – Test year

Month – test month

Day – Test day

HE – Test hour-ending

LOAD – Load forecast for test period

PJM ADHUB – price forecast for AEP-Dayton Hub in the PJM market

BASE – Load forecast time PJM ADHUB

CHANGE – Load forecast minus 100MW times PJM ADHUB

DIFF – Delta of older SCGT form of calculation between BASE and CHANGE

$/MW – price forecast for AEP-Dayton Hub in PJM Market

$/kW – converted units from dollars per megawatt to dollars per kilowatt

W-On – formula for determining if current HE occurs in the winter on-peak

W-Off – formula for determining if current HE occurs in the winter off-peak

S-On – formula for determining if current HE occurs in the summer on-peak

S-Off – formula for determining if current HE occurs in the summer off-peak

Winter On-Peak – average of all hours that occurred in the winter on-peak period

Winter Off-Peak – average of all hours that occurred in the winter off-peak period

Summer On-Peak – average of all hours that occurred in the summer on-peak period

Summer Off-Peak – average of all hours that occurred in the summer off-peak period

Overall Average – average of all hours that occurred in test year

Request 2e. In Exhibit 03, explain whether the administration fee of $0.00016 is included in the rates derived in tabs 2021-2025.

Response 2e. No, Exhibit 3 is the energy-only calculation and does not include the administration fee.

Request 2f. Explain where in the application the Non-Time Differentiated rates are derived and provide a narrative of how they were derived.

Response 2f. The Non-Time Differentiated rates are the overall annual average of all hours in a test year.

EAST KENTUCKY POWER COOPERATIVE, INC.

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COMMISSION STAFF'S REQUEST FOR INFORMATION DATED 06/14/21

REQUEST 3

RESPONSIBLE PERSON: **Julia J. Tucker**

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

Request 3. Refer to the Application, Cover Letter and Exhibit 05-Supporting_Data_-_COGEN-SPP_Market_participation_cost_-_15MAR21.xlsx (Exhibit 05).

Request 3a. Provide a comparison of the services ACES Power Marketing provides to EKPC that are included and excluded from the administrative service fee of $0.00016 per kWh.

Response 3a. The following services are provided by ACES.

I. Trading and Counterparty Controls and Risk Policies

   a. Credit

      i. Credit Analysis and Counterparty Monitoring
      ii. Credit Exposure Monitoring and Management
      iii. Credit Negotiations
      iv. Credit Reports
      v. ISO / RTO Credit Monitoring Service

b. Contracts
    i. Master Agreement Negotiations
    ii. iv. Contract Monitoring – Agreements
    iii. v. Structured / Customized Contract Evaluations

c. Trading Control
    i. Trade Capture Validation
    ii. Policy Compliance Monitoring
    iii. Forward Curve Reporting
    iv. Mark-to-Market Valuation and Reporting
    v. Transaction Reporting

d. Risk Management and Training
    i. Risk Management Policy Development
    ii. Iii. Education and Training (within limits)

e. Regulatory and Market Development Participation
    i. Iii. Regulatory and Market Development Participation
    ii. Iv. FERC Order 741 Support

f. Electric Reliability Organization ("ERO") Compliance Consulting
    i. Reliability Compliance Consulting

g. Compliance Service Associated with Financial Transactions and Dodd Frank Physical Trade Options
    i. Compliance Services Associated with Financial Transactions and Dodd Frank Physical Trade Options

II. Portfolio Strategy and Management

a. Long-term Portfolio Strategy
    i. Portfolio Strategy and Analysis
    ii. Origination (4 months to 20 years)
    iii. Emissions Allowances, Carbon and Renewable Strategy, and Analysis
    iv. Standard Portfolio Modeling and Risk Analysis
    v. Long-Term Generation and Transmission Planning Studies

b. Short-term Portfolio Management
    i. Portfolio Performance Reporting ("PPR")
    ii. Generation Management Services

iii. Optimization Modeling
iv. Capacity Services

c. Natural Gas and Fuels
   i. Physical Gas Trading and Scheduling
   ii. Gas Service Consulting
   iii. Short Term and Seasonal Weather Forecasting

d. Transmission Risk Management
   i. Financial Transmission Right Evaluations and Hedge Execution
   ii. Transmission Service Analysis and Advice (Physical)
   iii. Long Term Locational Price Studies

