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July 15, 2026

BY E-MAIL

Ms. Aisha R. Collier
Clerk of Council
Council of the City of New Orleans
City Hall, Room IE09
1300 Perdido Street
New Orleans, LA 70112

Re: Entergy New Orleans, LLC's 2026 Electric Formula Rate Plan Filing Pursuant to Council Resolution Nos. R-19-457, R-20-67, R-20-112, R-20-213, R-20-268, R-20-344, R-21-295, and R-23-491; Docket UD-18-07

Dear Ms. Collier:

Attached please find the *Advisors to the Council of the City of New Orleans' Investigation and Review of Entergy New Orleans, LLC's 2026 Electric Formula Rate Plan Evaluation Filing* in the above-referenced matter. Thank you.

Best regards,

Jay Beatmann

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Attachment

cc: Official Service List for UD-18-07

INVESTIGATION AND REVIEW
OF
ENTERGY NEW ORLEANS, LLC'S 2026 ELECTRIC
FORMULA RATE PLAN EVALUATION FILING

COUNCIL RESOLUTION NOS. R-19-457, R-20-67, R-20-112, R-20-213, R-20-268, R-20-344, R-21-295, AND R-23-491

DOCKET NO. UD-18-07

PUBLIC REDACTED VERSION

JULY 15, 2026

Legend Consulting Group Limited

INTRODUCTION

On April 30, 2026, Entergy New Orleans, LLC ("ENO") submitted to the Council of the City of New Orleans ("Council") its *Entergy New Orleans, LLC's 2026 Electric Formula Rate Plan Filing* ("FRP Evaluation Filing" or "instant FRP Evaluation Filing") for the 12-month evaluation period ending December 31, 2025 ("2025 Test Year") to initiate new electric rates effective with the first billing cycle of September 2026. In the FRP Evaluation Filing, ENO proposes a $16.6 million increase in FRP revenue. This $16.6 million change in FRP revenue includes $1.8 million in revenues that are realigned from Rider RSHCR (whose revenues are reflected in FRP rates). As such, the net increase to FRP revenues is $14.9 million. The FRP Evaluation Filing, inclusive of the RSHCR realignment, results in a $7.46/month increase to the typical residential electric bill.[1] Of note, this is the first FRP Evaluation to not involve gas, as ENO sold its gas utility effective July 1, 2025.

The Advisors have reviewed ENO's FRP Evaluation Filing, conducted extensive discovery, and provide this report identifying errors in the FRP Evaluation Filing that would reduce ENO's proposed electric FRP revenue increase by approximately $4.4 million while still allowing ENO a reasonable opportunity to recover its costs and earn the Council-approved rate of return. The residential typical bill increase resulting from these Advisor adjustments, but not from the regulatory asset that we discuss in the following paragraph, changes from $7.46/month to $3.36/month.

We also recommend allowing ENO to record an outside-the-bandwidth regulatory asset in the amount of $20.0 million, amortized over five years commencing September 2026, to recover the cost of refunds ENO has been ordered to pay to Entergy Louisiana, LLC ("ELL") and Entergy Arkansas LLC ("EAL") in Opinion No. 595 in FERC Docket No. EL22-6 ("FERC Order").[2] While the Council is currently appealing this FERC Opinion, and this refund amount may not be the final determination, payment of the refund is required during any appeal process.

The Advisors' recommended corrections and the revenue effect of the regulatory asset related to the FERC Order result in a $4.37/month typical residential electric bill increase. The same adjustments cause a Small Electric typical bill increase of $95.06/mo. and a Large Electric typical bill increase of $18.15.

BACKGROUND

Prior FRP Evaluation Filings

ENO prepared its 2020 FRP Evaluation Filing (based on a 2019 test year), which if filed, would have requested a $32 million electric and gas total combined revenue requirement increase that, if approved, would have become effective the first billing cycle of September 2020, in the midst of the COVID-19 pandemic.

To ease the burden on ratepayers during the COVID-19 pandemic, ENO, through negotiation with the Council, agreed to forego a likely rate increase effective beginning September 2020 in

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[1] *See* the FRP Evaluation Filing, *Compliance w Decoupling Bill Comparison*, which presents a Legacy ENO winter-summer average typical bill (1,000 kWh/month) impact of $7.46.

[2] FERC Opinion No. 595, *Order on Initial Decision* in FERC Docket No. EL22-6, 195 FERC ¶ 61,167 (June 2, 2026).

exchange for more favorable ratemaking treatment for each of the three FRP evaluations the Council authorized in the 2018 Rate Case[3] (*e.g.*, a 51% hypothetical equity ratio), beginning in November 2021.

ENO's 2021 FRP Evaluation Filing proposed an increase in electric revenue of $40 million and an increase in gas revenues of $18.8 million. The 2021 FRP Evaluation Filing also included outside-the-bandwidth collections of $5.2 million in electric revenues and $0.3 million in gas revenues. Accordingly, the 2021 FRP Evaluation Filing showed an increase in revenues of $45.2 million for the electric utility and $19.1 million for the gas utility. ENO's estimated residential typical monthly bill (*i.e.*, 1,000 kWh electric and 50 ccf gas) increases according to its 2021 FRP Evaluation Filing were $11.03 and $14.21 for electric and gas, respectively.

The Advisors' 2021 FRP report identified errors in ENO's 2021 FRP Evaluation Filing totaling $14.7 million (gas and electric) as well as rate mitigation opportunities totaling $16.5 million (gas and electric). While ENO did not agree with the Advisors' recommendations in their 2021 report, ENO implemented gas and electric FRP rates that reflected the revenues by rate class that the Advisors had recommended while allowing ENO the reasonable opportunity to earn its Council-allowed Return on Equity ("ROE") of 9.35%.[4]

ENO's 2022 FRP Evaluation Filing proposed electric and gas revenue increases of $37.0 million (including $4.7 million in agreed-to outside the bandwidth revenues) and $3.2 million, respectively. The Advisors recommended downward corrections to ENO's revenue proposals of $15.7 million and $1.4 million for electric and gas respectively, plus the application of $13.9 million in available electric credits to be applied as bill mitigation measures. ENO implemented gas and electric FRP rates that reflected the revenues by rate class that the Advisors had recommended, and the mitigation credits were applied to Rider PPCR.

