**BEFORE THE**

**LOUISIANA PUBLIC SERVICE COMMISSION**

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| ***IN RE:*** **APPLICATION OF ENTERGY LOUISIANA, LLC FOR CERTIFICATION OF GENERATION AND TRANSMISSION RESOURCES AND FOR OTHER RELIEF PURSUANT TO THE COMMISSION'S *LIGHTNING INITIATIVE*** | **)** **)** **)** **)** **)** **)** | **DOCKET NO. U-_____** |

# DIRECT TESTIMONY

**OF**

**DANIEL KLINE**

**ON BEHALF OF**

**ENTERGY LOUISIANA, LLC**

**PUBLIC REDACTED VERSION**

**MARCH 2026**

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## EXHIBITS

## I. WITNESS BACKGROUND

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Daniel Kline. My business address is 6540 Watkins Drive, Jackson, Mississippi 39213.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. As of mid-February, I am the Director, Project Delivery Engineering for Entergy Services, LLC ("ESL"),[1] the service company affiliate of Entergy Louisiana, LLC ("ELL" or the "Company"). Immediately prior to assuming this role, I was the Director of Power Delivery Planning for ESL.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am submitting this Direct Testimony to the Louisiana Public Service Commission ("Commission" or "LPSC") in support of the Application on behalf of ELL.

Q4. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, PROJECT DELIVERY ENGINEERING?

A. I am responsible for the leadership and oversight of a team of engineers, technicians, and drafters who perform the technical design work for new transmission and distribution facilities that will be constructed and owned by the Entergy Operating

[1] ESL is an affiliate of the Entergy Operating Companies that provides engineering, planning, accounting, legal, technical, regulatory, and other administrative support services to each of the Entergy Operating Companies. The Entergy Operating Companies are Entergy Arkansas, LLC ("EAL"), ELL, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.

Companies, including ELL. My team also oversees consultants in the performance of similar work. My team takes the projects that are identified by the Power Delivery Planning team and completes the technical specifications and designs needed to perform construction activities and complete those projects. In addition to these responsibilities, I have retained my responsibility for Project Laidley and Project Evest (as both are defined below) as well as an advisory role for large customer interconnections and federal policy.

Q5. WHAT WERE YOUR RESPONSIBILITIES AS DIRECTOR, POWER DELIVERY PLANNING?

A. I was responsible for the leadership and oversight of a team of engineers who studied the bulk electric system and the electric distribution network to identify transmission and distribution projects necessary to meet the customer service needs of the Entergy Operating Companies, support reliable service to customers, interconnect new generation, and maintain compliance with certain North American Electric Reliability Corporation ("NERC") reliability standards governing transmission planning as well as Entergy's internal criteria for transmission and distribution planning. The planning team works with the Entergy Operating Companies to develop necessary transmission and distribution projects and provide support through the regulatory permitting process. The planning team also maintains local planning criteria specific to Entergy's transmission and distribution assets and conduct studies to ensure compliance with those criteria. The planning team is also responsible for providing technical support to large industrial customers and engagement in the Midcontinent Independent System

Operator, Inc. ("MISO") stakeholder process on policy matters that affect transmission and distribution systems.

Q6. PROVIDE THE COMMISSION WITH A BRIEF SUMMARY OF YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I graduated from Iowa State University with a B.S. in Electrical Engineering and have worked for and with electric utilities for the past 20 years, primarily in the transmission space. I started my career with the Transmission Planning Group at Pacific Gas and Electric Company in 2003 before moving into software development with Open Systems International in 2004. At Open Systems, I focused on power system application development, installation, and support. In 2006, I moved back to transmission planning with Xcel Energy Inc. and progressed through a number of positions, including roles coordinating transmission planning and policy as a liaison to MISO, leading a regulatory policy team, and ultimately assuming responsibility for all large-scale transmission project development and construction across Xcel Energy Inc.'s service territory. In 2015, I began working for Black Hills Energy, a utility in South Dakota, where I was responsible for all aspects of transmission policy, planning, engineering, construction, and operations. In 2020, I started my employment with ESL as Director of Transmission Planning until the transmission and distribution organizations were combined in 2022, at which point I assumed my Power Delivery Planning role.

Q7. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. Exhibit DK-1 contains a list of the regulatory proceedings in which I have previously testified.

## II. OVERVIEW OF TESTIMONY

Q8. PROVIDE A BRIEF OVERVIEW OF THE PROJECT AT ISSUE IN THIS DOCKET?

A. Evest LLC ("Customer"), a subsidiary of Meta Platforms, Inc., has proposed to construct a new hyperscale data center in Richland Parish ("Project Evest") with a capacity of [redacted]. Project Evest will support the Customer's artificial intelligence (AI) business line and will be constructed on land adjacent to the data center site of Customer's affiliate, Laidley, LLC, in connection with which resources were approved in LPSC Docket No. U-37425 ("Project Laidley"). Company witness Laura Beauchamp provides a detailed overview of Project Evest and each of its components.

Q9. WHAT RESPONSIBILITIES DID YOU AND THE POWER DELIVERY PLANNING TEAM HAVE WITH RESPECT TO THE CUSTOMER'S PROJECT?

A. We were responsible for: (1) identifying a reasonable, cost-effective solution for the transmission and distribution facilities (the "Transmission Facilities") required to serve the new hyperscale data center considering load profile, the electric system topology in North Louisiana, and other electric system needs; (2) identifying the transmission-related electric system benefits expected to be realized from the generators and

transmission facilities proposed in connection with the Evest Project; (3) evaluating alternate solutions; and (4) providing the Customer with technical support in connection with its planning. My team performed this work under my direction.

Q10. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony is submitted in support of the Application. In my testimony, I provide an overview of the ELL Transmission System, including facilities relevant to Project Evest, in Louisiana. I then provide a general description of the Transmission Facilities proposed in connection with service to Project Evest and detail the planning evaluation that was performed to assess the costs, benefits, and necessity of the proposed Transmission Facilities (taking into account the costs and benefits of alternative solutions). I explain the costs and benefits of the proposed Transmission Facilities and why the proposed Transmission Facilities are a reasonable solution for providing service to Project Evest. I conclude by explaining the MISO transmission interconnection process for the generators needed to serve Project Evest and its impact on our analysis.

Q11. DO YOU SPONSOR ANY EXHIBITS?

A. Yes. I am the witness sponsor for the exhibits listed in the Table of Contents. I am familiar with each of the exhibits, which were prepared by me or under my supervision.

## III. ELL TRANSMISSION SYSTEM

Q12. BRIEFLY DESCRIBE THE ELL TRANSMISSION SYSTEM.

A. The ELL transmission system includes 69kV, 115kV, 138kV, 230kV, 345kV,[2] and 500kV transmission lines across portions of Louisiana. Major load centers served by the ELL transmission system include the cities of Lake Charles, Lafayette, Baton Rouge, Monroe, and Metairie/Kenner. Industrial loads make up a significant portion of the total load for ELL. These industrial loads are primarily located in Lake Charles and the Mississippi River corridor between Baton Rouge and New Orleans.

Q13. HOW HAS ELL UPGRADED AND EXPANDED THE TRANSMISSION SYSTEM IN NORTH LOUISIANA OVER THE PAST SEVERAL YEARS?

A. ELL is committed to providing secure, reliable, and resilient service for the future of North Louisiana. ELL recently obtained approval in LPSC Docket No. U-37425 to proceed with the Mt. Olive to Sarepta 500kV Transmission Line and Facilities which will be an essential building block to load growth in North Louisiana.[3] ELL also recently sought certification of the Babel to Webre 500kV Project (LPSC Docket No. U-37812), which was included in the MISO Transmission Expansion Plan 2025 ("MTEP25") as a Baseline Reliability Project following ELL's project submission (Project ID 50350) in September 2024, and MISO Board of Directors approval in

[2] ELL owns and operates a 345kV line beginning at the Arkansas state line and terminating at Sarepta substation in North Louisiana as well as a short portion of the Sarepta – Longwood 345kV line in Webster Parish.

[3] The Laidley Project includes several additional customer-funded transmission projects which were exempt from Commission certification under General Order 09-10-2024 (R-36199).

December 2025.[4] This project traverses South Central Louisiana, not North Louisiana, but is needed for compliance with applicable NERC regulations in connection with service to Project Laidley as well as other new customers and system changes. Further, in 2022, ELL completed a $100 million project across Ouachita Parish which positioned the region for economic growth and increased the resilience and reliability of the electric system in North Louisiana. The project included upgrading four transmission lines to 230kV, construction of a new three-mile 230kV transmission line, and the upgrade or expansion of five substations. Other recent reliability projects that are in progress in North Louisiana include the Delhi to Tallulah 115kV rebuild, the Gilbert to Wisner 115kV rebuild, and the Winnsboro to Gilbert 115kV rebuild. The Transmission Facilities associated with Project Evest represent the most recent example of the ways in which ELL is supporting its customers through significant infrastructure upgrades to improve reliability, to facilitate the interconnection of new resources and the delivery (or continued delivery) of new and existing resources, and to provide new load serving capability. Significantly, in the case of Project Evest, the investments associated with the Transmission Facilities either will be directly funded by the Customer or, in one instance, funded through revenue generated during the initial term of the Customer's Electric Service Agreement ("ESA") such that the investment will not affect the bills paid by other customers while the ESA is in place.

[4] Both the Mt. Olive to Sarepta 500kV project and the Babel to Webre 500kV project were contemplated by ELL before Project Laidley as reflected in the BP24 Long Range Transmission Study submitted in connection with LPSC Docket No. U-37425.

Q14. HOW IS THE INCREASING DEMAND FOR LOAD BY INDUSTRIAL CUSTOMERS IMPACTING THE TRANSMISSION SYSTEM IN LOUISIANA?

A. ELL has forecasted unprecedented load growth as data centers and new industrial customers construct new projects in Louisiana and other existing industrial customers expand. Serving these new large loads will require significant investments in the Louisiana transmission and distribution system for ELL to continue to provide secure, reliable, and resilient service. The investment in the Mt. Olive-to-Sarepta 500kV Transmission Line and Facilities, which was identified in planning studies even before the announcement of Project Laidley and approved in LPSC Docket No. U-37425, represents just one such system improvement needed to respond to this increasing demand. In pursuing this application, ELL is seeking to make sure that its customers receive the system benefits associated with strategic new load growth while continuing to provide secure, reliable, and resilient service.

Q15. WHAT WOULD BE THE IMPACT ON LOUISIANA UTILITY CUSTOMERS IF LOUISIANA STOPPED INVESTING IN THE TRANSMISSION SYSTEM?

A. New load growth would shift to other states, which would lead to lost economic opportunities and ultimately to higher rates for Louisiana utility customers. More specifically, if large load customers elect to site their investments elsewhere, there would be a number of adverse impacts on Louisiana utility customers and the State generally. First, as these new major block loads are sited elsewhere, the interconnected transmission grid and the direct and downstream effects of these large load additions likely would necessitate transmission improvements in Louisiana to maintain reliable

service to Louisiana utility customers. Second, ELL retail customers would likely bear a substantial portion, if not all, of the costs associated with any required upgrades without experiencing the benefits of increased load over which to spread them, putting upward pressure on utility rates. Finally, the economy of Louisiana would suffer the loss of the direct and indirect economic benefits of these significant customer projects.

## IV. OVERVIEW OF PROPOSED TRANSMISSION FACILITIES

Q16. HAVE YOU PROVIDED A SINGLE LINE DIAGRAM OF THE PROPOSED TRANSMISSION FACILITIES TO BE DEVELOPED IN CONNECTION WITH ADDING SERVICE TO PROJECT EVEST?

A. Yes, Exhibit DK-2 is a single line diagram of the proposed Transmission Facilities for Project Evest. Exhibit DK-3 contains drawings of typical 500kV structures. Specific structure design for the 500kV elements of the Transmission Facilities will depend on soil conditions, wind loading requirements, and other design requirements.

Q17. PROVIDE A GENERAL DESCRIPTION OF THE PROPOSED TRANSMISSION FACILITIES AND SUBSTATIONS NEEDED TO EXTEND SERVICE TO PROJECT EVEST?

A. ELL has proposed the three transmission projects described below:

(1) The West Fork Creek 500/230kV substation and a series of 230kV transmission lines in the vicinity of the Customer site to connect to customer load-serving substations (the "Customer-Funded Transmission Interconnection Project"). The

Customer will fully fund the Customer-Funded Transmission Interconnection Project.

(2) The Smalling to El Dorado 500kV Transmission Line. In addition to enabling service to Project Evest, the Smalling to El Dorado 500kV Transmission Line will provide benefits across the region in the form of enhanced reliability and resilience and will be fully funded by the Customer through a contribution in aid of construction ("CIAC") agreement.

(3) The West Fork Creek to St. Landry 500kV Transmission Line and St. Landry Switching Station. The West Fork Creek to St. Landry 500kV Transmission Line will bring system-wide benefits to the ELL Transmission System and will be indirectly funded by the Customer through a rate structure under the Customer's ESA that includes sufficient revenue to cover the cost of the West Fork Creek – St. Landry 500kV Transmission project during the term of the ESA – which means that other customers will see no billing impact during the term of the ESA.

Q18. WOULD ELL BE ABLE TO SERVE PROJECT EVEST WITHOUT TRANSMISSION UPGRADES?

A. No. Extending service to Project Evest will require additional transmission development for ELL to continue to provide secure, reliable, and resilient service to customers in North Louisiana and other parts of the State. Even with the significant investments made to support Project Laidley in North Louisiana, the existing electric system in Louisiana does not have adequate capacity to serve the magnitude of the load

contemplated for Project Evest, regardless of its location, without significant new transmission and baseload generation facilities.

Q19. WOULD ELL BE ABLE TO SERVE PROJECT EVEST WITH A TRANSMISSION-ONLY SOLUTION?

A. No. A transmission-only solution is not a viable option for Project Evest due to the size of the [redacted] MW load addition. ELL will require additional generation capacity and energy to serve the Customer's physical load serving needs reliably and to meet ELL's own planning reserve obligations. Satisfying these requirements and obligations requires additional generation somewhere on the system. Without this additional generation, all ELL customers would be exposed to unreasonable risk with respect to reliability and costs.[5] In addition, the reliability and cost risks associated with a transmission-only solution likely would cause the Customer to eliminate Louisiana as a potential location option for Project Evest. In this scenario, ELL would lose the opportunity to serve the Customer, and Louisiana would lose the substantial direct and secondary economic benefits attributable to industrial development in Richland Parish.

[5] This exposure arises, fundamentally, from tightening capacity supply and demand balances in Louisiana and MISO South, generally. Tighter supply and demand balances, in turn, are causing clearing prices in MISO's Planning Resource Auction ("PRA") to trend higher. MISO's implementation of a so-called "Reliability Based Demand Curve" beginning with the 2025-2026 Planning Year magnifies the risk of higher clearing prices in the PRA – and thus the risk of having insufficient capacity resources to cover ELL's planning reserve obligations. Further, a lack of adequate transmission investment will lead to constraints on the transmission system, which will place further upward pressure on energy market costs.

Q20. WHY WOULD ELL NOT BE ABLE TO MEET THE DEMAND NEEDS OF PROJECT EVEST SOLELY BY ADDING GENERATION?

A. A generation-only solution for the [redacted] MW load addition contemplated by Project Evest is not viable due to the size, location, and characteristics of this new load. Project Evest will operate nearly around-the-clock, at a load factor of [redacted]. Meeting these requirements will require a complex, integrated transmission and generation solution, including several high-capacity factor sources of energy to reliably serve the load while also maintaining the reliability of the bulk electric system and mitigating the cost impacts to ELL customers. The proposed Transmission Facilities and substations are needed to deliver the power to the Customer site and to maintain the reliability of the electric system in Louisiana with the addition of the sizable new load associated with Project Evest and the new generation resources necessary to serve Project Evest. The Transmission Facilities represent a reasonable and cost-effective solution for meeting the transmission requirements for Project Evest. Ms. Beauchamp describes the capacity and energy needs arising from the addition of the Project and the different scenarios considered, and Company witness Norman Grunden provides detailed testimony about the generation facilities that will be constructed to serve the Project.

Q21. WILL EXISTING CUSTOMERS BENEFIT FROM THE TRANSMISSION FACILITIES?

A. Yes. The Smalling to El Dorado 500kV Transmission Line, St. Landry Switching Station, and West Fork Creek to St. Landry 500kV Transmission Line will bring system-wide benefits to the transmission system; these benefits will flow to all users of

the transmission system, which include ELL retail customers, other utility customers in Louisiana and in neighboring states, and generation owners and developers in Louisiana and in neighboring states. Further, no material transmission costs will be shifted to existing customers that they otherwise would not be required to bear or for which they will not receive commensurate benefits: Company witnesses Phillip May and Ms. Beauchamp discuss the many other direct and indirect benefits expected to flow from Project Evest in their testimony.

