

BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE:* APPLICATION OF ENTERGY)**
LOUISIANA, LLC FOR APPROVAL TO)
CONSTRUCT WATERFORD 6 POWER)
STATION AND WESTLAKE POWER)
STATION, AND FOR COST RECOVERY)

DOCKET NO. U-_____

DIRECT TESTIMONY
OF
PATRICK A. SULLIVAN

ON BEHALF OF
ENTERGY LOUISIANA, LLC

PUBLIC REDACTED VERSION

FEBRUARY 2026

TABLE OF CONTENTS

	<u>Page</u>
I. INTRODUCTION AND PURPOSE	1
II. PROPOSED COST RECOVERY	3
III. ESTIMATED FIRST-YEAR REVENUE REQUIREMENTS	14
IV. REQUESTED REGULATORY APPROVALS AND TIMING THEREOF.....	22
V. COMPLIANCE WITH COMMISSION ORDERS.....	26
VI. PUBLIC INTEREST	32
VII. CONCLUSION.....	38

EXHIBITS

Exhibit PAS-1	WF6 Revenue Requirement
Exhibit PAS-2 (HSPM)	Westlake Revenue Requirement
Exhibit PAS-3 (HSPM)	Proposed Generators

1 **I. INTRODUCTION AND PURPOSE**

2 Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

3 A. My name is Patrick A. Sullivan. I am employed by Entergy Louisiana, LLC (“ELL”
4 or the “Company”) as a Manager, Regulatory Affairs. My business address is 4809
5 Jefferson Highway, Jefferson, Louisiana 70121.

6
7 Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

8 A. I am testifying before the Louisiana Public Service Commission (“LPSC” or the
9 “Commission”) on behalf of ELL.

10
11 Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL
12 EXPERIENCE.

13 A. I hold Bachelor of Science and Master of Science degrees in Geology from the
14 University of Florida. After earning those degrees in 2000, I worked as a project
15 hydrogeologist, a research scientist, and an environmental scientist. In 2009, I earned
16 a Master of Business Administration degree, with a concentration in finance, from the
17 Johnson Graduate School of Management at Cornell University. I then worked for two
18 years as a senior financial analyst for a specialty chemical manufacturer.

19 I joined Entergy Services, LLC (“ESL”)¹ in 2011 as a Lead Analyst and was
20 promoted to Senior Lead Analyst in 2014 and Senior Staff Analyst in 2015. In those

¹ ESL is an affiliated service company that provides engineering, planning, accounting, legal, technical, regulatory, and other administrative support services to each of the Entergy Operating Companies (“EOCs”). The EOCs are ELL, Entergy Arkansas, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.

1 roles, I provided financial modeling and analysis to support strategic decision-making
2 and external communications for Entergy Corporation and its affiliates. In 2019, I
3 transferred to work for Louisiana Regulatory Affairs with ELL and have accepted roles
4 of increasing responsibility since that time, including supporting the extension of
5 ELL's Formula Rate Plan ("FRP") and developing the financial model for ELL's
6 resilience plan. In my current capacity as Manager, Regulatory Affairs, I am
7 responsible for providing financial modeling and regulatory support services to ELL.
8 I also provide insight and guidance to various organizations across ELL and ESL on
9 regulatory matters and compliance with Orders of the Commission.

10

11 Q4. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A
12 REGULATORY COMMISSION?

13 A. Yes. I submitted Direct Testimony in support of ELL's Applications in LPSC Docket
14 No. U-37677 (Waterford 3 Uprate Project), LPSC Docket No. U-37735 (River Bend
15 Deregulated Asset Plan), and LPSC Docket U-37801 (Cottonwood Acquisition and
16 Cost Recovery).

17

18 Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

19 A. My testimony supports ELL's Application in this docket that seeks certification of and
20 approval for ELL's proposal to construct (1) the Waterford 6 Power Station ("WF6"),
21 a 754 megawatt ("MW") (ISO)² 1x1 Combined Cycle Combustion Turbine ("CCCT")

² ISO refers to the applicable standard established by the International Organization for Standardization. Company witness Nicholas D. Pressler describes this standard in greater detail in his Direct Testimony.

1 self-build proposal to be located at ELL's existing Waterford site near Killona,
2 Louisiana, and (2) the Westlake Power Station ("Westlake"), a 754 MW (ISO) 1x1
3 CCCT self-build proposal to be located at Entergy's existing Roy S. Nelson site in
4 Westlake, Louisiana, both of which were selected from the Request for Proposals
5 ("RFP") issued by ELL in 2024 seeking certain new-build CCCT resources (the "2024
6 CCCT RFP").³ More specifically, my testimony (i) presents ELL's proposed cost
7 recovery methodology for the construction of the two plants; and (ii) provides the first-
8 year revenue requirements associated with each of WF6 and Westlake. In addition, I
9 identify the regulatory approvals required under various Commission Orders, and I
10 explain the reasons for which the Commission should find that ELL has complied with
11 those Orders and that certification of the Proposed Generators should be found to be in
12 the public interest.

13

14 Q6. DO YOU SPONSOR ANY EXHIBITS?

15 A. Yes, I sponsor the exhibits listed in the Table of Contents.

16

17 **II. PROPOSED COST RECOVERY**

18 Q7. PLEASE DESCRIBE THE INVESTMENT NECESSARY TO CONSTRUCT THE
19 PROPOSED GENERATORS.

20 A. As discussed in greater detail in the Direct Testimony of Company witness Nicholas
21 D. Pressler, the primary cost of constructing the Proposed Generators is the cost of the

³ For ease of discussion, I refer to WF6 and Westlake collectively at times as the Proposed Generators.

1 two units' Engineering, Procurement, and Construction ("EPC") contracts. Other
2 direct costs needed for completing the projects include Entergy labor costs, costs for
3 other vendors, and other expenses such as sales taxes and costs for materials and tools.
4 As Mr. Pressler explains, the current estimate of the direct costs for WF6 is [REDACTED]
5 [REDACTED], and the estimate of direct costs for Westlake is [REDACTED]. Note that
6 these values do not include transmission interconnection costs or any transmission
7 system upgrades associated with the Planned Generators.

8 In addition to these direct costs, there are other construction-related costs.
9 First, as described in the testimony of Company witness Chad J. Ladner, there are
10 estimated costs related to transmission investments needed to connect the new
11 generators to the bulk electric system and, as to Westlake, to secure Network Resource
12 Interconnection Service ("NRIS") rights through the Midcontinent Independent System
13 Operator, Inc. ("MISO").⁴ ELL will also incur financing costs during the construction
14 of the projects, which will be reflected in the form of financing costs for WF6⁵ and as
15 Allowance for Funds Used During Construction ("AFUDC") for Westlake, as well as
16 certain indirect costs.

⁴ As both Mr. Pressler and Mr. Ladner explain in their respective testimony, ELL anticipates using MISO's replacement generator process at WF6, which should result in WF6 securing NRIS rights without need for any additional system upgrades (or, in turn, the associated expense for such upgrades). As to Westlake, Mr. Ladner discusses certain estimated transmission upgrades required for NRIS at that plant. But, as he discusses, the actual costs to interconnect and obtain NRIS will be determined by MISO, and MISO's determination is expected to be completed subsequent to the date of this filing. Once MISO completes its review and provides its results, the Company will update relevant components of the overall cost estimate.

⁵ As I mention below, the Company anticipates using construction period financing from a third party to finance the construction of WF6 such that AFUDC will not accrue as to that plant. ELL has included the estimated financing costs in the revenue requirement calculation.

1 Lastly, for the purpose of providing an estimate of the total costs of the
2 Proposed Generators, ELL has included a contingency for changes in scope or increases
3 in cost during the construction of the two projects. It is worth noting, however, that
4 only actual costs of construction will be included in the final rate determination, as I
5 explain further below.

6
7 Q8. HOW DOES ELL PLAN TO FINANCE THE COSTS OF THE PROPOSED
8 GENERATORS?

