COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For 1) A Certificate Of Public Convenience And Necessity To Construct A Natural Gas-Fired Combined Cycle Generating Facility In Lawrence County, Kentucky; 2) A Site Compatibility Certificate; 3) A Certificate Of Public Convenience And Necessity To Construct A New Transmission Substation In Boyd County, Kentucky; 4) Approval Of A Short-Term Capacity Purchase Agreement; And 5) For All Other Required Approvals And Relief	)))))))))	Case No. 2026-00324

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

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I. INTRODUCTION

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

A. My name is Alex E. Vaughan. I am employed by American Electric Power Service Corporation ("AEPSC") as Vice President – Regulated Pricing & Strategic Transactions. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company ("Kentucky Power" or the "Company"). AEPSC supplies engineering, financing, accounting, regulatory, and similar planning and advisory services to AEP's regulated electric operating companies, including Kentucky Power.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from Bowling Green State University with a Bachelor's of Science degree in Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later became the PJM Settlements Lead Analyst, and in that role, I was responsible for reconciling AEP's settlement of its activities in the PJM Interconnection, LLC ("PJM") market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of

Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the Federal Energy Regulatory Commission. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing and Analysis, where I was responsible for cost of service, rate design, and special contract analysis for the AEP east operating companies. In September 2018, I was promoted to Director of Regulated Renewables and Pricing, at which time oversight of regulated renewable, new generation and fuel filings across the AEP operating Companies was added to my responsibilities. In June of 2022, I was promoted to Managing Director of Regulated Pricing. I assumed additional rate case filing responsibilities across the AEP system in August of 2024 and was promoted to my current position in September of 2026.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for assisting Kentucky Power and the other AEP electric utility operating companies in the preparation of their regulatory filings before this and other commissions under whose jurisdiction these companies provide electric service. My responsibilities include the oversight of cost-of-service analyses, rate design, special contracts, energy supply costs, new generation resource approvals, and various matters concerning serving new large load customers for the AEP operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have presented testimony on behalf of the AEP operating companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky, Tennessee, Indiana, Michigan, Texas, and Oklahoma. In Kentucky, I have testified before the Public Service

Commission of Kentucky (the "Commission") in several cases, most notably in five of Kentucky Power's base rate case proceedings (Case Nos. 2013-00197, 2014-00396, 2017-00179, 2020-00174, and 2023-00159), the proposed transfer of ownership of Kentucky Power in Case No. 2021-00481, Case No 2023-00008 (the Company's last 2-year fuel review), and Case No. 2025-00175 (Mitchell ELG CPCN). I am filing testimony in Case No. 2026-00323 where the Company is seeking approval of the Amended and Restated Electric Service Agreement (Tariff I.G.S.) by and between Kentucky Power and DB Long Hunts Data LLC[1] dated November 4, 2026 (the "TeraWulf ESA").

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit AEV – 1 Summary of Customer Benefits
2. Exhibit AEV – 2 Incremental Cost Analysis
3. Exhibit AEV – 3 Combined-Cycle Generation Project Cost of Service Summary
4. Exhibit AEV – 4 Combustion Turbine Break Even Analysis

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my Direct Testimony is to describe and support the following:

[1] DB Long Hunts Data LLC is a wholly owned subsidiary of TeraWulf Inc.("TeraWulf"). Throughout this testimony, the customer taking service under the TeraWulf ESA is referred to as TeraWulf.

- The customer benefits and protections included in the TeraWulf ESA.

- Kentucky Power's plan to obtain the capacity and energy necessary to meet its obligations under the TeraWulf ESA, including short-term capacity purchases ("Bridge Capacity Agreement") and the construction of a new 769[2] megawatt (MW) natural gas-fired combined cycle generating station at the Company's Big Sandy site (the "Combined-Cycle Generation Project"), including the alternatives considered and the bases for choosing the selected resources.

- The calculations demonstrating that the Company's existing customers will benefit from the Terawulf ESA being served by the Bridge Capacity Agreement, the Combined-Cycle Generation Project, and the new substation to be constructed to serve the TeraWulf facility (the "Venator Substation Project") and that, in fact, the generation and transmission cost of service for existing customers will decrease.

The TeraWulf ESA and the infrastructure investments proposed in this case provide approximately $2.1 billion in benefits and avoided costs to Kentucky Power's customers over the full term, including $100,000,000 in residential bill credits. This is a win for Kentucky Power's customers.

IV. TERAWULF ESA

Q. PLEASE DESCRIBE THE TERAWULF ESA?

A. The TeraWulf ESA is a special contract entered into under the large load provisions in the Company's Industrial General Service Tariff ("Tariff I.G.S."). The TeraWulf ESA identifies the amount and timing of new load the Muskie Data Campus, a 1,000 MW data center that TeraWulf will develop at the EastPark Industrial Park in Boyd and Greenup Counties, will add to the system. Under the TeraWulf ESA, the Company will provide capacity and energy to the Muskie Data Campus on the following load ramp schedule:

MONTH	TOTAL LOAD
October 2028	100 MW
November 2028	200 MW
December 2028	250 MW

[2] The installed capacity varies by season due to ambient temperatures, current estimate is 769 MW for the summer and 783 MW for the winter season on a net basis.

MONTH	TOTAL LOAD
February 2029	350 MW
March 2029	450 MW
April 2029	500 MW
July 2029	650 MW
August 2029	800 MW
September 2029	950 MW
October 2029	1,000 MW

Q. CAN YOU DESCRIBE THE LARGE LOAD PROVISIONS OF THE COMPANY'S TARIFF I.G.S.?

A. Yes. To meet its obligation to serve new large loads that locate within its service territory while also protecting its existing customers, the Company updated Tariff I.G.S. in Case No. 2024-00305 to include the following additional requirements for customers adding new or incremental loads of 150 MW or more:

- a 20-year contract term with a five year notice period for termination;
- a minimum monthly billing demand of at least 90% of the customer's highest established demand;
- a requirement to provide collateral equal to 24 times the customer's previous maximum monthly non-fuel bill, subject to review and adjustments;
- a one-time payment equal to five years of minimum billing in the event of permanent closure before the contract term expires; and
- a five-year notice requirement for reducing contract capacity, with exceptions for mutual agreement.

Q. DOES THE TERAWULF ESA HAVE ANY DEVIATIONS FROM THE STANDARD LARGE LOAD TARIFF PROVISIONS IN TARIFF I.G.S.?

A. Yes. The TeraWulf ESA includes five provisions that differ from the standard large load provisions in Tariff I.G.S. These provisions:

- obligate TeraWulf to provide $100 million in bill credits to the Company's residential customers;

- obligate TeraWulf to pay up to $465 million in carrying charges on costs incurred by Kentucky Power during the construction of the Combined-Cycle Generation Project;

- establish a mechanism for energy pricing during the period from the beginning of TeraWulf facility load ramp through the date the Combined-Cycle Generation Project is placed into service;

- provide for a variance from the full 20-year term for the second phase of the TeraWulf load ramp; and

- allow for a limited capacity reduction during the term not just arising from a facility closure.

I describe each in more detail below.

Q. DO ANY OF THE TERMS INCLUDED IN THE TERAWULF ESA RESULT IN TERAWULF RECEIVING A DISCOUNT FROM TARIFF I.G.S. OR A SUBSIDY FROM EXISTING CUSTOMERS?

A. No. None of the non-standard provisions in the TeraWulf ESA result in a discount from tariff rates or a subsidy from existing customers. Instead, the TeraWulf ESA includes provisions that directly result in cost-of-service benefits for existing customers and result in TeraWulf paying an amount above Commission approved tariff levels for service from the Company.

Q. DOES THE TERAWULF ESA ALTER THE CALCULATION METHODOLOGY OF SECURITY REQUIRED TO BE POSTED BY TERAWULF TO PROTECT THE COMPANY'S EXISTING CUSTOMERS?

A. No. TeraWulf is providing security based on the requirements of the large load provisions of Tariff I.G.S. TeraWulf is currently committed to providing $756,013,200 in the form of a letter of credit as security. The amount of security is expected to increase as TeraWulf completes its load ramp.

