Southern Renewable Energy Association
11610 Pleasant Ridge Rd., Suite 103 #176, Little Rock, AR 72223

May 29, 2026

CC: JG/AV

LA PUBLIC SERVICE COMM
MAY 29 2026 AM 10:44

Via FedEx

Louisiana Public Service Commission
Attn: Krys Abel / Records Division
602 N. 5th Street, 12th Floor
Baton Rouge, Louisiana 70802

Re: LPSC Docket U-37812: Entergy Louisiana, LLC's Application for certification of the Babel – Webre 500 kV transmission project in accordance with General Order dated September 10, 2024 (R-36199)

Dear Ms. Abel:

Please find enclosed for filing in the above-referenced proceeding an original and two (2) hard copies of the **Direct Testimony and Exhibits of Michael Goggin on behalf of the Southern Renewable Energy Association**. This filing is public and contains no confidential information. Please contact me if you have any questions. Thank you for your assistance with this matter.

Respectfully submitted,

Whit Cox

Whit Cox
Regulatory Director
Southern Renewable Energy Association
11610 Pleasant Ridge Road, Suite 103 # 176
Little Rock, AR 72223
whit@southernrenewable.org
(501) 701-0874

Enclosures

cc: All parties of record in this docket (*via e-mail*)

Fedex

LA PUBLIC SERVICE COMM
MAY 29 2026 AM10:44

STATE OF LOUISIANA

BEFORE THE LOUISIANA PUBLIC SERVICE COMMISSION

APPLICATION OF ENTERGY LOUISIANA, LLC FOR CERTIFICATION OF THE BABEL -- WEBRE 5OOkV TRANSMISSION PROJECT IN ACCORDANCE WITH LOUISIANA PUBLIC SERVICE COMMISSION GENERAL ORDER DATED SEPTEMBER 10, 2024	)	**DOCKET NO. U-37812**

DIRECT TESTIMONY OF MICHAEL GOGGIN

ON BEHALF OF

THE SOUTHERN RENEWABLE ENERGY ASSOCIATION

MAY 2026

TABLE OF CONTENTS

1. INTRODUCTION 1
2. MISO AND ENTERGY IDENTIFIED THE PROJECT AS A REASONABLE AND COST-EFFECTIVE SOLUTION TO NEEDS 4
3. THE PROJECTS ARE NEEDED TO LOWER ELECTRICITY COSTS FOR LOUISIANA RATEPAYERS 7
4. THE PROJECT INCREASES ELECTRIC RELIABILITY AND RESILIENCE IN LOUISIANA 18

EXHIBIT LIST

Exhibit MSG-1: CV of Michael Goggin

Exhibit MSG-2: Entergy response to SREA 1-3

Exhibit MSG-3: Entergy response to Staff 2-2

Exhibit MSG-4: Entergy response to SREA 1-2

Exhibit MSG-5: Entergy response to SREA 1-1

1. INTRODUCTION

Q. Please state your name and job title.

A. My name is Michael Goggin, and I am the Executive Vice President of Grid Strategies LLC, a consulting firm based in the Washington, D.C. area.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southern Renewable Energy Association ("SREA").

Q. What is SREA?

A. SREA is an industry-led initiative that represents the interests of renewable energy stakeholders across seven states in the Southern United States. Focused on promoting clean energy solutions, the SREA brings together a diverse group of professionals, including developers, investors, and policymakers, to advocate for sustainable energy practices and policies.

Q. Have you previously testified before state utility commissions?

A. Yes. I have testified in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before the Federal Energy Regulatory Commission ("FERC") and the U.S. House of Representatives Energy and Commerce Committee's Subcommittee on Energy. I submitted written testimony to the Louisiana Public Service Commission in Docket No. U-37131, though that case was withdrawn before the hearing.

Q. What is your background and educational experience?

A. I have worked on renewable energy, transmission, and electricity market issues for over 20 years. At Grid Strategies I serve as an expert on those topics for a range of clients including state utility regulators, grid operators, and non-profit organizations. For the preceding ten years I worked at the American Wind Energy Association (now known as the American Clean Power Association), where I provided technical analysis and advocacy regarding renewable energy, transmission, and renewable integration into electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, I worked at a firm serving as a consultant to the U.S. Department of Energy, and at two environmental groups.

In the course of that work, I have co-authored more than one hundred filings to FERC; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; published academic articles and conference presentations on renewable integration, transmission, and policy; and been elected to the Standards, Operating, and Planning Committees of the North American Electric Reliability Corporation ("NERC"), the entity that oversees electric reliability, including currently serving on the NERC Standards Committee. I graduated with honors from Harvard University.

Q. What is the purpose of your testimony?

A. I am testifying in support of Entergy Louisiana, LLC's ("Entergy") request for Commission approval of their petition for a Certificate of Public Convenience and Necessity for the Babel - Webre Project ("the Project"), pursuant to the

Commission's 2024 Siting Order.[1] My testimony supports the conclusion that the Project is "in the public interest and the interests of affected ratepayers," based on "the expected impact of such Transmission Facility on costs, retail rates, service reliability, reduction of congestion, material economic benefits, the interstate or intrastate benefits expected to be achieved, and whether the proposed Transmission Facility is consistent with public policy, including policy goals of the Commission" and because "construction of this Transmission Facility (as opposed to construction of another transmission facility or construction of generation, or non-transmission alternative, for example) is a reasonable and cost-effective solution to the problem being addressed by the Transmission Facility proposed in the Application."[2]

Q. Please outline your testimony.

A. I first explain the broader context of the Midcontinent Independent System Operator ("MISO") and Entergy transmission planning process that identified the Project as a reasonable and cost-effective solution for providing customers reliable electric service at least cost that was superior to alternatives. Second, I explain that Entergy's estimate of the ratepayer economic benefits of the Project are reasonable if not conservative, most notably because production cost modeling tools like those used by Entergy tend to understate the ratepayer economic benefits of transmission. I also note that load growth projections have significantly increased since MISO developed the planning future used, increasing the need for transmission and the

[1] *See* General Order (September 10, 2024), In re: Review and Possible Modification of the Commission's General Order dated October 10, 2013 Governing Transmission Certification and General Siting (2024 Siting Order"), Docket No. R-36199.
[2] *Id.*, at Section IV.