9 A. ELL intends to self-finance Westlake using a mix of debt and equity financing. With
10 respect to WF6, ELL intends to pursue a construction period financing structure with a
11 third party under which WF6 would be recognized on ELL's books at or near the in-
12 service date. Under this approach, AFUDC would not accrue during construction, and
13 the costs of the construction period financing would be recognized instead.

14
15 Q9. ARE THERE ANY OTHER POTENTIAL COSTS ASSOCIATED WITH THE
16 PROPOSED GENERATORS?

17 A. Yes. In addition to the initial costs to construct the new generators, there will be
18 ongoing expense related to operations and maintenance ("O&M") of the plants. Such
19 O&M expenses include labor costs, parts and materials, natural gas fuel, Long Term
20 Service Agreement ("LTSA") expense, and property taxes, among others. A detailed
21 cost estimate of the costs related to each of the Proposed Generators is provided by Mr.
22 Pressler.

1 Q10. WHAT IS THE PROPOSED COST-RECOVERY MECHANISM FOR THE
2 PROPOSED GENERATORS?

3 A. In answering this question, I assume, first, that ELL will have an FRP in place that
4 requires an annual filing, which would provide ELL with a reasonable opportunity for
5 full recovery of the costs it incurs to provide customers with the benefits of the
6 Proposed Generators. Under that assumption, I propose that on or about twelve months
7 prior to the expected in-service date of each of the Proposed Generators,⁶ ELL make a
8 compliance submission in this docket providing the then-best estimate of the first-year
9 revenue requirement of the relevant plant and supporting data (“Revenue Requirement
10 Submission”). The Revenue Requirement Submission would reflect the first-year
11 revenue requirement for the relevant generator and related costs. For example, assume
12 the expected in-service date for one of the units to be July 31, 2030. In that case, the
13 Revenue Requirement Submission for that unit would be made on or about July 31,
14 2029. The parties would have an opportunity to request information regarding the
15 revenue requirement calculation and propose corrections. An additional update to the
16 estimated first-year revenue requirement would be submitted in this docket sixty days
17 prior to the expected in-service date for each of the Proposed Generators (“Final
18 Estimate Update”) and, again, the parties would have an opportunity to request
19 information regarding the revenue requirement calculation and propose corrections. I
20 propose that the parties be required to provide ELL any recommended adjustments to

⁶ As Company witness Chad J. Ladner explains, there are certain Interconnection Upgrades that ELL anticipates will be required for Westlake to secure NRIS rights. ELL proposes that the costs for the Interconnection Upgrades would be recoverable through (and in accordance with the provisions applicable to) the Transmission Recovery Mechanism (“TRM”), as discussed further below.

1 the Final Estimate Update within 25 days of filing. Absent proposed adjustments, each
2 of the Proposed Generators' Final Estimate Update would serve as the basis for the
3 amount that is included in rates for the first billing cycle following each unit's
4 placement in service, pursuant to Section 3.D of the FRP (the Additional Capacity
5 Mechanism, or "ACM") or a similar recovery mechanism.

6 In the event adjustments to the Final Estimate Update are proposed, any
7 adjustments agreed by ELL shall be reflected in the rates that are implemented with the
8 first billing cycle following placement in service. To the extent there are unresolved
9 issues regarding a proposed adjustment, the revenue requirement included in the Final
10 Estimate Update shall be implemented, subject to refund and resolution in the
11 subsequent FRP in accordance with the dispute resolution process provided for therein.
12 Any changes to the revenue requirement that result from that process would be reflected
13 in the FRP outside of sharing, just as the revenue requirement would have been initially
14 reflected in FRP rates.

15 Based on the current FRP procedures, ELL's initial Test Year 2029 Evaluation
16 Report would not include any effects of either of the Proposed Generators. The
17 Company proposes to implement interim adjustments to rates as described above,
18 followed by a true-up, in accordance with the terms of the ACM. After the true-up
19 pursuant to the ACM, the Evaluation Report for the applicable FRP and corresponding
20 prospective rates will reflect the realignment of the relevant revenue requirements and
21 will be taken into account within the bandwidth calculation of the applicable FRP (*i.e.*,
22 inside of sharing) through the subsequent FRP Evaluation Period with any required

1 change in rates taking effect with the corresponding Evaluation Period rate effective
2 date.

3 This recovery plan will allow for the synchronization in rates of the costs of the
4 Proposed Generators with the normal FRP cycle, and coordinates recovery from
5 customers of the non-fuel costs at the same time customers receive the fuel savings
6 from the Proposed Generators being placed in service. The Company specifically
7 requests that the Commission approve this procedure to implement the necessary
8 change in rates contemporaneously with the commercial operation of the Proposed
9 Generators. It should be noted that this in-service ratemaking treatment is consistent
10 with the rate recovery plan approved by the Commission in connection with ELL's
11 construction of Ninemile 6, St. Charles Power Station, and Lake Charles Power
12 Station.⁷

13
14 Q11. ASSUMING AN FRP EXISTS IN SUBSTANTIALLY THE SAME FORM WHEN
15 THE PROPOSED GENERATORS GO INTO SERVICE, WHAT MECHANISM
16 DOES THE COMPANY PROPOSE TO USE FOR RECOVERY OF THE COSTS TO
17 CONSTRUCT THE PROJECTS?

18 A. As mentioned above, under such an FRP cost recovery framework, ELL would seek to
19 recover the costs to construct the Proposed Generators (other than the costs for the
20 transmission-related Interconnection Upgrades for Westlake) through the ACM set
21 forth in Section 3.D.1 of the FRP, which authorizes recovery "fully through [the] Rider

⁷ See Commission Order Nos. U-31971, U-33033, and U-34283

1 FRP, outside of the FRP sharing mechanism” of the retail revenue requirement
2 associated with the construction of a new generating facility that has an annual revenue
3 requirement in excess of \$10 million.

4 The ACM is an acknowledgement in the FRP that the functionality of certain
5 FRP mechanisms (for example, the earnings bandwidth and sharing provisions) is
6 insufficient to account for significant increases in rate base and cost of service—like
7 those resulting from a new generating unit being placed in service)—while also
8 continuing to provide an opportunity for the Company to recover its investment and
9 earn a reasonable return on a timely basis. Moreover, use of the ACM in the manner I
10 have proposed is consistent with Commission precedent in which the Commission has
11 previously recognized that it is appropriate to provide for contemporaneous cost
12 recovery to avoid the effects of regulatory lag on large capital projects,⁸ including self-
13 build projects,⁹ and acquisitions.¹⁰

⁸ See Order No. U-30670 (May 5, 2010), *In re: Application of Entergy Louisiana, LLC for Authorization for Approval to Replace Waterford 3 Steam Generators, Reactor Vessel Closure Head, and Control Element Drive Mechanisms, and for Certain Cost Protection and Cost Recovery*, Docket No. U-30670.

⁹ See Order No. U-31971 (April 5, 2012), *Ex Parte: Joint Application of Entergy Louisiana, LLC for Approval to Construct Unit 6 at Ninemile Point Station and of Entergy Gulf States Louisiana, L.L.C. for Approval to Participate in a Related Contract for the Purchase of Capacity and Electric Energy, for Cost Recovery and Request for Timely Relief*, Docket No. U-31971.

¹⁰ See Order No. U-27836 (May 3, 2005), *In re: Entergy Louisiana, Inc. and Entergy Gulf States, Inc., ex parte. In re: Application of Entergy Louisiana, Inc. for Approval of the Purchase of Electric Generating Facilities and Entergy Gulf States, Inc. for Authority to Participate in Contract for the Purchase of Capacity and Electric Power*. See also, Order No. U-31196 (April 9, 2010), *In re: Application of Entergy Louisiana, LLC for Approval to Purchase Power Block Two of the Acadia Energy Center, and Joint Application of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. for Approval to Participate in Certain Related Contracts for the Purchase of Capacity and Electric Power and for Cost Recovery*.

