COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES	))))))))	**CASE NO. 2025-00045**

TESTIMONY OF JOHN W. CHILES

ON BEHALF OF JOINT INTERVENORS
KENTUCKIANS FOR THE COMMONWEALTH,
KENTUCKY SOLAR ENERGY SOCIETY,
METROPOLITAN HOUSING ASSOCIATION,
AND MOUNTAIN ASSOCIATION

Public Version

June 16, 2025

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I. INTRODUCTIONS & QUALIFICATIONS

Q. Please state for the record your name and business address.

A. My name is John W. Chiles. My business address is 1850 Parkway Place SE, Suite 800, Marietta, Georgia 30067.

Q. By whom are you employed and in what position?

A. I am employed by GDS Associates, Inc., as a Principal, Transmission Services.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Association, and Mountain Association (collectively, "Joint Intervenors").

Q. Please describe your educational background.

A. I have a Bachelor of Science in Engineering from the University of South Florida, Tampa, Florida.

Q. Please describe your professional background.

A. I have almost forty years of experience in the electric utility industry. This experience includes nine years in resource planning and production cost modeling between Seminole Electric Cooperative, Inc. in Tampa, Florida, and the North Carolina Electric Membership Corporation in Raleigh, North Carolina. Since 1996, I have specialized in transmission planning analysis, Federal Energy Regulatory Commission ("FERC") open access transmission and interconnection policy, wholesale energy market design, transmission origination and scheduling, and control area operations. For the last twenty-one years, I have been employed by GDS Associates, Inc., where I have served as a

Principal in the Transmission Services group. I currently serve electric cooperatives, municipal utilities, generation and transmission developers and public utility commissions throughout the United States. I have worked in several regional transmission organization ("RTO") regions, including Midcontinent Independent System Operator ("MISO"), Southwest Power Pool ("SPP"), Electric Reliability Council of Texas ("ERCOT"), PJM Interconnection ("PJM"), and California ISO ("CAISO"). I also have provided technical and regulatory support for clients in the Southeast, Mid-Atlantic, Western Interconnection, and Alaska on state/federal transmission policy and transmission planning/interconnection issues.

Q. Have you previously filed expert witness testimony in other proceedings before this Commission or before other regulatory commissions?

A. I have not testified before the Kentucky Public Service Commission. However, I have testified before the Federal Energy Regulatory Commission, along with submitting testimony in several other state utility commissions. A list of my testimony by jurisdiction is included as Exhibit JWC-1 to my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address:

1) The impact of transmission requirements on the cost of the Brown 12 and Mill Creek 6 natural gas combined cycle combustion turbine ("NGCC") facilities, and how these requirements compare to requirements from the LG&E/KU Request for Proposals ("RFP") for renewable energy resources.
2) How the Companies' modeling of Loss of Load Expectation ("LOLE") can be influenced by the modeling of transmission system constraints.

3) The treatment of load and generation interconnection in the Transmission Service Request ("TSR") process as referred to in the Companies' Open Access Transmission Tariff ("OATT").

4) The treatment of the Cane Run BESS units as a capacity resource versus treatment as a transmission resource and how modeling impacts that treatment.

II. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your findings and recommendations in this case.

A. Based on my review, I offer the following observations.

(1) The Companies have been unable to provide sufficient evidence for the interconnection costs of the requested NGCC projects.

(2) The Companies have rushed this application without fully vetting the cost of transmission facilities for delivery of energy to LG&E/KU ratepayers.

(3) Although BESS can provide benefits to utility systems with high levels of renewable resource penetration by firming up those resources on a short-term basis, assuming using BESS to serve significant high load factor load additions seems inconsistent with the best use of these project additions.

III. THE COMPANIES HAVE UNDERSTATED THE TYPE AND COST OF TRANSMISSION SYSTEM REQUIREMENTS WHEN COMPARED TO THE EVALUATION OF PROJECTS IN THE RFP.