III. Settlements

a. Bilateral Power and Transmission Settlements
b. Bilateral Natural Gas, Transportation Settlements
c. RTO/ISO Pool Settlements
d. Reporting
e. Submits Complete Electric Quarterly Reports ("EQR") Filing to FERC

IV. Ad Hoc Consulting and Other Services

a. Ad Hoc Consulting

EKPC estimated 40% of these services are directly related to power supply resources. Sections I.a.i. and ii., I.b.ii., I.c.i. and ii., II.a.i. and iv., II.b.i. and iv., II.d.i. and III.i. would all be services relevant to a cogenerator or small power producer.

Request 3b. Explain how EKPC recovers the ACES Power Marketing costs that are not presently but previously were included in the administration fee.

Response 3b. EKPC incurred ACES Power Marketing costs that were included as expenses in its last base rate case in 2010. Consequently, that level of costs have since been recovered in EKPC's base rates. Any difference in the level of ACES Power Marketing costs from the amounts in the test year impact EKPC's net margins in any year.

Request 3c. Explain what each of the columns represent for tabs Generation and Load.

Response 3c. EKPC utilizes an information system from Power Costs Inc. The Generation tab is a summary of the previous year's generation activity. The Load tab is a summary of load activity in the previous year.

Generation:

Reporting ID	Generating Unit
DART P&L ($)	Calculated Profit and Loss for Generation
DA En (MWh)	Day Ahead of planned energy
RT Meter (MWh)	Real Time of actual generation
RT Dev (MWh)	Deviation from DA to RT
DA LMP ($/MWh)	Price for DA energy
RT LMP ($/MWh)	Price for real time energy
DA Tot Rev ($)	Total revenue for DA expectation
RT Rev ($)	Revenue calculated
RT AS Rev ($)	Real-time ancillary revenue
RT OR Rev ($)	Real-time operating reserve revenue
OR Charge ($)	Charge for operating reserve
Reactive Credit ($)	Credit for reactive power from generators
Capacity Res. Deficiency ($)	Charge for capacity reserve deficiency
Fuel Cost Penalty Charge ($)	Charge for fuel cost penalty
RT Tot Rev ($)	Total revenue in Real Time
RT Startup Cost ($)	Cost for Startup in Real Time
RT En Cost ($)	Real-Time Energy Cost
RT AS Costs ($)	Real-Time Ancillary Services Cost
RT Tot Cost ($)	Total cost of Real-Time generation
Avg Cost ($/MWh)	Average cost of hourly generation
DART Rev ($)	Day-Ahead / Real-Time Revenue
RT Schedule ID	PJM cost/price schedule for unit
UOF (%)	Average Percentage of calculated unplanned outage factor

Load:

Month	Month of load activity
Load P&L ($)	Profit-and-Loss for load
DA Load (MWh)	Day-Ahead Load Expectation
RT Meter (MWh)	Real-Time Actual Load
DA En Charges ($)	Cost of load in the day-ahead
RT En Charges ($)	Cost of load in the real-time market
DA OR ($)	Cost of day-ahead Operating Reserve
RT OR ($)	Cost of real-time Operating Reserve
Tot Admin ($)	Administrative cost for load
Tot Trans ($)	Transmission cost for load
Tot AS ($)	Ancillary Service cost
Tot Misc ($)	Miscellaneous costs
Total Load Charges ($)	Total cost for load
Avg Load Charge ($/MWh)	Average dollar per megawatt cost
Load Revenue ($)	Revenue from the DA-RT market

EAST KENTUCKY POWER COOPERATIVE, INC.