Q. PLEASE DESCRIBE THE RESIDENTIAL BILL CREDITS.

A. Through the TeraWulf ESA, TeraWulf has agreed to fund a rate credit for residential customers ("Residential Bill Credits") totaling $100 million equally divided over the first 10 years of the contract. The Residential Bill Credits are in addition to payments for electric service under the terms of the TeraWulf ESA. The Residential Bill Credits will be applied to customer bills in January, February, and March (for usage in December, January, and February). The Residential Bill Credits will first appear on customer bills in January 2029. The $100 million in Residential Bill Credits is a direct benefit to existing customers that would not be available without the TeraWulf ESA. For the average residential customer, the Residential Bill Credits could be approximately $26 per month during the winter heating season. Please also refer to Table AJE-1 in Company Witness Elliott's Direct Testimony for examples of how the Company might propose to design the bill credits based on usage.

Q. PLEASE DESCRIBE THE RETURN ON LIFE TO DATE COSTS OF THE COMBINED-CYCLE GENERATION PROJECT.

A. As part of the long-term solution to serve system load growth, Kentucky Power is proposing to build the Combined-Cycle Generation Project, which I will discuss in more detail later. To help facilitate the construction of the Combined-Cycle Generation Project, the TeraWulf ESA includes a provision under which TeraWulf has agreed to pay materially all of the estimated carrying charges associated with the Combined-Cycle Generation Project while it is under construction. Specifically, TeraWulf has agreed to pay up to $465 million of carrying charges during the construction period of the Combined-Cycle Generation Project. Under the TeraWulf ESA, Kentucky Power will bill TeraWulf

quarterly for carrying charges on the life-to-date total investment (cash spent by the Company) to construct the Combined-Cycle Generation Project at its Commission-authorized cost of capital.

Because of this provision in the TeraWulf ESA, Kentucky Power will not accrue allowance for funds used during construction ("AFUDC") following regulatory approval, which results in a lower cost asset and rate base when the plant goes into service in 2031. This provision in the TeraWulf ESA ensures that TeraWulf is directly paying for the financing charges associated with serving system growth and not the Company's existing customers. Had the Company utilized AFUDC instead of this approach, all customers would pay for the carrying charges incurred during construction over the 40-year life of the Combined-Cycle Generation Project. Avoiding capitalization of $465 million in carrying charges via AFUDC is worth approximately $1.3 billion in total cost of service revenue requirement. Simply put, this provision of the TeraWulf ESA reduces the cost of service for the Combined-Cycle Generation Project by over a billion dollars and ensures that existing customers do not finance the cost of the new plant after approval even if TeraWulf were to exit the Company's system after its contract term is over.

If the total financing costs of the Combined-Cycle Generation Project turn out to be greater than $465 million, any excess would be accrued as AFUDC on the plant balance or covered by an additional large load ESA. Regardless, the roughly $1.3 billion benefit provided by the TeraWulf ESA would remain the same.

Q. PLEASE DESCRIBE THE TRANSITIONAL ENERGY PRICING PROVISION OF THE TERAWULF ESA.

A. The TeraWulf ESA includes a provision that establishes how TeraWulf's fuel costs will be billed during the period between when it begins taking service in October 2028 and when the Combined-Cycle Generation Project goes into service in April 2031 (the "Transition Period"). During the Transition Period, TeraWulf has agreed to pay for all of its energy usage at the applicable PJM Locational Marginal Prices ("LMP"), which is commonly referred to as the marginal cost of energy. To facilitate the billing of this purchased power and the associated load billing line items that would normally be included in the Company's Fuel Adjustment Clause ("FAC"), the Company will establish a separate PJM subaccount for TeraWulf's load. This separate PJM subaccount will ensure that the charges can be tracked in total and facilitate monthly billing.

This provision in the TeraWulf ESA provides additional protections for existing customers beyond those already included in the large load provisions of Tariff I.G.S. This additional protection ensures that the addition of the TeraWulf load during the Transition Period does not lead to increased fuel costs for existing customers in the form of additional market purchases of energy. The PJM market purchases made to serve TeraWulf's energy requirements during the Transition Period will be fully recovered from TeraWulf and will not be included in the calculation of the Company's monthly fuel adjustment clause rates.

Likewise, TeraWulf will not pay for the costs included in the Company's FAC during the Transition Period. TeraWulf will be billed the base fuel rate each month per Tariff I.G.S. The Company will then compare the base fuel rate to the actual cost incurred in the PJM subaccount to serve TeraWulf and bill TeraWulf the difference. This amount

could be a net charge or credit on TeraWulf's bill depending on the cost of market energy that month. Once the Combined-Cycle Generation Project is placed into service, the transitional energy pricing provision of the TeraWulf ESA will end and TeraWulf will be billed for fuel at the Company's otherwise applicable rates, including the fuel costs of the Combined-Cycle Generation Project.

The Company estimates that the transitional energy pricing provision of the TeraWulf ESA will protect existing customers from $195 million of fuel cost increases that would otherwise materialize under standard tariff provisions that would need to be addressed through cost allocation in future fuel review filings.

Q. HOW DOES THE CONTRACT TERM OF THE TERAWULF ESA DIFFER FROM THE LARGE LOAD PROVISIONS OF TARIFF I.G.S.?

A. The large load provisions of Tariff I.G.S. provide for a contract term of 20 years. Under the TeraWulf ESA, the first 500 MW of TeraWulf load will have the same 20-year term as included in the standard large load provisions of Tariff I.G.S. The Company has agreed to a 15-year contract term for the second 500 MW of TeraWulf load, once it has completed its agreed upon load ramp. The shorter contract term for the second 500 MW load (of the total 1000 MW project) provides TeraWulf with a measure of long-term flexibility as consideration for the other provisions in the TeraWulf ESA that are in excess, or above and beyond, the financial commitments included in the standard large load provisions of Tariff I.G.S. When taken as a whole, the contract term for the entire 1000 MW project is 17.5 years, once the load ramps are completed. This shortened term is still longer than any other contract term included in a Commission-approved large load tariff for the Company's

affiliates in their respective jurisdictions and represents a material long-term financial commitment by TeraWulf.

Q. HOW DOES THE CAPACITY REDUCTION PROVISION OF THE TERAWULF ESA DIFFER FROM THE STANDARD LARGE LOAD PROVISIONS IN TARIFF I.G.S.?

A. The large load provisions of the Company's Tariff I.G.S. do not address the possibility of an allowable capacity reduction beyond the limited reductions currently included in the tariff. The large load provisions in the comparable tariffs approved for use by the Company's affiliates in their respective jurisdictions contain language that addresses this possibility. The Company agreed to include language in the TeraWulf ESA allowing TeraWulf to reduce load to allow TeraWulf operational flexibility in the future in consideration of the significant near-term benefits TeraWulf has agreed to provide the Company's existing customers through the other special contract provisions discussed previously. While the TeraWulf ESA includes a provision expanding the rights of TeraWulf to reduce capacity in excess of what is provided in the tariff, that right is conditioned to protect existing customers. First, TeraWulf cannot utilize the expanded reduction rights during the first 10 years of the term. Second, TeraWulf must provide at least 42 months' notice prior to a reduction. Finally, TeraWulf must pay an exit fee associated with any capacity reduction.

Q. WHAT OTHER RATE BENEFITS WILL EXISTING CUSTOMERS REALIZE FROM THE INCREASE IN LOAD THAT IS FACILITATED BY THE TERAWULF ESA?