1 Q12. WHAT MECHANISM IN THE CURRENT FRP DOES THE COMPANY PROPOSE
2 TO USE FOR RECOVERY OF THE COSTS FOR THE PROPOSED
3 GENERATORS' TRANSMISSION-RELATED PROJECTS?

4 A. As both Mr. Ladner and Mr. Pressler explain, there are certain costs that are required
5 for transmission lines to connect both WF6 and Westlake to the point of interconnection
6 on the bulk electric system (the "Generator Tie-Ins"), and both witnesses explain the
7 current estimates for those facilities. The Company is asking that the costs of the
8 Generator Tie-Ins be found to be eligible for recovery in rates. The Company further
9 asks that, because the Generator Tie-Ins are necessary for the function of the Proposed
10 Generators—*i.e.*, by allowing the electricity produced by the units to reach the bulk
11 electric system for transport—those costs be included with the other costs for the
12 Proposed Generators and deemed eligible for recovery through the ACM.¹¹

13 As Mr. Ladner and Mr. Pressler further discuss, there are estimated costs for
14 anticipated projects that ELL expects will be needed to secure NRIS for Westlake. As
15 to those Interconnection Upgrades (as that term is defined by Mr. Ladner), ELL also
16 asks that the associated costs be found eligible for recovery in rates and proposes that
17 the costs should be recovered through the Transmission Recovery Mechanism
18 ("TRM") and in the normal course of the FRP. Moreover, it also bears noting that the
19 final cost to customers and associated bill impacts of these Interconnection Upgrades
20 will be less than presented in this testimony due to the inclusion of those upgrades in
21 the Company's MISO Attachment O billings and the collection of revenues, on account

¹¹ The Company notes that this requested treatment is consistent with, *e.g.*, the cost-recovery method approved for Lake Charles Power Station in LPSC Docket No. U-34283.

1 of these upgrades, from wholesale customers taking transmission service in the ELL
2 transmission pricing zone.

3
4 Q13. WHAT IS THE COMPANY'S PROPOSAL FOR COST RECOVERY IN THE
5 EVENT THE FRP DOES NOT EXIST IN ITS CURRENT OR SIMILAR FORM OR
6 COST RECOVERY IS DELAYED?

7 A. In the event that the FRP does not exist in its current or similar form when the Proposed
8 Generators are placed in service, or cost recovery is delayed beyond the dates on which
9 the Proposed Generators are placed in service, the Company requests that it be allowed
10 to defer all non-fuel costs, including a full return on the investment, until such time as
11 those costs are reflected in rates. Such a deferral would include the accrual of carrying
12 charges at the full Commission-authorized rate of return, and the Company proposes
13 that the deferred costs would be recovered over a two-year period beginning
14 contemporaneously with the time that the costs of the Proposed Generators begin to be
15 recovered from customers through rates.

16 Similarly, in the event that the FRP does not exist in its current or similar form
17 when the Interconnection Upgrades are placed in service, or cost recovery is delayed
18 beyond the date on which FRP cost recovery would have otherwise commenced, the
19 Company proposes that the retail revenue requirement associated with the actual
20 prudently incurred costs of the Interconnection Upgrades, an estimate of which is
21 provided by Mr. Pressler and Mr. Ladner in their respective testimony, should be
22 deemed eligible for recovery through the creation and authorization of a regulatory
23 asset in the amount of these costs, with interest to be accrued thereon at the full

1 Commission-authorized rate of return, beginning from the date on which the
2 Interconnection Upgrades are placed into service and accruing until such time that the
3 costs can be reflected in rates. As with the alternative-cost recovery proposal described
4 above for the costs associated with the Proposed Generators, ELL proposes that it
5 should be authorized to recover such regulatory asset over a two-year period, beginning
6 contemporaneously with the time that the costs reflected in that regulatory asset begin
7 to be recovered from customers through rates.

8
9 Q14. PLEASE EXPLAIN HOW CUSTOMERS WILL RECEIVE THE BENEFITS FROM
10 THE CAPACITY AND ENERGY MARGINS ATTRIBUTABLE TO THE
11 PROPOSED GENERATORS.

12 A. The energy margins and customer load payment benefits associated with the Proposed
13 Generators will be realized by the Company through the settlement statements received
14 from participation in the MISO energy and operating reserve market and will, in turn,
15 be directly passed on to customers through ELL's Fuel Adjustment Clause ("FAC").
16 Accordingly, customers will begin seeing these benefits upon the commercial operation
17 of the Proposed Generators.

18 As for the capacity revenues arising from the Proposed Generators, the
19 Company currently participates in the MISO short-term capacity market by generally
20 selling all of its capacity resources and purchasing all of its capacity needs in that
21 market. The net revenue or cost resulting from that participation is passed on to the
22 Company through its MISO invoices and reflected in the ACM pursuant to ELL's
23 currently effective FRP. Assuming the FRP remains in place, the capacity revenues

1 associated with the Proposed Generators would continue to be reflected in the ACM,
2 pursuant to LPSC Order No. U-36959. It should be noted that these benefits are not
3 reflected in Exhibit PAS-1 and PAS-2 (which provide the WF6 revenue requirement
4 and Westlake revenue requirement, respectively, and which are discussed below),
5 though they are discussed further in my testimony.

6
7 Q15. HOW WOULD YOU PROPOSE THAT THE COST OF THE PROPOSED
8 GENERATORS SHOULD BE ALLOCATED TO CUSTOMER CLASSES?

9 A. If ELL remains subject to an FRP with terms similar to the current FRP, the first-year
10 revenue requirements will be recovered as a percentage of base rates from those classes
11 of customers specified by the FRP. If ELL is no longer subject to an FRP ratemaking
12 construct, the allocation of the revenue requirements would be the subject of a future
13 rate proceeding, such as a base rate case.

14
15 Q16. WHAT IS YOUR RECOMMENDATION IN THE EVENT THAT ELL NO LONGER
16 HAS AN FRP IN PLACE WHEN THE PROPOSED GENERATORS ENTER
17 SERVICE?

18 A. As mentioned above, should that circumstance occur, then my recommendation is that
19 the Commission authorize the Company to defer all non-fuel costs of the Proposed
20 Generators (including the Generator Tie-Ins) and the costs of the Interconnection
21 Upgrades, including a full return on the investments, until such time as those costs can
22 be reflected in rates. Such a deferral would include the accrual of carrying charges at
23 the full Commission-authorized rate of return. In that scenario, the specific terms of

1 the future rate recovery would be the subject of a future rate proceeding such as a base
2 rate case. It bears noting that this alternative recovery is generally more costly to
3 customers due to the accumulation of carrying charges on the deferred balance.

4 ELL may also deem it necessary to file a general rate case prior to the
5 anticipated in-service dates of the Proposed Generators. Under such circumstances,
6 ELL would include pro forma adjustments to the test year to reflect the estimated first-
7 year revenue requirements of the Proposed Generators.

8
9 **III. ESTIMATED FIRST-YEAR REVENUE REQUIREMENTS**

10 Q17. WHAT ITEMS ARE INCLUDED IN THE ESTIMATED FIRST-YEAR REVENUE
11 REQUIREMENTS?

12 A. The estimated first-year revenue requirements consist of two main components. The
13 first component of the revenue requirements is the estimated non-fuel O&M expenses
14 for the Proposed Generators during each unit's first year of operation. The second
15 component of the revenue requirements is the return of and on rate base. Calculation
16 of this amount requires an estimation of the capital investment required to construct
17 each unit, and calculates the average rate base of the Proposed Generators for the first
18 year of operation after taking into account depreciation. The calculations of the
19 estimated first-year revenue requirements are detailed in Exhibits PAS-1 and PAS-2.

20

1 Q18. PLEASE DISCUSS IN MORE DETAIL THE FIRST COMPONENT OF THE
2 ESTIMATED FIRST-YEAR REVENUE REQUIREMENTS.

3 A. As described in the Direct Testimony of Mr. Pressler, the Company will incur O&M
4 expenses during the first year of operation to ensure that the Proposed Generators
5 operate safely and reliably. Generally, those costs consist of labor and labor-related
6 costs and baseline operations and maintenance costs.¹² In addition, there will be other
7 operating expenses consisting of insurance and property taxes. Estimated property tax
8 expense utilized in the economic evaluation model was provided by the tax group at
9 ESL.

