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APPLICATION OF CENTERPOINT	**§**	**BEFORE THE STATE OFFICE**
ENERGY HOUSTON ELECTRIC, LLC	**§**	
FOR APPROVAL OF ITS 2026-2028	**§**	**OF**
TRANSMISSION AND DISTRIBUTION	**§**	
SYSTEM RESILIENCY PLAN	**§**	**ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY

OF

MICHAEL E. IVEY

ON BEHALF OF THE

HOUSTON COALITION OF CITIES

APRIL 8, 2025

DIRECT TESTIMONY OF MICHAEL E. IVEY

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EXHIBITS

I. INTRODUCTION

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

A. My name is Michael Ivey. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067. I am a Senior Project Manager at GDS Associates, Inc. ("GDS").

Q. ON WHOSE BEHALF ARE YOU APPEARING AND IN WHAT CAPACITY?

A. I have been retained by the Houston Coalition of Cities ("HCC") as an expert witness in this proceeding.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY IN THIS CAPACITY?

A. I was asked to review the application of Centerpoint Energy Houston Electric, LLC ("CEHE") for approval of its 2026-2028 transmission and distribution system resiliency plan.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I earned a Bachelor of Science in Engineering, Specialization: Electrical from Mercer University in 1994.

Q. PLEASE STATE YOUR PROFESSIONAL REGISTRATIONS.

A. I am a Licensed Professional Engineer and Licensed Electrical Contractor in the state of Georgia.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. I have been an engineering consultant for utilities since 1994 with experience in the operation, maintenance, and design of substations, transmission lines, and distribution lines as well as in rate design, cost of service, and financial analysis. I also worked as an Engineer, Technical Service Manager, Assistant Manager, and General Manager at the Crisp County Power Commission in Georgia where I managed and oversaw utility operations that included hydro, coal, and natural gas generation pipeline and facilities, transmission and distribution facilities, finance and retail billing operations. I came to GDS as a Senior Project Manager in 2023. During my time at GDS I have provided, among other projects, teaching classes on system design, staking, and inspection, engineering analysis and support for distribution system design, operation, and construction, generation interconnects, reliability and resiliency projects, and assisting with testimony preparation for storm response, and for reliability and resiliency plans.

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Folsom, California; Bedford, New Hampshire; Redmond, Washington; Augusta, Maine; and Madison, Wisconsin. GDS has over 185 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, and statistical services. Our clients are primarily publicly owned utilities, municipalities, customers of privately owned utilities, groups or associations of customers, and government agencies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have provided testimony to the Public Utility Commission of Texas in Docket No. 56211, Docket No. 56548, and Docket No. 57271.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit MEI-E1, which is my resume containing a summary of my experience and qualifications.

II. SCOPE OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. The purpose of my testimony is to present an evaluation of CEHE's 2026-2028 Transmission and Distribution System Resiliency Plan ("Plan") and to provide recommendations regarding the prudence, reasonableness, and cost effectiveness of the associated projects.

Q. PLEASE SUMMARIZE YOUR OPINIONS AND RECOMMENDATIONS.

A. My opinions and recommendations are summarized as follows:

1. I detailed why reliability and resiliency measures are different even when they use similar methods or may provide both resiliency and reliability benefits.
2. I explained why some past reliability and resiliency project problems can be indicators that there may be problems with some of the proposed resiliency measures.
3. The conductor replacements under Distribution Circuit Resiliency (RM-1) RM-1 are capacity upgrades thus nor resiliency measures and I recommend removing the conductor capacity upgrades from this measure estimated at $313.17M in capital costs.
4. There has been a historic failure with deployment of IGSD devices like those proposed in Restoration IGSD (RM-3). I recommend the Commission direct CenterPoint to conduct a study to determine why past deployments have not

improved reliability. Until that issue is resolved, I recommend removing the entire measure for $107.3M in capital costs and $0.5M in O&M expense.

5. While addressing hazardous trees under Vegetation Management (RM-5) can be an effective vegetation management measure for resiliency, trimming trees has been shown to be an ineffective vegetation management measure for resiliency. I recommend removing this entire measure from the Resiliency Plan and developing a new measure to identify hazardous trees that are uniquely susceptible to resiliency weather events. This recommendation removes $146.1M in O&M expense.
6. Major Underground Control and Monitoring System (MUCAMS) (RM-12) is a routine measure and also seeks to increase capacity. As such it does not qualify as a resiliency measure, and I recommend removing the entire measure in the amount of $10.8M in capital costs.
7. Contamination Mitigation (RM-19) is a routine normal operating measure and does not qualify as a resiliency measure. I recommend removing the entire measure in the amount of $144.0M in capital costs and $6.0M in O&M expense.
8. Digital Substation (RM-21) is just modernizing components in a substation like we do every day and is not primarily related to resiliency as required by code, so it does not qualify as a resiliency measure. I recommend removing the entire measure in the amount of $31.8M in capital costs.
9. Substation Physical Security Fencing (RM-26) is not in the public interest because it does not significantly enhance system resiliency, has a high cost, and is not the most cost-effective measure. I recommend removing the entire

measure in the amount of $18.0M in capital costs.

10. Spectrum Acquisition (RM-28) is just updating telecommunications needs primary for normal operations and is not resiliency specific as required by code, so it does not qualify as a resiliency measure. I recommend removing the entire measure in the amount of $42.0M in capital costs.
11. Advanced Aerial Imagery Platform / Digital Twin (RM-33) is primarily used for day-to-day planning and has many features which only some can also be used for Resiliency planning, so it does not qualify as a Resiliency measure under the code. I recommend removing the entire measure in the amount of $18.4M in capital costs and $2.0M in O&M expense.
12. Voice and Mobile Data Radio System (RM-36) is just updating obsolete radio equipment primary used for normal operations and does not meet the code qualifications as a Resiliency measure. I recommend removing the entire measure in the amount of $20.9M in capital costs.
13. Backhaul Microwave Communication (RM-37) is just updating obsolete microwave communication equipment primarily used for normal operations, so it does not meet the code qualifications as a Resiliency measure. I recommend removing the entire measure in the amount of $12.7M in capital costs.
14. In total, I recommend removing $719.07M in capital costs and $154.6M in O&M expenses or a total of $873.67M from CEHE's proposed three-year budget of $5.74 billion.

III. TESTIMONY FOR PROJECTS ASSOCIATED WITH THE 2026-2028 RESILIENCY PLAN

Q. WHAT IS SYSTEM RELIABILITY?

A. Reliability is the ability of the system and its components to withstand instability and failures during routine, or reasonably expected events such as lightning, animal-caused outages, thunderstorms, etc.

Q. HOW IS SYSTEM RELIABILITY MEASURED?

A. Reliability performance is core to the utility industry. The industry has well developed metrics in the form of System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and/or Consumer Average Interruption Duration Index ("CAIDI"). Other metrics like Customer Minutes of Interruption ("CMI") can also help evaluate system performance. Forced Interruptions ("FI") are normally measured to study reliability improvements because those are interruptions that can be readily impacted by system improvements. SAIDI is a measure of the system outage duration. A lower duration index means a shorter outage duration. Accordingly, the lower the duration index, the better the system reliability performance. SAIFI is a measure of the system's interruption frequency. A lower frequency index indicates fewer occurrences. As such, the lower the frequency index, the better the system reliability performance. CMI is a measure of how many minutes customers are facing an outage during an interruption, so the lower the number, the better the system's reliability performance. Overall, a system's reliability is performing at its best when the index score is the lowest. Scheduled outages and customer-caused outages are normally removed from a system improvement analysis.

Q. WHAT IS SYSTEM HARDENING?

A. System hardening (grid hardening) is upgrading the system electric equipment to be stronger or more resilient in severe weather (storm hardening) and to reduce wildfire risk.

Q. WHAT IS SYSTEM RESILIENCY?

A. Resiliency is the ability of the system and its components to recover following a non-routine, high-impact disruption such as extreme storms. These disruptions are known as Resiliency Events. 16 TAC §25.62 "Transmission and Distribution System Resiliency Plans", defines a Resiliency Event in 16 TAC §25.62(b)(3) as, "an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems. A resiliency event is not primarily associated with resource adequacy or an electric utility's ability to deliver power to load under normal operating conditions."

Q. WHAT IS A RESILIENCY PLAN?

A. 16 TAC §25.62(c) defines a Resiliency Plan as "a plan to prevent, withstand, mitigate, or more promptly recover from the risks posed by resiliency events to its transmission and distributions systems".

Q. HOW IS SYSTEM RESILIENCY MEASURED?

A. There are no industry standard metrics for resiliency. However, my experience has been that resiliency is directly linked to the concept of reliability. A system cannot be resilient if it is not already reliable. Thus, it is important to evaluate the results of projects first by reliability and then resiliency can be evaluated after major events.