A. In addition to the Residential Bill Credits described above, existing customers will also realize benefits through lower rate billings for surcharges that recover existing fixed costs. These surcharges include the Securitization Savings Rider ("SSR"), the Environmental Surcharge ("ES"), the Generation Rider ("GR"), and the Decommissioning Rider ("DR").[3]. The rates for these surcharges are calculated by dividing the associated fixed costs by billing units. As the TeraWulf load ramps up and its associated billing units increase, the fixed costs associated with these surcharges will be spread over a much larger base of billing units. This is a function of the general "rate equation" where the costs in the numerator remain unchanged while the billing units in the denominator increase substantially. At maximum contract capacity, the TeraWulf load will approximately double the amount of billing units currently in the Company's system. At maximum contract capacity, the Company estimates these benefits to be:

[3] The DR revenue requirement recovery benefit is much lower, in the $200,000 to $300,000 range annually at full TeraWulf ESA load due to the small revenue requirement being collected in the DR. For this reason, those amounts have been left out of the rider savings tables found elsewhere in this testimony, but if more significant amounts are recovered through the DR in the future savings to existing customers from the TeraWulf ESA load growth would increase.

Table AEV-1

	2029	2030	2031	2032
SSR Savings	$ 14,166,796	$ 21,383,843	$ 21,383,843	$ 21,383,843
ES Savings	$ 11,363,665	$ 17,152,701	$ 17,152,701	$ 17,152,701
GR Savings	$ 8,337,960	$ 12,997,665	$ 3,249,416	$ -
Residential Bill Credits	$ 10,000,000	$ 10,000,000	$ 10,000,000	$ 10,000,000
Total Existing Customer Savings	$ 43,868,420	$ 61,534,209	$ 51,785,960	$ 48,536,544
Current Total Revenue	$ 734,884,728			
Average % Reduction to Overall Revenues *	6.0%	8.4%	7.0%	6.6%

*Class allocation has not been completed, and impacts are not to be interpreted as a specific rate decrease to a particular class of customers.

Q. TAKEN IN TOTAL, WHAT IS THE ESTIMATED AMOUNT OF CUSTOMER RATE BENEFITS THAT THE TERAWULF ESA PROVIDES FOR?

A. The combination of the surcharge rate benefits described above and the other terms included in the TeraWulf ESA produces the benefits for existing customers described in Exhibit AEV-1 and summarized below:

Table AEV-2

TeraWulf ESA Provisions	Life of Contract $
Avoided Return on and of CC Financing Charges	$ 1,302,095,123
Residential Bill Credits	$ 100,000,000
Transitional Energy - Fuel Cost Savings	$ 195,246,237
Total TeraWulf ESA Additional Benefits	$ 1,597,341,360
Standard Tariff Items	
SSR Savings	$ 334,924,435
ES Savings	$ 200,043,381
Total Standard Benefits	$ 534,967,816
Total Customer Benefits	**$ 2,132,309,176**

Q. DOES THE TERAWULF ESA COVER ALL INCREMENTAL COSTS TO SERVE THE CONTRACTED LOAD?

A. Yes, it does. Exhibit AEV-2 provides annual details regarding incremental non-fuel costs to serve the TeraWulf ESA load and expected revenues the load will produce at current rate levels. The estimated incremental non-fuel generation capacity and transmission service costs are provided in Exhibit AEV-2. During the period of time prior to the Combined-Cycle Generation Project coming online, the Company has procured bridge capacity resources that I will discuss below. Those along with the cost of providing network transmission service to TeraWulf are the main non-fuel incremental costs to serve the TeraWulf ESA. The Bridge Capacity Agreement costs are contractual in nature. The incremental cost of transmission service is based upon current forecast estimates and includes an "all other things being equal" assumption, so I would characterize it as a conservatively high estimate of the cost level. For example, if additional loads come online over the same period of time it would allocate system costs away from the Company and lower the incremental costs associated with providing network transmission service. Additionally, the Transitional Energy Pricing clause of the TeraWulf ESA provides for cost recovery of all incremental fuel and energy-related costs.

The expected revenues under the current IGS Transmission tariff rates produced by the TeraWulf load are estimated to meet or exceed the incremental cost to serve during the transitional load ramp period and when the Combined-Cycle Generation Project comes online. Furthermore, the Customer has also agreed to pay for materially all of the construction financing carrying charges to construct the proposed Combined-Cycle

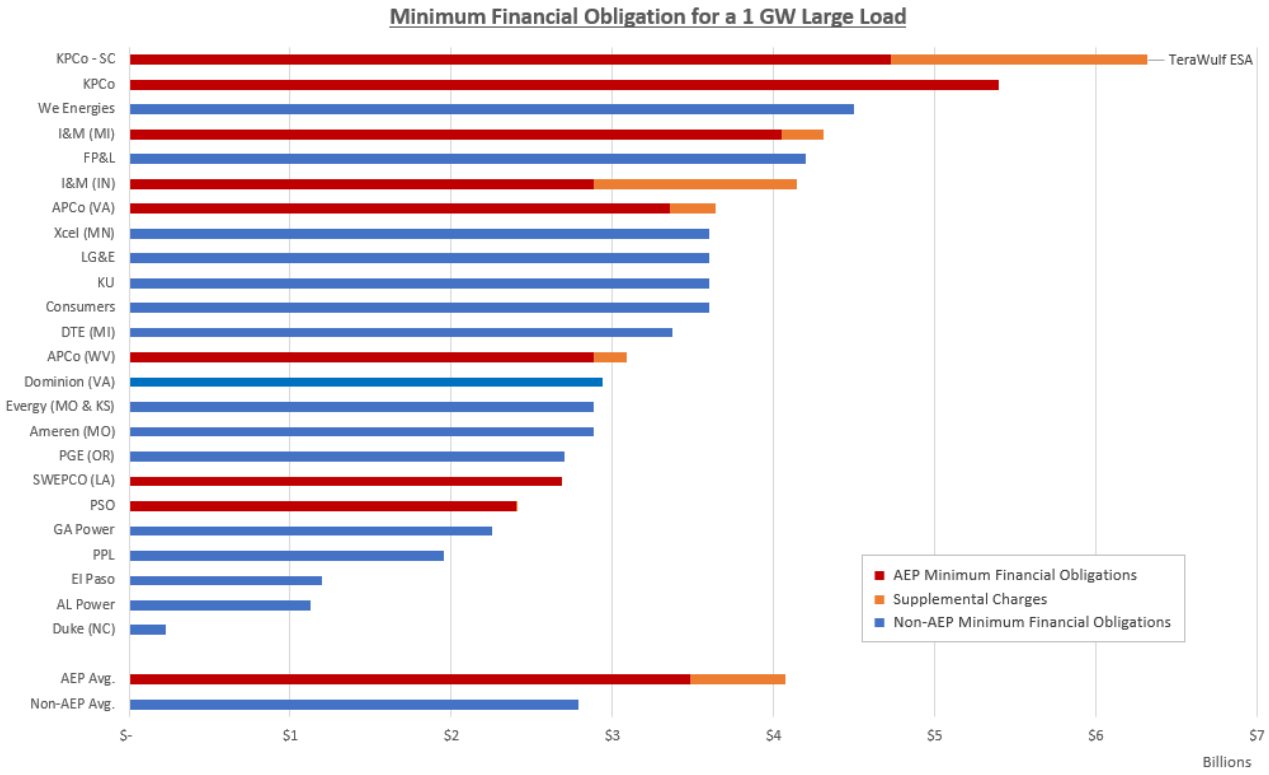
Generation Project which will be a key system asset addition that will aid the Company in serving the TeraWulf ESA load over the longer term.

Q. HOW DO THE FINANCIAL COMMITMENTS UNDER THE TERAWULF ESA COMPARE TO THE COMPANY'S STANDARD LARGE LOAD TARIFF OFFERING AND THOSE OF OTHER PEER UTILITIES?

A. The Commission-approved large load provisions included in Tariff I.G.S. are first in class when compared to those approved for the Company's peers across the country. The TeraWulf ESA and its special provisions expand upon those industry leading financial commitments and protections for existing customers. Table AEV-3 illustrates this by comparing the minimum financial obligations under the terms[4] of various approved large load tariffs across the country.

[4] The analysis in the table utilizes the approved terms in the various tariff offerings for each identified utility and the same assumed incremental cost to serve 1GW of large load growth to put the approved tariff terms on an apples to apples basis from a cost perspective.