### A. Customer-Funded Transmission Interconnection Project

Q22. WHAT IS THE CUSTOMER-FUNDED TRANSMISSION INTERCONNECTION PROJECT?

A. ELL will construct a new interconnection 500/230kV substation called West Fork Creek ("WFC"), 20-30 miles of 230kV transmission lines, and nine new auxiliary 230kV switching stations to connect the Customer's load to the ELL Transmission System. These facilities will be built on land directly adjacent to Project Evest and on the Customer's facility utilizing land and servitudes donated to ELL and will be funded directly from the Customer's CIAC Agreement.

Q23. IS ELL SEEKING CERTIFICATION OF THE INTERCONNECTION FACILITIES?

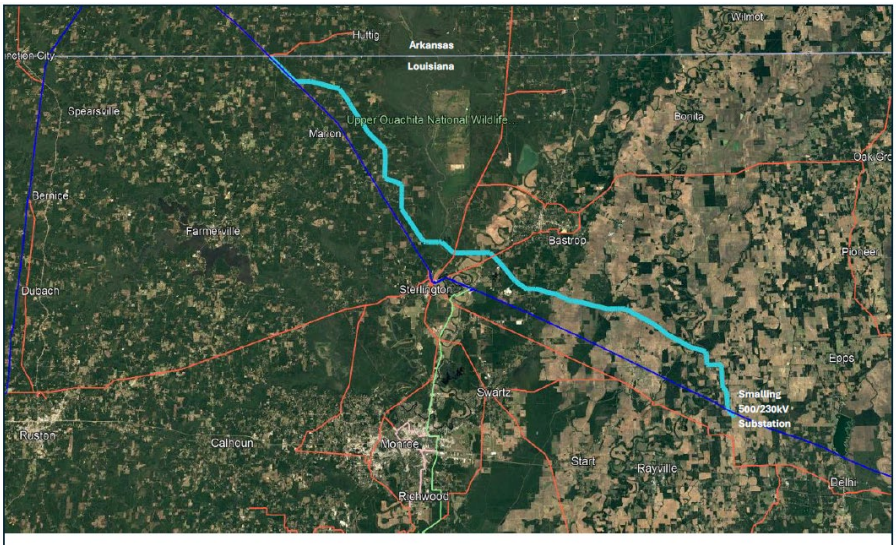
A. I am not a lawyer and I cannot offer a legal opinion, but my understanding is that these interconnection facilities are exempt from Commission Certification under General Order 09-10-2024 (R-36199) because they are fully customer-funded.

## B. Customer-Funded Smalling to El Dorado 500kV Transmission Line

Q24. WHAT IS THE SMALLING TO EL DORADO 500KV TRANSMISSION LINE?

A. A new ~90 mile 500kV transmission line will be developed from ELL's Smalling substation to Entergy Arkansas LLC's ("EAL") El Dorado substation, strengthening the 500kV Transmission network between North Louisiana and South Arkansas. ELL will develop and own the portion of this line from Smalling to the Arkansas state line, and EAL will develop and own the portion of this line from El Dorado to the Louisiana state line. Both portions of the project will also be funded directly by the Customer. The Louisiana portion of this line, which is depicted in Figure 1 below, will be funded from the Customer's CIAC Agreement with the Company, while the portion of this line in Arkansas will be funded by a CIAC agreement between the Customer and EAL.

**FIGURE 1**




Smalling-El Dorado 500kV Transmission Line – ELL Scope

Q25. IS THE SMALLING TO EL DORADO 500KV TRANSMISSION LINE REQUIRED TO MEET NERC STANDARDS?

A. Yes.

Q26. HOW WILL THE SMALLING TO EL DORADO 500KV TRANSMISSION LINE BENEFIT THE TRANSMISSION SYSTEM OVERALL?

A. In addition to meeting NERC compliance requirements, the Smalling to El Dorado 500kV line will help the system integrate new generation sources, including renewable generation; it will reduce reliance on lower voltage facilities in Arkansas and Louisiana, enabling those facilities to better serve their intended purpose of local load serving and reliability; and it will provide an additional north-south path, reducing the dependence on existing facilities and, together with other resources presented in the Company's application, increasing the resiliency and reliability of the transmission network across the region.

Q27. DO YOU CONSIDER THE SMALLING TO EL DORADO 500KV LINE A "SYSTEM IMPROVEMENT" FOR PURPOSES OF THE COMPANY'S LINE EXTENSION POLICY AND TERMS AND CONDITIONS OF SERVICE?

A. Yes. Based upon the line's voltage and the broad spectrum of benefits to the electric system that it provides, the Smalling to El Dorado 500kV line is the type of project that would ordinarily be treated as a system improvement and its costs included in the rates paid by all ELL customers. However, in this particular instance, ELL successfully negotiated a commitment from Evest to fund the full cost of the project through a CIAC.

Q28. WAS THE SMALLING TO EL DORADO 500KV LINE CONTEMPLATED PREVIOUSLY BY ELL'S EXTRA HIGH VOLTAGE ("EHV") TRANSMISSION EXPANSION VISION WHICH YOU DISCUSSED IN YOUR TESTIMONY IN PROJECT LAIDLEY?

A. Not directly, but conceptually. As I explained in my testimony in connection with Project Laidley, ELL's vision of future expansion of the ELL EHV transmission system contemplated a need for additional north-south EHV transmission due to the prevailing flows on the system from north to south. I expressly noted, at the time, that the transmission system build out in North Louisiana may not ultimately resemble the projects and project concepts included in the ELL vision. Any new customer of this magnitude will stress the transmission system, even as enhanced to serve Project Laidley, in ways that will require system reinforcement consistent with that EHV vision. The Smalling to El Dorado 500kV line is consistent in this manner with the ELL vision I discussed before, and, together with the other proposed Transmission Facilities, represents the best solution to meet the reliability, resiliency, sustainability, cost competitiveness, and speed to market requirements of the Customer taking into consideration the unprecedented load requirements of Project Evest.

Q29. IS ELL SEEKING CERTIFICATION BY THE COMMISSION OF THE SMALLING TO EL DORADO 500KV TRANSMISSION LINE?

A. No. While I am not an attorney and am not expressing a legal opinion, my understanding is that these facilities are exempt from Commission Certification under

General Order 09-10-2024 (R-36199) because they will be fully funded by the Customer and will not impact existing customer rates.

Q30. WILL CONSTRUCTION OF THE SMALLING TO EL DORADO 500KV TRANSMISSION LINE REQUIRE APPROVAL FROM THE ARKANSAS PUBLIC SERVICE COMMISSION?

A. Yes. It is my understanding that EAL must obtain a Certificate of Environmental Compatibility and Public Need ("CECPN") from the Arkansas Public Service Commission prior to commencing construction of the Arkansas portion of this facility.

Q31. EXPLAIN THE PROCESS AND TIMING FOR SEEKING APPROVAL FROM THE ARKANSAS PUBLIC SERVICE COMMISSION.

A. My understanding is that the certification process for transmission facilities in Arkansas is a roughly six-month process. I understand that EAL plans to file its application for certification of this project by mid-2026 after further development of EAL's filing including provision of required statutory notices. A decision from the Arkansas Public Service Commission is expected by the end of 2026.

Q32. DO THE BENEFITS OF THE PROJECT EXTEND INTO ARKANSAS?

A. Yes. It is reasonable to expect that the Smalling to El Dorado 500kV project will enable the interconnection of new generation onto the transmission system – particularly in the vicinity of the project, which extends from the Project Evest area in North Louisiana all the way into southern Arkansas, terminating at a substation northeast of the city of

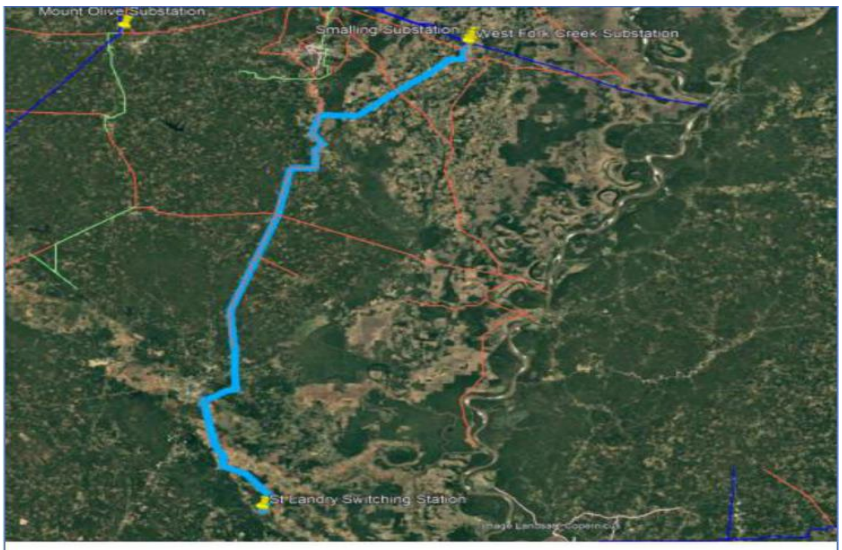
El Dorado, Arkansas. Further, because of the nature of the prevailing system power flows (generally flowing north to south from Arkansas into Louisiana), additional growth in the area between El Dorado, Arkansas, and Monroe, Louisiana – which encompasses parts of both states – will result in additional strain on the existing transmission facilities in the area. By relieving power flows on existing transmission facilities, the project will enable additional customer growth in those areas, spanning both states. As an additional consideration, without the project, customers served by the 115kV system in southern Arkansas and northern Louisiana will be exposed to service interruptions when nearby EHV facilities are out of service, as Project Evest load increases.

### C. WFC – St. Landry 500kV Transmission Line and Switching Station

Q33. WHAT IS THE WFC – ST. LANDRY 500KV TRANSMISSION LINE AND ST. LANDRY SWITCHING STATION?

A. As depicted below, ELL will construct a new St. Landry 500kV switching station that will intersect the to-be-constructed Babel-Webre 500kV line in St. Landry Parish north of Lafayette. ELL will construct a new ~150 mile WFC – St. Landry 500kV Transmission Line to strengthen the 500kV network between North and South Louisiana.

**FIGURE 2**




St Landry Switching Station – WFC 500kV Transmission Line

Q34. WHO WILL PAY FOR THE WFC – ST. LANDRY 500KV TRANSMISSION LINE AND ST. LANDRY SWITCHING STATION?

A. This project will be ELL funded, generally through a mix of debt and equity capital; however, the rate the Customer will pay under its ESA will afford sufficient revenue to cover the cost of this investment during the term of the ESA, so there will be no effect on other customers' bills during the term of the ESA.

Q35. PLEASE EXPLAIN WHY THE WFC – ST. LANDRY 500KV TRANSMISSION LINE AND ST. LANDRY SWITCHING STATION IS NECESSARY?

A. As a result of the increase in generation across the ELL system, along with the addition of significant high load factor load, Power Delivery Planning undertook an analysis to evaluate the ability of the system to serve energy and capacity during the fall and spring

periods of the year, when planned generation outages are at their peak. This analysis identified reliability and operational concerns when typical generation maintenance outages are factored into the growing system. The WFC – St. Landry 500kV Transmission Line is intended to increase north-south transmission connectivity, enabling available generation to move more freely to where it is needed. This connectivity will be particularly critical during the fall and spring generation outage periods, where we anticipate as much as 30 to 40 percent, or as much as 10,000 MW, of generation in the region could be offline for maintenance. As high load factor load develops, not only will that increase the peak loads experienced during typical outage seasons but also it will result in a lower proportion of load drop-off in the off-peak periods. This additional consumption will drive increased use of generation facilities and further increased maintenance needs on peaking and other short-duration generators as they increase their run-hours during periods where base load generators are offline. Without the addition of the WFC – St. Landry 500kV Transmission Line, Power Delivery Planning studies identified that ELL may not be able to take the outages needed to conduct essential seasonal maintenance on generation and transmission assets, an outcome that would be to the detriment of all customers. Recognizing this emerging risk, new NERC standards are contemplated under which the WFC – St. Landry 500kV Transmission Line may be required in the future, as discussed below.

Q36. HOW WILL THE WFC – ST. LANDRY 500KV TRANSMISSION LINE AND ST. LANDRY SWITCHING STATION BENEFIT CUSTOMERS OTHER THAN THE PROJECT EVEST CUSTOMER?

A. By adding a north-south 500kV corridor through central Louisiana, the WFC – St. Landry 500kV Transmission Line will improve ELL's ability to move power around the system to where it is needed. This connectivity is especially valuable during periods where generation outages are needed for maintenance or are forced due to a component failure as well as during extreme weather events such as hurricanes and winter storms. The added transmission capacity will also benefit the deliverability of generators as they seek interconnection to the transmission system. In an environment of high demand growth, most large customers also require the addition of generation capacity to the system to support them. Having transmission capacity that can benefit generator interconnection and deliverability will improve speed to market and increase the reliability and resilience of the overall transmission network in Louisiana. In addition, strengthening the transmission system beyond the bare minimum required for NERC compliance will aid in the interconnection of future customers – both native load customers bringing new load as well as interconnection customers bringing new generation, including new renewable generation.

Q37. IS THE WFC – ST. LANDRY 500KV TRANSMISSION LINE REQUIRED TO MEET NERC STANDARDS?

A. As currently drafted, the NERC Transmission Planning standards do not technically require the addition of the WFC – St. Landry 500kV Transmission Line. However, the

NERC board has provisionally approved a new standard, BAL-008-1, which mandates that seasonal studies be part of energy reliability risk assessments. This standard is currently moving through the approval process for implementation. While this standard covers the Operations Planning horizon (generally less than one year into the future), the trend over time has been to introduce more seasonality and outage-based criteria into NERC's compliance requirements. For example, NERC TPL-001-5, which became effective July 1, 2023, introduced requirements to include planned outages into NERC TPL studies. However, most scheduled outages are not considered "planned" more than a year into the future. Because of this, TPL-001-5 has resulted in limited impact on how reliability projects are identified. FERC Order No. 867, the order in which FERC approved TPL-001-5, specifically cited the impact of seasonal outages on system planning and transmission system capability as an area in which regulatory focus is needed, and it is clear that FERC's intent in approving the standard was to be more expansive in terms of requiring consideration of the effects of seasonal outages in long-term planning. Given the load growth occurring across the national electric grid, especially growth in high load factor loads, it is logical to expect NERC to continue in this vein. Once the new BAL standard is implemented, NERC will begin to develop a data set that informs the development of future standard revisions. As those standard revisions move into the long-term planning horizon, the WFC – St. Landry 500kV Transmission Line is the type of transmission project that may become necessary to meet more stringent seasonal compliance requirements.

Q38. IF NOT PRESENTLY REQUIRED TO MEET NERC STANDARDS, WHY IS THE WFC TO ST. LANDRY 500KV TRANSMISSION LINE NECESSARY IN CONNECTION WITH PROJECT EVEST?

A. As noted above, although not required by existing NERC Transmission Planning standards, the transmission system will reach levels of off-peak and shoulder-season load that preclude taking necessary outages to conduct seasonal maintenance on generators and transmission facilities. Further, these new loads will create challenges in taking seasonal outages for maintenance purposes that may interfere with the ability to take outages for new facility construction, including construction to add new customers to the system. Significantly, even in the absence of new standards requiring the facility, the WFC – St. Landry 500kV Transmission Line will be necessary to conduct maintenance and maintain system reliability overall. As discussed above, the rapid growth being experienced by ELL makes the system more complicated to operate, particularly as high load factor customers are added to the system. With the addition of high load factor customers that will be operating at high load levels nearly around-the-clock every day of the year, every generation asset on the system takes on added importance. Like most any machine, generators require periodic maintenance to keep them in good working order to ensure their availability during times of critical need, such as extreme summer heat or winter cold. Having the ability to conduct the maintenance necessary to service each of these assets therefore is critical to overall system reliability. The WFC – St. Landry 500kV Transmission Line will provide ELL with the flexibility needed to conduct this maintenance and to respond to generation outages in the event of an unexpected component failure. Finally, the WFC – St. Landry

500kV Transmission Line will improve the resilience of the ELL Transmission Systems during extreme weather events and in the event of other extreme events such as extreme overloads.

Q39. WOULD IT BE REASONABLE FOR ELL TO WAIT AND SEE IF NERC ADOPTS THE NEW BAL-008-1 RELIABILITY STANDARD BEFORE MOVING FORWARD WITH THE WFC – ST. LANDRY 500KV TRANSMISSION LINE?

