BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF GENERATION AND TRANSMISSION RESOURCES PROPOSED IN CONNECTION WITH SERVICE TO A SIGNIFICANT CUSTOMER PROJECT IN NORTH LOUISIANA, INCLUDING PROPOSED RIDER, AND REQUEST FOR TIMELY TREATMENT)	**DOCKET NO. U-_____**

DIRECT TESTIMONY

OF

DANIEL KLINE

ON BEHALF OF

ENTERGY LOUISIANA, LLC

PUBLIC REDACTED VERSION

OCTOBER 2024

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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. I am the Director, Power Delivery Planning, for Entergy Services, LLC ("ESL"),[1] the service company affiliate of Entergy Louisiana, LLC ("ELL" or the "Company").

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

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

Q4. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, POWER DELIVERY PLANNING?

A. I am responsible for the leadership and oversight of a team of engineers who study 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

[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, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.

Corporation ("NERC") reliability standards governing transmission planning as well as Entergy's internal criteria for transmission and distribution planning. Our team works with the Entergy Operating Companies to develop necessary transmission and distribution projects and provide support through the regulatory permitting process. We also maintain local planning criteria specific to Entergy's transmission and distribution assets and conduct studies to ensure compliance with those criteria. My 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.

Q5. 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 in my current role.

Q6. 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. <u>OVERVIEW OF TESTIMONY</u>

Q7. WHAT RESPONSIBILITIES DID YOU AND YOUR STAFF HAVE WITH RESPECT TO THE CUSTOMER'S PROJECT?

A. We were responsible for: (1) identifying a reasonable and cost-effective solution for the transmission facilities (the "Transmission Facilities") required to serve a new, [redacted] in Richland Parish (the "Project") considering the Project's 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 achieved by the completion of the generators and transmission facilities proposed in connection with the Project; (3) evaluating alternate solutions; and (4) providing technical support for the customer. My team performed this work under my direction.

Q8. 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 the Project, in North Louisiana. I then provide a general description of the Transmission Facilities proposed for the Project 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 the Project. I conclude by explaining the MISO transmission interconnection process for the generators needed to serve the Project and its impact on our analysis.

Q9. 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. <u>NORTH LOUISIANA TRANSMISSION SYSTEM</u>

Q10. BRIEFLY DESCRIBE THE ELL TRANSMISSION SYSTEM, INCLUDING ANY TRANSMISSION FACILITIES, IN NORTH LOUISIANA?

A. The ELL transmission system includes 69 kV, 115 kV, 138 kV, 230 kV, 345 kV[2] and 500 kV transmission lines across portions of Louisiana. Major load centers served by

[2] ELL owns and operates a 345 kV 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 345 kV line in Webster Parish.

the ELL transmission system include the cities of Lake Charles, Lafayette, Baton Rouge, West 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.

Q11. HOW HAS ELL UPGRADED AND EXPANDED THE TRANSMISSION SYSTEM IN NORTH LOUISIANA OVER THE PAST SEVERAL YEARS?

A. ELL is continually looking for ways to support existing and new customers and business through investing in 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. By way of example, in 2022, Entergy Louisiana completed a $100 million project across Ouachita Parish that better positioned the region for economic growth and increased the resilience and reliability of the electric system in North Louisiana. The project included upgrading 4 transmission lines to 230 kV, construction of a new three-mile 230 kV transmission line, and the upgrade or expansion of five substations.

Q12. HOW WOULD ECONOMIC DEVELOPMENT IN NORTH LOUISIANA BE IMPACTED BY FURTHER DEVELOPMENT OF THE TRANSMISSION AND LOAD

A. The economy of North Louisiana has not historically attracted significant industrial development which would, in turn, drive significant transmission development. Consequently, the transmission system in North Louisiana offers limited capacity for connecting new industrial customers on the existing (primarily 115 kV) system. Similarly, to date, MISO has not identified significant transmission needs in North Louisiana or potential transmission projects that would have projected benefits that are roughly commensurate with their costs. The Customer Project provides North Louisiana with a significant opportunity to grow its load and transmission system capacity with an individual customer willing to shoulder much of the cost.

Q13. ARE TRANSMISSION UPGRADES REQUIRED TO SERVE LARGE LOAD CUSTOMERS IN NORTH LOUISIANA?

A. Yes. As discussed in detail below, while North Louisiana has sufficient capacity to serve smaller load customers, the capacity of the electric system to add new substantial industrial load in the area is limited.

Q14. WHAT TYPES OF UPGRADES ARE NEEDED IN NORTH LOUISIANA TO ENABLE THE ADDITION OF NEW INDUSTRIAL LOAD?

A. In general, reliability, resiliency, sustainability, cost-competitiveness, and speed-to-market are key drivers for industrial customers in their project siting decisions. The existing electric system topology in North Louisiana currently cannot meet these needs and expectations. New baseload generation and significant transmission assets and upgrades are required to serve large load customers such as in North Louisiana. I discuss the transmission and generation upgrades that are required in more detail below.

Q15. WOULD ELL BE ABLE TO SERVE THE CUSTOMER PROJECT IN NORTH LOUISIANA WITHOUT TRANSMISSION UPGRADES?

A. No.

Q16. WHY NOT?

A. The existing electric system in North Louisiana does not have adequate capacity to serve the magnitude of load that typically comes with a facility similar to the Project, regardless of its location, without significant new transmission and baseload generation facilities.

Q17. WOULD ELL BE ABLE TO SERVE THE CUSTOMER PROJECT IN NORTH LOUISIANA WITH A TRANSMISSION-ONLY SOLUTION?

A. No.

Q18. WHY NOT?

A. A transmission-only solution is not a viable option for a facility similar to the Project in North Louisiana. To supply the Project or any facility similar to the Project in North Louisiana, ELL will require additional generation capacity and energy to serve reliably the customer's physical load serving needs and to meet ELL's own planning reserve obligations. Satisfying these requirements and obligations requires additional generation somewhere on the system. Without such additional generation, all ELL customers would be exposed to unreasonable reliability risks and unreasonable costs.[3]

In addition, as a practical matter given the reliability and other requirements and expectations of a [redacted] customer, coupled with their ability to choose the location of their facility, attempting or proposing to supply such a customer with a transmission-only solution would likely cause the Customer to eliminate North Louisiana as a potential location option for its Project. In this scenario, the Company would lose the opportunity to serve the Customer, and Louisiana would lose the substantial direct and secondary economic benefits attributable to industrial development in North Louisiana.

IV. <u>PROJECT OVERVIEW</u>

Q19. PROVIDE A BRIEF OVERVIEW OF THE PROJECT.

A. The Project is a new, [redacted] ("Customer") plans to build in Richland Parish, Louisiana. The Project is expected to begin taking service for construction power in [redacted] and ramp up to full capacity in [redacted], as shown in the HSPM Figure 1 below.

3 This exposure arises, fundamentally, from tightening supply and demand balance for capacity in Louisiana and MISO South generally. Tighter supply and demand balances, in turn, are resulting in clearing prices in MISO's Planning Resource Auction ("PRA") that are trending higher. MISO's planned implementation of a so-called "Reliability Based Demand Curve" for 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.

Figure 1 (HSPM)

[redacted]

Key considerations for serving this significant load are reliability, resiliency, sustainability, cost-competitiveness, and speed-to-market. ELL will require 2,133 MW (summer capacity) of new baseload generation and significant transmission upgrades to serve the Customer and seeks Commission approval of investments in three 1x1 combined cycle combustion turbine ("CCCT") generation resources – each with a nominal capacity rating of 754 MW – as part of this proceeding.[4] In addition, as Company witness Laura Beauchamp discusses, ELL also is and will be seeking to procure additional capacity from both new generation resources and demand response.[5]

ELL has also proposed a Corporate Sustainability Rider ("CSR") that contemplates other generation investments to help serve the Customer and meet its customers' needs for affordable, reliable, sustainable energy. The CSR, which is discussed in more detail in the Direct Testimony of Company witness Elizabeth Ingram, contemplates a number of potential future investments. First, ELL plans to procure 1,500 MW of solar and/or solar and storage ("hybrid") resources, subject to

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[4] As described in the testimony of Company witness Matthew Bulpitt, the output of the units will vary depending on system conditions. Based on this variability, Power Delivery used a dispatch assumption of 717 MW.

[5] See Ms. Beauchamp's Direct Testimony at 33-35.

future Commission approval. Second, if determined to be economical and beneficial to customers, ELL also plans, subject to future Commission approval in a separate proceeding, to implement carbon capture and storage ("CCS") technology at an existing CCCT to offset the emissions impact of the new generation. Finally, as discussed further by both Ms. Beauchamp and Ms. Ingram, ELL plans to explore the feasibility of incorporating commitments from the Customer for wind and other clean resources and, if determined to be economical and beneficial to customers, ELL plans to seek Commission approval in a separate proceeding for such resources. Again, ELL is not currently asking the Commission for approval of these sustainability investments; rather, it will seek certification for these investments in the future after further study and analysis, in accordance with Commission rules.

Q20. HAVE YOU PROVIDED A SINGLE LINE DIAGRAM OF THE PROPOSED TRANSMISSION FACILITIES?

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

Q21. WHAT TRANSMISSION FACILITIES WILL BE NEEDED TO SUPPORT PROJECT CONSTRUCTION AND COMMISSIONING?

A. The Customer requires [redacted] of construction/commissioning power in [redacted], ramping up to [redacted] in [redacted], and the full [redacted] by [redacted]. ELL is upgrading distribution circuits in the area to support customer construction power needs and plans to construct and operate temporary facilities to support commissioning activities. Upon completion of the Transmission Facilities, the temporary facilities to support commissioning activities will be removed. The cost of the construction/commissioning power facilities is estimated to be $9.5 million and will be funded by the Customer.

Q22. WHAT NEW GENERATION RESOURCES DOES ELL PLAN TO CONSTRUCT IN CONNECTION WITH THE PROJECT?