Table AEV-3



Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION TO THE COMMISSION REGARDING APPROVAL OF THE TERAWULF ESA?

A. The TeraWulf ESA is a great example of a large load customer taking cost responsibility for the costs it will cause a utility provider to incur to serve its load. TeraWulf has leaned into that cost responsibility and has gone above and beyond what could be achieved under the standard large load provisions of the Company's Tariff I.G.S. by making additional financial commitments around residential bill credits, the carrying charges on the proposed Combined-Cycle Generation Project, and the Transition Period energy pricing mechanism. These commitments will ensure that the load growth from the TeraWulf facility benefits the Company's existing customers.

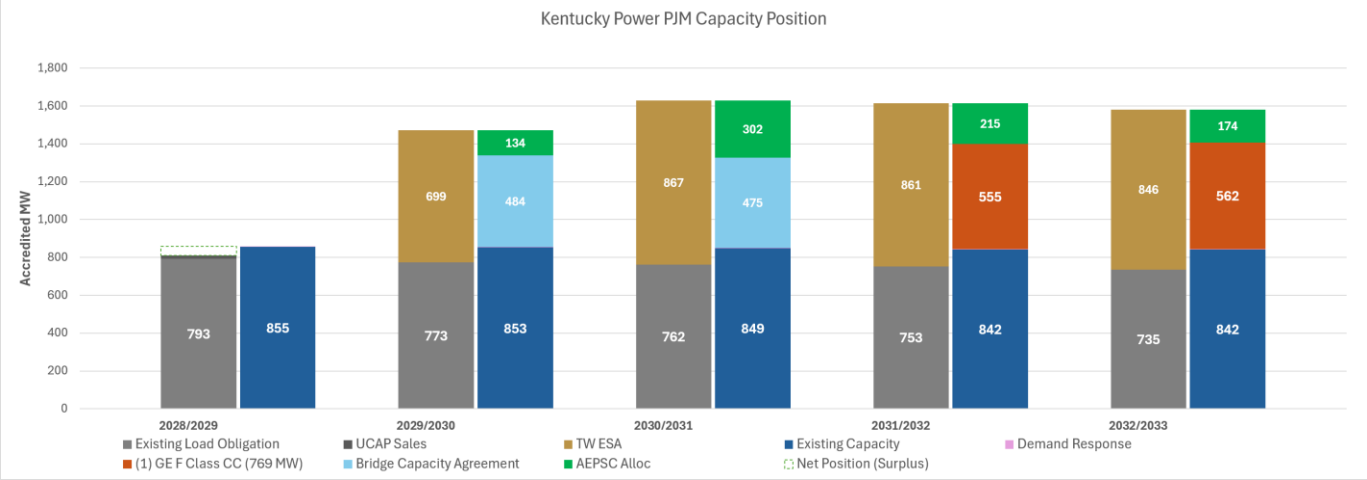
In my position with AEPSC, I am involved in the development of large load tariff provisions, related regulatory filings, and contract activities for large loads across the AEP footprint. I can say without hesitation, that to my knowledge, the TeraWulf ESA provides the greatest level of benefits and protections for existing customers of any large load agreement. The TeraWulf ESA adequately protects existing customers from unreasonable costs or risks and provides for adequate, efficient, and reasonable service. The Commission should approve the TeraWulf ESA.

V. KENTUCKY POWER'S CAPACITY PLAN

Q. HOW DOES THE TERAWULF ESA AFFECT KENTUCKY POWER'S CAPACITY POSITION?

A. As described in the Company Witness Elliott's Direct Testimony, without adding capacity, the TeraWulf ESA will create a capacity need for Kentucky Power. As can be seen in Table AEV-4, the TeraWulf ESA adds roughly 700 MW of UCAP obligation to the Company's capacity requirement in the 29/30 delivery year and grows to approximately 850 MW of UCAP as the contract reaches its ultimate capacity level of 1,000 MW.

Table AEV-4



The actual amount of UCAP related to the TeraWulf ESA will fluctuate over time as PJM's forecast pool requirement factors that determine the required amount of UCAP vary from delivery year to delivery year.

Q. HOW DOES KENTUCKY POWER INTEND TO ADDRESS THIS CAPACITY NEED?

A. Kentucky Power intends to address the capacity need in a multi-step process anchored around the new Combined-Cycle Generation Project. Because the Combined-Cycle Generation Project is not scheduled to be placed into service until April 2031 and the load ramp under the TeraWulf ESA runs from October 2028 through October 2029, the Company is entering into the Bridge Capacity Agreement to provide capacity to meet the requirements of the TeraWulf ESA until such time as the Combined-Cycle Generation Project is placed in commercial operation.

Q. CAN YOU DESCRIBE THE BRIDGE CAPACITY AGREEMENT?

A. The Bridge Capacity agreement is a two-year capacity agreement between AGR and Kentucky Power through which Kentucky Power will partially fill the balance of the

Company's capacity requirement. Under the Bridge Capacity Agreement, Kentucky Power will purchase 262.9 MW of ICAP from the Wolf Hills natural gas combustion turbine plant in Virginia and 430.3 MW from AGR's share of the OVEC/IKEC facilities located in Ohio and Indiana. The delivery term of the Bridge Capacity Agreement is from June 1, 2029 through May 31, 2031. The contract price is equal to the PJM BRA Auction Price in the applicable PJM Zone where the Facility is located for each such day of the applicable PJM Delivery Year. All of the capacity resources included in the Bridge Capacity Agreement are physically located inside the AEP transmission zone and are deliverable to the Company's load.

Q. IF THE BRIDGE CAPACITY AGREEMENT IS DESIGNED TO PROVIDE CAPACITY FOR THE TERAWULF ESA DURING THE PERIOD BEFORE THE COMBINED-CYCLE GENERATION PROJECT IS IN SERVICE, WHY DOES IT NOT START UNTIL JUNE 1, 2029?

A. Because the Muskie Data Campus load will not come on-line until after summer capacity season in 2028, the load is not included in the Company's 2028/2029 PJM planning year capacity requirement. Accordingly, the Company does not need capacity to meet the load until June 1, 2029 for the 2029/2030 PJM planning year.

Q. AGR IS AN AFFILIATE OF KENTUCKY POWER. IS THE PRICE PAID FOR CAPACITY UNDER THE BRIDGE CAPACITY AGREEMENT THE LOWER OF COST OR MARKET?

A. Yes. This price paid under the Bridge Capacity Agreement is the market price for capacity and is lower than the cost of the capacity.

Q. DO THE BRIDGE CAPACITY AGREEMENT AND THE COMBINED CYCLE PLANT MEET THE FULL CAPACITY REQUIREMENT?

A. No. As shown in Table AEV-3, the Bridge Capacity Agreement and the Combined-Cycle Generation Project do not meet the full capacity obligation under the TeraWulf ESA. To meet the remainder, the AEPSC Commercial Operations team has procured additional capacity purchase agreements on behalf of the AEP operating companies included in the fixed resource requirement ("FRR") plan to layer in as annual capacity purchases for the operating companies as needed. This process is similar to how the Company addresses capacity needs now. This purchase is being made by AEPSC on behalf of the FRR operating companies, will be included in the Company's joint FRR plan with its affiliates, and the relative amount of the AEPSC purchase needed by each operating company each year will be allocated to it to cover the respective load growth each delivery year.

Q. ARE THE BRIDGE CAPACITY PURCHASE AGREEMENT AND THE AEPSC ALLOCATION PROCESS THE COMPANY'S LONG-TERM CAPACITY SOLUTION?

A. No, they are not. Once the Commission has approved the TeraWulf ESA, and any other large load service agreement the Company is currently working on, the Company will issue RFPs for appropriate longer-term capacity and energy solutions for the new system requirements.