A. No. While the cost of the WFC – St. Landry 500kV Transmission Line is considerable, waiting for NERC to take official action to adopt the new BAL-008-1 standard before planning a project to address the reliability issues that drive this project would be unreasonable. It would leave ELL and other utility customers unreasonably exposed to reliability risks arising from the inability to take needed generation and transmission outages as explained further below. This risk, coupled with the lengthy development timeline for the project, would leave ELL and other utility customers exposed to unreasonable levels of reliability risk for too long. Moreover, the cost of the project is fully covered during the term of the Customer's ESA by revenues from that ESA, further supporting a conclusion that it is reasonable to proceed with this project now. Finally, while BAL-008-1 analyses will likely identify the need for and benefit of a project like the WFC – St. Landry 500kV line, the focus of the BAL-008-1 standard on the near-term operating horizon will not necessitate construction of new facilities. Rather, compliance with BAL-008-1 will likely be achieved through operating actions, such as the delay, deferral, or cancellation of outages. These delays, deferrals, or

cancellations will have the effect of jeopardizing the long-term reliability of those assets for which outages are impacted.

Q40. PLEASE EXPLAIN HOW THE WFC – ST. LANDRY 500KV TRANSMISSION LINE WILL IMPROVE THE RESILIENCE OF THE COMPANY'S TRANSMISSION SYSTEM DURING EXTREME WEATHER EVENTS.

A. The WFC – St. Landry 500kV Transmission Line will improve extreme event resilience by providing a new hardened north-south 500kV path for the transmission of bulk power across Central Louisiana. The new transmission line will be designed and constructed to Entergy's latest standards for wind-load rating. It will have a greater ability to transfer power than the existing 230kV and 138kV transmission lines that currently move power north-south across the region, while also providing geographic diversity that can be useful in restoration of service in the wake of major coastal storm events.

Q41. WILL THE BENEFITS OF THE WFC – ST. LANDRY 500 KV TRANSMISSION LINE THAT YOU DISCUSS ABOVE AND THAT ARE INCREMENTAL TO ENABLING RELIABLE SERVICE TO PROJECT EVEST EXTEND TO THE PERIOD AFTER THE ORIGINAL TERM OF THE ESA EXPIRES?

A. Yes. The resilience benefits of the line certainly will persist as the area ELL serves in Louisiana experiences future extreme weather events. These events – and the associated resilience benefits – will continue beyond the end of the initial term of the ESA (the "Original Term"). Further, it is reasonable to expect that any new generation

resources that are able to interconnect to the system by virtue of the additional deliverability and capability created by the new line, and any new load growth that is enabled by the new line, would remain beyond the expiration of the Original Term of the ESA. It is also reasonable to expect that the new line will continue to provide reliability benefits over its entire useful life, which extends well beyond the end of the Original Term of the ESA.

Q42. PLEASE EXPLAIN HOW THE WFC – ST. LANDRY 500KV TRANSMISSION LINE WILL IMPROVE THE RESILIENCE OF THE COMPANY'S TRANSMISSION SYSTEM DURING OTHER TYPES OF EXTREME EVENTS.

A. The extreme event scenario that raises the most concern is the loss of a "major load center." While "load center" is not defined in the standard, it is my belief that a total of [redacted] MW of load (the combined total of Project Laidley and Project Evest) would constitute a major load center. To put it into context, this would be roughly similar to the amount of load in [redacted]. While it is impractical to imagine losing [redacted], the energy density of Project Laidley and Project Evest along with what we know about how the load will behave during faulted conditions suggest that loss of this load center is a plausible scenario that merits consideration.

Q43. HOW WILL THE PROJECT LAIDLEY AND PROJECT EVEST LOAD BEHAVE DURING FAULT CONDITIONS?

A. Based on information communicated by the Customer, ELL understands that during a fault on the 500kV system in the vicinity of the project, all load at Project Laidley and Project Evest will disconnect from the system.

Q44. DID ELL EVALUATE THE IMPACT OF THIS EXTREME EVENT? IF SO, WHAT DID YOU FIND?

A. Yes. Load disconnect settings are modeled in all my team's stability analysis, and no system stability concerns were identified with the proposed projects in place. The unique concern in this scenario is steady state evaluation, since typical steady state evaluations do not simulate loss of load when the load in question still has a source. For this scenario, my team evaluated the system in 2035 (after all Customer load and new generators are online) with and without the WFC – St. Landry 500kV Transmission Line. Our detailed findings from this evaluation are discussed in the Extreme Event/Fault Section of CEII Exhibit DK-6. We found that without the WFC – St. Landry 500kV Transmission Line in service, in the event of loss of Project Evest and Project Laidley load, the Smalling – Baxter Wilson 500kV line would load to 123% in the summer and 137% in the winter. This finding is important because the 137% loading is above the 125% level that triggers a cascading analysis, per the TPL-001-5 standard and Entergy's planning criteria. With the WFC – St. Landry 500kV Transmission Line in service, and with the loss of the Project Evest and Project Laidley loads, the Smalling – Baxter Wilson 500kV line still loads highly but the loads are

reduced to 103% in the summer and 121% in the winter – below the cascading analysis level. In other words, our analysis indicated that loading with the WFC – St. Landry 500kV Transmission Line in service, while still significant, is something that could be managed in real-time operations of the system. In addition, when evaluating additional contingencies beyond just loss of the Project Evest and Project Laidley loads, my team identified a number of other overloads, primarily on the lower voltage system, ranging from barely overloaded to more than 140% of the line's rating.

Q45. DOES THE NERC TPL-001-5 STANDARD ADDRESS EXTREME EVENTS?

A. Yes. The TPL-001-5 reliability standard lists a number of scenarios it calls "extreme events" that Transmission Planners must study as part of their annual NERC compliance study work. However, although the TPL-001-5 standard requires Corrective Action Plans for planning criteria violations for a number of different contingency types, it does not impose the same Corrective Action Plan requirements for extreme events.

Q46. WHAT, IF ANY, REQUIREMENTS DOES THE TPL-001-5 STANDARD PLACE ON EXTREME EVENTS?

A. Requirement 4.2 of the TPL-001-5 standard requires that Transmission Planners study extreme events and "[i]f the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted."

So, the standard does not require mitigation of violations associated with extreme events but rather requires additional evaluation of possible actions that could be taken. Here, analysis conducted by Power Delivery Planning shows that the risk of extreme events with the Project Evest and Project Laidley loads is substantial and includes the risk of load shed due to cascading outages. Although the NERC TPL-001-5 standard does not technically require the WFC – St. Landry 500kV Transmission Line, construction of the line is thus prudent and necessary.

Q47. YOU MENTIONED THAT THE WFC – ST. LANDRY 500KV TRANSMISSION LINE WILL NOT FULLY MITIGATE THE RISK OF AN EXTREME EVENT. SHOULD ELL PURSUE ADDITIONAL PROJECTS THAT WOULD?

A. No, fully mitigating the risks of an extreme event would require a series of projects that would entail significant cost. Considering the relevant factors and the costs, it would be unreasonable to pursue development of all the projects necessary to ensure that the occurrence of this extreme event would not adversely affect system reliability and load-serving capability at all. Rather, the goal reasonably should be to keep the system intact and secure so that the system operators have the reaction time and flexibility to take any actions needed to address any reliability issues that remain after an extreme event occurs in a controlled manner. The WFC – St. Landry 500kV Transmission Line reasonably achieves that objective. I believe the WFC – St. Landry 500kV Transmission Line, on balance, appropriately addresses the risk of extreme events taking into consideration the density of the customer load, the likelihood that an extreme event could take place, and cost efficiency.

Q48. WHY IS THE CUSTOMER NOT DIRECTLY FUNDING THE WFC – ST. LANDRY 500KV TRANSMISSION LINE AS THE CUSTOMER IS DOING WITH THE SMALLING TO EL DORADO 500KV TRANSMISSION LINE?

A. New customers do not normally pay for major EHV infrastructure improvements that will provide benefits across the system. While the Customer's new load and generation contribute meaningfully to the need for the WFC – St. Landry 500kV Transmission Line, the driving force behind this line is customer growth, resiliency needs, and generation needs throughout the ELL system – and not just Project Evest. The extreme event issue discussed immediately above is an additional benefit. As discussed by Company witness Ryan Jones, the revenue from the Customer's ESA pays for the cost of the WFC – St. Landry 500kV Transmission Line such that existing customers will not be impacted by the cost of this facility for the duration of the Customer's ESA. It is my opinion that this arrangement strikes a reasonable balance by ensuring the Customer mitigates substantially the cost impact of this facility on other customers.

Q49. WHAT IS THE TIMELINE FOR THE WFC – ST. LANDRY 500KV TRANSMISSION LINE AND ST. LANDRY SWITCHING STATION?

A. An estimated timeline, with milestones, for completion of the new St. Landry Switching Station and WFC – St. Landry 500kV Transmission Line is attached as Exhibit DK-4.

### D. Project Construction and Commissioning

Q50. WHAT TRANSMISSION FACILITIES WILL BE NEEDED TO SUPPORT PROJECT CONSTRUCTION AND COMMISSIONING?

A. The Customer requires [redacted] of construction/commissioning power beginning in [redacted], ramping up to [redacted] in [redacted] then to [redacted] in [redacted] with the full load of [redacted] expected to come online by [redacted]. ELL is already upgrading distribution circuits in the area in connection with Project Laidley to support customer construction power needs and plans to construct and operate temporary power facilities to support commissioning activities. Any temporary facilities for Project Evest will be removed upon completion of the Transmission Facilities.

## V. COST ESTIMATE FOR PROPOSED TRANSMISSION FACILITIES

Q51. WHAT IS THE TOTAL PROJECTED COST FOR THE TRANSMISSION FACILITIES PROPOSED IN CONNECTION WITH PROJECT EVEST?

A. As reflected in Table 1 below, the total projected cost for the ELL scope of work for the Transmission Facilities to serve the Customer's full load based on a Class 5 estimate, as discussed further below, is [redacted]

**TABLE 1 (HSPM/AEO)**

| ***Transmission*** | [redacted] |
|---|---|
| Customer Interconnection | |
| Smalling-El Dorado 500kV (ELL Scope of Work) | |
| St. Landry 500kV Station | $67 M |
| WFC – St. Landry 500kV Line | $1,395 M |
| Perryville, Sterlington and Point Pleasant Breaker | [redacted] |
| ***Total Transmission*** | |

Q52. WHICH OF THESE INVESTMENTS WILL BE FUNDED BY ELL?

A. Of the projects and costs shown in Table 1, ELL will fund only the cost of the St. Landry 500kV Switching Station and the WFC – St. Landry Transmission Line investments. Exhibit DK-5 provides a more detailed itemization of the costs associated with the new St. Landry Switching Station and WFC – St. Landry 500kV Transmission Line. Importantly, as explained by Mr. Jones, the rate the Customer pays under its ESA affords sufficient revenue to cover fully the cost of those projects during the term of the ESA, which means that other utility customers will see no bill impacts from the investment during the term of the ESA.

Q53. HOW CERTAIN ARE THESE COSTS?

A. The estimated costs are based on a Class 5 Estimate. In October 2025, the Customer informed ELL of changes to its site layout, which are expected to impact the cost estimate for the Customer-Funded Transmission Interconnection Project. ELL has accounted for potential changes to the Class 5 Estimate by adding the Interconnection Scope Uncertainty line item in Table 1. ELL is continuing to work with the Customer on its modifications to the site layout and updating the impact of these modifications on the cost estimates.

Q54. COULD ELL BE SIGNIFICANTLY UNDERESTIMATING THE COST OF THE TRANSMISSION FACILITIES BY RELYING ON A CLASS 5 ESTIMATE?

A. While Class 5 estimates are, by definition, high level and preliminary, the Customer has elected to proceed with the ESA based on Class 5 estimates in order to meet its

project timelines. The Customer, therefore, will bear the financial risk associated with this uncertainty for the Customer-Funded Transmission Interconnection Project and Smalling to El Dorado 500kV Transmission Line under the terms of the CIAC Agreement and EAL CIAC Agreement. As to the St. Landry Switching Station and WFC – St. Landry 500kV Transmission Line, ELL has built into the Customer's ESA robust customer protections including a true-up mechanism to prevent ELL or its other customers from bearing the risk of changes to the costs versus what is shown in the Class 5 estimates for these system improvements. Company witness Thomas Kidd provides detailed testimony about the protections for other ELL customers against any cost overruns that are provided for under the terms of the Customer's ESA.

Q55. WHAT PERCENTAGE OF THE COST OF THE PROPOSED TRANSMISSION FACILITIES WILL BE FUNDED BY THE CUSTOMER?

A. During the term of the ESA, revenues received from the Customer are expected to offset 100% of the revenue requirements of the proposed Transmission Facilities. If the Customer were to terminate the ESA prior to the end of its term, and assuming the Customer does not ultimately fund these facilities through a CIAC agreement, it is ELL's current plan that the remaining costs of the investment in the St. Landry Switching Station and WFC – St. Landry 500kV Transmission Line would be mitigated through Evest's payment of a termination fee as per the terms of the ESA. Upon the conclusion of the Original Term of the ESA, and again assuming the Customer does not ultimately fund these facilities through a CIAC agreement, approximately [redacted] would be remaining in rate base associated with the project. While the

project would only have depreciated for approximately 16 years of its estimated 36-year life (that is, approximately 54% of its assumed useful life would remain), ELL's other customers will only be asked to bear the final 16% (on a net present value basis) of the estimated cost of the project in their rates. Mr. Jones discusses these potential rate impacts on other customers in his direct testimony.

Q56. DOES ELL ANTICIPATE THAT EXTENDING SERVICE TO THE CUSTOMER WILL REQUIRE OTHER TRANSMISSION SYSTEM UPGRADES?

A. Based on information available to ELL today, my answer is no. However, ELL expects that additional transmission upgrades that are required in connection with extending service to Project Evest may be identified once the Project Evest load becomes operational or at such point that the Customer has sufficient facility information to support detailed modeling of the facility's operations. Importantly, under the relevant contract terms, the Customer will be solely responsible for the cost of any additional transmission improvements needed to ensure that the system remains reliable with the addition and operation of the Project Evest load.

Q57. COULD THE TRANSMISSION PROJECTS PROPOSED IN CONNECTION WITH EXTENDING SERVICE TO THE CUSTOMER PROJECT SUPPLANT OTHER TRANSMISSION PROJECTS NEEDED TO IMPROVE THE RELIABILITY OF THE ELL TRANSMISSION SYSTEM IN LOUISIANA, NOW OR IN THE FUTURE?

A. Building the WFC – St. Landry 500kV Transmission Line may allow ELL to defer or avoid altogether future upgrades that would otherwise be needed to improve the existing lower voltage transmission system in central and eastern Louisiana. The development of the WFC – St. Landry 500kV Transmission Line will have the inherent effect of drawing flow off those facilities and reducing the extent to which those facilities support broader regional flows. This is a potential benefit of this project that is potentially very meaningful but that has not been quantified.

## VI. TRANSMISSION PLANNING FOR PROJECT EVEST

Q58. CAN YOU DESCRIBE THE TRANSMISSION PLANNING PROCESS ASSOCIATED WITH A BLOCK LOAD ADDITION?

A. Yes. The planning team undertakes an iterative planning process, in coordination with the ELL Resource Planning Team, to reflect evolving information and assumptions about customer load requirements as a customer project takes shape over time. ELL benefits from and takes into consideration its robust experience in planning transmission facilities and extensive library of prior facility studies.

Q59. WHAT TRANSMISSION PLANNING STANDARDS AND GUIDELINES DID YOU APPLY IN ANALYZING THE PROJECT?

A. The planning team owns and maintains a local transmission planning guideline and criteria for transmission system planning in accordance with the NERC TPL-001-5 reliability standard. ELL's local transmission planning guidelines and criteria are also applied when studying the impacts of adding block load additions onto the transmission

system. In addition, the planning team maintains a procedure for studying interconnections to ELL facilities that is compliant with the NERC FAC-002 reliability standard.

Q60. WHY WERE THESE STANDARDS AND GUIDELINES IMPORTANT TO YOUR WORK IN CONNECTION WITH THE PROJECT?

A. ELL's local transmission planning guidelines and the FAC-002 procedure establish a baseline that ensures compliance with the NERC reliability standards and consistency in the application of relevant standards. Compliance with these standards is required by applicable laws and rules, per my understanding, but also helps ensure the system is and continues to be reliable as loads, generation resources, and other circumstances change over time. Compliance with NERC reliability standards is necessary but, particularly from a transmission planning standpoint, is not always sufficient to ensure electric system reliability. This is why utilities maintain local transmission planning criteria to reflect the specifics of their own systems and why utilities sometimes construct projects that, although not needed strictly for NERC reliability standard compliance, are nonetheless needed to ensure reliable service to their customers. A utility that planned only to meet NERC standards would fail over time to deliver reliable service to its customers or other users of its transmission system.

Q61. CAN ELL IDENTIFY ALL POTENTIAL RELIABILITY IMPACTS ASSOCIATED WITH INTERCONNECTING THE PROJECT EVEST LOAD AND NECESSARY GENERATION, APPLYING ITS EXISTING LOCAL TRANSMISSION PLANNING CRITERIA?