benefits of the Project. Finally, I explain that Entergy's estimates of the reliability and resilience benefits of the Project are reasonable if not conservative.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit MSG-1: CV of Michael Goggin
- Exhibit MSG-2: Entergy response to SREA 1-3
- Exhibit MSG-3: Entergy response to Staff 2-2
- Exhibit MSG-4: Entergy response to SREA 1-2
- Exhibit MSG-5: Entergy response to SREA 1-1

2. MISO AND ENTERGY IDENTIFIED THE PROJECT AS A REASONABLE AND COST-EFFECTIVE SOLUTION TO NEEDS

Q. Please describe the Project.

A. As explained in Entergy's application, the Project consists of a new approximately 151-mile 500-kiloVolt ("kV") transmission line between the new Babel 500-kV Switching Station in Newton County, Texas and the existing Webre 500-kV Switching Station in Iberville Parish, Louisiana, construction of substation components at both ends of the line, and the associated right-of-way.

Q. What process led to the selection of the Project?

A. MISO completes an annual MISO Transmission Expansion Plan ("MTEP"). As Witness Ladner explains, "the MTEP process is broadly driven by multiple objectives: maintaining system reliability; meeting state and federal policy objectives; complying with federal regulations; lowering production cost by

proposing economic transmission projects, which include so-called Market Efficiency Projects ("MEPs") and Multi-Value Projects ("MVPs"); and addressing generation interconnection requests and transmission service requests."[3] MTEP is a bottom-up and top-down transmission planning process that incorporates input from transmission owners like Entergy and other stakeholders on reliability needs, alternative potential solutions to needs, and other key factors.

Q. What alternatives to the Project were evaluated as part of the Entergy and MISO planning process?

A. Witness Ladner explains that "Entergy engineers also considered an alternative involving between 220 and 270 miles of high-voltage facility upgrades (below 300 kV) to meet these load-serving capability objectives."[4] Entergy engineers determined that these alternatives would impair reliability by causing extensive and long-lasting transmission outages to rebuild existing lines, would provide less benefit for reliability and resilience, and would take longer to implement.[5] In response to discovery, Entergy indicates that since Witness Ladner submitted his direct testimony, MISO identified an additional 71 miles of transmission that would need upgrades if the Project is not built, bringing the total upgrades for this alternative to 341 miles.[6] In response to discovery, Entergy estimates that it would take 6-12 years to complete all 341 miles of upgrades, with the lower range of that timeline involving overlapping construction outages that could pose reliability risks

[3] Witness Ladner Direct Testimony, at 12.
[4] *Id.*, at 45.
[5] *Id.*, at 60-61.
[6] Entergy response to SREA 1-3, appended as Exhibit MSG-2.

like those that contributed to the May 25, 2025 load-shed event.[7] Entergy estimates the 341 miles of lower-voltage upgrades would cost around $1.1 billion, [8] comparable to the cost estimate for the Project. However, the larger number of outages required for construction of the lower-voltage alternative would pose a reliability risk and require a longer timeline for construction, and the lower-voltage upgrades would provide less reliability and resilience benefit relative to the Project because they do not add a new network path. The construction of a new 500-kV substation and new network path provides valuable optionality by facilitating future upgrades if greater transfer capacity is needed, including by reducing the risk associated with transmission outages. The superiority of the Project is supported by data showing the large economies of scale for transmission, with higher-voltage transmission providing far greater transfer capacity at a less than proportionate increase in cost.

Q. Can you quantify the economies of scale in transmission expansion?

A. Yes. The cost estimates presented in Table 1 show that 500-kV transmission, as proposed for the Project, is much more cost-effective than lower-voltage solutions. The higher-capacity lines on the right of the table are much more cost-effective on a $/MW-mile basis, which reflects the cost of transmission capable of transporting one Megawatt ("MW") of electricity one mile. For example, 500-kV lines like the Project are less than half as costly on a $/MW-mile basis as 230-kV transmission, and less than one-third as costly as 138-kV lines. Building higher-capacity lines

[7] Entergy's response to Staff 2-2(c), appended as MSG-3.
[8] Entergy's response to Staff 2-2(a), appended as MSG-3.

that meet multiple needs over a longer time horizon results in a lower cost for ratepayers versus multiple incremental transmission additions, while also reducing the need for either repeated outages from rebuilding existing lines or greater right-of-way acquisition and associated permitting proceedings for multiple lower-voltage lines.

Table 1: Economies of scale for higher-capacity transmission[9]

Voltage (kV)	69	115	138	161	230	345	500	765
$M/mile	2.1	2.3	2.4	2.5	2.7	4.2	5.2	6.5
MW or MVA	140	329	394	460	657	1792	2598	6625
$/MW-mile	**$15,000**	**$6,991**	**$6,091**	**$5,435**	**$4,110**	**$2,344**	**$2,002**	**$981**

3. THE PROJECTS ARE NEEDED TO LOWER ELECTRICITY COSTS FOR LOUISIANA RATEPAYERS

Q. What analysis does Entergy present regarding the economic benefits of the Project for Louisiana ratepayers?

A. Witness Ladner explains that the Project will reduce congestion and production costs for Entergy ratepayers, finding "production cost savings between $295 million and $360 million over the period 2025-2045."[10] Exhibit CJL-11 to Mr.

[9] Midcontinent Indep. Sys. Operator, *Transmission Cost Estimation Guide for MTEP25: Workbook* (June 2025), https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimate%20Workbook%20for%20MTEP25547535.xlsx Table 1 was prepared using the reported power rating in MegaVolt-Amperes or MVA, which roughly approximates MW, and MISO's estimated costs for Louisiana.

[10] Witness Ladner Direct Testimony at 54-59.

Ladner's testimony presents the historical congestion over the last several years along transmission paths where congestion will be alleviated by the Project.