10

11 Q19. ARE THERE ANY LONG-TERM SERVICE AGREEMENT COSTS INCLUDED IN
12 THE FIRST-YEAR REVENUE REQUIREMENTS?

13 A. No. As explained by Mr. Pressler, there will be an LTSA for major maintenance
14 activities. ELL requests that, consistent with past Commission practice, the LTSA
15 costs for each of the Proposed Generators be recovered through the FAC. Variable
16 costs such as LTSA costs are properly recovered through the FAC, and the Commission
17 has previously authorized FAC recovery for similar costs for ELL's Ninemile 6

¹² Consistent with current practice and prior Commission approvals, fuel costs as well as various environmental compliance-related costs such as air emissions allowances and ammonia will be recovered through the FAC or Environmental Adjustment Clause ("EAC"), as applicable, in accordance with the LPSC's relevant General Orders. *See, e.g., LPSC Order Nos. U-27836 (Perryville), U-30422-A (Ouachita), U-31196-C (Acadia), U-31971 (Ninemile 6), and U-32759-A (Calcasieu).*

1 combined-cycle gas turbine,¹³ St. Charles Power Station,¹⁴ and Lake Charles Power
2 Station,¹⁵ as well as several other facilities, including Perryville, Acadia Power Block
3 2, Ouachita Unit 3, Calcasieu, and Union Power Blocks 3 and 4.¹⁶ Further (and most
4 recently), the Commission has approved such recovery in connection with the
5 generators at issue in LPSC Docket No. U-37425.¹⁷

6
7 Q20. PLEASE DISCUSS IN MORE DETAIL THE SECOND COMPONENT OF THE
8 ESTIMATED FIRST-YEAR REVENUE REQUIREMENT FOR WF6.

9 A. The return of and on rate base component of the revenue requirement is calculated in
10 two parts. ELL proposes an annual return of rate base (*i.e.*, the depreciation expense)

¹³ See Order No. U-31971 (April 5, 2012), *Ex Parte: Joint Application of Entergy Louisiana, LLC for Approval to Construct Unit 6 at Ninemile Point Station and of Entergy Gulf States Louisiana, L.L.C. for Approval to Participate in a Related Contract for the Purchase of Capacity and Electric Energy, for Cost Recovery and Request for Timely Relief*, Docket No. U-31971.

¹⁴ See Order No. U-33770 (December 14, 2016), *In re: Joint Application for Approval to Construct St. Charles Power Station, and for Cost Recovery*, Docket No. U-33770.

¹⁵ See Order No. U-34283 (July 20, 2017), *In re: Application for Approval to Construct Lake Charles Power Station and for Cost Recovery*, Docket No. U-34283.

¹⁶ See Order No. U-27836 (May 3, 2005), *In re: Entergy Louisiana, Inc. and Entergy Gulf States, Inc., ex parte. In re: Application of Entergy Louisiana, Inc. for Approval of the Purchase of Electric Generating Facilities and Entergy Gulf States, Inc. for Authority to Participate in Contract for the Purchase of Capacity and Electric Power*, Docket No. U-27836. See also, Order No. U-30422-A (October 13, 2009), *In re: Application of Entergy Gulf States, Inc., for Approval to Enter into Contract for the Purchase of Electric Power from Entergy Arkansas, Inc., Sourced from the Ouachita CCGT Facility and Request for Timely Treatment*, Docket No. U-30422; see also, Order No. U-31196-C (February 9, 2011), *In re: Application of Entergy Louisiana, LLC for Approval to Purchase Power Block Two of the Acadia Energy Center, and Joint Application of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. for Approval to Participate in Certain Related Contracts for the Purchase of Capacity and Electric Power and for Cost Recovery*, Docket No. U-31196; see also, Order No. U-32759-A (November 21, 2013), *In re: Application on Behalf of Entergy Gulf State Louisiana, L.L.C. for an Accounting Order and Declaratory Relief Relating to the Commission's General Order Dated November 6, 1997 Governing the Treatment and Allocation of Fuel Costs*, Docket No. U-32759; see also, Order No. U-33510 (November 5, 2015), *In re: Application of Entergy Gulf States Louisiana, L.L.C. for Approval to Purchase Power Blocks Three and Four of the Union Power Station and Request for Timely Treatment and Cost Recovery*, Docket No. U-33510.

¹⁷ See Attachment A to Order Number U-37425 (Aug. 29, 2025), at § A.7, LPSC Docket No. U-37425, *In re: Application for approval of generation and transmission resources in connection with service to a single customer for a project in North Louisiana*.

1 of 3.12%, which is the rate utilized for other CCCT units in ELL's generation portfolio
2 and is the rate accepted by the LPSC associated with Ninemile 6, Union Power Blocks
3 Three and Four, St. Charles Power Station, and J. Wayne Leonard Power Station.

4 The return on rate base is calculated by multiplying the pre-tax rate of return by
5 the rate base for the proposed acquisition. For purposes of this calculation, the pretax
6 rate of return of 8.63% is based on the Company's capitalization ratios and cost rates
7 of capital, which were determined as of December 31, 2024, and were most recently
8 utilized in the Company's TY24 FRP Evaluation Report filing. (Note, however, that
9 the Company's actual pretax rate of return reflected in the most recently filed FRP
10 preceding each of the Proposed Generators' in-service dates would be utilized in
11 calculation of the revenue requirement for implementation in rates.)

12 The starting point for calculating the return of and on rate base revenue
13 requirement is the projected construction cost of \$[REDACTED]. This value constitutes
14 the rate base (inclusive of transmission interconnection costs) when WF6 is first placed
15 into service. Also capitalized to plant on WF6's in-service date are ELL's carrying
16 costs,¹⁸ currently estimated at \$[REDACTED], and contingency costs, currently
17 estimated at \$[REDACTED], for a total beginning-of-year rate base balance of \$2.027
18 billion, assuming the contingency is utilized.

19 During the first year of ownership, depreciation expense will be recognized in
20 the amount of approximately \$63.4 million. Depreciation expense also gives rise to an
21 accumulated reserve for depreciation in that amount, which is included in rate base.

¹⁸ As referenced elsewhere in this testimony, ELL is seeking to finance WF6 through bank financing, which would impact the use of AFUDC in calculating that unit's first-year revenue requirement.

1 The final component of rate base is accumulated deferred income taxes (“ADIT”),
2 which represents the tax effect of the timing differences between straight-line book and
3 accelerated tax depreciation and provides a reduction to rate base. The end result is an
4 estimated total rate base of \$1.961 billion at the end of the first year of ownership.
5 Thus, the average rate base during the first year of ownership is \$1.994 billion. The
6 return on rate base is \$172.1 million.

7
8 Q21. PLEASE DISCUSS IN MORE DETAIL THE SECOND COMPONENT OF THE
9 ESTIMATED FIRST-YEAR REVENUE REQUIREMENT FOR WESTLAKE.

10 A. The return of and on rate base component of the Westlake revenue requirement is
11 calculated in the same manner as WF6, using the same 3.12% depreciation rate and
12 pretax rate of return of 8.63% noted previously.

13 The starting point for calculating the return of and on rate base Westlake
14 revenue requirement is the projected construction cost of \$[REDACTED]. This value
15 constitutes the rate base (inclusive of the generation tie-in costs, but not transmission
16 system upgrades costs) when Westlake is first placed into service. Also capitalized to
17 plant on Westlake’s in-service date are ELL’s carrying costs, currently estimated at
18 [REDACTED], and contingency costs, currently estimated at [REDACTED], for a total
19 beginning-of-year rate base balance of \$1.928 billion.