A. The Project will operate nearly around-the-clock, at a load factor of [redacted]. This load 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. To meet Customer's requirements for speed, reliability, cost, and sustainability, ELL evaluated several scenarios to determine the best solution to serve the Project, mitigate impact on other customers, and meet the Customer's expectations, particularly with respect to timing which ELL understood to be a critical driver for the Customer in its investment decision. Company witness Laura Beauchamp describes the capacity and energy needs arising from the addition of the Project, and Company witness Matthew Bulpitt provides detailed testimony about the generation facilities that will be constructed to serve the Project.

Q23. WOULD ELL BE ABLE TO MEET THE DEMAND NEEDS OF THE PROJECT CUSTOMER SOLELY BY ADDING GENERATION?

A. No.

Q24. WHY NOT?

A. A generation-only solution is not viable due to the size, location, and characteristics of the [redacted] load addition required by the Project. ELL will require additional capacity and energy to serve a load of this size, therefore requiring generation to meet load servicing requirements. New Transmission Facilities and substations are needed to deliver the power to the Customer site and to maintain the reliability of the electric system in North Louisiana with the addition of both this sizable new load and the new generation resources necessary to serve it. The Transmission Facilities represent a reasonable and cost-effective solution for meeting the transmission requirements for the Project.

Q25. COULD EXISTING GENERATION RESOURCES BE USED TO MEET THE CUSTOMER'S NEEDS?

A. No. Existing generation resources are dispatched in the study models used to assess transmission impacts of new customer requests such as this one. This means that all the support and benefits of existing resources is assumed in our studies – regardless of whether a particular unit is owned by or contracted to ELL. If existing resources were adequate to address the Customer's needs, then the system models would have demonstrated that fact. While contracting with an existing generation resource would mitigate ELL's exposure to MISO Planning Resource Auction costs, it would do nothing to mitigate transmission system needs for the Project. For this reason, using existing generation resources amounts to a transmission-only solution, which is inadequate for the reasons discussed above.

Q26. PROVIDE A GENERAL DESCRIPTION OF THE PROPOSED TRANSMISSION FACILITIES AND SUBSTATIONS?

A. Table 1 below identifies the new substations, point of delivery projects, and certain system improvements that will be required to meet the Customer's power requirements and reliably serve the Project[6]:

TABLE 1	
Substation Projects	**General Description**
Smalling Substation	The Customer's site is located south of the Baxter-Wilson to Perryville 500 kV transmission line. A substation (tentatively called Smalling) will be constructed adjacent to the line. The substation will contain 500/230 kV autotransformers to reduce the voltage to a level at which the Customer will take service. The Baxter-Wilson to Perryville line will be cut in to the station. This project will be Customer funded and, per my understanding, is exempt from Commission certification under General Order 09-10-2024 (R-36199).
Car Gas Road 500 kV Substation	The ELL Perryville substation is in close proximity to the Customer's site but is not suitable for expansion on its existing footprint due to several physical constraints. As a result, a new 500 kV switchyard will be constructed approximately one mile away to receive transmission lines from Smalling substation and the connections to Perryville. This project will be Customer funded and, per my understanding, is exempt from Commission certification under General Order 09-10-2024 (R-36199).

[6] In her testimony, ELL witness Ms. Beauchamp defined the substation projects as the "Customer Paid Substations" and the Perryville to Smiling kV Lines 2 and 3 and the eight 230 kV lines to the Customer's six substations as the "Point-of-Delivery Transmission Facilities." See Ms. Beauchamp's Direct Testimony at 9-10.

Customer Substations 1-6	The Customer plans to build six substations on its property. The exact location and ultimate owner (Customer or ELL) of each substation is subject of ongoing discussion with the Customer. Regardless of who ultimately owns them, these substations will be Customer funded and, per my understanding, are exempt from Commission certification under General Order 09-10-2024 (R-36199) or, in the event the Customer ultimately builds and owns them, not subject to certification.
Point-of-Delivery Projects	**General Description**
Car Gas Road to Smalling Substation 500 kV Lines 2 and 3	A third and fourth source of 500 kV transmission service is required to meet the Customer load requirements. Two thirty-mile 500 kV transmission lines will be installed from the Customer substations to the Car Gas Road 500 kV switching station. A routing study is being conducted. ELL is undertaking a routing study to determine the optimal right of way. This project will be Customer funded and, per my understanding, is exempt from Commission certification under General Order 09-10-2024 (R-36199).
Smalling Substation to Customer Substations 1-6 230 kV Transmission Lines	ELL will build eight 230 kV lines to the Customer's six substations located at Franklin Farms. The location of the Customer substations and line routing on the property are the subject of ongoing discussions. This project will be Customer funded and, per my understanding, is exempt from Commission certification under General Order 09-10-2024 (R-36199).
System Improvement Projects	**General Description**
Mount Olive to Sarepta 500 kV Transmission Lines and Facilities	ELL will construct a new sixty-mile Mount Olive – Sarepta 500 kV transmission line from the existing Mount Olive 500 kV substation to the existing Sarepta 345/115 kV switching station. Both substations will require upgrades, most notably a new 500/345 kV 1,200 MVA autotransformer at Sarepta. A routing study is being conducted. ELL expects that the route for the new lines will largely parallel existing transmission lines. This project represents a system improvement and, per my understanding, is <u>not</u> exempt from Commission certification under General Order 09-10-2024 (R-36199). The Company is requesting certification of this project as an item of relief in this proceeding.
Substation Equipment Upgrades	ELL will upgrade station equipment at the Sterlington 500 kV substation to a minimum of 3,000 amps. This project takes place within an existing substation and, per my understanding, is exempt from Commission certification under General Order 09-10-2024 (R-36199).

Q27. WHAT IS THE TIMELINE FOR THE SYSTEM IMPROVEMENT PROJECTS?

A. An estimated timeline, with milestones, for completion of the proposed System Improvement Projects is attached as Exhibit DK-4.

Q28. WHAT IS THE TOTAL PROJECTED COST FOR THE PROPOSED TRANSMISSION FACILITIES?

A. Based upon the currently available estimate, the projected cost is [redacted]. This cost estimate includes [redacted] million for the Transmission Facilities necessary to provide the Customer with [redacted] of construction power and [redacted] million for the Transmission Facilities necessary to provide the Customer with [redacted] of commissioning power. Of the total transmission costs, the Customer will directly pay for all actual costs of the Substation Projects and Point-of-Delivery Projects which is currently estimated to be [redacted] (inclusive of the construction and commissioning costs). The balance consists primarily of the estimated cost of the Mt. Olive to Sarepta 500 kV line ($546.0M) and the Sterlington Substation equipment upgrades ($750k) and will be included in ELL's wholesale and retail rates. Importantly, the Customer will cover a significant portion of the costs of the Mt. Olive to Sarepta 500 kV line and Sterlington Substation equipment upgrades through its payment of those rates to receive service as discussed in more detail by Ms. Beauchamp.

Q29. WHAT PERCENTAGE OF THE COST OF THE PROPOSED TRANSMISSION FACILITIES WILL BE FUNDED BY THE CUSTOMER?

A. The Customer will fund [redacted] of the cost of the proposed Transmission Facilities through direct payments. This percentage does not include the substantial indirect financial contribution the Customer will make in the proposed investment in system improvements through its rates for electric service to the Project.

Q30. PROVIDE A BREAKDOWN OF THE ESTIMATED COST FOR THE MAJOR COMPONENTS OF THE PROPOSED TRANSMISSION FACILITIES?

A. Table 2 below identifies the estimated cost, funding source, and whether cost recovery is sought for each component part of the proposed Transmission Facilities exclusive of the construction and commissioning power estimates discussed above.

TABLE 2

Project	**Cost Estimate ($M)**	**Funding Source**	**Capital Recovery in Rates (Y/N)**
Smalling Substation, 8 230 kV customer source lines, and 6 230 kV customer load substations.	[redacted]	Customer Funded	N
Car Gas Road 500 kV Substation and 2 Smalling Substation to Car Gas Road 500 kV transmission lines.	[redacted]	Customer Funded	N
Mount Olive to Sarepta 500 kV Transmission Lines and Facilities and substation upgrades	$546.0	ELL Funded	Y

Q31. FOR THE TRANSMISSION FACILITIES TO BE FUNDED BY ELL, WHAT ARE THE ANTICIPATED SOURCES OF FUNDING?

A. At this time, funding for the Transmission Facilities that ELL is funding is expected to come from operating funds of the Company. Exhibit DK-5 provides a more detailed itemization of the costs of these ELL-funded Transmission Facilities.

Q32. 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 3 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 3		
Project	**New Right of Way (Y/N)**	**Existing Right of Way (Y/N)**
Smalling Substation to Car Gas Road 500 kV Lines 2 and 3	Yes, but this right of way may parallel existing rights of way	N
Smalling Substation to Customer Substations 1-6 230 kV Transmission Lines	Yes (ELL/customer-owned land)	N
Mount Olive to Sarepta 500 kV Transmission Lines and Facilities	Yes	N

Q33. 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.

Q34. 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.

Q35. DOES ELL ANTICIPATE THAT SERVICE TO THE CUSTOMER WILL CONTRIBUTE TO OTHER TRANSMISSION SYSTEM UPGRADES?

A. Yes. First, ELL's transmission studies have identified a need for substation equipment upgrades in southern Arkansas that will be required for the Project. This work will be completed by Entergy Arkansas, LLC. This upgrade is not located in Louisiana and would not be constructed or owned by ELL. My understanding is that ELL is not seeking certification from the Commission for the work in Arkansas.

Second, ELL anticipates a need for a new 500 kV transmission line from the to-be-constructed Babel substation near Toledo Bend in Texas to the existing Webre substation in south central Louisiana to address load growth in Louisiana generally, prepare for the future interconnection of various new generation resources reflected in the current MISO interconnection queue, and respond to the expected deactivation of aging resources. This new transmission line will be needed even if the Project does not move forward and, therefore, is not part of the Application. ELL has submitted this line as a candidate project for the 2025 MISO Transmission Expansion Plan ("MTEP25") and anticipates a subsequent filing with the Commission if the project is included in MTEP25.