Q. How are the Companies addressing the transmission facilities required for interconnection of the Brown 12 Project?

A. The Companies are not requesting a Certificate of Public Convenience and Necessity ("CPCN") for any electrical facilities in this proceeding.

Q. How are the Companies addressing the transmission facilities required for delivery

of the energy of the Brown 12 Project to serve Company load?

A. LG&E/KU Witness Robert M. Conroy stated that although the Companies are studying electric transmission needs, they do not believe that specific CPCNs will be required.[1]

Q. Why do the Companies believe that a CPCN for transmission facilities will not be required for the Brown Project?

A. According to LG&E/KU Witness Conroy, at the time of his Direct Testimony, the Companies believe any transmission facilities "will be an ordinary extension of an existing system in the usual course of business."[2]

Q. In the normal course of business, do the Companies study the addition of new generation or load as part of a single process or does the Open Access Tariff specifically address new generation or load additions?

A. The Companies rely on their Independent Transmission Organization ("ITO"), TranServ International, to perform serial studies to evaluate new generation and load additions. This is separate from the normal planning process, because expansion of transmission facilities related to normal load growth and addressing North American Electric Reliability Corporation ("NERC") reliability are not studied sequentially. The generation and load addition processes are specifically outlined in the LG&E/KU Facility Connection Requirements and Studies[3] and Business Practices for Transmission Service

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[1] Direct Testimony of Robert M. Conroy, Vice President Senior Director, Project Engineering on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case No. 2025-00045, at 12-13 (Feb. 28, 2025) ("Conroy Direct").
[2] *Id.* at 13.
[3] LG&E/KU, *LG&E/KU Facility Interconnection Requirements and Facility Interconnection Studies* (2025), http://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/Facility-Interconnection-Requirements-and-Studies.pdf.

and Scheduling[4] documents.

Q. Specifically related to the Brown project, what transmission system facilities have been identified to facilitate the interconnection?

A. LG&E/KU Witness David L. Tummonds states that "[o]nsite interconnection facilities will also be constructed or modified at Mill Creek and Brown, as needed, to interconnect the NGCCs with the transmission network at each site."[5] Witness Tummonds further states that "(t)he Companies have also…submitted a generation interconnection request to TranServ International."[6] However, the Companies have not identified the specific facilities identified by the ITO related to the Brown project interconnection, and per the Companies' Supplemental Data Responses, the ITO will not complete those studies necessary to identify specifically needed facilities until July 2025.[7] The Companies have not provided any studies performed by the ITO to confirm their assertions.

Q. Have the Companies identified any specific facilities required for the Mill Creek project interconnection?

A. No. Company Witness Tummonds states that the Companies were planning to submit the interconnection request in November 2025. However, because transmission studies for

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[4] LG&E/KU, *LG&E/KU Transmission Service and Scheduling Business Practices* (effective Feb. 12, 2025), http://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/Business_Practices_-_Transmission_Service_and_Scheduling_Clean_-_Effective_02-12-25.pdf.

[5] Direct Testimony of David L. (Dave) Tummonds, Senior Director, Project Engineering on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case No. 2025-00045, at 11 (Feb. 28, 2025) ("Tummonds Direct").

[6] *Id.* at 7.

[7] Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Supplemental Request for Information Dated May 2, 2025, Case No. 2025-00045, Question 58 (a)-(c) (May 16, 2025) ("LG&E/KU Resp. to JI 2-58 (a)-(c)").

the Mill Creek 6 and Cane Run BESS have not begun,[8] the Companies have not provided any studies performed by the ITO which confirm their assertions on the level of interconnection facilities required.

Q. The Companies have indicated that they use an assumption that the interconnection cost is 2%[9] of the total project cost. Do you support that assertion?