Q. EXPLAIN WHAT IS MEANT BY A SYSTEM CANNOT BE RESILIENT IF IT IS NOT ALREADY RELIABLE.

A. Resilience is an extension of reliability. "Resilience and reliability are interrelated concepts, with resilience as the higher-level concept that includes and extends reliability. Reliability typically deals with routine, shorter-term events, while resilience extends the focus to low-probability, high-consequence disruptions"[1]. "… to be resilient, a system must first be reliable"[2]. If a utility fails to keep a system reliable, then it will also fail to be resilient because if it performs poorly under day-to-day stress events it will certainly perform poorly under the higher stress experienced during resiliency events.

Q. DO WE HAVE A RELIABILITY PLAN SIMILAR TO A RESILIENCY PLAN?

A. The industry uses multiple programs like works plans, long range plans, vegetation management plans, protection studies, cost studies, and many other programs to deploy measures that focus on building and maintaining a well-run system to keep power flowing to the customers at a reasonable cost. Some programs, like work plans, focus on projects and activities needed to replace aging infrastructure and provide reliable service to customers in a safe, economical, reasonable, and prudent manner. Other programs, like long range plans, study how to change the system to economically serve existing customers, as well as system changes needed to serve future load growth at the least. Keeping the system running well for normal operations is a large majority of the work done on a system and requires coordinating many programs and studies.

[1] NREL: "Measuring and Valuing Resilience: A Literature Review for the Power Sector", page v.
[2] "Working together toward a more resilient future", Rocky Mountain Institute, May 2020, page 10.

Q. ARE THE RESILIENCY PLAN AND MEASURES MEANT TO REPLACE NORMAL OPERATING PLANS AND MEASURES?

A. No. The Resiliency Plan is supposed to focus on resiliency, not normal operations. A Resiliency Plan focuses on Resiliency Events. From 16 TAC §25.62(c) with emphasis added: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distribution systems." Resiliency Events are not associated with primarily normal operations. From 16 TAC §25.62(b)(3) with emphasis added: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems. A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating conditions**.

Q. WERE THE RESILIENCY MEASURES INTENDED TO REPLACE SIMILAR EXISTING PROGRAMS USED FOR DAY-TO-DAY OPERATIONS AND RELIABILITY?

A. No. The statute states that the focus is on resiliency events, not primarily normal operations. This very concern about the use of the Resiliency Plan was raised during the adoption of 16 TAC §25.62. From 16 TAC §25.62 (c)(2)(D): "If a resiliency plan includes measures that are similar to other existing programs or measures, such as a storm hardening plan under 16 TAC §25.95 of this title (relating to Electric Utility Infrastructure Storm Hardening) or a vegetation management plan under 16 TAC §25.96 of this title (relating to Vegetation Management), or programs or measures otherwise required by law, the electric utility must distinguish the measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another."

In proceedings to adopt the Resiliency Plan code, Southwestern Electric Power Company ("SWEPCO") recommended removing the references to 16 TAC §25.95 and §25.96 as examples of other requirements that are required by law, because these are only reporting requirements. The Commission responded: "The Commission agrees with SWEPCO's comments and clarifies the proposed rule to reflect that these programs are not required by law. However, the commission retains the references as examples of existing programs that must be distinguished from proposed resiliency measures."[3]

In proceedings to adopt the Resiliency Plan code, the City of Houston ("Houston") expressed concerns about moving standards programs into a resiliency plan: "Houston cautioned that utilities may seek to move standard maintenance programs, storm hardening programs, or cyber and physical security programs mandated by NERC as resiliency measures, into a resiliency plan." The Commission responded: "The existing rule expressly requires utilities to distinguish its proposed resiliency measures from any existing measures and program, and any measures are [sic] programs that are required by law." [4]

Q. HOW DO WE MAKE A SYSTEM MORE RELIABLE?

A. To make a system reliable, there are day-to-day programs in place to keep a system operating and performing well when facing day-to-day stress. These programs include

[3] TPUC Project No. 55250, Order Adopting New 16 TAC §25.62, pg. 27-28.
[4] TPUC Project No. 55250, Order Adopting New 16 TAC §25.62, pg. 29.

but are not limited to measures like:

- System inspections;
- Replacing broken and worn-out equipment;
- Monitoring and maintaining existing equipment;
- Upgrading equipment to improve reliability performance;
- Event response preparation;
- Education and training;
- Reconfiguring and optimizing existing components;
- Deploying smart grid equipment and metering technologies;
- Deploying system automation to detect and isolate system problems and restore power;
- Vegetation management.

Q. HOW DO WE MAKE A SYSTEM MORE RESILIENT?

A. In addition to first making the system more reliable, there are measures we can use to help a system avoid and recover faster when exposed to non-routine, high-impact stress (Resiliency Events).

Q. ARE THESE RESILIENCY MEASURES DIFFERENT FROM THE RELIABILITY MEASURES?

A. Not all are different. Some of the resiliency measures use the same fundamental techniques we use for improvements in reliability and can appear similar.

Q. PLEASE GIVE AN EXAMPLE OF A MEASURE THAT LOOKS SIMILAR FOR RELIABILITY AND RESILIENCY.

A. One example is replacing a legacy meter with a smart meter. For day-to-day operations, we use smart meters to measuring fundamental billing quantities like we used to do with a legacy meter. We also use smart meters to provide functions for many other day-to-day operations. A few of these functions are:

- Theft detection;
- Load control;
- Load monitoring;
- Power quality monitoring;
- Energy efficiency planning;
- Fault detection;
- Outage detection and restoration;
- In-home display;
- Interaction with home smart devices;
- Faulty appliance detection;
- Improved customer billing and payment options;
- Renewable energy and distributed energy support;
- System planning;
- System optimization.

Some of these functions are also used during resiliency events such as, for example, outage detection and restoration.

Q. DOES A RESILIENCY PLAN GENERALLY SERVE THE PUBLIC INTEREST?

A. Yes.

Q. DO ALL RESILIENCY PLANS SERVE THE PUBLIC INTEREST?

A. It depends. While resiliency plans generally serve the public interest to improve reliability and other items, they must be evaluated to ensure that the plan proposed, in fact, serves the public interest by assessing the extent the plan is expected to enhance system resiliency and ensuring the cost is prudent, reasonable, cost-effective, and within the confines of Public Utility Regulatory Act ("PURA") 38.078 and 16 TAC §25.62.

Q. IF UPGRADING TO A SMART METER PROVIDES SOME FUNCTIONALITY DURING A RESILIENCY EVENT, CAN'T THIS DEVICE BE JUSTIFIED AS A RESILIENCY COST?

A. Not logically. Upgrading to a smart meter is a naturally occurring process which will take place whether we have resiliency events or not because it is the current direction of our industry. Not dissimilar to the constant changes in iPhones, AMI meters are constantly evolving, and it is not possible to purchase an older model. The AMI meter's primary use is for day-to-day operations and planning. It is not primarily focused on resiliency impacts.

Q. SO WHERE DOES THE LOGIC OF ANYTHING THAT HAS A RESILIENCY BENEFIT IS A RESILIENCY COST LEAD US?

A. If faulty logic is applied and we take the position that some measure which has a use for resiliency makes the measure expense a resiliency cost, then an electric utility could just blanket the entire electric system under a resiliency umbrella since the goal is to make the system resilient. Better logic is that an electric utility first builds a system, then maintains it and upgrades it to be reliable for day-to-day operations and then, once the system and the necessary due diligence for handling the day-to-day stress is done, then it is possible to look to see where we are vulnerable for the extra stress during a resiliency event. That extra effort and expense we take on to handle the extra stress is a resiliency cost. In summary, a system must first be reliable in order to be resilient.

Q. IF THE ELECTRIC SYSTEM IS OLD, CAN'T IT JUST BE RE-BUILT AND CALL IT A RESILIENCY EXPENSE?

A. No. Not logically. That philosophy uses the same faulty logic which would lead to the entire system being built as a resiliency measure. A system must first be reliable to be resilient. A system needs to be built and maintained to provide power on a day-to-day basis as a perpetually renewed and reliable system. It is not logical to build a system and let it degrade and age to the point that it needs to be replaced and then try to replace it under a resiliency umbrella. As part of the normal rate-making process and prudent use of rate revenues, the system must be built and maintained to keep power flowing to the end users, not build a system and let it fail because of age and poor maintenance. The rates should provide funds to keep the system operating well and renewed. When a component becomes obsolete, underperforms, or reaches end-of-life, it should be replaced as part of routine operations for a perpetually renewed system. The perpetual system itself does not target an end of life because we continually replace the obsolete parts as part of normal operations.

Q. SO, CAN YOU EVER REPLACE AGED EQUIPMENT UNDER A RESILIENCY PLAN?

A. Yes. Under reliability planning, if a component is obsolete or at end of life, then it would be replaced under normal operations. However, if the component is still providing good functionality for the modern reliable system but is inadequate for resiliency events, then it would be replaced or upgraded as a resiliency measure and have a resiliency cost.

Q. SO, IF AN OBSOLETE COMPONENT IS REPLACED WITH A NEW COMPONENT THAT HAS MODERN CAPABILITIES THAT ARE USEFUL DURING RESILIENCY EVENTS, DOES IT AUTOMATICALLY BECOME A RESILIENCY COST?

