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BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

DOCKET NUMBER U-37882

ENTERGY LOUISIANA, LLC, EX PARTE.

In re: Application of Entergy Louisiana, LLC for Certification of Generation and Transmission Resources and for Other Relief Pursuant to the Commission's Lightning Initiative

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INITIAL POST HEARING BRIEF ON BEHALF OF THE LOUISIANA PUBLIC SERVICE COMMISSION STAFF

PUBLIC VERSION

November 12, 2026

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INTRODUCTION

This Initial Post-Hearing Brief is respectfully submitted on behalf of the Staff ("Staff" or "Commission Staff") of the Louisiana Public Service Commission ("Commission" or "LPSC") pursuant to the governing procedural schedule. This brief addresses the application of Entergy Louisiana, LLC ("ELL" or the "Company") for "Certification of Generation and Transmission Resources and for Other Relief Pursuant to the Commission's Lightning Initiative" (the "Application"). After a thorough review of the Application and all testimony, and an evidentiary hearing before Administrative Law Judge Verzwyvelt ("ALJ"), the Staff recommends that the Commission approve ELL's Application with the modifications and conditions included in the Final Stipulated Settlement Term Sheet entered into between the Staff, ELL, and Walmart, Inc. ("Walmart") on October 6, 2026 ("Stipulated Settlement").

As explained in more detail below, combined with the commitments made in the Stipulated Settlement, ELL's Application satisfies each of the Commission's Large Load Guidelines and meets the standards of the 1983 General Order and the Transmission Siting Order. Under the Electric Service Agreement entered into between the Customer, Evest LLC ("Evest" or "Customer"), and ELL, the Customer is responsible for the cost of the new resources needed to serve its data center. Evest's obligations include minimum monthly charges over a 20-year Original Term, contributions in aid of construction for customer-funded transmission facilities, early termination provisions, and financial assurances that include a Buyer's Guaranty, Credit Default Security, and other protections. The new resources will operate as system resources, bringing reliability, resilience, and fuel-cost benefits to all ELL customers. The Application also meets the factors set forth in the Commission's Lightning Initiative and further establishes good cause for an exemption from the MBM Order, given the Customer's commitment, the ramp schedule demonstrating an immediate resource need, and the benefits that Project Evest provides

to all ratepayers. Overall, the record supports ELL's claims that current customers will benefit significantly from the Evest project as a whole and certification is justified.

The Stipulated Settlement strengthens the protections already included in ELL's Application and resolves the contested issues in a manner that serves the public interest. It confirms that the Proposed Generators and Battery Storage Facilities are system resources. It also approves the depreciation lives of the assets, a revenue deferral framework, and the accounting treatment of Customer contributions, and it requires all of these costs to be offset by Customer revenues so that existing customers are protected. The Stipulated Settlement imposes additional customer protection conditions that benefit non-Evest customers:

- ELL must prudently manage and enforce the Electric Service Agreement, the related agreements, and the financial assurances.
- ELL must file quarterly Construction Monitoring Reports and annual Customer Monitoring Reports.
- ELL must notify the Commission of any dispute with the Customer and any modification, early termination, or non-renewal of the Electric Service Agreement.
- ELL must file, within six months of any notice of non-renewal or early termination, a transition plan for any assets with unrecovered net book value.
- The Commission retains full authority over prudence and cost recovery.

Importantly, the Stipulated Settlement is also expressly conditioned on the resolution of a separate proceeding concerning ELL's request for certification of its acquisition of the Cottonwood generating facility ("Cottonwood"). That certification request is currently being litigated in LPSC Docket No. U-37801. The settling parties agreed that the Stipulated Settlement "will not be presented to the Commission for consideration until such time, if any, as they have executed a stipulated settlement also with respect to resolution of Louisiana Public Service Commission Docket No. U-37801." [Stipulated Settlement § VII.A]. Accordingly, the Stipulated

Settlement will be submitted for the Commission's approval only if, and when, ELL and Staff also reach a stipulated settlement regarding ELL's request for certification of the Cottonwood acquisition.

Staff opposes the intervenors' challenges to ELL's Application. The intervenors' challenges are unsupported by the record, unnecessary, premature, and/or outside the scope of this proceeding. In many cases, the Stipulated Settlement either addresses the intervenors' concerns directly or preserves the Commission's authority to address it on a full record if the issue ever arises. Staff therefore respectfully recommends that the Commission approve ELL's Application as modified by the Stipulated Settlement, for all the reasons explained below.

I. COMMISSION JURISDICTION

The Commission's authority and jurisdiction are specifically set forth in the Louisiana Constitution. As its jurisdiction and power derive directly from the people, the Commission has plenary authority over the rates charged and services rendered by all LPSC-jurisdictional utilities. Article IV, Section 21 of the Louisiana Constitution of 1974 provides in pertinent part:

> The commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations and procedures necessary for the discharge of its duties, and perform other duties as provided by law.

Further, Louisiana Revised Statute 45:1163(A)(1) provides that the Commission shall exercise all necessary power and authority over any electric light, heat, power, or other local public utility "for the purpose of fixing and regulating the rates charged or to be charged by and service furnished by such public utilities." Louisiana Revised Statute 45:1176 provides that the Commission shall investigate the reasonableness and justness of all contracts entered into by public

utilities and shall have the power to disallow any expense under such contracts as the Commission may find to be unjust or unreasonable.

II. PROCEDURAL HISTORY

A. The Application

On March 25, 2026, ELL filed an application seeking approval from the Commission for generation and transmission resources to serve large load customer Evest, a subsidiary of Meta Platforms, Inc. ("Meta" or "Parent"), for a hyperscale data center in Richland Parish, Louisiana ("Project Evest"). [Application at 1]. The data center is adjacent to the facility currently being developed by Laidley, LLC ("Laidley"), another Meta subsidiary, for which certifications were approved by the Commission in LPSC Docket No. U-37425. [*Id.*]. ELL's Application cites the Commission's Lightning Initiative, adopted at the December 17, 2025 Business and Executive Session.[1] [*Id.* at 4-5]. The Lightning Initiative sets forth factors that may justify a waiver of the Commission's Market Based Mechanisms Order, General Order 10-14-2024 (R-34247) (the "MBM Order"), for a proposed capacity addition where there is a supported and demonstrated showing that the factors are fulfilled and the Commission finds good cause for a waiver. It contemplates a Commission vote within eight months of filing. [Minutes of Dec. 17, 2025 Business & Executive Session at 6-7, *available at* https://www.lpsc.louisiana.gov/docs/minutes/Dec_17_2025_Min.pdf (last visited Nov. 11, 2026)].

B. Notice and Interventions

The Application was published in the Commission's Official Bulletin No. 1372, dated March 27, 2026, for a fifteen-day intervention period. The following parties timely

[1] Alternatively, ELL requested waiver of the MBM Order if the Commission found that the Lightning Initiative did not apply. [Application at 4-5].

intervened: the Alliance for Affordable Energy and the Union of Concerned Scientists (collectively, the "NPOs"), the Louisiana Energy Users Group ("LEUG"), the Southern Renewable Energy Association ("SREA"), Sierra Club, the Association of Louisiana Electric Cooperatives, Inc. ("ALEC"), 1803 Electric Cooperative, Inc., Walmart, and the Gulf States Renewable Energy Industries Association ("GSREIA").[2] *Order No. U-37882-B*, Docket No. U-37882, *Entergy La., LLC, ex parte*, at 1 (Oct. 16, 2026).

C. *Order No. U-37882*: Procedural Directive

On April 2, 2026, ELL filed a *Motion Pursuant to Rule 57 for Procedural Directive* requesting the Commission to establish an expedited procedural schedule permitting a final decision at the November 2026 Business and Executive Session. ELL also requested the Commission to direct the Administrative Hearings Division to serve as hearing examiner and compile a record without a formal recommendation. [ELL Motion Pursuant to Rule 57 for Procedural Directive at 5 (Apr. 2, 2026)]. At its April 15, 2026 Business and Executive Session, the Commission voted unanimously to exercise original and primary jurisdiction under Rule 57. Commissioner Campbell moved to substantially grant ELL's motion. However, Commissioner Campbell proposed extending the final vote to the December 16, 2026 Business and Executive Session to align with the Lightning Initiative's requirement that a decision be made within eight months from the filing date. Commissioner Campbell's motion passed 4:1. *Order No. U-37882*, Docket No. 37882, *Entergy La. LLC, ex parte*, at 2-3 (May 14, 2026).

D. *Order No. U-37882-A*: The NPOs' Motion for Subpoena

On June 29, 2026, the NPO intervenors filed a *Motion for the Production of Documents* ("Motion for Subpoena") directed to Meta, which was not a party to the proceeding.

[2] GSREIA filed a late petition for intervention, which was granted by the ALJ on June 30, 2026.

NPOs sought documents relating to Project Evest's expected economic investment and job creation, electric load, and load factor, as well as Meta's communications with ELL regarding its sustainability commitments, and documents showing Meta's financial solvency. [Motion for Subpoena at 8].

ELL opposed the Motion for Subpoena on the grounds that it failed to satisfy the requirements of Rule 40 of the Commission's Rules of Practice and Procedure, including that the requests be narrowly tailored and that the information sought be necessary. [ELL Opposition to NPOs' Motion for Subpoena at 6 (July 2, 2026)]. Commission Staff initially took no position but ultimately opposed the Motion for Subpoena in its July 8, 2026 reply comments, finding that the NPOs failed to meet the requirements of Rule 40 for each category of documents requested. [Comments of the LPSC Staff at 3 (July 2, 2026); Reply Comments of the LPSC Staff at 1-2 (July 8, 2026)].

After briefing and oral argument on July 8, 2026, the ALJ issued a ruling on July 10, 2026, granting the motion in part and denying it in part, and issued a corresponding subpoena. *Order No. U-37882-A*, Docket No. U-37882, *Entergy La. LLC, ex parte*, at 1-2 (Sept. 17, 2026). Specifically, the ALJ granted NPOs' request for documents relating to Meta's economic investment and the amount of Project Evest's electric load and denied the remaining requests. *Ruling on Motion for Subpoena for the Production of Documents*, Docket No. U-37882, *Entergy La., LLC, ex parte*, at 14-17 (July 10, 2026) ("Subpoena Ruling"). On July 14, 2026, Meta filed a *Motion for Stay Pending Immediate Review of Interlocutory Ruling*, a *Motion for Immediate Review of Interlocutory Ruling*, and a *Motion to Quash Subpoena*. *Order No. U-37882-A* at 2. The ALJ granted the stay. After briefing and oral argument, the ALJ denied the motion to quash

by ruling dated August 4, 2026. The ALJ also declined to reconsider the subpoena ruling and referred it to the Commissioners for immediate review. *Id.* at 2-3.

At the August 12, 2026 Business and Executive Session, the Commission voted 3-1 to reverse the ALJ's ruling and vacate the subpoena, which rendered Meta's motion to quash moot. The Commission issued *Order No. U-37882-A* memorializing these decisions on September 17, 2026. *Id.* at 6.

E. *Order No. U-37882-B*: The NPOs' Motion for Access to "Attorneys' Eyes Only" Information

On July 15, 2026, the NPOs moved for access to information designated "Attorneys' Eyes Only" ("AEO") for certain client representatives. NPOs' representatives argued that they were unjustly denied access to confidential information, which limited their meaningful participation in the proceedings and effective representation of the NPOs. Because NPOs had signed the same confidentiality and non-disclosure agreements signed by the client representatives with access to AEO information, they argued there was no legitimate risk of public disclosure or justification for disparate treatment, which the ALJ in Docket No. U-37425 previously found sufficient to grant NPOs similar access. [Motion of the NPOs for Access to "Attorney's Eyes Only" Information at 1-2 (July 15, 2026)].

SREA filed a response requesting AEO access for all parties' client representatives who executed the confidentiality agreements. [SREA Response to the NPOs' Motion for Access to "Attorney's Eyes Only" Information at 1-3 (July 15, 2026)]. ELL opposed the motion, arguing that the confidentiality agreements, to which representatives of NPOs and SREA consented, plainly precluded NPOs and SREA's access to AEO information as defined therein. [ELL Memo in Opposition to Motion of the NPOs for Access to "Attorney's Eyes Only" Information at 2 (July 15, 2026)]. The NPOs filed a reply in support of their motion and in opposition to ELL's

memorandum on July 20, 2026. [NPOs' Motion for Leave to File Reply to ELL Opposition (July 15, 2026)].

After oral argument on July 29, 2026, the ALJ granted the NPOs' requested relief by ruling dated August 6, 2026 (the "AEO Ruling"). She found that ELL failed to meet its burden to show that the confidentiality agreement was insufficient for the NPOs to receive the requested information and that further protection was required. *Ruling on Access to "Attorneys' Eyes Only" Information*, Docket No. U-37882, *Entergy La., LLC, ex parte*, at 1, 9 (Aug. 6, 2026). On August 11, 2026, ELL sought immediate review of the AEO Ruling and a stay pending review. The stay was granted on August 12, 2026. On August 26, 2026, the ALJ declined to reconsider the AEO Ruling and referred it to the Commissioners. *Order No. U-37882-B*, Docket No. U-37882, *Entergy La., LLC, ex parte*, at 3 (Oct. 16, 2026).

On September 4, 2026, ELL and the NPOs filed a *Joint Motion to Vacate August 6, 2026 Ruling Pursuant to Rule 57*, together with a stipulation resolving the issues raised. The parties agreed to provide NPOs and SREA conditional access to AEO information. [Attorneys' Eyes Only Information Access Stipulation (Sept. 3, 2026)]. At the September 16, 2026 Business and Executive Session, the Commission unanimously granted the joint motion, accepted the stipulation, vacated the AEO Ruling, and declared ELL's motion for immediate review moot. The Commission issued *Order No. U-37882-B* on October 16, 2026. *Order No. U-37882-B* at 4-5.

F. Pre-Filed Testimony

ELL filed direct testimony of fifteen witnesses with the Application, and it later filed rebuttal testimony on September 4, 2026. Commission Staff filed testimony of two witnesses on July 31, 2026: the Direct Testimony of John A. Chapman and Direct Testimony of R. Lane Sisung. The NPOs submitted the Direct Testimony of Nicholas W. Miller and Edward Burgess. LEUG, Walmart, Sierra Club, and SREA each filed the testimony of one witness. [*See* Direct

Testimony of James Dauphinais (LEUG); Direct Testimony of Michael Marchand (Walmart); Direct Testimony of Devi Glick (Sierra Club); Direct Testimony of Jason Hoyle (SREA)]. Witnesses for LEUG, NPOs, and the Commission Staff also filed cross-answering testimony, which included the Cross-Answering Testimony of James Dauphinais, the Cross-Answering Testimony of Nicholas W. Miller and Edward Burgess, and the Cross-Answering Testimony of R. Lane Sisung.

G. Settlement, Joint Pre-Hearing Statement, and Hearing

On September 28, 2026, ELL filed a *Notice of Settlement* attaching the *Final Stipulated Settlement Term Sheet* that ELL and Commission Staff executed on September 25, 2026. Also on September 28, 2026, the parties filed a *Joint Pre-Hearing Statement*, which was later amended on October 2, 2026 ("Amended Jt. Pre-Hrg. Statement"). It identified no contested issues between ELL and Staff and set out the issues that remained contested by the intervenors. [Joint Pre-Hearing Statement at 2-10 (Sept. 28, 2026)]. On October 6, 2026, before the evidentiary hearing began, Walmart joined ELL and Staff in the *Final Stipulated Settlement Term Sheet*.

The evidentiary hearing began on October 7, 2026, and concluded on October 13, 2026. [Report of Proceedings by the ALJ at 10, (Oct. 19, 2026)]. On October 15, 2026, ELL filed a *Notice of Settlement* reflecting the October 6, 2026 settlement among ELL, Staff, and Walmart. [Notice of Settlement (Oct. 15, 2026)]. On October 19, 2026, the ALJ issued a *Report of Proceedings* in lieu of a formal recommendation, which set post-hearing briefs due November 12, 2026, and reply briefs due November 25, 2026. [Report of Proceedings by the ALJ at 11-12, (Oct. 19, 2026)]. The matter is set for Commission consideration at the December 16, 2026 Business and Executive Session. *Order No. U-37882* at 3.

H. Relief Requested in the Application

ELL seeks certification of seven new 1x1 combined cycle combustion turbine ("CCCT") generators, each rated at 754 MW, for a combined 5,278 MW of new generation. Four of the units will be located near the Customer's site in Richland Parish ("Richland Parish Proposed Generators") and three near the existing Big Cajun site in Pointe Coupee Parish ("Pointe Coupee Proposed Generators") (collectively, the "Proposed Generators"). ELL also requests certification of three battery energy storage systems (the "Battery Storage Facilities"). Regarding transmission plant, ELL requested certification of a new 150-mile 500 kV transmission line extending from Richland Parish to St. Landry Parish (the "WFC to St. Landry 500 kV Line") and a new 500 kV switching station in St. Landry Parish (together, the "Proposed Transmission Facilities"). [Application at 4]. Additionally, ELL seeks an exemption from certification for the West Fork Creek 500/230 kV substation and associated 230kV lines and the Smalling to El Dorado 500 kV Line, both of which the Customer will fully fund through a Contribution in Aid of Construction Agreement ("CIAC Agreement") (collectively, the "Customer-Funded Transmission Projects"). [*Id.* at 16-17, 28-29].

ELL asserts that its commercial arrangement with the Customer, informed by Commission guidance and the Customer's "Fair Share Plus" principles, will deliver billions of dollars of benefits to ELL's other customers over the Customer's Original Term of service. [*Id.* at 2]. Specifically, ELL contends the following obligations will provide such benefits over the 20-year Electric Service Agreement ("ESA"):

- The Customer's Minimum Monthly Charges ("MMCs") will fully offset the annual revenue requirements of resources not directly funded by the Customer, such that other customers' bills will not increase as a result of the requested resource additions. [*Id.* at 2, 7].
- The Customer will contribute $1.27 billion toward the Company's embedded costs through the Formula Rate Plan ("FRP") and an additional

$695 million toward storm securitization and grid resilience efforts that would have otherwise been paid by ELL's other customers. [*Id.* at 2].

- The Customer will fund the development of 2,500 MW of solar, onshore wind, and hybrid resources. [*Id.* at 2, 7].

- The Customer and ELL will together provide $260 million to low-income programs: $120 million for Entergy's The Power to Care program, consisting of $3 million per year from the Customer matched dollar for dollar by ELL, and $140 million, at $7 million per year, for energy efficiency and weatherization programs. [*Id.* at 2, 19-20].

- The Customer will fund certain nuclear-related efforts needed regardless of the Customer's Project, including a planned refueling cycle upgrade at Waterford 3 Steam Electric Station and a potential capacity uprate at River Bend Station. [*Id.* at 2, 19-20].

ELL further represents that the ESA and CIAC Agreement contain the following provisions designed to mitigate risk to its other, non-Evest customers:

- Recovery of outstanding and unrecovered costs from the Customer in the event of early termination. [*Id.* at 3].

- Credit and cash-flow protections, including a guaranty from Meta and other collateral. [*Id.*]

- A requirement of at least 36 months' advance notice should the Customer elect not to renew the ESA to provide sufficient time to adjust supply plans. [*Id.*]

- A process permitting ELL to determine whether to retain or sell the CCCT generators upon early termination. [*Id.*]

In its prayer for relief, ELL asks the Commission, among other things,[3] to grant the following relief:[4]

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[3] The Commission has previously addressed Prayers for Relief 21-22 (confidential treatment of Customer information), 23 (intervention period), 24 (procedural schedule), and 25 (notice). *Id.* at 35. Additionally, ELL requests other general and equitable relief. *Id.* at 36 (Prayer for Relief 26).

[4] Requests are categorized according to the testimony of Commission Staff Witness R. Lane Sisung. [*See* Sisung Direct at 4-9].

Generator Certification Requests

- Find that construction of the Proposed Generators and, to the extent required, the Battery Storage Facilities serves the public convenience and necessity, is in the public interest, and is therefore prudent under the 1983 General Order. [Application at 27 (Prayers for Relief 1 & 2)].

- Treat the Proposed Generators and Battery Storage Facilities as system resources for the benefit of all ELL customers, with the associated fuel and charging-energy costs eligible for recovery through the Fuel Adjustment Clause ("FAC"). [*Id.* at 27-28 (Prayer for Relief 3)].

MBM Waiver Request

- Find that ELL has satisfied the factors set forth in the Lightning Initiative and that good cause exists for a waiver and/or exemption from the requirements of the MBM Order. [*Id.* at 28 (Prayer for Relief 5)].

Transmission Certification Requests

- Find that the Customer-Funded Transmission Projects and the Smalling to El Dorado 500 kV Line are exempt from certification under the Transmission Siting Order[5] and find that the Proposed Transmission Facilities are in the public interest and appropriately sited. [*Id.* at 28-29 (Prayer for Relief 6)].

Ratemaking Requests

Approve the following ratemaking treatment:

- A regulatory liability to stabilize rates. [*Id.* at 31 (Prayer for Relief 10)].

- The requested accounting treatment of CIAC and early termination fees. [*Id.* (Prayer for Relief 11)].

- FRP recovery of the retail revenue requirements associated with prudently incurred costs of the Proposed Transmission Facilities, or alternatively, recovery through a regulatory asset with interest at ELL's weighted average cost of capital, until such costs can be reflected in rates through a future rate base proceeding. [*Id.* at 32 (Prayer for Relief 12)].

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[5] LPSC General Order, Docket No. R-36199 (Sept. 10, 2024) (*In re: Review and Possible Modification of the Commission's General Order dated October 10, 2013 Governing Transmission Certification and General Siting*) ("Transmission Siting Order").

- FRP recovery of the retail revenue requirements associated with the prudently incurred costs of the Proposed Generators and Battery Storage Facilities outside the FRP sharing mechanism and caps, and subject to offset by deferred Customer revenue, with deferral alternatives if no FRP is in effect, and the recovery of any remaining deferred balances over a two-year period. [*Id.* at 32-33 (Prayers for Relief 13-14)].

- Depreciable lives of twenty years for the Richland Parish Proposed Generators and thirty-two years for the Pointe Coupee Proposed Generators. [*Id.* at 33 (Prayer for Relief 15)].

- A return on interconnection-rights expenditures. [*Id.* at 33-34 (Prayer for Relief 16)].

- FAC treatment on Long Term Service Agreement expenses and Commissioning-Period revenues. [*Id.* at 34 (Prayers for Relief 17-18)].

Sustainability Agreement Requests

- Confirm the Customer's eligibility under the Commission's 3GW Order and Rider Geaux Zero for purposes of the 2,500 MW of Designated Renewable Resources contemplated by the Sustainability Agreement, approve the related protective and dispute-resolution provisions, and acknowledge that ELL may transfer to the Customer the Alternative Energy Credits ("AECs") associated with nuclear uprates. [*Id.* at 30-31 (Prayers for Relief 7-9)].

Monitoring Plan Approval

- Approve ELL's proposed Monitoring Plan and find that ELL has complied with all applicable Commission orders. [*Id.* (Prayers for Relief 19-20)].

- Find the Application complies with General Order in Docket R-34860 and that the requirements for entering into the ESA have been satisfied because ELL has submitted a filing pursuant to the 1983 General Order. [*Id.* at 28 (Prayer for Relief 4)].

I. Terms of the Stipulated Settlement among ELL, Commission Staff, and Walmart

The Stipulated Settlement between ELL, Commission Staff, and Walmart would resolve all issues between those parties upon Commission approval. [Stipulated Settlement at 1]. The principal terms are summarized below.[6]

1. Lightning Initiative and Large Load Guidelines

- The Application fulfills the factors set forth in the Lightning Initiative, and the Proposed Generators and Battery Storage Facilities are exempt from the MBM Order for good cause. [*Id.*, §§ I.A.1-2, B.4].

- ELL's Application has satisfied the Commission's Large Load Guidelines. [*Id.*, § I.A.3].

2. Proposed Generators and Battery Storage Facilities

- ELL has complied with the Industrial Load Rule, Rule 3 in General Order No. R-34860 dated July 29, 2019. [*Id.*, § I.B.1].

- Subject to enumerated Customer Protection Conditions in Section IV of the Stipulated Settlement and post-construction prudence reviews, construction of the Proposed Generators and Battery Storage Facilities serves the public convenience and necessity and is prudent in accordance with the September 20, 1983 General Order. [*Id.*, §§ I.B.2; *see id.*, §§ I.B.13, IV].

- The Proposed Generators and Battery Storage Facilities are to be treated as system resources. [*Id.*, § I.B.3].

- The Settlement does not address or determine any issue with respect to any purchased capacity (excepting the Proposed Generators and Battery Storage Facilities) required to serve the Customer's load, and ELL shall acquire such capacity pursuant to Commission approval, if applicable. [*Id.*, § I.B.14].

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[6] The October 6, 2026 Stipulated Settlement between ELL, Commission Staff, and Walmart is substantially similar to the settlement between ELL and Commission Staff filed on September 28, 2026, with only a few changes. *See, e.g.*, Stipulated Settlement at 18 (adding requirement that ELL include in its annual power monitoring reports SAIDI and SAIFI scores, both including and excluding major events, within fifty miles of the Project, and removing redundant condition that no other party shall have access to confidential information in Customer Monitoring Report).

3. Transmission

- The Customer-Funded Transmission Projects are exempt from certification. [*Id.*, § I.C.1-2].

- Subject to the Customer Protection Conditions in Section IV and post-construction prudence review, the Proposed Transmission Facilities are found to be in the public interest and therefore prudent in accordance with General Order R-36199 dated September 10, 2024. [*Id.*, § I.C.3; *see id.*, §§ I.C.5 & 8, IV].