A. I do not support that assertion. In my experience, reviewing Integrated Resource Plans and Certificates of Public Convenience and Necessity, a 5% value is more typical than the 2% assumption used here. Applying the 2% value to the total cost of the Brown project means that the transmission upgrade costs would be approximately $27 million and the Mill Creek project transmission cost would be approximately $28 million, for a total of approximately $55 million.[10] The Companies' own cost estimates for a single transformer plus two breakers for a minimal interconnection is approximately [redacted] which does not appear to include any additional work. Using a 5% interconnection cost factor results in interconnection costs more in the range of $67 million. A $39 million difference in interconnection costs between a greenfield and brownfield site puts third parties at a competitive disadvantage in the context of a competitive solicitation.

Q. Would this 2% assumption also be applicable to other projects such as those in the Companies' RFP?

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[8] *Id.*
[9] Tummonds Direct at 11 ("Transmission costs are estimated to be approximately 2% of the total cost of the NGCCs").
[10] *Id.* at 13 ("The Companies currently estimate the construction cost of Brown 12 and Mill Creek 6 will be $1.383 billion and $1.415 billion, respectively.").

A. That is unlikely. Research performed by the Berkeley Lab indicates that interconnection costs for completed wind and solar facilities range from 6-8% of total project capital cost. This amount rises to 30-37% of project capital cost for projects that are withdrawn from interconnection queues. [11]

Q. Why is that the case?

A. The transmission systems have been planned to deliver existing large central station project energy to the grid. New projects face a barrier to entry since access to these central station sites is controlled by the incumbent utility. In the RFP, respondents were told "Third party respondents should not assume access to, or utilization of, existing sites owned by the Companies for siting proposed project(s)."[12]

Q. Does the inability of RFP respondents to have comparable access to Companies' existing sites for interconnection create an economic disadvantage for new entrants?

A. Yes, it does. If one assumes that the Companies' 2% assumption for its proposed gas plants were correct, the cost of interconnection for new renewable projects is three times more than what the Companies assume for their projects. Even if one uses a more reasonable 5% interconnection factor assumption, new renewable projects are still at a competitive disadvantage.

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[11] Energy Technologies Area, *Summary: Grid Connection Barriers To New-Build Power Plants In the United States*, Lawrence Berkeley Nat'l Lab'y (Jan. 13, 2025), https://emp.lbl.gov/news/grid-connection-barriers-new-build-power-plants-united-states/; *see also* Will Gorman et al., *Grid Connection Barriers To New-Build Power Plants In the United States*, Joule 9 (Feb. 19, 2025), https://www.sciencedirect.com/science/article/pii/S2542435124005038.

[12] Direct Testimony of Charles R. (Chuck) Schram, Director, Power Supply on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case No. 2024-00045, Ex. CRS-1 at 2 (Feb. 28, 2025).

IV. THE COMPANIES HAVE NOT FACTORED IN THE IMPACT OF TRANSMISSION IMPORT CAPACITY ON THE CALCULATION OF THE LOSS OF LOAD EXPECTATION.

Q. What is loss of load expectation or "LOLE"?

A. Loss of Load Expectation ("LOLE") is a reliability metric used by utilities to assess the ability of a system to serve load. LOLE is the measure of how often, on average, available generation resources are insufficient to serve the load demand.[13]

Q. What factors influence the calculation of LOLE?

A. According to NERC, "although the primary drivers of LOLP [Loss of Load Probability] and ELCC [Effective Load Carrying Capacity] are load, unit capacity, available energy supply to the prime-mover and mechanically based forced outage rates, there are other factors that can influence the results."[14] Additional factors may include load diversity, random independent forced outage rate assumptions, and interconnections with neighboring systems.[15] Load diversity can impact line loading, which impacts import capability. Forced outage rates impact the loading of generating assets, which impacts the available reserve capacity at the peak. Interconnection capacity can lower LOLE and LOLP by having the ability to lean on external systems for serving load at the time of peak.