Q. PLEASE DESCRIBE THE COMBINED-CYCLE GENERATION PROJECT.

A. The Combined-Cycle Generation Project will consist of two natural gas-fired combustion turbine generators, associated heat recovery steam generators, one steam turbine generator, environmental control equipment, and the balance-of-plant facilities necessary for the safe,

reliable, and environmentally compliant operation of the generating facility, including electrical interconnection, natural gas, water, cooling, and related support systems. The Combined-Cycle Generation Project will be constructed on the site of Kentucky Power's Big Sandy plant in Lawrence County, Kentucky. Additional detail about the construction and operation of the Combined-Cycle Generation Project is included in the Direct Testimonies of Company Witnesses Dilley and Lewis.

Q. HOW DID KENTUCKY POWER DETERMINE THAT THE COMBINED-CYCLE GENERATION PROJECT WAS THE BEST ALTERNATIVE TO MEET ITS CAPACITY NEEDS?

A. As it does with all generation resource additions, Kentucky Power engaged in a thorough review of all reasonable alternatives to meet its need. The Company is in need of dispatchable generation that can achieve a high level of availability to aid in serving the high load factor system addition. Additionally, the Customer has large energy needs that require baseload, dispatchable energy. As described in Company Witness Elliott's Direct Testimony, the Company issued a request for proposals ("RFP") for in-state, dispatchable generation, to which there was no response. The Company recognizes that being a price taker in the current PJM market for both capacity and energy for demand this high, is not a viable option, nor is it a reasonable long-term solution given the current state of the PJM market.

Q. DID THE COMPANY RUN A CAPACITY EXPANSION MODEL MORE COMMONLY REFERRED TO AS AN INTEGRATED RESOURCE PLAN TO EVALUATE ALTERNATIVES?

A. No. The Company performed a market analysis which would render an Integrated Resource Plan ("IRP") moot. An IRP is a complicated and intricate modeling exercise that is costly and requires months to complete. An IRP does not represent the Company's decisions regarding the generation resources it utilizes to serve its customers. Instead, an IRP is intentionally a snapshot in time and is a tool used to help inform the Company's policy decisions and strategies. Additionally, the IRP planning tool does not perform its analyses utilizing retail revenue requirement calculations for the generation options. Therefore, the portfolios it selects are not necessarily the lowest cost options for the Company's customers. IRPs are planning tools, when a need emerges that was not foreseen in a previous IRP it is more cost effective, time efficient, and prudent to go to the market and evaluate what options are available to the Company to serve the energy and capacity needs of the emergent system need.

The Company performs revenue requirement analyses for any potential actual resources as part of its ultimate resource selection process, accounting for real-world resource availability and costs that are obtained through an RFP or other market evaluations. This revenue requirement analysis drives the Company's resource acquisition process as it evaluates the reasonable, least cost option of available generation to provide reliable service to its customers.

Q. PLEASE PROVIDE THE BACKGROUND FOR HOW THE COMPANY DETERMINED POSSIBLE ALTERNATIVES TO MEET ITS UPCOMING NEEDS.

A. Kentucky Power determined that a capacity need existed with a need to cover its winter peak load. Then, Kentucky Power signed a contract with TeraWulf for an incremental one gigawatt of demand. TeraWulf's addition to the system requires dispatchable generation that can achieve a high level of availability. The Company then conducted an RFP for in-state, dispatchable generation, to which there was no response. The Company recognized that being a long-term price taker in the current PJM market for both capacity and energy for demand this high is not a viable option. Which brought the Company to the conclusion to analyze the natural gas combined cycle plant against solar, wind, and a simple-cycle combustion turbine ("CT"). However, the Company notes that renewables do not provide dispatchable energy nor provide large amounts of accredited capacity given PJM's Effective Load Carrying Capability ("ELCC") ratings.

Q. WHY DID KENTUCKY POWER CHOOSE A COMBINED CYCLE PROJECT OVER A SIMPLE-CYCLE COMBUSTION TURBINE?

A. The nature of the Company's new system needs was the main driver behind the Company's decision to pursue a combined cycle natural gas project rather than a simple-cycle CT project. The addition of the high load factor TeraWulf ESA made it apparent to the Company that a more energy dense resource was needed, therefore the decision was made to pursue the Combined-Cycle Generation Project because of its greater efficiency and expected energy production. Furthermore, the addition of the heat recovery steam generator

("HRSG") added more ICAP and UCAP capacity that the Company needs than the equivalent CT project would.

Q. DID YOU PREPARE A BREAK-EVEN ANALYSIS OF THE INCREASED CAPITAL COST OF A COMBINED-CYCLE SOLUTION VERSUS A CT AS FURTHER VALIDATION OF THE COMPANY'S DECISION?

A. Yes. This analysis shows at what price market energy would have to be priced over the Combined-Cycle Generation Project's life to make the CT, which costs less from a capital outlay perspective but also produces a great deal fewer MWh of energy, a more prudent investment for the Company. The analysis shows that nominally over the forty-year life of the project PJM LMPs would have to average roughly $8/MWh. Said another way, if one reasonably expected to be able to purchase market energy at $8/MWh over the 40 year period, then the additional capital cost of the Combined-Cycle Generation Project would not be worth the additional energy the project provides. This is not a reasonable or prudent assumption. LMPs year to date for the Company's load aggregate have averaged roughly $60/MWh. The break-even analysis is provided as Exhibit AEV-4.

Q. WHAT NON DISPATCHABLE ALTERNATIVES DID THE COMPANY EVALUATE TO ADDRESS THE UPCOMING CAPACITY NEED?

A. Kentucky Power analyzed the Project against solar and wind resources. While the Company needs dispatchable generation that can achieve a high level of availability, the Company felt it was an important basing point to present the analysis of these renewable sources of generation. Renewables have a place in the system, but they do not provide dispatchable energy nor provide large amounts of accredited capacity given PJM's ELCC ratings.

Q. WHY DID KENTUCKY POWER NOT CONSIDER OTHER TECHNOLOGY TYPES IN ITS ANALYSIS?

A. The F Class combustion turbines have been in operation for well over 25 years and are a proven technology with significant amounts of industry maintenance and operations support. The HRSG and steam turbine technologies utilized in natural gas combined-cycle generating units are also well known and supported within the industry. The low heat rate that can be achieved by a combined cycle configuration also provides a great energy benefit in the form of energy that is typically the lowest cost among all dispatchable generation besides nuclear.

New coal units are not economically feasible in today's environmental climate given the high installed cost largely driven by compliance with environmental regulations. As for battery energy storage systems as an option, storage suffers from an accredited capacity discount compared to other dispatchable resources. Storage is not an optimal solution for fulfilling the needs of both capacity and energy the Company is attempting to address with its next addition of generation capacity.

Q. PLEASE DESCRIBE THE MARKET ALTERNATIVE YOU EVALUATED AND WHY IT IS NOT A VIABLE OPTION.

A. Typically, a market comparison would include the purchase of the capacity and energy commodities in the PJM market. However, we find ourselves in a unique position in that the market cannot support its forecasted long-term resource adequacy targets, let alone additional demand from the Company should the Company not construct the contemplated natural gas plant discussed earlier. PJM discussed this issue in a recent report:[5]

[5] 2027/2028 Base Residual Auction Reserve Target Shortfall Report February 9, 2026

> The auction results reveal that PJM has entered a critical period, or "transition gap," where demand growth has temporarily outpaced infrastructure development. This shortfall is due to a confluence between an unprecedented surge in data center load, the realities of global supply chain friction [as detailed in PJM's recent Periodic Review Filing (PRF)], the inability for developers to timely respond to pricing signals due, and the queue transition. This "transition gap" is further exacerbated by the deactivation of legacy thermal assets, which depleted the region's historical capacity surplus precisely before the onset of the current demand growth. Given the demand forecasts, a reliability deficit was practically unavoidable, as the required volume of new generation could not be built fast enough to match the surge in consumption.

This reliability deficit grew with the most recent 2028/2029 BRA. This market dynamic was reinforced by a recently published PJM publication[6] that shows the expected gap between supply and demand to widen over the long-term.