Q. How does the Project reduce electricity costs for Louisiana ratepayers?

A. As Entergy's production cost modeling indicates, the Project allows more low-cost generation to be delivered to Louisiana ratepayers by alleviating transmission congestion. Transmission congestion occurs when higher-cost generation near a load center must be used because there is insufficient transmission to deliver lower-cost resources that are available elsewhere, and it imposes major costs on Louisiana ratepayers today. MISO Independent Market Monitor ("IMM") data indicate that congestion increased consumer costs in the South subregion, which is Entergy's footprint, by $201 million in 2024.[11]

Q. Can you provide more detail on how transmission congestion affects consumers and the economics of generation development?

A. The MISO wholesale energy market runs an economic optimization that calculates Locational Marginal Prices ("LMPs") for each pricing node for each pricing interval, which reflects the value provided by the marginal MWh at each point on the grid after accounting for transmission constraints. When transmission congestion prevents the delivery of generation, this results in lower LMPs on the generation side of the transmission constraint and higher LMPs on the load side of the constraint. While the higher LMP harms consumers on the load side of the constraint, the lower LMP on the generation side reduces the value of the

[11] https://www.potomaceconomics.com/wp-content/uploads/2025/07/2024-MISO-SOM_Appendix_Final.pdf, at 70.

generation. This reduction in generation value due to transmission congestion is called basis risk. The lower LMP on the generation side also sends a price signal to reduce generation. If congestion is extreme, it can even lead to the curtailment of zero marginal cost renewable generation, which is typically replaced by much higher cost generation from a resource that is closer to load.

Importantly, the local LMP clearing price applies to all MWh generated in those areas. As a result, the cost of this congestion for generators and their consumers can be much higher than just the cost of any low-cost generation lost to curtailment. As explained in more detail below, congestion deters the development of new generation, in addition to directly harming ratepayers. Basis risk and curtailment risk can greatly reduce the willingness of a utility to purchase output from a generator, as this risk is uncertain over the life of a generator as it depends on unpredictable factors like market entry by competing generators. Transmission congestion can also force generation development to occur in suboptimal areas where generation costs are higher. Finally, transmission congestion causes generators to incur greater costs for connecting to the grid, through higher network upgrade costs and the need to build longer interconnection tie lines.

Q. Do you believe Entergy's economic analysis is reasonable?

A. Yes. If anything, Entergy's analysis is a conservative estimate of the economic benefits of the Project.

Q. Why is Entergy's economic analysis conservative?

A. First, Entergy's analysis is based on MISO modeling assumptions, published in the Series 1A Futures in November 2023, that pre-date most of the recent upswing in load growth projections. Second, production cost modeling and MISO's modeling assumptions tend to understate the benefits of transmission expansion. Third, production cost modeling does not fully capture the benefits of transmission expansion from enabling the interconnection of new low-cost generation that benefits ratepayers. Finally, I explain that transmission expansion protects consumers by facilitating more competitive electricity markets and hedging against uncertainty, benefits that are not captured in production cost modeling.

Q. How have estimates for load growth in MISO changed since the Series 1A Futures were finalized?

A. Projections for load growth have increased dramatically since MISO published the Series 1A Futures in November 2023, increasing the need for transmission both to accommodate that load and deliver the new generation needed to serve it. For example, Grid Strategies has documented that MISO's load growth projections for the year 2030 have increased by 12,700 MW since 2022.[12] Because the increase in load and the corresponding need for generation is greater than MISO assumed in Future 1A, the benefits of the Project are likely greater than indicated by Entergy's analysis.

[12] https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf, at 22.

Q. Are there other reasons why production cost modeling provides a conservative estimate of transmission's benefits?

A. Yes. Production cost modeling does not capture transmission's higher value when other transmission lines are out of service due to forced or planned outages, as production cost modeling assumes all transmission lines are in service and does not typically model extreme weather events. For example, MISO caveats that its production cost modeling

> represents value under normal system intact conditions. In practice, numerous outages occur throughout the year which introduce additional congestion which is not reflected in the calculation of the economic benefits.[13]

A report I co-authored[14] catalogued the following conservative assumptions in typical production cost modeling:

- No change in transmission-related energy losses as a result of adding the proposed transmission project;
- No planned or unplanned transmission outages;
- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Only weather-normalized peak loads and monthly energy (i.e., no typical heat waves, typical cold snaps, or more extreme weather conditions);
- Perfect foresight of all real-time market conditions (i.e., no day-ahead and intra-day forecasting uncertainty of load and renewable generation);

[13] https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf, at 72
[14] https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf, at 36-37.

- Incomplete cycling costs of conventional generation;
- Over-simplified modeling of ancillary service-related costs (e.g., assuming all operating reserves are deliverable);
- Incomplete simulation of reliability must-run conditions

MISO production cost modeling assumptions are based on forecasted peak loads and then typical hourly energy shapes, which excludes the impact of extreme weather events.[15] The exclusion of extreme weather events from production cost modeling greatly understates the value of transmission. For example, MISO's IMM has calculated that Winter Storm Elliott "contributed to more than $350 million in congestion across just two days."[16] Separate analysis by LBNL has shown that around half of transmission's value for reducing energy costs accrues during 5-10% of hours, typically during severe weather events.[17] Production cost analysis does not capture these benefits of transmission.

Q. Are there other reasons why Entergy's calculated production cost savings for the Project are conservative?

A. Yes. MISO's production cost modeling for transmission planning does not account for the value of federal renewable production tax credits, with MISO noting "the associated tax revenue received by the applicable resources are not reflected in the

[15] https://www.icc.illinois.gov/docket/P2024-0088/documents/346850/files/605634.pdf at 6, footnote 12: "These loads reflect forecasts for annual peak load and annual energy shaped over every hour in each study year."
[16] https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 48
[17] https://emp.lbl.gov/news/latest-market-data-show-potential.

[Adjusted Production Cost] savings value shown for the transmission portfolio."[18]

As noted below, a major benefit of the Project is that it will enable the interconnection of significant solar resources, many of which are likely eligible for the production tax credit. The value of federal production tax credits directly reduces the cost of generating energy, and when transmission expansion allows more renewable generation by enabling more renewable development and reducing curtailment, the value of additional tax credits flows to ratepayers. Renewable projects can qualify for federal tax credits if they start construction by July of this year and come online by 2030. Entergy's calculated production cost benefits are thus conservative, as the Project increases access to highly productive solar resources that can generate a large quantity of tax credits.