ENO's 2023 FRP Evaluation Filing proposed electric and gas revenue increases of $20.8 million (including $3.4 million in agreed-to outside the bandwidth revenues) and $8.2 million, respectively. The Advisors recommended downward corrections to ENO's revenue proposals of $7.0 million and $1.3 million for electric and gas respectively, plus the application of $12.1 million in recommended bill mitigation measures. As part of a negotiated settlement, ENO agreed to implementing 50% of the Advisors' recommended electric corrections and all of the Advisors' recommended gas corrections. Further, the negotiated settlement implemented the Advisors' recommended bill mitigation measures with certain non-substantial adjustments.

ENO's 2024 FRP Evaluation Filing proposed a $7.0 million increase to its electric revenues and a $5.6 million increase to its gas revenues. The Advisors recommended a reduction to ENO's proposed electric revenue increase of $1.3 million and a reduction to the proposed gas revenue increase of $0.3 million. Following discussions between the Parties, ENO implemented a $5.8 million increase to its electric revenues (a $1.2 million decrease from its proposal) and a $5.4 million increase to its gas revenues (a $0.2 million decrease from its proposal).

ENO's 2025 FRP Evaluation Filing proposed an effective a net electric revenue increase of $11.7 million and a $0.5 million increase to its gas FRP revenues. The Advisors recommended a

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3 In this report, we refer to ENO's most recent rate case established by Resolution No. R-18-434 as the "2018 Rate Case".

4 *See* Investigation and Review of Entergy New Orleans LLC's 2022 Electric and Gas Formula Rate Plans Evaluation Filings, "ENO's 2021 Financial Performance" at 6-7.

reduction to ENO's proposed electric revenue increase of $7.2 million and a reduction to ENO's proposed gas revenue increase of $0.5 million. Following discussions between the Parties, ENO implemented the Advisors' recommended adjustments. As ENO's final gas Earned ROE ("EROE") was within the FRP's bandwidth, gas revenues were unchanged.

SUMMARY OF ADVISORS REVIEW AND ADJUSTMENTS

As part of our review and as discussed later in this report, we identified errors in the instant FRP Evaluation Filing and prepared what we refer to as Advisor Adjustments to correct them. If these Advisor Adjustments are agreed to by the Parties, they would result in a reduction to the ENO proposed increases of approximately $4.4 million. As discussed elsewhere in this report, we recommend that the Council approve a regulatory asset to allow recovery of a refund paid by ENO to ELL and EAL in the FERC Order in the amount of $20.0 million. As presented in the below Table 1, we estimate that the overall revenue impact of this regulatory asset is $5.1 million. The net revenue impact when including these recommendations is an approximate $0.7 million revenue increase from ENO's requested amount (*i.e.*, the Advisor corrections' revenue decreases are less in magnitude than the revenue increase from the regulatory asset).

Table 1 presents a summary of the total proposed revenue impacts of the FRP Evaluation Filing, Advisor Adjustments, and the net FRP revenue impact.

Table 1
Summary of Advisor Recommended Adjustments
($ in Millions)

ENO Proposed FRP Revenue Increase	**$14.9**[1]
Advisor Adjustments to Evaluation Report (Decrease)	($4.4)
Establish $20 million regulatory asset related to FERC Order	$5.1
FRP Revenue Increase After Adjustments	**$15.6**

Note:

1. This value reflects ENO's proposed $16,619,439 in additional FRP revenues less $1,768,227 in revenue reduction attributable to the realignment of certain costs from Rider RSHCR to base revenues.

In addition to these Advisor Adjustments, our report also discusses the allocation of electric revenue requirement (decoupling) among the rate classes pursuant to Rider EFRP Section II.B.2 and other items for Council consideration that we have identified during our investigation and review.

ENO'S FRP EVALUATION FILING

ENO's FRP Evaluation Filing proposes a FRP revenue increase, and as such ENO has requested FRP rate adjustments to prospectively (*i.e.*, commencing with the first billing cycle of September 2026) reset electric rates consistent with the FRP's midpoint ROE of 9.35%. As discussed later in this report, decoupling is a required element of the FRP Evaluation filing, and the decoupling mechanism is utilized in determining customer class revenue requirement allocations in each test year FRP Evaluation filing.

Table 2 presents the as-filed FRP Evaluation Filing revenue change by rate class.[5]

Table 2
ENO FRP Evaluation Filing Change in FRP Revenues

Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue Net of RSHCR Realignment	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$182,389,082	$12,678,245	6.95%
Small Electric Service	$72,700,395	4,238,562	5.83%
Municipal Buildings	$2,473,664	1,416,549	57.27%
Large Electric	$24,584,313	(1,525,061)	-6.20%
Large Electric High Load Factor	$93,384,626	(2,205,036)	-2.36%
Master Metered Non-Residential	$439,832	(36,657)	-8.33%
High Voltage	$5,584,082	123,635	2.21%
Large Interruptible	$3,635,973	(86,499)	-2.38%
Large Municipal	$1,792,980	(407,483)	-22.73%
Lighting Service	$3,939,175	654,956	16.63%
Total	$390,924,123	$14,851,212	3.80%

Earned Rate of Return

ENO's FRP Evaluation Filing reports Earned Rate of Return ("EROE").[6] ENO's stated EROE is 7.55%.[7] Per the FRP rider's bandwidth of +/- 50 bp,[8] when ENO's EROE for a test year falls below 8.85%, an upward adjustment to ENO's FRP rate is required to allow ENO the reasonable opportunity to earn its allowed ROE of 9.35%. Similarly, if ENO's EROE rises above 9.85%, a downward adjustment to ENO's FRP rate is required.

After applying the Advisor Adjustments to correct identified errors in the FRP Evaluation and also including the regulatory asset related to the FERC Order, ENO's EROE is 7.39%. ENO's Advisor-adjusted EROE value remains below 8.85%, and therefore we have calculated an upward FRP rate adjustment to allow ENO the reasonable opportunity to earn an EROE of 9.35%.

Comparative calculations of ENO's EROE between that filed by ENO and that calculated by the Advisors are provided as Attachment D to this report.

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5 Table 2 summarizes ENO's decoupling results provided in Attachment A, and the supplemental workpapers supporting Compliance with Decoupling.

6 *See* FRP Evaluation Filing Attachment B at 1.

7 *Id*.

8 *See* Rider EFRP-7, Section II.C.1.g.

Typical Bill Impact

ENO's estimate of typical bill impacts from its FRP Evaluation Filing are presented in Table 3 below.