4. Cost Recovery and Ratemaking

The Stipulated Settlement sets forth terms governing cost recovery:

- The retail revenue requirements for the Proposed Generators, Battery Storage Facilities, and Proposed Transmission Facilities are deemed eligible for recovery following commercial operation of the Proposed Generators and Battery Storage Facilities and the in-service dates of the Proposed Transmission Facilities through applicable FRP mechanisms, and outside the sharing mechanism and caps, and subject to offset by deferred Customer revenue. If no FRP is then in effect, the Stipulated Settlement provides for deferral with carrying charges at the weighted average cost of capital, until the costs may be reflected in rates. The amortization and cost recovery period of any such deferred balances shall be determined by future Commission action in a separate proceeding. [*Id.*, §§ I.B.5, I.C.4].

- The revenue requirements shall not be determined for ratemaking purposes until proposed to be included in rates or as otherwise prescribed by the then-effective FRP and shall be subject to future change pursuant to a prudence review of the actual costs of the resources. [*Id.*, §§ I.B.6, I.C.5].

- ELL shall utilize a depreciable life of twenty years for the Richland Parish Proposed Generators and all Battery Storage Facilities and thirty-two years for the Pointe Coupee Proposed Generators. [*Id.*, § I.B.7].

- Interconnection-rights costs may be recovered using ELL's weighted average cost of capital and in the same manner as construction costs. [*Id.*, § I.B.8].

- Variable expenses incurred under the Long Term Service Agreements and Commissioning Period energy costs may be recovered through the FAC. [*Id.*, §§ I.B.9-10].

As for ratemaking treatments, the Stipulated Settlement:

- Accepts the requested CIAC accounting treatment to offset the full amount of the Customer-Funded Transmission Projects and account for other contributions received from the Customer through the CIAC Agreement, such that costs will not be collected from other customers. [*Id.*, § III.A].

- Accepts the requested accounting treatment of the Customer's other contributions made pursuant to the ESA and/or CIAC Agreement, as well as the receipt of any termination fee. [*Id.*, § III.B].

- Adopts a Deferral Proposal Framework for in-service rate adjustments for the Proposed Generators and Proposed Transmission Facilities and deferral and amortization of Customer revenues into rates. [*Id.*, §§ III.C-E].

- Reallocates Customer revenues within Rider Schedule RPCR and the storm cost securitization riders. [*Id.*, §§ III.F-G].

5. Monitoring and Prudence Review

ELL is to submit quarterly Construction Monitoring Reports and annual confidential Customer Monitoring Reports regarding the status of the management of the Customer Agreements to the Commission Staff. [*Id.*, §§ I.B.12, I.C.7, VI]. ELL's actual construction costs and its management of construction remain subject to a Commission prudence review, with ELL's compliance filing due within 180 days after ELL's final acceptance of the last resource. [*Id.*, §§ I.B.13, I.C.8].

6. Customer Protection Conditions

Section IV of the Stipulated Settlement provides certain Customer Protection Conditions. While the parties acknowledge that the ESA, CIAC, and Related Agreements[7] provide justification for the Application, the Stipulated Settlement expressly provides that it does not constitute Commission approval of the ESA or Related Agreements. [*Id.*, §§ I.B.2, IV.A.2]. ELL

[7] "Related Agreements" includes the other agreements entered into with the Customer besides the ESA itself, including Rider 1 to the ESA, Contribution in Aid of Construction agreements, and collateral agreements.

agrees to prudently manage the ESA and Related Agreements, including the CIAC Agreement, the true up of Minimum Monthly Charges, the associated collateral, the Customer Supply Plan,[8] and the Customer's ramp schedule. [*Id.*, § IV.B]. The Commission explicitly reserves the right to examine the prudence of any of ELL's actions and agreements with respect to its service to the customer if and when there are stranded costs and/or other customers are harmed by any aspect of the transaction that resulted from imprudent action by the utility.

ELL also agrees to:

- Make filings with the Commission upon any material change to the Customer Supply Plan or upon early termination or non-renewal. [*Id.*, §§ IV.B.4, IV.D.5-6].
- Report disputes and contract modifications within thirty days. [*Id.*, §§ IV.D.3-5].
- Seek to prudently maximize the value of any excess capacity that may result from termination or nonrenewal of the ESA and file a proposal for the Commission to approve the manner in which any termination fee is utilized. [*Id.*, § IV.C].
- File a transition plan within six months of any notice of non-renewal or early termination. [*Id.*, § IV.D.6].
- Provide to the Commission a confidential operational control and emergency load shed plan, as well as confidential annual reports of Customer usage, demand, and billing. [*Id.*, § IV.D.1-2].

7. Reliability and Power Quality

ELL will conduct analyses of the interplay between the Customer's Project and ELL's transmission system. The costs of any material transmission or power-quality upgrades required solely because of the Customer's project are to be excluded from the rates of other

[8] The "Customer Supply Plan" consists of the resources identified on the tab titled Capacity Resources on Attachment 3 Ex. 1 Deferral Proposal Framework Workbook (AEO) which is attached to this Stipulated Settlement.

customers. Additionally, ELL shall include in its Construction Monitoring Reports updates on compliance with regulatory operational requirements relating to large load. [*Id.*, § V.A]. ELL is to install power-quality monitoring equipment and file annual reports on material power quality issues and remediation efforts. [*Id.*, § V.B-C].

8. Sustainability Agreement

ELL may use AECs associated with the Waterford 3 uprate if approved by the Commission, the Waterford 3 refueling cycle upgrades described in the Sustainability Agreement, and any other uprate to an ELL nuclear facility to the extent fully paid for by the Customer, including any uprate for River Bend Station approved by the Commission in a future proceeding. [*Id.*, § II.A].

III. CONTESTED ISSUES

ELL's Application, when combined with the additional customer protections provided in the Stipulated Settlement, results in a just and reasonable solution that allows ELL to serve Evest consistent with the public convenience. ELL has demonstrated that it can reliably serve the new load required by Evest with the Proposed Generators and Battery Storage Facilities included in its filing. The Company has also demonstrated that it will be able to reliably serve all its load, including the new Evest load, with the Customer-Funded Transmission Projects and Proposed Transmission Facilities. ELL's Application and witness testimony make clear that its non-Evest customers will benefit from the totality of Project Evest on a net present value basis. The ESA was drafted thoughtfully with customer protections in mind, including numerous mechanisms that protect non-Evest customers from subsidizing the Customer. Those protections include MMCs, accelerated depreciation of the Richland Parish Proposed Generators, a Buyer's Guaranty with a downgrade matrix, liquidation procedures in the event of an early termination,

credit default security, [redacted], a CIAC Agreement that requires the Customer to self-fund many projects, monitoring plans, and numerous other benefits and protections.

Based on its analysis and the Stipulated Settlement, the Staff does not have any remaining contested issues with ELL, except Cottonwood. However, some intervenors in this proceeding have not joined the Stipulated Settlement and continue to oppose the application, and therefore, contested issues remain. Each of those contested issues is analyzed in detail below.

The first contested issue addressed is whether ELL's Application satisfies the Commission's twelve nonbinding Large Load Guidelines ("Large Load Guidelines"). Due to the comprehensive nature of that issue, several other contested issues are subsumed within the Large Load Guideline analysis, and therefore, are not addressed separately thereafter. Those issues include Contested Issues (d), (j), (k), (l), and (m). Identification of those issues and where they are addressed within the Large Load Guideline section is shown below:

Contested Issue (d) - Whether the Company has adequately ensured that existing customers will be protected from the costs and risks associated with the Newly Constructed Assets, including adequate protections from increases in fuel costs. This issue is addressed in subsections 4 (Stranded Asset & Exit Risk), 5 (Rate Design & Cost Recovery), 8 (Fuel Supply & Infrastructure Risk), 9 (Load Ramp Management), and 10 (Market & Planning Impacts) of the Large Load Guideline analysis in Section III.A.

Contested Issue (j) - Whether there should be any conditions, reporting requirements, or review placed on the certification of the Proposed Generators and/or the Proposed Transmission Facilities. This issue is addressed in subsections 5(d) (Storm and Resilience Riders), 6 (Operational Control & Curtailment), 7 (Ancillary Services & Power

Quality), 9 (Load Ramp Management), and 12 (Ongoing Oversight) of the Large Load Guideline analysis in Section III.A.

Contested Issue (k) - Whether the Company is adequately planning for the reliability stresses that the Customer's load will place on the distribution and transmission systems. This issue is addressed in subsections 3 (Transmission & Interconnection), 6 (Operational Control & Curtailment), 7 (Ancillary Services & Power Quality), and 9 (Load Ramp Management) of the Large Load Guideline analysis in Section III.A.

Contested Issue (l) - Whether the Company should be required to monitor power quality issues within a 50-mile radius of the Evest project (or some other equally reasonable approach) for a period of at least ten (10) years and to report to the Commission the results of this monitoring, including the impact of power quality issues on customers within the established radius of the Evest project. This issue is addressed in subsection 7 (Ancillary Services & Power Quality) of the Large Load Guideline analysis in Section III.A.

Contested Issue (m) - Whether the Company has established net benefits accruing to all customers and customer classes. This issue is addressed in subsections 5(d) (Storm and Resilience Riders) and 5(e) (Total Customer Impact) of the Large Load Guideline analysis in Section III.A.

All other contested issues that are not fully discussed within the Large Load Guideline analysis are addressed independently below.

A. ELL Complied with the Commission's Non-Binding Large Load Guidelines and Applicable Executive Order(s) From the Governor of Louisiana (Contested Issue "g").

The Commission adopted the non-binding Large Load Guidelines at its February 25, 2026 Business and Executive Session to address recurring issues that utilities should consider when proposing to interconnect and serve large load customers. [Sisung Direct at 41; Staff Ex.

19]. They are intended to give utilities, potential large load customers, and the public transparency about the Commission's known areas of concern regarding large load additions. [Sisung Direct at 37]. As their name indicates, the Large Load Guidelines are not binding. However, the guidelines expressly warn that "failure to adequately address these concerns is a risk on the utility." [Staff Ex. 19 at 1 n.1].

The Commission's directive provides that, in any proceeding involving large load additions, the areas of concern identified in the Large Load Guidelines will be part of the Commission's analysis. [Sisung Direct at 41-42]. A utility seeking Commission action in such a proceeding must therefore be prepared to explain either how it has addressed each issue or why its proposal remains in the public interest without addressing those concerns. [*Id.*]. The Large Load Guidelines do not replace the traditional certification analysis; they supplement it. [Sisung Direct at 37]. As demonstrated below, ELL's Application, together with the commitments in the Stipulated Settlement, satisfies each of the twelve non-binding Large Load Guidelines.

1. Large Load Guideline #1 – Need, Scope, and Load Characteristics.

The first of the Commission's Non-Binding Large Load Guidelines asks whether the proposed large load addition is clearly defined as to maximum demand, annual energy consumption, load factor and operating profile, coincident peak contribution, and expected ramp schedule. [Staff Ex. 19 at 1]. It also states that the customer's load profile must be evaluated under peak and off-peak conditions, seasonal extremes, and abnormal system stress scenarios. [*Id.*]. ELL has adequately addressed each of these matters, and Large Load Guideline #1 is therefore satisfied.

Regarding the definition of the Customer's load, ELL witness Ms. Beauchamp provides a detailed analysis and discussion. Ms. Beauchamp explains that the Customer's maximum demand is [redacted] MW and that ELL expects the Customer to operate at a [redacted] load

factor, resulting in an annual energy consumption of approximately [redacted] Megawatt-hours. [Beauchamp Direct at 38]. Ms. Beauchamp also provides the expected coincident peak contribution of the Customer's load for each season through the year 2050. [*Id.* at 38-39]. For the Customer's expected ramp, Ms. Beauchamp provides the following schedule: "(1) construction power beginning in [redacted]; (2) commissioning power beginning in approximately [redacted]; and (3) increases in Customer's demand from September 2028 through full capacity in [redacted]." [*Id.* at 42-43]. Ms. Beauchamp explains that the expected ramp schedule is based on information received directly from the Customer. [*Id.*].

ELL's definition of the load does not rest on testimony alone. Appendix C to the ESA identifies the quantities of total and non-firm load the Customer may take during each month of the ramp period, and ELL confirmed in discovery that Appendix C reflects the operative ramp schedule. [Sisung Direct at 46; Exhibit RLS-006; Exhibit LKB-002 at 87-89]. ELL also produced the Customer's hourly, monthly and annual load forecasts for the ESA term, together with the underlying load factor assumptions and supporting calculations. [Sisung Direct at 46; Exhibit RLS-007].

ELL sufficiently evaluated the Customer load under peak and off-peak conditions, seasonal extremes, and abnormal system stress scenarios. Mr. Sisung explained that ELL "evaluated the load under several operating conditions through both its production-cost and transmission-planning analyses." [Sisung Direct at 46]. ELL witness Mr. Datta analyzed both peak and off-peak periods in his production cost analysis. That analysis used the AURORA model that simulated "the security constrained unit commitment and economic dispatch in a Day 2 energy market such as MISO and incorporates assumed heat rates in conjunction with gas price forecasts, gas delivery costs, and an emissions price forecast." [Datta Direct at 12]. The AURORA model

simulated energy market operations "using hourly demand and individual resource operating characteristics," thereby satisfying the need to evaluate the Customer's load under peak and off-peak conditions. [*Id.*]. The AURORA Change Case discussed by Mr. Datta "included the hourly load forecast for the Customer as the load ramps up, consistent with the ESA terms, from the end of 2026 through the duration of the Original Term of the ESA." [*Id.* at 13]. Mr. Sisung also explained that ELL witness Mr. Kline performed a "transmission planning analysis" that "included full-load conditions, a reduced-load shoulder season case set at 77% of peak, and sensitivities involving multiple generation outages." [Sisung Direct at 46].

As for abnormal system stress scenarios, ELL's analysis considered the consequences of the loss of a major load center, including the potential for cascading outages and load shed. [Sisung Direct at 47; Exhibit RLS-005 at 4-7]. ELL's analysis also considered fall and spring maintenance periods during which substantial regional generation may be unavailable, north-to-south transfer capability during outages, and extreme-weather conditions such as hurricanes and winter storms. [Sisung Direct at 47; Exhibit RLS-005 at 97-98] In that analysis, ELL studied whether the WFC to St. Landry 500 kV Line would: "(1) permit essential fall and spring maintenance periods, during which 30-40% (up to 10,000MW) of regional generation may be offline; (2) provide the capability to serve load during high load factor growth; (3) provide North to South power transfer capability across central Louisiana **particularly during outages and extreme weather events such as hurricanes and winter storms**; (4) maintain reliability **during extreme weather events**; and (5) mitigate operational constraints that would defer or cancel outages." [Exhibit RLS-005 at 98 (emphasis added)]. The need for the WFC to St. Landry 500 kV line itself is addressed under Large Load Guideline #3 below.

SREA witness Mr. Hoyle questions whether the Customer will operate at the load factor ELL assumed, contending that "even small adjustments in the assumed load factor result in comparable reductions in the annual energy requirement and could result in underutilized or unnecessary CCCT units." [Hoyle Direct at 32]. Mr. Sisung agreed that this is "a legitimate forecasting uncertainty," but explained that the relevant planning question is what ELL can reasonably be expected to plan to serve based upon the information presently available and the service the Customer has requested. [Sisung Cross-Answering at 84-85]. Mr. Hoyle does not translate the information he cites into an alternative Evest load forecast, identify a different Maximum Contract Demand, determine what load factor should replace ELL's assumption, or perform an alternative Load & Capability analysis demonstrating that any particular CCCT is unnecessary. [*Id.* at 85]. Moreover, if the Customer's usage is lower than projected, the MMC establishes a contractual payment floor, and thus provides significant protection against underutilization. [*Id.* at 86]. Contrary to positions taken by the NPOs in seeking a subpoena against Meta, the Customer has already provided Entergy its best-known current information about its load profile. As Mr. Sisung concluded, ELL "should update its planning when materially better Customer information becomes available; it should not be required to replace the best information presently available with a lower assumption simply because future Customer usage cannot be forecast with certainty." [Sisung Cross-Answering at 87].

After reviewing all of ELL's testimony and discovery responses, Mr. Sisung concluded that ELL had "adequately addressed the matters identified in this Large Load Guideline." [Sisung Direct at 45]. Specifically, Mr. Sisung found that "ELL has sufficiently presented the proposed load and evaluated its operational characteristics under peak, off-peak, seasonal, and stressed system conditions." [*Id.* at 47].

2. Large Load Guideline #2 – Resource Adequacy & Capacity

Large Load Guideline #2 asks whether the utility has demonstrated that sufficient firm, deliverable capacity exists or will be constructed to serve the Customer's new large load without impairing system reliability. [Staff Ex. 19 at 1]. More specifically, the utility should demonstrate that: (1) capacity accreditation reflects actual availability during system peak; (2) deliverability constraints have been evaluated; and (3) capacity resources are aligned temporally and geographically with the load. [*Id.*]. Mr. Sisung concluded that, "subject to [his] discussion related to the Load Ramp Period in Large Load Guideline #9, ELL has adequately addressed the requirements of this guideline." [Sisung Direct at 48]. The Commission should find that ELL has adequately addressed Large Load Guideline #2.

It is clear from ELL's application that the addition of the Customer's load will require ELL to acquire additional capacity resources. To do this, ELL has proposed to construct the Proposed Generators and Battery Storage Facilities. [Application at 4]. ELL has also explained that revenues received from the Customer will cover a Bayou Cove Capacity Credit Purchase Agreement ("Bayou Cove CCPA") and that the Customer will fund a 45 MW uprate at the Waterford 3 Steam Electric Station. [Ingram Direct at 10]. The annual costs of all these capacity additions will be assigned to the Customer through the Minimum Monthly Charges for the term of the ESA. [Sisung Direct at 48].

ELL planned its supply against two related metrics: the Customer's projected contribution to coincident peak together with the applicable MISO Planning Reserve Margin Requirement ("PRMR"), and the Customer's projected maximum demand. [Sisung Direct at 22-23]. As to the first, Ms. Beauchamp explains that "the Company has developed a supply plan that will provide [redacted] of Summer Seasonal Accredited Capacity . . . to support the total need of [redacted] to serve the Project, which amount is inclusive of the [redacted] coincident peak of

Customer demand and [redacted] of capacity needed to cover the PRMR established by MISO (which is inclusive of transmission line losses.)" [Beauchamp Direct at 10]. As to the second, ELL's broader supply plan, particularly the Bayou Cove CCPA and the Waterford 3 uprate, addresses the Customer's maximum demand. [Sisung Direct at 23; Exhibit RLS-002].

Those figures are stated in accredited capacity, not nameplate capability, consistent with the Guideline's requirement that accreditation reflect actual availability during system peak. As Mr. Sisung explained, "ELL's planning analysis appropriately focuses on the accredited capacity value of the proposed resources rather than simply their installed nameplate capability." [Sisung Direct at 48]. Ms. Beauchamp identifies the Customer's projected coincident peak contribution, the applicable planning reserve requirements, and the accredited capacity associated with the proposed resource portfolio; and the Load and Capability Report produced in discovery demonstrates how ELL proposes to satisfy its projected resource adequacy obligations associated with serving Project Evest. [*See id.*].

ELL also evaluated the deliverability of the proposed resources. As Mr. Sisung explained, "the proposed generation locations and associated transmission facilities were selected through an integrated planning process that considered the ability to interconnect the resources, deliver their accredited capacity to load, and maintain system reliability under the assumed planning scenarios." [Sisung Direct at 49]. Mr. Kline testified that a "generation-only solution" for Project Evest was "not viable due to the size, location, and characteristics" of the Customer's new large load. [Kline Direct at 12]. As a result, ELL proposed new transmission facilities and substations that were necessary to deliver the power to the Evest data center. [*Id.*].

Specifically, the WFC to St. Landry 500 kV Line, a corridor through central Louisiana, provides substantial deliverability benefits to all ELL customers. That line "will

improve ELL's ability to move power around the system to where it is needed" and is "especially valuable during periods where generation outages are needed for maintenance or are forced due to a component failure as well as during extreme weather events such as hurricanes and winter storms." [*Id.* at 21]. This added transmission capacity will "benefit the deliverability of generators as they seek interconnection to the transmission system." [*Id.*].

ELL has also shown that capacity resources are properly aligned geographically with the Evest load. Four of the new Proposed Generators, Richland Parish Units 1 through 4, will be located near the Customer's site. Building the Richland Parish Proposed Generators near the Customer's load will "reduce the net load demand on the system and mitigate the need for additional significant transmission upgrades." [Beauchamp Direct at 76]. Construction of four CCCTs at the Richland Parish site near the Evest and Laidley loads also prevents potential thermal and low-voltage violations in North Louisiana, South Arkansas and Central Mississippi. [Exhibit RLS-004 at 2].

The other three Proposed Generators are being constructed in Pointe Coupee Parish in the Southeast Louisiana Planning Region ("SELPA"), which is considered a load pocket that relies heavily on imports to serve load in the area. Siting the three Pointe Coupee Proposed Generators in SELPA is beneficial because it introduces additional generators in a load pocket that will assist with outage management and [redacted] [Beauchamp Direct at 77]. Land availability and speed to market were also contributing factors for choosing to construct three of the Proposed Generators in Pointe Coupee Parish. [Sisung Direct at 27; Kline Direct at 39-40].

ELL has shown that its capacity resources are aligned temporally with the Customer's load. As Mr. Owens explains, "[t]he CCCTs provide firm capacity and, because the

CCCTs can operate around the clock, they are aligned temporally with the Customer's around-the-clock load." [Owens Rebuttal at 11]. Mr. Sisung likewise found that the proposed generation locations were selected "to align the timing and location of the proposed capacity additions with the projected Customer load ramp," and that the proposed resources "have been evaluated with respect to accreditation, deliverability, and their temporal and geographic relationship to the projected load." [Sisung Direct at 49-50]. Mr. Sisung separately addressed the timing of those resources and the projected capacity shortfalls during the Customer's ramp period under Large Load Guideline #9. [*Id.* at 49]. As discussed in Section III.A.9 below, the Stipulated Settlement resolves those load ramp concerns.

No intervenor has shown that ELL's resource adequacy analysis is deficient. NPO witness Mr. Miller contends that the justification for seven CCCTs is based on insufficiently detailed resource adequacy analysis and that more granular modeling might show that fewer CCCTs are needed. [*See* Owens Rebuttal at 12]. But Mr. Miller "does not identify any specific deficiencies in the process that ELL used to determine its incremental capacity needs," including the modeling used to determine planning reserve margins and capacity accreditation. [*Id.*]. NPO witness Mr. Burgess's alternative changes the timing of the proposed generation and assumes that Customer demand response can remain available to support it. [Sisung Cross-Answering at 97]. But Evest has not agreed to the resulting amount or duration of non-firm service, and "[p]otential flexibility is different from committed capacity upon which ELL can reasonably rely for resource-adequacy purposes." [*Id.*]. Alternatives to the proposed portfolio are further addressed under Contested Issue "c" below in Section III.D.

Accordingly, subject to the load ramp concerns addressed under Large Load Guideline #9, ELL has demonstrated that firm, deliverable capacity is planned to satisfy its

projected resource adequacy obligations associated with serving Project Evest, and that the proposed capacity resources have been evaluated with respect to accreditation, deliverability, and their temporal and geographic relationship to the projected load. [Sisung Direct at 49-50]. ELL has therefore adequately addressed Large Load Guideline #2.

3. Large Load Guideline #3 – Transmission & Interconnection

Large Load Guideline #3 asks the utility to "identify all required transmission upgrades that need to be constructed or have their planned construction accelerated due to the new load." [Staff Ex. 19 at 1]. Specifically, the utility should demonstrate three things: (1) network and interconnection costs caused by the load are fully assigned to the load; (2) no material transmission costs are shifted to existing customers that they otherwise might not bear or for which they do not receive commensurate benefits; and (3) any transmission upgrades timelines are consistent with the load ramp. [*Id.* at 2]. Lastly, the utility should "demonstrate that queue priority and interconnection treatment are consistent with tariff requirements and do not disadvantage existing customers." [*Id.*]. The Commission should find that ELL's application sufficiently addresses all of the recommendations included in Large Load Guideline #3.

ELL has sufficiently identified all transmission upgrades that will be required due to the new Evest load. ELL requests certification of the new 150-mile WFC to St. Landry 500 kV Line and the new St. Landry 500 kV Switching Station. [Application at 4]. ELL also asks the Commission to find that certain Customer-funded projects are exempt from certification under the Transmission Siting Order, which includes the West Fork Creek 500/230 kV substation, nine auxiliary 230 kV switching stations, 20-30 miles of 230 kV lines connecting the Customer, and the Smalling–El Dorado 500 kV line. [*Id.* at 28-29]. The Stipulated Settlement provides that those Customer-funded facilities are exempt from certification and that, subject to the Customer

protection conditions, the Proposed Transmission Facilities are in the public interest. [Stipulated Settlement §§ I.C.1–3].

ELL has demonstrated a need for all the transmission assets requested in its application. As a group, the transmission assets are needed for ELL to serve Project Evest. A generation-only solution is not viable "due to the size, location, and characteristics of the new load." [Kline Direct at 12]. The transmission assets are "needed to deliver the power to the Customer site and to maintain the reliability of the electric system in Louisiana with the addition of the sizable new load associated with Project Evest and the new generation resources necessary to serve Project Evest." [*Id.*].

ELL has provided justification for each of the transmission assets on an individual basis. ELL's transmission planning studies showed that, with the addition of the Evest load, the WFC to St. Landry 500 kV Line is "needed to address the identified thermal constraints on the 500kV, 230kV and 115kV transmission systems in Central Louisiana." [*Id.* at 45]. Without that line, "ELL may not be able to take the outages needed to conduct essential seasonal maintenance on generation and transmission assets, an outcome that would be to the detriment of all customers." [*Id.* at 20].