Finally, MISO's production cost modeling does not account for the benefit that transmission expansion that reduces energy market prices also reduces the price of operating reserves and other ancillary services, benefiting consumers.

Q. Are there other reasons why Entergy's production cost modeling is conservative?

A. Yes, production cost modeling does not fully capture the role of transmission in enabling generation interconnection. Production cost modeling quantifies fuel cost savings, which captures much of the impact of curtailment but only a small part of the impact of congestion. As noted above, the local LMP clearing price applies to all MWh generated in an area, so congestion reduces the value of all electricity

[18] https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf, at 17.

generated in the constrained area, not just the MWh that are affected by curtailment. Modeling production costs does not capture how transmission congestion suppresses MISO market prices and generator revenues. The production cost analysis thus understates how congestion deters generation development by suppressing its value.

Q. How do current transmission constraints limit generation development?

A. Transmission constraints limit generation development by increasing congestion, curtailment, interconnection costs and delays, and other factors. As explained above, transmission congestion reduces the value of a generator for utilities and other customers. Transmission constraints also increase the interconnection costs, including network upgrade costs, that are assigned to interconnecting generators.

Q. What proposed generation projects depend on the Project?

A. In response to discovery, Entergy identifies around 3,000 MW of proposed solar and battery resources that MISO found depend on the Project to enable their interconnection.[19] While some of these proposed projects withdrew from the queue because there was insufficient transmission capacity at the time they applied to interconnect, Entergy indicates that many remain in the queue. Moreover, other generation projects may enter the queue and be built to utilize the transmission capacity added by the Project.

[19] Entergy response to SREA 1-2, Exhibit MSG-4.

Q. What role does transmission expansion play in enabling the development of generation?

A. Transmission is essential, both for allowing new generation to be developed and enabling resources to avoid congestion that reduces their value. A lack of transmission capacity increases the cost of network upgrades required for a resource to interconnect, and can also add lengthy delays to the interconnection process. Increasing transmission capacity is the only viable solution for alleviating those constraints.

Q. What is the trend for interconnection network upgrade costs in MISO?

A. According to recent analysis from LBNL, interconnection costs in MISO have been "rapidly growing"[20] as demand for interconnecting renewable resources has outpaced transmission expansion. Active projects in the MISO queue now face average upgrade costs of $156/kW,[21] which is a significant share of total project capital costs for a typical generation project. These costs are passed through to consumers, either in a higher cost of rate-based generation or a higher Power Purchase Agreement price.

Q. Do generation projects in the MISO interconnection queue face long backlogs?

A. Yes. As LBNL has documented, many proposed generators facing large upgrade costs withdraw from MISO's interconnection queue.[22] A withdrawal typically triggers a restudy for all projects after that generator in the queue, which can change the interconnection costs assigned to those generators. This uncertainty results in

[20] https://emp.lbl.gov/news/data-miso-show-rapidly-growing.
[21] *Id.*
[22] *Id.*

significant shuffling of the interconnection queue, in many cases triggering additional withdrawals. Interconnection cost uncertainties also drive developers to submit more speculative interconnection applications, further exacerbating the uncertainty and shuffling. High-capacity transmission expansion like the Project is a more efficient method for planning and paying for large-scale transmission upgrades, instead of assigning interconnecting generators the cost of network upgrades that benefit many users of the grid, and will help alleviate the queue backlog by reducing the need for generators to pay for large network upgrades.

The Project can also enable the development of generation in more diverse locations, reducing the risk of localized drops in generation due to weather events like passing clouds reducing solar output or extreme cold forcing gas generators offline. As discussed in the next section of my testimony, by accessing a more geographically diverse portfolio of resources, transmission increases the contribution of generation towards meeting peak demand and offsets variability in the output of local resources.

Q. Does transmission increase the competitiveness of electricity markets?

A. Yes, both during normal operations and extreme weather events. By increasing transmission capacity into constrained parts of the grid, the Project protects against the potential for generators to exercise market power in both the MISO energy and capacity markets. The energy market competitiveness benefits are more pronounced during extreme events when supply is short. There is likely to be greater opportunity for profiting from economic withholding of generation when an electricity market is on the steep right side of the generation supply curve, as

occurs during periods of high demand and short supply. Generator outages and transmission congestion also tend to be high during extreme events, which further creates an opportunity for the local exercise of market power. By reducing congestion and increasing the supply of generation from more distant sources, transmission helps ensure that power markets remain competitive.

Q. Does transmission help to hedge against uncertainty and protect consumers from risk?

A. Yes. Transmission is an important mechanism to protect consumers against unpredictable volatility in the price of fuels used to produce electricity. Transmission can alleviate the negative impact of fuel price fluctuations on consumers by making it possible to buy power from other resources. As utilities Xcel and ITC noted in an approved application to build a transmission line in Minnesota, "[A] robust regional transmission system is also key to enabling access to a diverse mix of generation resources, which in turn allows customers to access the least expensive power available at any given time."[23] Renewable generation itself also provides significant hedging value against fuel price fluctuations,[24] so the hedging benefit of transmission is even larger for transmission that connects new renewable generation, such as the Project. For example, MISO's benefits analysis of the Tranche 1 transmission projects included a gas price sensitivity, which shows production cost savings more than doubling in a scenario in which

[23] Northern States Power Company and ITC Midwest LLC, *Application to the Minnesota Public Utilities Commission for a Certificate of Need for the Huntley-Wilmarth 345 kV Transmission Line Project*, at 8, MPUC Docket No. E-002, (January 2018).
[24] Lawrence Berkeley National Laboratory, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, page i, (March 2013) https://www.osti.gov/servlets/purl/1171998.

natural gas prices are 20% higher than the baseline forecast, with savings increasing from $19.9 billion to $45.1 billion over 40 years at a 6.9% discount rate.[25] A more robust transmission grid can provide valuable protection against a variety of uncertainties in the electricity market,[26] including fluctuations in fossil fuel prices and uncertainty regarding electricity demand growth.

4. THE PROJECT INCREASES ELECTRIC RELIABILITY AND RESILIENCE IN LOUISIANA

Q. What analysis does Entergy present regarding the reliability and resilience benefits of the Project for Louisiana ratepayers?