A. Interconnecting very large loads of this type while maintaining reliability to existing customers is an emerging issue in the power industry, and ELL will need to update its existing standards as learnings become actionable. Entergy is an active participant in industry discussions such as NERC's Large Loads Task Force ("LLTF"), which is focused on gaining a better understanding of the reliability impacts of emerging loads such as hyperscale facilities and their impact to the Bulk Electric System. Feedback from the LLTF participants across the industry and ongoing operational experience prompted ESL's Power Delivery Planning group to perform additional study work to evaluate the ability of the system to serve the ELL energy and capacity needs during the fall and spring periods of the year, as described above. ELL's local transmission planning guidelines are reviewed on an annual basis and will be updated in the future as the potential reliability impacts of serving very large loads are better understood through continued industry engagement, operational experience, and additional study work. Changes may include additional provisions for off-peak evaluations similar to what was performed to identify the need for the WFC – St. Landry 500 kV Transmission Line, more requirements related to stability assessments, or enhanced voltage requirements in the vicinity of hyperscale or other sensitive customer load. As data center load penetration grows on the Entergy system, ELL performs additional

system stability assessments to better understand how the load will impact grid stability.

Q62. WHAT NERC RELIABILITY STANDARDS DID ELL CONSIDER IN CONNECTION WITH ITS TRANSMISSION PLANNING FOR PROJECT EVEST?

A. The following NERC reliability standards were the primary focus for consideration when studying the impact to ELL's transmission system and identifying upgrades that are needed to reliably accommodate the Project:

- TPL-001 establishes performance requirements for the transmission system in the long-term planning horizon (up to 10 years into the future);
- FAC-002 establishes requirements governing how to study the interconnection of new or materially modified transmission facilities to the bulk electric system; and
- NUC-001 dictates the coordination that must occur between nuclear plant operators and transmission entities to ensure the requirements for safe operation and shutdown of nuclear facilities are maintained. This includes consideration of voltages that must be maintained at nuclear sites to ensure site safety. The size of the Customer and location of Grand Gulf Nuclear Station in Port Gibson, Mississippi, not far from the Project, necessitate consideration of this standard.

Q63. WHAT TRANSMISSION PLANNING ASSESSMENTS DID ELL UNDERTAKE IN CONNECTION WITH PROJECT EVEST?

A. On behalf of ELL, my team performed steady-state, stability, and short circuit analysis to identify the transmission and generation upgrades that are needed to accommodate

the Project. The required upgrades serve to ensure ELL maintains compliance with the NERC reliability standards and also to ensure reliable service is maintained for existing customers as the Project ramps to full capacity.

Q64. HOW DID YOUR ASSESSMENT FOR ADDING SERVICE TO PROJECT EVEST COMPARE WITH THE ASSESSMENTS THAT YOU HAVE PERFORMED ON OTHER NEW LOAD ADDITIONS?

A. The transmission planning team followed our standard load study process which involved multiple peer reviews and several levels of management review; subsequent studies of additional scenarios have confirmed our findings and recommendations. Our assessment was thorough and consistent with sound planning, engineering, and economic principles, appropriately factoring in the Customer's speed-to-market requirements.

Q65. HOW DID YOU DETERMINE WHAT TYPE OF GENERATION RESOURCES WOULD BE BEST SUITED TO ADDING SERVICE TO THE CUSTOMER PROJECT?

A. The transmission planning team understood that some combination of resources capable of serving in a baseload and load following role, specifically combined cycle combustion turbine generators, would be required. We worked closely with the ELL Resource Planning Team to ascertain the generation resources best suited to addressing the needs of the Project, and in particular its [redacted] load factor and significant reliability

requirements. Ms. Beauchamp discusses the basis for this determination in her direct testimony.

Q66. HOW WERE THE ASSUMPTIONS ON THE SITING OF THE BASELOAD RESOURCES DETERMINED?

A. Once ELL determined what set of resources would be needed in connection with service to Project Evest, the Power Delivery Planning team provided feedback to ELL on the siting of those resources – which include seven 1x1 CCCTs – in order to develop an integrated generation and transmission plan and to most efficiently accommodate the Project Evest load, including the generation needed for capacity and energy coverage. Considerations included the co-location of four 1x1 CCCTs essentially onsite with the [redacted] load to reduce the net load demand on the system and mitigate the need for additional significant transmission upgrades. Considerations also included [redacted]. Ms. Beauchamp discusses these siting considerations and baseload generation requirements in greater detail in her testimony.

Q67. HOW DID THE POWER DELIVERY TEAM DETERMINE THAT SELECTING SEVEN 1X1 UNITS AND BATTERY STORAGE WAS THE BEST CONFIGURATION FOR SERVICE IF THE CUSTOMER DECIDES TO PROCEED WITH A [redacted] PROJECT?

A. The type and number of resources were determined by ELL in consultation with ESL's supply planning team as described in the Direct Testimony of Ms. Beauchamp.

Q68. WHAT POTENTIAL POWER QUALITY IMPROVEMENTS WOULD THE NEW CCCTS PROVIDE?

A. The new CCCTs add dynamic reactive power capability to the system, in addition to real power. A lack of reactive power capability in the system can result in difficulty in regulating voltage, resulting in power quality issues, such as voltage dips and sags, which may be experienced by customers. Some voltage dips may also be caused by induction motor starts in a system that has an insufficient amount of reactive power to maintain voltage and dynamic reactive power capability to support voltage recovery. Further, as quick-start and fast ramping resources, the new CCCTs will add synchronous inertial response and short-circuit capability to the system, both of which may be increasingly valuable ancillary service market assets as the MISO market more broadly sees an increased penetration of renewable resources and inverter-based resources.

Q69. HOW MANY SCENARIOS WERE STUDIED FOR ADDING SERVICE TO PROJECT EVEST?

A. The Planning team studied three distinct scenarios with some sensitivities involved in each.

Q70. BRIEFLY DESCRIBE EACH SCENARIO THAT YOU STUDIED?

A. The scenarios reflected the uncertainty in the number and location of generation resources that were included in the Project Evest supply plan. At one point, Project Evest was two separate projects before being combined into one. This explains the difference in load levels.

Scenario 1

[redacted] Project Evest load at West Fork Creek

- (2) 1x1 CCCTs at West Fork Creek
- (2) 1x1 CCCTs at Mt. Olive

Scenario 2

[redacted] Project Evest load at West Fork Creek

- Smalling to El Dorado 500kV Transmission Line
- (2) 1x1 CCCTs at West Fork Creek
- (2) 1x1 CCCTs at Mt. Olive
- Scalable load reduced to 77% of peak to simulate shoulder model
- Generation Offline
  - Montgomery County Power Station
  - Lone Star CT
  - Waterford 3
  - Big Cajun
  - Delta Blues
  - Little Gypsy
  - Lake Charles Power Station

Scenario 3[6]

[redacted] Project Evest load at West Fork Creek

- (4) 1x1 CCCTs at West Fork Creek
- (2) 1x1 CCCTs at Big Cajun
- 1x1 CCCT at St. Landry

Scenario 2 evaluates the generation outage concerns that led to the addition of the WFC – St. Landry 500kV Transmission Line to the Transmission Facilities. I will discuss those in more detail when discussing Scenario 2.

Q71. WHAT TRANSMISSION UPGRADES WERE IDENTIFIED FOR THE FIRST SCENARIO?

A. The identified upgrades include:

1. El Dorado – Smalling 500kV: New Line
2. Smalling – WFC 500kV: New 2nd circuit Line
3. Upgrades 1 and 2 above were needed to maintain compliance with the NERC TPL-001-5 standard. When the 3,000 MW was added to our models and contingencies from Table 1 of the NERC TPL-001-5 standard were studied, several thermal overloads and instances of low voltage in the area were identified and mitigated by project 1 and 2.

[6] Scenario 3 differs from the Company's current resource plans for Project Evest in that the seventh CCCT unit will be located at the Big Cajun site, not at St. Landry. This difference does not present a significant risk, however. First, Big Cajun and St. Landry are electrically quite proximate and likely to have similar system impacts. [redacted] Finally, and perhaps most importantly, during the 20-year Original Term of the ESA, the Customer will bear the cost of any additional network upgrades that may be identified arising from the location of the seventh unit at Big Cajun, insulating other ELL customers from these costs.

Q72. WHAT CONSTRAINTS INDICATED A NEED FOR THESE UPGRADES IN THE FIRST SCENARIO?

A. The need for the El Dorado to Smalling 500kV line was identified for the first scenario due to the constraints identified in Section P-1 of CEII Exhibit DK-6. The need for the Smalling to WFC 500kV second line was identified for the first scenario due to the constraints identified in Section P-2 of CEII Exhibit DK-6.

Q73. WHAT ARE YOUR OVERALL IMPRESSIONS OF SCENARIO 1?

A. The Smalling to El Dorado 500kV line is needed to address identified thermal constraints consisting of eight (8) existing line sections in North Louisiana and South Arkansas totaling approximately 70 miles and two (2) autotransformers in North Louisiana. The Smalling to WFC 500kV second line is created by cutting another Smalling to Car Gas Road in and out of West Fork Creek and mitigates projected low voltages at West Fork Creek that would extend into Mississippi. The Smalling to El Dorado 500kV line and Smalling to WFC 500kV second line are needed to maintain NERC TPL-001 compliance with the load addition and proposed generation that are assumed in this scenario.

Q74. WHAT TRANSMISSION UPGRADES WERE IDENTIFIED FOR THE SECOND SCENARIO?

A. The need for the WFC – St. Landry 500 kV Transmission Line was identified for the second scenario due to the constraints identified in Section P-3 of CEII Exhibit DK-6.

Q75. WHAT ARE YOUR OVERALL IMPRESSIONS OF SCENARIO 2?

A. The WFC – St. Landry 500kV Transmission Line is needed to address the identified thermal constraints on the 500kV, 230kV and 115kV transmission systems in Central Louisiana. Without the addition of the WFC – St. Landry 500kV Transmission Line, ELL would not be able to conduct essential seasonal maintenance on generation and transmission assets and maintain reliability – to the detriment of all customers.

Q76. WHAT TRANSMISSION UPGRADES WERE IDENTIFIED FOR THE THIRD SCENARIO?

A. The upgrades identified in Scenarios 1 and 2 were assumed as a basis for Scenario 3, and no additional upgrades were identified.

Q77. WHAT ARE YOUR OVERALL IMPRESSIONS OF SCENARIO 3?

A. The upgrades from Scenarios 1 and 2 were confirmed to be robust enough to accommodate the increased load level at West Fork Creek and changes to the generation assumptions while maintaining NERC TPL-001 compliance.

Q78. WHAT SCENARIO DID ELL ULTIMATELY SELECT FOR THE PROPOSED TRANSMISSION FACILITIES AND WHY?

A. Scenario 1 and Scenario 2 were selected to support the need for the proposed upgrades, and Scenario 3 was used to confirm the robustness of the upgrades.

Q79. DO YOU BELIEVE THAT THE PROPOSED TRANSMISSION FACILITIES REPRESENT A REASONABLE SOLUTION FOR ADDING SERVICE TO THE PROJECT?

A. Yes.

Q80. WHY?

A. The proposed Transmission Facilities and proposed timeline (i) will meet the reliability, resiliency, sustainability, and speed to market requirements of Project Evest, (ii) are based upon sound engineering principles, and (iii) find further support in prior ELL analyses, as I explain in more detail below.

Q81. HOW DID YOUR ANALYSIS ADDRESS POTENTIAL THERMAL RISKS ASSUMING REDUCED LEVELS OF DISPATCH OR SCENARIOS WHERE ONE OR MORE OF THE CCCTS IS OFFLINE?

A. Entergy undertook an analysis to evaluate the ability of the system to serve energy and capacity during the fall and spring periods of the year, when planned generation outages are at their peak, as I discussed in more detail above. This analysis identified reliability and operational concerns when typical generation maintenance outages are factored into the growing system. The Smalling to El Dorado 500kV Transmission Line and WFC – St. Landry 500kV Transmission Line were also tested for robustness by performing additional contingency analysis using TPL-001 events with one of the proposed WFC generators offline.

Q82. ARE MUST-RUN COSTS A POTENTIAL CONCERN?

A. No. With the proposed Smalling to El Dorado 500kV Transmission Line and WFC – St. Landry 500kV Transmission Line, must-run costs for the proposed generation are not a concern. Also, must-run units are typically units that have to run out of economic dispatch order. The new units will be among the most efficient units in the Entergy Operating Companies' combined fleet and will have an economic profile that allows them to be committed by the market based on dispatch cost.

Q83. HOW DID YOUR ANALYSIS ADDRESS POTENTIAL VOLTAGE RISKS?

A. Steady-state analysis was performed on Scenarios 1-3 while monitoring voltage.

Q84. HOW DID YOUR ANALYSIS ADDRESS POTENTIAL TRANSIENT STABILITY RISKS?

A. Transient stability analysis was performed with the proposed transmission upgrades as a basis for a robustness test of the solution set, and no additional constraints were identified.

Q85. SHOULD THE COMMISSION BE CONCERNED ABOUT SYSTEM VOLTAGE CONSTRAINTS?

A. While it is reasonable for the Commission to be concerned about any new customer's impact on system voltage, I believe such concerns should be mitigated by the proposed Transmission Facilities.

Q86. PLEASE EXPLAIN FURTHER WHY THE COMMISSION SHOULD NOT BE CONCERNED ON THIS POINT.

A. The voltage constraints during the multiple scenarios that were studied are being addressed by the proposed transmission upgrades. Further, should Customer operational or detailed load modeling data indicate additional issues, ELL has adequate protections in place under its Terms and Conditions and the terms of the ESA to ensure that Project Evest will be responsible for the cost of mitigation of those issues.

Q87. WHAT IS THE RISK THAT THE LOAD ASSOCIATED WITH PROJECT EVEST WILL DISRUPT THE SYSTEM?

A. Each of the studies discussed above were undertaken to understand how Project Evest could impact the system overall and whether mitigation steps were necessary. The Application fully accounts for system risks based on the best information available at this time. ELL continues to work with the Customer as the Customer completes detailed facility design and will continue to study how the Project will impact the system as additional information about Project Evest and Project Laidley becomes available. The Customer also will be required to adhere to Institute of Electrical and Electronics Engineers ("IEEE") standards governing harmonics and flicker and address any issues caused by the Customer. In this regard, the Company's standard Terms and Conditions, which are applicable to the Customer, as well as additional provisions in its ESA, require that the Customer pay to resolve any issues caused by fluctuations in voltage

or power demand on Customer's system.[7] ELL also is installing power quality meters and phasor measurement units ("PMUs") at each of the Customer load-serving substations to provide visibility into any power quality issues that do arise.

Q88. DID YOUR ANALYSIS TAKE INTO ACCOUNT THE RISK AND IMPACT OF TORSIONAL STRESS AND OTHER RISKS ASSOCIATED WITH THE DYNAMIC BEHAVIOR OF THE CUSTOMER FACILITY?

A. As best we can at this point in time. Each of the studies discussed above were undertaken to understand how the Project could impact the system overall and whether mitigation steps were necessary. Further, torsional stress issues do not cause catastrophic failure – they are repetitive stress issues that cause damage over time and can be nearly impossible to detect ahead of time due to the level of detail required to accurately model the impacts of system changes. Typically, these issues are identified once the issue is detected on the system when the cause of the issue is in operation and then addressed before serious harm occurs. The EOCs have identified (and resolved) these sorts of issues various times over the years including an issue that was resolved as recently as 2023 and involved installing a single new transmission structure on one of the lines leaving Grand Gulf Nuclear Station. That is an example of the incredibly fine margins involved in identifying issues of this type. The conductor geometry in a single span of transmission line caused an issue that needed to be resolved to preserve the long-term health of the generation unit. In sum, while it is possible that additional

[7] *See* Terms and Conditions of Electric Service Provided by Entergy Louisiana, LLC, Section 18. *See also* ESA Section V.

facilities could be identified as ELL learns more detail about the Customer's facility, any upgrades will be limited in scope and the resulting costs will be paid by the Customer.

Q89. DID YOUR ANALYSIS OF THE STABILITY RISKS ASSOCIATED WITH PROJECT EVEST LOAD FULLY TAKE INTO ACCOUNT THE PROJECT LAIDLEY LOAD?

A. The presence of the Project Laidley load was included in the models used to study the stability impacts of Project Evest. For both projects, the load profile and behavior (connection/disconnection) settings provided by the Customer were modeled.

Q90. WHAT RISK IS THERE THAT YOUR ANALYSIS OF THE STABILITY RISKS ASSOCIATED WITH PROJECT EVEST LOAD IS MATERIALLY LIMITED BY THE FACT THAT THE PROJECT LAIDLEY LOAD IS NOT YET ONLINE AND ITS IMPACT HAS NOT YET BEEN FULLY STUDIED?