V. PROJECT TRANSMISSION PLANNING

Q36. CAN YOU DESCRIBE THE TRANSMISSION PLANNING PROCESS ASSOCIATED WITH A BLOCK LOAD ADDITION?

A. Yes. My 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.

Q37. WHAT TRANSMISSION PLANNING STANDARDS AND GUIDELINES DID YOU APPLY IN ANALYZING THE PROJECT?

A. My 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 guideline and criteria are also applied when studying the impacts of adding block load additions onto the transmission system.

Q38. WHY WERE THESE STANDARDS AND GUIDELINES IMPORTANT TO YOUR WORK IN CONNECTION WITH THE PROJECT?

A. ELL's local transmission planning guidelines establish a baseline that ensures compliance with the NERC reliability 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.

Q39. WHAT RELIABILITY STANDARDS DID ELL CONSIDER IN CONNECTION WITH ITS TRANSMISSION PLANNING FOR THE PROJECT?

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.

Q40. WHAT TRANSMISSION PLANNING ASSESSMENTS DID ELL UNDERTAKE IN CONNECTION WITH THE PROJECT?

A. My team on behalf of ELL 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.

Q41. HOW DID YOUR ASSESSMENT FOR THIS PROJECT COMPARE WITH THE ASSESSMENTS THAT YOU HAVE PERFORMED ON OTHER NEW LOAD ADDITIONS?

A. My team followed our standard load study process which involved multiple peer reviews and several levels of management review; subsequent studies have confirmed our findings and recommendations. While ELL conducted the evaluation under a compressed timeline to meet the Customer's timeline expectations, our assessment was thorough and consistent with sound planning, engineering, and economic principles, appropriately factoring in the Customer's speed-to-market requirements.

Q42. HOW DID YOU DETERMINE WHAT TYPE OF GENERATION RESOURCES WOULD BE BEST SUITED TO SERVING THE CUSTOMER PROJECT?

A. My 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 what types of generation resources would be 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.

Q43. HOW WERE THE ASSUMPTIONS ON THE SITING OF THE BASELOAD RESOURCES DETERMINED?

A. In further working with the ELL Resource Planning Team, the Power Delivery Team identified the options for baseload generation resources to be either three 1x1 CCCTs or a single 2x1 CCCT paired with a 1x1 CCCT. ELL ultimately selected the option involving three 1x1 CCCTs as the better option.

Q44. HOW DID THE POWER DELIVERY TEAM DETERMINE THAT SELECTING THREE 1X1 UNITS WAS THE BEST CONFIGURATION?

A. ELL analyzed a 2x1 CCCT versus two 1x1 CCCTs – *i.e.*, the area of difference between the two options considered – in several scenarios as discussed below. This analysis determined that selecting a 2x1 generator to meet the needs of the Project would require the installation of a 1x1 generator for redundancy at the location of the Project to protect against the simultaneous loss of a generator and a transmission line (NERC Category P3 events, also called N1G1). In North Louisiana, developing both a 2x1 and 1x1 CCCT generator would cause generation outlet risks, meaning that, under certain contingencies, too much generation would be injected onto the grid in a location that cannot reliably receive that quantity of power, which would result in both thermal overloads and system stability issues creating unreasonable reliability risks for the electric system. By contrast, developing two 1x1 CCCT generators at Smalling and developing one 1x1 CCCT generator at a location outside North Louisiana would equalize the distribution of generation which, in turn, would mitigate the generation outlet risk.

In addition, siting a large load in the north area of the system would result in diminishing north-to-south system flow that occurs today and that helps supply power to customers in the southern part of ELL's transmission system, including in the Amite South and DSG load pockets. Placing the third generator in the southern part of ELL's system replaces some of this diminished flow to ensure the southern portion of ELL's transmission system remains reliable.

Q45. 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, that 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.[7] 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 MISO sees an increased penetration of renewable resources and inverter-based resources. The ability to supply these essential and increasingly needed ancillary services at the Customer's site is another basis to view the CCCTs as superior to an "all renewable" supply solution for this Customer, as the solar, wind, and battery resources evaluated as part of that solution are not uniformly capable of supplying these ancillary services.

Q46. HOW MANY SCENARIOS WERE STUDIED FOR THE PROJECT?

A. The Customer's load addition was studied across three different scenarios with the second scenario including multiple iterations to identify the most cost-effective locations for siting the baseload generation to address the capacity and energy needs arising from the Project. Each scenario was driven primarily by the Customer's guidance about the parameters and needs of its Project. That guidance evolved somewhat as negotiations progressed.

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7 [redacted]

Q47. WHAT WAS STUDIED FOR THE FIRST SCENARIO?

A. Consistent with initial guidance from the Customer, the first scenario assumed a Customer load of [redacted] served from the proposed Smalling 500/230 kV switchyard. We terminated our analysis of this scenario when the Customer revised its requested load level for the Project to [redacted].

Q48. WHAT WAS STUDIED FOR THE FIRST ITERATION OF THE SECOND SCENARIO?

A. The first iteration of the second scenario studied the Customer's load at [redacted] served from the proposed Smalling 500/230 kV switchyard. Base assumptions for the study included the following transmission and generation upgrades:

1. Smalling 500/230 kV switchyard including four 500-230 kV autotransformers; and
2. Siting of generation for capacity needs: two 1x1 CCCTs at Smalling for a total of 1,434 MW, one 1x1 CCCT at Big Cajun 2 totaling 717 MW, and multiple changes in other jurisdictions to account for what other Entergy Operating Companies recently submitted into MISO's Definitive Planning Process ("DPP") study queue.

Q49. WHAT ARE YOUR OVERALL IMPRESSIONS OF THE FIRST ITERATION?

A. The generation siting assumptions paired with the additional transmission needs that were identified during this iteration appeared to be the most optimal cost-effective solution set for meeting the Customer's needs and maintaining reliability to existing customers. The major components of the additional transmission upgrades that were identified also aligned with ELL's long-term vision for EHV expansion that supports sustainability and resiliency. I discuss this long-term vision for EHV expansion later in my direct testimony.

Q50. WHAT ADDITIONAL TRANSMISSION NEEDS WERE IDENTIFIED FOR THE FIRST ITERATION OF THE SECOND SCENARIO?

A. The following transmission upgrades would be required in addition to the base assumptions:

1. Install six 61 MVAR capacitor banks at the Smalling 230 kV bus;
2. Smalling to Perryville 500 kV transmission line;
3. Mount Olive to Sarepta 500 kV transmission line;
4. Sarepta 500/345 kV new autotransformer;
5. Mount Olive 500/230 kV upgrade autotransformer;
6. Sterlington and El Dorado station equipment upgrades;
7. El Dorado 500-345 kV upgrade autotransformer; and
8. Babel to Webre 500 kV transmission line.

Q51. WHAT WAS STUDIED FOR THE SECOND ITERATION OF THE SECOND SCENARIO?

A. The second iteration of the second scenario, like the first iteration, studied the Customer's load at [redacted] served from the proposed Smalling 500/230 kV switchyard. Base assumptions for the study included the following transmission and generation upgrades:

1. Smalling 500/230 kV switchyard including four 500-230 kV autotransformers; and
2. Siting of generation for capacity needs: three 1x1 CCCTs at Smalling for a total of 2,151 MW and multiple changes in other jurisdictions to account for what other Entergy Operating Companies recently submitted into MISO's DPP study queue.

Q52. WHAT ADDITIONAL TRANSMISSION NEEDS WERE IDENTIFIED FOR THE SECOND ITERATION OF THE SECOND SCENARIO?

A. The following transmission upgrades would be required in addition to the base assumptions:

1. Install six 61 MVAR capacitor banks at the Smalling 230 kV bus;
2. Smalling to Perryville 500 kV transmission line;
3. Sterlington and El Dorado station equipment upgrades;
4. Babel to Webre 500 kV transmission line; and
5. Smalling to Webre 500 kV transmission line.

Q53. WHAT ARE YOUR OVERALL IMPRESSIONS OF THE SECOND ITERATION?

A. The generation siting assumptions paired with the additional transmission needs that were identified during this second iteration are not the most optimal cost-effective solution set for meeting the Customer's needs and maintaining reliability to existing customers. The major components of the additional transmission upgrades that were identified for this iteration do, however, align with ELL's long-term vision for EHV expansion that supports sustainability and resiliency. This scenario results in *too much* generation in the vicinity of the project. When these three 1x1 CCCTs are combined with the existing resources at Sterlington, Perryville, and Ouachita, the North Louisiana area has excess generation that creates additional reliability challenges that did not appear in the initial solution set. The added costs that make this solution set less optimal when compared to the first iteration are associated with the differences in the assumed line lengths for the Smalling to Webre 500 kV line, which is part of the solution set for the second iteration, as compared to the Mt Olive to Sarepta 500 kV line, which is part of the solution set for the first iteration (the former being approximately 100 miles longer).

Q54. WHAT WAS STUDIED FOR THE THIRD ITERATION OF THE SECOND SCENARIO?

A. The third iteration of the second scenario, like the other two iterations, studied the Customer's load at [redacted] served from the proposed Smalling 500/230 kV switchyard. Base assumptions for the study included the following transmission and generation upgrades:

1. Smalling 500/230 kV switchyard including four 500-230 kV autotransformers; and
2. Siting of generation for capacity needs: one 1x1 CCCT at Smalling, one 1x1 CCCT at Big Cajun, and one 1x1 CCCT at Patton for a total of 2,151 MW

along with multiple changes in other jurisdictions to account for what other Entergy Operating Companies recently submitted into MISO's DPP study queue.

Q55. WHAT ADDITIONAL TRANSMISSION NEEDS WERE IDENTIFIED FOR THE THIRD ITERATION OF THE SECOND SCENARIO?