A. No. Because the world is becoming more digital, computerized, and technically advanced, any old piece of equipment will naturally be replaced with modern technology that has more bells and whistles than yesterday's technology, just like we see with cars and appliances. As the grid also becomes more modern, we make use of these new bells and whistles as part of our day-to-day operations, maintenance, and planning. We use the new capabilities to improve operations, efficiency, and reliability for normal operations. There may be nothing resiliency-unique about the new features even though we can make use of them during resiliency events the same as we use them during day-to-day events. Logically speaking, just because a piece of equipment may have one feature out of a hundred that is more useful during a resiliency event wouldn't necessarily make the whole piece of equipment a resiliency-specific piece of equipment because it is primarily associated with normal operations.

Q. IF WE DON'T UNDERTAKE A MEASURE AS PART OF THE RESILIENCY PLAN DOES THAT MEAN WE WILL FAIL TO ADDRESS THE UNDERLYING CONCERN?

A. No. Utilities should have planning processes to address the day-to-day concerns dealing with safety, reliability, and aging infrastructure that all relate to how the system functions day-to-day. The Resiliency Plan is designed to focus on concerns that tend to be unique to resiliency events, not primarily normal operation concerns. The Resiliency Plan is meant to address the concerns that extend above and beyond day-to-day operations. Resiliency is an extension of Reliability, not a surrogate for Reliability. An electric utility should build a reliable system as a foundation, then enhance that system to also be resilient. A system must first be reliable before it can be resilient.

Q. DID CEHE IDENTIFY MEASURES AND PROJECTS ASSOCIATED WITH SYSTEM RESILIENCY IN THEIR APPLICATION?

A. Yes. CEHE identified 39 measures and one pilot project, grouped into the following risk categories: Extreme Wind, Extreme Water, Extreme Temperature (Freeze), Extreme Temperature (Heat), Physical Attack, Technology & Cybersecurity, and Situational Awareness. The proposed measures and costs are shown in the following Figure MEI-1.

Figure MEI-1

Risk Category	Resiliency Measure	Estimated Capital Costs (millions)	Estimated Incremental O&M Expense (millions)
Extreme Wind	Distribution Circuit Resiliency (RM-1)	$ 513.4	-
	Strategic Undergrounding (RM-2)	$ 860.0	-
	Restoration IGSD (RM-3)	$ 107.3	$ 0.5
	Distribution Pole Replacement/Bracing Program (RM-4)	$ 251.6	-
	Vegetation Management (RM-5)	-	$ 146.1
	Transmission System Hardening (RM-6)	$ 1,467.3	$ 0.8
	69kV Conversion Projects (RM-7)	$ 369.3	-
	S90 Tower Replacements (RM-8)	$ 118.4	-
	Coastal Resiliency Projects (RM-9)	$ 177.4	$ 0.8
Extreme Water	Substation Flood Control (RM-10)	$ 43.8	-
	Control Center Flood Control (RM-11)	$ 7.0	-
	Major Underground Control and Monitoring System (MUCAMS) (RM-12)	$ 10.8	-
	Mobile Substation (RM-13)	$ 30.0	-
Extreme Temperature (Freeze)	Anti-Galloping Technologies (RM-14)	$ 14.0	$ 1.0
	Load Shed IGSD (RM-15)	$ 4.5	$ 0.1
	Microgrid Pilot Project (PP-1)	$ 35.0	$ 1.5
Extreme Temperature (Heat)	Distribution Capacity Enhancements/Substations (RM- 16)	$ 579.6	-
	MUG Reconductor (RM-17)	$ 245.0	-
	URD Cable Modernization (RM-18)	$ 128.4	-
	Contamination Mitigation (RM-19)	$ 144.0	$ 6.0
	Substation Fire Barriers (RM-20)	$ 9.0	-
	Digital Substation (RM-21)	$ 31.8	-
	Wildfire Advanced Analytics (RM-22)	-	$ 0.9
	Wildfire Strategic Undergrounding (RM-23)	$ 50.0	-
	Wildfire Vegetation Management (RM-24)	-	$ 30.0
	Wildfire IGSD (RM-25)	$ 19.4	$ 0.3
Physical Attack	Substation Physical Security Fencing (RM-26)	$ 18.0	-
	Substation Security Upgrades (RM-27)	$ 19.4	$ 0.1
Technology & Cybersecurity	Spectrum Acquisition (RM-28)	$ 42.0	-
	Data Center Modernization (RM-29)	$ 12.7	$ 1.3
	Network Security & Vulnerability Management (RM-30)	$ 7.5	$ 2.0
	IT/OT Cybersecurity Monitoring (RM-31)	$ 13.4	$ 4.2
	Cloud Security, Product Security & Risk Management (RM-32)	$ 4.0	$ 6.0
Situational Awareness	Advanced Aerial Imagery Platform / Digital Twin (RM-33)	$ 18.4	$ 2.0
	Weather Stations (RM-34)	-	$ 0.3
	Wildfire Cameras (RM-35)	-	$ 0.9
	Voice and Mobile Data Radio System (RM-36)	$ 20.9	-
	Backhaul Microwave Communication (RM-37)	$ 12.7	-
	Emergency Operations Center (RM-38)	$ 50.0	$ 6.0
	Hardened Service Centers (RM-39)	$ 107.6	-
	Total	$ 5,543.3	$ 210.7

Q. ARE SOME OF THESE MEASURES MORE APPROPRIATELY CATEGORIZED AS RELIABILITY MEASURES FOR NORMAL SYSTEM OPERATIONS?

A. Yes. The measures which are primarily for normal operations are listed in Figure MEI-2. While they are all more appropriately classed as reliability measures for normal system operations, I will also discuss some of them in more detail later.

Figure MEI-2

Normal Operations Measures
Distribution Circuit Resiliency (RM-1)
Restoration IGSD (RM-3)
Vegetation Management (RM-5)
69kV Conversion Projects (RM-7)
Coastal Resiliency Projects (RM-9)
Major Underground Control and Monitoring System (MUCAMS) (RM-12)
Distribution Capacity Enhancements/Substations (RM- 16)
MUG Reconductor (RM-17)
URD Cable Modernization (RM-18)
Contamination Mitigation (RM-19)
Digital Substation (RM-21)
Spectrum Acquisition (RM-28)
Advanced Aerial Imagery Platform / Digital Twin (RM-33)
Voice and Mobile Data Radio System (RM-36)
Backhaul Microwave Communication (RM-37)

Q. ARE THERE CONCERNS ABOUT INCLUDING RELIABILITY MEASURES IN THIS SYSTEM RELIABILITY PLAN?

A. Yes. In looking at the past performance of the reliability expenditures and results, there has been a noticeable lack of return on investment. In fact, in spite of hundreds of millions of dollars being spent to improve the system reliability, the reliability has grown worse. The idea of using the historic deployment of projects that have not produced results and accelerating them is not done by a prudent utility. To use a popular witticism often attributed to Albert Einstein: "Insanity is doing the same thing over and over and expecting different results." If spending hundreds of millions of dollars of rate-payer monies on the system has made the system reliability worse, it is not reasonable to expect spending billions of dollars of rate-payer monies going forward is going to improve the system. Benefit/Cost Analysis ("BCA") projections can be made to show possible future results, but historic real documented results are hard to ignore. No doubt there were also projections made about past spending that showed there were going to be performance benefits and a good return on investment, but in actual practice the positive results did not materialize, and the system experienced negative results instead. Before committing to spending billions of dollars to become, as CEHE posits, "the most resilient coastal utility within the U.S.", how about first becoming a utility that meets minimum reliability goals? Find out what is wrong with the fundamentals before you start swinging for the fences. A utility must first be reliable before it can be resilient.

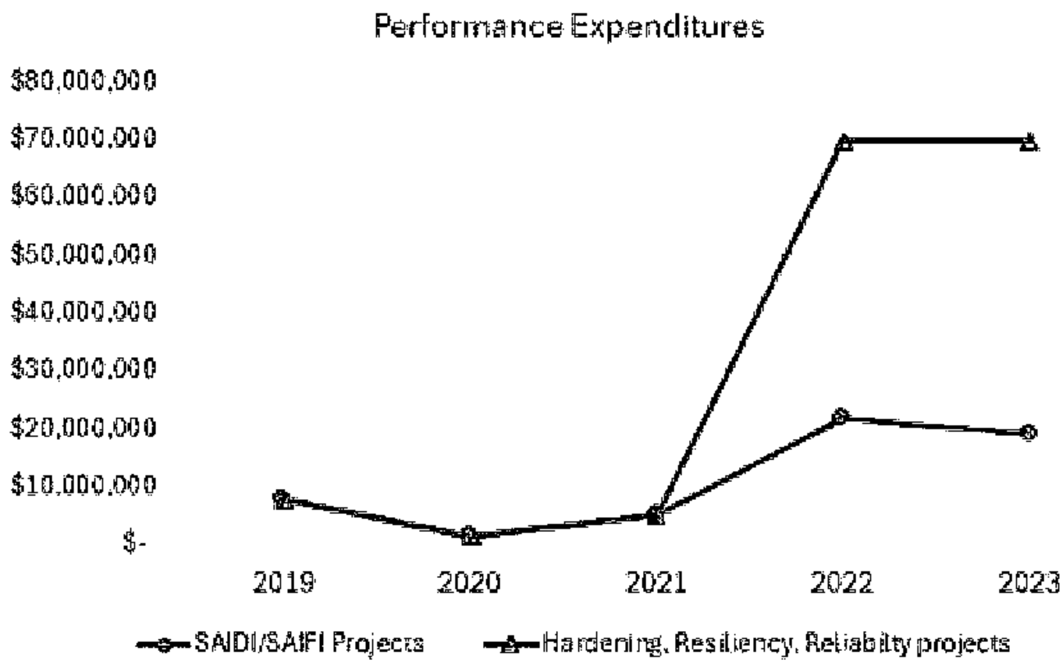
Q. ARE YOU SAYING THAT THE RESILIENCY MEASURES ARE NO GOOD?