Given this current market dynamic, it would not be prudent or reasonable for the Company to utilize a market option long-term to plan for this portion of its generation portfolio. As for the energy commodity, the market evaluation would utilize forecasted locational marginal prices LMPs which by definition are likely to be more expensive than the energy produced by the Combined-Cycle Generation Project. This is because the natural gas plant evaluated is dispatched on an economic basis meaning that it runs when the internal cost of generating is less than the LMP. This was recognized by the Commission in Case No. 2025-00175 when they stated:

> Notably, the market for generation capacity is tightening at all levels from the ability to obtain new generators for generating facilities to the availability of PPAs for energy and capacity and limited excess supplies in energy and capacity markets such as those operated by PJM. In that environment, the Commission is reluctant to place Kentucky Power's customers at the mercy of merchant or other third party generators, or energy markets for a significant majority of their load.[7]

[6] 2026 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS), published October 30, 2026. https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-pjm-elcc-rrs.pdf

[7] Final Order Case No. 2025-00175 at page 56

For these reasons, the Company concluded that the Market Alternative is not feasible or a prudent long-term option for the Company regarding the increment of capacity and energy in question.

Q. PLEASE DESCRIBE THE ANALYSIS YOU PREPARED AND COMPARED FOR THE PROJECT AND THE RENEWABLE OPTIONS.

A. I prepared an analysis of the hourly load needs of the Company, inclusive of TeraWulf's load, against the hourly generation, inclusive of the Company's current generation, of the various options that would produce the same amount of accredited capacity within PJM. The summary results are included below as Table AEV-5

Table AEV-5 – Comparison of Generation Alternatives

	CC Gen Project	All Solar	50% Solar 50% Wind	All Wind
New ICAP[8] (MWs)	769	7,209	4,364	1,518
Total ICAP (MWs)	1,845	8,285	5,439	2,593
UCAP (MWs)	1,454	1,454	1,453	1,454
Capital Cost of New Generation ($ millions)	$2,846	$22,378	$14,375	$6,372
Market Exposure (MWhs)	3,126,287	4,871,678	3,911,358	5,053,755
Net Present Value of Revenue Requirement ($ millions)	$3,670	$22,465	$14,778	$7,091

[8] ICAP is the measure of "installed capacity" while UCAP is "unforced capacity" also known as accredited capacity or the amount of capacity which the Company can utilize in its planning purposes for meeting the capacity obligations of its native load customers.

Q. WHERE DID YOU SOURCE THE MAIN INPUTS FOR THE ANALYSIS CONTAINED IN TABLE AEV-4?

A. The inputs were sourced from different internal sources as described below:

- Kentucky Power's hourly load: The current load was an average of three years of historical load on the Company's system. TeraWulf's estimated load was then layered in on top of that average.

- Kentucky Power's current hourly generation: The Company utilized its most recent net energy cost forecast for the existing Mitchell and Big Sandy units, which is an output of the Plexos modeling software.

- The Combined-Cycle Generation Project's hourly generation: The Company utilized an estimated unit dispatch model (also from Plexos) for the Combined-Cycle Generation Project.

- The Renewable resources hourly generation: This was an average of the Company's sister company's owned and contracted for resources in PJM. For solar, this was a mix of four PPAs with an average capacity of 13.75 MW and three owned facilities with an average capacity of approximately 87 MW. For wind, this was a mix of six PPAs with an average capacity of 82.5 MW and two owned facilities with an average capacity of approximately 172 MW.

- Cost assumptions of the resources: the total capital cost for the Combined-Cycle Generation Project were provided by Company Witness Dilley. The capital costs for solar and wind were sourced from the preparation of the 2027 IRP.

Q. PLEASE EXPLAIN WHY THE COMPANY WOULD STILL HAVE TO MAKE MARKET PURCHASES WITH THE ADDITION OF THE COMBINED-CYCLE GENERATION PROJECT.

A. As described before, this need for purchase arises because the Company's dispatchable generation is dispatched on an economic basis, meaning that the Company's generation resources run when their internal cost of generating is less than the LMP. The market purchases would occur during times where it is more economical to buy from the market than run the Company's dispatchable resources. As shown in Tables AEV-6 and AEV-7 below, the Company's total load could be covered by the energy potential of its installed

capacity after the addition of the Combined-Cycle Generation Project. Table AEV-7 illustrates the Company's monthly peak load MW versus the installed capacity MW after the addition of the Combined-Cycle Generation Project. In summary, although the Company's installed capacity could cover its average energy requirements, the Company will continue to purchase market energy when doing so will reduce customers' costs.

Table AEV-6

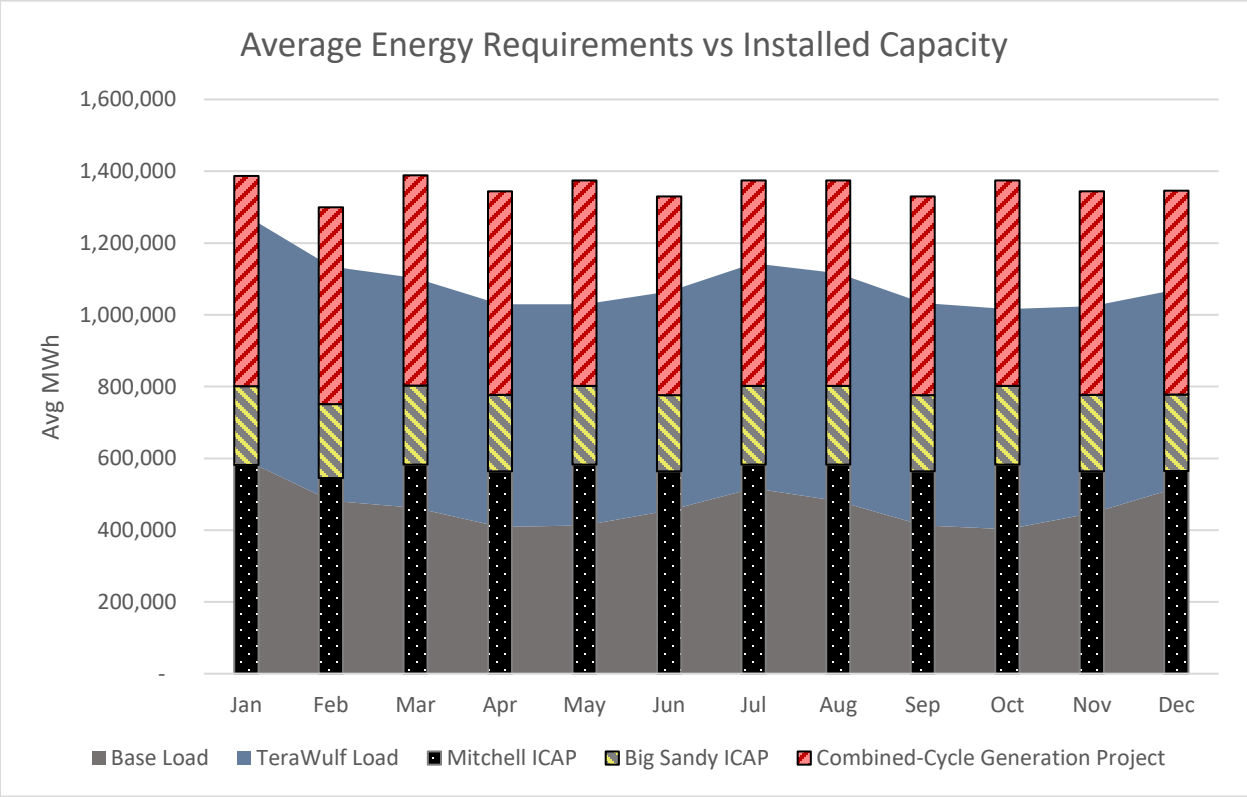
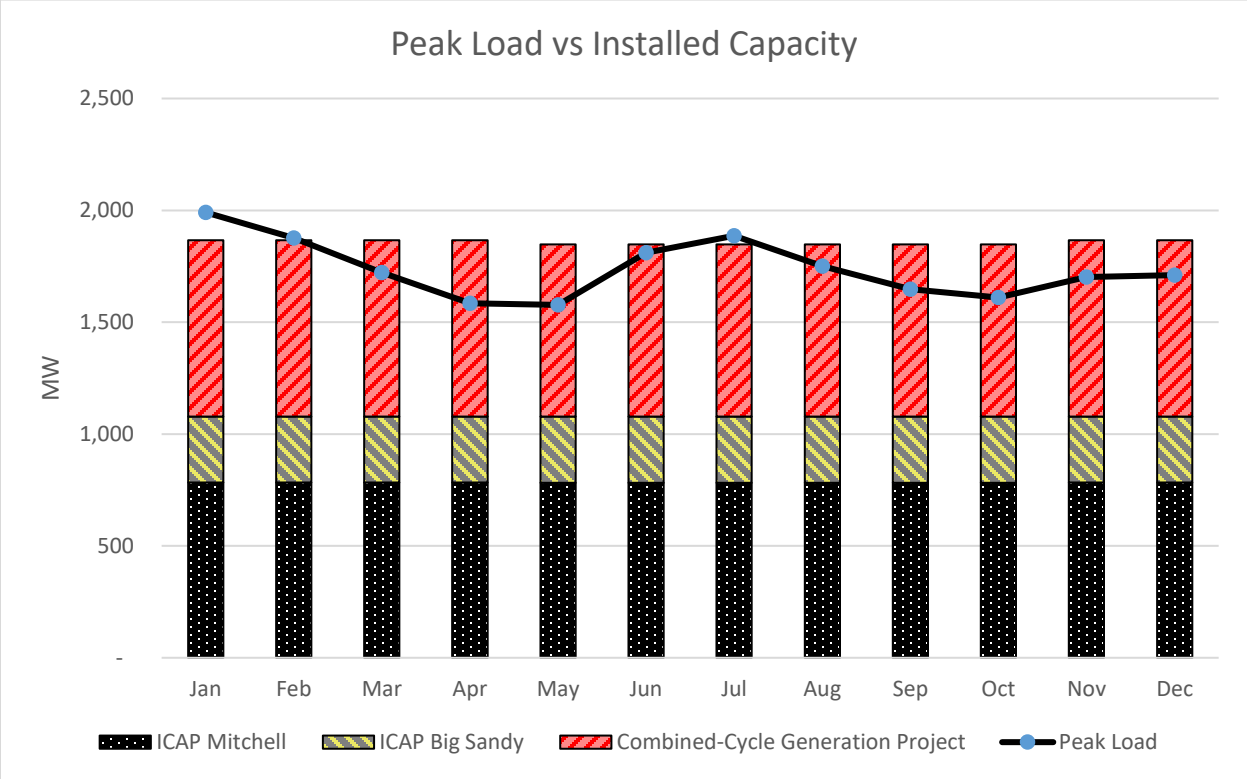