Table 3
ENO FRP Evaluation Filing Estimated Change to Typical Customer Monthly Bill[1]

Rate Class	Energy (kWh)	Demand (kW)	Present	Proposed	Change
Residential[2]	1,000	-	$148.63	$156.09	$7.46
Small Electric	9,125	50	$1,482	$1,534	$52.41
Large Electric	91,250	250	$10,802	$10,385	$417.63

1. Typical bills reflect ENO's "Compliance with Decoupling" revenue allocation. All typical bills are calculated using the Francise Fee applicable throughout New Orleans except in Algiers, which has a lower Franchise Fee.
2. ENO's presented residential typical bills are calculated using a simple average of summer and winter typical bills (in both cases, 1,000 kWh/month).

Of note, ENO's above typical bill calculations do not reflect the regulatory asset related to the FERC Order that we are including in our typical bill calculations. Table 6, later in this Report, presents comparable typical bill impacts that reflect the Advisor Adjustments without the regulatory asset related to the FERC Order.

ADVISOR REVIEW OF THE FRP EVALUATION FILING

The Advisors have, during the FRP's prescribed 75-day review period, reviewed ENO's FRP Evaluation Filing to ensure that it complies with the requirements of the FRP Tariff (specifically Section II.C of the FRP rider). The Advisors are directed to identify and formally communicate in writing to ENO and/or other Parties any identified errors in the application of the principles and procedures set forth in the annual redetermination of Rate Adjustments.

In the conduct of our investigation and examination of the FRP Evaluation Filing we: (i) reviewed ENO's FRP Evaluation Filing and associated work papers; (ii) issued five sets of discovery to ENO consisting of 79 single and multi-part questions; (iii) reviewed and analyzed all discovery responses; and (iv) reviewed ENO's FERC Form 1 filings, Entergy Corp.'s SEC 10-K filings, and other informational filings.

Our investigation, review, and examination of ENO's FRP Evaluation Filing focused on:

1) Review of ENO's reported revenue amounts and consideration of their reasonable predictive value for revenues ENO may earn during the rate-effective period (*i.e.*, September 2026-August 2027);
2) adherence to the EFRP-7 tariff, Attachment H. B) Revenues, including that rider's provisions for known and measurable adjustments to revenues or cost of providing utility service; and
3) adherence to sound ratemaking principles, especially those applied precedentially by the Council in the 2018 Rate Case.

Our review identified several adjustments to ENO's proposed FRP revenues. Table 4 presents the Advisor Adjustments. While we believe the estimates are accurate, ENO employs an array of proprietary and licensed (*i.e.*, not readily available to the public) software tools to generate the schedules and attachments to its FRP Evaluation Filing, including tools such as Utilities International's UI Planner software, which appears to be the basis of ENO's Plan to Results (P2R) regulatory filing system. Further, ENO uses licensed software such as Power Plan and Power Tax for key revenue requirement inputs. As such, ENO's final compliance calculations may differ somewhat from the revenue impacts summarized in Table 4 below.

Table 4
Summary of Advisor Adjustments
($ Millions)

Description	*Adjustment*
ENO Proposed Change in FRP Revenue (Inside the Bandwidth)	**$16.6**
Change to Outside the Bandwidth Revenues	
Rider RSHCR Revenue Requirement Change[1]	*($1.8)*
ENO Proposed Incremental FRP Revenues (Total FRP Revenues)	**$14.9**
Advisor Adjustments	
ADV01 – Rider Revenues	($0.1)
ADV02 – FIN 48 ADIT	($0.1)
ADV03 – LCFC (Lost Contribution to Fixed Costs)	$0.1
ADV04 – Storm Proforma	($0.3)
ADV05 – FIN 48 Interest	$0.0
ADV07 – Prospective LME Rate Class Revenues	($2.6)
ADV09 – Return Corporate Franchise Tax Overcollection	($1.4)
Total – Advisor Adjustments	**($4.4)**
Regulatory Asset Related to the FERC Order	$5.1
Total Advisor Adjusted Net FRP Revenue Change from Filing	**$0.7**

Notes:

1. $1.8 million represents a realignment of outside-the-bandwidth revenues from the 2025 FRP Evaluation to inside-the-bandwidth revenues in the instant FRP Evaluation. This realignment is the result of $10.0 million in Rider RSHCR revenues in the instant FRP Evaluation Filing as compared to $11.8 million in Rider RSHCR revenues in the 2025 FRP Evaluation Filing.

Advisor Adjustments

Here, we discuss each Advisor Adjustment regarding identified errors in the FRP Evaluation Filing. These Advisor Adjustments are enumerated as "ADVXX." Additionally, for each Advisor Adjustment, the specific adjustment dollar amount by ENO Account is detailed in Attachment C to this report.

Rate Schedule and Other Revenues Adjustment (ADV01)

ENO describes Adjustment AJ01A as an "[a]djustment to annualize and synchronize Rate Schedule Revenues and Riders, reclassify certain Rate Schedule Revenues to Other Electric Revenue, and remove interdepartmental sales and unbilled revenues.." While the Advisors confirmed ENO's annualization of FRP revenues and reclassification of certain rate schedule revenues[9] to be appropriate, with the minor exceptions noted below, ENO's adjustment to "synchronize" test period revenues is contrary to Council directives and industry best practices related to development of a test year cost of service. In Council Resolution No. R-19-457, the Council approved the FRP mechanisms and directed that the total utility cost of service include total ENO revenues and expenses[10] and further that, "The revenue deficiencies/excesses shall be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period <u>total actual revenues</u>,"[11] (Emphasis added.) The Advisors' investigation, review and examination of ENO's 2021, 2022, 2023, 2024 and 2025 Evaluation Filings focused on, among other issues, validation of ENO's reported test year revenue amounts, and the correlation of the FRP revenues with ENO's FERC Form 1 filings, Entergy Corp.'s SEC 10-K filings, and other informational filings.[12] Based on these Council directives, the FRP revenue increase/decrease is the difference between the proposed estimated total revenues, subject to evaluation, and the total revenues ENO collected in the test year, or would have collected had the present rates (*e.g.*, FRP rates) been in effect for all of the test year.