ELL evaluated the impact of a fault occurring on the 500 kV system in the vicinity of the Evest Project. In that event, all load at Project Laidley and Project Evest would disconnect from the system. [*Id.* at 27]. ELL's study, conducted by Mr. Kline's team, evaluated the transmission system in 2035 with and without the WFC to St. Landry 500 kV. Without that line, the loss of Project Evest and Laidley load would cause the Smalling – Baxter Wilson 500 kV line to load to 123% in the summer and 137% in the winter. [*Id.*]. The 137% loading is critical because it is above the 125% level that triggers a cascading analysis. [*Id.*]. But with the WFC to St. Landry

500 kV Line in service, the Smalling – Baxter Wilson 500 kV line would load to 103% in the summer and 121% in the winter. [*Id.* at 27-28]. Those figures are still elevated but are below the cascading analysis level. With the WFC to St. Landry 500 kV Transmission Line in service, a loss of the Evest and Laidley load "could be managed in real-time operations of the system." [*Id.* at 28].

The WFC to St. Landry 500 kV Line provides additional benefits to the ELL system. That line adds a hardened north-south 500 kV path for resilience in extreme weather and generator deliverability. [*Id.* at 25]. The line provides greater ability to transfer power than ELL's existing transmission lines that move power north to south across the region. [*Id.*]. Constructing the WFC to St. Landry 500 kV Line now may also allow ELL to defer or avoid future upgrades to the Company's existing lower voltage transmission system, a benefit that Mr. Kline describes as "potentially very meaningful" but that has not yet been quantified. [*Id.* at 35].

The St. Landry 500 kV Switching Station can be viewed in conjunction with the WFC to St. Landry 500 kV Line. The St. Landry Switching Station will "intersect the to-be-constructed Babel-Webre 500kV line in St. Landry Parish north of Lafayette." [*Id.* at 18]. That station is necessary to connect the new north–south corridor to the southern 500 kV network.

The West Fork Creek 500/230 kV Substation is necessary to connect the Customer's load to the ELL transmission system. [*Id.* at 9-10]. The substation will be built on land next to Project Evest and paid for by the Customer through the CIAC agreement. [*Id.* at 13]. The series of 230 kV lines are needed to connect West Fork Creek to the Customer's load-serving substations. [*Id.* at 9-10]. Those 230 kV lines will also be paid for by the Customer pursuant to the CIAC agreement. [*Id.*]. The nine auxiliary 230 kV switching stations are also needed to

connect the Customer's load to the ELL Transmission System and will be funded by the Customer pursuant to the CIAC agreement. [*Id.* at 13].

Lastly, ELL has identified the Smalling – El Dorado 500 kV line as necessary for Project Evest. That line will strengthen the 500 kV network between North Louisiana and South Arkansas. ELL plans to build the Louisiana portion of the line and Entergy Arkansas, LLC will build the Arkansas portion. [*Id.* at 14]. Both portions of the line will be funded by the Customer, with the Louisiana portion being funded pursuant to the CIAC agreement. [*Id.*]. ELL has represented that the Smalling – El Dorado 500 kV line is necessary to comply with NERC standards. [*Id.* at 15]. The line will also provide benefits to the transmission system overall, including helping the system integrate new generation sources, including renewable generation. [*Id.*]. The line will reduce reliance on lower-voltage facilities in Arkansas and Louisiana and add a second north-south path, which improves regional resilience. [*Id.*]. Without the Smalling – El Dorado 500 kV line, customers on Entergy's 115 kV system in southern Arkansas and northern Louisiana would face "service interruptions when nearby EHV facilities are out of service" as the Evest load grows. [*Id.* at 18].

ELL has also shown that its transmission upgrade timelines are consistent with the Customer's load ramp. Mr. Sisung found that "the proposed transmission facilities have been planned to correspond with the Customer's projected load ramp," and that the transmission planning process "was developed in coordination with the proposed generation additions and the Customer's anticipated in-service schedule." [Sisung Direct at 51]. ELL's milestone schedule projects in-service dates of August 1, 2030 for the customer interconnection, December 30, 2030 for the Smalling – El Dorado 500 kV line, and December 1, 2031 for the WFC to St. Landry 500 kV Line and St. Landry Switching Station. [Exhibit DK-4 at 3]. Those dates track closely the

needs ELL identified and the Customer's load ramp schedule. [*See* LKB-2 at 87-89; *see also* Kline Direct at 19-30 (explaining reasons the WFC to St. Landry 500 kV line is recommended)].

To the Staff's knowledge, no witness in this proceeding alleges that ELL has failed to demonstrate that queue priority and interconnection treatment are consistent with tariff requirements and do not disadvantage existing customers. The only non-ELL witness that addresses this component of Large Load Guideline #3 was Mr. Sisung and he did not find any tariff violations related to queue priority and interconnection treatment. [Sisung Direct at 51-52]. Mr. Sisung cited ELL's explanation that "the proposed generation resources at Big Cajun [redacted] and that the remaining interconnection facilities will be developed consistent with the applicable MISO and Entergy transmission planning and interconnection processes." [*Id.* at 52]. He concluded that there was no evidence to indicate that "the proposed interconnection treatment or queue position is inconsistent with the applicable tariff requirements or that existing customers will be disadvantaged through preferential queue treatment." [*Id.*].

The remaining components of Large Load Guideline #3 – that network and interconnection costs caused by the load are fully assigned to the load and that no material transmission costs are shifted to existing customers that they otherwise might not bear or for which they do not receive commensurate benefits – are substantially related to ELL's economic analysis, the Customer Agreements, and the Company's proposed allocation of costs and risks. [Sisung Direct at 52]. To summarize those issues, the Customer will fund 100% of the cost of the Customer-Funded Transmission Projects through the CIAC Agreement, so that those facilities carry a zero plant-in-service balance and are not collected from other customers. [Stipulated Settlement § III.A]. The Proposed Transmission Facilities are ELL-funded, but their costs are

included in the Customer's MMCs during the term of the ESA, which includes a true-up mechanism to prevent ELL or its other customers from bearing the risk of changes in their costs. [Sisung Direct at 148; Kline Direct at 33]. The Customer will also be responsible for the cost of any additional transmission improvements needed to ensure that the system remains reliable with the addition of its load and the Stipulated Settlement provides that, to the extent material upgrades are required to the transmission system as a result of the Customer's Project, "the costs of those upgrades shall not be included in the rates of customers other than the Customer." [Kline Direct at 34; Stipulated Settlement § V.A]. These issues are discussed more fully below under Large Load Guideline #5 and Contested Issue "i."

Based on the foregoing, Mr. Sisung concluded that, other than the cost considerations addressed under Large Load Guideline #5, "ELL has identified the transmission facilities necessary to support its proposed service to Project Evest, demonstrated that the proposed transmission schedule has been developed to correspond with the anticipated load ramp, and represented that the proposed interconnection approach is consistent with the applicable transmission planning and tariff requirements." [Sisung Direct at 52-53]. ELL has therefore adequately addressed Large Load Guideline #3.

4. Large Load Guideline #4 – Stranded Asset & Exit Risk

Large Load Guideline #4 states that the utility should demonstrate that reasonable mechanisms are in place to protect customers from stranded generation, transmission, and fuel infrastructure. Specifically, the guideline asks that the utility demonstrate the following:

- Contract terms align with asset lives;
- Excess generation at end of contract can be economically used by remaining load;
- Adequate financial security (including corporate guarantees) is in place to prevent ratepayers from paying for unneeded generation; and

- Contractual arrangements adequately address the risks associated with partial reductions in the customer's electric load.

[Staff Ex. 19 at 2]. Mr. Sisung opines that Large Load Guideline #4 "is intended to evaluate whether the utility has appropriately mitigated the risk that existing customers could be left paying for stranded assets or other unrecovered costs if the anticipated load does not materialize or ceases to take service." [Sisung Direct at 105].

The phrase "stranded asset" generally refers to "utility property or investments that remain unrecovered after the assets cease to provide the utility service or economic benefits originally anticipated." [*Id.* at 106]. In the event an asset becomes stranded, questions may arise as to whether the utility is allowed to recover those stranded asset costs. But that determination is not made in a certification proceeding such as this one. To be clear, whether ELL is allowed to recover any stranded asset costs if an asset certified in this proceeding later becomes stranded is not being determined in this proceeding. Instead, this proceeding addresses only whether ELL's application should be granted because it is in the public interest.

Numerous witnesses agree that stranded asset cost recovery, including whether the ESA and related agreements prudently protect against the risk of future stranded costs, is not an issue in this proceeding and will be determined later if an asset does ultimately become stranded. Mr. Hinkson, for example, testifies that the Commission "has not been requested by ELL to determine whether ELL would be entitled to recover stranded costs in the event of early termination." [Hinkson Rebuttal at 4]. He concludes that it would be "premature" for the Commission to determine now whether ELL would be entitled to stranded asset cost recovery. [*Id.*].

Similarly, ELL witness Mr. Jones testifies that, in the case of an early termination, the LPSC "fully retains its authority, both legally and practically, to make a future determination

about the prudence" of a decision to retain or liquidate a generator, based on the facts at that time. [Jones Rebuttal at 33-34]. He says "[i]t is not reasonable to predetermine a disallowance now." [*Id.*]. Additionally, Mr. Jones testifies that "[t]here is no compelling basis for predetermining now whether the remaining costs of the Proposed Generators will be recoverable in the future if the Customer does not renew." [*Id.*].

Staff witness R. Lane Sisung testified that certifying the proposed resources does not decide, and should not decide, who ultimately bears the cost of any stranded investment. In his view, the existence of a stranded asset "does not itself determine whether, or to what extent, the remaining investment should ultimately be recovered from customers." [Sisung Direct at 106]. Instead, it "presents a ratemaking question that must be resolved . . . based on the particular facts and circumstances existing at that time." [*Id.*]. Certification, prudence findings, and future ratemaking treatment "are separate regulatory determinations that occur at different points in the life of an investment." [*Id.* at 107].

The Stipulated Settlement leaves the question of stranded-asset recovery for future proceedings, and the three parties to that agreement expressly acknowledge this. In Section IV.A, the parties agree that ELL "did not seek approval of the ESA and Related Agreements" and are explicitly "not expressing approval or recommending that the Commission approve" them. [Stipulated Settlement § IV.A.2]. The parties also agree that they "reserve all rights afforded by applicable law," and that "the Commission retains fully its authority consistent with applicable law regarding prudence." [*Id.*]. That authority expressly includes "ELL's recovery of any costs associated with assets with unrecovered net book value at the effective date of any termination or non-renewal of the ESA or Customer's breach of the ESA or Related Agreements." [*Id.*].

The settlement also establishes how that future stranded asset question will be presented. Within 30 days of receiving a notice of non-renewal or early termination, ELL must notify the Commission. [*Id.*, § IV.D.5]. Within six months, ELL must file a transition plan that addresses three things: the retention or disposition of the Proposed Generators and Proposed Transmission Facilities; "proposals to mitigate customer rate impacts from any assets with unrecovered net book value"; and the continued use or monetization of those assets and "any proposed ratemaking treatments." [*Id.*, § IV.D.6]. The settlement does not presume that recovery will be allowed. If ELL proposes to keep recovering the costs of those assets, it "shall demonstrate why continued recovery is reasonable under the facts then existing and applicable law and regulations." [*Id.*]. These provisions implement Mr. Sisung's recommendations that certification not be read as "predetermining the future ratemaking treatment of any stranded assets" and that ELL file a transition plan upon notice of non-renewal. [Sisung Direct at 134-35, 155].

Although stranded cost responsibility is not at issue in this proceeding, Large Load Guideline #4 still asks whether ELL has reasonably protected existing customers against the risk that they could be left paying for stranded assets or other unrecovered costs. As explained below, ELL has done so through (a) the Minimum Monthly Charges, which also address partial reductions in the Customer's load; (b) depreciable lives that align the recovery of asset costs with the contract term and expected use of each asset; (c) early termination and liquidation provisions; and (d) a layered financial assurance package. Mr. Sisung concluded that ELL's protections against both early termination and non-renewal are sufficient to satisfy the intent of the Large Load Guidelines. [Sisung Direct at 131, 134].

a. Minimum Monthly Charges

The ESA requires the Customer to pay Minimum Monthly Charges. Those MMCs are fixed **minimum** payments that the Customer owes under Rider 1 to the ESA. They are one of

the main ways that ELL recovers the cost of the resources built to serve Project Evest. The Customer owes MMCs regardless of whether it uses the power. Importantly, the MMCs are the minimum charges that are assessed to the customer; if the Customer's usage causes its calculated monthly charge to exceed the MMCs under the Large Load High Load Factor Power Service Rate Schedule ("LLHLFPS-L"), the Customer is required to pay that higher amount. As a result, the cost of Project Evest falls on the Customer rather than on ELL's non-Evest customers during the ESA's term.

ELL witness Mr. Jones testifies regarding the significant protections that the MMCs provide to current ELL customers. He explains:

> [T]he MMCs are a necessary customer protection to shield other customers from unreasonable cost shifts or burdens associated with the investments proposed in connection with extending service to Project Evest. They are designed to ensure there is a minimum level of revenue from the Customer to offset the cost of the incremental system resources necessary to serve the Customer regardless of the Customer's actual demand and energy usage. . . . [T]he MMCs also serve to support the Company's financial health during the construction of the Generation Assets and ELL-Funded Transmission Project by providing operational cash flow. Thus, the MMCs protect other customers from bearing either the direct incremental cost to serve Customer or any indirect costs associated with potential adverse credit actions.

[Jones Direct at 20].

Mr. Sisung reviewed the MMC schedule and found that, in the aggregate, the projected MMCs approximately equal the projected revenue requirements of the assigned resources over the term of the ESA. [Sisung Direct at 86]. He also modeled a worst case scenario in which the Customer takes only enough service to stay at its MMCs for the entire term. [*Id.* at 151]. Even under that scenario, existing customers realize a positive Total Customer Impact ("TCI") of $1.46 billion on a net present value ("NPV") basis, and $479.9 million in the corresponding case that assumes the Customer leaves at the end of the Original Term and existing

customers bear the entire residual net book value of the assets with no offsetting value. [*Id.* at 152]. The MMCs, therefore, also answer the Guideline's concern with partial reductions in the Customer's load: if the Customer's usage declines, its payment obligation cannot fall below the MMC floor, and existing customers still benefit. [*Id.* at 151-52].

The MMCs are an important customer protection mechanism relevant to Large Load Guideline #4 but are also relevant to Large Load Guideline #5, which relates to rate design and cost recovery. As a result, the mechanics and operation of the MMCs will be discussed in more detail below under Large Load Guideline #5.

b. Accelerated depreciation and alignment of asset lives with the contract term.

A second customer protection provided by the ESA contract is the accelerated depreciation of the four Richland Parish Proposed Generators. For those four units, the Customer has agreed to a 20-year accelerated depreciation schedule that will result in those four units being depreciated by approximately 90% over the 20-year Original Term of the ESA. [Jones Direct at 16; Beauchamp Rebuttal at 10]. The accelerated depreciation expense of the four Richland Parish Proposed Generators will be paid for by the Customer and incorporated into the MMCs, thereby obligating the Customer to pay for 90% of the original cost of those generators by the end of the Original Term of the ESA. [Sisung Direct at 132]. Those payments for accelerated depreciation help protect customers by mitigating the "risk that the Richland Parish units will have limited use after the Original Term of the ESA expires." [Beauchamp Rebuttal at 10-11].

The Stipulated Settlement authorizes a 20-year depreciable life for the four Richland Parish Proposed Generators and all three Battery Storage Facilities, and a thirty-two-year depreciable life for the three Pointe Coupee Proposed Generators. [Stipulated Settlement § I.B.7]. The difference reflects the location and expected use of each set of units. The Richland Parish

Proposed Generators are located in a region that is more isolated from significant non-Customer load, so their costs are recovered from the Customer on an accelerated schedule. [Beauchamp Rebuttal at 10 & n.17]. The Pointe Coupee units, by contrast, are located in SELPA, closer to areas of traditional load growth and high-load industrial customers, and ELL anticipates that they "will have significant independent value and usefulness even in the absence of the Customer." [*Id.*]. Mr. Sisung agreed that the record supports depreciating the Pointe Coupee Proposed Generators over thirty-two years, "the actual projected life of the assets and current depreciation rate used by ELL for generation," and he recommended that the Commission approve both depreciable lives. [Sisung Direct at 165, 180].

The WFC to St. Landry 500 kV line is expected to have substantial remaining service life when the Original Term expires. [Sisung Direct at 133]. Unlike assets that benefit only a single customer, however, the line is expected to provide benefits extending well beyond Project Evest, including improved system reliability and resilience, increased transmission capability, and the ability to facilitate future generation interconnections. [*Id.*; Kline Direct at 21-24]. The line's full annual revenue requirement is included in the MMCs for the entire Original Term, so the Customer covers its cost during that term regardless of how the Evest load operates. [Sisung Direct at 148-49]. Even if the Customer does not renew the ESA at the end of the Original Term, ELL estimates that other customers will bear only the final 16% of the line's cost on a net present value basis, even though approximately 54% of the line's 36-year useful life will remain. [Kline Direct at 33-34].

c. Early termination protections and liquidation procedures.

ELL has contracted with the Customer to provide significant protections to current customers in the case of an early termination. The Customer Agreements set up two separate early-termination tracks. The CIAC Agreement controls before service starts, and the ESA (mainly

Rider 1) controls after service starts. Each track has its own liquidation process but both rest on the same idea: ELL gets first choice of which resources to keep, the rest are sold, and the Customer pays whatever costs remain unrecovered.

If the CIAC Agreement is terminated for default or before the Service Commencement Date, Section 8 of the CIAC Agreement controls the termination and liquidation procedures. Pursuant to that section, ongoing work on Project Evest must stop as soon as practicable in the event of a termination or default before service to the Customer commences. [Beauchamp Direct at 28]. ELL then must use commercially reasonable efforts to liquidate material components of assets under construction and any batteries it does not keep. [*Id.*]. The Customer and ELL then perform a termination accounting of final costs and the Customer pays "Liquidation Proceeds." [*Id.*]. The payment formula is: final costs, minus the Customer's prior payments, plus Other Unrecouped Costs, minus net proceeds from the liquidation. [*Id.* at 29]. The effect is that the Customer pays the construction costs of the generators and of any batteries ELL does not keep, after crediting sale proceeds. [*Id.*]. Mr. Sisung summarizes the termination and liquidation procedures under the CIAC Agreement as follows: "ELL calculates the remaining construction costs, credits the Customer for [redacted], and requires the Customer to reimburse the remaining balance, including applicable Other Unrecouped Costs." [Sisung Direct at 116].

In the event of a termination or default after the Service Commencement Date, Rider 1 of the ESA controls the liquidation procedures. Under Rider 1, a covered termination event triggers the liquidation process. Pursuant to that process, ELL first chooses which Proposed Generators it wants to keep as "Retained Generators," and the rest are liquidated. [Beauchamp Direct at 30]. ELL's first choice is meant to let it capture generators useful to its other customers

while making sure those customers "do not have to bear the expense associated with any surplus generators for which ELL has not identified a then current or future need." [*Id.* at 88-89]. Retained Generator status requires Commission approval. [Sisung Cross-Answering at 49]. If approval is not obtained, the unit becomes a Liquidated Generator. [*Id.*]. Mr. Sisung describes the outcome of the liquidation procedure as follows: "[D]epending on the applicable agreement and the circumstances giving rise to the termination, [the Customer's] obligations may include unrecovered construction costs, the net book value of certain in-service assets, Other Unrecouped Costs, [redacted] and various other contractual payments." [Sisung Direct at 121].

The protections afforded to customers through the early termination provisions and liquidation procedures are consistent with Large Load Guideline #4. These provisions "provide substantial protection against the financial consequences of an early termination" and serve the public interest. [*Id.* at 118].

d. Financial security protections.

In addition to the protections described above, ELL negotiated with the Customer to obtain a financial assurance package with multiple security mechanisms that provide the Company and its non-Evest customers additional protections against potential nonpayment by Evest and/or its parent company Meta. Those security mechanisms include a Buyer's Guaranty with a downgrade matrix, [redacted], and credit default security.

Because Evest had no standalone credit rating, ELL gave the Customer no credit value in its credit analysis. It instead required a layered financial assurance package backing the Customer's contractual obligations. [Sisung Direct at 118-20]. The first and largest layer is a guaranty from Meta Platforms, Inc., which places "a financially strong entity behind the Customer's contractual obligations." [Sisung Direct at 123; Exhibit LKB-2 at 44-48, 93 (ESA

Rider 1, § 7(D) and Appendix E); Exhibit LKB-3 at 34-36 (CIAC Agreement § 5)]. Meta is rated AA- by S&P and Aa3 by Moody's, which ELL witness Hinkson describes as high investment grade. [Hinkson Direct at 8]. Less than 4% of U.S. companies hold a rating in that category. [Hinkson Rebuttal at 7].

The Buyer's Guaranty is not open-ended. It follows a Guaranty Schedule, is subject to a Guaranty Cap, and may be adjusted under procedures in the Customer Agreements. [Sisung Direct at 121-22]. The ESA Guaranty rises while the Proposed Generators are built and placed in service. It then declines as net book value falls and as the three Pointe Coupee units drop out of the calculation after Years 5, 7, and 9. [Sisung Direct at 127-28]. Payment is due within ten days of ELL's written demand. [Hinkson Rebuttal at 5].

The Customer Agreements also address the risk that Meta's credit could weaken over the 20-year term. Under the Downgrade Matrix, the Customer must post additional cash or letters of credit if Meta's rating declines. The amount equals the applicable percentage reduction in the Guaranty's value multiplied by the then-current Guaranty amount. Below a specified rating, Meta must replace a portion of the Guaranty with cash or a letter of credit. [Sisung Direct at 123-24; Exhibit LKB-2 at 46-47 (ESA Rider 1, § 7(D)(b)); Exhibit LKB-3 at 35-36 (CIAC Agreement § 5(d))]. Any letter-of-credit issuer must carry at least an A- rating and hold $10 billion in assets. [Hinkson Direct at 15-16]. According to Mr. Hinkson, the first posting trigger is calibrated to require "substantial liquid collateral well before Meta's credit would approach speculative grade." [Hinkson Rebuttal at 7-8]. In short, the Buyer's Guaranty draws its strength from Meta's present financial position, and the Downgrade Matrix "is intended to preserve the value of the protection if that financial strength deteriorates." [Sisung Direct at 124].

The second layer of ELL's negotiated financial assurance package is [redacted]

A third layer of the package is Credit Default Security. Mr. Hinkson explains that it is designed "to supplement and backstop the Buyer's Guaranty for the overall exposure associated with the Customer." [Sisung Direct at 125 (citing Hinkson Direct at 13)]. Credit insurance is one form of Credit Default Security the Customer Agreements contemplate. Under it, a financially qualified insurer or other financial-services provider agrees to pay ELL if Evest and/or Meta fails to make a required payment. If the Customer fails to pay, ELL may pursue the Buyer's Guaranty. If Meta then fails to perform, ELL may make a claim on the Credit Default Security. This gives ELL an additional, independent source of recovery, and the insurer takes on the burden of pursuing Meta or Evest. [*Id.* (citing Hinkson Direct at 14-15)]. ELL sized the Credit Default Security to cover a target share of its projected exposure to the Customer, limited by the capacity of the available market. The annual amounts appear in Appendix E to Rider 1 and decline

as ELL's projected exposure declines. [Sisung Direct at 128; Exhibit LKB-002 at 93 (Rider 1, Appendix E)].

The cost of the Credit Default Security is included in the Minimum Monthly Charges, so the Customer, not existing ratepayers, pays for it. [Sisung Direct at 85]. Mr. Hinkson testifies that the instrument is "among the largest instruments of its kind." [Hinkson Rebuttal at 9]. The market currently offers policy terms of three to five years, and ELL plans to keep coverage in place for the full term of the Customer Agreements, either by extending it or by obtaining alternative products. [*Id.*]. Staff witness Sisung acknowledged that Credit Default Security "does not . . . eliminate all counterparty or collectability risk." [Sisung Direct at 125]. He nevertheless concluded that the package as a whole reflects a good-faith effort that is "sufficient to satisfy the intent of the Commission's Large Load Guidelines requiring the Company to reasonably protect its existing customers against the risk of stranded investment." [Sisung Direct at 125, 131].

5. Large Load Guideline #5 – Rate Design & Cost Recovery

The Commission's fifth non-binding Large Load Guideline is especially important because it asks whether the rates and other financial terms applicable to the load (1) "Recover the full incremental revenue requirement of all generation and transmission and ancillary assets needed to serve the load"; (2) "[a]void cross-subsidization by existing customers"; and (3) "[e]nsure that other customers will not be impacted from an early termination." [Staff Ex. 19 at 2]. Mr. Sisung thoroughly reviewed ELL's proposed ratemaking treatment and determined that ELL satisfied Large Load Guideline #5. Multiple components of ELL's proposed recovery of the incremental costs of Project Evest contribute to a just and reasonable ratemaking paradigm. The first two elements of the Guideline are addressed in subsections (a) through (e) below. The third element, protection against early termination, is addressed principally under Large Load Guideline #4 above.

a. Contribution in Aid of Construction Agreements.

ELL and Evest have entered into an agreement, known as the CIAC Agreement, that provides direct cash funding from Evest for certain costs of Project Evest. Included among the costs that are funded through the CIAC agreement are: (1) the new West Fork Creek 500/230 kV interconnection substation; (2) nine new auxiliary 230 kV switching stations; (3) 20-30 miles of 230 kV transmission lines; and (4) the Louisiana portion of the Smalling-El Dorado 500 kV transmission line. [Kidd Direct at 5]. The CIAC Agreement requires Evest to offset 100% of the cost of those projects so that each one carries a zero plant-in-service balance. Evest pays to ELL the cost of the projects covered by the CIAC Agreement in advance of ELL incurring the construction costs based on estimates of those costs. [*Id.* at 5]. As a result, the actual costs of the projects covered by the CIAC Agreement are trued up after the actual costs become known. [Dumas Direct at 9]. Evest ultimately pays any shortfall and ELL refunds any excess once all project costs are determined. [*Id.*].