A. There is some uncertainty about the stability results, as is always the case when performing studies before a project is online. This is true of any large load project as well as with any generator. The study process includes restudies as more information becomes known, and that applies to information about Project Laidley as well. As Power Delivery Planning learns more about Project Laidley, the planning team will perform additional analysis to ensure all issues that can be identified are flagged and resolved as quickly as possible.

Q91. HOW WILL ELL INCORPORATE THE LOAD CONTEMPLATED BY PROJECT EVEST INTO ITS EMERGENCY LOAD-SHED PLANS?

A. ELL has a cross-functional team comprised of Operations, the Transmission and Distribution Control Centers, and the Local Balancing Authority team that is developing the protocols for exactly how hyperscale customers will be incorporated into load shed plans. The specific protocols, including how and to whom notice is provided, the timing of such notice, and how communications take place internally and with external stakeholders are complex. With that said, it is ELL's intent that Project Evest will be situated similarly to other LLHLFPS customers with respect to emergency load shed; this intent has been communicated to the Customer and is memorialized in the ESA.

Q92. HOW WILL THE CUSTOMER FACILITY BE IMPACTED DURING AN EMERGENCY EVENT?

A. This depends on the type and timing of the emergency event that occurs as well as the location of such an event. Some emergency events may not impact the customer facility at all; others may have more significant impacts to the ability to serve load at the Customer's facility. For example, a tornado that strikes near the facility and impacts some of the EHV transmission facilities in the area may require some reduction in Customer demand until the facilities are restored. Similarly, a regionwide capacity shortfall may necessitate reduction in Customer demand for a short period. However, to offer another example, a windstorm in the Jackson area would not be expected to impact Customer operations.

Q93. ARE THERE ADDITIONAL STUDIES WHICH COULD BE TAKEN NOW THAT WOULD BE LIKELY TO REVEAL RISKS NOT CONSIDERED BY YOUR TEAM?

A. No. My team considered all relevant information that would be expected to be reasonably available at this stage of an industrial development project and performed comprehensive and methodical analyses utilizing, where appropriate, conservative assumptions. These analyses included steady-state, stability, and short-circuit studies, to identify the necessary transmission and generation upgrades needed to accommodate the Customer's load and ensure compliance with the applicable NERC Reliability Standards and ELL's local transmission planning guideline and criteria.

Q94. WHAT FUTURE STEPS DOES ELL PLAN TO TAKE TO RESPOND TIMELY TO POWER QUALITY IMPACTS CAUSED BY PROJECT EVEST?

A. I do not anticipate significant power quality impacts for the reasons discussed above, but ELL is prepared to report to the Commission annually on any power quality impacts and would propose terminating such reporting once three (3) consecutive years of full facility operation have occurred with no material power quality issues. To the extent any material power quality issues occur solely as a result of the operation of the Customer facility, the cost of the upgrades necessary to resolve these issues will be paid for by the Customer. Although this obligation is explicitly detailed in ELL's Terms and Conditions, the Company negotiated additional language in the ESA regarding these commitments from the Customer regarding power quality impacts, harmonics, flicker, and system oscillations. This language also reiterates the requirements obligating the

Customer to address issues they cause and specifies the timing in which those requirements must be addressed. While these obligations exist for all Customers as noted above, this additional language was added to the Evest ESA in direct response to concerns raised in LPSC Docket No. U-37425.

Q95. HOW WILL THE TRANSMISSION FACILITIES SUPPORT THE INTEGRATION OF RENEWABLE RESOURCES INTO ELL'S GENERATION SYSTEM?

A. By providing a new 500kV path from the El Dorado, Arkansas area to south of Alexandria, Louisiana, the Transmission Facilities will help bypass lower voltage facilities in North and Central Louisiana and southern Arkansas that have historically constrained generator interconnections.

Q96. WHAT HAS YOUR TEAM'S LONG-TERM PLANNING ANALYSIS SHOWN WITH RESPECT TO HOW THE PROJECT WILL IMPACT LOAD SERVING CAPABILITY IN THE BROADER REGION OF NORTH LOUISIANA?

A. We believe the load serving capability of these Transmission Facilities significantly exceeds that of the Project Evest load. As such, these facilities are expected to help support additional load growth in northern Louisiana and southern Arkansas. I would caution that the 500kV network in the project vicinity operates somewhat separately from the 115kV network, and the 115kV network will likely require additional reinforcement in the event that additional growth occurs in northern Louisiana.

Q97. DID YOU UNDERTAKE A COST/BENEFIT AND BENEFITS METRICS ANALYSIS FOR EACH OF THE POTENTIAL SOLUTIONS?

A. Yes. Our evaluation for each alternative sought to determine whether the solution would be effective and reasonable while taking into consideration sound engineering principles and the Customer's need for speed-to-market. The proposed Transmission Facilities were the only cost-effective alternative identified that would meet the Customer's need for speed-to-market while also maintaining reliability for existing customers in the area and balancing concerns of cost-effectiveness.

Q98. HOW DID THE COST/BENEFIT AND BENEFITS METRICS ANALYSIS FOR THE PROPOSED TRANSMISSION FACILITIES COMPARE TO THE ALTERNATE SOLUTIONS THAT YOU CONSIDERED?

A. The proposed Transmission Facilities were identified as the lowest reasonable cost solution to provide the level of reliability required by the Project and thus to secure the economic development benefits of the Project, to maintain compliance with the NERC reliability standards, and to ensure system reliability for existing customers.

Q99. DO THE PROPOSED TRANSMISSION FACILITIES FALL WITHIN A NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDOR (NIETC)?

A. No. The proposed Transmission Facilities do not involve any designated NIETC and, as such, federal backstop siting authority is not a factor in this proposal.

## VII. MISO PROCESS AND IMPACT

Q100. PLEASE DESCRIBE MISO'S ROLE AND HOW IT AFFECTS THIS PROJECT.

A. MISO is the Transmission Planner for the entire MISO region, which extends across all or part of fifteen states in the central United States, including most of Louisiana. As Transmission Planner, MISO administers two processes that are pertinent to the Project: the transmission planning process and the generator interconnection process. New substations (such as Smalling) must be studied through the transmission planning process, and new generators must be studied through the generator interconnection process.

Q101. CAN YOU DESCRIBE THE MISO TRANSMISSION PLANNING PROCESS?

A. To connect a new load serving substation to the system, a MISO member must submit a request to MISO. MISO studies that request by adding the proposed substation to its system models and simulating outages of facilities across the system to determine whether the system can support the request and whether any system upgrades are needed to accommodate the new substation reliably. Most such requests are studied annually through MISO's MTEP process. This process has a deadline in September of each year for the submission of proposed new transmission facilities, including new load serving substations; MISO then evaluates and analyzes the proposed new facilities and decides whether to recommend them for approval by MISO's Board of Directors. Such approval occurs in December of the year following the year of submission (*i.e.,* approximately 16 months later).

Q102. ARE THERE ANY ALTERNATIVES TO THE PROCESS DESCRIBED ABOVE?

A. Yes. MISO also administers a process called Expedited Project Review ("EPR") that allows members to submit proposed new transmission projects that require faster approvals – for example, because they are needed to serve a new load – at any time of the year, and these typically are considered within 30 to 90 days of submission. ELL will use the EPR process for the transmission projects listed in Table 1 above that are required to serve the Project, because expedited consideration is needed to meet the in-service date driven by Customer's speed-to-market needs. EPRs are considered by MISO on an expedited timeline and then, if approved, formally incorporated into the MTEP in the following December's MTEP report.

Q103. WHEN DO YOU EXPECT THE EPR PROCESS FOR THE TRANSMISSION FACILITIES TO BEGIN?

A. The Transmission Facilities and associated load were submitted to MISO in March, and it is expected that the EPR process will commence on April 7, 2026.[8]

Q104. PLEASE DESCRIBE THE MISO GENERATOR INTERCONNECTION PROCESS.

A. There are three MISO generator interconnection processes available for this project. By way of background, the MISO generator interconnection process is a process governed by the MISO Tariff that provides a set of rules and procedures that a new

[8] Beginning in June 2025, MISO transitioned from an "on demand" EPR process to a bi-monthly process. The new process gathers EPRs into clusters every two months and studies them with the goal of completing review during the two-month period. Some projects require more than one two-month cycle for MISO to complete its analysis.

generator looking to interconnect to the MISO administered transmission system must follow in order to secure the right to interconnect. As shown in my Exhibit DK-7, the traditional interconnection process, known as the Definitive Planning Phase ("DPP") is conducted in three phases over a period of approximately 355 days (although in recent years the timeline has been much longer). Each phase consists of a series of studies that assess whether the proposed new generator may interconnect to the transmission system reliably and whether transmission upgrades are needed to reliably accommodate the injections of energy from the proposed generator. In MISO, the process is conducted in cycles in which all proposed new generators submitted within that cycle are studied as a group. For the last several years, due in significant part to the large volume of individual generators exploring areas on the grid at which it would be advantageous to site new generation, the MISO DPP process has been plagued by significant delays, including delays arising from restudies needed because of the withdrawal of speculative projects.

In August 2025, the Federal Energy Regulatory Commission ("FERC") accepted a filing by MISO creating another generator interconnection process known as the Expedited Resource Addition Study ("ERAS"). ERAS was developed in part in response to the delays associated with the DPP process that I noted above and the need to add significant new generation to the electric system in a relatively short period of time to maintain resource adequacy and reliability as utilities work to serve large volumes of expected load growth. This process created a limited set of fifty interconnection requests that would be studied by MISO separately from the standard DPP. Per the rules and requirements of ERAS, these requests must be related to

resource adequacy needs in the MISO footprint, must have an attestation from the load serving entity's retail regulator that the project is needed to serve resource adequacy needs, and must meet several other requirements that are more restrictive than standard DPP requests. The ERAS process studies fifteen projects per three-month cycle and at the end of that process, the projects receive an executed Generator Interconnection Agreement.

[redacted]

Q105. HOW DO YOU COMMENCE THE MISO GENERATOR INTERCONNECTION PROCESS?

A. As shown in Exhibit DK-7, the process commences with the submittal of generator interconnection requests by Generator Owners, which are also known as Interconnection Customers. Next, once all necessary completeness milestones are met for the entire DPP study cycle, MISO commences a Pre-Screen Analysis. The completeness milestones involve MISO reviewing each application, determining whether the Interconnection Customer's evidence of site control is sufficient, determining whether all the necessary information for the request has been submitted, and confirming that queue entry payments have been received. The non-binding Pre-Screen Analysis identifies potential thermal and voltage constraints for the entire DPP study group. The Pre-Screen Analysis concludes with MISO communicating the results to the Interconnection Customers prior to DPP Phase I kick-off. For projects in the ERAS process, because there were only fifty interconnection slots available, Interconnection Customers had an incentive to submit their requests as soon as possible. MISO created a separate interconnection request portal for the ERAS process; this process is similar to that described above for DPP requests and a flowchart is shown in Exhibit DK-8.

Q106. HAVE THE GENERATOR PROJECTS BEEN SUBMITTED TO MISO FOR STUDY?

A. Yes, ELL submitted requests for the Richland Parish 1, 2, 3, & 4 units when the ERAS portal opened in August 2025. An ERAS request for a portion of the NRIS needed for

the three units in Pointe Coupee Parish was submitted in early November 2025. The remainder of the NRIS for the three Pointe Coupee Parish units will be obtained through the DPP [redacted] as discussed in more detail by ELL witness Ms. Beauchamp.

Q107. HOW ARE THE PROPOSED TRANSMISSION LINE UPGRADES CLASSIFIED UNDER THE MISO TARIFF?

A. While MISO has not completed its review of the transmission line upgrades, ELL expects the following classifications:

- El Dorado – Smalling 500kV Transmission Line: Baseline Reliability Project
- West Fork Creek 500/230kV Substation: Reliability – Other
- West Fork Creek – St. Landry 500kV Transmission Line: Reliability – Other.

Q108. HOW WILL THE COST OF THE PROPOSED TRANSMISSION LINE UPGRADES BE ALLOCATED UNDER THE MISO TARIFF?

A. The costs of the El Dorado – Smalling 500kV Transmission Line and West Fork Creek 500/230kV Substation are being fully funded by the Customer through a CIAC agreement, so there will be no allocation of costs under the MISO Tariff. Our expectation is the cost of the West Fork Creek – St. Landry 500kV Transmission Line will be allocated to the ELL Transmission Pricing Zone.

Q109. IS THE CLASSIFICATION OF THE PROJECT UNDER THE MISO TARIFF IMPACTED BY CONTRIBUTIONS FROM THE PROJECT CUSTOMER?

A. No, MISO makes an independent determination as to the classification of any new Transmission Facilities that are proposed, and MISO's determination does not consider any direct contributions from individual customers.

Q110. HOW LONG DO YOU ANTICIPATE THE ERAS, DPP, [redacted] WILL TAKE?

A. As explained above, the entire ERAS process takes roughly 90 days to complete after commencement. Richland Parish 1 & 2 is included in ERAS Cycle 3, which commenced in March 2026. MISO has not clarified which cycles future projects will be included in, but my expectation is that Richland Parish 3 & 4 will be included in ERAS Cycle 4, commencing in June 2026, and Pointe Coupee 1 & 2 will be included in ERAS Cycle 6, commencing in December 2026. It is possible these cycles could change, but the dates on which cycles begin and end are established by the MISO Tariff. By comparison, the entire DPP process takes about a year and a half to complete, although this has been trending longer in recent cycles. [redacted]

Q111. WHEN DO YOU EXPECT TO KNOW DEFINITIVELY WHAT UPGRADES WILL BE NEEDED FOR THE GENERATION PROJECTS?

A. For the resources included in the ERAS process, upgrades will be known by the end of the study cycle for each resource, with the possibility that some additional upgrades could be identified through Affected Systems Studies on neighboring systems (such as SPP, TVA, and Southern Company). However, because of the proximity of these units to nearby load, it is unlikely the Affected Systems Studies will identify significant facilities. For the resource in the DPP study process, it is difficult at this time to precisely determine when the DPP study process will conclude, but I would expect to have more clarity about needed upgrades sometime in 2027. [redacted] It is my understanding that the Customer will bear the actual cost of the interconnection network upgrades associated with these seven CCCT resources as determined by MISO – through an adjustment to the billing terms for the Customer's electric service. This provision of the ESA is discussed in more detail in the Direct Testimony of Mr. Jones.

Q112. WHAT ACTIONS WILL THE COMPANY TAKE FOLLOWING THE RECEIPT OF THE ERAS, DPP, [redacted] STUDY RESULTS?

A. Following the results of the ERAS, DPP, [redacted] studies, the Company will take the necessary steps to sign the Generator Interconnection Agreements for the transmission projects, if any, determined to be needed to obtain the necessary interconnection service for the seven CCCT resources.

Q113. WILL THE REQUIRED UPGRADES FROM THE ERAS, [redacted] AND DPP STUDIES BE DEFINITIVE OR ARE THEY SUBJECT TO FURTHER CHANGE?

A. The required upgrades provided by MISO at the conclusion of the ERAS, [redacted] or DPP process (including any required restudies) are final and will not be subject to further revision. Definitive cost estimates for transmission upgrades associated with the generation projects will be known at that time.[9]

Q114. WHAT TYPES OF TRANSMISSION SERVICE ARE SECURED THROUGH THE GENERATOR INTERCONNECTION PROCESS?

A. The normal DPP generator interconnection process offers two levels of service: Energy Resource Interconnection Service ("ERIS") and Network Resource Interconnection Service ("NRIS"). ERIS is basic service that allows a resource to connect to the transmission system and bid into energy markets, but it does not confer any capacity accreditation to contribute toward meeting a load-serving entity's ("LSE") resource adequacy requirements. NRIS is a more advanced level of service that is typically more expensive to secure but that does allow the capacity of a resource to count toward an

[9] While these cost estimates are definitive, there is a circumstance that could result in the lowering of these costs. If MISO's annual deliverability process identifies upgrades needed for ongoing NRIS deliverability that overlap with those upgrades identified in the DPP process and those upgrades are approved by the MISO Board of Directors within one year of GIA execution, those upgrades would no longer be the financial responsibility of the generator. I presume the same possibility for removal of a network upgrade from the GIA applies to EGIAs executed through the ERAS process, but because of the novelty of the ERAS process, that issue has not arisen. The generator's interconnection service would continue to be conditional upon completion of those facilities, but the generator would no longer be responsible for funding those upgrades.

LSE's resource adequacy requirements. One of the conditions of the ERAS process requires that an applicant secure NRIS. [redacted]

Q115. ARE THERE ANY ALTERNATIVE MEANS OF BEING ABLE TO ACCREDIT A RESOURCE'S CAPACITY TO MEET A LSE'S RESOURCE ADEQUACY REQUIREMENTS?