A. The following transmission upgrades would be required in addition to the base assumptions:

1. Install six 61 MVAR capacitor banks at the Smalling 230 kV bus;
2. Smalling to Perryville 500 kV transmission line;
3. Mount Olive to Sarepta 500 kV transmission line;
4. Mount Olive to Smalling 500 kV transmission line;
5. Sarepta 500/345 kV new autotransformer;
6. Mount Olive 500/230 kV upgrade autotransformer;
7. Sterlington and El Dorado station equipment upgrades;
8. El Dorado 500-345 kV upgrade autotransformer; and
9. Babel to Webre 500 kV transmission line.

Additional upgrades were also needed in other parts of Louisiana in order to maintain NERC TPL compliance. Consideration was also given to the risk of network upgrades associated with MISO's DPP study process for the Patton site because it was remote to the Customer load addition and would not be able to utilize existing NRIS service. Once this iteration had a list of needed transmission upgrades that was the same as the others, it was abandoned because additional transmission upgrades were still needed to resolve reliability issues.

Q56. WHAT ARE YOUR OVERALL IMPRESSIONS OF THE THIRD ITERATION?

A. The generation siting assumptions paired with the additional transmission needs that were identified during this iteration are not the most optimal cost-effective solution set for meeting the Customer's needs and maintaining reliability to existing customers. The major components of the additional transmission upgrades that were identified do, however, align with ELL's long-term vision for EHV expansion that supports sustainability and resiliency. This configuration was an attempt to balance the transmission system flows between the West of the Atchafalaya Basin (WOTAB), Amite South, and North Louisiana. The results demonstrated that the configuration worked only as long as the load, generation, and system topology in WOTAB, Amite South, and North Louisiana remained precisely as designed. As soon as load or generation changed or a bulk system outage took place, thermal overloads resulted, which would require additional mitigation. For example, the solution resulted in additional flow from the West of the Atchafalaya Basin (WOTAB) area north into the Project area, leading to additional flow on the lower voltage system during contingencies on the 500 kV system. The added costs that make this solution set less optimal when compared to the first iteration are primarily associated with the Mt. Olive to Smalling 500 kV line (assumed route is approximately 70 miles). There are also the additional NERC TPL compliance upgrades associated with the Patton generator site that will further add to the cost difference and the cost and schedule uncertainty associated with the MISO DPP queue and study process that made this iteration less desirable when considering cost competitiveness and the Customer's strong desire for speed-to-market.

Q57. WHAT WAS STUDIED FOR THE FOURTH ITERATION OF THE SECOND SCENARIO?

A. The fourth iteration of the second scenario, like the other three, studied the Customer's load [redacted] served from the proposed Smalling 500/230 kV switchyard. Base assumptions for the study included the following transmission and generation upgrades:

1. Smalling 500/230 kV switchyard including four 500-230 kV autotransformers; and
2. Siting of generation for capacity needs: one 2x1 CCCT and one 1x1 CCCT at Sterlington for a total of 2,230 MW and multiple changes in other jurisdictions to account for what other Entergy Operating Companies recently submitted into MISO's DPP study queue.

Q58. WHAT ADDITIONAL TRANSMISSION NEEDS WERE IDENTIFIED FOR THE FOURTH ITERATION OF THE SECOND SCENARIO?

A. The following transmission upgrades would be required in addition to the base assumptions:

1. Install six 61 MVAR capacitor banks at the Smalling 230 kV bus;
2. Smalling to Perryville 500 kV transmission line;

3. Sterlington and El Dorado station equipment upgrades;
4. Babel to Webre 500 kV transmission line; and
5. Smalling to Webre 500 kV transmission line.

Q59. WHAT ARE YOUR OVERALL IMPRESSIONS OF THE FOURTH ITERATION?

A. The generation siting assumptions paired with the additional transmission needs that were identified during this iteration appear not to be the most optimal cost-effective solution set for meeting the Customer's needs and maintaining reliability to existing customers. Similar to the second iteration (discussed above), this scenario results in excess generation at the site which, when combined with existing generation in North Louisiana, leads to reliability issues when components of the EHV system are removed from service. In addition, subsequent site evaluation at Sterlington revealed a lack of real estate to accommodate new generation interconnections. The major components of the additional transmission upgrades that were identified do, however, align with ELL's long-term vision for EHV expansion that supports sustainability and resiliency. The added costs that make this solution set less optimal when compared to the first iteration are associated with the differences in the assumed line lengths for the Smalling to Webre 500 kV line, which is part of the solution set for the fourth iteration, as compared to the Mt. Olive to Sarepta 500 kV line, which is part of the solution set of the first iteration (the former being approximately 100 miles longer than the latter).

Q60. WHAT WAS STUDIED FOR THE FIFTH ITERATION OF THE SECOND SCENARIO?

A. The fifth iteration of the second scenario, like the other four, studied the Customer's load at [redacted] served from the proposed Smalling 500/230 kV switchyard. Base assumptions for the study included the following transmission and generation upgrades:

1. Smalling 500/230 kV switchyard including four 500-230 kV autotransformers; and
2. Siting of generation for capacity needs: one 2x1 CCCT and one 1x1 CCCT at Smalling for a total of 2,230 MW and multiple changes in other jurisdictions to account for what other Entergy Operating Companies recently submitted into MISO's DPP study queue.

Q61. WHAT ADDITIONAL TRANSMISSION NEEDS WERE IDENTIFIED FOR THE FIFTH ITERATION OF THE SECOND SCENARIO?

A. The following transmission upgrades would be required in addition to the base assumptions:

1. Install six 61 MVAR capacitor banks at the Smalling 230 kV bus;
2. Smalling to Perryville 500 kV transmission line;
3. Sterlington and El Dorado station equipment upgrades;
4. Babel to Webre 500 kV transmission line; and
5. Smalling to Webre 500 kV transmission line.

Q62. WHAT ARE YOUR OVERALL IMPRESSIONS OF THE FIFTH ITERATION OF THE SECOND SCENARIO?

A. The generation siting assumptions paired with the additional transmission needs that were identified during this iteration are not the most optimal cost-effective solution set for meeting the Customer's needs and maintaining reliability to existing customer. Similar to the second iteration (discussed above), this scenario results in excess generation at the site which, when combined with existing generation in North Louisiana, leads to reliability issues when components of the EHV system are removed from service. The major components of the additional transmission upgrades that were identified do, however, align with ELL's long-term vision for EHV expansion that supports sustainability and resilience. The added costs that make this solution set less optimal when compared to the first iteration are associated with the differences in the assumed line lengths for the Smalling to Webre 500 kV line, which is part of the solution set for the fifth iteration, as compared to the Mt. Olive to Sarepta 500 kV line, which is part of the solution set of the first iteration (the former being approximately 100 miles longer than the latter).

Q63. WHAT WAS STUDIED FOR THE THIRD SCENARIO?

A. The third scenario studied the Customer's load at [redacted] served from the proposed Smalling 500/230 kV switchyard. Base assumptions for the study included the following transmission and generation upgrades:

1. Smalling 500/230 kV switchyard including four 500-230 kV autotransformers;
2. Car Gas Road 500 kV switchyard;
3. Smalling to Car Gas Road 500 kV transmission line;
4. Smalling to Customer 230 kV transmission lines (eight);
5. Mount Olive to Sarepta 500 kV transmission line;
6. Sarepta 500/230 kV new autotransformer;
7. Mount Olive 500/230 kV upgraded autotransformer;
8. Sterlington and El Dorado station equipment upgrades;
9. El Dorado 500-345 kV upgraded autotransformer;
10. Babel to Webre 500 kV transmission line; and
11. Siting of generation for capacity needs: two 1x1 CCCTs at Smalling for a total of 1,434 MW, one 1x1 CCCT at Big Cajun 2 totaling 717 MW, and multiple changes in other jurisdictions to account for what other Entergy Operating Companies recently submitted into MISO's DPP study queue.

Q64. WHAT ADDITIONAL TRANSMISSION NEEDS WERE IDENTIFIED FOR THE THIRD SCENARIO?

A. The study of the third scenario determined that a second new Smalling to Car Gas Road 500 kV transmission line would be required in addition to the baseline upgrades in order to create a third EHV path between the two switchyards.

Q65. WHAT SCENARIO DID ELL ULTIMATELY SELECT FOR THE PROPOSED TRANSMISSION FACILITIES AND WHY?

A. ELL selected the facilities from the third scenario. For clarity, this meant the facilities from the first iteration of the second scenario along with the additional transmission line from the third scenario. ELL determined that this solution is the most cost-effective means of addressing the Customer's needs while maintaining system reliability and addressing ELL's capacity and energy needs.

Q66. DO YOU BELIEVE THAT THE PROPOSED TRANSMISSION FACILITIES REPRESENT A REASONABLE SOLUTION FOR THE PROJECT?

A. Yes.

Q67. WHY?

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

Q68. WHY ARE THE PROPOSED TRANSMISSION FACILITIES THE BEST SOLUTION TO MEET THE RELIABILITY, RESILIENCY, SUSTAINABILITY,

COST-COMPETITIVENESS, AND SPEED-TO-MARKET REQUIREMENTS OF THE CUSTOMERS?

A. The proposed Transmission Facility aligns with ELL's long-term strategic vision for the area, which includes EHV expansion that would accommodate additional load growth in a timely manner while maintaining reliability for existing customers, add resiliency to the system, and facilitate the continued transition to a more sustainable generation portfolio. See Exhibit DK-6 (HSPM) for an overview of ELL's long-term strategic EHV expansion vision.[8]

Q69. HOW WILL THE ELECTRIC SYSTEM IN NORTH LOUISIANA BENEFIT FROM THE PROPOSED TRANSMISSION FACILITIES?