The CIAC Agreement is an important component of the overall rate design and cost recovery mechanisms included in the ESA. Because that agreement requires Evest to fund the construction costs of those projects in advance, subject to true-up, non-Evest ELL customers are protected from the construction-cost risk of those projects. As observed by Mr. Sisung, the CIAC Agreement also "requires a final termination accounting under which the Customer remains responsible for costs incurred to construct the Proposed Generators and non-retained Battery Storage Facilities," in the event of a termination of the ESA before the commercial operation date of the applicable facilities. [Sisung Direct at 83-84]. The CIAC Agreement, therefore, is a "critical component of ELL's overall cost recovery framework." [*Id.* at 84].

b. Rate Design, Minimum Monthly Charges, and Average Demand.

The overall structure of the rate that Evest will pay for service utilizes multiple mechanisms that operate together to protect non-Evest customers from subsidizing the costs of serving Evest. As mentioned previously, in addition to Evest's commitments under the CIAC Agreement, Evest will take service from ELL pursuant to the LLHLFPS-L rate schedule with contractual Minimum Monthly Charges designed to recover the projected incremental revenue requirements of the resources assigned to Evest; in the aggregate, the projected MMCs approximately equal those revenue requirements over the term of the ESA. [Sisung Direct at 85-86]. The rate structure involves two primary features: (1) MMCs; and (2) a contractual Average Demand billing determinate.

The MMCs were previously discussed above under Large Load Guideline #4. To briefly summarize, MMCs are the Minimum Monthly Charge that Evest will be obligated to pay regardless of its usage. [Sisung Direct at 85]. Mr. Sisung explained that the MMCs "were established to recover the projected revenue requirements associated with (i) ELL's assignment to Evest of the seven Proposed Generators, the Battery Storage Facilities, the Waterford 3 uprate, the West Fork Creek–St. Landry transmission facilities, and the Bayou Cove PCA; (ii) other incremental operation and maintenance expenses; and (iii) the Credit Default Security." [*Id.*].

The MMCs operate as a backstop to the charges that Evest owes pursuant to the LLHLFPS-L rate schedule. Pursuant to the ESA, ELL will calculate the monthly charges owed by Evest pursuant to that rate schedule, compare that amount to the MMCs, and require Evest to pay the higher of those two amounts each billing cycle. As a result, at worst, Evest is obligated to pay MMCs that, in the aggregate, approximately equal the projected incremental revenue requirements associated with serving Project Evest. [Sisung Direct at 85-86]. But if the charges

calculated pursuant to the LLHLFPS-L rate schedule exceed the MMCs, Evest is required to pay that higher amount and will contribute more than the cost of the incremental revenue requirement necessary to serve it to ELL's overall cost of service, thus reducing the cost responsibility of other customers.

The LLHLFPS-L rate schedule is a tariff used for high load and load factor customers to take service from ELL. Most of the charges under that tariff come from a four-tier demand formula, which is determined in large part by the Customer's "Average Demand." [Jones Direct at 22]. The Average Demand is a billing determinant included in the LLHLFPS-L rate schedule that is ordinarily determined by the customer's Maximum Demand over the prior 12 months. However, a new customer with no billing history, such as Evest, has its Average Demand set by contract. [Sisung Direct at 86]. Mr. Sisung explains that "the Average Demand serves as the contractual billing determinant used to identify the applicable pricing tier and to calculate the revenues to be produced under the tariff based on the Customer's usage." [*Id.* at 86-87].

Importantly, the contractual Average Demand billing determinant is separate and distinct from the Customer's MMCs. Mr. Jones testified that "ELL and Customer have agreed to establish the Average Demand at a value sufficient to cover the estimated cost of the incremental capacity necessary to serve Project Evest plus a reasonable contribution to embedded FRP costs in excess of the estimated incremental revenue requirements." [Jones Direct at 22]. In other words, ELL and Evest agreed to an Average Demand billing determinant, which is included in the ESA, that is estimated to result in revenues greater than what would be received by ELL if only the MMCs were paid by Evest each month. Mr. Jones explained that "excess revenue above the revenue requirement of the incremental resources serves as a contribution to embedded costs, reducing the rates other ELL customers pay, all else equal." [*Id.* at 23].

The MMCs and contractual Average Demand billing determinant work together to prevent non-Evest ELL customers from subsidizing the costs of the Evest Project. The result is that Evest will likely contribute more revenues to ELL than the estimated cost of the incremental capacity necessary to serve Project Evest, thereby providing significant benefits to non-Evest customers that help prove that Large Load Guideline #5 has been satisfied.

The MMCs and the Average Demand are also subject to true-up. The Billing Terms are updated immediately before the Service Commencement Date and then recalculated after construction is complete, using the actual, prudently incurred costs of the Newly Constructed Assets. [Sisung Direct at 87-90]. Both billing determinants are adjusted together so that the negotiated relationship between the minimum revenue floor and the expected contribution to embedded FRP costs is preserved. [*Id.* at 90-91]. The true-up keeps the risk of construction cost changes with the Customer rather than with existing non-Evest customers, and ELL has committed in the Stipulated Settlement to prudently manage the true-up of the MMCs. [Stipulated Settlement § IV.B.2].

Sierra Club witness Devi Glick contends that the MMCs fall short of the incremental revenue requirement by approximately $31 million. [Glick Direct at 18]. Even accepting that figure as true, it is only one component of a larger overall economic package and is small compared with the $1.46 billion NPV benefit that Mr. Sisung calculated under his MMC-only worst case, and any change in actual costs is captured by the true-up. [Sisung Direct at 87-88, 152].

c. Deferred Revenue Proposal

Another rate design concept that is included in ELL's application, and that further evidences satisfaction of Large Load Guideline #5, is ELL's deferred revenue proposal. The need for a deferred revenue plan arises from a timing mismatch built into the ESA's billing terms. The

MMCs that Evest is obligated to pay ramp up during construction and reduce as the newly constructed assets depreciate later in the ESA term. [Jones Direct at 19]. The ESA, however, takes effect before all of the Proposed Generators and the ELL-Funded Transmission Projects are in service. [Jones Direct at 28]. As a result, Evest's MMC payments begin "in an amount that is greater than the incremental costs being incurred by ELL at that time." [Jones Direct at 28–29]. The minimum demand used to set the MMCs during the ramp exceeds the demand ELL can reliably serve, so Evest pays for demand it cannot yet call upon. [Dumas Direct at 14].

ELL's projections show Evest's revenues exceeding the test-year revenue requirement in the first few years of the term and then generally falling below it as time progresses. [Jones Direct at 27]. The excess revenues above Evest's revenue requirement in those early years supply cash and credit support while ELL finances construction. [Kidd Direct at 19–20]. If those revenues were recognized in rates as received in the early years of the ESA, they would cause ELL to report over-earnings and sharply reduce rates. Rates would then rise significantly as each new asset entered service. [Jones Direct at 29]. The result would be "repeated rate shock for ELL's other customers." [*Id.* at 28].

ELL's Deferral Proposal Framework resolves this revenue timing mismatch. Pursuant to that plan, during the construction period, ELL will recognize in rates only the Customer revenue needed to offset the revenue requirement of the Newly Constructed Assets then in service. The remaining excess revenue would be recorded as a regulatory liability instead of immediately flowing through the FRP. [Sisung Direct at 92; Jones Direct at 30]. That liability would be excluded from rate base until all Proposed Generators are in service, and it would accrue carrying charges at ELL's weighted average cost of capital. [Jones Direct at 31]. The carrying charges preserve the time value of the deferred revenues so that, when recognized, they appropriately offset

the associated revenue requirements. [Dumas Direct at 15–16; Sisung Direct at 158]. After all the Proposed Generators are in service, the deferred revenues would be amortized in "an amount equal to the difference between the minimum monthly charges and the incremental revenue requirements pursuant to the Deferral Proposal Framework." [Dumas Direct at 16; Sisung Direct at 92].

ELL witness Mr. Jones testified that, with this deferral and amortization, adjusted revenues from Evest exceed the projected incremental costs in every period, so other customers are "effectively shielded from significant rate impacts." [Jones Direct at 31]. Mr. Sisung found that the rate design and deferral framework were "thoughtfully designed" to recover the incremental annual cost of serving Evest, to contribute meaningfully to embedded FRP costs, and to avoid significant year-to-year swings in rates. [Sisung Direct at 93]. Mr. Sisung recommended approval of the deferred revenue regulatory liability and its accounting treatment. [Sisung Direct at 179]. The Stipulated Settlement between ELL and the Staff adopts the framework, providing that ELL will defer as a liability the portion of Customer revenues received during the ramp period and account for them under the Deferral Proposal Framework. [Stipulated Settlement § III.C & Att. 2 ¶ 5]. The Stipulated Settlement also extends that framework to offset any net cost of uncovered capacity during the Customer's load ramp, as discussed under Large Load Guideline #9 below. [*Id.*, § III.E].

d. Storm and Resilience Riders.

ELL's Storm and Resilience Riders play an important role in determining whether the Company has sufficiently demonstrated that its rate design and cost recovery proposals satisfy Large Load Guideline #5. As a customer taking service under Rate Schedule LLHLFPS-L, Evest will pay an allocated share of applicable riders, including the Financed Storm Cost Riders and Resilience Riders. [Jones Direct at 4-5]. ELL's Financed Storm Cost Riders recover previously securitized storm costs net of the shared tax benefits that are included in the Storm Cost Offset.

[*Id.* at 23]. Mr. Jones estimates that Evest will contribute approximately $511 million towards those storm costs that other ELL customers would have had to pay without the Evest load and for storm damage that occurred before Meta decided to construct its data center in Louisiana. [*Id.*]. ELL's Resilience Rider ("Resilience Rider" or "Rider RPCR") recovers costs incurred by ELL to harden the transmission and distribution infrastructure to provide more resilience. [Sisung Direct at 95]. Mr. Jones estimates that the Customer will contribute approximately $184 million towards the Company's current Resilience Program costs. [Jones Direct at 24].

For the Resilience Rider, Evest will generally be subject to charges in the same manner as other similarly situated retail customers, except that the Resilience Rider will not apply to Evest during billing periods where Evest pays the MMC instead of the amount that results from the Rate Schedule LLHLFPS-L tariff calculation. [Sisung Direct at 96; Exhibit RLS-010 at 1 ("[T]he [Resilience] Rider is excluded from contract minimums.")]. Unlike the Resilience Rider, ELL's Financed Storm Cost Riders will apply regardless of whether the Customer pays the MMC or it pays the cost that results from application of Rate Schedule LLHLFPS-L. [Sisung Direct at 96; Exhibit RLS-010 at 1]. As Mr. Sisung explains, "the applicable MMC serves as the billing determinant on which the Storm Riders charge is calculated" during the periods that the Customer only pays the MMC. [Sisung Direct at 96].

Despite recognizing that ELL revenues received from Evest pursuant to the Storm and Resilience Riders provide an additional benefit to ELL's other customers, Mr. Sisung expressed some concerns regarding their application to the Customer. Most significantly, for the Resilience Rider, Mr. Sisung testified that ELL's proposed ratemaking treatment of Evest's revenue could result in ELL over-collecting an amount that should otherwise be applied to the capital improvements that the Resilience Rider was intended to facilitate. [Sisung Direct at 97].

The Resilience Rider is intended to recover the Resilience Plan revenue requirement as a percentage surcharge on base rate bills. As a simplified explanation of the mechanics of the Resilience Rider, ELL divides the resilience revenue requirement by Applicable Base Revenues taken from its most recent FRP filing, which gives a percentage factor. [*See* Sisung Direct at 98]. Each customer pays that percentage of its own base revenue.

The proposed FRP treatment of Evest's revenue, however, results in an overcollection of Resilience Rider revenues that ELL would keep if not corrected. Mr. Sisung explains how this overcollection occurs:

> [I]f Evest's revenue is treated as a revenue offset to the retail revenue requirement, as ELL proposes for the FRP, then that revenue will not appear as Applicable Base Revenue for the LLHLFPS-L class in the FRP filing that supplies the Resilience Rider's denominator. Yet Evest, taking service under Rate Schedule LLHLFPS-L, will still be billed the Resilience Rider on its actual base-rate revenue (when it is billed on actual usage: rather than on its MMC). The result in that situation is that Evest is charged the rider on revenue that was never, and never will be, included in the base against which the rider factor is set. ELL therefore would collect more than the Resilience Plan revenue requirement.

[Sisung Direct at 99-100].

In rebuttal testimony, Mr. Jones acknowledged Mr. Sisung's concern, stating that "Mr. Sisung has identified a legitimate potential over-collection issue that must be addressed with respect to both Evest and Laidley . . . to which these concerns equally apply." [Jones Rebuttal at 16]. Mr. Jones largely adopted a remedy proposed by Mr. Sisung to resolve the issue, whereby Evest and Laidley are excluded from the Applicable Base Revenues that form the denominator of the RPCR billing factors, and the actual revenues collected from those customers are credited as an offset to future revenue requirements. [*Id.* at 20]. Mr. Jones refined the remedy by proposing that the actual Evest revenues be credited in the subsequent rider update filing against the Distribution Revenue Requirement and the Transmission Revenue Requirement on an 80/20 split,

so that transmission-voltage and distribution-voltage customers alike see the same percentage reduction in their Resilience Rider charges. [*Id.*]. He testified that the 80/20 split results in all customers experiencing approximately the same 20% reduction in their aggregate Resilience and Securitized Storm Rider charges, consistent with Mr. Sisung's objective that the benefits to each rate class be proportionate to the risk it bears within the FRP. [*Id.* at 25].

Mr. Jones also testified that the remedy does not treat Evest or Laidley differently from other customers because both will pay the same rider factors as all other customers in their rate class, and only the manner in which those revenues are credited for the benefit of other customers changes. [*Id.* at 24]. He stated that the remedy would not change any previously approved allocation or impose additional cost on transmission customers. [*Id.* at 18]. Mr. Jones also urged the Commission to resolve the issue in this proceeding because the Resilience Rider over-collections will materialize in the near term for Laidley. [*Id.* at 19–20].

The Stipulated Settlement adopts the remedy proposed by Mr. Sisung and Mr. Jones. Section III.F of the Term Sheet requires ELL, in calculating the Resilience Rider billing factors, to exclude Evest and Laidley revenues from Applicable Base Revenues to the extent those revenues are not already excluded under the Deferral Proposal Framework. [Stipulated Settlement § III.F]. Any proceeds from the Customer under Rider RPCR are recorded to a regulatory liability and credited back to all customers in the next RPCR update as an annualized reduction to the revenue requirement, amortized over the subsequent rate effective period, with 20% offsetting the Transmission Revenue Requirement and 80% offsetting the Distribution Revenue Requirement. [*Id.*]. The result is that Evest's rider payments, which otherwise would have been collected on top of a fully recovered Resilience Plan revenue requirement and retained by ELL, are returned to ratepayers through lower rider factors.

The Customer's contributions to the Storm and Resilience Riders are a significant benefit to current, non-Evest customers of ELL. Although Mr. Sisung identified problems with the ratemaking concerning those riders, the Stipulated Settlement resolves those concerns in a just and reasonable manner.

The Stipulated Settlement also addresses how these benefits are distributed among customer classes, which bears on Contested Issue "m." Mr. Sisung recommended that ELL address the riders and allocators affected by Project Evest so that they "equitably allocate costs and benefits among customer classes." [Sisung Direct at 178]. Under the 80/20 crediting adopted in Section III.F of the Stipulated Settlement, transmission-voltage and distribution-voltage customers receive approximately the same percentage reduction in their Resilience and Storm Rider charges. [Jones Rebuttal at 20, 25; Stipulated Settlement § III.F]. Customer revenues credited through the FRP and the FAC likewise reduce rates for all customer classes.

e. Total Customer Impact

ELL witness Mr. Datta provides a Total Customer Impact ("TCI") economic analysis that measures "the costs and benefits to other ELL customers of the generation and transmission resources needed to serve Project Evest, net of the Customer's contributions to the costs of those resources during the initial 20-year term" of the ESA. [Datta Direct at 3]. The analysis does not simply compare revenue requirements; it incorporates an AURORA production-cost model that simulates security-constrained unit commitment and economic dispatch to quantify the effect of the Customer's load, the Proposed Resources, and the Proposed Transmission Projects on ELL's wholesale variable supply costs over the full Original Term of the ESA. [Sisung Direct at 77–78].

Mr. Datta's TCI analysis accounts for the increased fuel costs imposed on the system by serving Evest together with the Customer's corresponding fuel-related contributions.

[Sisung Direct at 79]. It quantifies any change in ELL's capacity position, including shortfalls during the ramp period, using the levelized cost of a combustion turbine. [*Id.* at 61, 64, 79]. The analysis includes the full annual revenue requirement of the ELL-Funded Transmission Projects for the entire duration of the ESA. [*Id.* at 148–149]. Mr. Datta's study also reflects the deferred Customer revenue stream as it will actually be realized in rates rather than as-billed amounts. [*Id.* at 139].

The TCI analysis credits the Customer's contributions under the Storm and Resilience Riders for the applicable periods. [*Id.* at 96–97]. Mr. Datta incorporates the $13 million per year commitments to The Power to Care and to energy efficiency and weatherization programs (the Customer's $10 million plus a $3 million ELL shareholder match), which contribute approximately $132 million to the TCI on an NPV basis. [*Id.* at 149]. To provide a conservative estimate of benefits, Mr. Datta excluded potential pipeline-transportation synergies and the unquantified reliability and resilience benefits of the West Fork Creek to St. Landry 500 kV line and St. Landry Switching Station. [*Id.* at 79–80].

Based on these inputs, Mr. Datta calculated a positive TCI of $3.94 billion on a nominal basis and approximately $1.96 billion on an NPV basis over the course of the 20-year Original Term of the ESA. [Datta Direct at 28-29; Sisung Direct at 137]. Mr. Datta also evaluated a non-renewal scenario in which the Customer discontinues service at the end of the ESA term in 2048 and ELL's other customers are assigned the entire residual net book value of the Proposed Generators, Battery Storage Facilities, and ELL-Funded Transmission—approximately $976.6 million on an NPV basis—as a cost, with no credit for continued operation, resale, or service to other load. [Datta Direct at 30-33; Sisung Direct at 144–145]. Even under that deliberately conservative treatment, the TCI remains positive at approximately $991 million, leading Mr. Datta

to conclude that "even in this conservative scenario, ELL's other customers are expected to benefit substantially from the Customer's Project." [Datta Direct at 32; Datta Rebuttal at 22].

The TCI also shows that incremental fuel-deliverability costs will not be shifted to existing customers. ELL's production-cost modeling incorporates fuel-transportation costs and measures the full change in variable supply cost from serving the Customer, and the Customer's fuel and energy revenue exceeds that variable supply cost over the Original Term, so the Customer's fuel-related activity makes a net positive contribution to the TCI. [Sisung Direct at 78, 146-47].

Mr. Sisung independently reviewed the TCI and found that ELL had largely addressed the concerns he raised with the comparable analysis in the Laidley proceeding. [*Id.* at 138–139]. ELL priced the incremental resources at the projected cost of identifiable owned and purchased generation, incorporated the deferred Customer revenue stream, and captured the effect of the Evest load on variable supply costs recovered through the FAC, which increases the net benefit to other customers. [*Id.* at 139]. Mr. Sisung confirmed that the Customer's fuel-related activity makes a net positive contribution to the TCI rather than imposing a net cost [*Id.* at 146–147].

Mr. Sisung did make one adjustment to Mr. Datta's analysis. Although ELL properly reflected that its retail customers bear only approximately 87% of the transmission revenue requirement, with the remainder allocated to wholesale customers under the MISO OATT, ELL did not account for the offsetting effect of adding the Customer's load to the OATT billing determinant, which lowers the per-unit transmission rate and reduces wholesale transmission revenue. [*Id.* at 140]. Mr. Sisung estimated that effect at roughly $20 million to $28.5 million per year once the Customer is fully ramped, or approximately $197 million on an NPV basis, and

incorporated it into the TCI analysis. [*Id.* at 140–141]. He otherwise accepted Mr. Datta's analysis, which he reviewed and found reasonable. [*Id.* at 150-51].

To be thorough, rather than rely on a single estimate, Mr. Sisung evaluated three scenarios covering the plausible range of outcomes, and in every one ELL's non-Evest customers realize a substantial net benefit. [*Id.* at 150]. In his expected case—Mr. Datta's analysis with the OATT adjustment—Mr. Sisung determined that the TCI is approximately $1.77 billion on an NPV basis, and $789.5 million in the corresponding non-renewal case. [*Id.* at 150–151].

For his worst-case scenario, Mr. Sisung analyzed the TCI in the event the Customer takes only enough service to remain at its MMCs for the entire term. Mr. Sisung reduced base revenue to the MMCs, removed Resilience Rider revenue, recalculated Storm Rider revenue on the MMCs, and retained the full OATT loss and capacity dynamics as though the Customer were taking full load. [*Id.* at 151–152]. Even under those assumptions, the TCI remains positive at $1.46 billion on an NPV basis and $479.9 million in the corresponding non-renewal case. [*Id.* at 152].

Mr. Sisung also modeled a best-case scenario where the Customer continues taking service over the remaining commercial life of the generators, and its continuing base-rate payments more than offset the residual cost of the assets. He explained that he did not model that case in detail because "its direction and magnitude are not in doubt: continued service can only improve the outcome for ELL's other customers." [*Id.* at 152–153]. The TCI, as originally calculated by Mr. Datta or as determined under any of Mr. Sisung's scenarios, therefore confirms that the Evest rate design recovers the incremental cost of serving the Customer and avoids cross-subsidization by existing customers.

f. Early termination.

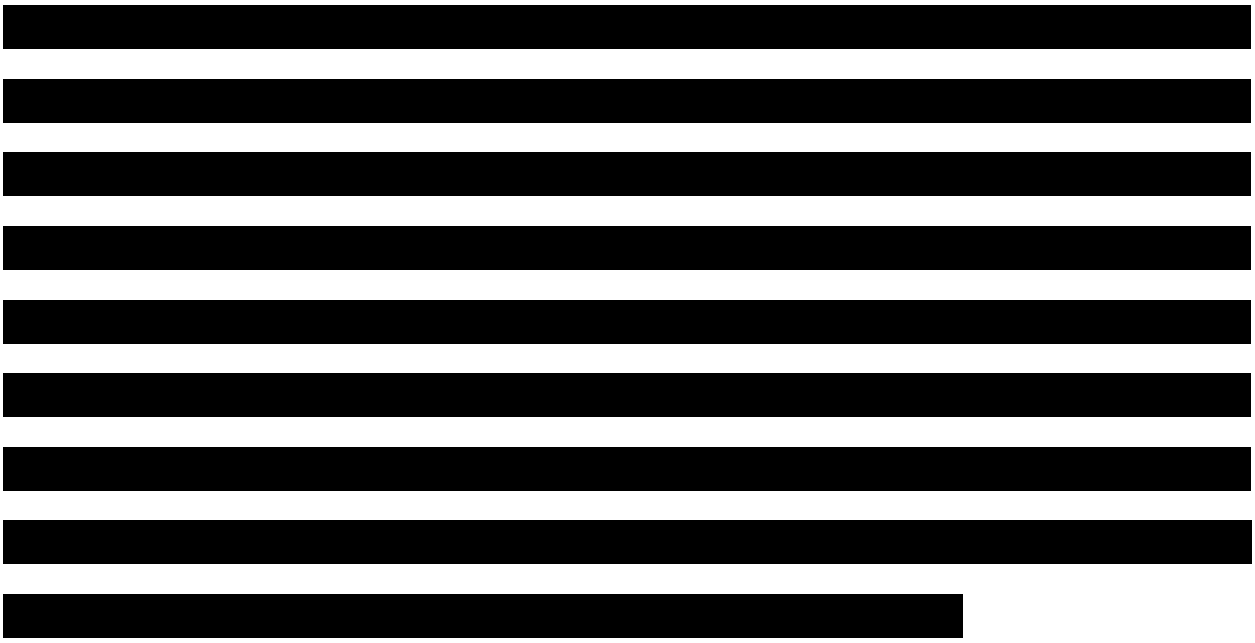
Finally, Large Load Guideline #5 asks whether other customers are protected from the effects of an early termination. [Staff Ex. 19 at 2]. As discussed under Large Load Guideline #4 above, the CIAC Agreement and Rider 1 to the ESA require the Customer to pay unrecovered construction costs, the net book value of in-service assets, Other Unrecouped Costs, and other contractual payments upon an early termination, and those obligations are backed by the Buyer's Guaranty and Credit Default Security, among other security mechanisms. [Sisung Direct at 83-84, 118, 121]. The Stipulated Settlement further requires ELL to file a transition plan within six months of a notice of early termination and to justify any proposed recovery of unrecovered net book value. [Stipulated Settlement § IV.D.6]. ELL has therefore satisfied each element of Large Load Guideline #5.

6. Large Load Guideline #6 – Operational Control & Curtailment

For Large Load Guideline #6, the Commission assesses whether the utility has retained sufficient operational control over the proposed large load to maintain the reliability of the electric system under both normal and emergency operating conditions. [Staff Ex. 19 at 3]. Specifically, the utility should demonstrate that (1) it retains sufficient operational control, including the right to curtail service when necessary to maintain system reliability; (2) any curtailment rights are clearly defined and contractually enforceable; (3) the priority of service during emergency conditions is clearly established; and (4) any compensation associated with curtailment is transparent and established in advance. [Sisung Direct at 66-67].

ELL has satisfied Large Load Guideline #6 for the Commissioning Period, and the Stipulated Settlement provides a binding mechanism to resolve the remaining items before the Customer takes full firm service. Appendix C to the Customer Agreements provides the ramp schedule for the Commissioning Period, including the firm and non-firm service obligations.