However, in the FRP Evaluation Filing, ENO replaced test year reported revenue by setting current test year rider revenue equal to rider expenses, such that the revenue credit to the test year cost of service was not the actual rider revenues collected. This step of replacing actual test year revenues ignores the long-held industry regulatory concept of first developing a test year total cost of service, which then provides the basis for subsequent evaluation of cost recovery through rate design.[13] Developing a revenue requirement and revenue deficiency/excess from a cost of service analysis does not include inserting a guaranteed revenue collection based on a rider design. Guaranteed revenue in the regulatory process, or an assurance of "exact cost recovery," is not the nature of FRP rates, and it is not a regulatory concept specifically approved by the Council for FRP purposes.

Based on the detail provided in discovery responses, the Advisors confirmed the reported test year base rate revenues and each rider per book revenue for each of the customer classes, as well as the various other operating revenues. The Advisors' ADV01 adjustment consists of reversing ENO's

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9 Reclassification of certain rate schedule revenues include revenues to Other Electric Revenue, removal of interdepartmental sales, and unbilled revenues.

10 *See* Council Resolution No. R-19-457, Directive 25. a.

11 Council Resolution No. R-19-457, Directive 26.

12 Related to the analysis of test year reported revenue and monthly rider filings, the Advisors issued the following Data Requests: CNO 1-2a, 1-31, 2-1, 2-19, and 3-8 in the 2021 FRP; CNO 1-2, 2-6, and 2-9 in the 2022 FRP; CNO 1-6 and 1-23 in the 2023 FRP; CNO 1-14, 4-5, 4-6, 4-7, and 5-2 in the 2024 FRP; CNO 1-6, 1-15, 1-16, 1-52, 2-4, 2-5, 3-3, 3-7, 3-8, and 3-9 in the 2025 FRP; and 2-28, 2-29, 2-31, 3-1, 3-4, 4-2, 4-3 in the 2026 FRP.

13 The basic steps include: development of the test period total utility revenue collected from all sources; calculation of the test period revenue requirement from all sources; cost allocation to each customer class; and design of rates, including consideration of the effectiveness in yielding total revenue requirements. NARUC Cost Allocation Manual, 1992 at 13 & 24.

"The auditor should begin by looking at an analysis of the test year revenues…" NARUC Rate Case and Audit Manual 2003 at 31.

"Cost allocation typically occurs after a cost of service study, which determines the utility's revenue requirement, and before rate design, which determines what and how customers will be charged." Cost of Service -> Cost allocation -> Rate Design. Emerging Trends in Utility Cost Allocation. Pacific Northwest National Laboratory. May 1922 at 3-4.

"Exact Recovery of Expense" adjustment[14] for each of the riders to restore test year per book values as the appropriate present revenue credit to the test year cost of service/ revenue requirement. The only Rider tariffs whose revenue and expense are to be eliminated from the FRP evaluation (per EFRP Attachment C, 1 B) are the SSCR, SSCO, SSCRII, and SSCOII Riders.

The individual electric revenue-related credit adjustments we make in ADV01 are $182,318 fuel (FAC), $13,747 MISO, $(23,143) PPCR, and $5,516 EECR, (which reflects $2,060,082 in revenues and a corresponding $2,054,566 expense account adjustment), and corresponding federal and state income tax adjustments, for a total increase to ENO's present revenue (i.e., decrease to ENO's revenue deficiency) of $0.1 million.

FIN 48 ADIT (ADV02)

Accepted ratemaking principles[15] as well as precedential Council directives[16] require that temporary timing differences (recognized as ADIT) be reflected in rate base, regardless of their degree of uncertainty of being upheld by the IRS (*i.e.*, regardless of their status under FIN 48). As such, ENO erred by excluding a total of $[redacted] in FIN 48 ADIT from its rate base.[17] The Advisors have reversed this inappropriate exclusion through Advisor Adjustment ADV02.

LCFC (ADV03)

In Council Resolution No. R-20-51, the Council noted that an adjustment to prospective billing determinants corresponding to the approved savings goals will be implemented in determining the FRP revenue requirement.[18] In the LCFC discussion in the 2018 general rate case, ENO's proposal advocated LCFC recovery based on actual results.[19] The use of the actual recent year Energy Smart program kWh reductions compared to the kWh Savings goal included in the Energy Smart three-year Implementation Plan provides a more certain estimate for determining a LCFC adjustment. The EFRP tariff requires, "In calculating the LCFC adjustment, ENOL shall use the most current actual data and not the kWh savings goals included in the approved Energy Smart Implementation Plan."[20]

ENO did utilize actual data in calculating its LCFC adjustment in the instant FRP Evaluation Filing, using the three-year average of the percent of Energy Smart kWh savings goal that was achieved (program years 2022 through 2024),[21] which is consistent with the agreed-to ratemaking treatment for LCFC. As with last year's FRP evaluation, we are able to add Energy Smart Program

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14 It was necessary for ENO to support the source of expenses used in the "Exact Recovery of Expense" adjustments made to per book revenue. See DRs CNO 2-28 and 2-29.

15 *See e.g.*, FERC Opinion No. 581 (181 FERC ¶ 61,243) at 322 ("Coupling the Commission's tax normalization policy with FIN 48 requires that all uncertain tax positions taken in a given tax year, regardless of their level of certainty, shall be recognized in the proper ADIT accounts and appropriately included in rate base. ").

16 *See* Council Resolution No. R-19-453, Ordering Paragraph 4 ("ENO's proposal to exclude FIN 48 ADIT liability balances from its rate bases is denied.").

17 *See* ENO's response to DR CNO 2-11.a.

18 Council Resolution No. R-20-51, at 27-28.

19 See Council Resolution No. R-19-457, at 156.

20 Rate Schedule EFRP-7, Attachment H, B.

21 *See* Evaluation Report, AJ05D.2, FN 2.

Year 2025 kWh savings data, filed on June 30, 2026,[22] to the 2026 FRP's calculation with ENO's Program Year 2023-2024 kWh savings data.

Accordingly, the Advisors have adjusted ENO's LCFC proforma amount to reflect an average kWh savings as percent of goal for the 2023-2025 Program Years. This adjustment improves the predictive quality of that Evaluation's LCFC adjustment.

Regardless of the LCFC adjustment reflected in ENO's FRP rate, there will be a true-up to actual LCFC costs through Rider EECR.[23] The LCFC true up for ENO's 2026 pro-forma estimate will be included in the EECR Filing mid-year 2027, for recovery in EECR rates effective for calendar year 2028.