A. No. The problem is not the measures, but how they are deployed. Experience has shown that past deployment of measures has not been effective in improving reliability. That does not mean certain measures can't be good tools. The problem is with how the measures are being implemented. The utility industry has well-defined metrics for measuring reliability performance and those metrics can be used to identify when the deployment of the reliability tools fails to achieve desired results. Thus, the measure is not prudent, and ratepayers suffered. Many of the same tools are being proposed as resiliency measures with less precise metrics to measure successful deployment. If CenterPoint keeps deploying these tools in a similar fashion for resiliency, how should we expect better results? Many resiliency measures have been successful at other utilities. But CenterPoint has not been successful in applying these tools with success on system reliability. If CenterPoint is having trouble getting simple things correct, like reliability that has well defined metrics, how can we expect CenterPoint to get the more complex matters correct with resiliency which has fewer metrics to measure success? Rate-payers are at risk of throwing money at a problem which is simply not prudent. The BCA projections used may predict success and predictions are one thing, but factual historic data has shown CenterPoint is failing to meet the predicted success with the use of rate-payer monies for previous Reliability and Resiliency projects. An expansion from spending millions to spending billions is reckless and imprudent. CenterPoint needs to determine why the measures are not successful and make adjustments. An expansion on this scale when CenterPoint has a historic problem of not meeting goals is not in the public interest. You must learn to walk before you run. Prove your basic driving skills before driving a race car. Be reliable and you can be resilient.

Q. HAVE HISTORIC RELIABILITY EXPENDITURES NOT PROVIDED A RETURN ON INVESTMENT?

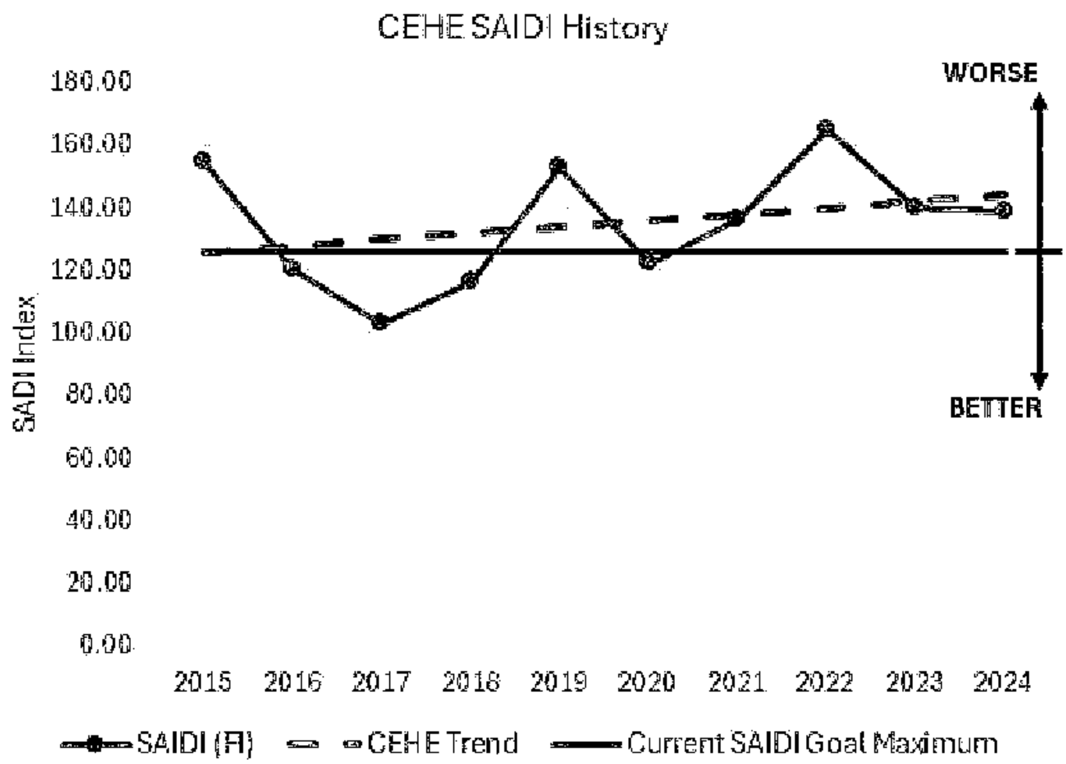
A. Yes. There is concern about the hundreds of millions of dollars CEHE has spent on Reliability and Resiliency projects without seeing a meaningful reduction in reliability scores over many years. CEHE has been spending increasing amounts of rate-payer monies on Reliability and Resiliency with decreasing returns on investment. In CEHE's most recent rate case, CEHE identified projects which were targeted to improve system performance. CEHE identified projects targeting SAIDI/SAIFI scores (IGSD and TripSaver projects) as well as projects targeted to improve Grid Hardening, Resiliency, and Reliability (IGSD, TripSaver, Grid Resiliency, and MUG projects). The increasing trend in these expenditures is shown in the following Figure MEI-3:

Figure MEI-3



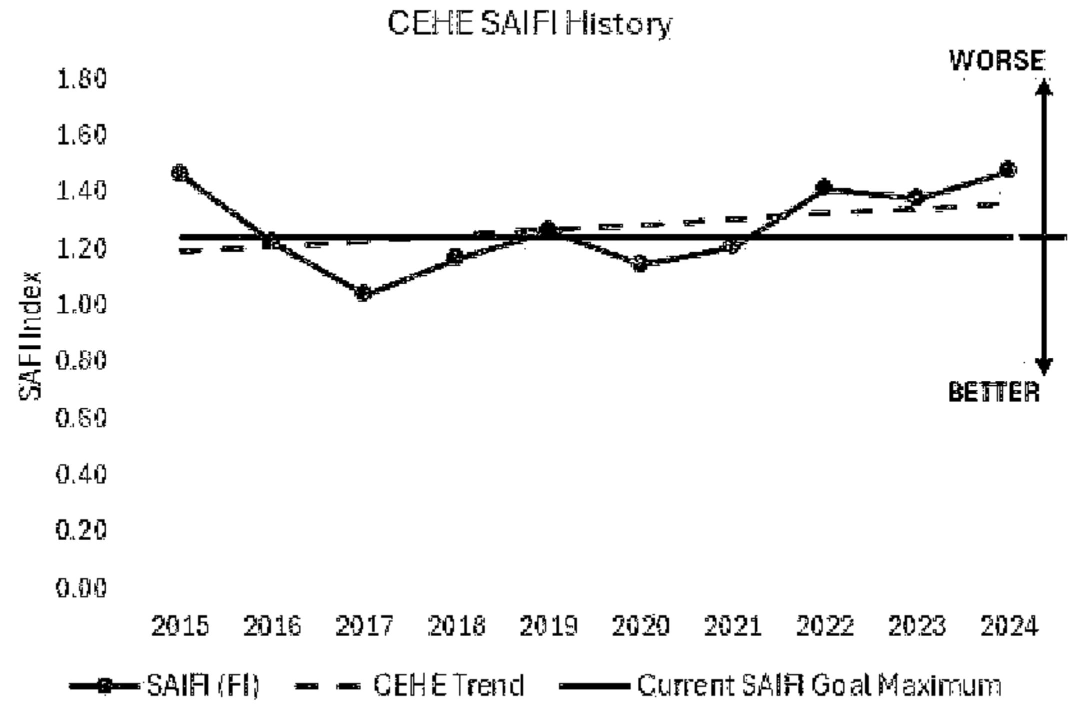
CEHE has been spending more and more but what has been the result? Examining the published SAIDI history for CEHE for the years 2015-2024, the SAIDI index trend continues to increase and indicates the system reliability is continuing to get worse and has moved above the goal maximum limit of 125.72. This SAIDI trend is illustrated in Figure MEI-4 below.

Figure MEI-4



When considering the published SAIFI history for CEHE for 2015 to 2024, the SAIFI index trend continues to increase and indicates the system reliability trend is continuing to get worse and has moved above the goal maximum limit of 1.24. This SAIFI trend is illustrated in Figure MEI-5 below:

Figure MEI-5



The reliability scores have not been improving despite CEHE pouring hundreds of millions of dollars into the system. This trend indicates there is a problem with Reliability and Resiliency planning that is causing a lack of correlating results in the performance scores. A closer look at the Reliability and Resiliency planning process should be taken before committing to such large blocks of Resiliency Plan spending; indeed, even for the current Reliability and Resiliency spending.