[Exhibit LKB-002 at 87-89 (Rider 1, Appendix C)]. That appendix shows [redacted]





[Datta Direct at 22].

ELL has also explained that the Company negotiated with the Customer to arrive at an amount of firm and non-firm load that the Customer was permitted to take service during the Commissioning Period "with the aim of maintaining the same level of reliability and supply adequacy as would have existed for the ELL system if the Customer load and resources proposed in connection with serving the Customer had not been connected to the system." [Exhibit RLS-006

at 2]. Considering ELL's discovery responses, testimony, and the Customer Agreements, Mr. Sisung concluded that ELL has developed a reasonable contractual framework for operational control during the Commissioning Period. [Sisung Direct at 67].

After the Commissioning Period, however, the full load of the Customer, approximately [redacted], will become firm. [*Id.*]. For that period, Mr. Sisung testified that the information that ELL provided was "incomplete." [*Id.* at 68]. He found that ELL had not demonstrated how the Company was to balance the firm load requirements that the Customer agreed to pay for and the benefits it should receive as a firm customer with the need for the Customer to be subject to emergency operating procedures in a fair, reasonable, and non-discriminatory manner consistent like other firm customers. [*Id.* at 67-68]. In response to Staff discovery, ELL explained that it had "not yet designated whether Project Evest load would be treated as (i) a single, non-divisible load block or (ii) a load capable of curtailment in discrete increments during a MISO directed load shed or Max Gen event. [Exhibit RLS-005 at 96 (ELL Response to Staff 1-132)].

As a result of the incomplete information provided by ELL, Mr. Sisung recommended that the Commission condition approval of ELL's application on a requirement that ELL "develop and submit, sufficiently in advance of the commencement of full firm service, a detailed operational control and emergency load shed plan for Commission review and approval." [Sisung Direct at 69]. He suggested that the plan explain: (1) how Project Evest will be included in ELL's emergency operating procedures; (2) whether and how the Project Evest load would be curtailable in increments, including the sequence of those curtailments; (3) how those curtailments would be communicated; (4) any limitations that could affect ELL's operational control of the Customer's load; and (5) "how those procedures will be implemented in a manner that preserves

the Customer's rights as a firm service customer while ensuring that emergency operating measures are applied in a fair, reasonable, and non-discriminatory manner consistent with other customers." [*Id.*].

Mr. Sisung's recommended condition is addressed in the Stipulated Settlement. Section IV.D.1 requires ELL to provide to the Commission, Commission Staff, and its delegates, "ahead of commencement of full firm service to the Customer, a comprehensive operational control and emergency load shed plan governing the integration of Project Evest into ELL's emergency operations procedures." [Stipulated Settlement § IV.D.1]. The plan will remain confidential. [*Id.*]. Although Section IV.D.1 requires that the plan be provided to the Commission rather than submitted for approval, as Mr. Sisung had recommended, the Commission retains its full authority over ELL's management, implementation, and enforcement of the Customer Agreements. [Stipulated Settlement § IV.A.2].

7. Large Load Guideline #7 – Ancillary Services & Power Quality

For the seventh large load guideline, the Commission asks that the utility demonstrate that the large load's impacts on frequency regulation, voltage support, and power quality have been identified and mitigated. [Staff Ex. 19 at 3]. Mr. Sisung explains that this guideline was intended "to ensure that the proposed customer can be integrated into the utility's electrical system without adversely affecting the reliability or quality of electric service provided to other customers." [Sisung Direct at 69]. The Guideline contemplates evaluation of voltage stability, power quality, harmonic distortion, flicker, reactive power requirements, and frequency response, and whether appropriate technical standards, monitoring requirements, and mitigation measures have been identified. [*Id.* at 70]. ELL has satisfied Large Load Guideline #7.

ELL required the Customer to provide information regarding its voltage and frequency ride through settings in addition to anticipated oscillatory behavior. [JWH-2 at 5-6].

ELL incorporated this data into a dynamic model that evaluated angular and voltage stability for system disturbances when large load reductions would occur. [*Id.*]. With the proposed Mt. Olive–Cargas, El Dorado–Smalling, and WFC to St. Landry 500 kV projects included in the modeling, no stability constraints were observed. [*Id.*]. ELL also screened for rapid load oscillations, conservatively assuming that 70% of the facility's load oscillated and flagging any induced fluctuation exceeding 1% of a nearby generator's MVA rating. [*Id.*]. Using the Customer's updated oscillation data, the induced oscillations fell below that threshold, and electromagnetic transient studies confirmed that torque amplification at nearby generator shafts did not exceed 10%, presenting "no risk to nearby generator shaft integrity." [*Id.*].

Regarding power quality specifically, Mr. Kline testified that the new CCCTs add dynamic reactive power capability to the system, in addition to real power. [Kline Direct at 41]. He testified that "as quick-start and fast ramping resources, the new CCCTs will add synchronous inertial response and short-circuit capability to the system, both of which may be increasingly valuable ancillary service market assets as the MISO market more broadly sees an increased penetration of renewable resources and inverter-based resources." [*Id.*].

Further, Mr. Kline conducted analyses to assess voltage and system stability concerns related to Project Evest. [*Id.* at 47]. Steady-state analyses were performed for three different scenarios while monitoring voltage. A transient stability analysis was also performed with the proposed transmission upgrades and no additional constraints were identified. [*Id.*]. Mr. Kline concluded that his analyses and modeling showed that any concerns regarding system voltage constraints should be mitigated by the proposed transmission facilities. [*Id.* at 47-48].

The Customer also must comply with Institute of Electrical and Electronics Engineers ("IEEE") standards governing harmonics and flicker, and ELL's Terms and Conditions

and the ESA require the Customer to pay to resolve any issues caused by fluctuations in voltage or power demand on its system. [*Id.* at 48-49]. ELL is also installing power quality meters and phasor measurement units at each of the Customer's load-serving substations to provide visibility into any power quality issues that arise. [*Id.* at 49].

Mr. Sisung recognized that some dynamic-system interactions cannot be identified at this stage. [Sisung Direct at 72]. Describing Mr. Kline's testimony, he explained that torsional-stress issues, for example, "may be nearly impossible to detect in advance because of the detailed information necessary to accurately model the effects of system changes and that such issues are generally identified through system operation and then corrected." [*Id.*].

Mr. Sisung concluded that ELL's inability to fully analyze every potential dynamic interaction does not render ELL's application deficient as to Large Load Guideline #7. [Sisung Direct at 72-73]. Mr. Sisung found that Mr. Kline's team considered all relevant information that was currently available and performed comprehensive and methodical analyses using conservative assumptions where appropriate. [*Id.* at 72-73]. He concluded that the ESA's measurable standards, correction obligations, implementation deadlines, and assignment of mitigation costs to the Customer provide a reasonable framework for issues that can be identified only after the Customer's equipment is energized. [*Id.* at 74-75].

The Stipulated Settlement provides for additional monitoring of power quality issues after the Proposed Generators go into service, including monitoring of issues that could not be fully studied at the current time. The Stipulated Settlement provides:

> B. ELL will install power quality monitoring equipment on the substations serving the Customer's Project. In the event the monitoring indicates any substantial power quality concerns, including the potential of torsional stress or violations of IEEE 2800, then . . . such issues will be investigated. To the extent material upgrades are required to resolve any noted substantial power quality

> issues solely as a result of the Customer's Project, . . . the costs of those upgrades shall not be included in the rates of customers other than the Customer.
>
> C. Starting on the last day of the calendar quarter of the one-year anniversary following installation of the power monitoring equipment, ELL will file annual reports in this docket that disclose any material power quality issues that are observed and any resulting remediation efforts. The Company's obligation to file such annual reports shall expire once three (3) consecutive years of full facility operation have occurred with no material power quality issues. As part of this power monitoring report, ELL will include SAIDI and SAIFI scores, both including and excluding major events, for the substations that are located within 50 geographical miles of the Customer's project.

[Stipulated Settlement, § V(B), (C)].

Intervenor witnesses Miller and Hoyle point to recent large-load disturbances and evolving NERC and MISO requirements and urge formal, ongoing processes for modeling, ride-through performance, and monitoring. [Miller Direct at 19-23; Hoyle Direct at 39-48]. Those concerns do not show a deficiency in ELL's showing requested under this Guideline. As Mr. Sisung explained, they reinforce the need for a continuing process, and the Commission need not resolve the cause or significance of every recent large-load event to conclude that Evest should be required to operate in a manner that does not impose unreasonable reliability risks on ELL or the broader transmission system. [Sisung Cross-Answering at 123-24]. The ESA obligations, the monitoring equipment, and Sections V.A through V.C of the Stipulated Settlement provide that continuing process.

ELL has sufficiently studied, modeled, and analyzed the large load's impacts on frequency regulation, voltage support, and power quality with no major concerns being identified. For those power quality issues that cannot be fully studied currently, ELL has committed to monitor, address, and mitigate those power quality issues after the in-service date of Project Evest. The costs of material transmission upgrades required as a result of the Customer's Project, and of

material upgrades required to resolve substantial power quality issues caused solely by the Customer's Project, will not be included in the rates of other customers. [Stipulated Settlement §§ V.A-B]. ELL has sufficiently demonstrated that Large Load Guideline #7 has been satisfied.

8. Large Load Guideline #8 – Fuel Supply & Infrastructure Risk.

For the eighth Large Load Guideline, the Commission requests that ELL demonstrate that fuel supply arrangements supporting the Evest Project are adequate under peak and contingency conditions and that risks related to fuel deliverability are not shifted to non-Evest customers. [Staff Ex. 19 at 3]. Large Load Guideline #8 also requires ELL to address any incremental costs related to fuel deliverability, such as pipeline upgrades, firm transport, or storage. [*Id.*]. Mr. Sisung summarizes this guideline as intending to "ensure that the utility has appropriately evaluated the reliability of the proposed fuel supply arrangements and that any risks or costs associated with providing that fuel are not improperly shifted to existing customers." [Sisung Direct at 53].

ELL's supply plan for the Proposed Generators is built around new long-term supply and firm transportation contracts that provide access to multiple upstream natural gas hubs. [Goin Direct at 8]. ELL does not depend on existing transportation capacity. [*Id.*]. Instead, it will obtain firm transportation sufficient to cover one hundred percent of the gas required for the maximum capability of all seven Proposed Generators, so that "there will be adequate supply for the Proposed Generators under peak and contingency conditions." [*Id.*]. ELL also showed that access to multiple upstream hubs, rather than receipts in a single constrained area, enhances reliability and lowers costs by creating supply optionality. [*Id.* at 12].

The record also establishes site-specific deliverability for both the Richland and Pointe Coupee generating locations. The Richland Parish Proposed Generators are within ten miles of five high-capacity, high-pressure backbone pipelines to which those generators can

interconnect and that can deliver gas at sufficient pressure without additional compressor infrastructure. [*Id.* at 9]. For Pointe Coupee Units 1–3, ELL acknowledged that existing infrastructure lacks open capacity and cannot meet the units' pressure requirements, and that a new pipeline would be required. [*Id.* at 11]. Since filing its direct testimony, ELL has entered into an agreement to develop a greenfield pipeline capable of serving those units, which will connect Southeast Louisiana to upstream supplies from the Gillis hub. [Goin Rebuttal at 2]. Because that infrastructure provides firm access to supply, the Pointe Coupee Proposed Generators and other Southeast Louisiana resources will remain able to operate during extreme weather and other stressed system conditions, one of several benefits that accrue to ELL customers as a result of the new pipeline. [*Id.* at 5].

As to the second element of the Guideline, that risks related to fuel deliverability are not shifted to non-Evest customers, the firm transportation arrangements are new and dedicated to the Proposed Generators rather than drawn from capacity serving ELL's existing fleet. [Goin Direct at 8]. These arrangements and the pipeline expansion they support may give non-Evest customers new opportunities to obtain firm service and reduce their own deliverability risk. [*Id.*].

Mr. Sisung independently reviewed this evidence and concluded that "ELL has adequately addressed the operational and planning requirements of this Large Load Guideline." [Sisung Direct at 53]. He found that, "other than cost considerations," ELL "has demonstrated that it evaluated the fuel supply and infrastructure necessary to support the Proposed Generators" and that the proposed arrangements "are intended to provide reliable natural gas service under both peak and contingency conditions." [*Id.* at 55].

Mr. Sisung also considered and rejected Mr. Hoyle's contention that greater fuel diversity is needed for reliability during natural gas supply constraints. [Sisung Cross-Answering

at 30-31]. While agreeing that fuel diversity can provide reliability value, Mr. Sisung explained that renewable generation and storage "present their own availability characteristics," and that Mr. Hoyle "does not identify a particular deficiency in those arrangements or demonstrate that a specific natural-gas supply or transportation contingency renders one or more of the proposed CCCTs unreliable." [*Id.*]. Similarly, although Ms. Glick and Mr. Hoyle raise legitimate concerns about increased reliance on natural gas, their testimony does not establish "a net fuel-related harm to existing customers that warrants rejection of the proposed resources." [*Id.* at 29].

Large Load Guideline #8 also requires ELL to address incremental costs related to fuel deliverability, such as pipeline upgrades, firm transport, or storage. [Staff Ex. 19 at 3]. That issue is significantly related to Large Load Guideline #5 regarding rate design and cost recovery and is addressed above in Section III.A.5.e.

9. Large Load Guideline #9 – Load Ramp Management.

To fully satisfy the Commission's Large Load Guidelines, a utility should demonstrate that it has appropriately coordinated the customer's load ramp with the resources needed to serve it. Pursuant to Large Load Guideline #9, ELL must show that its ramp schedule: (1) is coordinated with resource and transmission availability; (2) includes enforceable milestones; and (3) prevents interim reliability degradation. As recognized by Mr. Sisung, "it is not sufficient to demonstrate only that adequate resources will ultimately be available once the [customer] has ramped to its full load. Rather, the utility should also demonstrate that the proposed load additions will occur in a manner that remains consistent with the availability of those resources throughout the customer's ramp to full operation." [Sisung Direct at 59]. To fully analyze this guideline, the Commission must determine whether ELL has demonstrated that its load ramp can be implemented without degrading system reliability and whether the proposed load ramp results in any economic consequences to non-Evest customers.

ELL's Load and Capability Report ("LCR"), produced in discovery, shows that the Company's proposed ramp schedule presents a potential resource adequacy shortfall during certain periods of Evest's load ramp. ELL does not dispute the possible load ramp shortfall, and its own economic analysis assigns a cost for net capacity shortfalls during the ramp period. [*Id.* at 60-61]. ELL witness Mr. Datta explained that this shortfall will be mitigated, at least in part, with Evest's firm and non-firm commitments. [Datta Direct at 21-23; Sisung Direct at 61]. The amount of firm load that the Customer will be permitted during the ramp period "was negotiated with the Customer with the aim of maintaining the same level of reliability and supply adequacy as would have existed for the ELL system if the Customer load and resources proposed in connection with serving the Customer had not been connected to the system." [Exhibit RLS-006 at 2].

Mr. Sisung found that ELL's methodology for managing reliability during the ramp period was "a reasonable analytical approach." [Sisung Direct at 62]. Based on the information then available, however, he could not conclude that ELL had adequately addressed the reliability issue. [*Id.* at 60]. Mr. Sisung explained that Staff was not provided with the proprietary reliability models or modeling iterations underlying the firm and non-firm load schedules in Appendix C, so he could not independently validate them. [*Id.* at 62]. Additionally, Mr. Sisung recognized that ELL's load ramp analysis was dependent on assumptions regarding future events, such as the timely completion of the proposed generators, battery storage facilities, and transmission projects. [*Id.*]. Although there is no reason now to think that those resources will not be constructed, any material change to one of the resources could have a significant impact on ELL's ramp schedule. [*Id.* at 62-63]. Mr. Sisung pointed to the Iberville Parish moratorium on battery storage development as an example, and noted that although Rider 1 addresses delayed resources, he could

not identify a corresponding mechanism for a resource that is cancelled or permanently removed from the supply plan. [*Id.*].

Because of these concerns, Mr. Sisung recommended that the Commission condition its approval of ELL's application. He stated:

> [I]f the Commission grants the requested certifications, I recommend that the certifications be limited to the facilities requested in this proceeding and not be construed as approval of ELL's future operational decisions regarding implementation of the Customer Agreements or the Customer's Ramp Schedule. ELL should retain full responsibility for prudently administering those agreements and modifying the Customer's ramp schedule as changing resource availability, construction progress, system conditions, and reliability considerations may require.

[*Id.* at 63].

ELL's ramp, nonetheless, appears structured so that interim reliability is not degraded. During the Commissioning Period, the amount of firm service is tied to available firm capability, and additional Customer load is served only on a non-firm basis. [Sisung Cross-Answering at 36-37]. The ramp is also subject to enforceable milestones. Appendix C to the ESA is the operative ramp schedule, setting the total and non-firm load the Customer may take in each month of the ramp. [Sisung Direct at 46; Exhibit RLS-006]. Under the settlement, ELL must notify the Commission immediately when it is conclusively determined that a resource's commercial operation date will be extended and must report updated project milestones quarterly. [Stipulated Settlement § I.B.12, Att. 1 at 2].

Regarding the possible economic consequences of ELL's capacity shortfall during the ramp period, Mr. Sisung explains that ELL has acknowledged that possibility and has incorporated the potential costs of acquiring additional capacity resources during the ramp period into its economic analysis, including its TCI analysis. [Sisung Direct at 64; Exhibit SD-2]. ELL, therefore, has already considered the costs associated with a potential capacity shortfall during the

ramp period and the revenues from the Customer during that period, and concluded that the "long-term economic benefits associated with Project Evest substantially outweigh those interim costs." [Sisung Direct at 65].

Despite these long-term benefits, Mr. Sisung has concerns regarding the possibility of significant increases in capacity costs that may be absorbed by current customers in the near term. [*Id.*]. He therefore concluded that "ELL has not adequately demonstrated this issue" and recommended that, if the Commission chose to certify ELL's application, it should condition that certification on ELL developing a ratemaking mechanism to better align the costs associated with the likely ramp period capacity shortages with the benefits projected to be received once all of the new generators are in service. [*Id.*].

ELL responded to both aspects of Mr. Sisung's Large Load Guideline #9 analysis. On the reliability issue, ELL witness Samrat Datta testified that ELL's supply plan during the ramp period includes bridging resources, such as the Waterford 3 uprate, the Bayou Cove 2–4 Capacity Credit Purchase Agreement, the Big Cajun 2 Unit 3 PPAs, and the Battery Storage Facilities, which reduce customers' exposure to scarcity pricing during that time. [Datta Rebuttal at 24]. He further testified that his reliability analysis is distinct from the economic analysis that identifies near-term capacity deficits, and that it demonstrates that, notwithstanding those deficits, ELL will maintain the same level of reliability during the ramp as existed before the addition of the Evest load and resources. [*Id.* at 25].

On the economic issue, ELL witness Ryan Jones disagreed that ELL had failed to demonstrate adequate protections under Guideline #9, given the substantial net benefits expected regardless of annual variability in the net capacity position but acknowledged Mr. Sisung's concern about potential bill effects during the ramp period. [Jones Rebuttal at 14–15]. Mr. Datta

likewise agreed that Mr. Sisung had "reasonably identified the possibility that ELL may bear certain costs during that bridging period." [Datta Rebuttal at 25]. To address the concern, Mr. Jones proposed to modify the Deferral Proposal Framework addressed above under Large Load Guideline #5 to include the net cost, if any, of uncovered load ramp capacity before the last Proposed Generator enters service, and to amortize additional deferred Customer revenues to offset those costs in rates. [Jones Rebuttal at 15].

Under Mr. Jones's proposed resolution, ELL would calculate the net cost of uncovered load ramp capacity annually using the seasonal MISO Planning Resource Auction ("PRA") clearing price, Evest's planning reserve margin requirement (including projected load, transmission losses, and planning reserves), and the seasonal accredited capacity of the resources included in the MMCs. [*Id.*]. Based on the most recent PRA prices, ELL projects that 2030 is the only year with an Evest-specific net capacity deficit in every season, with approximately $30 million of uncovered load cost to be absorbed through the deferral mechanism rather than borne by other customers. [*Id.* at 15–16].

The Stipulated Settlement resolves the issues Mr. Sisung identified. Section III.E adopts ELL's proposed ratemaking mechanism. Until the last Proposed Generator is placed in service, the net cost of uncovered demand attributable to the Customer's load ramp, priced at the seasonal PRA clearing price against the seasonal accredited capacity of the resources included in the MMCs, is included in the Deferral Proposal Framework and offset by amortizing additional deferred Customer revenues. [Stipulated Settlement § III.E]. That provision implements Mr. Sisung's recommendation that ramp-period capacity costs be aligned with the benefits realized once all generation is in service, rather than imposed on existing customers in the near term. [Sisung Direct at 65]. The settlement also addresses Mr. Sisung's reliability and implementation

concerns. ELL commits to prudently manage implementation of the Customer's ramp schedule, considering changing construction schedules, resource availability, system conditions, and reliability requirements. [Stipulated Settlement § IV.B.5].

ELL also agreed that the Commission retains its full prudence authority over ELL's management of the ESA and Related Agreements and any decision to modify the Customer Supply Plan. [Stipulated Settlement § IV.A.2]. This provision closes the gap Mr. Sisung identified for cancelled resources. If material changes are made to the Customer Supply Plan, including the cancellation or replacement of a planned resource, ELL must make a filing that identifies the resource change, seeks certification of any new resource as required, identifies its cost, and demonstrates how that cost will be included in the Customer's minimum bills or otherwise allocated to the Customer, with a separate reporting requirement for changes to the Battery Storage Facilities. [Stipulated Settlement § IV.B.4]. ELL must also report any changes to the Customer Supply Plan, and their estimated rate impact, in both its Construction Monitoring Reports and its Customer Monitoring Reports. [*Id.*, Att. 1 at 5; Att. 4 at 3].

Together, these provisions keep the load ramp tied to enforceable milestones and resource availability, place responsibility for prudently administering the ramp on ELL subject to the Commission's full prudence authority, and prevent ramp-period capacity costs from being shifted to existing customers. Therefore, with the Stipulated Settlement, Large Load Guideline #9 is satisfied.

10. Large Load Guideline #10 – Market & Planning Impacts

The Commission's tenth Large Load Guideline states that the utility must demonstrate that the load's impact on the following have been evaluated: (1) resource adequacy obligations; (2) capacity markets (if applicable); (3) long-term system planning; and (4) impacts on energy markets and Fuel Adjustment Clause ("FAC") pricing. Mr. Sisung explains that the

purpose of this large load guideline is to "ensure that the proposed large load is appropriately incorporated into the utility's resource planning and market operations and that the addition of the load does not create unreasonable impacts on either the utility's planning processes or wholesale market participation." [Sisung Direct at 75]. He testifies that this guideline concerns the broader planning and market implications associated with integrating the large load into the electric system. [*Id.*]. Based on Mr. Sisung's thorough review, he concluded that ELL has satisfied Large Load Guideline #10. [*Id.* at 76].

Mr. Sisung relies on Mr. Datta's economic assessment as one of the bases for his conclusion. He explains that Mr. Datta's analysis "does not simply compare revenue requirements," but instead "incorporates a production-cost analysis intended to quantify the effect that serving Project Evest will have on ELL's wholesale variable supply costs." [*Id.* at 77]. That analysis includes data regarding forecasted hourly load, reserve-margin requirements, transmission-transfer limits, individual generating-resource operating characteristics, projected unit deactivation dates, future resource additions, natural-gas price forecasts, fuel-transportation costs, emissions costs, and assumptions from ELL's 2026 Business Plan. [*Id.* at 78]. Mr. Datta's assessment separately analyzes Project Evest's impact on fuel and capacity costs. [*Id.*]. While Mr. Sisung noted that he "may disagree with certain assumptions utilized in those analyses," he found that ELL "reasonably identified and evaluated the principal market and planning issues associated with serving Project Evest," and he addressed the modeling results separately in his review of the TCI. [*Id.* at 77, 81].

ELL's analysis also directly addresses the FAC pricing element of the Guideline. ELL used a production-cost model to simulate resource commitment and dispatch in the MISO energy market over the full 20-year Original Term, measuring the change in ELL's total variable

supply cost with and without Project Evest. [*Id.* at 146]. Because the Proposed Generators are efficient relative to the broader MISO market, their positive energy margins are credited to ELL's customers through the FAC. [*Id.* at 146-47]. That approach corrects a gap Mr. Sisung identified in ELL's Laidley analysis, which did not capture that project's effect on FAC costs. [*Id.* at 139]. ELL witness Datta likewise explained that the existing FAC process already captures changes in variable supply cost caused by new load, so that no separate FAC proceeding is warranted. [Datta Rebuttal at 20-21].

As to the capacity-market element, NPO witness Mr. Burgess argued that ELL improperly credits the post-2031 capacity surplus at the avoided cost of a combustion turbine. [Burgess Direct at 25]. Mr. Sisung agreed that the long-term value of a modeled surplus is uncertain but explained that Staff need not resolve that valuation question because, even assigning zero value to the post-2031 surplus, the non-renewal TCI remains materially positive. [Sisung Cross-Answering at 37-38]. Under Mr. Burgess's own sensitivity, approximately $733 million of non-renewal net benefit remains. [Datta Rebuttal at 21].

Ms. Beauchamp testifies that the Proposed Generators are being constructed and proposed in ELL's application as system resources that will become part of ELL's resource portfolio. [Beauchamp Direct at 40]. She states that the seven new CCCTs "are being built to serve ELL's total system load in the future." [*Id.*]. The Battery Storage Facilities are similarly being acquired as system resources to serve ELL's overall system load in the future. [*Id.* at 41]. The Stipulated Settlement confirms that the Proposed Generators and Battery Storage Facilities are to be treated as system resources for all ELL customers. [Stipulated Settlement § I.B.3].