Table AEV-7



Q. WHAT ARE YOUR CONCLUSIONS FROM THE ALTERNATIVES ANALYSIS?

A. The Company has a capacity need and has conducted a thorough analysis of alternatives to select the proposed Combined-Cycle Generation Project. As can be seen in Table AEV-5, the construction of installed capacity that would be required to achieve the same level of accredited capacity from non-dispatchable resources would cause rate impact and affordability issues, in addition to exposing the Company to the energy market on a larger scale. Furthermore, this Commission and associated stakeholders have been clear in many cases that their preference is for in-state, dispatchable "steel in the ground.". The proposed

Combined-Cycle Generation Project meets the Company's needs, the preference for in-state dispatchable generation, and is the least-cost, most reasonable solution.

Q. HOW DOES THE DECISION TO BUILD A 40 YEAR ASSET LINE UP WITH THE SYSTEM GROWTH DRIVEN BY A 17.5 YEAR CONTRACT?

A. Although the Company is facing the potential of once-in-a-generation system load growth, it must remain focused on long-term, portfolio-based system planning. Just because the Company may have a need to add new supply resources now to meet system needs, it does not mean that the Company will not have multiple opportunities to rebalance the total size and makeup of the generation supply portfolio in the coming years. For example, the Company has roughly 1,100 MW of current generation capacity resources that are potentially set to retire by 2041. As these resources retire, or new supply contracts end, the Company will have multiple opportunities, and the advantage of multiple years of operational experience with new large load customers, to rebalance the generation supply portfolio and adjust the size and terms of new resources. Simply put, it is not as simple and direct as comparing the proposed TeraWulf ESA contract term to the depreciable life of a new generation asset to determine the reasonableness of how it fits into the Company's portfolio.

VI. REVENUE REQUIREMENT AND RATE IMPACT

Q. DID YOU PREPARE AN ESTIMATED COST OF SERVICE STUDY FOR THE COMBINED-CYCLE GENERATION PROJECT?

A. Yes. Once the Company selected the Combined-Cycle Generation Project, I completed a cost-of-service study specific to it. Through this study, I determined what the Company's incremental annual revenue non-fuel requirement would be for the Combined-Cycle

Generation Project. The revenue requirement associated with the Combined-Cycle Generation Project is $253,544,106 for 2031 and $329,270,612 for 2032, the first full year of operation. These figures are inclusive of all non-fuel costs of the plant. A summary of the cost-of-service study results is provided as Exhibit AEV-3.

Q. HOW DOES THE COMPANY PROPOSE TO TREAT THE LONG-TERM SERVICE AGREEMENT ("LTSA") COSTS FOR RATEMAKING PURPOSES?

A. As described by Company Witness Lewis, the LTSA includes variable payments that are used to fund future O&M and capital work associated with major maintenance of the combustion turbines. The Company proposes to record these payments as a prepaid asset and include the unamortized prepaid balance in rate base until the related maintenance work is performed. As the work is performed, the applicable amounts will be removed from the prepaid balance and reflected as either O&M expense or plant in service, depending on the nature of the work. The Company requests Commission approval of this ratemaking treatment.

Q. WHO PROVIDED THE PRIMARY INPUTS USED IN YOUR COST-OF-SERVICE ANALYSIS FOR THE COMBINED-CYCLE GENERATION PROJECT?

A. The primary inputs to my cost-of-service analysis are supported by other Company witnesses in this proceeding. Company Witness Dilley supports the initial capital cost of the Project, its 40-year useful life, and the estimated decommissioning cost net of salvage value. Company Witness Lewis supports the forecasted ongoing non-fuel O&M and capital expenditures, including the costs associated with the LTSA. Company Witness Stutler supports the natural gas transportation and supply arrangements and associated costs reflected in the analysis. I used these inputs, along with the Company's current cost of

capital, to calculate the Project's annual revenue requirement. The actual revenue requirement will reflect the Company's then-prevailing Commission-authorized cost of capital.

Q. WILL EXISTING CUSTOMERS SEE A RATE INCREASE FROM THE ADDITION OF THE COMBINED-CYCLE GENERATION PROJECT TO THE COMPANY'S GENERATION FLEET?

A. No. The Company's existing customers will see no net increase in generation revenue requirement attributable to the addition of the Combined-Cycle Generation Project to the Company's generation fleet. This outcome is the result of the manner in which the costs associated with the Combined-Cycle Generation Project will be allocated across customer classes. As a result of this allocation, existing customers will see no change in their allocated revenue requirement as a result of the Combined-Cycle Generation Project.

Q. CAN YOU EXPLAIN HOW THE COMPANY WILL ALLOCATE THE REVENUE REQUIREMENT FOR THE COMBINED-CYCLE GENERATION PROJECT TO AVOID INCREASES TO EXISTING CUSTOMERS?

A. Yes. Before describing the cost allocation process, it is important to realize that the addition of the Combined-Cycle Generation Project and the system load growth from the TeraWulf ESA will lead to immediate cost of service reductions for existing customers besides those that will occur in the ES and the SSR. First, the addition of the Combined-Cycle Generation Project will result in a decrease in fuel costs because the Combined-Cycle Generation Project is a more efficient generating unit meaning that the average fuel cost per kWh will be lower. The amount of this benefit has been estimated by the Company utilizing a Plexos hourly dispatch analysis. In 2032, the first full year that the Combined-Cycle Generation

Project is in service, the fuel cost savings for existing customers is expected to be $39.9 million. Second, the addition of the TeraWulf ESA load will reduce the existing generation revenue requirement amount allocated to existing customers under the Company's Generation Rider as existing fixed costs are spread over more billing units. In 2032, the Generation Rider savings for existing customers is expected to be $12.9 million. The total savings to customers in 2032 is equal to $52.8 million.