Items of focus include checking appropriate contingency scenarios to avoid a lot of unused reserve capacity. Also, a check should be made to see if routine growth expansions are being included along with Reliability and Resiliency contingency capacity. Since the current Reliability and Resiliency project expenses are not producing correlating results, I recommend a slower deployment approach with resultsoriented metric analysis rather than moving forward with the same planning process that is not currently producing performance-based results. Referring again to the Einstein witticism: "Insanity is doing the same thing over and over and expecting different results." How much worse is it to say we need to do even more of the same stuff that hasn't been working? Perhaps it is time to find out why past efforts have failed so we stop repeating the same mistakes.

Storms like Hurricane Beryl also indicate that there is a problem with the system that hasn't been addressed by past spending. These concerns about past project results illustrate that past Reliability and Resiliency expenditures have not been cost-effective and have not improved system performance. Moving forward with similar planning will not be in the public interest since there will be limited expectations of enhancing system resiliency and past performance has shown the measures are not expected to be cost-effective.

Q. ARE YOU PROPOSING TO USE RELIABILITY METRICS TO EVALUATE RESILIENCY MEASURES?

A. No. However, some of the proposed measures are fundamentally reliability measures and, based on the reliability scores, these have not been deployed effectively. The reliability metrics have shown that we have a fundamental planning and deployment problem and what has been tried historically is not working. Because of things like infrequency and scale of events, it is not possible to use reliability metrics to measure resiliency, but it is important to get the fundamentals correct, how is expanding into the resiliency realm, which is an extension of reliability, expected to produce great results? You must first be reliable to be resilient. If we keep failing at reliability, we are going to fail at resiliency, and that is not in the public interest.

Q. WHAT IS YOUR UNDERSTANDING OF THE DISTRIBUTION CIRCUIT RESILIENCY (RM-1) MEASURE?

A. This measure is to harden the system by replacing approximately 25,000 poles in areas with risk of tree fall-in that do not meet the new design loading criteria for extreme wind. This measure also proposes replacing existing small, aging conductors with newer and larger sized conductors that can handle additional capacity. The 3-year capital cost for this measure is $513.4 M.

Q. WHAT ARE YOUR THOUGHTS ABOUT REPLACING THE POLES UNDER THIS PROJECT BEING A RESILIENCY MEASURE?

A. The pole hardening portion can be a resiliency measure if the poles are replaced primarily as a resiliency measure to meet added loading under the newly applied extreme storm design conditions. These new pole designs criteria add extreme wind loadings that were not part of the original design so this upgrade can be considered system hardening.

Q. WHAT ARE YOUR THOUGHTS ABOUT REPLACING THE CONDUCTORS UNDER THIS PROJECT BEING A RESILIENCY MEASURE?

A. This is a capacity increase. CEHE proposes to replace the conductors in these areas with "Advanced Conductors". According to CEHE: ""Advanced conductors" in this context refers to wires that are upgraded for higher capacity or are being installed to phase out older smaller conductors such as copper conductors with all aluminum conductors."[5] Replacing conductors because of capacity, loading, and age is a measure

[5] *See* CEHE's Response to HCC-RFP04-03.

used primarily for normal operations, not a resiliency measure.

Q. DOES REPLACING THE CONDUCTORS FOR CAPACITY QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No, 16 TAC §25.62(c)(1) states a resiliency plan is comprised of one or more measures designed to prevent, withstand, mitigate, or more promptly recover from resiliency events. The rule says each measure must utilize one or more of the following methods:

(A) hardening electric transmission and distribution facilities;

(B) modernizing electric transmission and distribution facilities;

(C) undergrounding certain electric distribution lines;

(D) lightning mitigation measures;

(E) flood mitigation measures;

(F) information technology;

(G) cybersecurity measures;

(H) physical security measures;

(I) vegetation management; or

(J) wildfire mitigation and response.

Increasing capacity is not one of the listed measures. Adding capacity is a result of the normal planning process and should be based on the results from a planning study, not just increasing capacity as a resiliency measure.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DISTRIBUTION CIRCUIT RESILIENCY (RM-1) MEASURE?

A. I recommend removing the conductor capacity upgrades from the Resiliency Plan. CEHE does not have the conductor and pole costs separated. Referring to the recent rate case in docket #56211, if we use the gross plant for distribution Poles, Towers & Fixtures (Account 36401) in the amount of $1,397,970,176.42, and the gross plant for distribution Overhead Conductors and Devices (Account 36501) in the amount of $1,454,568,543.00, we get a total of $2,852,538,719.42 for poles and conductors.[6] Using these amounts, conductors are 51% of the total for poles and conductors. We can use this percentage to estimate the conductor portion of this measure's cost. 51% of the $513.4 M cost for this measure is $313.17M and is an estimate of the conductor upgrade cost in this measure. I recommend removing the conductor capacity upgrades from this measure estimated at $313.17M in capital costs.

Q. WHAT IS YOUR UNDERSTANDING OF THE RESTORATION IGSD (RM-3) MEASURE?

A. This measure proposes installing 900 Intelligent Grid Switching Devices (IGSDs) used to automatically isolate portions of the system that have sustained damage (cut and clear). The 3-year capital cost for this measure is $107.3M and the 3-year O&M cost is $0.5M.

Q. WHAT ARE THE CONCERNS WITH THE RESTORATION IGSD (RM-3) MEASURE?

A. One concern is this is IGSD devices are used for primarily normal operations. It is possible that they can also be used for issues that are mostly resiliency related, but this measure does not identify issues that are resiliency unique. These devices will primarily be used to enhance reliability under normal operations as cut and clear is a routine, everyday use for these devices to improve reliability. While they could

[6] *See* CEHE RFP Workpapers B (redacted).xlsx, sheet "WP II-B-1", lines 29-30.

possibly provide resiliency benefits, resiliency is an extension of reliability, and these devices are primarily solving a reliability issue. A system must first be reliable before it can be resilient. Another concern is the historic failure to improve reliability by deploying these devices. CEHE has a historic record of not being able to effectively improve reliability scores even though they have been deploying these devices for years at great cost to the rate payers. It is not in the public interest to keep deploying these devices until we can figure out why the historic program continues to fail.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESTORATION IGSD (RM-3) MEASURE?

A. I recommend the Commission direct Centerpoint to analyze the deployment of this type of equipment to determine why reliability numbers have not improved. Due to a well-documented lack of results in the past, there is little confidence that future results will be any different. Unless the historic problem can be identified, I recommend removing the entire measure for $107.3M in capital costs and $0.5M in O&M expense.

Q. WHAT IS YOUR UNDERSTANDING OF THE VEGETATION MANAGEMENT (RM-5) MEASURE?

A. This measure will change the vegetation trim cycles from 4.2 and 5.5 years to 3 years for all circuits and includes increased efforts to remove hazardous trees.

Q. WHAT ARE THE CONCERNS WITH THE VEGETATION MANAGEMENT (RM-5) MEASURE?

A. Vegetation Management is part of a program for normal system operations. Changing trimming cycles is not a different program, it is adjusting the routine program. Changing an existing vegetation program's schedule to adjust for high growth periods or for maintaining adequate clearance is a routine procedural adjustment. Also, consider a 5.5-year or 4.2-year trim cycle vs. a 3-year trim cycle. Logic will tell you that an extra year or two of growth is not going to make much difference with hurricane force winds that will blow broken limbs long distances. In a hurricane, broken limbs are going to blow much further than that small growth distance, so the trimming remains a normal operations measure. Trimming trees is not the sort of measure that is resiliency specific because it is a routine measure. In the Public Utility Commission of Texas Project No. 36375, Quanta Technology published a report titled "Hazard Trees: Benchmark Survey and Best Practices" that included the following statement: "Tree pruning is an important and expensive activity but will not generally impact the amount of tree-related damage that a utility experiences during a major storm. This is because most tree-related storm damage is caused by entire trees falling over into the power lines."[7]. The Quanta report also states: "Baltimore Gas & Electric, Eastern Utilities Associates, and TransAlta Utilities have reported only 2% of tree-related outages due to in-growth when the pruning program is on cycle. Even if wind gusts increased these outages by hundreds of percent, they will still comprise a very small component of all storm related tree outages."[8] Note the statement "**<u>when the pruning program is on cycle"</u>** (emphasis added). This is saying if there is a problem with vegetation in-growth, then there is a problem with the trim cycle, and it should be adjusted as part of routine trimming. An example of a resiliency measure would be a one-time cost to increase the right-of-way width and then you would maintain that wider right-of-way using future normal trim cycles. As another resiliency measure

[7] *See* CEHE's Response to HCC RFP 1-2: Attachment A2 Quanta Benchmark Report, pg. 12 of 81, ¶ 2.
[8] *See* CEHE's Response to HCC RFP 1-2: Attachment A2 Quanta Benchmark Report, pg. 22 of 81, ¶ 3.

example, hurricanes will blow down more trees than normal storms so a hazard tree measure that identifies trees susceptible to high winds, even trees which would be classified as healthy under normal storms, would be an example of a resiliency measure. Identifying unhealthy hazardous trees under normal weather events would still be part of the normal Vegetation Management Program but might not capture those healthier trees susceptible to Resiliency Event loads.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE VEGETATION MANAGEMENT (RM-5) MEASURE?