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[13] MISO, *LOLE Modeling and Accreditation Workshop*, slide 4 (Sept. 22, 2023), https://cdn.misoenergy.org/20230922%20LOLE%20Modeling%20and%20Accreditation%20Workshop%20Presentation630256.pdf.
[14] NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, at 19 (Mar. 2011), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF1-2.pdf ("NERC Report").
[15] *Id.*

Q. How are LOLE and LOLP related?

A. Loss of Load Probability ("LOLP") is the probability that, for a given hour, the available generation is insufficient to meet the system load demand. LOLE is the sum of the daily peak LOLP values for a given year. Another factor, called Loss of Load Hours ("LOLH"), is the sum of the hourly LOLP values over the year. LOLE measures the frequency of load shed events and LOLH measures the duration of load shed events.

Q. How does Effective Load Carrying Capability ("ELCC") relate to LOLE?

A. An important component of the LOLE calculation is the amount of available generating capacity at the time of each daily peak. In planning, there are different ways to calculate available generating capacity, including for example PJM's Effective Load Carrying Capacity approach. For each resource class, PJM applies class-specific capacity derate—the ELCC—to account for possible unit availability at daily system peaks. The ELCC for each class attempts to account for specific operating capabilities and limitations of each resource type. For example, fossil unit capacity availability is impacted by the effective forced outage rate which derates nameplate capacity. Renewable resource capacity is derated to account for limited availability.[16]

[16] The details of PJM's ELCC approach for capacity accreditation can be found through PJM's OATT, Manuals, and various other stakeholder materials available on PJM's public-facing webpage.

The Companies, of course, are not members of PJM or another Regional Transmission Organization, and they have taken different approaches to estimating the amount of available generating capacity in their PLEXOS and SERVM modeling, as discussed in Chelsea Hotaling and Anna Sommer's Review of LG&E/KU's 2024 Integrated Resource Plan.[17]

Q. Can transmission capacity influence LOLE?

A. Yes. In the report cited above, NERC identifies that transmission ties to external regions can influence the value of LOLP. The report states "Building new transmission can reduce LOLP, and can therefore reduce the need for new generation."[18]

By the same token, not adding new transmission capacity can increase the need for new generation.

Q. Can you explain?

A. Yes. Adding transmission capacity to external systems can create pathways for generators located in adjacent energy markets which can now be available in emergency conditions to improve the ability of the area to serve load. This was seen during Winter Storm Elliott when the Companies claimed they had plenty of transmission capacity to import from PJM. Under extreme weather conditions, capacity from other markets may not be available, but if insufficient transmission capacity exists, then it does not matter how

[17] Sierra Club's Corrected Comments: A Review of Louisville Gas & Elec. and Kentucky Utilities' 2024 Integrated Resource Plan, by Chelsea Hotaling and Anna Sommer, Energy Futures Group, *In the Matter of Electronic 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2024-00326, at 21-22 (Mar. 14, 2025).
[18] NERC Report at 19.

much external capacity is available.

Q. What energy markets are adjacent to LG&E/KU that could provide support in an emergency state?

A. The Tennessee Valley Authority, MISO, and PJM regional transmission organizations have the ability to meet load requirements if necessary.

Q. In the modeling for the need certification for the projects the Companies are proposing, is there any reference to updating interface capacity to adjacent regions?

A. Not based on the materials supplied in the Companies' application.

Q. Is there any reference to existing interface capacity in the calculation of LOLE and LOLP?

A. The Companies refer to their interface capacity on pages 3-6 of the Transmission Section included in Volume III of the Companies' 2024 IRP filing, and provides further capacity detail in response to a post-hearing data request.[19]

Q. Is it your assertion that by not including the effect of expansion of transmission ties on the LOLE calculation, that the Companies have potentially overstated their need for new generation?