A. In addition to strengthening the ties between the Customer site and the Monroe area (where existing generation resources can be found at Ouachita, Sterlington, and Perryville stations), the proposed Transmission Facilities will enable the North Louisiana system to reliably serve the Customer's demand. Growth in area load will also reduce the reliance on an existing system operating guide that addresses excess generation in the region, and the proposed Transmission Facilities provide a foundation

[8] It is important to note that HSPM Exhibit DK-6 is only a vision for future expansion of the ELL EHV transmission system to meet a variety of expected needs in a reasonable manner consistent with sound planning principles. The vision is based on current information about future needs and trends as well as forecasts about potential needs that exceed the typical transmission planning horizon. As such, those needs and trends are uncertain and subject to change. The vision is not a transmission plan, and the project concepts reflected therein may or may not ultimately be pursued. Because of the inherent uncertainty of long-term planning, and changing facts and circumstances, it is possible the transmission system build out in North Louisiana may not ultimately resemble the projects and project concepts shown in HSPM Exhibit DK-6.

to serve the ancillary growth that will result from the development associated with the Customer's Project as well as additional development in the area.

Q70. HOW WILL THESE UPGRADES IN THE NORTH LOUISIANA ELECTRIC SYSTEM BENEFIT RETAIL CUSTOMERS OTHER THAN THE INSTANT CUSTOMER?

A. The proposed Transmission Facilities, particularly the Mount Olive to Sarepta 500 kV line, strengthen north-south transmission ties by beginning the development of a third extra high voltage path between generation and load centers in Arkansas and South Louisiana. As customer demand grows, existing generation resources retire, and renewable resources increase in penetration, the ability to move power north and south to respond to system needs will be ever more critical.

Q71. HOW WILL THE TRANSMISSION FACILITIES SUPPORT THE INTEGRATION OF RENEWABLE RESOURCES INTO ELL'S GENERATION SYSTEM?

A. The proposed Transmission Facilities align with the long-term strategic vision for the area which includes EHV expansion that would accommodate the continued transition to a more sustainable generation portfolio. The added capacity to the transmission system will make renewable energy more accessible, especially in the remote areas of North Louisiana where land availability and cost, transmission access, solarity,[9] and other factors make it likely that solar farms will locate.

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[9] In the electric industry, "solarity" refers to the strength of the solar resource in a given geographic area or alternately the capacity factor that can be expected from a solar resource in a given geographic area.

Q72. 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. The proposed Transmission Facilities are a "building block" for the future that can be paired with additional transmission upgrades or baseload generation facilities to increase load serving capability in the broader region of North Louisiana.

Q73. WHAT OTHER TRANSMISSION SOLUTIONS DID YOU CONSIDER?

A. ELL considered a second 500 kV line from El Dorado to Perryville or a second 500 kV line from Baxter Wilson to Perryville 500 kV but rejected these alternatives for the reasons summarized below.

For El Dorado to Perryville:

- The route would cross the Ouachita River, requiring a lengthy federal permitting process and, therefore, would not meet the Customer's timeline and speed-to-market needs.
- The route would likely have an impact to the Upper Ouachita National Wildlife Refuge requiring an additional federal permitting process that would not accommodate the Customer's need for speed-to-market.
- ELL determined that the existing Perryville 500 kV switchyard does not have room for expansion to accommodate a new transmission line bay without relocating existing pipeline and railroad infrastructure that borders the switchyard.

- The existing Sterlington 500 kV switchyard has also been similarly determined not to have room for expansion due to its location and the presence of other facilities in the area.
- The line would not mitigate risk associated with an extreme event involving the loss of the El Dorado 500 kV switchyard.
- The line does not align with ELL's long-term strategic vision for EHV expansion (see Exhibit DK-6).

For Baxter Wilson to Perryville:

- The line would require a new crossing of the Mississippi River, requiring a lengthy federal permitting process that could not be completed within the Customer's timeline or meet its speed-to-market needs.
- The line would not mitigate transmission constraints involving the loss of both 500 kV transmission tie lines between Arkansas and North Louisiana.
- The line does not align with ELL's long-term strategic vision for EHV expansion (see Exhibit DK-6).

Q74. 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.

Q75. PLEASE DESCRIBE THE METRICS ANALYSIS.

A. The metrics analysis used to compare the alternatives was primarily focused on cost-effectiveness and the Customer's need for speed-to-market. Once the proposed Transmission Facilities were identified as the most cost-effective alternative that would meet the Customer's timeline during the multiple iterations of Scenario 2, they were further tested using sound engineering principles during Scenario 3 to ensure they met the requirements mandated in the NERC reliability standards and Entergy's Local Transmission Planning Criteria when serving the Customer's ramp to the [redacted] load level.

Q76. 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.

VI. MISO PROCESS AND IMPACT

Q77. 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.

Q78. 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.

MISO also administers a process called Expedited Project Review ("EPR") process 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 typically to obtain approval 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 since an expedited approval is needed to meet the Customer's speed-to-market needs. EPRs are approved by MISO on an expedited timeline and then formally incorporated into the MTEP in the following December's MTEP report.

Q79. WHEN DO YOU EXPECT THE EPR PROCESS FOR THE TRANSMISSION FACILITIES LISTED IN TABLE 1 THAT ARE NEEDED TO SERVE THE PROJECT TO BEGIN?

A. ELL plans to submit an EPR to MISO on or about October 30, 2024, for the projects listed in Table 1.

Q80. PLEASE DESCRIBE THE MISO GENERATOR INTERCONNECTION PROCESS.

A. The MISO generator interconnection process is a process governed by the MISO Tariff that provides a set of rules and procedures that a new 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 interconnection process is conducted in three phases over a period of approximately 355 days. 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.

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 DDP 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.

Q81. WHERE DO THE TWO GENERATOR PROJECTS AT THE PROJECT SITE CURRENTLY STAND IN THE INTERCONNECTION PROCESS WITH MISO?

A. The two CCCTs at the Project site have not yet been submitted to MISO for study in the interconnection process. At the time the most recent DPP submission window closed in April 2024, discussions with the Customer were not mature enough to support the cost needed to submit two CCCTs into the DPP. In addition, ELL did not have the necessary site control required under the MISO Tariff for MISO to confirm an entry to the DPP.

Q82. WHERE DOES THE THIRD GENERATOR PROJECT (THE GENERATOR NOT LOCATED AT THE PROJECT SITE) CURRENTLY STAND IN THE INTERCONNECTION PROCESS WITH MISO?

A. ELL is still determining precisely where the third generator will be located, although it has narrowed the potential siting to a location in the Southeast Louisiana Planning Area. Certain potential locations for the third CCCT may involve using MISO's generator replacement process to satisfy some or all of the necessary interconnection rights. Should the generator replacement not provide all of the necessary interconnection rights, ELL would enter the DPP queue for the remaining level of service.

Q83. WHEN WILL ELL SUBMIT THE GENERATION PROJECTS TO THE DPP?

A. ELL expects MISO to gather submissions for its next queue cycle in early 2025 after the Federal Energy Regulatory Commission (FERC) takes action on MISO's forthcoming proposal and FERC filing to impose a cap on the quantity of resources that may be studied in each interconnection queue cycle.[10] ELL will submit the projects in that next queue cycle. In the meantime, the filing of the Company's application in this proceeding will serve as a commitment to these generation projects that will enable MISO to rely on these generators as part of the mitigation for transmission issues that are identified through its EPR study process. MISO also has a Provisional Generator

[10] A recent version of MISO's queue cap proposal can be found here: https://cdn.misoenergy.org/20240930%20IPWG%20Item%2002a%20MISO%20Cap%20Proposal%20(PAC-2023-1)650633.pdf indicating MISO plans to file its queue cap proposal with FERC in late October 2024, requesting an effective date of January 17, 2025.

Interconnection Agreement (PGIA) process that enables generators to come online before the end of its DPP study process. I will discuss that process in more detail below.

Q84. HOW LONG DO YOU ANTICIPATE THE DPP PROCESS TO TAKE?

A. The entire DPP process takes roughly a year and a half to complete, although this has been trending longer in recent cycles.

Q85. WHEN DO YOU EXPECT TO KNOW DEFINITIVELY WHAT UPGRADES WILL BE NEEDED FOR THE GENERATION PROJECTS?

A. While it is difficult at this time to precisely determine when the DPP study process for these resources will conclude, I would expect to have more clarity about needed upgrades sometime between mid-2026 and mid-2027. It is my understanding that the Customer will bear the actual cost of the interconnection network upgrades associated with these three 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 Company witness Ryan Jones.

Q86. WHAT ACTIONS WILL THE COMPANY TAKE FOLLOWING THE RECEIPT OF THE DPP STUDY RESULTS?

A. Following the results of the DPP study, the Company will take the necessary steps to sign the Generator Interconnection Agreements for the transmission projects determined to be needed to obtain the necessary interconnection service for the three CCCT resources.

Q87. WILL THE REQUIRED UPGRADES FROM THE DPP STUDY BE DEFINITIVE OR ARE THEY SUBJECT TO FURTHER CHANGE?

A. The required upgrades provided by MISO at the conclusion of the 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.[11]

Q88. CAN YOU DESCRIBE THE PGIA PROCESS?

A. Yes. The PGIA process is a mechanism in the MISO tariff that allows interconnection customers to seek an interconnection agreement that will allow them to connect to the grid before their DPP cycle is complete. The process is available to any interconnection customer – whether a load-serving entity or a merchant generation developer. An interconnection customer can request a PGIA from MISO any time after their interconnection request is deemed complete up to the completion of DPP Phase 2. Once MISO receives a request for a PGIA, they study the new generator in system models for the period the generator is expected to begin commercial operation. This determines a level of upgrades required as well as a level of production the generator can produce without upgrades. Because the generator is studied without the rest of the

[11] 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. 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.

generators in its queue, the upgrades associated with this request are typically lower than what is identified in the DPP studies.

Q89. WHAT COMMITMENTS ARE REQUIRED TO USE THE PGIA PROCESS?