A. I recommend removing this entire measure from the Resiliency Plan and developing a new measure to identify hazardous trees that are uniquely susceptible to resiliency weather events. This recommendation removes $146.1M in O&M expenses.

Q. WHAT IS YOUR UNDERSTANDING OF THE MAJOR UNDERGROUND CONTROL AND MONITORING SYSTEM (MUCAMS) (RM-12) MEASURE?

A. This measure includes upgrading the communications from copper to fiber and upgrading the interface to handle the growing number of underground services. The 3-year capital cost for this measure is $10.8M.

Q. WHAT ARE THE CONCERNS WITH THE MAJOR UNDERGROUND CONTROL AND MONITORING SYSTEM (MUCAMS) (RM-12) MEASURE?

A. MUCAMS is used to monitor equipment that is located on underground circuits. This is primarily a normal system operations function as this monitoring takes place every day and not primarily during resiliency events. Also, the application states the following about the Human-Machine-Interface (HMI) upgrade: "The HMI component involves replacing the existing software application with a more robust system that can support the growing number of underground services."[9] Upgrading the communications and the interface for growth in underground services is capacity related. CEHE admits this is not a new program but an ongoing program with a life of 20-25 years: "MUCAMS is an ongoing program with no planned end of service life. Service life of equipment used in MUCAMS will vary depending on operational and environmental conditions at each site. Based on information provided by different manufactures, service life of communication equipment is on average at least 25 years and service life of microprocessor-based relays is on average at least 20 years"[10] and also states that the system has been in service for approximately 20 years.[11] So, this is also replacing aged infrastructure used for normal system operations that is nearing end of life, not addressing a resiliency specific issue.

Q. DOES REPLACING THE COMMUNICATIONS AND INTERFACE FOR CAPACITY QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62(c)(1) states a resiliency plan comprises one or more measures designed to prevent, withstand, mitigate, or more promptly recover from resiliency events. The rule says each measure must utilize one or more of the following methods:

(A) hardening electric transmission and distribution facilities;

(B) modernizing electric transmission and distribution facilities;

(C) undergrounding certain electric distribution lines;

(D) lightning mitigation measures;

[9] *See* Application Section 5.2.5.3, pg 156, ¶ 2.
[10] *See* CEHE's Response to HCC-RFI04-32.
[11] *See* CEHE's Response to HCC-RFI04-39.

(E) flood mitigation measures;

(F) information technology;

(G) cybersecurity measures;

(H) physical security measures;

(I) vegetation management; or

(J) wildfire mitigation and response.

Increasing capacity is not one of the listed measures. Adding capacity is a result of the normal planning process that accounts for the system growth not just increasing capacity as a resiliency measure. Also, the Resiliency Plan is supposed to focus on resiliency, not normal operations. A Resiliency Plan focuses on Resiliency Events. A Resiliency plan is defined in the code as: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distributions systems."[12] So if a Resiliency Plan focuses on Resiliency Events, then what is a Resiliency Event? The code defines a Resiliency Event as: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems."[13] So, what is **NOT** a resiliency event? The code states: "A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating conditions**."[14] By being a capacity measure to handle the growth in underground conductors and

[12] *See* 16 TAC §25.62(c).
[13] *See* 16 TAC §25.62(b)(3).
[14] *See* 16 TAC §25.62(b)(3).

associated with delivering power to load under normal operating conditions since this is part of daily routine monitoring, this is not a Resiliency measure.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE MAJOR UNDERGROUND CONTROL AND MONITORING SYSTEM (MUCAMS) (RM-12) MEASURE?

A. I recommend removing the entire measure in the amount of $10.8M in capital costs.

Q. WHAT IS YOUR UNDERSTANDING OF THE CONTAMINATION MITIGATION (RM-19) MEASURE?

A. This measure adds to the existing insulator monitoring program by adding more sensors and additional monitoring to measure salt contamination. This monitoring is being used to determine when insulators need to be washed to prevent flashovers. It also replaces some wood poles with fiberglass poles and these two together reduce the risk of flashover due to salt contamination. The 3-year cost for this measure is $144.0M in capital costs and $6.0M in O&M expenses.

Q. WHAT ARE THE CONCERNS WITH THE CONTAMINATION MITIGATION (RM-19) MEASURE?

A. This is primarily a normal system operations function as this is just monitoring and cleaning insulators and is not a primarily resiliency event issue but primarily a normal operations project to ensure reliability. The application states the following: "This Resiliency Measure allows for the Company to add more sensors and use technology to predict when power washing is needed."[15] Salt accumulation happens all the time and is not just something that occurs during a resiliency event.

[15] *See* Application Section 5.4.5.4, pg 197, ¶ 1.

Q. DOES ADDING CONTAMINATION SENSORS AND USING FIBERGLASS POLES QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62 states the Resiliency Plan is supposed to focus on Resiliency Events. A Resiliency plan is defined in the code as: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distributions systems."[16] So if a Resiliency Plan focuses on Resiliency Events, then what is a Resiliency Event? The code defines a Resiliency Event as: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems."[17] So, what is **NOT** a resiliency event? The code states: "A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating conditions**."[18] By using a measure to address salt contamination, which is an everyday issue, not something that is specific to Resiliency Events, this is not a Resiliency measure.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CONTAMINATION MITIGATION (RM-19) MEASURE?

A. I recommend removing the entire measure in the amount of $144.0M in capital costs and $6.0M in O&M expenses.

[16] *See* 16 TAC §25.62(c).
[17] *See* 16 TAC §25.62(b)(3).
[18] *See* 16 TAC §25.62(b)(3).

Q. WHAT IS YOUR UNDERSTANDING OF THE DIGITAL SUBSTATION (RM-21) MEASURE?

A. This measure is replacing aged, obsolete relays and communications with new relays and fiber communications.

Q. WHAT ARE THE CONCERNS WITH THE DIGITAL SUBSTATION (RM-21) MEASURE?

A. This measure is just modernizing components in a substation like we do every day and is not primarily related to resiliency. Older substation relays and equipment are being replaced every day with modern digital equipment, and we primarily use these new features in day-to-day operations. The application states the following: "These features will help drive down O&M costs, collectively enhance reliability and resiliency, and, over time, lower the cost of constructing new substations." [19] The fact that replacement devices may come with more bells and whistles is just part and parcel of buying new equipment, much like new cars and appliances have more bells and whistles than the old ones.

Q. DOES REPLACING AGED, OBSOLETE RELAYS AND COMMUNICATIONS WITH NEW RELAYS AND FIBER COMMUNICATIONS QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62 states the Resiliency Plan is supposed to focus on Resiliency Events. A Resiliency plan is defined in the code as: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distributions systems."[20]

[19] *See* Application Section 5.4.5.6, pg. 203, ¶ 3.
[20] *See* 16 TAC §25.62(c).

So if a Resiliency Plan focuses on Resiliency Events, then what is a Resiliency Event? The code defines a Resiliency Event as: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems."[21] So, what is **NOT** a resiliency event? The code states: "A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating conditions**."[22] By using a measure to replace aging infrastructure like we would normally do, this is not something that is specific to Resiliency Events and is not a Resiliency measure.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DIGITAL SUBSTATION (RM-21) MEASURE?

A. I recommend removing the entire measure in the amount of $31.8M in capital costs.

Q. WHAT IS YOUR UNDERSTANDING OF THE SUBSTATION PHYSICAL SECURITY FENCING (RM-26) MEASURE?

A. This measure replaces existing chain link fencing with less permeable wire mesh fencing. The 3-year capital cost for this measure is $18.0M.

Q. WHAT ARE THE CONCERNS WITH THE SUBSTATION PHYSICAL SECURITY FENCING (RM-26) MEASURE?

A. The Substation Physical Security Fencing Resiliency Measure will replace chain link fences with wire mesh fences. The wire mesh fencing is expensive and does not stop someone determined to enter a substation so it is not expected to enhance resiliency.

[21] *See* 16 TAC §25.62(b)(3).
[22] *See* 16 TAC §25.62(b)(3).