A. Yes, it is. The Companies provided a sensitivity analysis in the IRP SERVM analyses which looked at both a "No Access to Neighboring Markets" and a "High ATC" (i.e.,

[19] Case 2024-00326, 2024 IRP, Vol. III at p. 195/259 to 198/259 (Oct. 18, 2024) ("2024 IRP"); Case No. 2024-00326, Attachment to LG&E/KU Resp. to JI PH Q 4(c); *see also Long-Term Firm Transfer Analysis – Impact to the LG&E/KU Transmission System*, at 2 (Oct. 2024). This document is included in the 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Vol. III, at p. 247/259.

high available transmission capacity) scenario. [20] The annual LOLE values were 1.10 and 0.15, respectively.[21] The Companies claim that increasing the ATC to a minimum of 700 MW in every hour would cost $101 million plus losses.[22] However the Companies have not provided the basis for the need to have 700 MW of ATC in every hour for a calculation that is based on a one day in ten years scenario. My assumption is that the cost of yearly firm point-to-point transmission is the foundation of the $101 million price tag. In most months, the full amount of 700 MW would not be needed. An order of magnitude difference in LOLE values would send a strong signal that additional internal generation requirements need to be reviewed carefully.

V. THE COMPANIES ARE REQUESTING APPROVAL OF THE PROJECTS WITHOUT SUFFICIENT EVALUATION OF THE EFFECTS ON THE LOCAL AND ADJACENT SYSTEMS.

Q. In your experience, what is the typical process for addition of new generation resources to an electrical system?

A. There are typically two parts to the addition of a new generating resource to serve network load. The first part is the generation interconnection process and the second part is the transmission service request. The generation interconnection process only guarantees the generator the ability to connect to the electrical system, subject to the addition of interconnection facilities and the mitigation of any issues beyond the point of interconnection, such as over-duty breaker replacement or line overloads. It is important to note that getting an interconnection does not confer any rights to deliver the energy from the generation facility to the load. The TSR process results in deliverability rights to

[20] Case 2024-00326, 2024 IRP, Vol. III, at p. 51/259 (Oct. 18, 2024) ("2024 IRP").
[21] *Id.*
[22] *Id.*

a specific load.

Q. Are these processes typically done in sequential order or can they be done concurrently?

A. If the interconnection is at a new point of interconnection in the electrical system, then the generation interconnection process is required first to establish that the point of interconnection is a valid injection point. After that, the project would request transmission service. In cases where the generator is interconnecting to an existing point of interconnection, as contemplated by the Brown and Mill Creek projects, then the process can run concurrently.

Q. Can a generator get any sort of deliverability rights through the interconnection process?

A. Yes, a generator has the ability to be studied under one of two options under the Open Access Transmission Tariff: Energy Resource Interconnection Service ("ERIS") or Network Resource Interconnection Service ("NRIS"). ERIS assets have the ability to inject power onto the grid but have no ability to deliver firm power to a counterparty absent a Transmission Service Agreement. NRIS assets have the ability to deliver their output to any point on the Transmission Provider system on a firm basis. Under the NRIS study methodology, a generator can be studied to determine what transmission facilities are required to deliver their output to any point within the Balancing Authority. This is also used in various Regional Transmission Organizations to qualify the capacity under a Resource Adequacy construct. If a generator is granted NRIS for its output, the Network Customer can point to the NRIS resource and have guaranteed delivery.

Q. Have the Companies requested NRIS for any of the resources they are requesting in this proceeding?

A. No, they have not.

Q. Have the Companies made Transmission Service Requests to the Independent Transmission Organization for the proposed resources?

A. My understanding is that Transmission Service Requests have been submitted for all of the projects, but those results have not been finalized.

Q. So what is the basis for the transmission upgrade costs in Witness Wilson's testimony and Exhibit SAW-1?

A. The Companies performed an independent transmission siting assessment for the projects.[23]

Q. Are the results of that independent study inclusive of all needed transmission system upgrades?

A. It is unlikely. Transmission upgrades can take the form of directly assigned interconnection upgrades, upgrades beyond the point of interconnection (such as other system replacements in nearby substations to address short circuit concerns), and upgrades on nearby transmission systems, which are referred to as "Affected Systems" upgrades. The numbers provided by the Companies do not indicate that these results consider any affected systems outside the LG&E/KU system.