Mr. Kline addresses the transmission facilities that ELL is proposing to construct. He states that ELL did not evaluate those resources as only being needed to serve Evest but

assessed the benefits that they would provide to the overall transmission system. [Kline Direct at 12-13]. Mr. Kline explains that the Smalling to El Dorado 500 kV Transmission Line, the St. Landry Switching Station, and the West Fork Creek to St. Landry 500 kV Transmission Line will provide a "broad spectrum of benefits to the electric system" for all customers, not just Evest. [*Id.* at 15-16, 21].

As Mr. Sisung testifies, "ELL has evaluated and presented the principal market and planning impacts associated with Project Evest." [Sisung Direct at 81]. Because ELL has evaluated the load's effects on its resource adequacy obligations, capacity market position, long-term system planning, and energy markets and FAC pricing, and because the record does not show that integrating the load will create unreasonable planning or market impacts, Large Load Guideline #10 has been satisfied.

11. Large Load Guideline #11 – Environmental & Local Impacts.

Pursuant to Large Load Guideline #11, the utility must "demonstrate that environmental and local system impacts associated with the utility serving the load have been identified, and to the extent mitigation is required, a mitigation plan is developed and that compliance costs are appropriately assigned." [Staff Ex. 19 at 4]. ELL witness Jeremy Halland describes the environmental due diligence and permitting ELL has undertaken for the Proposed Generators, and Staff witness Sisung, who evaluated that showing, concluded that "ELL has adequately addressed the requirements of this Large Load Guideline." [Sisung Direct at 56].

Mr. Halland testifies that ELL "will manage the Proposed Generators in accordance with all applicable federal, state, and local regulations, rules, and standards and has taken reasonable steps to protect the public welfare and health against adverse environmental impacts." [Halland Direct at 4]. Mr. Halland testified that the Proposed Generators will be built and operated under the oversight of LDEQ, EPA, the Louisiana Department of Conservation and Energy, and

the U.S. Army Corps of Engineers, consistent with the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and the Louisiana Environmental Quality Act. [*Id.* at 3-4]. He explains that ELL will meet all environmental regulations that are necessary and that the generators were designed so that they could accommodate future regulations, rules, and standards as they are changed. [*Id.* at 4]. Mr. Halland also found that the Proposed Generators will not adversely impact any "recreational and park areas, historical and aesthetic values, or the environmental integrity of the surrounding areas." [*Id.*].

As to local impacts, the Richland Parish Proposed Generators will be sited on cultivated farmland between Rayville and Delhi. [*Id.* at 14]. The Pointe Coupee Proposed Generators will be sited on a rural industrial site near other industrial development. [*Id.*]. Although the Richland Parish Proposed Generators will alter the existing visual landscape, ELL does not expect either site to impair native vegetation or significantly increase operating noise at nearby residences, and construction noise and dust will be temporary and managed through best management practices. [*Id.* at 12-14].

Regarding air quality, the Proposed Generators will be a "major stationary source," so they must comply with National Ambient Air Quality Standards and Prevention of Significant Deterioration ("PSD") requirements, the New Source Performance Standards for Nitrogen Oxide ("NOx") and greenhouse gases, hazardous air pollutant requirements, and continuous monitoring and allowance obligations. [*Id.* at 5]. For each site, ELL will obtain a combined PSD/Title V (Part 70) air permit and an Acid Rain Permit. ELL has submitted PSD applications for the Richland Parish Proposed Generators, and on April 7, 2026, it submitted a combined Title V and PSD air permit application to LDEQ for the Pointe Coupee Proposed Generators. [*Id.* at 6; Sierra Club Ex.

6]. The units are also designed to support carbon capture and storage and ELL commits to "rigorously evaluating CCS." [*Id.* at 7-8].

On water quality, ELL will obtain any required Louisiana Pollutant Discharge Elimination System ("LPDES") permits, submitting applications about three years before operations begin at each site, as well as construction stormwater permits. [*Id.* at 8-9]. Because an LPDES permit cannot issue if a facility would cause or contribute to a violation of water quality standards, Mr. Halland testifies that permitting and ongoing compliance "will minimize any water quality impacts." [*Id.*]. All seven units will use air-cooled condensers instead of water cooling and will draw on municipal potable water or Mississippi River surface water. Mr. Halland explains that the units will therefore not cause water shortages in the host communities. [*Id.* at 10]. He anticipates no wetland impacts resulting from the Richland Units. [*Id.* at 11].

Staff witness Sisung reviewed Mr. Halland's testimony and ELL's supplemental permitting schedule that was provided in discovery in response to Staff data request 1-155. [Sisung Direct at 56-59; Exhibit RLS-008 at 2-3]. He concluded that ELL "has identified the environmental impacts associated with the proposed utility facilities, described the anticipated mitigation and permitting requirements, and incorporated those requirements into its project development and permitting schedule." [Sisung Direct at 58]. As to the third element, Mr. Sisung explained that environmental compliance costs "will be included in the revenue requirements of the generation and transmission projects to which they are applicable," and that the allocation of those costs is addressed under Large Load Guideline #5. [*Id.*]. Accordingly, other than the cost recovery implications addressed in Section III.A.5, ELL has demonstrated that Large Load Guideline #11 has been satisfied. [*Id.* at 58-59].

12. Large Load Guideline #12 – Ongoing Oversight.

The last Large Load Guideline requires the utility to propose ongoing reporting requirements that include the following: (1) contract compliance and milestone status; (2) actual load versus forecast; (3) resource and transmission status; and (4) cost Recovery performance. [Staff Ex. 19 at 4]. "The objective of [this] Large Load Guideline is to ensure the Commission receives timely information necessary to monitor the project, evaluate whether it continues to perform as anticipated, and identify any emerging issues that warrant further regulatory review." [Sisung Direct at 136]. Mr. Sisung deferred the evaluation of ELL's compliance with Large Load Guideline #12 to Staff witness John A. Chapman. [*Id.*].

Here, ELL proposed a monitoring plan that was "substantively the same" as the monitoring plan that was approved by the Commission for the Laidley Project. [Chapman Direct at 28; Exhibit TRH-2]. ELL's plan provided for quarterly progress reports regarding the Planned Generators, Transmission Facilities, and Battery Storage. Those progress reports were to be submitted to the Staff and Intervenors on the 15th of February, May, August, and November of each year, starting on May 15, 2027. In addition to the quarterly progress reports, ELL also proposed to provide the Staff with informal reports within ten days of "any significant developments." [Exhibit TRH-2 at 1-2].

Staff witness Mr. Chapman analyzed ELL's proposed monitoring plan in detail. He summarized the proposed contents of ELL's progress reports as including the following seven elements:

> 1) a summary of the status of the schedule of the ELL Generation, Transmission, and Battery Projects;
>
> 2) the status of the budget of the ELL Generation, Transmission, and Battery Projects;

> 3) other business issues relevant [to] the ELL Generation, Transmission, and Battery Projects;
>
> 4) an update of the status of the construction, costs, and schedule (among other issues) of the Transmission Facilities;
>
> 5) safety information including the recordable incident rate and lost workday injury and illness rate;
>
> 6) an environmental compliance report identifying any environmental permitting or compliance issues that may arise and affect the ELL Generation, Transmission, or Battery Projects, or any new environmental laws and regulations that have the potential to affect the ELL Generation, Transmission, and Battery Projects; and
>
> 7) an Executive Summary containing additional relevant matters not previously discussed in the previous elements.

[Chapman Direct at 30].

ELL's proposed monitoring plan also provided the Staff an opportunity to ask questions regarding the contents of the quarterly progress reports. The plan requires the Staff to ask questions regarding the contents of each progress report within 30 days of the submission of each report. [Exhibit TRH-2 at 1]. The plan also provides the Staff and intervenors with an opportunity to request a conference call or in-person meeting to request clarifications and discuss issues related to each progress report. [*Id.*]. ELL proposed to "arrange for the Staff to undertake site visits at least quarterly, or as otherwise requested by the Staff." [*Id.* at 2].

After performing his review, Mr. Chapman proposed changes to ELL's monitoring plan. [Exhibit JAC-002 (redline monitoring plan); Exhibit JAC-003 (clean monitoring plan)]. The most significant of Mr. Chapman's proposed revisions included:

1) ELL's quarterly reports "shall continue until such time that Staff relieves ELL of this obligation via written communication filed in the docket." [Exhibit JAC-002 at 1].

2) Customer-funded transmission projects were added to the scope of the monitoring plan to cover all six transmission components. [*Id.* at 1 n.2].

3) Section VI of the 2024 Siting Order was incorporated into the monitoring plan, requiring reporting in the next quarterly report of any cost or scope change over $5 million to any single component of the generation, transmission or battery projects. [*Id.* at 7-8].

4) Amends the project completion report due within 120 days of the in-service date to include actual costs, AFUDC, land and right-of-way costs, and rate effects of all projects, not just Transmission Facilities. [*Id.* at 8].

5) Requires ELL to report any amendment or change to agreements governing the Company's relationship with the Customer, with a detailed justification. [*Id.* at 3].

6) Adds a new power quality section that requires ELL to summarize power quality results, describe any material issues, explain ELL's investigation and corrective actions, and identify the corrective measures and costs to be assessed to the Customer when an issue is caused solely by its facility. [*Id.* at 4-5].

7) Adds a new true-up provision that requires ELL to give notice if deferred customer revenues may no longer offset the revenue requirements of the newly constructed assets and explain any proposed change to the true-up methodology and its effect on customers. [*Id.* at 6].

8) Adds a new FRP rebalancing provision that requires ELL to report any time the FRP Rebalancing Mechanism is triggered, including the billing factor, the adjustment to Average Demand, the dollar effect under the ESA, and impact on retail customers. [*Id.*].

9) Requires more details on supply-plan and billing changes, such as including the estimated impact of supply-plan changes on both the Customer's and non-participating customer's rates. [*Id.* at 7].

10) Requires notice to be provided of changes to the MMCs and the contractual Average Demand. [*Id.* at 8].

ELL witness Mr. Jones stated in rebuttal testimony that The Company "generally agrees" with Mr. Chapman's recommended adjustments to the Monitoring Plan. However, Mr. Jones offered three revisions to Mr. Chapman's recommendations. [Jones Rebuttal at 3]. First, Mr. Jones rejected Mr. Chapman's recommendation to include Customer-funded transmission projects in the scope of the monitoring plan because those projects are funded directly by the Customer and are not subject to Commission approval. [*Id.* at 4]. Second, Mr. Jones recommended creating a new "Customer Monitoring Report" requirement that would specifically

focus on Customer-related issues, such as the True-Up Methodology, FRP Rebalancing, and Customer-related Business Issues. The Customer Monitoring Report would only be provided to the Commission, Staff, and Staff's counsel and consultants. [*Id.* at 4-5]. Third, ELL agreed with Mr. Chapman's proposal to include a power quality monitoring report but suggested making that report a separate report as well that would be distinct from the Construction Monitoring Report and the Customer Monitoring Report. [*Id.* at 5].

The Stipulated Settlement incorporates most of Mr. Chapman's proposed amended monitoring plan and the three adjustments recommended by Mr. Jones, with two further changes. First, the quarterly Construction Monitoring Reports continue until the ELL Generation, Transmission, and Battery Projects are all in service, rather than until Staff relieves ELL of the obligation in writing; the Staff-release provision instead governs the Customer Monitoring Report. [Stipulated Settlement, Att. 1 § 1; Att. 4 § 1]. Second, the quarterly reports are due on October 15, January 15, April 15, and July 15 of each year, beginning October 15, 2027, rather than on the schedule previously proposed in testimony. [*Compare id.*, Att. 1 § 1, *with* Exhibit JAC-002 at 1].

Under the Stipulated Settlement, ELL must submit quarterly Construction Monitoring Reports to Staff and all intervenors, with a public redacted version filed in the docket, beginning nine months after the Commission's order. [Stipulated Settlement §§ I(B)(12), I(C)(7), VI(A); Att. 1 § 1]. ELL must also submit a confidential Customer Monitoring Report to Staff and its counsel and consultants within 60 days after the Service Commencement Date and annually thereafter, until Staff relieves ELL of that obligation in writing. [*Id.*, Att. 4 § 1]. Because the Customer Monitoring Report continues until Staff releases ELL, rather than ending when construction is complete, the reporting framework extends "throughout the term of the Customer Agreements," as the Guideline contemplates. [Sisung Direct at 136].

Finally, ELL must file annual power quality reports in this docket, beginning on the last day of the calendar quarter of the one-year anniversary of the installation of the power quality monitoring equipment and continuing until three consecutive years of full facility operation have occurred with no material power quality issues. Each report must include SAIDI and SAIFI scores for substations within 50 miles of the Customer's project. [Stipulated Settlement § V(C)]. Although Mr. Sisung supported a default of at least ten years of monitoring after full load, he emphasized that those parameters should not be "immutable" and should be adjusted based on actual operating experience. [Sisung Cross-Answering at 128]. The Commission retains that flexibility under the settlement.

Together, these reports address each of the four elements of Large Load Guideline #12 as follows:

- **Contract compliance and milestone status:** The Construction Monitoring Report must describe changes to project milestones and schedule, the status of the Customer's performance of its obligations, any disputes that trigger the dispute resolution procedures of the ESA or CIAC Agreement, and whether the required Financial Assurances are in place, and the Customer Monitoring Report must disclose and justify any amendment to the Customer Agreements. [Stipulated Settlement, Att. 1 § 2; Att. 4 § 2]. In addition, ELL must notify the Commission within 30 days of any Dispute under Rider 1, any material modification or cancellation of the ESA or Related Agreements, and any notice of non-renewal or early termination, and must notify the Commission immediately once it is conclusively determined that costs will exceed the application estimate or that commercial operation will be delayed. [*Id.* §§ I(B)(12), IV(D)(3)-(5)];

- **Actual load versus forecast:** ELL must provide Staff and its delegates annual reporting of the Customer's usage, demand, and billing. [*Id.* § IV(D)(2)]. During the Construction Period, the Deferral Proposal Framework also requires ELL to determine each year the Customer's actual contribution to the coincident peak demand forecast submitted to MISO. [*Id.*, Att. 3 § II(A)(iii)]. With this data, Staff can compare actual usage and demand against the Appendix C ramp schedule and the hourly, monthly, and annual load forecasts ELL produced in discovery. [Sisung Direct at 46];

- **Resource and transmission status:** The Construction Monitoring Report must report the schedule, budget, and construction status of the Proposed Generators, Battery Storage Facilities, and Transmission Facilities, along with any changes to the Customer

Supply Plan, the reasons for those changes, and their estimated rate impact. [Stipulated Settlement, Att. 1 § 2]; and

- **Cost recovery performance:** The Customer Monitoring Report must report Customer base and FRP revenues, the balances of revenue deferrals accumulated and amortized, revenues received in excess of the MMCs, ELL's estimate of when the revenue deferrals will be fully depleted, any determination that deferred revenues may no longer be sufficient, any proposed change to the true-up methodology, any application of the FRP Rebalancing Mechanism, and any change to the MMCs or contractual Average Demand. [*Id.*, Att. 4 § 2].

Because the reporting framework in the record addresses each element of the Guideline, ELL has satisfied Large Load Guideline #12.

13. Governor Landry's Executive Order No. JML 26-058

On June 25, 2026, Louisiana Governor Jeff Landry issued Executive Order No. JML 26-058, the "Louisiana Ratepayer and Community Protection Initiative." [Exhibit JRD-3]. The order directs the Secretary of Louisiana Economic Development to set criteria for data center and large-load projects that seek the Data Center Sales and Use Tax Exemption. Pursuant to the order, those large load projects must commit to "ensuring large-load customers fully fund the incremental generation, transmission, and infrastructure investments necessary to serve their projects—preventing cost shifts onto existing residential and commercial customers." [*Id.* at 3]. The order also provides that nothing in it "shall be construed to limit or impair the constitutional or statutory jurisdiction of the Louisiana Public Service Commission." [*Id.* at 4].

LEUG witness Mr. James Dauphinais relies on the order, together with the Large Load Guidelines, to argue that additional protections are needed so that the costs of serving Evest are not shifted to ELL's other customers. [Dauphinais Direct at 6]. Sierra Club witness Ms. Glick contends that the ESA does not comply with the order because Evest will not "fully fund" the Proposed Generators and Proposed Transmission Facilities unless all of those assets are fully depreciated over the 20-year Original Term. [Glick Direct at 5, 27]. In response, ELL witness

Mr. Jones testifies that the order is properly read to prohibit subsidization of service to a data center. [Jones Rebuttal at 39]. He testifies that Evest is not subsidized and that, if anything, Evest is subsidizing service to ELL's non-Evest customers. [*Id.*]. Mr. Jones further testifies that a remaining net book value at the end of the Original Term reflects the expected continuing value of the assets and is not evidence of a subsidy. [*Id.*].

Staff agrees with Mr. Jones that the record does not show that ELL's non-Evest customers will subsidize service to Evest. The cost-shift and stranded-asset concerns the intervenors raise under the Executive Order are the same concerns the Commission's Large Load Guidelines already address. Staff has evaluated those concerns in its analysis of Large Load Guideline #4 (Stranded Asset and Exit Risk) and Large Load Guideline #5 (Rate Design and Cost Recovery) above, and the Executive Order does not require any further or different analysis or relief.

B. The Proposed Generators and Battery Storage Facilities Serve the Public Convenience and Necessity and Are in the Public Interest and Prudent, in Accordance with the Commission's 1983 General Order (Contested Issue "a").

The Commission's 1983 General Order[9] requires a utility to file for and receive certification before it may construct any new electric generating facilities. The primary standard that must be satisfied pursuant to the 1983 General Order is that the new proposed generators must serve the public convenience and necessity. The order states:

> No electric public utility subject to the jurisdiction of the Commission shall commence any on site construction activity or enter into any contract for construction or conversion of electric

[9] LPSC General Order dated September 20, 1983 (*In re: In the Matter of the Expansion of Utility Power Plant; Proposed Certification of New Plant by the LPSC*), as amended by General Order (Corrected) in Docket No. R-30517 (*In re: Possible modifications to the September 20, 1983 General Order to allow (I) for more expeditious certifications of limited-term resource procurements and (2) an exception for annual and seasonal liquidated damages block energy purchases*) dated May 27, 2009 ("1983 General Order").

> generating facilities or contract for the purchase of capacity or electric power, other than emergency or economy powered purchases, as well as the exemption listed in Paragraph 7(a), without first having applied to the Commission for a certification **that the public convenience and necessity would be served** through completion of such project or confection of such contract. Feasibility and engineering studies, site acquisition and related activities preliminary to a determination of the desirability or need for plant construction or conversion on purchase power contracts are exempted from this requirement.

1983 General Order, ¶ 1 (emphasis added). ELL's primary request in this proceeding is for the Commission to conclude that the Proposed Generators and Battery Storage Facilities should be certified as serving the public convenience and necessity in accordance with the 1983 General Order. After a thorough investigation of ELL's application, the Staff concludes that the Proposed Generators and Battery Storage Facilities meet the applicable standard and recommend that the Commission approve ELL's certification request consistent with the Stipulated Settlement and the customer protections contained therein.

Although the 1983 General Order does not elaborate on what a utility must show to satisfy the "public convenience and necessity" standard, Mr. Sisung testifies regarding that required showing based on his extensive experience before the Commission. Mr. Sisung explains that a utility must prove two things for an application to construct new generators to be approved as being in the public convenience and necessity: (1) whether there is a demonstrated need for the proposed facilities; and (2) whether the proposed facilities represent an appropriate means of satisfying that need at the lowest reasonable cost consistent with the public interest. [Sisung Direct at 36]. Mr. Sisung testifies that the second inquiry "typically includes consideration of whether the proposed facilities are reasonably designed, appropriately sized and located, and whether they represent a reasonable and cost-effective means of meeting the identified need." [*Id.* at 36-37].

ELL has sufficiently demonstrated that the first inquiry—whether there is a demonstrated need for the proposed facilities—has been met. Evest is planning to locate a new hyperscale data center in Louisiana; that fact is accepted by all parties. The "Customer Questionnaire" attached to the CIAC Agreement shows that the Evest load will be [redacted] MWs. [Exhibit LKB-3 at 84]. That amount was confirmed by several ELL witnesses and not questioned by the opponents of ELL's application. [Beauchamp Direct at 7; May Direct at 4; Jones Direct at 2; *see also* Miller Direct at 13 & n.25; Tr. 34-35 (Oct. 13, 2026) (NPO witness Miller)]. As Mr. Sisung concluded, "ELL has adequately demonstrated that, if ELL is to provide the level of electric service contemplated by the Customer Agreements, additional capacity resources will be required." [Sisung Direct at 40].

The more contested issue regarding whether ELL has demonstrated that its application satisfies the 1983 General Order is whether the proposed facilities represent an appropriate means of satisfying its resource need at the lowest reasonable cost consistent with the public interest. After analyzing ELL's application holistically and within the context of the Commission's twelve non-binding Large Load Guidelines, the Staff concludes that ELL has sufficiently met its burden when the customer protection conditions of the Stipulated Settlement are considered.

The record satisfies each factor Mr. Sisung identified. As to sizing, ELL determined that six or fewer CCCTs would not produce enough energy at the Customer's contracted load factor and added battery storage rather than an eighth CCCT to meet the remaining capacity need. [Owens Direct at 4–5]. As to location, the Richland Parish Proposed Generators are sited near the Customer's load to reduce net load on the transmission system and mitigate the need for additional transmission upgrades. The Pointe Coupee Proposed Generators add

generation in the SELPA load pocket. [Beauchamp Direct at 76–77; *see supra* Section III.A.2]. As to cost, the Proposed Generators and Battery Storage Facilities will not be subsidized by non-Evest customers, but instead, will produce substantial net benefits for those existing customers, as discussed below.

The Commission's Large Load Guidelines provide a roadmap for analyzing whether ELL's application satisfies the public convenience and necessity requirement. Although those guidelines are "non-binding," they assist the Commission in evaluating whether the risks associated with extraordinary large loads are appropriately addressed and provide transparency regarding known areas of concern. As detailed thoroughly above, ELL's application, with the additional provisions contained in the Stipulated Settlement, satisfies all twelve of the Commission's guidelines.

The Staff will not repeat the analysis of each guideline analyzed above here but will highlight some of the more significant conclusions that emerge from that analysis. That analysis shows that ELL can reliably serve Project Evest with the Proposed Generators and Battery Storage Facilities. [Sisung Direct at 47, 49-50, 53]. ELL projects that its existing customers could receive approximately $1.96 billion in net benefits on a net present value basis over the 20-year Original Term of the ESA, and those benefits remain substantial under every alternative scenario analyzed, including non-renewal at the end of the Original Term. [Sisung Direct at 137, 150-52]. The rate design places the incremental cost of serving Project Evest on the Customer. The Customer Agreements, backed by numerous protections and security mechanisms, protect existing customers against the risk of early termination and stranded investment. [Sisung Direct at 84-85, 118, 121, 130-31]. The use of Minimum Monthly Charges ensures that the Customer will pay for the

incremental revenue requirement increase caused by the new data center over the 20-year Original Term.

The intervenors opposing certification principally argue that ELL did not adequately consider alternatives to the seven CCCTs, that certification of the units should be staggered, and that the Proposed Generators expose existing customers to fuel-price risk. [Burgess Direct at 28–31, 54–58; Glick Direct at 31, 36]. Those arguments are addressed in Sections III.D, III.F, and III.A.8, respectively. None of the intervenors has shown that an alternative would reliably serve the Customer's firm load while producing a better overall result for existing customers. [Sisung Cross-Answering at 118, 120].

To the extent the Staff's analysis identified gaps in ELL's showing, the Stipulated Settlement closes them. The settlement addresses capacity costs and reliability during the Customer's load ramp, requires an operational control and emergency load shed plan before full firm service begins, and corrects the potential over-collection under the Resilience Rider. [Stipulated Settlement §§ III.E-G, IV.B.5, IV.D.1]. It also preserves the Commission's full prudence authority over ELL's management of the Customer Agreements and over the recovery of any stranded costs. [*Id.*, §§ IV.A.2, IV.D.6]. Pursuant to the Stipulated Settlement, certification does not insulate ELL's actual construction costs, which, along with ELL's management of construction, remain subject to a Commission prudence review. [*Id.* § I.B.13]. Accordingly, ELL's Application has satisfied the Commission's Large Load Guidelines and the Proposed Generators and Battery Storage Facilities serve the public convenience and necessity. [*Id.*, §§ I.A.3, I.B.2].

C. The Proposed Generators and Battery Storage Facilities are to be Treated as System Resources for all ELL Customers (Contested Issue "b").

As evidenced by the Stipulated Settlement, the Staff agrees that the Proposed Generators and Battery Storage Facilities should be treated as system resources for all ELL customers. [Stipulated Settlement § I.B.3 ("The Proposed Generators and the Proposed Battery Systems are to be treated as system resources for all ELL customers.")]. As system resources, the Proposed Generators and Battery Storage Facilities will be used to serve all of ELL's combined load. [Jones Direct at 10]. Those assets and their costs will be included in ELL's rate base. [*Id.*]. As Mr. Sisung explained, "the Proposed Generators and Battery Storage Facilities once placed into commercial operation should operate as part of ELL's integrated generation portfolio for the benefit of all retail customers." [Sisung Direct at 169; *see also supra* Section III.A.10]. As system resources, they will also be offered, when applicable, into the MISO markets to provide all ELL customers with the resulting capacity and energy credits/revenues. [Jones Direct at 42]. The Commission adopted the same treatment for the generators serving Laidley. [*See supra* Section III.A].