This year's adjustment constitutes a small increase to ENO's FRP revenue requirement. LCFC adjustments in recent FRP Evaluations have become less significant in magnitude. Considering that LCFC is trued-up in Rider EECR, if LCFC adjustments in any future FRP Evaluations continue to be insignificant, we expect that these FRP adjustments may become unnecessary.

Proforma Storm Capital Investments (ADV04)

The FRP rider allows ENO to proform costs into its cost of service related to the year following the test year (*i.e.*, 2026 for the instant FRP Evaluation Filing). Rider Schedule EFRP-7 says,

> For purposes of this Rider EFRP, adjustments for changes to Rate Base, Revenues, and Expense for the prospective twelve months following the EFRP evaluation period (*i.e.,* Proforma Adjustments) can be made as long as they are "Known and Measurable." Known and Measurable changes, including attendant impacts, are those changes that reflect changes in operating conditions and/or costs incremental to test year evaluation period operations. Such costs must be expected to be incurred and reasonably budgeted with sufficient information to be verified as appropriate proforma adjustments as set forth in Attachment H.[24]

ENO has requested a $[redacted][25] proforma addition to distribution plant in service related to storm restoration capital costs that may be incurred in 2026 with respect to minor weather events. As with ENO's prior FRP Evaluation Filings, ENO errs in proposing this proforma adjustment because these estimated investment amounts do not meet the "known and measurable" standard for inclusion in the FRP Evaluation's cost of service.

As such, consistent with our recommendations in our 2025 report, ENO erred in proposing the proforma adjustment to add $[redacted] to its plant in service. Advisor Adjustment ADV04 corrects this error by removing this proforma and its related ratemaking effects.

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22 *See Entergy New Orleans, LLC's Lost Contribution to Fixed Costs and Utility Performance Incentive Filing for Energy Smart Program Year 15 Resolutions R-15-140, R-20-51, and R-24-570 CNO Docket UD-08-02 (IRP-Energy Smart-RFP), UD-17-03 (2018 IRP) and UD-23-01 (2024 Triennial IRP)*, June 30, 2026.

23 Council Resolution No. R-23-491, at 5.

24 Rider Schedule EFRP-7, FN 1 at 30.3.

25 *See* FRP Evaluation Filing, Attachment H, funding project "F1PCDSTR0N: DISTR STORM DAMAGE CAPITAL, ENOI".

Interest on FIN 48 Tax Liabilities (ADV05)

In ENO's Adjustment AJ06B, ENO reflects [redacted][26] in interest on tax positions that in ENO's opinion do not meet the "more-likely-than-not recognition threshold"[27] of being allowed by the IRS upon audit (*i.e.*, FIN 48 tax positions). In past FRP Evaluation Filings, ENO's FIN 48 interest amounts have been, from year to year, positive and negative in amount. Regardless of whether the interest adjustment is a debit or a credit, ENO has erred in its proposal, and it is appropriate to correct ENO's error. We have corrected ENO's error regarding FIN 48 interest by reversing this proforma expense through Advisor Adjustment ADV05.

Prospective LME Rate Class Revenue (ADV07)

While the FRP rider generally provides for the use of actual test year revenues, it also provides for known and measurable adjustments to revenues.[28] Past Advisor reports on annual FRP Evaluation filings have properly reflected adjustments to ENO's revenues to reflect non-typical test years. In the 2022 FRP evaluation, ENO estimated that its electric revenues were negatively impacted due to the loss of service to all of its service territory in the days following Hurricane Ida. To reflect that non-typical test year, we adjusted ENO's Present Revenues by $11.3 million (which represented a decrease to ENO's FRP revenue requirement). In the 2025 FRP Evaluation Filing, ENO proformed LME rate class revenues to establish baseline prospective revenues for the new rate class, as the first bill to this rate class was issued in December 2024.[29] In the instant FRP Evaluation, there is a substantial known and measurable difference between prospective LME rate class revenues and annualized actual 2025 Test Year LME rate class revenues (which ENO employed in the instant FRP Evaluation Filing).[30]

The operations related to the LME rate class changed permanently by October 2025, substantially increasing LME rate class revenues for the remainder of 2025 and for the foreseeable future. Both the extrapolation of such increased revenues through the instant FRP Evaluation's rate effective period (*i.e.*, September 2026-August 2027) as well as ENO's LME rate class revenue forecasting for this period[31] provide a measurable LME rate class revenue amount that is substantially greater than annualized 2025 LME rate class revenues, upon which ENO based the instant FRP Evaluation.

Corporate Franchise Tax (ADV09)

Louisiana changed (reduced) its state corporate income tax rate effective January 1, 2025 through Act 5 of the 2024 Third Extraordinary Legislative Session, which was signed into law on

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26 *See* the Evaluation, *AJ06B - ESL, Bank Loans, and Customer Deposits Interest_WP_HSPM,* Tab *Tax Interest_2025-2026 HSPM*.

27 *See* FASB Interpretation No. 48 at 5.

28 *See* Rider EFRP-7, Sec. II.C.1.a (1), and Attachment H, B) Revenues.

29 *See* ENO's response to DR CNO 2-4 in the 2025 FRP Evaluation.

30 2025 per book base revenues for this new rate class totaled $1.66 million, but monthly operations closer to normal began around October 2025, with previous months billed for minimal energy usage. To annualize LME per book revenue, ENO calculated a proforma base revenue value of $1.79 million for the LME rate class, based on an average of the lowest three months of base revenue from October 2025 through April 2025, annualized for 12 months of 2025.

31 *See* ENO's HSPM response to DR CNO 2-31.c.

December 4, 2024.[32] In the 2025 FRP Evaluation Filing, through Proforma AJ03D, ENO returned to ratepayers state income tax overcollection for the period January-August 2025.[33]

At the same time as Act 5, Act 6 of the Third Extraordinary Session repealed the State Corporate Franchise Tax. Act 6 was also signed into law on December 4, 2024, and effective January 1, 2026.[34] As part of the instant FRP Evaluation Filing, ENO proposes to reduce its prospective (*i.e.*, beginning September 2026) revenue requirement to reflect this tax reduction,[35] but ENO does not propose to return related revenues it will collect relative to corporate franchise taxes for the period January-August 2026. This constitutes recovery of franchise taxes that ENO will not pay, or an overcollection.

The FRP tariff states,

> "In the event of a change in the state or federal corporate income tax rate(s) applicable to ENOL, **and/or any related changes to tax law,** including, but not limited to changes that may affect the effective tax rate(s) and/or changes that may affect the treatment of accumulated deferred income tax, ENOL shall include in the EFRP Evaluation Report following the change in law, all relevant information for the Council to determine the effect on the revenue requirement and propose related ratemaking treatment to become effective as of the date of the change in law."[36] (Emphasis added.)