A. Yes, if a resource has ERIS, an LSE can submit a Transmission Service Request ("TSR") from that resource to the LSE's load and, upon the granting of that TSR, use Network Integrated Transmission Service ("NITS"). This combination of ERIS plus NITS also provides an avenue for the capacity of a resource to count toward the LSE's resource adequacy requirements.

Q116. CAN YOU DESCRIBE NITS?

A. Yes. NITS is one of the services included in the *pro forma* Open Access Transmission Tariff. When a generation resource has interconnection service (ERIS), it allows Network Customers (load-serving entities such as ELL) to use NITS to designate resources to serve their own load. Because the study process measures the transmission system's capability to deliver the proposed resource only to the load of the requesting LSE, the impacts on the transmission system shown in the study results are generally less significant than those of NRIS. Consistent with this approach, whereas NRIS confers upon the Interconnection Customer the ability to serve (*i.e.*, to supply capacity

credit to) any load in the MISO market, NITS only confers the ability to serve the load of the requesting LSE – here, ELL.

Q117. PAST ELL RESOURCES HAVE SECURED NRIS. IS IT REASONABLE TO INSTEAD USE NITS FOR THE GENERATION FACILITIES?

A. It is reasonable, but a decision to use NITS has not been made. In this scenario, because only one of the generation facilities is in the DPP, the majority of the facilities will receive NRIS by virtue of the ERAS process requirement on this point. However, a decision on how best to achieve deliverability for the final resource will be made as more information is known about upgrades that are identified through the MISO process. Securing NRIS preserves future optionality should a decision ever be made to sell those generation assets. However, in cases where the cost of NRIS is high because ELL only needs its generation facilities to serve its own customer demand, it is reasonable to obtain NITS in the interest of mitigating the cost to ELL's customers. If ELL does pursue NITS for any of the generation resources and subsequently determines that NRIS is needed, ELL can pursue that service at that time.

Q118. CAN YOU CONFIRM FOR THE COMMISSION THAT QUEUE PRIORITY AND INTERCONNECTION TREATMENT ARE CONSISTENT WITH TARIFF REQUIREMENTS AND DO NOT DISADVANTAGE EXISTING CUSTOMERS?

A. Yes. As explained above, ELL has submitted requests for the generator projects in compliance with the ERAS process, which MISO independently administers according to the terms of its Tariff. Further, the Customer will fully fund all interconnection costs

and make substantial investments in transmission system-wide improvements, such that existing customers are not disadvantaged.

## VIII. RIGHTS OF WAY AND PERMITTING

Q119. PLEASE DESCRIBE WHETHER RIGHTS OF WAY WILL BE ACQUIRED FOR THE CONSTRUCTION OF THE TRANSMISSION FACILITIES AND WHETHER EXISTING RIGHTS OF WAY WILL BE UTILIZED?

A. Table 2 below specifies whether new rights of way will need to be acquired or existing rights of way utilized for the construction of each transmission facility.

**TABLE 2**

| Project | New Right of Way (Y/N) | Existing Right of Way (Y/N) |
|---|---|---|
| Interconnection Project | Yes, for lines to load serving substations | No |
| Smalling-El Dorado 500kV | Yes, with some right of way sharing possible | No |
| WFC – St. Landry 500kV Line | Yes | No |

Q120. WHAT IS ELL'S PLAN FOR OBTAINING ANY NECESSARY RIGHTS OF WAY FOR THE NEW TRANSMISSION LINES?

A. ELL will work proactively and constructively with impacted landowners to reach a mutually agreeable outcome to obtain rights of way. However, in the unlikely event those discussions were unsuccessful, ELL would need to rely on expropriation procedures.

Q121. WHAT PERMITTING WILL BE REQUIRED FOR THE CONSTRUCTION OF THE PROPOSED TRANSMISSION FACILITIES AND UPGRADES?

A. In addition to Commission certification for the relevant components of the Transmission Facilities, the Transmission Facilities will require permits from, among others, the Department of Transportation, parish planning commissions, and the Army Corp of Engineers for wetland permitting. Company witness Jeremy Halland discusses in his testimony the permitting requirements for the Transmission Facilities.

## IX. CONCLUSION

Q122. PLEASE SUMMARIZE YOUR CONCLUSIONS FOR THE COMMISSION.

A. The main points of my direct testimony are that:

- ELL conducted a thorough and robust evaluation of potential solutions for extending service to the Project in a manner consistent with sound planning, engineering, and economic principles, appropriately factoring in the Customer's speed-to-market requirements.
- The proposed Transmission Facilities represent the only reasonable solution that would meet the Customer's need for speed-to-market while also maintaining reliability for existing customers and balancing concerns of cost-effectiveness.
- The proposed Transmission Facilities constitute a critical building block for system expansion in Louisiana and are foundational to effectively managing the system impact of growing customer demand, planned retirements of existing generation resources, and the increasing penetration of renewable resources.

Q123. WHAT WOULD BE THE CONSEQUENCES TO THE PROJECT IF ELL IS UNABLE TO TIMELY SECURE THE REQUESTED RELIEF FOR THE TRANSMISSION FACILITIES?

A. If the proposed Transmission Facilities are not timely certified or found to be exempt, I would expect the Customer to look at siting opportunities in other states. As discussed by Mr. May, the Project's potential benefits to Louisiana are only achievable if ELL can meet the Customer's desired timeline. Failure to meet the Customer's timeline expectations could result in the loss of this Project and the economic development opportunity it represents.

Q124. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

**AFFIDAVIT**

STATE OF MISSISSIPPI

COUNTY OF HINDS

**NOW BEFORE ME,** the undersigned authority, personally came and appeared, **DANIEL KLINE**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Daniel Kline

**SWORN TO AND SUBSCRIBED BEFORE ME**
**THIS 17th DAY OF MARCH, 2026**

Aletta B. Walker
**NOTARY PUBLIC**

**My commission expires:** 1/4/2030

STATE OF MISSISSIPPI
ALETTA B. WALKER
NOTARY PUBLIC
Madison County
Commission Expires
January 4, 2030
COMMISSION NUMBER 116794

# LIST OF PREVIOUS TESTIMONY FILED BY DANIEL KLINE

## Before the Public Utility Commission of Texas

**Docket No. 52487,** *Application of Entergy Texas, Inc. to Amend Its Certificate of Convenience and Necessity to Construct Orange County Advanced Power Station (2021).*

**Docket No. 56693,** *Application of Entergy Texas, Inc. to Amend Its Certificate of Convenience and Necessity to Construct a Portfolio of Dispatchable Generation Resources (2024).*

## Before the Louisiana Public Service Commission

**Docket No. U-35927,** *1803 Electric Cooperative, Inc., Ex Parte. In Re: Application for Approval of Power Purchase Agreements and for Cost Recovery (2021).*

**Docket No. U-36190,** *Application of Entergy Louisiana, LLC, for Approval of the 2021 Solar Portfolio, the Geaux Green Option, Cost Recovery and Related Relief (2021).*

**Docket No. U-36135,** *Jefferson Davis Electric Cooperative, Inc. and Nextera Energy Marketing, LLC, Ex Parte. In Re: Joint Application for Approval of Power Supply Agreement (2022).*

**Docket No. U-36133,** *Dixie Electric Membership Corporation, Nextera Energy Marketing, LLC and Amite Solar, LLC, Ex Parte. In re: Joint Application for Approval of Power Supply Agreements (2022).*

**Docket No. U-36514,** *Concordia Electric Cooperative, Inc., Nextera Energy Marketing, LLC, and Mondu Solar, LLC, Ex Parte. In Re: Joint Application for Approval of Long-Term Power Supply Agreements (2023).*

**Docket No. U-36515,** *Pointe Coupee Electric Membership Corporation, Nextera Energy Marketing, LLC, and Mondu Solar, LLC, Ex Parte. In re: Joint Application for Approval of Long-Term Power Supply Agreements (2023).*

**Docket No. U-36516,** *Southwest Louisiana Electric Membership Corporation, Nextera Energy Marketing, LLC, and Beauregard Solar, LLC, Ex Parte. In re: Joint Application for Approval of Long-Term Power Supply Agreements (2023).*

**Docket No. S-37143,** *Application of Entergy Louisiana, LLC for Exemption and/or Certification of the West Bank 230kV Transmission Project in Accordance with Louisiana Public Service Commission General Order Dated October 10, 2013 (2024).*

**Docket No. U-37425, *Application of Entergy Louisiana, LLC for Approval of Generation and Transmission Resources in Connection with Service to a Single Customer in North Louisiana (2024).***

**Before the Wyoming Public Service Commission**

**Docket No. 20003-180-EN-19 (Record No. 15205),** *In the Matter of the Application of Cheyenne Light, Fuel and Power Company d/b/a Black Hills Energy for a Certificate of Public Convenience and Necessity to Construct and Operate a 115 kV Switching Substation and Associated Transmission Lines, and Related Facilities in Laramie County, Wyoming* (2019).

**Docket No. 20003-173-ET-18 (Record No. 15104),** *In the Matter of Cheyenne Light, Fuel and Power d/b/a Black Hills Energy for Authority to Implement a Blockchain Interruptible Service Tariff* (2018).

**Before the South Dakota Public Utilities Commission**

**Docket No. EL 19-006,** *In the Matter of the Application of Black Hills Power Inc. dba Black Hills Energy for a Facility Permit to Construct a 230 kV Transmission Line and Associated Facilities in Pennington County* (2019).

**Before the Colorado Public Utilities Commission**

**Proceeding No. 16AL-0326E,** *In the Matter of Advice Letter No. 721 Filed by Black Hills/Colorado Electric Utility Company, LP to Increase Its Base Rates For All Rate Schedules, Implement a General Rate Schedule Adjustment, Revise Its Transmission Cost Adjustment Tariff, and Implement Other Proposed Changes to Its Colorado PUC No. 9-Electric Tariff To Be Effective June 5, 2016* (2016).

**Proceeding No. 14A-0287E,** *In the Matter of the Application of Public Service Company of Colorado (A) For a Certificate of Public Convenience and Necessity for the Pawnee to Daniels Park 345 kV Transmission Project, and (B) For Specific Findings with Respect to EMF and Noise* (2014).

**Proceeding No. 19A-0055E,** *In the Matter of the Verified Application of Black Hills Colorado Electric, LLC for Expedited Approval of a Service Agreement Pursuant to Its Economic Development Rate Tariff* (2019).

**Before the Minnesota Public Utilities Commission**

**Docket No. E002/GR-13-868,** *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota* (2013).
**Docket No. E002/CN-06-1115,** *In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for Three 345-kV Transmission Lines with Associated Systems Connections* (2008).

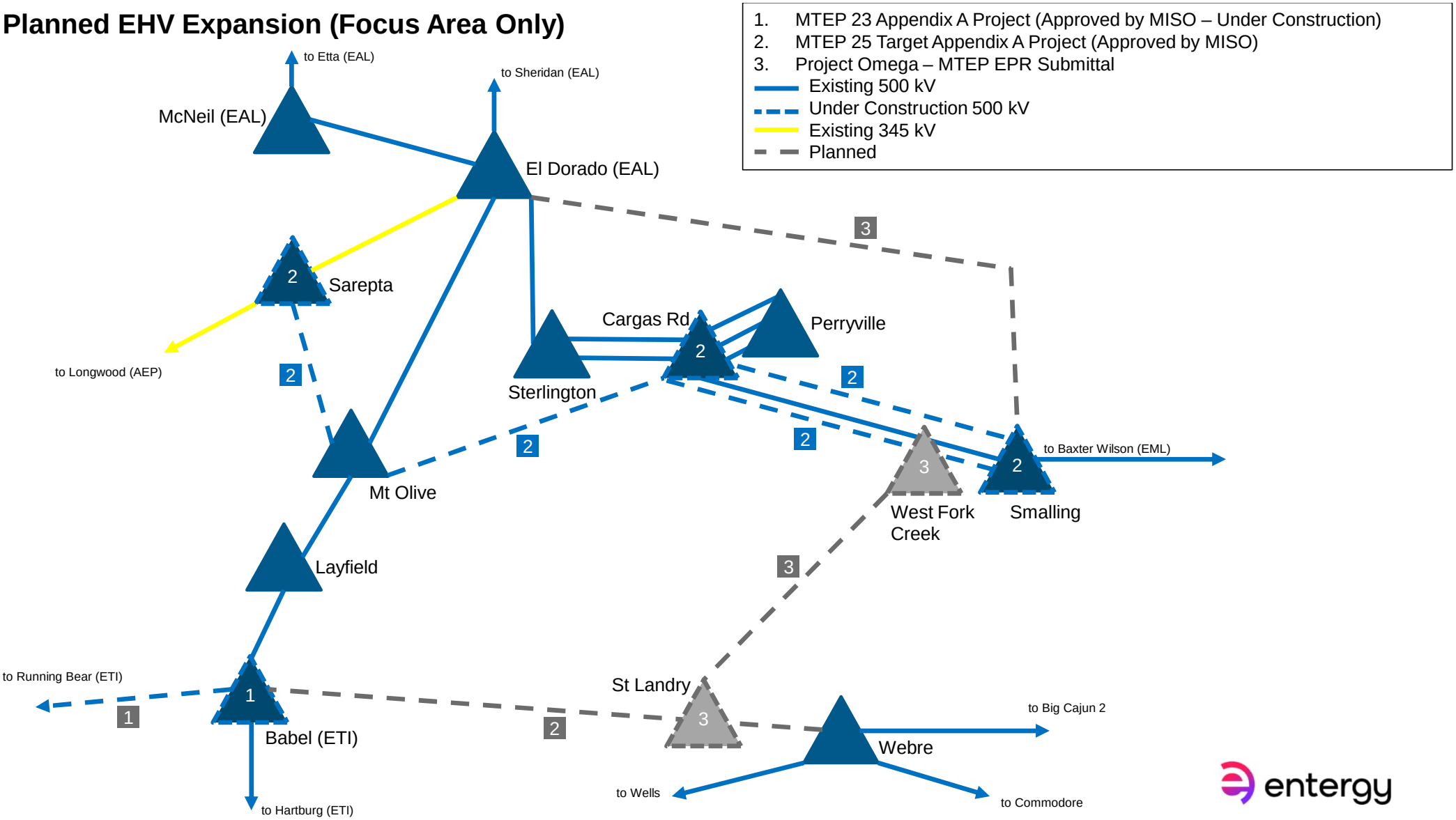
**Before the Public Service Commission of Wisconsin**

**Docket No. 4220-CE-172,** *Application of Northern States Power Company-Wisconsin to Construct and Operate a 69 kV Transmission Line and Substations to be Built in the Towns of Stanton and Star Prairie, St. Croix County, Wisconsin* (2009).

**Before the Federal Energy Regulatory Commission**

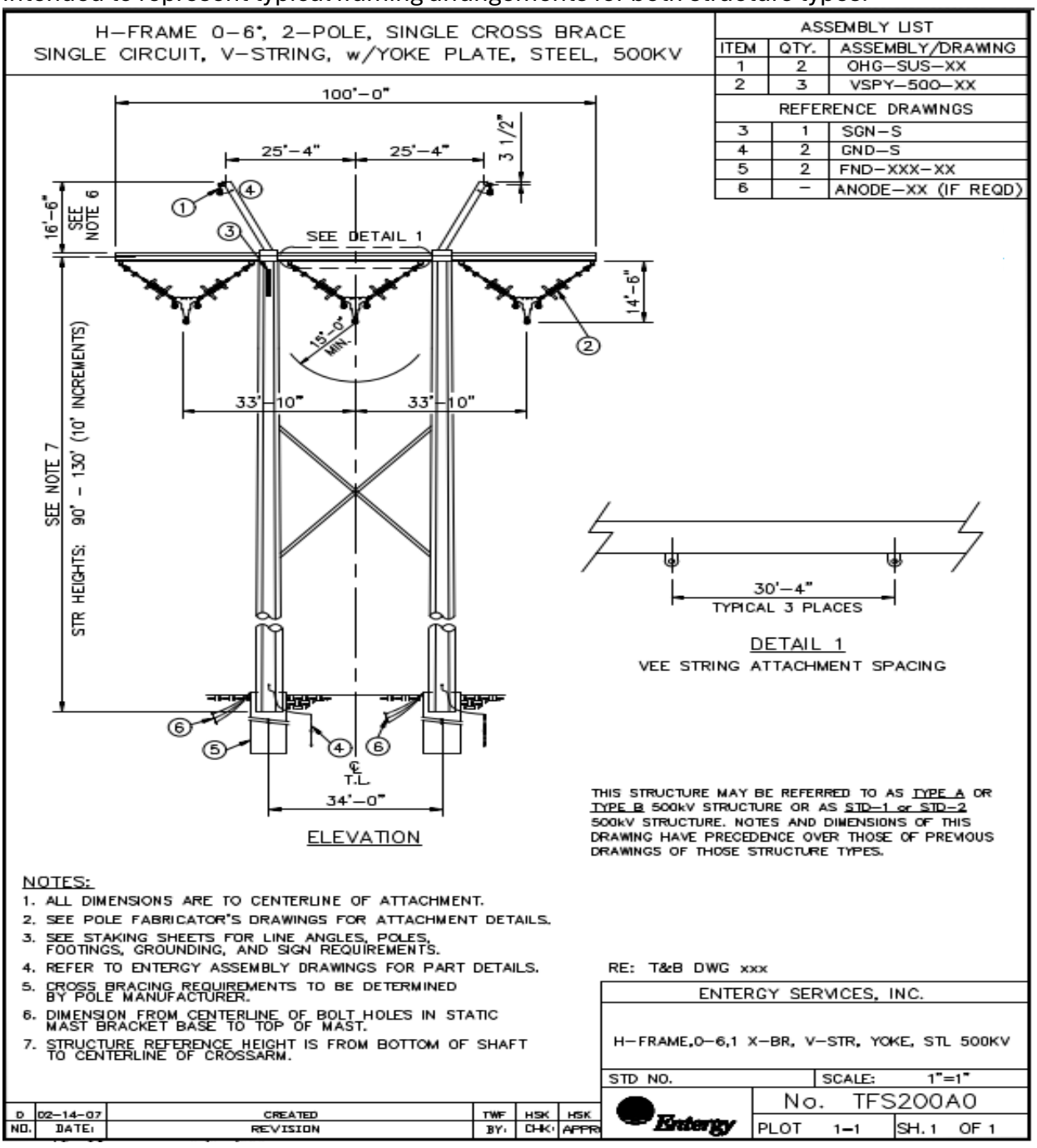
**Docket No. EL12-28-000,** *Complaint and Request for Fast Track Processing of Xcel Energy Services Inc. and Northern States Power Company, a Wisconsin Corporation* (2012) (affidavit).