A. Entergy demonstrates that the Project strengthens the transmission network in Louisiana and across MISO South, resolves overloads of existing lines and stability concerns that would emerge due to load growth and changes in the generation mix, and improves the voltage profile. Entergy also explains that strengthening the transmission network with an additional inland west-to-east transmission path improves resilience against hurricanes and other threats to power system resilience, including cold snap events like Winter Storm Uri and conditions like those that triggered last year's rolling blackout.

---

[25] https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf, at 85

[26] B. Hobbs et al., *Large-Scale Stochastic Programming to Cooptimize Networks and Generation in the Face of Long-Run Uncertainties: What Lines Should We Build Now?* (June 2015) https://www.ferc.gov/sites/default/files/2020-08/T4-A-2-HOBBS.pdf.

Q. Do you believe Entergy's analysis is reasonable?

A. Yes. If anything, Entergy's analysis is a conservative estimate of the reliability and resilience benefits of the Project. Entergy used the TPL-001-5 standard, which is currently the primary NERC transmission planning standard.

Q. Going forward, will other more stringent NERC standards also apply?

A. Yes. As Entergy notes in response to discovery, NERC standard TPL-008-1 became effective on April 1, 2026.[27] By 2030, it requires the Planning Coordinator, which for Entergy is MISO, to conduct assessments to ensure reliability can be maintained under extreme heat and cold conditions, and to address any concerns that are identified. Entergy explains that TPL-008 is intended "to address the transmission planning reliability gaps in TPL-001-5, that do not expressly require transmission planners and planning coordinators to address: (1) normal and extreme natural events, (2) gas-electric interdependencies, and (3) Distributed Energy Resources," and that as a result "the Company expects there will be a need for additional grid upgrades to address the "gaps" that NERC references."[28] As discussed below, extreme heat and cold conditions have stressed grid reliability in the Entergy area on multiple occasions in recent years. Therefore, it is highly likely that TPL-008-1 will identify reliability concerns that must be addressed by either adding new transmission, generation, or other solutions that can meet electricity demand under extreme heat and cold.

[27] Entergy response to SREA 1-1a, appended as Exhibit MSG-5.
[28] Entergy response to SREA 1-1c, appended as Exhibit MSG-5.

Q. How does transmission reduce the risk of generation shortfalls?

A. Transmission is essential for realizing the benefits of geographic diversity in electricity supply and demand. Electricity supply and demand vary due to weather-driven fluctuations in electricity demand, random and weather-driven generator outages, and weather-driven output from variable renewable resources. A foundational principle of the power system is that a networked aggregation of many customers and sources of supply greatly reduces cost and risk because changes in individual customers' demand or outages of individual generators are not perfectly correlated. Diversity benefits reduce the cost of building the power system, as less power plant capacity is needed to reliably meet peak demand if diverse resources are available. MISO and PJM have each documented how transmission enables them to take advantage of diversity in load patterns across their large footprints, saving billions of dollars per year.[29] Diversity benefits also reduce the cost of operating the power system, as lower variability reduces the need for flexible resources to quickly change their level of output.

Q. How does the Project tap into geographic diversity?

A. The primarily east-west transmission paths expanded by the line tap into diversity created by the typical movement of weather systems from west to east, and the daily movement of the sun from east to west. The line also taps into other geographic diversity in electricity supply and demand patterns within Energy's footprint. This includes diversity in solar output due to local weather events and the daily

[29] https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/, https://www.pjm.com/-/media/DotCom/about-pjm/the-value-of-pjm.pdf.

movement of the sun, but also in demand and conventional generator correlated outages.

Q. Are there examples of transmission improving resilience by tapping into diversity in load and conventional generator outages?

A. Yes. Inter-regional transmission is particularly valuable during severe weather events. Extreme weather is typically most severe in a limited geographic area and weather systems move over time, so importing from a neighboring region that is less affected by the severe weather is a highly effective solution.[30] For example, SPP, MISO, and PJM saw large diversity in the timing of their peak needs during Winter Storms Elliott[31] and Uri and recent polar vortex and bomb cyclone events, but those regions experienced costly price spikes because there was insufficient transmission to fully meet their needs.[32] Analysis I conducted for Winter Storm Elliott found that expanded transmission ties between Entergy and its neighbors would provide tens of millions of dollars in value for ratepayers.[33] As noted above, MISO ratepayers incurred $350 million in congestion costs during Winter Storm Elliott, and LBNL analysis confirms that severe weather events account for about half of the total benefit of transmission lines, even though these extreme weather events are not typically included in production cost or other transmission benefit analyses.

---

[30] https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[31] https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.
[32] https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[33] https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf, at 7.

NERC's recent Interregional Transfer Capability Study concluded Entergy has a significant need for expanded transmission import capacity to maintain electric reliability in the face of load growth. It found that if extreme heat events that occurred in the summers of 2009 and 2011 re-occurred in the future with expected growth in electricity demand, Entergy could face a generation shortfall of 629 MW.[34] As a result, the report recommends increasing Entergy's transmission capacity with Texas and the Southeast by 300 MW each,[35] and potentially expanding total ties to those regions by more than 1,600 MW.[36] The report notes that expanding these ties "would allow for access to surplus resources, resulting in part from load diversity during extreme summer heat events."[37] The study recommended even larger expansion of the ties between Texas and Entergy to improve reliability in Texas if a cold snap event like Winter Storm Uri were to recur. While the Project does not directly connect Entergy to the Southeast or the main Texas power system, by enabling greater east-west power flows it can improve resilience to extreme weather.

NERC's recommended increase in transfer capacity is likely conservative due to a number of factors,[38] including because the study was completed in 2024 based on even earlier load growth assumptions, before most of the recent upswing in load growth projections. Analysis I conducted found large economic savings for

---

[34] NERC, *Interregional Transfer Capability Study Final Report*, https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/ITCS_Filing_Fall2024_signed.pdf, at 105.
[35] *Id.*, at xvii.
[36] *Id.*, at 106.
[37] *Id.*, at 100.
[38] https://gridstrategiesllc.com/wp-content/uploads/GS_NRDC_NERCs-Recommended-Grid-Expansion-Report54.pdf, at 8-12.

ratepayers from the "prudent additions" to transmission capacity identified in NERC's report.[39]

Q. Is the value of transmission for accessing geographic diversity likely to increase with ongoing changes in the generation mix?