Of the full revenue requirement for the Combined-Cycle Generation Project, only the amount equal to the savings resulting from savings described above will be allocated to existing customers. The remaining incremental revenue requirement for the Combined-Cycle Generation Project will be allocated to the large-load customers. For 2032, that means that existing customers will be allocated $52.8 million of the Combined-Cycle Generation Project revenue requirement, and large-load customers will be allocated the remaining $276.4 million. Because the existing customers will experience savings of $52.8 million the net revenue requirement impact to existing customers is zero. There will be similar generation cost of service savings from inter-class cost reallocation when a base rate case occurs after the Muskie Data Campus and the Combined-Cycle Generation Project are online related to other non-rider generation costs such as those associated with Big Sandy Unit 1. The Generation Rider and fuel savings will accrue to existing customers immediately because they are both captured in riders with deferral accounting.

Q. WHY DID THE COMPANY NOT ASSIGN ALL COSTS ASSOCIATED WITH THE COMBINED-CYCLE GENERATION PROJECT DIRECTLY TO TERAWULF?

A. While it may seem appealing to simply directly assign all of the costs associated with the Combined-Cycle Generation Project directly to TeraWulf, doing so eliminates nearly all of the benefits included in the Company's proposal. Utilizing traditional system cost recovery allows the increased load from the TeraWulf to increase system billing units. These increased billing units spread common costs over the increased load putting downward pressure on existing rates. Because the revenue requirement for the Combined-Cycle Generation Project will be allocated in a manner that is neutral to existing customers, existing customers will see an overall revenue requirement reduction as a result of the TeraWulf ESA and the Combined-Cycle Generation Project.

Q. HAVE YOU BEEN ABLE TO ESTIMATE THE REVENUE REQUIREMENT IMPACTS TO EXISTING CUSTOMERS FROM THE TERAWULF ESA AND THE COMBINED-CYCLE GENERATION PROJECT?

A. Yes. Table AEV-8 below shows the change in revenue requirement for existing customers from the beginning of the load ramp period under the TeraWulf ESA through the first full year of operation of the Combined-Cycle Generation Project.

Table AEV-8

Net Rate Impact to Existing Customers from TeraWulf ESA and CC				
	2029	**2030**	**2031**	**2032**
CC Revenue Requirement	0	0	$33,280,697	$52,861,990
CC Fuel Benefit	0	0	$(23,532,449)	$(39,864,325)
Gen Rider Benefit	$(8,337,960)	$ (12,997,665)	$(9,748,248)	$(12,997,665)
Subtotal	$(8,337,960)	$(12,997,665)	$-	$-
Gen Rider Benefit Jan-Mar 2031			$(3,249,416)	$ -
SSR Savings	$(14,166,796)	$(21,383,843)	$(21,383,843)	$(21,383,843)
ES Savings	$(11,363,665)	$(17,152,701)	$(17,152,701)	$(17,152,701)
Residential Bill Credits	$(10,000,000)	$(10,000,000)	$(10,000,000)	$(10,000,000)
Total Rate Increase/(Decrease)	$(43,868,420)	$(61,534,209)	$(51,785,960)	$(48,536,544)

As a result of the manner in which the Company will allocate the revenue requirement for the Combined-Cycle Generation Project and the benefits to customers included in the TeraWulf ESA, existing customers will see a reduction in their total revenue requirement in the amounts estimated in Table AEV-8.

VII. TRANSMISSION COST ALLOCATION

Q. HOW WILL THE TRANSMISSION COSTS ASSOCIATED WITH PROVIDING SERVICE TO THE TERAWULF FACILITY BE RECOVERED?

A. The Company will incur two distinct transmission service-related costs to serve the TeraWulf ESA.

First, the Company will construct the interconnection facilities described by Company Witnesses Koehler and Rafay that are required to interconnect the Muskie Data Campus load to the Company's transmission system and provide it with service. These include the Venator Substation Project and the transmission lines to connect the Muskie Data Campus to the Company's transmission system. The annual revenue requirement associated with this investment made by the Company will be treated like any other transmission investment. The cost of such facilities will be allocated throughout the AEP transmission zone to all of the load-serving entities ("LSE") within it, both AEP and non-AEP. The amount allocated to the AEP LSEs will then be allocated via 12CP to all of the LSEs including the Company. This means the Company will ultimately be allocated less than 5% (the current 12 CP allocation) of the total revenue requirement associated with the interconnection facilities (85% x 5% = 4.25%).

Second, the Company will be charged for the network transmission service charges caused by TeraWulf's contribution to the zonal 12CP. Essentially this is the "postage

stamp" cost of receiving transmission service in the AEP transmission zone. It is equivalent to the Customer's 12CP contribution times the zonal rate for transmission service that is updated annually by the transmission owning Companies in the zone. Table AEV-9 provides a quantitative example of how the TeraWulf interconnection project's revenue requirement would be allocated within the AEP transmission zone.

Table AEV-9

Transmission Cost Allocation – TW Load Example

Example of zonal cost allocation associated with the TW transmission project:

Terawulf Project Panda Transmission Investment	$	321,000,000	a
Net Plant Carrying Charge		15.53%	b
Annual Revenue Requirement Estimate	$	49,851,300	c = a*b
Wholesale Cost Allocation			
Amount Allocated to Non-AEP LSEs in AEP Zone	$	7,050,819	
Amount Allocated to AEP LSEs in AEP Zone	$	42,800,481	
KPCO Allocated Share	$	2,203,617	
Other AEP LSE Share	$	40,596,864	
Average Zonal T Rate Before TW at Full Load	$	146,617	$/MW-year
Average Zonal T Rate After TW at Full Load	$	143,165	$/MW-year

- The project causes a roughly $50 million Annual revenue requirement, all of which will be recovered in the AEP zone
- Roughly $43 million is allocated to the AEP Companies
- $2.2 million of that is allocated to Kentucky Power
- TW's incremental transmission revenues will cover that amount and any other incremental allocated transmission costs
- The addition of the TW load to the zone will drive average transmission rates down, all other things being equal, because they add more billing units than cost

The Terawulf Kentucky Power transmission project will not raise existing customers' rates in the Commonwealth

Q. HOW ARE EXISTING CUSTOMERS PROTECTED FROM TRANSMISSION RATE INCREASES?

A. The Company estimates that the addition of the TeraWulf ESA load and current estimate of related transmission investment will actually lower zonal transmission rates, all other things being equal, as the TeraWulf ESA adds more billing units to the denominator than cost to zonal transmission numerator. Additionally, TeraWulf will pay full cost of service rates via the large load provisions of the IGS tariff. Any needed future increases in transmission rates would be captured for TeraWulf just like the Company would for its

existing customers but this would be for other reasons besides the addition of TeraWulf and the associated transmission investment to serve the new load.

Q. WOULD OTHER TRANSMISSION CUSTOMERS' RATES IN THE COMMONWEALTH INCREASE FROM THE ADDITION OF THE TERAWULF ESA?

A. No, they would not. The cost of service associated with the investment needed to serve TeraWulf will not be allocated outside of the AEP transmission zone so East Kentucky Power Cooperative, Louisville Gas &Electric/Kentucky Utilities and the Tennessee Valley Authority distributors would all be unaffected. Also, the two non-AEP wholesale entities in the AEP zone (Olive Hill and Vanceburg) will be unaffected as I described earlier with all other things being equal the TeraWulf addition will lower zonal transmission rates.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Vice President Regulated Pricing – Strategic Transactions for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Alex E. Vaughan

Commonwealth of Kentucky)
) Case No. 2026-00324
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on November 10, 2026.

Marilyn Michelle Caldwell
Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841