A. Using the PGIA process requires a study deposit of $60,000. MISO charges the interconnection customer the actual costs of the study and refunds any remainder. The Interconnection Customer is also required to pay the M3 and M4 milestone payments upfront. If M3 and M4 milestones have not yet been calculated, the Customer must pay $8,000 per MW for each milestone (for a total of $16,000 per MW). That payment is refundable if the Interconnection Customer withdraws its PGIA request before M3 and M4 are calculated. In addition, seeking a PGIA also commits the Interconnection Customer to moving through the M3 and M4 milestones, meaning that unless the Interconnection Customer withdraws their request, they must pay the actual M3 and M4 milestone payments when those are ultimately calculated.

Q90. DOES ELL EXPECT TO USE THE PGIA PROCESS TO FACILITATE INTERCONNECTION OF THE GENERATION PROJECTS?

A. ELL has not yet determined whether the PGIA process will be necessary. ELL has the option to request a PGIA with the submission of its interconnection request or at any time thereafter (up to Decision Point 2) – and will do so if and when it determines that submission of a PGIA would be a reasonable option to pursue for one or more of the three CCCT resources. In addition, ELL is monitoring MISO stakeholder discussions regarding the process and rules governing load and generator interconnections that, while in very early stages, may provide an additional path for generator interconnection that is better suited to the circumstances of the Customer's Project.

Q91. WHAT TYPES OF TRANSMISSION SERVICE ARE SECURED THROUGH THE GENERATOR INTERCONNECTION PROCESS?

A. The 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 LSE's resource adequacy requirements.

Q92. 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.

Q93. 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.

Q94. 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 two of the generation facilities will be located in close proximity to the Project, it is likely that the cost for NRIS for those two generation facilities will be low. 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.

VII. BENEFITS OF PROJECTS SEEKING CERTIFICATION

Q95. HOW WILL THE PROPOSED TRANSMISSION LINES BENEFIT CUSTOMERS OTHER THAN THE PROJECT CUSTOMER?

A. ELL expects that the proposed new transmission lines will generally improve the reliability of the transmission system and help ensure its secure and reliable operation. The Mount Olive – Sarepta 500 kV transmission line will improve reliability for customers throughout Louisiana by increasing load serving capability and improving operational flexibility to allow for maintenance outages to take place. The line will also provide resilience benefits in this area, which experiences ice storms and tornadoes.

In addition, as I noted above, the Mount Olive to Sarepta 500 kV line would strengthen north-south transmission ties by beginning the development of a third extra high voltage path between generation and load centers in Arkansas and South Louisiana. As customer demand grows, existing generation resources retire, and renewable resources increase in penetration, the ability to move power north and south to respond to system needs will be ever more critical.

Further, as noted above, the Mt. Olive to Sarepta 500 kV line aligns with the long-term strategic vision for the area which includes EHV expansion that would accommodate the continued transition to a more sustainable generation portfolio. The added capacity to the transmission system will make renewable energy more accessible, especially in the remote areas of North Louisiana where land availability and cost, transmission access, solarity, and other factors make it likely that solar farms will locate.

Finally, the Mt. Olive to Sarepta 500 kV line is a "building block" for the future that can be paired with additional transmission upgrades or baseload generation facilities to increase load serving capability in the broader region of North Louisiana.

Q96. HOW ARE THE PROPOSED TRANSMISSION LINE UPGRADES CLASSIFIED UNDER THE MISO TARIFF?

A. Once approved, ELL expects that the proposed transmission lines will be classified as Other – Load Growth, though a designation as Baseline Reliability Projects is not out of the question. The Mount Olive – Sarepta 500 kV transmission line would be the most likely of the proposed Transmission Facilities to receive a Baseline Reliability Project designation. The cost allocation within MISO, however, would be the same for either designation.

Q97. HOW WILL THE COST OF THE PROPOSED TRANSMISSION LINE UPGRADES BE ALLOCATED UNDER THE MISO TARIFF?

A. If classified as either Other – Load Growth or Baseline Reliability Projects, the costs of the proposed transmission lines not funded by contributions from the Customer will be recovered from loads within the ELL Transmission Pricing Zone, and all transmission customers within the zone – including ELL – will pay their load ratio shares of the revenue requirements for the transmission lines. Revenues received from wholesale customers taking service within the ELL Transmission Pricing Zone will directly offset the costs included in ELL's retail rates. Likewise, revenues received from the Customer's direct contributions will offset the cost that is recovered through wholesale transmission and retail rates, meaning that if the Customer fully funds a particular transmission line, it will not result in any increase in ELL Pricing Zone rates or ELL retail rates. Finally, even for the costs of the Transmission Facilities that are included in ELL's retail rates, a significant portion of those costs will be borne by the Customer due to the magnitude of its Project and the associated load together with the fact that ELL's Formula Rate Plan will be part of the Customer's rate, as discussed by Ms. Beauchamp.

Q98. WILL CUSTOMERS PAYING ELL'S TRANSMISSION RATES BENEFIT FROM THE ADDITION OF THE CUSTOMER'S LOAD?

A. Yes. The addition of the Customer's load to the rate divisor in the ELL Pricing Zone will result in a reduction in ELL's zonal transmission rate, even after considering the additional cost of the Mount Olive – Sarepta 500 kV transmission line.

Q99. 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.

Q100. 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.

Q101. WILL THE TRANSMISSION PROJECTS PROPOSED TO SERVE THE CUSTOMER PROJECT SUPPLANT OTHER TRANSMISSION PROJECTS NEEDED TO IMPROVE THE RELIABILITY OF THE TRANSMISSION SYSTEM IN NORTH LOUISIANA, NOW OR IN THE FUTURE?

A. No. While additional transmission projects will be needed as the system continues to expand and develop in response to other customer growth projects as well as ancillary economic development and associated load growth that results from this Project, the Proposed Transmission Facilities represent a critical building block for system expansion.

VIII. CONCLUSION

Q102. 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 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 North 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.

Q103. WHAT WOULD BE THE CONSEQUENCES TO THE PROJECT IF ELL IS UNABLE TO TIMELY SECURE THE REQUESTED RELIEF FOR THE TRANSMISSION FACILITIES?

A. My understanding is that the final investment decision of the Customer will be driven in large part on whether ELL can meet its timeline expectations. These expectations are understandable given the importance of being first to market in the market segment for a project such as the Customer Project, and ELL has committed itself to meeting those expectations. 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 Company witness Phillip May, the Project's potential benefits to the Louisiana and local economies are only achievable if the utility service providers can meet the Customer's desired timeline. In short, failure to meet the Customer's timeline expectations could result in the loss of this Project and the economic development opportunity it represents.

Q104. 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 15th **DAY OF** October **2024**

Aletta B. Walker
NOTARY PUBLIC

My commission expires: 11/4/25

STATE OF MISSISSIPPI
ALETTA B WALKER
NOTARY PUBLIC
Madison County
My Commission Expires November 4, 2025
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).*

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).

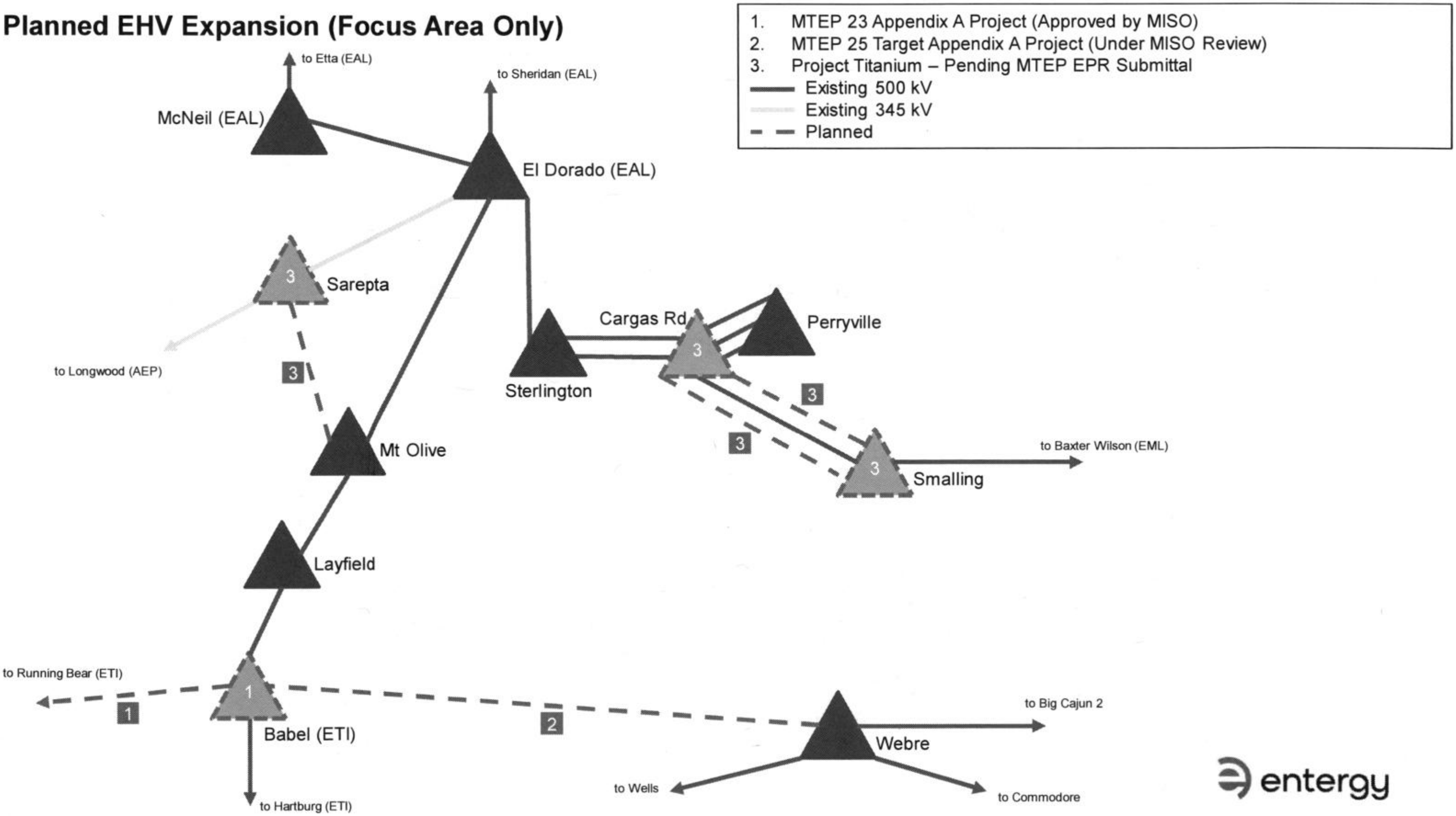
Before the Public Service Commission of Wisconsin

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).