[23] Ex. SAW-1, *LG&E/KU 2025 CPCN Resource Assessment, Generation Planning & Analysis*, attached to the Direct Testimony of Stuart A. Wilson, Director, Energy Planning, Analysis, and Forecasting on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case No. 2025-00045 (Feb. 28, 2025) ("Wilson Direct).

Q. How could Affected Systems impact the costs presented by the Companies?

A. Any violations of thermal, voltage, or stability criteria on the Affected System would require mitigation. Such mitigation could take the form of additional transmission expansion costs to be paid by LG&E/KU customers.

Q. Are any of the results of the Companies-conducted studies binding on the ITO?

A. No, they are not.

Q. Is it possible that the cost of transmission could be higher than what the Companies are touting?

A. Yes. Any model changes, generation additions or retirements, or new load additions, in either the LG&E/KU system or adjacent systems could result in higher costs to the Companies' ratepayers.

Q. Is it possible to estimate the magnitude of the economic impacts that could be attributed to these changes at this time?

A. No. Until the ITO completes the evaluation of the TSRs related to the projects, we cannot project if there will be any changes to project economics. What we do know is that if additional upgrades are identified either on the Companies' systems or on Affected Systems, the impact will either be a reduction in project output (if upgrades are not funded) or an increase in project costs (if projects are identified). In either scenario, the Companies' projects do not have a fully vetted transmission cost until the ITO completes their analyses.

VI. THE COMPANIES NEED TO DEFINE THE ACTUAL BUSINESS USE CASE FOR THE CANE RUN BESS AS THIS IMPACTS THE VALUE OF THE ASSET FOR ANCILLARY SERVICES VERSUS RESOURCE ADEQUACY.

Q. Please describe the Cane Run 400 MW BESS facility.

A. The Companies' Witness Tummonds describes the Cane Run facility as follows:

> The Companies will construct the Cane Run BESS at the Cane Run Generating Station in Jefferson County. The Companies plan to use lithium-ion battery technology similar to what will be used for Brown BESS absent a shift in technology in the battery industry. The Companies' Project Engineering team will lead the Companies' efforts to develop, permit, and construct the Cane Run BESS using an EPC. The power required to charge the Cane Run BESS and the subsequently delivered power will be transmitted via the existing electric transmission infrastructure at the Cane Run Generating Station.[24]

Q. Are the Companies planning to use the BESS as part of the resource portfolio for meeting capacity requirements?

A. Yes, in SAW-1 at 7, table 1, the BESS is shown as providing 400 MW at the time of the peak for meeting resource adequacy needs.

Q. What is the duration of the BESS?

A. My understanding is that the BESS is a 400 MW/1600 MWh battery.[25] This means that it can provide up to four hours of output at a 400 MW level.

Q. What happens when the BESS facility is fully used for the full four-hour duration?

A. The BESS needs to be recharged from other system resources to be ready for the next need. For a four-hour BESS, I expect the recharge rate to be similar to the discharge rate, therefore it will take at least four hours to go from empty to a full charge for the next discharge cycle.

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[24] Tummonds Direct at 12.
[25] Wilson Direct at 11.

Q. What is the typical load factor for a data center?

A. Most data centers are projected to operate at a 80%-90% load factor. This means that the data center load is assumed to be at its peak a significant portion of the time.

Q. If the BESS has a four-hour cycle and the data center has an 80%-90% load factor, is it reasonable to assume that the BESS unit can provide 100% of the capacity needed for the load for their requirements?

A. The BESS may be available to provide capacity in a limited context, but it is not capable to provide capacity over a long duration, because the battery discharge cycle is for a maximum of four contiguous hours. In addition, additional generation will be required to recharge the battery, which means that the charging capacity will not be available to meet data center load requirements. However, the battery energy storage system is not operating independent of the Companies' generation resource mix. Renewable resources such as wind and solar are still competitive when paired with storage systems to act as a "virtual" power plant that can achieve high capacity factors similar to traditional fossil units.