The tariff language is primarily concerned with income tax rate changes, but the contemporaneous change to corporate franchise taxes is addressed under "related changes to tax law". At a minimum, the intent of this section of the FRP Rider is to allow rates to recover taxes that are actually incurred or accrued, whether such taxes go up or down. Considering the 2025 FRP Evaluation's treatment of state income tax rate changes and the fact that ENO knew or should have known about the franchise tax change effective January 1, 2026 and included it as a known and measurable proforma in the 2025 FRP Evaluation, it is appropriate to return ENO's overcollection relative to this tax change for the period January-August 2026. As such, we have created Advisor Adjustment ADV09, which returns this overcollection.

Cost Allocation/Customer Class Decoupling Adjustments

The mechanics of the decoupling provision in the FRP require (i) supportable allocations of total costs among rate classes to develop allocated revenue requirements, and (ii) the corresponding total revenues to develop revenue deficiency by rate class. While the methods of cost allocation used in the 2018 Rate Case are to be maintained throughout the EFRP Evaluation Filings, updating external allocation factors from updated billing determinants with a complete supporting analysis is necessary to maintain fairness in the customer class decoupling revenue adjustments. Ordering Paragraph 14 of Council Resolution No. R-19-457 stated that the utility's total revenue requirements, as determined by compliance with each of the Council's directives in this Resolution, will be recovered from each customer class on the basis of the Advisors' proposal for customer

32 *See,* https://www.legis.la.gov/legis/ViewDocument.aspx?d=1391650

33 *See*, ENO's 2025 FRP Evaluation Filing, AJ03D.

34 *See,* https://www.legis.la.gov/legis/ViewDocument.aspx?d=1391651

35 *See* FRP Evaluation Filing, proforma AJ05P.

36 Rider Schedule EFRP-7 at II.C (Changes in Tax Rates).

class revenue requirements as indicated in Advisors' Exhibit VP-20 Council Docket No. UD-18-07. Also, Rider EFRP-7 Tariff Sec. II.B.2 states that the determination of the fixed and variable revenue requirements by rate class shall be consistent with the allocation methodologies approved in Docket UD-18-07 except that the return on rate base component shall be based on class rates of return corresponding to the relative rate class revenues set in Docket UD-18-07. Consistence with allocation methodologies would include a rigorous examination of how each allocation factor is derived because of the impacts that allocation factor values have on decoupling results.

Although there has been no change to the methodology ENO uses to produce the underlying demand data for the FRP Evaluation Filings, an ENO contractor has developed demand peak data for recent test periods, including the FRP Evaluation Filings. The services of the contractor have enabled the Company to incorporate large amounts of data that are now available from the implementation of AMI. ENO provided workpapers in response to discovery[37] that support the current approach and processes implemented by ENO to develop coincident peak demands, allowing for rigorous validation, editing and estimation (“VEE”).

However, it is still reasonable to recognize variations in data occurring over a period of recent years, to provide more consistency in allocated costs in annual FRP evaluations. As an example, ENO’s peak demand for each of the twelve months in the previous (2024) test year occurred during daylight or non-dark hours, when lighting did not contribute to the monthly coincident peaks. Based on that one test period set of results, the lighting class of service would receive no portion of production and transmission fixed costs and related expenses. Yet in the eight years since the 2018 general rate case, in all but two test periods, there was an allocation to lighting service of some portion of production and transmission fixed costs. There has not been a fixed costs analysis for lighting service to reflect the changes to the lighting service production & transmission demand allocation factor over time, and these changes will impact cost of service adjustments for the lighting class.

The Advisors have selected averaging the demand allocation factors developed from the most recent three test periods to recognize both the recent approach and processes implemented by ENO to develop peak-related demand allocation factors, as well as to strive towards consistency in cost allocation factors from year to year. The kW peak demands from each of the recent three FRP test periods were combined for each of the customer classes resulting in weighted capacity-related fixed cost allocation factors which were used in the Advisors’ decoupling analysis.

Notwithstanding the use of consistent allocation methodologies, the Advisors’ examination of the capacity-related fixed cost allocation factors included in the 2026 FRP Evaluation Filing raised some questions. Notably, a proforma adjustment of base revenues for the new LME rate class is appropriate as discussed previously, assuming that appropriate adjustments are also applied to billing determinants and cost allocation factors. However, ENO’s assumptions in annualizing the LME rate class kWh billing determinants and revenue for the 2025 test year were not applied consistently to the LME rate class demand allocation factors. The billing demand for the same three months that ENO chose to annualize LME rate class kWh billing determinants averaged 25,088 kW, compared to the 5,027 kW value that ENO used as an LME rate class production and transmission level demand allocation factor. Recognizing LME as a new rate class with limited data to reflect full operation, the Advisors used an LME rate class demand allocation factor of 23,564 kW, averaging seven months of operation beginning October 2025. To determine an

[37] See response to CNO-ENO 5-3, 2024 FRP, Docket No. UD-18-07.

appropriate FRP adjustment for this new rate class, the Advisors' adjusted LME rate class billing demand corresponds to the Advisors' adjusted LME rate class revenue.

Rider EFRP-7 provides that rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service shall have a decoupling revenue adjustment cap of 10%, provided that the total electric utility FRP revenue adjustment for that evaluation does not exceed 10%.[38] With the Advisors' proposed change in total FRP revenue, (see Table 8) that decoupling revenue adjustment cap was not exceeded for those three customer classes.

The comparative results of electric rate class revenue and corresponding rates of return are presented herein in the following Attachments, Attachment A, page 1, which presents the results of the Advisors' 2018 Rate Case Recommended Electric Revenue Requirements by Rate Class; Attachment A, page 2 which presents ENO's current decoupling compliance with Rider EFRP's tariff; and Attachment B, which presents the Advisors' Adjusted Revenue Requirement and Decoupling analysis for the 2025 Test Year. In comparing Attachment A and Attachment B, the Advisors' application of decoupling results in equitable EFRP percent revenue changes among most customer classes, as well as adjustments to customer class rates of return.