A. Yes. As gas generation and variable renewable resources like wind and solar make up a larger share of our generation mix, diversity benefits grow even larger. Even a relatively small amount of geographic distance is enough for the output profiles of two solar plants[40] to be less than perfectly correlated, as local weather phenomena no longer affect both plants simultaneously. As a result, a diverse portfolio of renewable resources has more constant output, ensuring a higher level of output is available during times of peak demand. The value of transmission for accessing diverse renewable resources is confirmed by a number of regional[41] and national studies.[42]

DOE's National Transmission Planning Study compellingly illustrated this phenomenon with maps showing that when one region experiences a weather-driven lull in wind or solar output or a spike in electricity demand, neighboring

---

[39] *Id.*, at 5

[40] Andrew Mills & Ryan Wiser, *Implications of Wide-Area geographic Diversity of Short-Term Variability of Solar Power*, Lawrence Berkeley National Laboratory (September 2010), available at: https://www.osti.gov/servlets/purl/1196768.

[41] Christopher T.M. Clack, Michael Goggin, Aditya Choukulkar, Brianna Cote & Sarah McKee, Consumer, *Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, (October 2020), available at: https://cleanenergygrid.org/wp-content/uploads/2020/11/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S.pdf.

[42] For example, see https://ieeexplore.ieee.org/document/9548789; https://www.nrel.gov/analysis/100-percent-clean-electricity-by-2035-study.html; Alexander E. MacDonald, Christopher T.M. Clack, Anneliese Alexander, Adam Dunbar, James Wilczak & Yuanfu Xie, *Future Cost-Competitive Electricity Systems and Their Impact on US CO2 Emissions*, Nature Climate Change 6, available at: https://www.nature.com/articles/nclimate2921.

areas often do not.[43] As a result, transmission can tap into these interregional diversity benefits in wind and solar output and electricity demand patterns, saving ratepayers by reducing the need for generating capacity in both regions.

Q. Does the Project provide other reliability benefits that were not assessed by Entergy?

A. Yes. MISO's MTEP notes another major benefit of transmission: "Additional transmission improves system utilization and allows more opportunity for scheduling transmission outages with less risk of causing operational issues or rescheduling of outages."[44] As noted above, transmission outages increase reliability risks, and by strengthening the transmission network the Project reduces reliability risks during transmission outages that must be taken for routine maintenance, transmission upgrades, generation and load interconnection, and other factors.

Q. In summary, what is your recommendation to the Commission?

A. Based on the economic and reliability benefits of the proposed Project and its demonstrated superiority to alternatives, I respectfully recommend that the Commission grant Entergy's petition for a Certificate of Public Convenience and Necessity.

Q. Does this conclude your testimony?

A. Yes.

---

[43] https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf at 51-53.

[44] MISO MTEP21 LRTP Addendum, https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf, at 72.

AFFIDAVIT

BS ~~**STATE OF**~~ District of Columbia

BS ~~**COUNTY OF**~~ Washington

NOW BEFORE ME, the undersigned authority, personally came and appeared, Michael Goggin, 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 matter and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Michael Goggin

SWORN AND SUBSCRIBED BEFORE ME

THIS 27 **DAY OF MAY 2026**

NOTARY PUBLIC

My commission expires: 01/01/2029

BRIAN SIMPKINS NOTARY PUBLIC DISTRICT OF COLUMBIA EXPIRES JAN 1 2029

Michael Goggin

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis "Is it Time for a Change? Science, Policy, and Climate Change"

Experience:

Grid Strategies — Executive Vice President — February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and policy issues for non-profit, grid operator, state regulator, and industry clients
- Have testified before FERC and in dozens of state regulatory commission cases
- Actively engaged in NERC Standards development processes related to renewable and storage resources

AWEA — Senior Director of Research, other titles — February 2008-February 2018

- Led team responsible for all American Wind Energy Association analysis
- Served as primary technical and economic expert on market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (RTO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- Directed economic and power sector modeling to inform AWEA's policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. — Research Analyst — October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, hydrogen, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE's renewable energy R&D funding decisions

Union of Concerned Scientists — Clean Energy Intern — May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups — Policy Analyst — August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

Publications available at https://gridstrategiesllc.com/reports/

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37812

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Southern Renewable
Energy Association

Question No.: SREA 1-3 Part No.: Addendum:

Question:

Please see the discussion in the Direct Testimony of Chad Ladner at pages 45, 55, 59, and CJL-4 regarding the lower-voltage upgrades that would be needed without the Babel - Webre 500kV project. For example, at page 59 Ladner notes "As an alternative to constructing the Babel - Webre 500kV Project, the Company considered the rebuild and/or reconductoring of 270 miles of existing 230/138kV lines in the south Louisiana corridor between Lake Charles and Baton Rouge that are forecasted to be overloaded in the contingency scenarios studied with the anticipated system conditions of increased load in southeast Louisiana," and CJL-4 at page 10 notes the project "prevents ~26 individual line rebuilds ranging from 138kV, 230kV & 500kV."

a. Please list these individual line rebuilds that would be required without the project, specifying the voltage, length, and needed upgrades for each of these ~26 individual lines.

b. Please provide any estimate made by ELL or MISO of the cost of these rebuilds and other upgrades that would be needed without the project.