20 During the first year of ownership, depreciation expense will be recognized in
21 the amount of approximately \$60.3 million, representing the first year of the return of
22 the total capital investment for Westlake. Depreciation expense will also again give
23 rise to an accumulated reserve for depreciation in that amount, which is included in rate

1 base. As with WF6, the final component of rate base for Westlake is ADIT. The end
2 result is an estimated total Westlake rate base of \$1.865 billion at the end of the first
3 year of ownership. Thus, the average rate base during the first year of ownership is
4 \$1.897 billion. The return on rate base is \$163.7 million.

5 The Company has also included the cost of the estimated transmission system
6 upgrades associated with Westlake in its revenue requirement calculation, although it
7 should be noted that the proposed cost recovery methodology for these transmission
8 system upgrades differs from that for the Proposed Generators.¹⁹ The estimated first-
9 year average rate base of the transmission system upgrades is [REDACTED]. The
10 return on rate base associated with the transmission system upgrades is [REDACTED].

11
12 Q22. ARE THERE ANY FURTHER ADJUSTMENTS NEEDED TO CALCULATE THE
13 TOTAL FIRST YEAR REVENUE REQUIREMENTS FOR THE PROPOSED
14 GENERATORS?

15 A. Yes, there are two additional adjustments necessary to compute the retail revenue
16 requirements. First, the retail revenue requirement for each unit is adjusted by the
17 Revenue Conversion Factor to reflect uncollectible revenues and local franchise taxes.
18 Then, the total revenue requirement must be multiplied by the LPSC-Jurisdictional
19 Retail Allocation Factor (currently at 100%) to arrive at the authorized retail revenue

¹⁹ As discussed, the Company anticipates that the Interconnection Upgrades will be recovered through the TRM rather than the ACM. For simplicity, the cost of the transmission system upgrades is reflected in the Westlake first-year revenue requirement and the Westlake bill impact estimates presented in this Application. Also, as mentioned above, it is probable that the final cost to customers and associated bill impact of the transmission system upgrades will be less than presented herein due to the inclusion of the transmission system upgrades in the Company's MISO Attachment O transmission billings and associated collection of revenues from wholesale customers in the ELL transmission pricing zone.

1 requirement. The Revenue Conversion Factor and the LPSC-Jurisdictional Retail
2 Allocation Factor from ELL's Test Year 2024 FRP are used for purposes of these
3 calculations.

4
5 Q23. WHAT ARE THE ESTIMATED FIRST-YEAR REVENUE REQUIREMENTS?

6 A. The total Commission jurisdictional first-year revenue requirement for WF6 is
7 estimated to be \$244.7 million, as shown on Page 2 of Exhibit PAS-1. The total
8 Commission jurisdictional first-year revenue requirement for Westlake is estimated to
9 be \$253.1 million, as shown on Page 3 of Exhibit PAS-2. Of the latter amount,
10 approximately [REDACTED] is attributable to the Interconnection Upgrades associated
11 with Westlake.²⁰ Both values include the return of and on rate base as well as O&M
12 expenses, taxes, and insurance.

13
14 Q24. WHAT IS THE ESTIMATED RESIDENTIAL BILL IMPACT OF THE PROPOSED
15 GENERATORS?

16 A. While the two units are not expected to enter service simultaneously, a residential
17 customer using 1,000 kWh per month is expected to experience a first-year bill increase
18 of approximately \$14.37 per month as a result of the Proposed Generators. Of this
19 amount, \$7.06 is attributable to WF6, and \$7.30 is attributable to Westlake.²¹ The
20 calculations supporting the estimated residential bill impacts at a 1,000 kWh usage

²⁰ *Id.*

²¹ Of the estimated bill impact of \$7.30 for Westlake, [REDACTED]
[REDACTED].

level are set forth on Page 4 of Exhibit PAS-1 (for WF6), and Page 5 of Exhibit PAS-2 (for Westlake). Estimated residential bill impacts (inclusive of both units and the Interconnection Upgrades at Westlake) at higher usage levels are demonstrated in Exhibit PAS-3.²²

Q25. ARE THERE ANY OFF-SETTING EFFECTS TO THE ESTIMATED RESIDENTIAL BILL IMPACT OF THE PROJECTS THAT ARE NOT DEMONSTRATED IN THE FIRST-YEAR REVENUE REQUIREMENTS?

A. Yes. As discussed by Company witness Phong D. Nguyen, there is a “Total Supply Cost Savings” associated with the Proposed Generators that evaluates the difference between ELL’s Total Supply Cost under a change case where a proposal is included relative to the base case in which the proposal is replaced with two CCCTs within the Company’s portfolio. Any fuel savings—which are expected to be significant—will inure to customers’ benefit through the Fuel Adjustment Clause. These effects are not captured within the estimated bill impacts provided in Exhibits PAS-1 and PAS-2.

²² ELL is presenting these impacts in materially the same format as specified on Exhibit B to Attachment 1 to the LPSC General Order dated August 1, 2024 (R-35462). ELL notes, however, that the Application does not seek approval of a change in rates and, as typical for the Company’s resource certification filings, is instead seeking a finding that the prudently incurred costs of the Proposed Generators and transmission system upgrades are eligible to be recovered in customer rates. ELL thus asserts that compliance with the provisions of Section 201 in the Order issued in LPSC Docket No. R-35462 is not required for this filing.

1 **IV. REQUESTED REGULATORY APPROVALS AND TIMING THEREOF**

2 Q26. PLEASE DISCUSS THE REGULATORY APPROVALS SOUGHT BY ELL.

3 A. In the Application, ELL seeks, among other things, the following findings by the
4 Commission:

- 5 1. Find that the Company's construction of the Proposed Generators, including the
6 Generator Tie-Ins and Interconnection Upgrades, serves the public convenience
7 and necessity and is in the public interest, and is therefore prudent, in accordance
8 with the Commission's 1983 General Order;²³
- 9 2. Find that the selection of the Proposed Generators through the 2024 CCCT RFP is
10 consistent with the terms of the Commission's then-applicable MBM Order;²⁴
- 11 3. Find that the retail revenue requirement associated with the Proposed Generators
12 (to be determined in a subsequent revenue requirement filing, and including the
13 costs for the Generator Tie-Ins, but excluding the costs for the Interconnection
14 Upgrades, which are discussed below) is deemed eligible for recovery in the first
15 billing cycle of the month following commercial operation of each of the Proposed

²³ The 1983 General Order was amended by General Order dated May 27, 2009, in LPSC Docket No. R-30517, *In re: Possible modifications to the September 20, 1983 General Order to allow (1) for more expeditious certifications of limited-term resource procurements and (2) an exception for annual and seasonal liquidated damages block energy purchases.*

²⁴ See LPSC Docket No. R-26172, Sub-Docket C, *In re: Possible suspension of, or amendments to, the Commission's General Order dated November 3, 2006 (Market Based Mechanisms Order) to make the process more efficient and to consider allowing the use of on-line auctions for competitive procurement*, as amended October 29, 2008. As I explain below, the MBM Order was amended in October 2024, but those amendments applied prospectively and thus did not apply to the 2024 CCCT RFP, which was initiated before the amendments were approved by the Commission. See generally General Order 10-14-2024 (R-34247) (Oct. 14, 2024), LPSC Docket No. R-34247, *In re: Rulemaking to consider changes to Commission General Order dated October 29, 2008 (Docket No. R-26172 Subdocket C) ("Market Based Mechanisms Order") to incorporate formal complaint procedures.*

1 Generators in accordance with the terms of the Company's then-effective FRP,
2 outside of the FRP sharing mechanism and outside of any applicable cap;

3 4. In the alternative, if ELL does not have an FRP in place at the time the Proposed
4 Generators are placed in service (or if recovery is delayed beyond the commercial
5 operation dates for the Proposed Generators), authorize (i) a deferral of the non-
6 fuel revenue requirement (*i.e.*, costs that are not eligible to be recovered through
7 the FAC, including the costs for the Generator Tie-Ins, but excluding the costs for
8 the Interconnection Upgrades, which are discussed below) associated with the
9 Proposed Generators and creation of an associated regulatory asset until such time
10 as the costs of the Proposed Generators are reflected in the Company's retail rates,
11 and (ii) the accrual of carrying charges at the full Commission-authorized rate of
12 return on the deferred costs, commencing on the relevant date of commercial
13 operation of each of the Proposed Generators and continuing until such time as such
14 costs of the Proposed Generators are reflected in the Company's retail rates;