We note that, due to the customary application of the decoupling and cost allocation methods that have been employed for each of the FRP Evaluations (i.e., 2021, 2022, 2023, 2024, and 2025), certain rate classes present anomalous FRP revenue change amounts. Specifically, the Municipal Building ("MB") rate class presents an Advisor adjusted FRP revenue increase of $1,291,723 (a 35% increase over proformed present revenues), and the Large Electric High Load Factor ("LEHLF") rate class presents a ($1,846,688) revenue decrease (a 1.34% decrease over proformed present revenues). Overall, the Advisor FRP bandwidth revenue increase is 2.91% over proformed present revenues).

Our review indicates that the cause of these anomalous FRP revenue changes relates to changes in allocation of cost of service relative to changes in 2025 per book revenues. In particular, we observe a likely delay before allocated cost of service catches up with revenues when electric usage changes substantially. We believe these anomalous results will correct themselves in any future FRP Evaluation as calculated cost allocations align with per book revenues.

In the interest of equity among rate classes and in the interest of avoiding rate shock, we recommend a one-time adjustment. We recommend that $1,147,500 in cost responsibility attributed to the MB rate class be reassigned to the LEHLF rate class. Through these adjustments, the MB rate class will experience the company-average 2.91% FRP bandwidth revenue increase when calculating its FRP rate, while the LEHLF rate class will experience a $699,189 reduction in the calculation of its FRP rate.

RATEPAYER IMPACT OF ENO'S FRP EVALUATION FILING AS ADJUSTED BY ADVISORS

The below Table 5 presents FRP revenue increases after applying the Advisor Adjustments to correct for the errors we identified in the FRP Evaluation Filing, including our recommended regulatory asset related to the FERC Order and our LEHLF and MB rate class cost responsibility adjustment that we discuss above. Table 2, which presents ENO's proposed change in FRP revenue is reproduced for comparison.

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38 *See* Rider EFRP-7, Section II.C.3.

Table 2 (reproduced from above) ENO FRP Evaluation Filing Change in FRP Revenues			
Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue Net of RSHCR Realignment	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$182,389,082	$12,678,245	6.95%
Small Electric Service	72,700,395	4,238,562	5.83%
Municipal Buildings	2,473,664	1,416,549	57.27%
Large Electric	24,584,313	(1,525,061)	-6.20%
Large Electric High Load Factor	93,384,626	(2,205,036)	-2.36%
Master Metered Non-Residential	439,832	(36,657)	-8.33%
High Voltage	5,584,082	123,635	2.21%
Large Interruptible	3,635,973	(86,499)	-2.38%
Large Municipal	1,792,980	(407,483)	-22.73%
Lighting Service	3,939,175	654,956	16.63%
Total	$390,924,123	$14,851,212	3.80%

Table 5 Advisor Adjusted Electric Change in FRP Revenues (Including Regulatory Asset Related to the FERC Order, Net of Rider RSHCR Realignment)			
Rate Class	Applicable Base Revenue	Advisor Adjusted Change in EFRP Revenue	Adjusted Change in EFRP Revenue as Percent of Applicable Base Revenue
Residential	$182,389,082	$5,795,360	3.2%
Small Electric Service	72,700,395	7,544,546	10.4%
Municipal Buildings	2,473,664	104,150	4.2%
Large Electric	24,584,313	112,289	0.5%
Large Electric High Load Factor	93,384,626	(1,092,444)	-1.2%
Master Metered Non-Residential	439,832	60,392	13.7%
High Voltage	5,584,082	116,625	2.1%
Large Interruptible	3,635,973	71,799	2.0%
Large Municipal	1,792,980	2,392,864	54.7%
Lighting Service	3,939,175	484,811	12.3%
Total	$390,924,123	$15,590,391	4.0%

Applying the Advisor Adjustments, but not the recommended regulatory asset related to the FERC Order, results in estimated changes to typical bills as indicated in Table 6 below.

Table 6 Estimated Change to Typical Customer Monthly Bill (Without Regulatory Asset Related to the FERC Order)					
Rate Class	Energy (kWh)	Present	ENO Proposal	After Advisor Adjustments	Change from ENO Proposal
Residential	1,000	$148.63	$156.09	$151.99	($4.10)
Small Electric	9,125	$1,482	$1,534	$1,564	($30)
Large Electric	91,250	$10,802	$10,385	$10,727	($343)

Applying the Advisor Adjustments, including the recommended regulatory asset related to the FERC Order, results in estimated changes to typical bills as indicated in Table 6a below.

Table 6a Estimated Change to Typical Customer Monthly Bill (Including Regulatory Asset Related to the FERC Order)					
Rate Class	Energy (kWh)	Present	ENO Proposal	After Advisor Adjustments	Change from ENO Proposal
Residential	1,000	$148.63	$156.09	$153.00	($3.09)
Small Electric	9,125	$1,482	$1,534	$1,577	$43
Large Electric	91,250	$10,802	$10,385	$10,820	$436

OTHER MATTERS FOR COUNCIL CONSIDERATION

Below, we discuss certain matters that we identified for Council consideration, but which are not properly addressed in the FRP evaluation process. The Council may wish to address the Mark to Market issue in a future proceeding, while we recommend that the Council address the regulatory asset related to the FERC Order in the instant FRP Evaluation.

Mark to Market ADIT

Mark to Market or "MTM" is an optional tax position under IRC Sec. 475 that allows ENO to record a balance sheet entry based on the expected costs of Purchase Power Agreement ("PPA") contracts relative to market costs for the same capacity and energy. ENO is not obligated to undertake MTM accounting and tax positions, but should ENO opt for MTM treatment, all contracts must be given MTM treatment. As ENO's taxable income and taxable deductions are part of a consolidated return involving other companies, it is our understanding that ENO's MTM election is tied to the broader interests of the consolidated taxable entity (*i.e.*, the EOCs as a whole).

In the instant FRP Evaluation Filing, per book MTM balances are recorded in ENO Accounts 283225 ($9,791,833) and 283226 ($2,713,786) (credit balances). These values are largely allowed by ENO to credit ENO's rate base, except for inappropriate reversals through what ENO calls FIN

48 adjustments,[39] which we reverse in Advisor Adjustment ADV02. In the instant FRP Evaluation Filing, MTM ADIT is a credit (*i.e.*, a reduction to rate base). However, in prior FRP Evaluation Filings, MTM has been a debit.