Although inclusion of the Proposed Generators and Battery Storage Facilities will result in the total costs of those assets being included in ELL's overall rate structure, Evest's commitment to pay MMCs, at the very least, will cover the incremental revenue requirement increase for those assets. The MMCs and other protective billing terms cover the incremental costs of the Proposed Generators and Battery Storage Facilities to "shield other customers from any unreasonable cost shifting that could otherwise result during the term of the Customer's ESA or if those assets became stranded in the event of an Evest termination." [Jones Direct at 10].

Sierra Club witness Ms. Glick argues that labeling the Proposed Generators and Battery Storage Facilities as system resources causes fuel risks to be shared with all ELL

customers. She testifies that when "gas prices spike or increase, the added fuel cost will be spread across all ratepayers, not just the Meta data center." [Glick Direct at 31]. But as Mr. Sisung testified, the Proposed Generators are expected to be highly efficient generators that can result in positive energy margins that benefit ELL customers. He states that "[a]n efficient CCCT may therefore experience increased energy-market margins relative to higher-cost marginal generation, providing a partial economic offset to higher fuel expense." [Sisung Cross-Answering at 25]. ELL witness Mr. Jones explains that "Evest will cover its entire share of fuel costs for the entire ELL system, and not just the highly efficient generation whose costs its supporting through MMC." [Jones Direct at 42-43 (internal quotation omitted)].

Mr. Sisung further testifies that ELL's Aurora modeling projections show positive energy margins for all seven of the Proposed CCCTs. Mr. Sisung concludes that assigning the gross fuel costs of the seven new Proposed Generators directly to Evest, as Ms. Glick suggests, would not correctly measure the incremental costs caused by the Customer. [Sisung Cross-Answering at 28]. The economic benefits of the efficient Proposed Generators can be assigned to non-Evest customers only if their costs are assigned on the same basis. [*Id.*]. Labeling the Proposed Generators and Battery Storage Facilities as system resources satisfies that symmetry.

Mr. Burgess argues that under system-resource treatment the Customer pays "the average cost of fuel supply (including firm transportation) across ELL's entire fleet rather than the marginal cost" of the new pipelines. [Burgess Direct at 22-23 (emphasis omitted)]. That means, according to Mr. Burgess, that the new pipeline costs are being subsidized by current customers and that if Evest's load comes in low, its share of fixed firm transportation costs falls but the costs do not, resulting in higher costs to existing customers. [*Id.* at 21]. But as Mr. Datta observes, Mr. Burgess's criticisms are "oversimplified" and a holistic analysis of the net effect of a reduced

customer load can meaningfully evaluate that scenario. [Datta Rebuttal at 10-11]. Additionally, as Mr. Datta correctly indicates, "a sustained reduction in Customer's load implicitly means that [the new] highly efficient CCCTs would become a greater portion of the overall mix of resources used by ELL to provide energy and/or capacity value to all of ELL's customers." [*Id.*].

Assigning the Proposed Generators and Battery Storage Facilities a system resource designation is proper and beneficial to all ELL customers. No witness has provided any legitimate basis for the Commission to reject the Company's request to assign system resources status to those new assets. As a result, the Commission should accept Mr. Sisung's recommendation that the Commission "approve treatment of the Proposed Generators and Battery Storage Facilities as system resources for the benefit of all ELL customers and approve recovery of their prudently incurred fuel costs through the Fuel Adjustment Clause." [Sisung Direct at 181].

D. ELL Adequately Considered Alternative Resources for Purposes of Certification, Subject to Continuing Commission Oversight (Contested Issue "c").

The intervenors contend that ELL did not adequately consider alternatives to the seven CCCTs. They allege that ELL's economic analysis only consists of two AURORA runs with predetermined portfolios under a single gas-price scenario, that no economic modeling was performed for an alternative portfolio, and that ELL has performed no capacity-expansion modeling since its 2023 IRP. [Burgess Direct at 56–58; Glick Direct at 36]. Staff does not dispute that ELL's alternatives analysis was narrower than conventional integrated-resource-planning. But the certification question is not whether more modeling could have been performed. It is whether ELL has shown that its supply plan is a reasonable means of meeting a demonstrated need, and whether any party has shown an alternative that produces a better overall result for existing

customers while reliably serving the firm load Evest has requested.[10] [Sisung Direct at 31–32, 40; Sisung Cross-Answering at 83–84, 120]. Both questions support certification here.

Staff independently confirmed, using ELL's own Load and Capability Report, that serving the Customer will require additional capacity "generally consistent with the magnitude of the proposed generation resources." [Sisung Direct at 21–22, 40]. ELL then sized the portfolio to the Customer's energy requirement. The Company determined that six or fewer CCCTs would not produce enough energy at the Customer's contracted load factor, and ELL added battery storage rather than an eighth CCCT to cover the remaining capacity need. [Owens Direct at 4–5]. ELL's production-cost modeling confirms that the seven units operate near the planning capacity factor. [*Id.* at 5]. Even with all seven units, the portfolio is still expected to fall slightly short of the Customer's estimated load. [Owens Rebuttal at 10].

ELL did consider alternatives, including evaluating new nuclear, simple-cycle CTs, renewables paired with storage, and reliance on the existing fleet and the wholesale market. [Owens Direct at 6–8]. It also evaluated an all-CCCT plan (with no renewable resources), a 2x1 CCCT in place of two 1x1 CCCTs, and a transmission-only solution. [Beauchamp Direct at 77-79]. Ms. Beauchamp explained that this list of proposed alternatives considered by the Company is not exhaustive and that it would be "impossible to recreate or reproduce all of [the] iterations and related discussions." [*Id.* at 79]. Staff reviewed the Company's planning process, including the integrated generation and transmission analysis, and concluded that ELL presented a reasonable supply plan subject to certain Staff conditions, which are now incorporated in the Stipulated Settlement. [Sisung Cross-Answering at 86].

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[10] Whether ELL is exempt from the Commission's MBM Order requirement to conduct a Request for Proposal competitive solicitation process will be assessed under Contested Issue "f" below.

The Staff acknowledges that the analyses ELL provided in this proceeding are narrow and that the Company did not provide a detailed comparison of its supply plan with alternative portfolios. But the analysis that ELL did provide shows that its proposed supply plan is reasonable considering the large load requirements of the Customer. Moreover, none of the intervenors performed a complete economic analysis showing that an alternative produces a better net result for existing customers once the changes in Customer payments, MMC operation, and production costs are taken into account. [Sisung Cross-Answering at 118]. "The relevant question is not whether reasonable alternatives to CCCT generation exist." [*Id.* at 120]. The question is whether a particular combination has been shown to be a sufficiently reliable and economic substitute, and none has. [*Id.*].

The absence of a broader alternatives analysis is also a consequence of the MBM Order waiver, which Staff supports as satisfying both the Lightning Initiative factors and the good-cause standard. [*See infra* Section III.F]. That waiver does not leave the Commission without a check on ELL's resource choices. If material changes are made to the Customer Supply Plan, ELL must make a filing that identifies the resource change, seeks certification of any new resources as required, identifies their cost, and demonstrates how that cost will be included in the Customer's minimum bills or otherwise allocated to the Customer. [Stipulated Settlement § IV.B.4]. The settlement does not determine any purchased capacity needed to serve the Customer, which ELL must acquire subject to Commission approval, if applicable. [*Id.* § I.B.14]. ELL must also report supply-plan changes, and their estimated rate impacts, in its Construction Monitoring Reports. [*Id.*, Att. 1 § 2; *see supra* Section III.A.12].

Accordingly, the Commission should find that ELL adequately considered alternative resources for purposes of certifying the Proposed Generators and Battery Storage Facilities, subject to the continuing oversight provided in the Stipulated Settlement.

E. It is Reasonable to Depreciate the Pointe Coupee Proposed Generators Over a 32-Year Life (Contested Issue "e").

ELL's application requests approval to depreciate the three Pointe Coupee Proposed Generators over a 32-year life, while using a 20-year depreciable life for the four Richland Parish Proposed Generators. [Jones Direct at 16]. ELL claims that the 32-year depreciation schedule for the Pointe Coupee Proposed Generators is "consistent with other CCCTs approved by [the] Commission" whereas the 20-year life for the Richland Parish Proposed Generators is accelerated. [*Id.*]. The Staff believes that the depreciable lives proposed by ELL are just and reasonable and in the public interest and should be approved by the Commission. The Stipulated Settlement authorizes these depreciable lives. [Stipulated Settlement § I.B.7].

Sierra Club witness Ms. Glick argues that the Commission should not approve a 32-year depreciable life for the Pointe Coupee Proposed Generators. [*See* Glick Direct at 25-26]. Ms. Glick testifies that the "Company's justification for the different depreciable lives is not robust or well supported." [*Id.*]. But as ELL has recognized, a 32-year depreciable life, when assessed on its own, is not unreasonable. Indeed, that depreciation timeline is consistent with the depreciable lives of other similar generators. [Jones Direct at 16]. "Given the high likelihood that the Pointe Coupee units will have value from a reliability perspective and remaining economic useful life from an operational perspective, it would be unreasonable to require ELL to depreciate those units on the faster timeline." [Jones Rebuttal at 53]. The fact that the Customer agreed to fund accelerated depreciation of the Richland Parish Proposed Generators does not make an

otherwise reasonable 32-year depreciable life unreasonable for the Pointe Coupee Proposed Generators.

Although further justification is not necessary for the Commission to conclude that a 32-year depreciable life that is already consistent with precedent should be certified, Ms. Beauchamp explains why ELL settled on that depreciation timeline for the Pointe Coupee units. She testifies that the Pointe Coupee units are located in SELPA, and therefore, "are situated closer to areas of traditional load growth and high-load industrial customers." [Beauchamp Rebuttal at 10 n.17]. As a result, ELL expects that those units "will have significant independent value and usefulness even in the absence of the Customer." [*Id.*]. It is reasonable to apply a customary depreciable life to new generators, as opposed to a contract-specific accelerated depreciation schedule, especially when the Company expects that those units will have significant independent value after the Original Term of the ESA. ELL's request for a reasonable depreciation timeline for three units in a load pocket should not be rejected because the Company was able to secure a favorable depreciation timeline for four other units in a more industrial-remote region.

Several intervenor witnesses argue that the depreciable life for all the Proposed Generators should be set at 20 years to lessen the remaining net book value of the generators at the end of the Original Term of the ESA. [Glick Direct at 26; Hoyle Direct at 33-34]. But remaining net book value does not, by itself, establish stranded cost or customer harm, and the Commission retains full authority over the treatment of any such investment. [Sisung Cross-Answering at 68-69; Stipulated Settlement §§ IV.A.2, IV.D.6; *see supra* Section III.A.4; *infra* Section III.I].

Moreover, Mr. Jones anticipates that the Pointe Coupee units are likely to be valuable and needed in 2048 and that ELL will have sufficient time to incorporate the impact of non-renewal into its planning given that the ESA includes a three-year notice provision that

requires the Customer to inform ELL whether it will renew the ESA within three years of the expiration of the Original Term. [Jones Rebuttal at 53]. But even if Mr. Jones is wrong and the Pointe Coupee Proposed Generators have no value at the end of the Original Term, the Evest Project will still provide a $991 million net present value benefit to ELL's other customers. [Datta Rebuttal at 13].

F. ELL's Application Satisfies the Lightning Initiative Factors and Has Shown Good Cause for an Exemption From the Commission's Market Based Mechanisms Order (Contested Issue "f").

ELL seeks an exemption from the MBM Order based on a showing of satisfaction of the Lightning Initiative factors and under the Commission's general good cause standard. [Application at 4-5, 22-24, 28]. As reflected in the Stipulated Settlement, Staff agrees that ELL's Application should be exempt from the MBM Order because it meets the factors set forth in the Lightning Initiative requirements and because ELL has shown good cause for an exemption. [Stipulated Settlement at 1-2].

1. ELL Satisfies the Lightning Initiative Factors.

The Lightning Initiative sets forth the following factors that should be demonstrated and proven in a certification proceeding seeking to waive the MBM Order process in large load service applications:

> a. A signed electric service agreement ("ESA") with a new or expanding load with a requested initial in-service date within five years of the certification application;
>
> b. Without the proposed capacity, the utility is projected to be short of the energy or capacity needed to meet the customer's electric requirements on the requested in-service dates;
>
> c. A letter from the Secretary of Louisiana Economic Development confirming the customer's interest and the importance of power availability within the five-year initial in-service date;

> d. The ESA has a term of at least 15 years, with an option to renew; and
>
> e. The ESA ensures a level of fixed revenue over the term of the ESA that will cover at least one-half of the fixed revenue requirement associated with the requested capacity during the term of the customer ESA.

[Minutes of Dec. 17, 2025 Business & Executive Session at 6-7, *available at* https://www.lpsc.louisiana.gov/docs/minutes/Dec_17_2025_Min.pdf (last visited Nov. 11, 2026) ("Dec. B&E Minutes")].

Mr. Jones asserts that ELL meets all five criteria, and Staff witness Mr. Sisung agrees. [Jones Direct at 56-57; Sisung Direct at 33-36]. First, ELL has signed an ESA setting forth the expectation of taking service for construction power in [redacted] before ramping up in [redacted] to full capacity by [redacted], within five years of the 2026 Application. [Jones Direct at 56; Exhibit LKB-2 at 87-88 (ESA Appendix C, Ramp Schedule); Exhibit LKB-9, Customer Ramp Timeline; Beauchamp Direct at 7, 42-43; Sisung Direct at 45-46].

Second, as explained by Ms. Beauchamp, the Customer's proposed load cannot be met without constructing new generation. [Beauchamp Direct at 40-43; Sisung Direct at 40]. Ms. Beauchamp further explains why the Proposed Generators and Battery Storage Facilities, as opposed to alternatives, sufficiently provide the necessary capacity for the Project. [*Id.* at 40-42, 77-87; *see also* discussion of Large Load Guidelines #1 & #2, *supra* Sections III.A.1 & 2]. NPOs' witness Mr. Burgess argues that not all seven CCCT generators are needed to meet ELL's capacity needs by the in-service date and suggests staggering certification. [Burgess Direct at 28-31; Burgess Cross-Answering at 2-6]. Ms. Beauchamp rejects Mr. Burgess's proposal as presenting unacceptable risks to ELL and the Customer, including regulatory uncertainty; an improperly open-ended supply plan without certainty that the Customer would be able to cover incremental

costs; increased costs, particularly associated with construction and the supply plan; and delays in the ramp schedule. [Beauchamp Rebuttal at 31-33].

Staff witness Mr. Sisung also disagrees with Mr. Burgess's approach because "ELL's service obligation under the ESA is not limited to the amount of load that can be served by the first generator" but "extends to the Customer's full contractual service requirements as they develop over the ramp," corresponding with each generator's in-service date [Sisung Cross-Answering at 47]. Given this and the "extraordinary magnitude of that load," Mr. Sisung recommends that the Commission evaluate the Application holistically. [*Id.*]. Furthermore, Mr. Sisung and Mr. Jones point out that while intervenors have argued certification issues, none has shown that ELL has not qualified for the Lightning Initiative, a distinct issue from certification. [*Id.* at 47-48; Jones Rebuttal at 36].

Third, Mr. Jones attaches as Exhibit RDJ-5 the requisite letter from the Secretary of Louisiana Department of Economic Development confirming the Customer's interest in the Project and need for power within five years. Fourth, the ESA has a term of 20 years, exceeding the minimum, and has an option to renew. [Jones Direct at 56; Exhibit LKB-2, ESA at 2]. Fifth, the ESA provides fixed revenues to cover more than one-half of the fixed revenue requirement for the term of the ESA, as addressed above in the discussion of Large Load Guidelines #4 & #5. [*See supra* Sections III.A.4 & 5; *see also* Sisung Direct at 34, 85-86 (confirming that "Exhibit RDJ-2 demonstrates that, in the aggregate, the projected MMCs approximately equal the projected revenue requirements over the term of the ESA")]. NPOs' witness Mr. Burgess did "not dispute that under ELL's projections, the fixed revenues under the Customer Agreements exceeds [sic] the 50% threshold." [Burgess Cross-Answering at 7].

Additionally, the Lightning Initiative requires the applicant to communicate with the Executive Counsel for the Commission at least 60 days prior to any filing made at the Commission. [Dec. B&E Minutes at 7]. Mr. Jones testified that ELL provided the Commission with more than 60 days' notice. [Jones Direct at 56-57]. Because ELL has proven all of the applicable criteria, ELL's Application merits exemption from the MBM Order under the Lightning Initiative.

2. Good Cause Exists for Exemption from the MBM Order.

Louisiana Constitution Article IV, § 21(B) authorizes the Commission to "adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties." The Louisiana Supreme Court construes this as a delegation of "the exclusive and plenary power to regulate all common carriers and public utilities." *Bowie v. La. Pub. Serv. Comm'n*, 627 So. 2d 164, 166 (La. 1993). This power "is as complete in every respect as the regulatory power that would have been vested in the legislature in the absence of Article IV § 21(B)." *Id*. Thus, "the Commission can on its own initiative adopt and enforce reasonable rules and procedures necessary to govern" matters within its jurisdiction. *Id*. at 167. Further, the Commission is afforded great weight in "its interpretation and application of its *own* General Orders." *Dixie Elec. Membership Corp. v. La. Pub. Serv. Comm'n*, 441 So. 2d 1208, 1211 (La. 1983) (emphasis in original).

Accordingly, the Commission has plenary authority under the Louisiana Constitution to waive the requirements of the MBM Order, a General Order promulgated by the Commission. The MBM Order generally requires that electric utilities employ a market-based mechanism—ordinarily a Request for Proposals ("RFP") competitive solicitation process—to support covered acquisitions of generating capacity or purchase power contracts intended to serve retail customers, subject to the Order's exemptions and its allowance for an alternative market-based mechanism when a formal RFP would not be in the public interest. MBM Order, Att. A,

¶¶ 1-3. The MBM Order "augments the procedures of the 1983 General Order" as the results and analysis of the market-based-mechanism are used as justification to show that paragraph (2) of the 1983 General Order is met. *Sw. Elec. Power Co., ex parte*, No. S-34594, 2017 WL 3718001, at *1 (La. P.S.C. Aug. 24, 2017). That paragraph requires applications to "include the specific data utilized by the utility in justification of the generation project or purchased power agreement, an itemized projection of total costs, the scheduled completion date with appropriate time schedules for the percentage of the total project to be completed by specific target dates, and, in cases of purchased power or capacity agreements, the proposed contract in its entirety." 1983 General Order, ¶ 2.

The Commission has previously granted waiver of MBM Order requirements. For instance, the Commission granted ELL such an exemption in the Laidley proceeding. *Order No. U-37425*, Docket No. U-37425, *Entergy La., LLC, ex parte*, 2025 WL 2530715, at *7-9 (Aug. 29, 2025). ELL argued that it should be exempted because of the customer's urgent need for power, significant third-party funding for construction of the proposed facilities, contractual terms that shielded ratepayers from bearing incremental costs, and the substantial economic benefits to Louisiana citizens. *Id.* at *2; [Laidley Application, Docket No. 37435, at 2 (Oct. 30, 2024) & Attached Direct Testimony of Joshua Thomas at 19-26]. The Commission adopted a settlement that stipulated "ELL has established good cause for and is granted an exemption from the MBM Order for the Planned Generators, including in particular the [RFP] process and the stated prohibition against alternative market-based mechanisms being 'limited to self-build or utility-owned resources.'" *Order No. U-37425*, 2025 WL 2530715, at *7-9 (quoting MBM Order, Att. A, ¶ 3).

Likewise, in Docket No. S-34594, the Commission granted Southwestern Electric Power Company ("SWEPCO") an exemption from the RFP requirements to apply for certification to acquire wind resources pending the expiration of a Production Tax Credit. *Sw. Elec. Power Co.*, 2017 WL 3718001, at *1, *3. SWEPCO had argued in part that the "timeframe requirements set forth in the MBM Order adversely impact[ed] [SWEPCO's] ability to pursue this unique opportunity to obtain wind resources for the benefit of ratepayers." *Id.* at *2. The Commission granted SWEPCO's request but reserved all rights related to reviewing SWEPCO's decision in the certification proceeding. *Id.* at *3.

The Commission also excepted Dixie Electric Membership Corporation ("DEMCO") from the MBM Order where DEMCO conducted an internal RFP process for a power purchase agreement that was evaluated and approved by an outside consultant and Staff. DEMCO's agreement also met several of DEMCO's objectives including being least cost, providing for a stable term, exposing DEMCO to low environmental risk, affording DEMCO new capacity without incurring economic penalties, and providing reliable power. *Cleco Power LLC, ex parte*, No. U-32275, 2012 WL 6759435 (La. P.S.C. Dec. 20, 2012). Similarly, the Commission in Docket No. U-36697 granted an exemption from the standard RFP process where the alternative market-based mechanism was found to be in the public interest and therefore consistent with the MBM Order. *Entergy La., LLC, ex parte*, No. U-36697, 2024 WL 3067205, at *2 (La. P.S.C. June 14, 2024).

Consistent with the Commission's previous findings, waiver of the MBM Order procedures is warranted in this case because ELL's application satisfies the specific factors laid out by the Lightning Initiative, but also more generally because of the Customer's demonstrated need for speed to market, the significant ratepayer protections and benefits provided by the

Customer Agreements, and to promote Louisiana's economic interests. Ms. Beauchamp explains that the Customer's timeline did not permit a full RFP. [Beauchamp Rebuttal at 34]. Moreover, Ms. Beauchamp testifies that following the traditional MBM Order process for even some of the units would materially delay the ramp schedule and supply plan. [*See id.* at 33]. Additionally, the need for a formal RFP process is lessened because the Customer has substantially mitigated economic and financial risks to non-Evest customers through ratepayer protections in the Customer Agreements. [Application at 24; Beauchamp Direct at 70; *see supra* Sections III.A.4 & 5].

Record evidence also supports the conclusion that conducting an RFP would likely increase the costs of this project to ratepayers. Ms. Beauchamp testifies that ELL has secured a favorable business arrangement with Mitsubishi Power Americas to secure turbines for the Proposed Generators, and that ELL is currently in other negotiations that mitigate against risk of increased costs. [Beauchamp Rebuttal at 32-33]. Ultimately, Ms. Beauchamp testifies that, without waiver of the MBM process, Louisiana likely would have lost the Project. [*Id.* at 34]. Retaining the opportunity for Louisiana to benefit from this unprecedented investment aligns with State policy. *See La. Lightning Speed Initiative*, State of La. E.O. No. JML25-102 (Sept. 16, 2025).

Finally, it bears repeating that waiver of the MBM Order process does not abrogate the Commission's right to determine whether the proposed facilities are in the public interest. The MBM Order only "augments the ***procedures***" of the 1983 General Order by providing additional data. *Sw. Elec. Power Co.*, 2017 WL 3718001, at *1. Nor does waiver of the MBM Order preclude the Commission's prudence and ratemaking reviews or its oversight of later changes to the Customer Supply Plan. [Stipulated Settlement § I.B.13; *see supra* Section III.D]. Furthermore,

no intervenor testimony directly contests the waiver on good cause grounds. For all these reasons, the Commission should grant ELL a waiver of the MBM Order's requirements for good cause.

G. ELL's Proposed Transmission Facilities Serve the Public Convenience and Necessity and Are in the Public Interest and Prudent, in Accordance with the Commission's Transmission Siting Order (Contested Issue "h").

The Transmission Siting Order prohibits a utility from beginning construction of a Transmission Facility in Louisiana without first obtaining a Commission order certifying that the facility serves the public convenience and necessity. Transmission Siting Order, Att. A at 3. A "Transmission Facility" is a line constructed and operated at or above a nominal 100 kV, exceeding one mile in length, and having an estimated construction cost exceeding $20 million, including associated switching stations and substations. *Id*. at 4 & n.1. The applicant bears the burden of demonstrating that the proposed facility is in the public interest. *Id.* at 5. In making that determination, the Commission may consider the facility's expected impact on costs, retail rates, reliability, congestion, economic development, and expected benefits, as well as its consistency with public policy. *Id.* The Commission may also consider whether the facility offers a reasonable and cost-effective solution compared to other alternatives. *Id.* The Commission's siting review is limited to a generalized substation-to-substation corridor and does not extend to parcel-by-parcel routing, expropriation, land use, zoning, or environmental concerns. *Id.* at 6.

ELL requests two forms of relief under the Transmission Siting Order. First, ELL asks the Commission to find that the Customer-Funded Transmission Projects, including the Smalling to El Dorado 500 kV Line, either do not require certification or are exempt. [Application at 28-29]. Second, ELL asks the Commission to find that the Proposed Transmission Facilities are in the public interest and appropriately sited. [*Id.* at 29-30]. The Stipulated Settlement resolves both requests, subject to Customer Protection Conditions and post-construction prudence review.

[Stipulated Settlement §§ I.C.1-3]. As explained further below, the Commission should approve ELL's transmission requests consistent with the Stipulated Settlement.

The Customer-Funded Transmission Projects qualify for an exemption from certification. The Customer will fund 100% of their costs through the CIAC Agreement, so they will carry a zero plant-in-service balance and will not be reflected in other customers' rates. [*See supra* Section III.A.5.a; Stipulated Settlement at 10; s*ee also* Kidd Direct at 4-5; Beauchamp Direct at 10-11; Kline Direct at 12-13]. Staff witness Mr. Chapman reviewed each component of the Customer-Funded Transmission Projects under the Transmission Siting Order and concluded that each is exempt from certification. [Chapman Direct at 35-36]. He stated:

> [The] Customer-Funded Transmission [Projects] . . . primarily qualify for exemption from Commission certification pursuant to VIII(a) of the 2024 Siting Order, which states that "a Certificate and siting approval will not be required for . . . [a] new switching station, or substation." Further, . . .[those projects] qualify for exemption under Section VIII(h) of the 2024 Siting Order, which states that "a Certificate and siting approval will not be required . . . [i]f the costs of the Transmission Facility, and the cost of any associated System Impacts, will never be reflected or recovered in the retail or wholesale rates to be assessed to customers of Louisiana electric utilities including cooperatives." As indicated by ELL witnesses Ms. Beauchamp and Mr. Kline, . . . the costs of these Customer-Funded Transmission Interconnection Facilities are being completely paid for by the Customer through its CIAC Agreement, and the associated costs will not be included in ELL's jurisdictional retail rates.