15 5. Find that the retail revenue requirement associated with the actual prudently
16 incurred costs of the Interconnection Upgrades, an estimate of which is provided
17 by Mr. Pressler and Mr. Ladner in their respective testimony, is deemed eligible for
18 recovery through the applicable mechanisms of the FRP to the extent the Company
19 remains subject to an FRP at the time the referenced facilities are placed in service,
20 or in the alternative, if ELL does not have an FRP in place at the time the referenced
21 facilities are placed in service or cost recovery is delayed beyond the date on which
22 FRP cost recovery would have otherwise commenced, through the creation and
23 authorization of a regulatory asset in the amount of these costs, with interest to be

- 1 accrued thereon at the full Commission-authorized rate of return, beginning from
2 the date on which the Interconnection Upgrades are placed into service and
3 accruing until such time that the costs are reflected in the Company's retail rates;
- 4 6. Authorize the recovery, over a two-year period, of the regulatory asset referenced
5 in Paragraph 4 above beginning contemporaneously with the time that the costs of
6 the Proposed Generators begin to be recovered from customers through rates;
- 7 7. Authorize the recovery, over a two-year period, of the regulatory asset referenced
8 in Paragraph 5 above beginning contemporaneously with the time that the costs of
9 the Interconnection Upgrades begin to be recovered from customers through rates;
- 10 8. Approve recovery, through the FAC, of the variable expenses incurred under the
11 LTSAs applicable to the Proposed Generators;
- 12 9. Approve the Monitoring Plan under which the Company will report to Commission
13 Staff on a quarterly basis the status of the Proposed Generators and Interconnection
14 Upgrades, including schedule, costs, and other critical associated activities; and
- 15 10. Rule that, with respect to the Proposed Generators described in the Application, the
16 Company has complied with, or is not in conflict with, the provisions of all
17 applicable LPSC Orders.

18

19 Q27. DOES THE COMPANY REQUEST A PARTICULAR TIMELINE FOR
20 COMMISSION CONSIDERATION?

21 A. Yes. As Company witness Michael J. Plaisance discusses in greater detail, the
22 Company is asking that the Commission consider ELL's Application no later than the

1 LPSC's December Business & Executive Session, which is currently scheduled for
2 December 16, 2026.

3
4 Q28. WHY IS A TIMELY DECISION FROM THE COMMISSION IMPORTANT AND
5 IN THE BEST INTEREST OF CUSTOMERS?

6 A. Mr. Plaisance also discusses this issue in his Direct Testimony, but there generally are
7 significant financial and operational implications for ELL's customers if the Proposed
8 Generators are not constructed on the proposed timeline. As discussed by Company
9 witness Nicolas D. Pressler, development and deployment of significant generation
10 projects is a time-consuming process that must begin several years in advance of the
11 need-by date. If the Commission finds that a proposed resource option does not serve
12 the public interest, ELL must then pursue that time-consuming process to seek out other
13 options to maintain reliable and affordable electric service. Moreover, a delay in
14 certification could delay the in-service date for the Proposed Generators, which could
15 lead to additional costs from the Company's contractors and additional exposure for
16 ELL's customers to energy and capacity markets. On the latter issue in particular, ELL
17 has forecasted significant and rapid increases in load growth throughout its service area
18 as industrial customers expand, and Mr. Pressler explains in his Direct Testimony that
19 the Company must issue final notices to proceed for construction of the Proposed
20 Generators in 2027—including, most pressingly, in February 2027 for Westlake—in
21 order to maintain the projected in-service dates (and therefore to begin timely assisting
22 with serving this substantial load growth). A timely decision by the Commission is
23 critical to ensuring the Company is able to construct the Proposed Generators on a

1 timeline that meets customers' needs, avoids additional costs from delay, and adds
2 much-needed capacity in the region
3

4 **V. COMPLIANCE WITH COMMISSION ORDERS**

5 Q29. HAS ELL MET THE REQUIREMENTS OF PARAGRAPH 1 OF THE
6 COMMISSION'S 1983 GENERAL ORDER WITH RESPECT TO THE PROPOSED
7 GENERATORS?

8 A. Yes. Paragraph 1 of the 1983 General Order provides, in pertinent part, that:
9 No electric public utility subject to the jurisdiction of the Commission shall commence
10 any on site construction activity or enter into any contract for construction or
11 conversion of electric generating facilities or contract for the purchase of capacity or
12 electric power, other than emergency or economy power purchases, without first having
13 applied to the Commission for a certification that the public convenience and necessity
14 would be served through completion of such project or confection of such contract.
15 Feasibility and engineering studies, site acquisition and related activities preliminary
16 to a determination of the desirability or need for plant construction or conversion on
17 purchase power contracts are exempted from this requirement.

18 The Application satisfies the terms of Paragraph 1 of the 1983 General Order.
19 The costs incurred and analyses conducted to date have related to the "[f]easibility and
20 engineering studies . . . preliminary to a determination of the desirability . . . for plant
21 construction or conversion." Moreover, as explained by Mr. Pressler in his Direct
22 Testimony, the current timeline for the Proposed Generators provides that the final

1 notices to proceed with construction will be issued to the Company's Engineering,
2 Procurement, and Construction ("EPC") contractors in December 2026.

3

4 Q30. HAS ELL MET THE REQUIREMENTS OF PARAGRAPH 2 OF THE
5 COMMISSION'S 1983 GENERAL ORDER WITH RESPECT TO THE PROPOSED
6 GENERATORS?

7 A. Yes. Paragraph 2 of the 1983 General Order provides, in pertinent part:

8 Applications submitted pursuant to this order shall include the
9 specific data utilized by the utility in justification of the
10 generation project or purchased power agreement, an itemized
11 projection of the total costs, the scheduled completion date with
12 appropriate time schedules for the percentage of the total project
13 to be completed by specific target dates, and, in cases of
14 purchased power or capacity agreements, the proposed contract
15 in its entirety.

16 Company witnesses Michael J. Plaisance, Phong D. Nguyen, Nicholas D. Pressler, and
17 Chad J. Ladner provide a detailed account, through their testimony and exhibits, of the
18 reasons for which the Proposed Generators are necessary and further provide detailed
19 cost estimates, the current development schedules, and other information required by
20 Paragraph 2 of the 1983 General Order.

21

22 Q31. HAS ELL MET THE REQUIREMENTS OF PARAGRAPH 3 OF THE
23 COMMISSION'S 1983 GENERAL ORDER WITH RESPECT TO THE PROPOSED
24 GENERATORS?

25 A. Yes. Paragraph 3 of the 1983 General Order requires ELL to "notify the Commission
26 immediately when it is determined that project or contract costs will exceed that stated

1 in the application or the completion date for commercial operation is extended.” As
2 Company witness Michael J. Plaisance explains, ELL is proposing a Monitoring Plan
3 that contemplates quarterly reporting that will provide detailed information about the
4 development status of the Proposed Generators and their costs.

5
6 Q32. WHAT IS THE MBM ORDER?

7 A. The version of the MBM Order applicable to ELL’s Application was adopted on
8 October 29, 2008, and established various procedures and requirements for the market
9 testing of any proposed capacity acquisition. The MBM Order augments the
10 procedures of the 1983 General Order and requires a utility proposing to acquire or
11 build new generating capacity to “employ a market-based mechanism” consisting of a
12 “Request For Proposal (‘RFP’) competitive solicitation process” that meets certain
13 specified requirements.²⁵ The utility must present the results and analysis from this
14 RFP to the Commission as part of the “justification” required by Paragraph (2) of the
15 1983 General Order.²⁶ In addition, the MBM Order prescribes procedures to be
16 followed by the utility in conducting the RFP process and presenting the results of that
17 process to the Commission Staff.²⁷ The procedures required by the MBM Order
18 include, among other things, the use of an IM to track the utility’s conduct of the RFP
19 process in which self-build proposals are competing, and the obligation to alert the Staff

²⁵ See MBM Order, ¶¶ 1 and 3.