Response:

a. The 270-mile rebuild alternative referenced in the Direct Testimony of Chad J. Ladner is in reference to the following transmission corridors consisting of 20 line sections that were identified as needed during ELL's and MISO's study work:

- Nelson – Lake Charles Bulk 138kV circuit 1 (17 mile rebuild)
- Nelson – Lake Charles Bulk 138kV circuit 2 (17 mile rebuild)
- Lake Charles Bulk – Hebert 138kV (30 mile rebuild)
- Lake Charles Bulk – Jennings 138kV (30 mile rebuild)
- Rork – Sellers Road 230kV (30 mile rebuild) Cleco line
- Cocodrie – Ville Platte 230kV (21 mile rebuild) Cleco line
- Ville Platte – Wells 230kV (29 mile rebuild) Cleco line
- Champagne – Wilbert 138kV (47 mile rebuild)
- Scott – Bonin 138kV (5 mile rebuild)

- Richard – Colonial Academy 138kV (11 mile rebuild)
- Acadia – Scanlan 138kV (8 mile rebuild)
- Colonial Academy – Acadia 138kV (2 mile rebuild)
- Richard – Bayou Cove 138kV (23 mile rebuild)

MISO has also recently disclosed approximately 71 miles of additional transmission constraints that were first identified in their 2025 studies but were not publicly available to stakeholders and are unique constraints that would not be addressed by the 270-mile rebuild alternative evaluated by ELL. See the Company's response to Staff 2-9 for additional information on MISO's study of the Project and identified constraints. The following additional unique constraints identified by MISO would necessitate a 341-mile rebuild alternative (in lieu of the 270-mile rebuild alternative detailed in the Direct Testimony of Chad J. Ladner at page 60) to address all of the constraints that have been identified by the ELL and MISO study work to date:

- Sabine – Mud Lake 230kV (22 mile partial rebuild)
- Orange – Mossville 138kV (32 mile rebuild)
- Orange – Hollywood 138kV (10 mile partial rebuild)
- Nelson – Hollywood 138kV (7 mile rebuild)

See also the Company's responses to Staff 1-7, Staff 1-8, Staff 1-9, Staff 1-66, Staff 2-1, Staff 2-2, Staff 2-4, and Staff 2-5.

b. See the Company's response to Staff 2-2(a) for a planning-level estimate associated with the 341-mile rebuild alternative.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37812

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 2-2 Part No.: Addendum:

Question:

For each alternative identified in response to Staff 2-1, provide:

a. Estimated capital cost;

b. Estimated annual revenue requirement;

c. Expected in-service date;

d. Expected useful life;

e. The extent to which the alternative resolves the identified constraint(s), including any residual violations;

f. Any operational limitations or risks; and

g. The duration over which the alternative is expected to remain sufficient.

Provide all supporting analyses, studies, and assumptions used to develop these estimates.

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that "these requests are continuing so as to require supplemental responses" as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows:

a. See the Company's response to Staff 1-7, including the attachments titled:

- Staff 1-7 0916_25 Babel Webre 500kV Project Inv Prop Redacted_HSPM (pages 14-15);
- Staff 1-7 10 2025 ELL Babel-Webre 500kV (IAI) (1)_HSPM (page 9); and
- Staff 1-7 11 7 2025 ELL Babel-Webre 500kV (IA2) (1)_HSPM (pages 7-8).

The $500 million rebuild alternative estimate included in the attachments provided in response to Staff 1-7 only accounted for a portion (16 of 20 line sections) of the 270-mile rebuild alternative discussed in the Direct Testimony of Chad J. Ladner (Q44). Four additional line sections at a length of approximately 44 miles were included in the 270-mile rebuild alternative to account for unique constraints publicly shared by MISO for TPL compliance and ELL for generation deliverability. When assuming $5 million/mile for the incremental 138kV rebuilds plus the prior $500 million estimate for the 16 other segment rebuilds, the 270-mile rebuild alternative planning level estimate would be approximately $720 million. Based upon the same $5 million/mile assumption for the rebuild of the additional 71 miles of constrained line segments discussed in the Company's responses to Staff 2-1 and Staff 2-9, the cost of the 341-mile rebuild alternative would be a planning level estimate of approximately $1.1 billion. This is comparable in cost to the proposed Project, but the rebuild alternative does not address all of the objectives of the Project and was rejected for reasons discussed in response to Staff 2-1.

b. ELL did not perform and is not in possession of estimates of the revenue requirements for the alternative projects described in the attachments referenced in subpart (a) above and Q44 of Mr. Ladner's Direct Testimony.

c. Because the rebuild alternative identified in the Company's response to Staff 2-1 was rejected during the initial feasibility evaluation, ELL did not develop estimated in-service dates, project timelines, or other implementation schedules for that alternative.

The Company's response to Staff 2-1 also identifies certain complications and risks that would be presented by attempting to implement the rebuild alternative on a practical timeline. The rebuild alternative would entail rebuilds of 20 transmission line sections. At a rate of 2-4 line segment rebuilds per year, it would take approximately 5-10 years to complete the rebuilds of those 20 segments. If such alternative were pursued, the Company would limit construction outages and performing construction work to the spring and fall outage seasons to ensure reliability to existing customers. Overlapping construction outages would raise the reliability risk for existing customers, so if the Company performed one rebuild per outage season and two rebuilds per year, it would result in a 10-year timeline to complete the rebuild. If the Company performed two rebuilds per outage season and four rebuilds per year, it would result in a 5-year timeline to

complete the rebuild. The risks to reliability are qualitative and supported by real-time events during outage seasons (such as the May 25, 2025 load-shed event). When accounting for the four additional constraints identified by MISO and detailed in ELL's response to Staff 2-1, the rebuild of the 24 transmission line sections would take approximately 6-12 years to complete, using the same logic.

d. The rebuilt line segments would be expected to have a useful life similar to the useful life of any newly constructed transmission line, including the proposed Babel – Webre 500kV line.

e. See the Company's response to Staff 2-1 and the Direct Testimony of Chad J. Ladner at Q44 (pages 59–61).

f. See the Company's responses to subparts (a) and (e) above.

g. The rebuild alternative was not selected because it was determined that it would not be sufficient to meet all of the objectives that are addressed by the proposed Babel – Webre 500 kV Project, as discussed in Q44 in the Direct Testimony of Chad J. Ladner. This includes the failure to address the low-voltage violation at the Grand Gulf nuclear plant and the overload of the Franklin – McKnight 500kV line, which are directly tied to the NERC TPL-001 and NUC-001 reliability standards.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37812

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Southern Renewable
Energy Association

Question No.: SREA 1-2 Part No.: Addendum:

Question:

Please see the discussion in the Direct Testimony of Chad Ladner at pages 34 and 55 regarding how the project facilitates generator interconnection. Please identify the MISO generator interconnection queue projects for which the Babel - Webre 500 kV project was identified as a contingent facility, including the queue number and other relevant information for each queue generator.