Q. BESS units have to be studied from a transmission perspective for both charging and discharging cycles. Is that correct?

A. That is correct. In most cases, the Transmission Planner studies the unit to make sure that under both charging and discharging, that the transmission system is sufficient to support either state.

Q. Do you support using the BESS to be a resource for serving data center loads?

A. If paired with other renewable resources, such as wind and solar, battery storage units can provide sufficient energy to serve high-load factor loads. If viewed as independent of those resources, BESS units fall short from a capacity perspective because the battery has a limited four-hour discharge cycle. BESS can provide some relief for peak shaving but for seasons with a longer peak window, such as summer, the effectiveness is limited.

Q. If a BESS is not the right resource for capacity requirements, are there other uses that make sense from an operational perspective?

A. Yes, the BESS can supply energy and several ancillary services that would bring benefits to the electric system.

Q. Please explain.

A. Battery storage systems can provide economic benefits to the energy requirements by charging when energy prices are at their lowest during off-peak hours and by discharging when energy prices are high. This ability to arbitrage the hourly energy prices can result in customer savings. From an ancillary services viewpoint, battery storage facilities can deliver energy imbalance service (meeting hourly mismatch between scheduled and actual load) and can also provide both spinning reserves and supplemental reserves. They can provide spinning or "quick-start" reserves due to their fast discharge characteristics. They can provide supplemental reserves because the duration of the battery exceeds the one-hour requirement for supplemental reserves.

Q. Is it necessary to have the entire BESS requirement at a single substation?

A. Not necessarily. It depends on how the asset is interconnected. If a single tie is used to connect the BESS to the transmission system, then that single line becomes the single point of failure. Also, breaking the BESS into smaller footprints improves siting ability, and can be used to back up critical loads (hospitals, pumping stations, etc.)

Q. Is there a precedent to adding BESS systems for gaining operational experience?

A. Yes. In the Georgia Power Company 2022 Integrated Resource Plan, the company requested to add three different BESS scenarios to understand the interplay between the BESS and co-located generation and BESS and co-located load[26]. It is important to note that the Georgia Public Service Commission required the company to report back on the lessons learned based on their operational experience.

Q. Would the Companies benefit from this approach?

A. If the Companies can gain experience with BESS to maximize value of the asset, then that sets the stage for further effective use of BESS which informs Commission understanding and ultimately benefits ratepayers.

Q. Do large loads such as data centers present any other issues for the transmission system?

A. There are issues such as voltage stability, power harmonics, and electromagnetic transients ("EMTs") that can impact the grid.

Q. Does the ITO or the Companies perform any studies specifically designed to identify and resolve these issues?

A. There is no specific requirement that these studies are performed as part of a normal interconnection process.

Q. Would the Companies benefit from additional analyses beyond the traditional power flow and short circuit analyses for interconnections?

[26] Ga. Pub. Serv. Comm'n, Georgia Power Company's 2022 Integrated Resource Plan, Docket No. 44160, at p. 3-19, Par. 17 (Jan. 31, 2022).

A. If the Companies are aware of risks that exist with these interconnections, then, as a matter of prudency, I recommend that EMT and sub-synchronous reactance (“SSR”) be performed. The studies may be in excess of NERC standards, but the NERC standards are a minimum requirement only. There is nothing in the NERC standards that limits a utility from implementing best practices.

VII. RECOMMENDATIONS

Q. Do you recommend that the Commission approve the proposed generation projects and budgets as proposed by LG&E/KU?

A. I do not recommend the approval of the proposed generating projects at this time. The record is incomplete without a full accounting of the need and cost for additional transmission facilities until the TSR results have been fully vetted. The cost estimates for interconnection upgrades and transmission system upgrades may be understated and ratepayers should have a full picture of the costs of these assets, including transmission costs, before approving the projects.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

The undersigned,_John W. Chiles_being first duly sworn, deposes and says that _he_ has personal knowledge of the matters set forth in the foregoing testimony and that the information contained therein is true and correct to the best of _their_ information, knowledge, and belief, after reasonable inquiry.