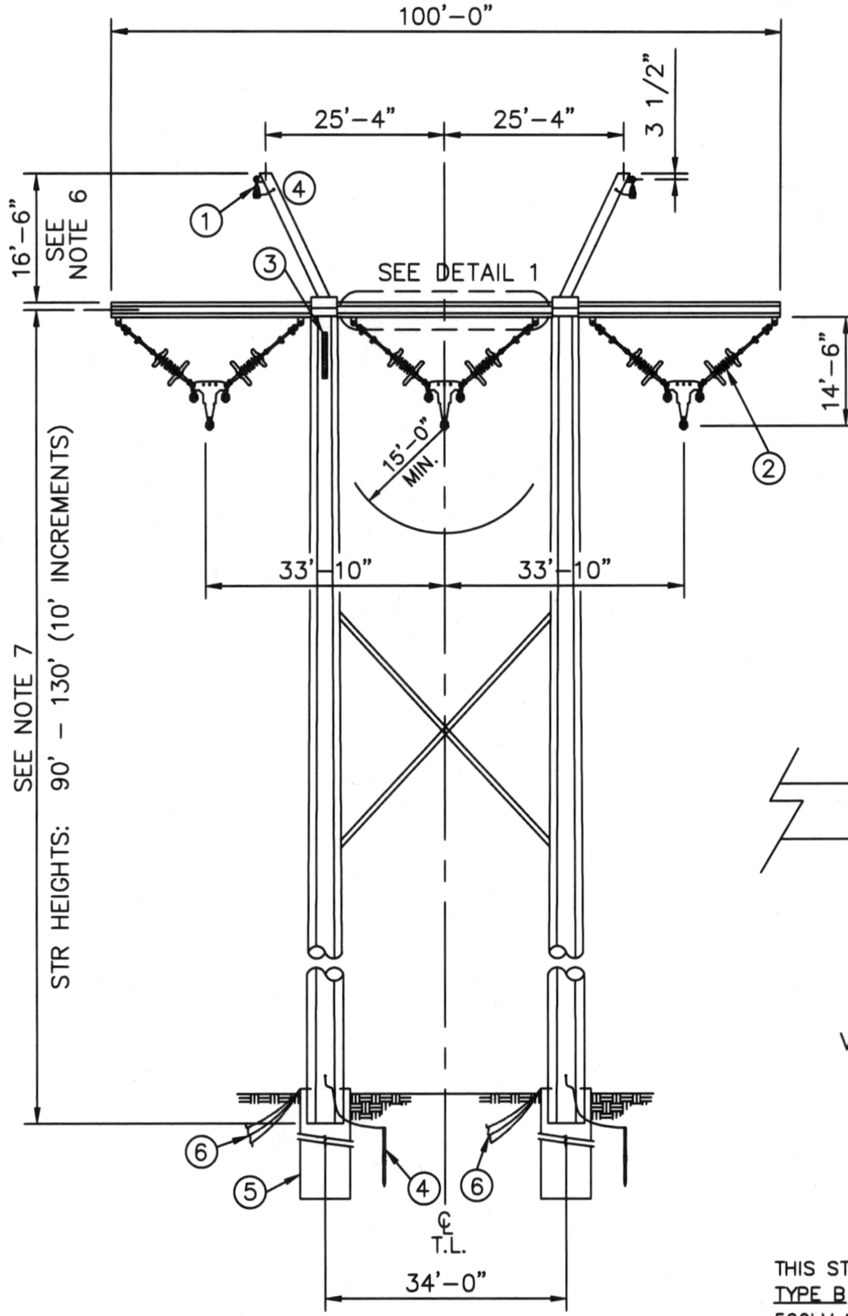
Planned EHV Expansion (Focus Area Only)



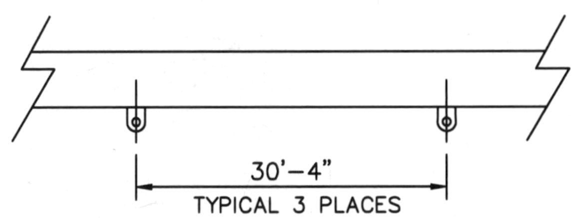
H-FRAME 0-6°, 2-POLE, SINGLE CROSS BRACE SINGLE CIRCUIT, V-STRING, w/YOKE PLATE, STEEL, 500KV

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

Exhibit DK-3
LSPC Docket No. U-____
Page 1 of 3



ELEVATION



DETAIL 1

VEE STRING ATTACHMENT SPACING

THIS STRUCTURE MAY BE REFERRED TO AS TYPE A OR TYPE B 500kV STRUCTURE OR AS STD-1 or STD-2 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

ENTERGY SERVICES, INC.

H-FRAME,0-6,1 X-BR, V-STR, YOKE, STL 500KV

STD NO.	SCALE: 1"=1"
Entergy	No. TFS200A0
PLOT 1=1	SH. 1 OF 1

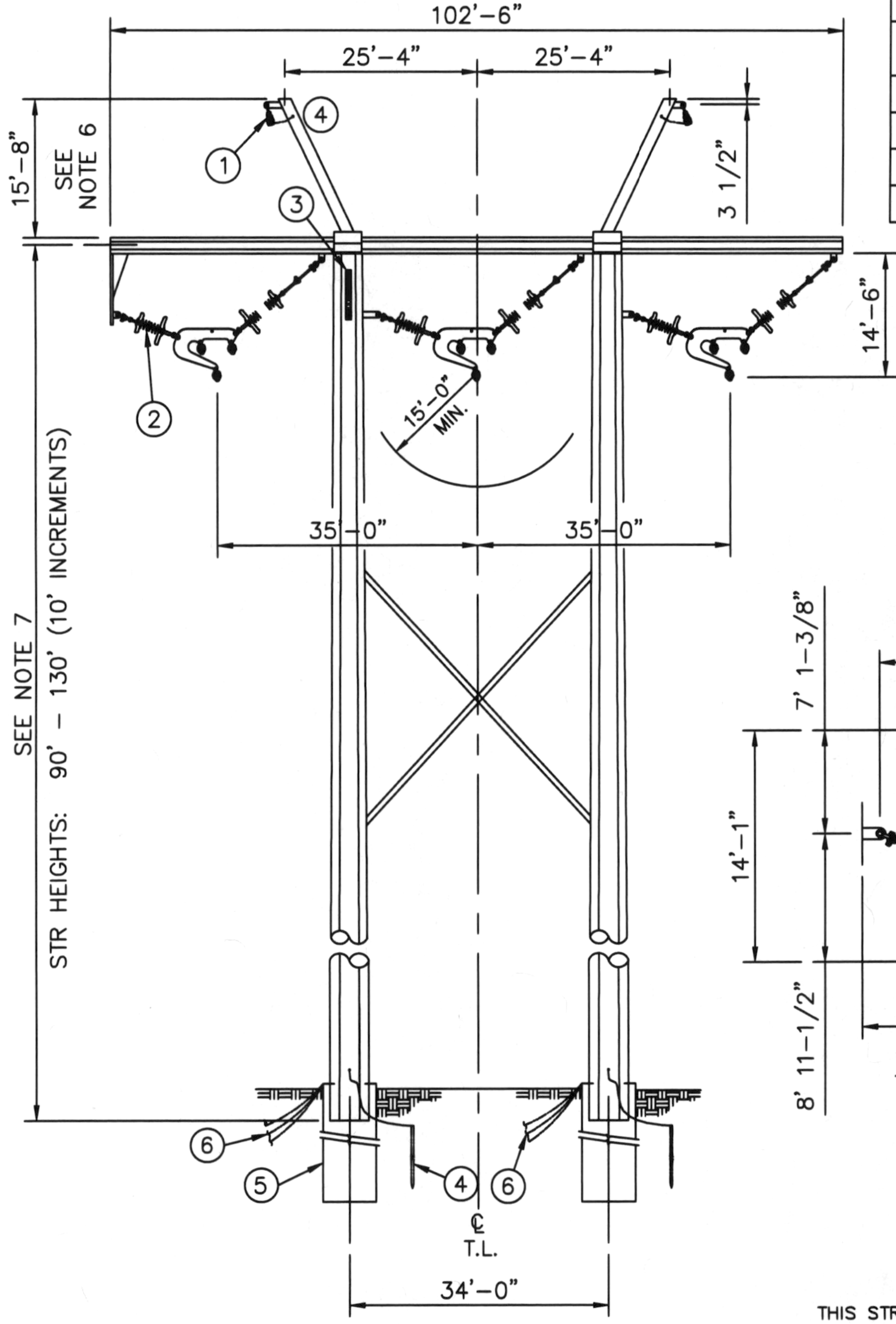
NO.	DATE:	REVISION	BY:	CHK:	APPR
0	02-14-07	CREATED	TWF	HSK	HSK

tfinc90 2/27/2007 HA2-X-VSPY-S 500

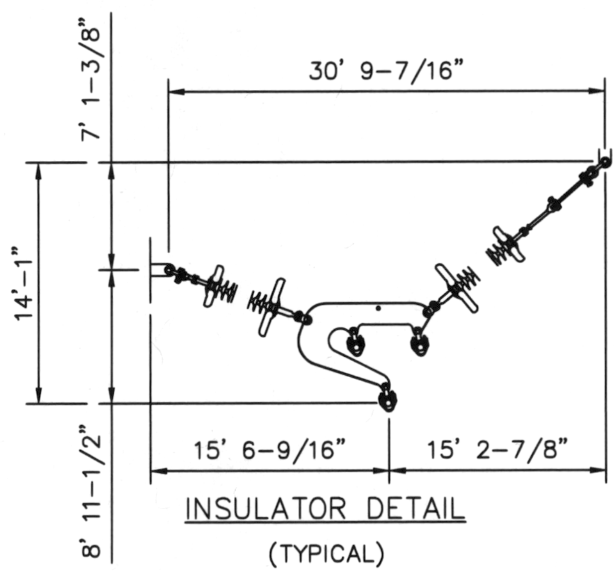
H-FRAME 6-15°, 2-POLE, SINGLE CROSS BRACE
SINGLE CIRCUIT, V-STRING RUNNING ANGLE, w/YOKE PLATE, STEEL, 500KV

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)

Exhibit DK-3
LSPC Docket No. U-____
Page 2 of 3



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

ENTERGY SERVICES, INC.