Response:

In MISO's DPP21 Phase 3 analysis for NRIS, the Babel – Webre 500kV line was identified as a contingent facility to secure network service for interconnection J1890, which is a 270 MW solar facility actively targeting to interconnect on the Hartburg – Layfield 500kV line in Louisiana.

Constraints addressed by the Babel – Webre 500kV Project were also present in MISO's DPP21 Phase 2 analysis, and the following set of interconnection projects totaling approximately 3 GW of capacity were tagged to the constraints:

- J1872: 250 MW solar facility that is actively targeting to interconnect at the El Dorado 500kV bus in Arkansas but dropped its request to ERIS only.
- J1873: 250 MW solar facility that is actively targeting to interconnect at the El Dorado 500kV bus in Arkansas but dropped its request to ERIS only.
- J1874: 75 MW battery storage facility that was withdrawn from the DPP study process but was targeting to interconnect at the El Dorado 500kV bus in Arkansas.
- J1875: 75 MW battery storage facility that was withdrawn from the DPP study process but was targeting to interconnect at the El Dorado 500kV bus in Arkansas.

- J1890: 270 MW solar facility that is actively targeting to interconnect on the Layfield – Hartburg 500kV line in Louisiana.

- J1907: 100 MW battery storage facility that was withdrawn from the DPP study process but was targeting to interconnect at the Hartburg 230kV bus in Texas.

- J2041: 200 MW solar/battery hybrid facility that was withdrawn from the DPP study process but was targeting to interconnect at the Amelia North 230kV bus in Texas.

- J2075: 200 MW solar facility that is actively targeting to interconnect on the China – Batiste Creek 230kV line in Texas but dropped its request to ERIS only.

- J2163: 200 MW solar facility that was withdrawn from the DPP study process but was targeting to interconnect on the Nelson – Penton Road 230kV line in Louisiana.

- J2169: 99 MW solar facility that was withdrawn from the DPP study process but was targeting to interconnect on the Deridder – Centennial 138kV line in Louisiana.

- J2180: 250 MW solar facility that is actively targeting to interconnect at the Fisher 230kV line in Louisiana but dropped its request to ERIS only.

- J2208: 99 MW solar facility that was withdrawn from the DPP study process but was targeting to interconnect on the Mansfield – Red River 138kV line in Louisiana.

- J2214: 62 MW battery storage facility that was withdrawn from the DPP study process but was targeting to interconnect at the Fisher 230kV bus in Louisiana.

- J2235: 100 MW battery storage facility that was withdrawn from the DPP study process but was targeting to interconnect at the Shepard 138kV bus in Texas.

- J2240: 120 MW solar facility that was withdrawn from the DPP study process but was targeting to interconnect on the Prescott – Emmett 115kV line in Arkansas.

- J2242: 100 MW solar/battery hybrid facility that was withdrawn from the DPP study process but was targeting to interconnect at the SHECO Corrigan 138kV bus in Texas.

- J2249: 144 MW solar facility that is actively targeting to interconnect at the Bayou Cove 138kV bus in Louisiana but dropped its request to ERIS only.

- J2253: 100 MW battery storage facility that was withdrawn from the DPP study process but was targeting to interconnect at the Fork Creek 138kV bus in Texas.

- J2314: 150 MW solar facility that is actively targeting to interconnect at the Petry Woods 138kV bus in Texas but dropped its request to ERIS only.

- J2317: 225 MW solar facility that is actively targeting to interconnect at the Sterlington – Bastrop Cahoon 115kV line in Louisiana but dropped its request to ERIS only.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37812

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Southern Renewable
Energy Association

Question No.: SREA 1-1 Part No.: Addendum:

Question:

Please see the Application at 3, and the Direct Testimony of Chad Ladner at 19-20 and 40-42, regarding how the Babel-Webre 500 kV project ("project") is needed to meet NERC requirements under standard TPL-001-5.

a. Has ELL conducted any assessment, or is ELL aware of any assessment conducted by MISO, regarding what grid upgrades may be needed for NERC standard TPL-008 compliance, and whether the project fills that need?

b. If not, please confirm that TPL-008, starting in April 2030, will require modeling the transmission system under extreme heat and cold scenarios with higher loads and generator outages.

c. Please confirm your expectation that, due to the more challenging scenario being modeled, violations and thus grid upgrade needs identified under TPL-008 will be more severe and more numerous than those identified under TPL-001.

Response:

a. ELL has not conducted any assessment and is not aware of any assessment conducted by MISO regarding what grid upgrades may be needed for the NERC TPL-008 reliability standard.

TPL-008 became effective on April 1, 2026, and entities must complete their first Extreme Temperature Assessment no later 48 months after the effective date. In order to perform the TPL-008 analysis, ELL will need access to benchmark planning cases representing the extreme temperature scenarios, and MISO as the Planning Coordinator for ELL has the obligation to develop the benchmark planning cases between now and April 1, 2030.

b. See the Company's response to subpart (a) above.

c. The Company objects to subpart (c) of the request as it constitutes a request for admission in contravention to Rule 63 of the Commission's Rules of Practice and Procedure. Subject to and without waiving this objection, the Company responds as follows.

According to NERC, the purpose of the development of TPL-008 is "to address the transmission planning reliability gaps in TPL-001-5, that do not expressly require transmission planners and planning coordinators to address: (1) normal and extreme natural events, (2) gas-electric interdependencies, and (3) Distributed Energy Resources."[1]

With that understanding, the Company expects there will be a need for additional grid upgrades to address the "gaps" that NERC references.

[1] https://www.nerc.com/standards/reliability-standards-under-development/2023-07-transmission-system-planning-performance-requirements-for-extreme-weather.

CERTIFICATE OF SERVICE

I hereby certify that I have served all parties with the foregoing document by electronic mail on this 29th day of May, 2026.

Whit Cox

Whit Cox
Regulatory Director
Southern Renewable Energy Association
11610 Pleasant Ridge Road, Suite 103 # 176
Little Rock, AR 72223
whit@southernrenewable.org
(501) 701-0874