John Webster Chiles
____

Subscribed and sworn to before me by John Webster Chiles this 16th day of June, 2025.

COMMONWEALTH OF VIRGINIA • ELECTRONIC NOTARY PUBLIC
N
Sonya Mack
REGISTRATION NUMBER
7543946
COMMISSION EXPIRES
September 30, 2029

Sonya Mack
____
Notary Public

My commission expires: 09/30/2029

Notarized remotely online using communication technology via Proof.

EXHIBIT JWC-1

JOHN W. CHILES

EXPERT WITNESS TESTIMONY

EXHIBIT JWC-1

JOHN W. CHILES EXPERT WITNESS TESTIMONY

Federal Energy Regulatory Commission (FERC)

- PJM Interconnection, LLC, American Transmission Systems, Inc., Docket No. ER12-2399-003
- Southwestern Electric Cooperative, Inc., et al., Docket Nos. EL15-72, et al., Panel Member for Technical Conference

Arkansas Public Service Commission (APSC)

- In the Matter of a Show Cause Order Directed to Entergy Arkansas, Inc. Regarding Its Continued Membership in the Current Entergy System Agreement, or Any Successor Agreement Thereto, and Regarding the Future Operation and Control of Its Transmission Assets, Docket No. 10-011-U

Georgia Public Service Commission (GPSC)

- In the Matter of: Georgia Power Company's 2010 Integrated Resource Plan, Docket No. 31081
- In the Matter of: Georgia Power Company's 2013 Integrated Resource Plan, Docket No. 36498
- In the Matter of: Georgia Power Company's 2016 Integrated Resource Plan, Docket No. 40161
- In the Matter of: Georgia Power Company's 2019 Integrated Resource Plan, Docket No. 40161
- In the Matter of: Georgia Power Company's 2022 Integrated Resource Plan, Docket No. 40161

Mississippi Public Service Commission (MPSC)

- In Re: Joint Application of Entergy Mississippi, Inc., and The Midwest Independent Transmission System Operator, Inc., for Transfer of Functional Control of Entergy Mississippi's Transmission Facilities To MISO, Docket No. 2011-UA-376

Public Utility Commission of Texas (PUCT)

- Entergy Gulf States, Inc.'s Transition to Competition Plan, PUC Docket No. 33687

- Application of Sharyland Utilities, L.P. to Approve Study and Plan Pursuant to the Commission's Order in Docket No. 37990 Concerning the Movement of Sharyland's Stanton and Colorado City Divisions from the Southwest Power Pool to ERCOT, PUC Docket No. 39070

- Application of Entergy Texas, Inc., ITC Holdings Corp., MidSouth Transco LLC, Transmission Company Texas, LLC, and ITC MidSouth LLC for Approval of Change of Ownership and Control of Transmission Business, Transfer of Certification Rights, Certain Cost Recovery Approvals, and Related Relief, PUC Docket No. 41223

- Updated Application of Entergy Texas, Inc., ITC Holdings Corp., Mid-South Transco LLC, Transmission Company Texas, LLC, and ITC Midsouth LLC for Approval of Change of Ownership and Control of Transmission Business, Transfer of Certification Rights, and Related Relief, PUC Docket No. 41850

Commonwealth Of Virginia State Corporation Commission Division of Energy (VSCC)

- Virginia Electric and Power Company for Approval and Certification of Electric Facilities for the Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, and Skiffes Creek 500 kV-230 kV-115 kV Switching Station, Case No. PUE-2012-00029

- Virginia Electric and Power Company for Approval and Certification of Electric Transmission Facilities for the Remington CT-Warrenton 230 kV Double Circuit Transmission Line, Vint Hill-Wheeler and Wheeler-Loudoun 230 kV Transmission Lines, 230 kV Vint Hill Switching Station, and 230 kV Wheeler Switching Station, Case No. PUE-2014-00025