CEHE has said wire mesh fencing increases the intrusion time using old intrusion techniques by 47.6 minutes.[23] However, should the intruder upgrade the attack, which it is reasonable to expect they would, the intrusion time is only delayed by 4.5 minutes.[24] I can prove there is practically no delay in time with other techniques but will forgo discussing these in an open format. Fences only keep out honest people and the more economical but effective chain link fence has historically been an effective deterrent against normal and accidental intrusion. In my experience with substation design and implementing security measures in substations, I can say if someone wants to get in the substation, they are getting in. The question is, what do we do about an unwanted intrusion? The extra money that would be spent on upgrading from chain link to wire mesh fencing would be better spent on more cost-effective measures. Based on my experience in deterring normal intrusions, my recommendation would be to spend the money on better lighting and active monitoring with cameras and motion detection devices like we find in the measure Substation Security Upgrades (RM-27). This will be an adequate deterrent against normal intrusions and give a means to respond to aggressive intrusions where the intruder will cross any barrier. CEHE should continue to maintain the current fencing under the existing substation maintenance program. Since this measure is easily thwarted, it provides little enhancement to system resiliency. A single $715,000 fence around a substation which can be easily thwarted with equipment that costs less than $1,000 is a poor investment and not in the public interest. Wire Mesh Fencing is a $18M capital investment that should not be included in the Resiliency Plan. The Wire Wall Fencing measure is not

[23] *See* Docket No. 56548, CEHE's response to HCC-RFP01-07.
[24] *See* Docket No. 56548, CEHE's response to HCC-RFP01-07.

in the public interest because it is a high cost, it provides practically no enhancement to system Resiliency, and there are more cost-effective measures available.

Q. DOES REPLACING THE SUBSTATION FENCING QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62(d)(4) states in reviewing a Resiliency Plan, the Commission will consider:

(A) the extent to which the plan is expected to enhance system resiliency, including whether the plan prioritizes areas of lower performance;

(B) the estimated costs of implementing the measures proposed in the plan; and

(C) whether the plan is in the public interest. The commission will not approve a plan that is not in the public interest. In evaluating the public interest, the commission may consider:

(i) the extent to which the plan is expected to enhance system resiliency, including:

(I) the verifiability and severity of the resiliency risks posed by the resiliency events the resiliency plan is designed to address;

(II) the extent to which the plan will enhance resiliency of the electric utility's system, mitigate system restoration costs, reduce the frequency or duration of outages, or improve overall service reliability for customers during and following a resiliency event;

(III) the extent to which the resiliency plan prioritizes areas of lower performance;

(IV) the extent to which the resiliency plan prioritizes critical load as defined in §25.52 of this title (relating to Reliability and Continuity of Service);

(ii) the estimated time and costs of implementing the measures proposed in the resiliency plan;

(iii) whether there are more efficient, cost-effective, or otherwise superior means of preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the resiliency events addressed by the resiliency plan; or

(iv) other factors deemed relevant by the commission.

The wire mesh fence is not expected to enhance resiliency since it can be easily defeated with no significant delay when compared to a traditional chain link fence. The cost is significantly higher than the traditional chain link fence used in substations across the country but fails to provide significant security improvement against an attack. This measure is not in the public interest because it does not significantly enhance system resiliency, has a high cost, and is not the most cost-effective measure.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SUBSTATION PHYSICAL SECURITY FENCING (RM-26) MEASURE?

A. I recommend removing the entire measure in the amount of $18.0M in capital costs.

Q. WHAT IS YOUR UNDERSTANDING OF THE SPECTRUM ACQUISITION (RM-28) MEASURE?

A. This measure is adding additional communications capacity by acquiring additional communications spectrum bandwidth. The 3-year capital cost for this measure is

$42.0M.

Q. WHAT ARE THE CONCERNS WITH THE SPECTRUM ACQUISITION (RM-28) MEASURE?

A. This measure is just updating telecommunications needs primary for normal operations and is not resiliency specific. The application states the following: "To maintain future levels of reliability and resiliency, along with accommodating new communication demands on the power grid, additional spectrum needs to be acquired. The spectrum acquisition is the long-term solution to support the multitude of utility use cases to satisfy the T&D systems and functions." [25] This is primarily part of normal operations and is just adding additional communication capacity for day-to-day operations.

Q. DOES AQUIRING ADDITIONAL SPECTRUM QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62 states the Resiliency Plan is supposed to focus on Resiliency Events. A Resiliency plan is defined in the code as: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distributions systems."[26] So if a Resiliency Plan focuses on Resiliency Events, then what is a Resiliency Event? The code defines a Resiliency Event as: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems."[27] So, what is **NOT** a resiliency event? The

[25] *See* Application Section 5.6.1, pg 224, ¶ 2-3.
[26] *See* 16 TAC §25.62(c).
[27] *See* 16 TAC §25.62(b)(3).

code states: "A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating conditions**."[28] This is a measure to add more capacity due to growth of day-to-day communications on the system replace aging infrastructure like we would do in the normal course of business, this is not something that is specific to Resiliency Events and is not a Resiliency measure.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SPECTRUM ACQUISITION (RM-28) MEASURE?

A. I recommend removing the entire measure in the amount of $42.0M in capital costs.

Q. WHAT IS YOUR UNDERSTANDING OF THE ADVANCED AERIAL IMAGERY PLATFORM / DIGITAL TWIN (RM-33) MEASURE?

A. This measure creates a digital computerized model of the electric system. The 3-year capital cost for this measure is $18.4M and the 3-year O&M cost is $2.0M.

Q. WHAT ARE THE CONCERNS WITH THE ADVANCED AERIAL IMAGERY PLATFORM / DIGITAL TWIN (RM-33) MEASURE?

A. This measure creates a digital version of the system. Users can track system usage, data, maintenance data, trends and run various scenarios and models in studying how the system may respond to different loads, configurations, outages, etc. This digital version of the system can be used to model resiliency events but are also used to model normal events and design options, track normal vegetation management, track equipment maintenance, improve efficiency, power flow analysis, loss analysis, interconnection impacts, load studies, 3D construction and physical space conflict

[28] *See* 16 TAC §25.62(b)(3).

modeling, and a wealth of other day-to-day operational and planning activities. The primary use is for day-to-day planning and its use as a resiliency event modeling tool is just one of its uses. This is used primarily as part of normal operations so is not a Resiliency measure.

Q. DOES MAKING A COMPUTERIZED DIGITAL VERSION OF THE SYSTEM QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62 states the Resiliency Plan is supposed to focus on Resiliency Events. A Resiliency plan is defined in the code as: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distributions systems."[29] So if a Resiliency Plan focuses on Resiliency Events, then what is a Resiliency Event? The code defines a Resiliency Event as: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems."[30] So, what is **NOT** a resiliency event? The code states: "A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating conditions**."[31] This is a measure which is primarily used for day-to-day planning and has many features which only some can also be used for Resiliency planning so is not something that is specific to Resiliency Events and is not a Resiliency measure.

[29] *See* 16 TAC §25.62(c).
[30] *See* 16 TAC §25.62(b)(3).
[31] *See* 16 TAC §25.62(b)(3).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ADVANCED AERIAL IMAGERY PLATFORM / DIGITAL TWIN (RM-33) MEASURE?

A. I recommend removing the entire measure in the amount of $18.4M in capital costs and $2.0M in O&M expenses.

Q. WHAT IS YOUR UNDERSTANDING OF THE VOICE AND MOBILE DATA RADIO SYSTEM (RM-36) MEASURE?

A. This measure replaces obsolete mobile and portable radio communications equipment. The 3-year capital cost for this measure is $20.9M.

Q. WHAT ARE THE CONCERNS WITH THE VOICE AND MOBILE DATA RADIO SYSTEM (RM-36) MEASURE?

A. This measure is just updating obsolete radio equipment primarily used for normal operations and is not resiliency-specific. The application states the following: "Manufacturer support for the Company's current mobile data radio system is "end of life" and spare equipment is limited." [32] This is just replacing obsolete equipment and is primarily part of normal operations so can't be in the Resiliency Plan.

Q. DOES REPLACING AGED, OBSOLETE MOBILE AND PORTABLE RADIO COMMUNICATIONS EQUIPMENT QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62 states the Resiliency Plan is supposed to focus on Resiliency Events. A Resiliency plan is defined in the code as: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distributions systems."[33]

[32] *See* Application Section 5.7.4, pg 246, ¶ 3.
[33] *See* 16 TAC §25.62(c).

So if a Resiliency Plan focuses on Resiliency Events, then what is a Resiliency Event? The code defines a Resiliency Event as: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems."[34] So, what is **NOT** a resiliency event? The code states: "A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating conditions**."[35] By using a measure to replace aging infrastructure like we would normally do, this is not something that is specific to Resiliency Events and is not a Resiliency measure.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE VOICE AND MOBILE DATA RADIO SYSTEM (RM-36) MEASURE?

A. I recommend removing the entire measure in the amount of $20.9M in capital costs.

Q. WHAT IS YOUR UNDERSTANDING OF THE BACKHAUL MICROWAVE COMMUNICATION (RM-37) MEASURE?

A. This measure is replacing aging and obsolete microwave communications used for monitoring and controlling field devices. The 3-year capital cost for this measure is $12.7M.