²⁶ See *id.*, ¶ 1.

²⁷ See generally *id.*, ¶¶ 3, 8-10, and 14.

1 to any irregularities in the RFP process or any concerns.²⁸ The MBM Order also
2 provides a number of procedural safeguards designed to protect against changes to the
3 self-build cost estimate during the RFP evaluation and selection process.²⁹
4

5 Q33. YOU MENTIONED ABOVE THAT THE MBM ORDER HAS RECENTLY BEEN
6 AMENDED. WHY DO THE AMENDMENTS TO THE MBM ORDER NOT APPLY
7 TO THE 2024 CCCT RFP?

8 A. As mentioned briefly above, the MBM Order was amended by General Order 10-14-
9 2024 (R-34247) in LPSC Docket No. R-34247, *In re: Rulemaking to consider changes*
10 *to Commission General Order dated October 29, 2008 (Docket No. R-26172 Subdocket*
11 *C) (“Market Based Mechanisms Order”)* to incorporate formal complaint procedures.
12 The Order in Docket No. R-34247 was issued on October 14, 2024, which was nearly
13 three months after the 2024 CCCT RFP was initiated in accordance with the terms of
14 the existing MBM Order. The amendments were prospective only; indeed, LPSC Staff
15 made clear that the amendments applied prospectively during the Business & Executive
16 Session at which the amendments to the MBM Order were adopted, explaining “[i]t is
17 Staff’s intention that the Commission’s adoption of any of these rules would only apply
18 prospectively after the issuance of an order in this proceeding.”³⁰ Thus, the October

²⁸ See *id.*, ¶ 15.

²⁹ See *id.*, ¶ 16.

³⁰ See Transcript of September 17, 2024 LPSC Business & Executive Session, at p. 53:5-7; see also *id.*, at p. 53:9-13 (adopting Staff’s recommendations and the amendments to the MBM Order).

1 2024 amendments to the MBM Order post-dated the commencement of the 2024 CCCT
2 RFP and are inapplicable.

3 In addition, it warrants mentioning that one of the significant modifications
4 from the October 2024 amendments to the MBM Order was the requirement that any
5 RFP “shall be constructed as broadly as possible to allow for review of all available
6 options to add generating capacity.”³¹ As Mr. Plaisance explains in his Direct
7 Testimony, the Company issued a number of RFPs contemporaneously with the 2024
8 CCCT RFP and had therefore cast a wide net for available generation options to serve
9 its customers. Thus, while the Company was not required to comply with the
10 amendments to the MBM Order, the Company nevertheless performed a diligent search
11 for available options to add generating capacity.³²

12
13 Q34. HAS THE COMPANY COMPLIED WITH THE APPLICABLE VERSION OF THE
14 COMMISSION’S MBM ORDER?

15 A. Yes. As demonstrated in the testimony of Company witnesses Michael J. Plaisance,
16 Nicholas D. Pressler, and Phong Nguyen, the Company has complied with the

³¹ See Attachment A to General Order 10-14-2024 (R-34247), LPSC Docket No. R-34247, *In re: Rulemaking to consider changes to Commission General Order dated October 29, 2008 (Docket No. R-26172 Subdocket C) (“Market Based Mechanisms Order”)* to incorporate formal complaint procedures, at ¶ 3.

³² At its December 2025 Business and Executive Session, the LPSC adopted its Lightning Amendment, which, among other things, waives the requirements of the MBM Order under specific circumstances related to new or expanding loads. A central requirement of the Lightning Amendment is that an applicant requesting certification of a new generator under the amendment must demonstrate that it has a signed electric service agreement for the new or expanding load and that, without the proposed capacity, the applicant would be short of the energy or capacity needed to meet the customer’s electric requirements on the requested in-service dates. Because ELL is seeking approval of the Proposed Generators to assist with its base supply needs (and not in connection with serving a specific customer), ELL is not invoking or relying upon the Lightning Amendment in this Application.

1 requirements of the MBM Order in selecting the Proposed Generators by conducting
2 the RFP in a manner consistent with the requirements of the MBM Order. In particular,
3 Mr. Plaisance and Mr. Nguyen describe the 2024 CCCT RFP (including the
4 involvement of an IM) and the selection of the Proposed Generators from that RFP,
5 while Mr. Pressler discusses the submission of the Proposed Generators in response to
6 the RFP. In addition, Mr. Nguyen presents an analysis of the net economic benefits
7 that can be expected as a result of the Proposed Generators, and I describe below the
8 manner in which the cost-competitiveness of the Proposed Generators—as supported
9 by the results of the 2024 CCCT RFP—support a finding that the Proposed Generators
10 should be certified pursuant to the 1983 General Order.

11
12 Q35. IS THE CONSTRUCTION OF THE PROPOSED GENERATORS CONSISTENT
13 WITH THE INTEGRATED RESOURCE PLAN REQUIRED BY THE
14 COMMISSION’S CORRECTED GENERAL ORDER R-30021, DATED APRIL 18,
15 2012?

16 A. Yes. As Mr. Plaisance explains in greater detail in his Direct Testimony, the latest final
17 Integrated Resource Plan (the “Final 2023 IRP”) that was submitted by ELL in 2023
18 contemplated major investments in new energy resources, including natural gas
19 resources, to meet demand forecasts and industrial growth. Mr. Plaisance explains in
20 greater detail the reasons for which the Proposed Generators are consistent with the
21 conclusions in the Final 2023 IRP

1 **VI. PUBLIC INTEREST**

2 Q36. WHAT IS THE PUBLIC INTEREST?

3 A. I want to preface this section with an acknowledgment that I am not a lawyer, and my
4 testimony is not intended to provide a legal opinion or conclusion, but rather my
5 understanding of what constitutes the public interest as that concept has been developed
6 over the years in numerous matters before the Commission.

7 The public interest is that which is thought to best serve everyone; it is the
8 common good. If the net effect of a decision is believed to be positive or beneficial to
9 society as a whole, it can be said that the decision serves the public interest.

10 Public utilities in general, and electric utilities in particular, affect nearly all
11 elements of society. Public utilities and the regulation thereof influence the cost of
12 production of the businesses that are served by them, to affect the standard of living of
13 their customers, to affect employment levels in the areas they serve, and to affect the
14 interests of their investors. In sum, public utilities affect the general economic activity
15 in the state in which they operate.

16 Although I will reiterate that I am not a lawyer, it is my understanding that in
17 determining whether a particular decision or policy is in the public interest, there is no
18 immutable law or principle that can be applied. While the public interest is often
19 defined in terms of net benefits, such a test or standard merely substitutes one
20 expression for another. The difficulty is in defining and, if possible, quantifying the
21 net benefits that result from a given action or decision.

22 It is recognized that net benefits cannot simply be defined as lower prices. For
23 example, if lower prices are achieved through a reduction in the reliability or quality of

1 service, it may very well be perceived that the lower prices have not produced net
2 benefits. Similarly, higher prices might not produce negative net benefits or detriments.
3 For example, if an existing price is low due to a cross-subsidy, removing that subsidy
4 would raise that price, but doing so would not necessarily be detrimental. The
5 Louisiana Supreme Court reached just such a conclusion in *City of Plaquemine v.*
6 *Louisiana Public Service Commission*, 282 So. 2d 440, 442-43 (1973), when it found
7 that:

8 The entire regulatory scheme, including increases as well as decreases
9 in rates, is indeed in the public interest, designed to assure the furnishing
10 of adequate service to all public utility patrons at the lowest reasonable
11 rates consistent with the interest both of the public and of the utilities.