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COMMISSION STAFF'S REQUEST FOR INFORMATION DATED 06/14/21

REQUEST 4

RESPONSIBLE PERSON: Julia J. Tucker

COMPANY: East Kentucky Power Cooperative, Inc.

Request 4. Refer to the Commission's January 13, 2021 Order in Case No. 2020-00174[1] (2020-00174 Order) in which the Commission directed revisions to Kentucky Power Company's Cogeneration Tariff.

Request 4a. Explain why the same revisions should not be applied to EKPC's Cogeneration Tariff.

Response 4a. EKPC estimates the hourly variable LMP at the ADHub for its avoided energy costs going forward. The referenced Commission Order refers to variable LMP at the time of delivery. EKPC's value is estimated based on current projections while the Order utilizes real time actuals. Utilizing the actual LMPs would eliminate all

[1] Case No. 2020-00174, *Electronic Application of Kentucky Power Company for (1) A General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief* (Ky. PSC Jan. 13, 2021), Order at 96–101.

risks associated with the projections for either party. EKPC would be agreeable to changing its tariff to actual real-time LMP at the EKPC load zone.

The Commission recognized in the referenced Order that there is a balancing of risk in establishing the appropriate rate, and determined that for the avoided energy calculation component that risk of economic feasibility should be placed on the QF instead of the utility's ratepayers. EKPC agrees, and that is the reason EKPC uses the PJM capacity market clearing price for the capacity component of the CoGen rate. The capacity market price is the best measure of a fair, just and reasonable rate.

The referenced Order found that the avoided capacity component for Kentucky Power should be the net CONE value. However, the net CONE value is not a market price. Rather, it is an administratively determined value that is used in establishing the Variable Resource Requirement curve, which in turn is an input to the capacity market clearing optimization performed by PJM. The price of capacity is established through the auction based on the interaction of offered supply and modeled demand (the VRR curve) in a manner that is similar to how PJM clears the energy market to establish the LMPs. All capacity resources must offer into the capacity auction, and Load Serving Entities like EKPC are responsible to pay the resulting clearing price associated with its load location in the PJM region. The appropriate avoided capacity cost, therefore, is the market clearing price.

EKPC uses the third incremental auction clearing capacity price for the avoided capacity component of its CoGen rate.

<u>Request 4b.</u> Provide recalculated tariffs with the revisions prescribed in the 2020-00174 Order. Include the work papers and a narrative explanation of how the revised rates were calculated.

<u>Response 4b.</u> The energy-only rates would still be the same for the projected time periods as filed in this case. The Capacity Credit per kW per month would be the same as those filed in the referenced 2020-00174 Order. EKPC and Kentucky Power would both reference the Area 3 Combustion Turbine CONE. However, EKPC does not believe that CONE is the appropriate value to be used in its avoided capacity calculation. Using CONE assumes that EKPC could avoid the investment cost of a new combustion turbine by securing capacity from a third party cogenerator or small power producer. That is not correct. EKPC has no plans for a new combustion turbine within the next five years, as demonstrated in its 2019 Integrated Resource Plan filed with the Commission in Case No. 2019-00096. Using CONE would significantly over-compensate new power supply and create additional cost burden to EKPC's owner-members and end-use retail members. The net effect would be to unnecessarily raise utility rates for customers in order to subsidize cogenerators or small power producers. Any new power supply investment incurred by EKPC must demonstrate that it is needed and will not result in wasteful duplication. Without demonstrating that it is the reasonable least-cost alternative, a utility could not obtain a Certificate of Public Convenience and Necessity for a new generation source. PURPA projects are not subject to this type of review. Purchasing capacity at CONE is not the least-cost alternative and would create a subsidization of the small power producer or cogeneration project. EKPC can purchase capacity from the PJM RPM auction at substantially lower rates than CONE and that is the capacity value that would be avoided with a small power producer or cogeneration project.