# Planned EHV Expansion (Focus Area Only)



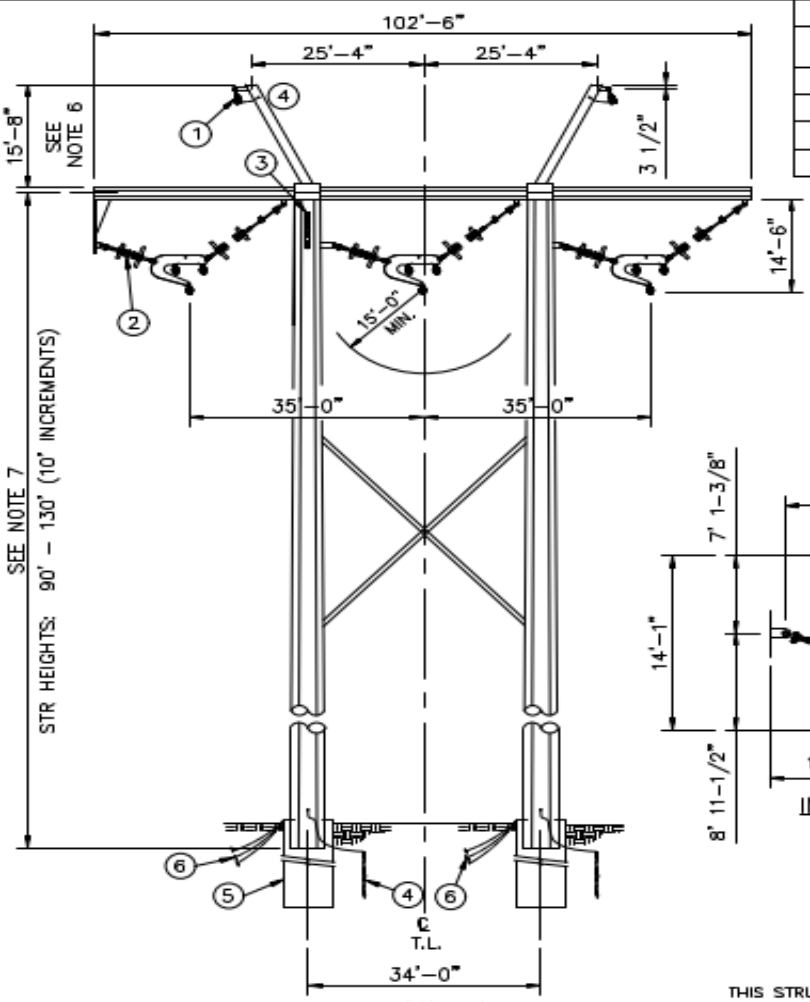
## Illustrative 500kV Structural Drawings

500kV Transmission estimates assume use of standard tubular steel structures. Lattice tangent structures and light angle structures will be also evaluated as an alternative during detailed engineering to ensure an optimized solution. The structural drawings below are intended to represent typical framing arrangements for both structure types.

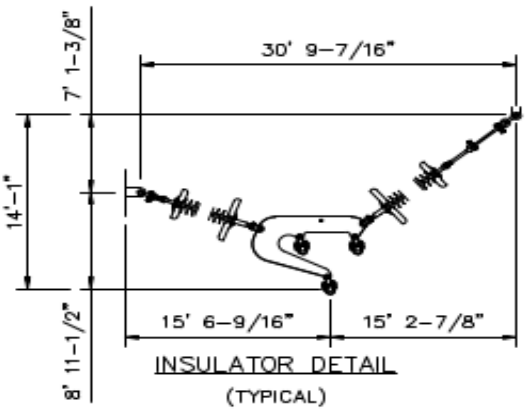


H-FRAME 6-15', 2-POLE, SINGLE CROSS BRACE
SINGLE CIRCUIT, V-STRING RUNNING ANGLE, w/YOKE PLATE, STEEL, 500KV

| ASSEMBLY LIST | | |
|---|---|---|
| ITEM | QTY. | ASSEMBLY/DRAWING |
| 1 | 2 | OHG-SUS-XX |
| 2 | 3 | VSPR-500-XX |
| REFERENCE DRAWINGS | | |
| 3 | 1 | SGN-S |
| 4 | 2 | GND-S |
| 5 | 2 | FND-XXX-XX |
| 6 | - | ANODE-XX (IF REQD) |




ELEVATION




INSULATOR DETAIL
(TYPICAL)

THIS STRUCTURE MAY BE REFERRED TO AS TYPE C 500kV STRUCTURE OR AS STD-3 500kV STRUCTURE. NOTES AND DIMENSIONS OF THIS DRAWING HAVE PRECEDENCE OVER THOSE OF PREVIOUS DRAWINGS OF THOSE STRUCTURE TYPES

NOTES:

1. ALL DIMENSIONS ARE TO CENTERLINE OF ATTACHMENT.
2. SEE POLE FABRICATOR'S DRAWINGS FOR ATTACHMENT DETAILS.
3. SEE STAKING SHEETS FOR LINE ANGLES, POLES, FOOTINGS, GROUNDING, AND SIGN REQUIREMENTS.
4. REFER TO ENTERGY ASSEMBLY DRAWINGS FOR PART DETAILS.
5. CROSS BRACING REQUIREMENTS TO BE DETERMINED BY POLE MANUFACTURER.
6. DIMENSION FROM CENTERLINE OF BOLT HOLES IN STATIC MAST BRACKET BASE TO TOP OF MAST.
7. STRUCTURE REFERENCE HEIGHT IS FROM BOTTOM OF SHAFT TO CENTERLINE OF CROSSARM.

RE: T&B DWG xxx

| NO. | DATE | REVISION | BY | CHK | APPR |
|---|---|---|---|---|---|
| 0 | 02-14-07 | CREATED | TWF | HSK | HSK |

ENTERGY SERVICES, INC.

H-FRAME,6-15,1 X-BR,V-STR,RA,YOKE,STL 500kV

STD NO. | SCALE: 1"=1"

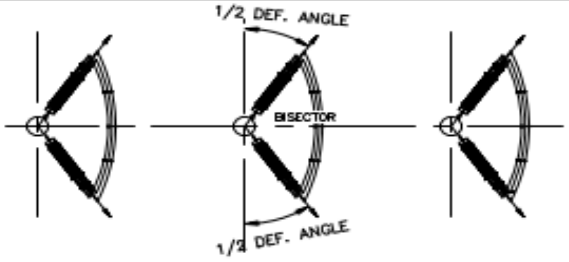
Entergy

No. TFS201A0

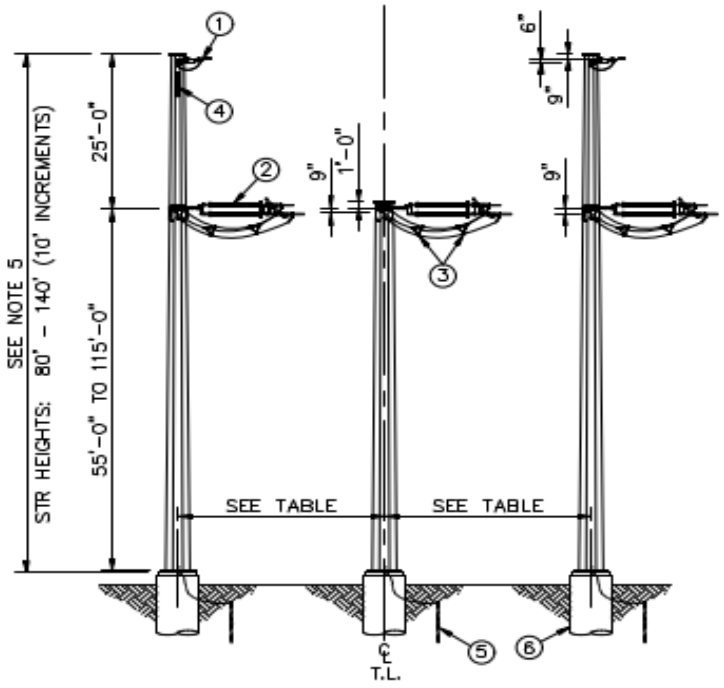
PLOT 1=1 | SH. 1 OF 1

# DEADEND 70°–120° SELF SUPPORTING, 3–POLE SINGLE CIRCUIT, DE POLY w/YOKE, STEEL 500kV

| ASSEMBLY LIST | | |
|---|---|---|
| ITEM | QTY. | ASSEMBLY/DRAWING |
| 1 | 4 | OHG–DE–XX |
| 2 | 6 | DEPY–500–XX |
| REFERENCE DRAWINGS | | |
| 3 | NOTE 6 | SD–CG318–XX |
| 4 | 1 | SGN–S |
| 5 | 2 | GND–S |
| 6 | 2 | FND–XXX–XX |




PLAN




ELEVATION

| POLE SPACING TABLE | |
|---|---|
| DEF ANGLE RANGE | POLE SPACING |
| 53 – 63 | 40 |
| 63 – 71 | 42 |
| 71 – 78 | 44 |
| 78 – 84 | 46 |
| 84 – 89 | 48 |
| 89 – 94 | 50 |
| 94 – 98 | 52 |
| 98 – 101 | 54 |
| 101 – 105 | 40 |
| 105 – 108 | 42 |
| 108 – 110 | 44 |
| 110 – 113 | 46 |
| 113 – 115 | 48 |
| 115 – 117 | 50 |
| 117 – 120 | 52 |
| 120 – 121 | 54 |

(SEE NOTE 7)

NOTES:

1. ALL DIMENSIONS ARE TO CENTERLINE OF ATTACHMENT.
2. SEE POLE FABRICATOR'S DRAWINGS FOR ATTACHMENT DETAILS.
3. SEE STAKING SHEETS FOR LINE ANGLES, POLES, FOOTINGS, GROUNDING, AND SIGN REQUIREMENTS.
4. REFER TO ENTERGY ASSEMBLY DRAWINGS FOR PART DETAILS.
5. STRUCTURE REFERENCE HEIGHT IS FROM BOTTOM OF SHAFT TO TOP OF POLE.
6. PLACE SPACERS ON JUMPERS AS REQUIRED TO MAINTAIN UNIFORM DISTANCE BETWEEN SUB–CONDUCTORS.
7. LEG SPACING BASED ON MAINTAINING 34' PHASE TO PHASE SPACING.

THIS STRUCTURE MAY BE REFERRED TO AS TYPE E 500kV STRUCTURE OR AS STD–5 500kV STRUCTURE. NOTES AND DIMENSIONS OF THIS DRAWING HAVE PRECEDENCE OVER THOSE OF PREVIOUS DRAWINGS OF THOSE STRUCTURE TYPES

SLE3–DEPY–S 500

| NO. | DATE: | REVISION | BY: | CHK: | APPR |
|---|---|---|---|---|---|
| 1 | 12–15–10 | VERT. DIMENSION, FOR SW VANGS | TWF | HSK | HSK |
| 0 | 02–14–07 | CREATED | TWF | HSK | HSK |

ENTERGY SERVICES, INC.

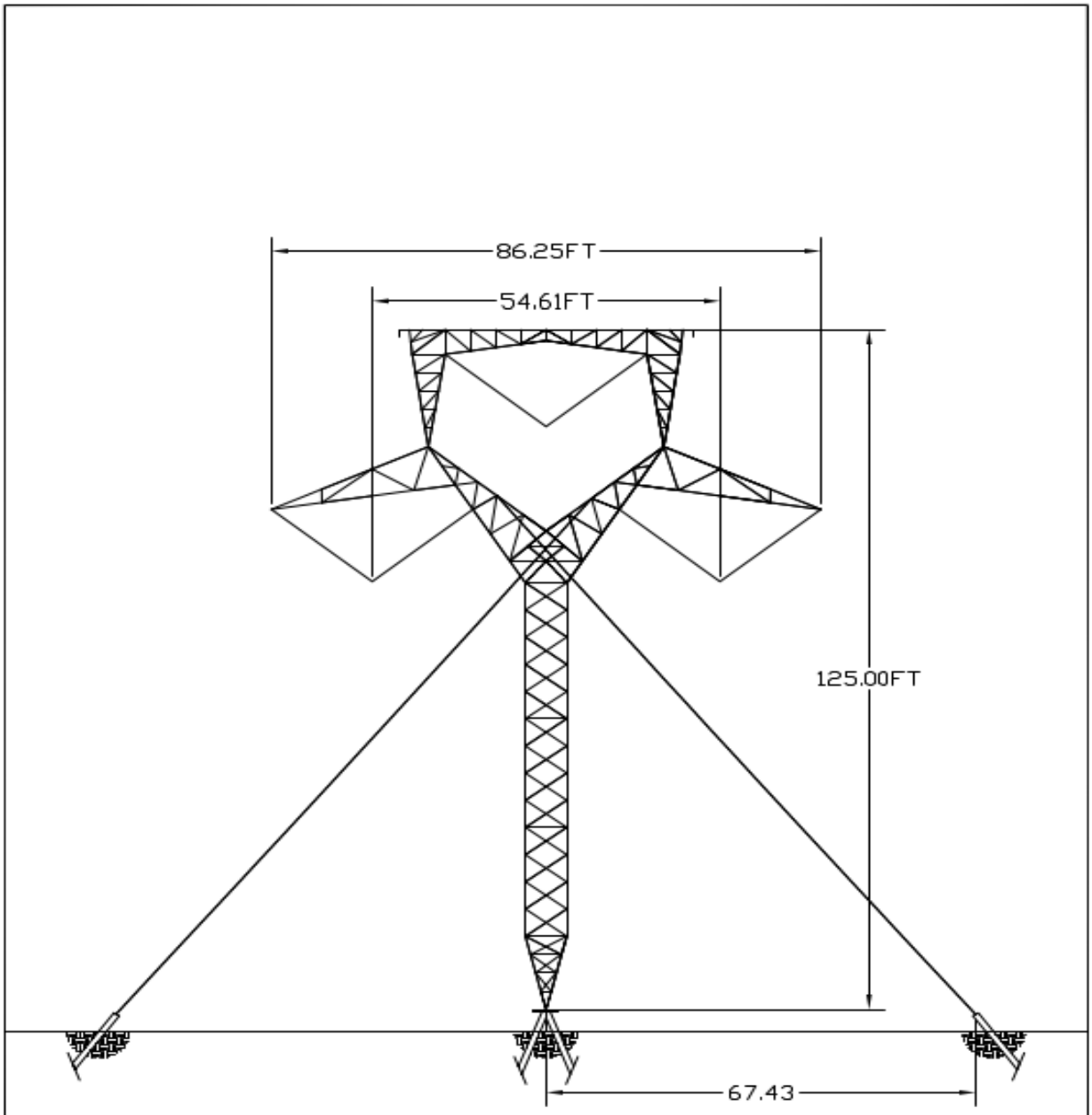
DE 70–120 SS, 3–POLE, POLY, YOKE, STL 500kV
STRUCTURE DRAWING & DETAIL

STD NO. | SCALE: 1"=1"

Entergy

No. TFS202A1

PLOT 1–1 | SH. 1 OF 1




ENTERGY SERVICES, INC.