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

STD NO. | SCALE: 1"=1"

No. TFS201A0

Entergy

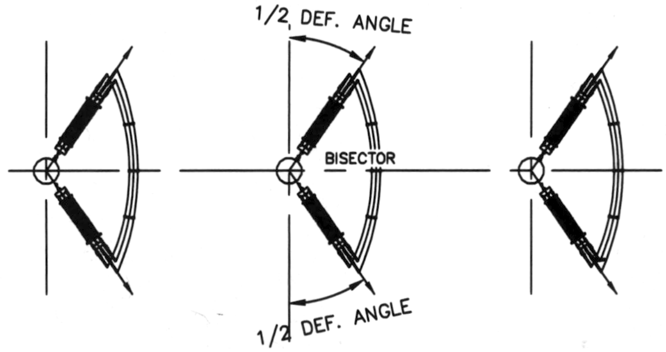
PLOT 1=1 | SH. 1 OF 1

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

tfinc90 2/27/2007 HC2-X-VSPR-S 500

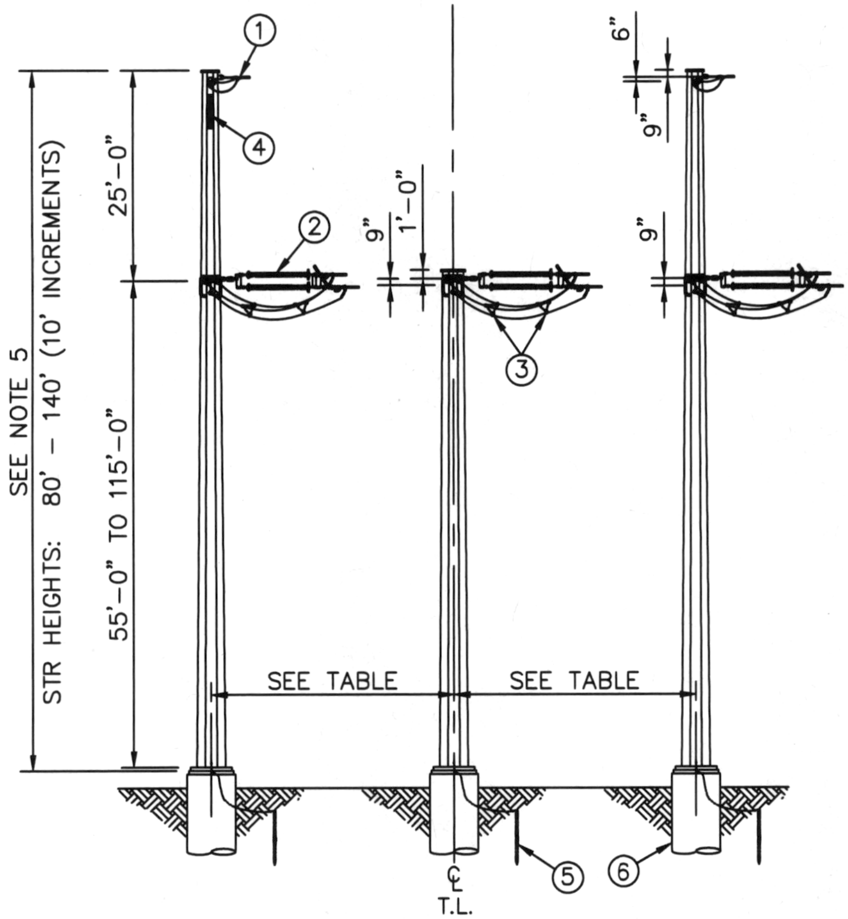
DEADEND 70°–120° SELF SUPPORTING, 3–POLE
SINGLE CIRCUIT, DE POLY w/YOKE, STEEL 500kV

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

Exhibit DK-3
LSPC Docket No. U-____
Page 3 of 3



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

ENTERGY SERVICES, INC.

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

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

STD NO. | SCALE: 1"=1"

Entergy

No. TFS202A1

PLOT 1=1 | SH. 1 OF 1

tfinc90 12/15/2010 SLE3–DEPY–S 500

Project Schedule Milestones – System Improvement Projects

Schedule Milestones		
Activity/Milestone	**Target Start**	**Target Finish**
Stage 1 - Business Case Justification	**7/30/2024**	**10/30/2024**
Stage 2 - Project Scope Selection	**10/30/2024**	**1/30/2025**
Write PO for Autos and Major Material	1/30/2025	9/30/2027
Stage 3 - Project Definition	**1/30/2025**	**1/30/2026**
Full Funding Approval	1/30/2025	1/30/2026
T-Line Route Study	1/30/2026	7/30/2026
T-Line ROW Acquisition	7/30/2026	7/30/2027
PEP / RCRC / OCE / BOD	1/30/2026	7/30/2026
Prepare CCN	1/6/2026	4/6/2026
Stage 4 - Engineering & Procurement	**1/30/2026**	**10/30/2027**
File CCN / ROW acquisition	1/30/2026	1/30/2027
Permitting	7/30/2026	1/30/2027
Engineering - Substation & Relay	1/30/2026	7/30/2026
Engineering - T-Line	7/30/2027	11/30/2027
Procurement - Substation & Relay (09/30/2027 current slot)	1/30/2026	10/30/2027
Procurement - T-Line	4/30/2026	10/30/2027
Stage 5 - Construction	**10/30/2027**	**4/30/2029**
Substation Construction	1/30/2027	7/30/2028
T-Line Construction	10/30/2027	9/30/2029
Stage 6 - Operate/Produce (In-Service Date)*	**4/30/2029**	**4/30/2029**
Stage 7 - Benefits Realization & Closeout	**4/30/2029**	**7/30/2029**

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF GENERATION AND TRANSMISSION RESOURCES PROPOSED IN CONNECTION WITH SERVICE TO A SIGNIFICANT CUSTOMER PROJECT IN NORTH LOUISIANA, INCLUDING PROPOSED RIDER, AND REQUEST FOR TIMELY TREATMENT	)))))))))	**DOCKET NO. U-_____**

EXHIBIT DK-5

HIGHLY SENSITIVE PROTECTED MATERIAL

INTENTIONALLY OMITTED

OCTOBER 2024

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF GENERATION AND TRANSMISSION RESOURCES PROPOSED IN CONNECTION WITH SERVICE TO A SIGNIFICANT CUSTOMER PROJECT IN NORTH LOUISIANA, INCLUDING PROPOSED RIDER, AND REQUEST FOR TIMELY TREATMENT	)))))))))	**DOCKET NO. U-_____**

EXHIBIT DK-6

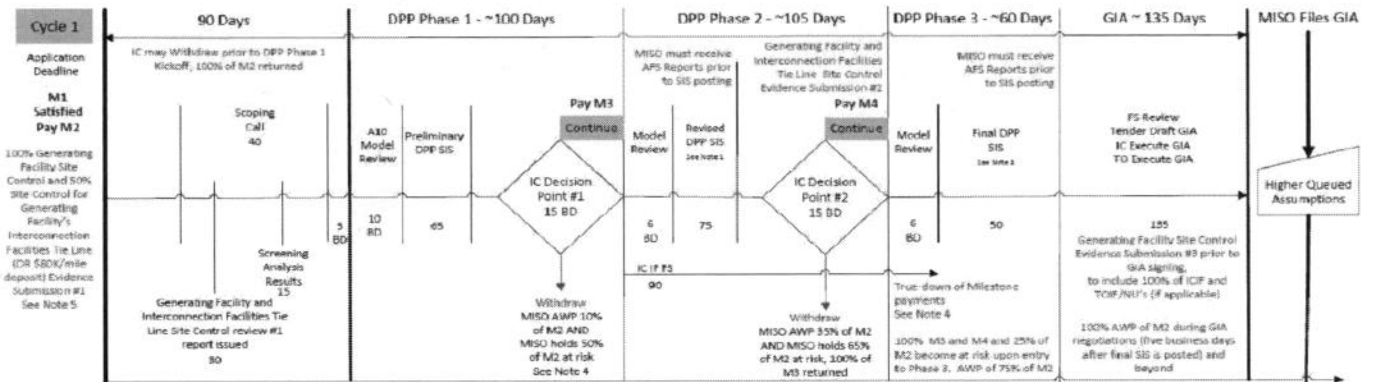
HIGHLY SENSITIVE PROTECTED MATERIAL

INTENTIONALLY OMITTED

OCTOBER 2024

Generator Interconnection Process

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



M1 = Technical requirements, D1 + 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:

AFS: Affected Systems Study	GIA : Generator Interconnection Agreement	AWP : Automatic Withdrawal Penalty
BD : Business Days	IC : Interconnection Customer	
DPP : Definitive Planning Phase	IF : Interconnection Facility	
D1 : Application Fee	M1, M2, etc. : Milestones	
D2 : DPP Study Funding Deposit	NU : Network Upgrades	
FS : Facilities Study	POI : Point of Interconnection	
	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 studies as available during the time of the study
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