[*Id.* at 17-18]. The Commission reached the same conclusion for similar customer-funded facilities in the Laidley proceeding, and the Stipulated Settlement provides for the same treatment here. [*See Order No. U-37425* at 6; Stipulated Settlement §§ I.C.1-2].

Unlike the Customer-Funded Transmission Projects, the WFC to St. Landry 500 kV Line requires certification. Mr. Chapman confirmed that the line meets each element of the definition of a Transmission Facility and qualifies for none of the exemptions under Section VIII

of the Transmission Siting Order. [Chapman Direct at 22-25]. Specifically, the line's cost exceeds the $75 million ceiling for the Section VIII(e) exemption, and ELL proposes to recover its costs through rates, making the Section VIII(h) exemption inapplicable. [*Id.*; Jones Direct at 46]. Although a switching station alone does not require certification, the St. Landry Switching Station is the endpoint of the line, and its cost is properly included with the line for purposes of the Transmission Siting Order. [Transmission Siting Order, Att. A at 4, Kline Direct at 18-19]. Mr. Chapman also reviewed ELL's Application against each requirement of Section V of the Transmission Siting Order and concluded that it "includes the contents necessary for the Commission to make a determination of certification" for the line. [Chapman Direct at 26-28].

The need for and system-wide benefits of the Proposed Transmission Facilities are addressed in detail under Large Load Guideline #3 above and are not repeated here. [*See supra* Section III.A.3; *see also* Sections III.A.2 & III.H]. In short, the line is needed to relieve thermal constraints in Central Louisiana and to keep a loss of the Evest and Laidley load below the level that triggers a cascading analysis, and it will benefit ELL's system as a whole through improved maintenance flexibility, resilience and generator deliverability. [Kline Direct at 20-21, 25, 27-28, 45; Kline Rebuttal at 18]. Those findings bear directly on the reliability, congestion, and expected benefit factors the Commission considers under the Transmission Siting Order. [Transmission Siting Order, Att. A at 5].

ELL has also demonstrated that the Proposed Transmission Facilities are a reasonable and cost-effective solution compared with alternatives. A generation-only solution is not viable for a load of this size and location. [*See supra* Section III.A.2; Kline Direct at 12]. ELL developed its transmission plan through an iterative planning process that evaluated multiple scenarios involving changes in the Customer's projected load, the location and amount of the

proposed generation, and the resulting system impacts. [Sisung Direct at 28 (citing Kline Direct at 35-45)]. And although ELL will fund the line, its costs are included in the Customer's Minimum Monthly Charges during the term of the ESA, so that other customers do not pay them during that term. [Kline Direct at 19, 33; Sisung Direct at 15]. Whether the line should be treated as a system resource is addressed under Contested Issue (i) below. [*See infra* Section III.H].

As to siting, ELL proposes a generalized corridor between the new West Fork Creek substation near the Customer's site and the new St. Landry Switching Station in St. Landry Parish, north of Lafayette, where the line will intersect the Babel-Webre 500 kV line. [Kline Direct at 18]. That substation-to-substation corridor is the full extent of the siting determination the Transmission Siting Order requires. [Transmission Siting Order, Att. A at 6]. ELL's milestone schedule projects a December 1, 2031 in-service date for the line and switching station, consistent with the Customer's anticipated load ramp. [Exhibit DK-4 at 3; *see supra* Section III.A.3]. Additionally, Staff witness Mr. Sisung reviewed ELL's testimony, studies, and discovery responses, and concluded that ELL identified the transmission facilities necessary to serve Project Evest and planned them to correspond with the Customer's load ramp. [Sisung Direct at 50-53; *see supra* Section III.A.3].

The intervenors' objections to the Proposed Transmission Facilities are narrow. No party contests the generalized siting of the facilities. [Amended Jt. Pre-Hrg. Statement at 5 (Uncontested Issue "k")]. Nor does any intervenor witness dispute ELL's planning studies or offer an alternative transmission solution. Instead, the intervenors challenge who should bear the line's costs. Sierra Club witness Ms. Glick contends that ELL has not justified passing those costs on to all ratepayers because the line "would not be needed but for Meta's load." [Glick Direct at 5]. SREA witness Mr. Hoyle similarly argues that, even if the Customer fully performs, other

ratepayers will see rate increases from the approximately $1.462 billion capital cost of the line and switching station and the associated operation and maintenance costs. [Hoyle Direct at 24-25].

Neither argument is sufficient to defeat a public-interest finding. First, the record does not support Ms. Glick's premise that the line serves only Project Evest. As discussed in Section III.H below, the line provides system-wide benefits that extend beyond the Original Term. [*See infra* Section III.H]. Second, Mr. Hoyle's rate-impact concern overlooks the structure of the Customer Agreements. During the term of the ESA, the line's costs are included in the Customer's Minimum Monthly Charges, so other customers do not pay them, and ELL estimates that other customers will bear only the final 16% of the line's cost on a net present value basis. [Kline Direct at 19, 33-34; Sisung Direct at 15; *see supra* Section III.A.4]. Additionally, pursuant to the Stipulated Settlement, any material transmission upgrades required as a result of the Customer's Project may not be included in the rates of other customers. [Stipulated Settlement § V.A].

The Stipulated Settlement addresses any remaining concerns. It provides that, subject to the Customer Protection Conditions in Section IV and post-construction prudence review, the Proposed Transmission Facilities are in the public interest and therefore prudent in accordance with the Transmission Siting Order. [Stipulated Settlement § I.C.3]. ELL's actual construction costs and management of construction remain subject to a Commission prudence review, and the retail revenue requirements of the Proposed Transmission Facilities remain subject to change based on prudence review of actual costs. [*Id.* §§ I.C.5, I.C.8]. The monitoring plan adopted in the Stipulated Settlement also incorporates the construction reporting requirements of Section VI of the Transmission Siting Order, requiring ELL to report cost or scope changes exceeding $5 million. [*Id.*, Att. 1 § 3]. These protections, together with the demonstrated need for and benefits of the facilities, support a finding that the Proposed Transmission Facilities serve

the public convenience and necessity, are in the public interest and appropriately sited, and are prudent under the Transmission Siting Order.

H. The WFC to St. Landry Line Provides Benefits to All ELL Customers and Should Be Treated as a System Resource (Contested Issue "i").

The record supports that the WFC to St. Landry Line provides benefits to all users of the transmission system and that the benefits are commensurate to its cost. ELL witness Mr. Kline testifies that the St. Landry Switching Station and the WFC to St. Landry Line "will bring system-wide benefits to the transmission system." [Kline Direct at 12]. He says those benefits "will flow to all users of the transmission system, which include ELL retail customers, other utility customers in Louisiana and in neighboring states, and generation owners and developers." [*Id.* at 12-13]. Mr. May further testifies that the new 500 kV lines "will benefit all ELL customers by increasing north-south transmission connectivity" and "improve resilience for ELL's customers." [May Direct at 33]. Staff witness Mr. Sisung concurs with Mr. Kline's analysis that the WFC to St. Landry Line "is expected to provide benefits extending well beyond serving Project Evest." [Sisung Direct at 133].

Mr. Kline enumerates several reasons the line is needed beyond Evest: customer growth, resiliency needs, and generation needs throughout the ELL system. [Kline Direct at 21, 30]. First, "the added transmission capacity will . . . benefit the deliverability of generators as they seek interconnection to the transmission system." [*Id.* at 21]. Mr. Kline notes that large customers typically require addition of generation capacity to the system, and that the WFC to St. Landry Line will improve speed to market. [*Id.*]. Sierra Club witness Ms. Glick takes the view that because this improvement will directly benefit Evest, the line delivers no other system-wide benefits. [Glick Direct at 13]. However, the customer benefit is not so narrowly defined. Mr. Kline testifies that all future customers, whether native load customers or interconnection

customers bringing new generation, including renewable generation, will benefit from the improved transmission system, both in the short term and beyond the ESA's original 20-year term. [*Id.* at 21, 25-26].

Relatedly, Mr. Kline testifies that the line is needed for seasonal maintenance. ELL's planning analysis found reliability and operating concerns during the fall and spring outage seasons. In those seasons, 30 to 40 percent of regional generation, or up to 10,000 MW, could be offline. Moreover, the development of high-factor loads contribute to a lower proportion of load-drop off in the off-peak periods. [*Id.* at 19-20; *see also id.* at 23]. Without the WFC to St. Landry Line, ELL determined that it "may not be able to take the outages needed to conduct essential seasonal maintenance on generation and assets, an outcome that would be to the detriment of all customers." [*Id.* at 20].

Mr. Kline further testifies that ELL's ability to move system power to where it is needed is not only valuable during planned outages but also to address component failures. [*Id.* at 21]. The line will provide ELL "flexibility . . . to respond to generation outages in the event of an unexpected component failure," which is critical for reliability if large loads disconnect from the system. [*See id.* at 23-24, 26-29]. In fact, ELL's analysis shows that the WFC to St. Landry Line would enable ELL to manage the loss both Evest and Laidley. [*Id.* at 27-28].

Additionally, the line will improve ELL's resilience during extreme weather events "by providing a new hardened north-south 500kV path for the transmission of bulk power across Central Louisiana." [*Id.* at 25]. Mr. Kline testifies the line will be "designed and constructed to Entergy's latest standards for wind-load rating" and have "a greater ability to transfer power than the existing 230kV and 138kV transmission lines that currently move power north-south across the region, while also providing geographic diversity that can be useful in restoration of service in

the wake of major coastal storm events." [*Id.*]. Mr. Kline concludes that the reliability benefits will extend over the line's "entire useful life, . . . beyond the end of the Original Term of the ESA." [*Id.* at 26]. Mr. Kline even suggests that the line "may allow ELL to defer or avoid altogether future upgrades that would otherwise be needed to improve the lower voltage transmission system in central and eastern Louisiana." [*Id.* at 35].

While the line is not currently required by NERC's Transmission Planning Standards, and Ms. Glick criticizes the need for the line on this ground, Mr. Kline explains that the WFC to St. Landry Line will nonetheless be "necessary to conduct system maintenance and maintain system reliability overall." [Glick Direct at 13; Kline Direct at 21, 23]. Moreover, Mr. Kline anticipates NERC is likely to publish heightened transmission requirements soon. [*Id.* at 21-22]. Thus, it is reasonable to construct the line now, while the Customer has agreed to cover the anticipated cost of the line with ESA revenues, to avoid having ELL and other utility customers unreasonably exposed to reliability risks. [*Id.* at 24].

Mr. Kline's testimony regarding system-wide reliability improvements, necessary maintenance, anticipated NERC compliance, and increased customer demand rebuts Ms. Glick's assertion that the WFC to St. Landry Line is not needed "but for" the Customer Project. [*See* Glick Direct at 13]. In further response to her criticism, Mr. Kline emphasizes that these "EHV transmission facilities . . . connect a north-south corridor through an expansive area of central Louisiana, with load serving capability well beyond what is required to serve Project Evest's load." [Kline Rebuttal at 18]. Mr. Kline opines that the facilities' voltage class and breadth of benefits justify classifying the WFC to St. Landry Line as a "System Improvement." [*See id.* at 18-19; Kline Direct at 15].

ELL has also proven that the system-wide benefits of the WFC to St. Landry Line are, at minimum, commensurate with the costs. Ratepayer protections for these transmission facilities are discussed in the previous Section III.G. Additionally, as addressed in the discussion of Large Load Guideline #4, the MMCs include the cost of the WFC to St. Landry Line. Therefore, retail customers will not pay the line's revenue requirement during the ESA term while receiving the benefits. Furthermore, retail customers' post-term share of the overall costs is small compared with the remaining useful life of the line. [*See supra* Section III.A.4.a & b]. Moreover, the risk of cost-overrun stays with the Customer due to true-ups of the MMCs. [*See supra* Section III.A.5.b]. Finally, Staff witness Mr. Sisung verified the net positive impact to retail customers projected by Mr. Datta's TCI, which took a conservative approach by excluding the benefits of the WFC to St. Landry Line. [*See supra* Section III.A.5.e]. In conclusion, the record supports a finding that the WFC to St. Landry Line is a system resource because it provides benefits across ELL's customer base and because the costs are commensurate with those benefits.

I. The Liquidation Procedures Included in the ESA Reasonably Apply in the Event of Early Termination, but Not at the End of the ESA Term (Contested Issue "n").

As explained under Large Load Guideline #4 above, the ESA provides for certain liquidation procedures upon the early termination of the agreement. Under those liquidation procedures, ELL chooses which Proposed Generators it wishes to keep as "Retained Generators," and the rest are liquidated. [Beauchamp Direct at 30]. Generally, the proceeds from the liquidation of the non-Retained Generators offset a portion of the remaining net book value of those generators, and the Customer pays the remainder of the net book value. [Sisung Direct at 117]. This protects customers from having to bear the expense of any surplus generators for which ELL no longer has a need. Although these liquidation procedures protect customers in an early

termination scenario, they are not triggered by a normal termination at the end of the ESA's Original Term or one of the subsequent renewal terms. [Beauchamp Direct at 30].

LEUG witness Mr. Dauphinais testified that the absence of comparable protections upon a normal termination is concerning. He testifies that ELL's non-Evest customers may become responsible for the net book value of the Evest resources once the ESA term expires. [Dauphinais Direct at 18]. Mr. Dauphinais states that the terminal costs of those resources will be approximately $3.85 billion in nominal dollars at the end of the 20-year Original Term of the ESA. [*Id.* at 19]. To mitigate this potential risk to non-Evest customers, Mr. Dauphinais proposes to condition certification and approval of ELL's Application on a modification of the ESA so that the retention and liquidation procedures that apply upon an early termination also apply upon a normal termination. [*Id.* at 21-22]. Mr. Dauphinais claims that this condition "would help to ensure Evest fully funds the incremental generation, transmission, and infrastructure investments necessary to serve its project." [*Id.* at 22].

The Staff understands Mr. Dauphinais's concern but does not agree with his remedy. [Sisung Cross-Answering at 73]. Non-renewal of the ESA may be a real concern, especially for the three Pointe Coupee units, but remaining net book value at the end of the 20-year Original Term does not by itself show stranded cost or harm to ELL's non-Evest customers. [*Id.* at 68]. That is because ELL will continue to own the assets, and their economic significance will depend on many factors, such as the condition of the generators, their remaining useful lives, ELL's load and resource position in twenty years, potential sale and other disposition opportunities, and the costs that ELL would otherwise incur to replace any of the generators that may be needed. [*Id.*]. For the same reasons, a liquidation framework designed to protect against an earlier-than-expected termination will not necessarily produce the appropriate economic result

upon the normal expiration of a 20-year agreement. [*Id.* at 73-74]. If a generator remains needed and economic at the end of the Original Term, "requiring its liquidation or imposing a predetermined treatment simply because Evest does not renew could itself disadvantage existing customers." [*Id.* at 74].

The terms of the current ESA also already significantly mitigate the risks identified by Mr. Dauphinais. The four Richland Parish Proposed Generators will be depreciated over twenty years, the length of the ESA's Original Term, so that those units will be approximately 90% depreciated, on average, by the end of the Original Term. [Jones Direct at 16; Beauchamp Rebuttal at 10]. Additionally, the significant benefits that will be realized by ELL's non-Evest customers more than offset any potential stranded asset risk at the end of the ESA, even in the unlikely event that all the remaining assets have zero value at the end of the Original Term. [Datta Rebuttal at 14 ("Even in the extremely unlikely event that the entire remaining net book value is written off as a total loss, customers will still have realized nearly $1 billion in net NPV benefits.")].

Regardless of whether Mr. Dauphinais's concerns are likely to materialize, the Stipulated Settlement resolves them reasonably. The settlement addresses the concern underlying Mr. Dauphinais's recommendation without rewriting the ESA. Mr. Dauphinais's core objection appears to be that, upon a normal termination, ELL could simply retain the system resources without any Commission review. [Dauphinais Direct at 18]. Indeed, ELL stated in discovery that, because the Commission would have found the assets to be system resources, "no additional regulatory approvals would be expected to be necessary to retain approved assets in the event of a non-renewal" of the ESA. [Exhibit JRD-4 at 4 (ELL Response to Sierra 2-7(b))]. The Stipulated Settlement closes that gap.

Under the Stipulated Settlement, ELL must notify the Commission within 30 days of receiving a notice of non-renewal or early termination from the Customer. [Stipulated Settlement § IV.D.5]. Within six months of that notice, ELL must file a transition plan addressing (1) the retention or disposition of the Proposed Generators and the Proposed Transmission Facilities; (2) proposals to mitigate customer rate impacts from any assets with unrecovered net book value at the effective date of non-renewal or early termination; (3) the continued utilization and/or monetization of those facilities; and (4) any proposed ratemaking treatments. [*Id.*, § IV.D.6]. If ELL proposes to continue recovering the costs of any assets with unrecovered net book value, it "shall demonstrate why continued recovery is reasonable under the facts then existing and applicable law and regulations." [*Id.*]. Because the Customer must give at least three years' notice of non-renewal, the transition plan will be filed well before the ESA expires, giving ELL and the Commission a meaningful period to evaluate the consequences. [Sisung Cross-Answering at 74; Beauchamp Rebuttal at 11-12].

The Stipulated Settlement also preserves the Commission's full authority over the issue Mr. Dauphinais raises. The Commission retains its authority regarding prudence, including over "ELL's recovery of any costs associated with assets with unrecovered net book value at the effective date of any termination or non-renewal of the ESA." [Stipulated Settlement § IV.A.2]. In the event of non-renewal, ELL must also "prudently seek to maximize the value of any excess capacity that may result from the termination or nonrenewal." [*Id.* § IV.C.1]. The Stipulated Settlement also authorizes the 20-year depreciable life for the four Richland Parish Proposed Generators and all three Battery Storage Facilities, which reduces the net book value that could remain at the end of the Original Term. [*Id.* § I.B.7]. Together, these provisions implement Mr. Sisung's recommendation that certification create no presumption that whatever net book value

remains after non-renewal will be recovered from existing customers, while leaving the actual disposition and ratemaking treatment to be determined on the facts that exist at that time. [Sisung Cross-Answering at 74-75]. ELL has agreed to this approach. [Beauchamp Rebuttal at 11-12].

The Stipulated Settlement therefore gives existing customers the protection Mr. Dauphinais seeks—an affirmative Commission review of the ratemaking treatment of any remaining Evest investment before it flows into rates—without fixing today a liquidation outcome that may prove contrary to customers' interests two decades from now. The Commission should decline to condition certification on Mr. Dauphinais's proposed modification of the ESA and should instead approve the Stipulated Settlement.

J. Responsibility for Any Future Inability to Collect on the Buyer's Guaranty Should Be Determined on the Facts If It Arises, Not Predetermined Here (Contested Issue "o").

The question of whether ratepayers or ELL shareholders bear the risk of the Company's ability or inability to collect on the Buyer's Guaranty is not ripe for adjudication in this proceeding because the cost responsibility in that scenario must be determined in the future, based on the specific facts that cause ELL to be unable to collect on the guaranty. [Sisung Cross-Answering at 64-65 ("[T]he Commission should determine the actual net harm and responsibility based upon what occurred.")]. Mr. Sisung acknowledges that there is a risk that ELL may be unable to fully collect on the Buyer's Guaranty in the future but concludes that the Commission should "preserve its ability to evaluate the actual consequences if the financial protections are materially called upon while making clear that certification does not transfer responsibility for the sufficiency of ELL's negotiated protections to existing customers." [Sisung Cross-Answering at 59, 64].

The Stipulated Settlement resolves this issue by putting the burden of implementing and enforcing the Guaranty on ELL as a matter of prudence. It states that ELL "will ensure that

all collateral support, including guaranty agreements, is obtained and fully executed timely, and prudently enforce its rights with respect to the collateral, including the guaranty agreement and the Credit Default Security." [Stipulated Settlement § IV.B.3]. The Settlement also provides that the Commission keeps full prudence authority over ELL's "management, implementation, and enforcement of the ESA and the Related Agreements." [*Id.*, § IV.A.2]. These settlement provisions preserve the Commission's authority to disallow recovery if ELL fails in its duty to act prudently and avoids predetermining that any collateral shortfall is a shareholder loss regardless of cause or harm. The cost responsibility for ELL's failure to collect on the Buyer's Guaranty in the future, therefore, is speculative and not properly before the Commission here.

K. The Transfer of Nuclear-Uprate Alternative Energy Credits to the Customer Is Resolved in the Stipulated Settlement (Contested Issue "p").

The Stipulated Settlement largely resolves Contested Issue "p." In its application, ELL asked the Commission to acknowledge that it may transfer to, use, or retire on behalf of the Customer any Alternative Energy Credits ("AECs") from three sources: the Waterford 3 uprate (if approved), the Waterford 3 refueling cycle upgrades, and any other uprate to an ELL nuclear facility that the Customer pays for, including a possible future uprate at River Bend. [Application at 31]. ELL is not seeking certification of any of these possible upgrades in its application and does not request that the Sustainability Agreement be approved as a whole in this proceeding. [Ingram Direct at 11]. The Waterford 3 uprate is pending in Docket No. U-37677, and certification of any River Bend uprate would be filed for separately. [*Id.* at 11-12].

Staff supports ELL's request that the Commission acknowledge the potential transfer of AECs. Because the Customer will be funding the investments that produce the environmental attributes, it is reasonable for the Customer to receive the resulting AECs, as long as the underlying project is approved and the Customer bears its costs. [Sisung Direct at 174-75].

The Stipulated Settlement adopts that position and states that ELL may transfer to, and/or otherwise utilize or retire AECs on behalf of the Customer, but only for uprates that are "fully paid for by the Customer." [Stipulated Settlement § II.A]. Additionally, the settlement provides that any River Bend uprate must first be approved by the Commission in a future proceeding. [*Id.*]. Those limits ensure that other customers did not give up attributes from resources they paid for. Additionally, Ms. Ingram testifies that "[a]ll customers will benefit from the incremental energy and capacity associated with the Nuclear Upgrades to the system, which will be entirely paid for by the Customer." [Ingram Direct at 33].

LEUG witness Mr. Dauphinais recommends conditioning any acknowledgement on ELL filing a proposal to give all retail customers transparent and non-discriminatory access to nuclear AECs within 180 days of a final order in this proceeding. [Dauphinais Direct at 7, 28]. Staff, however, agrees with ELL that this proposal is outside the scope of this proceeding. [*See* Ingram Rebuttal at 13]. As Ms. Ingram explains, "LEUG's request is not related to the requests for relief and certification in this docket, however, and is accordingly out of the scope for this proceeding." [*Id.*]. This docket concerns whether the Proposed Generators, Battery Storage Facilities, and Proposed Transmission Facilities serve the public convenience and necessity, along with the related ratemaking relief. It does not concern the design of a new, system-wide AEC offering.

Declining to adopt LEUG's condition here does not reject LEUG's underlying concern. ELL has acknowledged that current and prospective customers have recently asked about buying AECs. ELL has also said it is evaluating whether to offer customers access through a Commission-approved subscription program. [Ingram Rebuttal at 13]. Any such program, and

any broader question about fair access to nuclear AECs, can be raised in a separate proceeding where the Commission has a full record and all affected parties can take part.

L. Certification Should Not Be Conditioned on Removal of Section B.6 of the Sustainability Agreement, Which the Commission Is Not Being Asked to Approve (Contested Issue "q").

SREA witness Mr. Hoyle asks the Commission to condition certification on ELL removing Section B.6 from the Sustainability Agreement, arguing that ELL should not use its retail monopoly to require large-load customers to forgo wholesale and other renewable-energy arrangements, such as virtual power purchase agreements and private-use networks, that may be beyond the Commission's jurisdiction. [Hoyle Direct at 8]. That request is outside the scope of this proceeding. The Sustainability Agreement is Appendix G to Rider 1 of the ESA and is therefore one of the Related Agreements that the Stipulated Settlement expressly does not approve. [Exhibit LKB-2 at 97-118; Stipulated Settlement §§ I.B.2, IV.A.1]. Consistent with Mr. Sisung's recommendation that the Commission not "approve or ratify provisions contained in the Sustainability Agreement" in this certification docket, the Stipulated Settlement grants none of ELL's requested Sustainability Agreement relief other than the AEC acknowledgment addressed in Section III.K. [Sisung Direct at 171–73; Stipulated Settlement § II.A].

ELL likewise takes the position that the issue "is not properly before the Commission," because it concerns a provision of an agreement for which ELL did not seek approval in this case. [Amended Jt. Pre-Hrg. Statement at 10 n.8; *see also* Ingram Rebuttal at 13–14 (the agreements are negotiated and "not subject to being reopened and revised in this proceeding")]. It would therefore be improper to condition certification on removing or amending any provision of the Related Agreements.

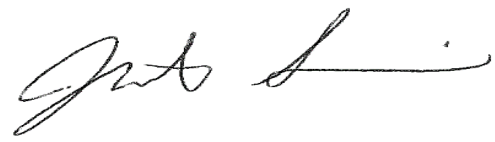
IV. CONCLUSION

ELL has demonstrated that its application, as amended by the Stipulated Settlement, serves the public convenience and necessity and should be approved.

Respectfully submitted,



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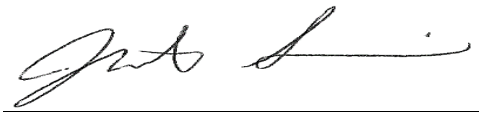


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CERTIFICATE OF SERVICE

I hereby certify that a copy of the above and foregoing Initial Post-Hearing Brief on Behalf of the LPSC Staff has been served upon all counsel of record by e-mail this 12th day of November, 2026.



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