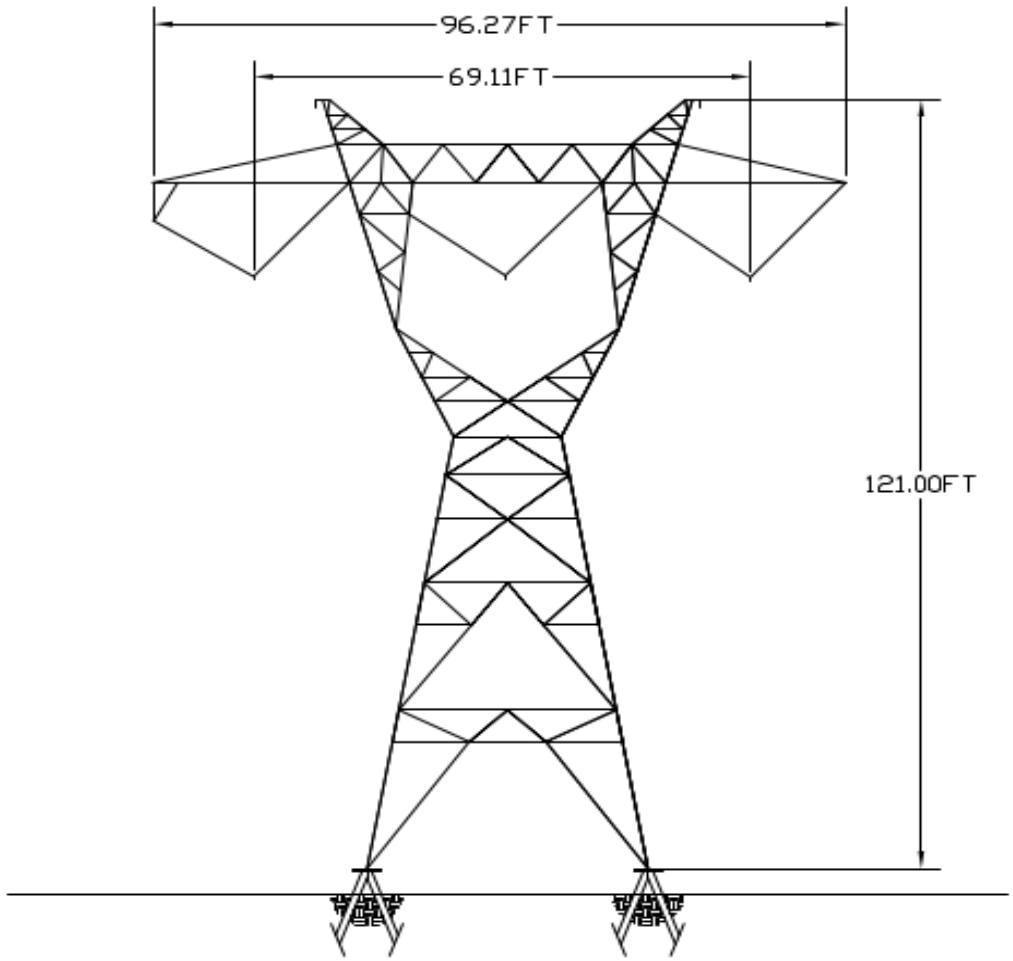
500kV BANJO TANGENT
STRUCTURAL ASSEMBLY OVERVIEW

STD NO. | SCALE: NONE

entergy | No.

PLOT NTS | SH. 1 OF 1

| NO. | DATE | REVISION | BY | CHK | APPR |
|---|---|---|---|---|---|
| A | 3/14/2025 | FOR ENTERGY REVIEW | | | |




ENTERGY SERVICES, INC.

500kV LIGHT RUNNING ANGLE
STRUCTURAL ASSEMBLY OVERVIEW

STD NO. | SCALE: NONE

entergy | No.

PLOT NTS | SH. 1 OF 1

| NO. | DATE | REVISION | BY | CHK | APPR |
|---|---|---|---|---|---|
| A | 3/14/2025 | FOR ENTERGY REVIEW | | | |

## Timeline with Milestones – System Improvement Projects

The milestone schedule below includes key dates for the ELL work scope. For reference, it also includes relevant milestones for the Arkansas portion of the Smalling-El Dorado 500kV transmission line.

| Schedule Milestones | | |
|---|---|---|
| **Activity/Milestone** | **Target Start** | **Target Finish** |
| **Stage 1 - Business Case Justification** | | |
| Class 5 Scope and Estimate Development | 7/22/2025 | 12/2/2025 |
| **Stage 2 - Project Scope Selection** | | |
| Issue PO's for Long Lead Materials | 5/5/2025 | 5/1/2026 |
| **Stage 3 - Project Definition** | | |
| Entergy BOD Approval | 12/5/2025 | 12/5/2025 |
| Smalling-El Dorado 500kV T-Line Route Study (ELL Scope) | 5/28/2025 | 2/20/2026 |
| Smalling-El Dorado 500kV T-Line Route Study (EAL Scope) | 5/28/2025 | 2/9/2026 |
| West Fork Creek-St. Landry 500kV T-Line Route Study | 12/16/2025 | 3/13/2026 |
| Smalling-El Dorado 500kV T-Line ROW Acquisition (ELL Scope) | 8/5/2026 | 6/27/2028 |
| Smalling-El Dorado 500kV T-Line ROW Acquisition (EAL Scope) | 11/2/2026 | 2/18/2028 |
| West Fork Creek-St. Landry 500kV T-Line ROW Acquisition | 3/2/2026 | 6/15/2028 |
| St. Landry 500kV Station Property Acquisition | 6/1/2026 | 2/1/2027 |
| Customer Interconnection ROW & Property Acquisition | 3/2/2026 | 7/28/2027 |
| Prepare CCN for Smalling-El Dorado (ELL Scope) | Exempt | Exempt |
| Prepare CCN for West Fork Creek-St Landry | 3/1/2026 | 3/27/2026 |
| Prepare CECPN for Smalling-El Dorado (EAL Scope) | 4/2/2026 | 7/30/2026 |

| Schedule Milestones | | |
|---|---|---|
| **Activity/Milestone** | **Target Start** | **Target Finish** |
| **Stage 4 - Engineering and Procurement** | | |
| File CCN Smalling-El Dorado (ELL scope) | Exempt | Exempt |
| File CCN for West Fork Creek-St Landry (requested through ELA filing) | 3/27/2026 | 3/27/2027 |
| File CECPN Smalling-El Dorado (EAL scope) | July 2026 | December 2026 |
| Permitting for Smalling-El Dorado (EAL Scope) | 2/8/2027 | 2/18/2028 |
| Permitting for Smalling-El Dorado (ELL Scope) | 2/8/2027 | 2/18/2028 |
| Permitting for West Fork Creek-St. Landry | 4/1/2027 | 4/12/2028 |
| Permitting for St. Landry 500kV Station | 4/13/2026 | 9/22/2027 |
| Permitting for Customer Interconnection | 6/2/2026 | 7/21/2027 |
| Engineering for Smalling-El Dorado (EAL Scope) | 3/1/2027 | 12/3/2027 |
| Engineering for Smalling-El Dorado (ELL Scope) | 3/1/2027 | 12/3/2027 |
| Engineering for West Fork Creek-St. Landry | 7/13/2026 | 12/31/2026 |
| Engineering for St. Landry 500kV Station | 3/30/2026 | 3/13/2029 |
| Engineering for Customer Interconnection | 4/1/2026 | 8/18/2028 |
| Engineering for Perryville, Sterlington and Point Pleasant Breaker Upgrades | 6/17/2026 | 1/21/2027 |
| Procurement for Smalling-El Dorado (EAL Scope) | 12/6/2027 | 5/1/2029 |
| Procurement for Smalling-El Dorado (ELL Scope) | 12/6/2027 | 5/1/2029 |
| Procurement for West Fork Creek-St. Landry | 9/16/2027 | 12/6/2028 |
| Procurement for St. Landry 500kV Station | 3/30/2026 | 9/1/2028 |
| Procurement for Customer Interconnection | 5/5/2025 | 1/1/2030 |
| Procurement for Perryville, Sterlington and Point Pleasant Breaker Upgrades | 5/5/2025 | 3/1/2030 |
| **Stage 5 - Construction** | | |
| Construction of Smalling-El Dorado (EAL Scope) | 3/23/2028 | 12/30/2030 |
| Construction of Smalling-El Dorado (ELL Scope) | 3/23/2028 | 12/30/2030 |
| Construction of West Fork Creek-St. Landry | 6/15/2028 | 12/1/2031 |
| Construction of St. Landry 500kV Station | 11/3/2027 | 8/31/2029 |
| Construction of Customer Interconnection | 9/9/2026 | 8/1/2030 |
| Construction of Perryville, Sterlington and Point Pleasant Breaker Upgrades | 1/8/2027 | 8/1/2030 |

| Schedule Milestones | | |
|---|---|---|
| **Activity/Milestone** | **Target Start** | **Target Finish** |
| **Stage 6 - Operate Produce (In-Service Date)** | | |
| Smalling-El Dorado (EAL Scope) | - | 12/30/2030 |
| Smalling-El Dorado (ELL Scope) | - | 12/30/2030 |
| West Fork Creek-St. Landry | - | 12/1/2031 |
| St. Landry 500kV Station | - | 12/1/2031 |
| Customer Interconnection | - | 8/1/2030 |
| Perryville, Sterlington and Point Pleasant Breaker Upgrades | - | 8/1/2030 |
| **Stage 7 - Benefits Realization and Closeout** | 11/1/2030 | 3/1/2032 |

**BEFORE THE**

**LOUISIANA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| ***IN RE:*** **APPLICATION OF ENTERGY LOUISIANA, LLC FOR CERTIFICATION OF GENERATION AND TRANSMISSION RESOURCES AND FOR OTHER RELIEF PURSUANT TO THE COMMISSION'S *LIGHTNING INITIATIVE*** | **)** **)** **)** **)** **)** **)** | **DOCKET NO. U-_____** |

**EXHIBIT DK-5**

**HIGHLY SENSITIVE PROTECTED MATERIALS**
**FILED UNDER SEAL**

**INTENTIONALLY OMITTED**

**MARCH 2026**

**BEFORE THE**

**LOUISIANA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| ***IN RE:*** **APPLICATION OF ENTERGY LOUISIANA, LLC FOR CERTIFICATION OF GENERATION AND TRANSMISSION RESOURCES AND FOR OTHER RELIEF PURSUANT TO THE COMMISSION'S *LIGHTNING INITIATIVE*** | **)**<br>**)**<br>**)**<br>**)**<br>**)**<br>**)** | **DOCKET NO. U-_____** |

**EXHIBIT DK-6**

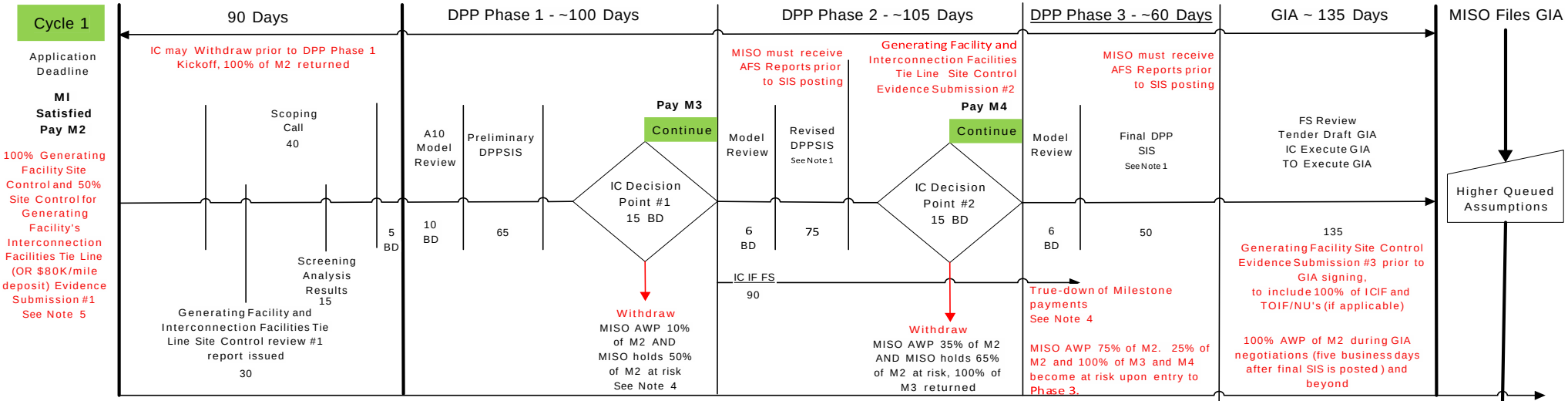
**CRITICAL ENERGY INFRASTRUCTURE INFORMATION**

**INTENTIONALLY OMITTED**

**MARCH 2026**

# Generator Interconnection Process

DPP Phase 1 + DPP Phase 2 + DPP Phase 3 +GIA = ~ 373 Days




| | | |
|---|---|---|
| MI = Technical requirements, DI + D2 | | |
| M2 = $8000/MW | | |
| M3 = The greater of (20% of NU - M2) or $1,000/MW | See Note 2 | |
| M4 = (30% of NU) - M3 - M2 | See Note 2 | |

| | | |
|---|---|---|
| **Acronyms:** | GIA : Generator Interconnection Agreement | AWP : Automatic Withdrawa1Penalty |
| AFS: Affected Systems Study | IC : Interconnection Customer | |
| BD : Business Days | IF : Interconnection Facility | |
| DPP : Definitive Planning Phase | MI, M2, etc. : Milestones | |
| DI : Application Fee | NU : Network Upgrades | |
| D2 : DPP Study Funding Deposit | POI : Point of Interconnection | |
| FS : Facilities Study | SIS : System Impact Study | |

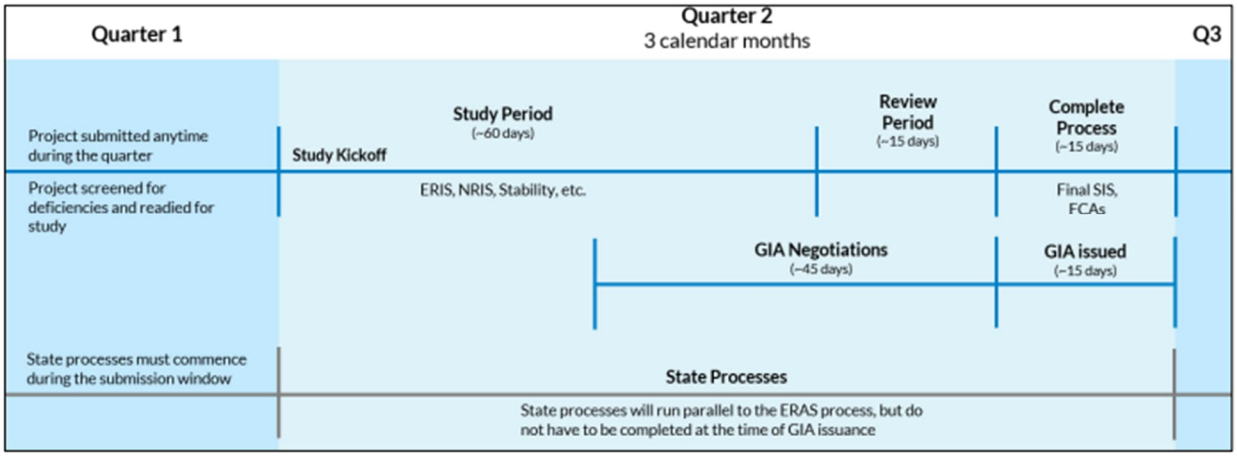
Notes:
1) Effective September 19th 2018, for new cycles, Affected System, Stability, and Short Circuit Studies are required only for DPP Phase 2 and DPP Phase 3
2) M3 and M4 will be adjusted based on previously paid M3 and M4 for Provisional Requests
3) DPP Phase 1 and Phase 2 of each cycle will model higher queued assumptions from previous Phase 3 studiesasavailableduringthetimeofthestudy
4) True-down and Milestone M2 50% at risk should a project withdraw go into effect beginning with DPP-2020-Cycle
5) Site Control documentation for Review #1 is due at least 90 Calendar Days prior to the kick-off of DPP Phase 1 beginning with DPP-2020-Cycle
6) Days on this diagram are Calendar Days unless where noted as Business Days —"BD"

Updated: 2/29/2024

# ERAS PROCESS FLOWCHART

## ERAS Timeline

**ERAS studies will be completed and GIAs will be issued in 3 calendar months.**




**The ERAS process will kick off quarterly starting September 2025 and will integrate with existing processes without negatively impacting those ongoing studies.**