Q. WHAT ARE THE CONCERNS WITH THE BACKHAUL MICROWAVE COMMUNICATION (RM-37) MEASURE?

A. This measure is just updating obsolete microwave communication equipment primarily used for normal operations and is not resiliency specific. The application states the

[34] *See* 16 TAC §25.62(b)(3).
[35] *See* 16 TAC §25.62(b)(3).

following: "Much of The Company's current microwave equipment is nearing obsolescence and thus support is limited, and it is incompatible with newer platforms. The Backhaul Microwave Communication Resiliency Measure will replace this aging microwave equipment with new equipment that is compatible with the Company's newer microwave equipment, enabling the use of a single network management tool to see issues and remotely troubleshoot." [36] This is just replacing obsolete equipment and is primarily part of normal operations so can't be in the Resiliency Plan.

Q. DOES REPLACING AGING AND OBSOLETE MICROWAVE USED FOR MONITORING AND CONTROLLING FIELD DEVICES QUALIFY FOR THE SYSTEM RESILIENCY PLAN AS DEFINED BY 16 TAC §25.62?

A. No. 16 TAC §25.62 states the Resiliency Plan is supposed to focus on Resiliency Events. A Resiliency plan is defined in the code as: "Resiliency Plan. An electric utility may file a plan to prevent, withstand, mitigate, or more promptly recover from the **risks posed by resiliency events** to its transmission and distributions systems."[37] So if a Resiliency Plan focuses on Resiliency Events, then what is a Resiliency Event? The code defines a Resiliency Event as: "Resiliency event -- an event involving extreme weather conditions, wildfires, cybersecurity threats, or physical security threats that poses a material risk to the safe and reliable operation of an electric utility's transmission and distribution systems."[38] So, what is **NOT** a resiliency event? The code states: "A resiliency event is **not primarily associated with** resource adequacy or an electric utility's ability to deliver power to load under **normal operating**

[36] *See* Application Section 5.7.5, pg. 249, ¶ 1.
[37] *See* 16 TAC §25.62(c).
[38] *See* 16 TAC §25.62(b)(3).

conditions."[39] By using a measure to replace aging infrastructure like we would normally do, this is not something that is specific to Resiliency Events and is not a Resiliency measure

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE BACKHAUL MICROWAVE COMMUNICATION (RM-37) MEASURE?

A. I recommend removing the entire measure in the amount of $12.7M in capital.

IV. CONCLUSION

Q. DOES YOUR TESTIMONY ADDRESS EVERY POTENTIAL ISSUE IN THE CASE?

A. No. My testimony addresses a very limited scope of issues. My silence on other issues in the case should not be interpreted as my agreement on those issues.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, with the reservation of the right to file an errata should answers to RFIs be received and based on rebuttal testimony, if necessary.

[39] *See* 16 TAC §25.62(b)(3).

○ Michael Ivey

EDUCATION ○

B.S., Engineering, Specialization: Electrical, Mercer University School of Engineering, Macon, GA, 1994

Continuing education and certifications in electrical and utility engineering

PROFESSIONAL MEMBERSHIPS ○

Institute of Electrical and Electronics Engineers where he has served as chair and secretary of the Central Georgia section and currently serves as the section treasurer.

Power Engineering Society, IEEE
Smart Grid Community, IEEE

PROFESSIONAL REGISTRATIONS ○

Licensed Professional Engineer in Georgia (PE038037)
Licensed Electrical Contractor in Georgia (EN210717)

AREAS OF EXPERTISE ○

- Utility Supply/Generation/Transmission/Distribution, regulatory and code compliance, system engineering and design, finance and billing, data analysis, system modeling and analysis, programming, training, and personnel.

PROFESSIONAL EXPERIENCE ○

GDS Associates, Inc., Marietta, Georgia, January 2023-present
Senior Project Manager

- Currently consulting on projects that include: system rebuilding, work order inspections, training classes, system expansions, miscellaneous system engineering, testimony assistance on storm response, reliability and resiliency plans, and rate case testimony.

Crisp County Power Commission, Crisp County, Georgia, December 2017 – November 2022
Assistant General Manager; General Manager
Managing a multi-faceted electric utility with assets including local hydro and natural gas generation, a hydro generating reservoir, gas and electric transmission lines, distribution substations and lines, and a fiber system used both for control and leased capacity. Also served as the utility principal engineer and expert on design and construction to ensure compliance with NESC and NEC codes and well as regulatory compliance with agencies such as FERC, EPA, EPD, USACE, Georgia DNR, etc.

Addressed multiple challenges in areas needing improvement including aged infrastructure, system protection and coordination, mapping, metering, system and equipment maintenance, reliability, right-of-way, safety, adequate staffing, employee satisfaction, training, efficiency, and succession planning. Some of the projects and improvements included:

- Updated design and construction practices and training to provide better safety and reliability.
- Began conversion from a 12kV system to a 25kV system in anticipation of future growth in distribution DG, battery storage, and electric vehicle charging.
- Implemented operational equipment safety inspection and replacement procedures to ensure safer working conditions and reduce down time due to equipment failure.
- Updated an old mapping system to a modern system with connectivity and intelligence to allow real-time system analysis and planning.
- Replaced a radio-read meter system with a modern AMI system. This solution provides system data for analysis and interacts with other systems while also solving multiple staffing issues.
- Modernized the SCADA system to allow better control capability and data exchange with other system software.

- Implemented a substation, line, and distribution equipment inspection program to improve reliability and system safety.
- Established sectionalizing practices and training to ensure proper equipment selection and coordination to reduce outages, reduce equipment failure, and provide better safety.
- Changed right-of-way maintenance practices to provide for routine, scheduled clearing of vegetation to improve system safety, reliability, and ready access to the system for repairs, upgrades, and inspection.
- Filled staff shortages, provided technical training, and cross-training to adequately maintain workflow, prepare for succession planning, and improve morale.
- Began a program of culture change to improve employee morale and efficiency. Focused on making system improvements and tasks a team effort as well as provide better interaction between management and staff.
- Upgraded workplace facilities to provide for a more efficient and safe layout as well as replace failed and outdated components.
- Installed AVR, call-management, and OMS systems to improve outage response and customer interaction.
- Interconnected the mapping, AMI, SCADA, OMS, and AVR systems together to provide a better response during outages and a better means to analyze the system state in real time.
- Implemented a digital staking interface and digital inventory system with a tie to the accounting system to improve material count and cost tracking as well as control.
- Began implementation of digital field staking to reduce paperwork and design time and to allow more efficient job creation and mapping updates.
- Began implementation of digital warehouse control that would tie to the accounting system as well as the digital field staking and work order systems to improve inventory maintenance and material tracking.
- Implemented broader long-term planning that added to the existing long-term power supply planning. This added long-term R&R planning and costs for the hydro generation and hydro reservoir facilities, transmission lines, substations, and distribution system as well as improving the long-term cost forecasts.
- For lake dock and pier policy management, converted from paper records to digital records and incorporated aerial imagery and computerized structure analysis to improve efficiency and accuracy in compliance tracking and records management.

Crisp County Power Commission, Crisp County, Georgia, May 2014 – December 2017
Manager of Technical Services
Overseeing and supervising the Engineering, Substation Operations, Meter Shop, and Warehouse Inventory, providing Technical Support to the Generation Department, and serving as the utility's Staff Engineer.

McLean Engineering Company, Inc., Moultrie, Georgia, July 2011 – May 2014
Principal Senior Engineer
Applied engineering and business skills in utility consulting including:

- Serving as an authority in many areas of utility engineering and troubleshooting.
- Design and analysis of transmission, substation, and distribution facilities and protection systems.
- Conducting analysis and studies for distribution systems including work plans, coordination studies, and capacitor studies.
- System mapping and modeling
- Conducting and presenting costs of service studies, rate design and analysis.
- Training new employees in various aspects of power engineering.
- Conducting training sessions and classes in power engineering and rates.
- Developing and maintaining engineering analysis software.

Municipal Electric Authority of Georgia / Electric Cities of Georgia, Atlanta, Georgia, September 2000 – July 2011
Senior Engineer
Applied engineering and business skills to assist local governments in many areas including:

- Develop, analyze and present cost of service studies, load and sales forecasts, rate designs, budgets, retail billing, wholesale and retail cost analysis, policies, customer choice rate and supply options across various services.
- Develop and conduct training sessions on retail and wholesale rates, distribution electrical system design, distribution electrical system operations, and computer software use.
- Develop computer models to assist with economic analysis, billing, forecasting, and various business and engineering analysis.

- Analyze wholesale and retail generation opportunities and power supply needs.
- Serve as an authority on costs, rates, distribution line design and operations, regulatory compliance, territorial issues, NESC and NEC code compliance.
- Conduct analysis on power quality and energy conservation issues.
- Act as an expert resource on legislative impacts on the management, cost, and operations of the electrical system.
- Help negotiate agreements and disputes with customers, other service providers, and other governing agencies.
- Presentations to councils, boards, and staff.

McLean Engineering Company, Inc., Moultrie, Georgia, August 1994 – September 2000
Electrical Engineer
Applied engineering and business skills in utility consulting including:

- Transmission, substation, and distribution protection and design
- System work plan studies
- System mapping and modeling
- Wholesale & retail metering installation and testing
- Cost of services studies and rate design and analysis
- Designed, developed, and maintained company software including CAD mapping systems and engineering analysis tools.
- Trained employees in the use of computer software and hardware.