12
13 Thus the public interest necessity in utility regulation is not offended,
14 but rather served by reasonable and proper rate increases
15 notwithstanding that an immediate and incidental effect of any increase
16 is improvement in the economic condition of the regulated utility
17 company.

18 Objective measurement of how a decision affects the public interest is problematic at
19 best. For the past eighty or more years, regulatory decision-making has been tested in
20 the courts by a balancing-of-interests standard. In these cases, beginning with *Federal*
21 *Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944), the
22 courts have found that if the regulatory body's decision reflected a reasonable
23 balancing of customer and investor interests, the decision was to be affirmed as just
24 and reasonable.

25 In sum, determining whether a decision is in the public interest requires a
26 balancing of the various effects of a particular course of action measured subjectively
27 over the longer run. Whether a course of action is in the public interest will depend

1 upon relevant factors that are potentially quantifiable on an estimated basis, such as
2 likely changes in costs, as well as upon other factors that are not quantifiable, such as
3 the effect of that course of action on the robustness of a competitive market.³³ Finally,
4 although witnesses can provide facts and opinions that bear on this issue, the decision-
5 maker, the Commission, in the first instance must ultimately weigh all of these factors
6 and conclude whether the particular proposed course of action is in the public interest..
7

8 Q37. IN YOUR OPINION, WOULD APPROVAL OF THE PROPOSED GENERATORS
9 BE IN THE PUBLIC INTEREST?

10 A. Yes, for a number of reasons. Overarchingly, the Proposed Generators were selected
11 as the most competitively priced resources from an RFP that was issued to fill an
12 identified need, specifically to add new generation resources in light of aging, legacy
13 gas generation in ELL’s service area. Even more, the two self-build proposals were
14 market-tested through the 2024 CCCT RFP to add this new generation in two load
15 pockets—the West of Atchafalaya Basin (or “WOTAB”) and Amite South load
16 pockets—in which the need for both additional capacity and replacement generation
17 are particularly acute. The Proposed Generators will provide much needed capacity in
18 two load pockets that are experiencing significant industrial load growth and, for that
19 reason alone, should be certified as being in the public interest.

20 Moreover, the specific issues identified with respect to the WOTAB and Amite
21 South load pockets—significant load growth at a time when legacy units are aging past

³³ *See Permian Basin Area Rate Cases*, 390 U.S. 747, 815 (1968).

1 their useful lives—are not limited solely to those regions and are instead a systemwide
2 issue that ELL is working to address. As Company witness Michael J. Plaisance
3 describes, the Company has identified a need for substantial additional energy and
4 capacity in the near and long terms, and the Proposed Generators will add
5 approximately 1,500 MW (ISO) of critical capacity to assist with mitigating that need.
6 Absent certification of the Proposed Generators, the overall need for capacity in the
7 Company’s service area will only grow more acute, while certification of the Proposed
8 Generators will help with insulating ELL’s customers from the impacts from
9 overreliance on MISO’s energy and capacity markets.

10 Certification will also allow the Company to build modern, new efficient
11 generation that will lead to net economic benefits for ELL’s customers. On this point,
12 it bears emphasizing that the 2024 CCCT RFP was broadly drafted to capture any
13 proposals to build new CCCT (and other gas-fired) units in LRZ 9, and the Proposed
14 Generators were significantly more cost-competitive than the proposal submitted by a
15 third party. Moreover, as Company witness Phong D. Nguyen explains in his Direct
16 Testimony, the cost-effectiveness of the Proposed Generators translates to clear
17 economic benefits for ELL’s customers as well as fuel savings from the efficient use
18 of natural gas. The Proposed Generators are fuel-efficient generators that will be
19 dispatched by MISO in economic order and can therefore be expected to be dispatched
20 before less-efficient legacy generators. The expected economic and cost-related
21 benefits further support that the Commission should certify the Proposed Generators.

22 Lastly, but perhaps most importantly, certification of the Proposed Generators
23 will enable the continued, unprecedented economic growth that Louisiana is

1 experiencing. As Mr. Plaisance explains in his testimony, the Company's Application
2 comes on the heels of a series of major economic announcements in the state, including
3 in particular announcements for new industrial developments along the Mississippi
4 River in Southeast Louisiana and in the vicinity of Lake Charles, Louisiana—the exact
5 areas in which the Proposed Generators will be located. These announcements
6 demonstrate both the accuracy of ELL's planning in connection with the 2023 Final
7 IRP as well as the ongoing (and strengthening) need for new capacity to support these
8 economic wins. As I explained above, public utilities like ELL affect the general
9 economic activity of the states in which they operate, and certification of the Proposed
10 Generators will allow Louisiana to continue on its path towards greater economic
11 prosperity for all its citizens—a result that is plainly in the public interest.

12
13 Q38. HOW WILL THE PROPOSED GENERATORS IMPACT CUSTOMER ENERGY
14 COSTS?

15 A. As I referenced above, CCCTs use less fuel to produce more power than older units,
16 resulting in fuel savings that benefit customers. ELL witness Phong D. Nguyen
17 estimates that the cost savings to customers (*i.e.*, net benefits) will total [REDACTED]
18 over the life cycle of the Proposed Generators (based on the described reference case).
19 In addition to the cost savings achieved through more efficient power generation, the
20 Proposed Generators are designed to protect against unpredictable energy costs.
21 Having sufficient local energy resources will diminish the need to purchase wholesale
22 electricity in a tightening spot market. Moreover, because the Proposed Generators
23 also will sell power at the Locational Marginal Prices ("LMP") established by MISO

1 but are relatively low cost to run, the difference between the LMP and variable costs
2 to operate the Proposed Generators will help offset the load costs ELL incurs when it
3 buys power through MISO. This built-in protection keeps prices steadier for
4 customers.

5
6 Q39. WHAT OTHER ECONOMIC BENEFITS DOES ELL ATTRIBUTE TO THE
7 PROPOSED GENERATORS?

8 A. New, modern energy resources like the Proposed Generators also create substantial
9 economic development opportunities, ranging from direct job creation and increased
10 tax revenues to enhanced grid reliability that attracts future business investment. The
11 construction phase of the Proposed Generators will generate thousands of direct jobs
12 for skilled laborers, engineers, and project managers, as well as indirect jobs in the
13 supply chain (e.g., equipment manufacturing, logistics). Permanent, long-term
14 operational and maintenance jobs also will be created once the facilities are online.
15 Investing in modern energy infrastructure will accommodate growing demand from
16 existing ELL customers and provide a reliable, resilient, and affordable energy supply
17 attractive to new industrial customers. The new capital development and job growth
18 associated with the Proposed Generators will, in turn, expand the tax base needed to
19 fund essential public services. Mr. Plaisance's Direct Testimony includes additional
20 detail concerning the expected economic impacts from construction and operation of
21 the Proposed Generators.

1 Q40. DO THE DEVELOPMENT AND CONSTRUCTION COSTS ASSOCIATED WITH
2 THE PROPOSED GENERATORS OFFSET THEIR BENEFITS?

3 A. No. As more fully explained by Mr. Nguyen in his Direct Testimony, the economic
4 analysis undertaken by ELL for each of the two projects took into consideration fixed
5 and variable costs, including forecasted energy and capacity revenues and ELL
6 customer load payments. The Proposed Generators are projected to produce significant
7 cost savings for customers over 30 years on a net present value basis and are expected
8 to result in net economic benefits for the Company's customers.

9

10 **VII. CONCLUSION**

11 Q41. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

12 A. Yes, at this time.

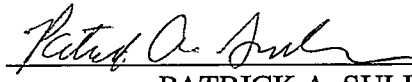
AFFIDAVIT

STATE OF LOUISIANA

PARISH OF Jefferson

NOW BEFORE ME, the undersigned authority, personally came and appeared,
PATRICK A. SULLIVAN, who after being duly sworn by me, did depose and say:

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


PATRICK A. SULLIVAN

SWORN TO AND SUBSCRIBED BEFORE ME

THIS 4th DAY OF FEBRUARY 2026



NOTARY PUBLIC

My commission expires: At Death