ENO states, "From year-to-year, whether Accounts 283225 and 283226 will have credit balances or debit balances depends on power/energy market activities that drive the MTM taxable income or tax deductions in each tax year. ENO's position is that MTM ADIT associated with third-party PPAs should be included in rate base exclusive of amounts subject to FIN 48."[40] We note that ENO is wrong when arguing that FIN48 ADIT is not properly includable in rate base.[41]

ENO states that it ". . . requested that the Council and its Advisors establish a ratemaking rule regarding the treatment of MTM ADIT associated with third-party PPAs and their inclusion in rate base, in previous FRP Reports, and has made the same request this year."[42] We repeat from last year's FRP report a hypothetical treatment that addresses ENO's concern regarding MTM ADIT:

In years in which a debit rate base balance related to a particular MTM tax position may occur, the revenue requirement (at ENO's WACC for FRP purposes) related to that debit balance may be deferred as a regulatory asset that is not reflected in rate base and that does not amortize. The similar revenue requirement related to future MTM credit rate base balances may be used to credit the position's regulatory asset before such revenue requirement credit flows to rates (as a rate base credit). This way, ENO does not credit ratepayers in some years, while absorbing debit balances in other years. However, ratepayers cannot be penalized for MTM tax positions; they can only benefit. Additionally, once any contract subject to MTM accounting terminates, any regulatory asset balance related to the terminated contract would be written off from any deferral balance without affecting ENO's rates.

Regulatory Asset Related to the FERC Order

The FERC Order was issued on June 2, 2026, well after the filing of the instant FRP Evaluation Filing. In the FERC Order, ENO is ordered to refund money to ELL and EAL related to what FERC believes is a tariff violation by ESL regarding the MSS-4R tariff. ELL and EAL are ordered to submit a compliance filing calculating the refund amount within 90 days of the FERC Order (*i.e.*, by August 31, 2026). The Advisors consider the FERC Order to be deeply flawed, and in fact no refunds payable by ENO are appropriate. Multiple parties, including the Council, have filed motions for rehearing and clarification in this proceeding. Regardless, even should the Council or its aligned parties to this proceeding ultimately prevail in their appeals, ENO must pay ELL and EAL the refund amount in the interim. No refund amount calculation has been provided by ELL and EAL as of the date of this Report, and if ELL and EAL take the entire allowed 90 days to make their compliance filing, August 31, 2026, is too late to include recovery of this amount in the FRP Evaluation's rates, which are effective September 2026.

Importantly, without establishing a recovery mechanism in the instant FRP Evaluation, ENO would likely seek recovery of the refund outside of a base rate action (especially if there is no 2027

39 *See* ENO's HSPM response to DR CNO 2-11.

40 FRP Evaluation Filing, *Summary Pleading*, XXVIII at 14.

41 *See Supra*, our discussion related to Advisor Adjustment ADV02.

42 ENO's response to DR CNO 2-11.a.

FRP Evaluation[43]). In this scenario, ENO could seek recovery of the full amount of the refund payable to ELL and EAL over a year or even in a single billing cycle, which if allowed by the Council would result in unacceptable rate shock. Even should ENO wait to seek recovery until the next base rate action, whose date is uncertain at present, ENO would likely seek recovery of carrying charges on the unrecovered refund balance, which would further burden ratepayers.

As such, and consistent with longstanding Council ratemaking practice of allowing regulatory assets to recover significant one-time expenses, we recommend that the Council allow ENO to record a regulatory asset in the amount of $20 million, which falls within the range of initial estimates of the total amount ENO may owe ELL and EAL. We recommend that costs related to this regulatory asset be given outside-the-bandwidth treatment in any future FRP evaluations. Our recommended FRP rates reflect a 5-year amortization of this regulatory asset and inclusion of its effect in rate base (*i.e.*, return on the regulatory asset's rate base effect at ENO's WACC).

As part of the creation of this recommended regulatory asset, we recommend that the Council note that $20 million is an estimate, and the actual amount will differ, possibly substantially. The amount of the regulatory asset shall be adjusted to reflect the actual refund amount once the ELL and EAL compliance filing is made and a final refund amount is known. Further, we note that ENO will gain the benefit of this regulatory asset on September 1, 2026, while the actual date of ENO's payments to ELL and EAL may be later. As such, we recommend that the balance of this regulatory asset be adjusted as part of the next Council base rate action (*i.e.*, a rate case or an FRP Evaluation should the Council allow ENO an FRP extension). This adjustment should take into account both the amount of ENO's payments to ELL and EAL as well as those payments' timing relative to the effective date of the regulatory asset.

[43] *See* Rider Schedule EFRP-7 at IV. ("Rider EFRP shall be in effect for three years with annual Evaluation Report filings to be made on or before April 30 of 2024, 2025, and 2026. . ."). At present there are no further base rate actions approved by the Council or initiated by ENO.

Attachment A
Advisors' 2018 Rate Case Recommended Electric Revenue
Requirements by Rate Class

Line No.	Description	Total Company Adjusted	RES	Large Electric	Small Electric	Large Interruptible Service	Large Electric High Load Factor	High Voltage	Municipal Building	Master Metered Non Res	Lighting
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]
1	Rate Base	777,383,427	425,338,913	48,750,285	114,482,471	4,645,876	164,739,772	5,995,785	3,942,686	75,013	9,412,623
2	ENO Required Rate of Return on Rate Base After taxes	6.91%									
3	ENO Required Rate of Return on Rate Base Including taxes	8.48%	1.60%	15.73%	18.32%	18.50%	15.79%	13.96%	21.31%	18.26%	20.16%
4	Return on Rate Base including income taxes	65,924,364	6,819,490	7,667,160	20,974,047	859,487	26,016,382	836,718	840,005	13,696	1,897,379
5	Operation & Maintenance Expense	404,211,278	190,661,260	29,152,919	60,943,027	6,183,538	104,114,314	7,715,058	2,118,224	42,493	3,280,454
6	Gains from Disp of Allowances	-	-	-	-	-	-	-	-	-	-
7	Regulatory Debits & Credits	4,538,904	2,420,822	295,209	678,021	30,096	1,003,174	38,751	23,427	452	48,952
8	Interest on Customer Deposits	895,555	489,996	56,161	131,885	5,352	189,782	6,907	4,542	86	10,843
9	Other Credit Fees	46,620	25,508	2,924	6,866	279	9,880	360	236	4	564
10	Depreciation & Amortization Expense	53,459,952	29,395,752	3,296,141	7,899,949	353,263	11,167,569	467,754	268,365	5,046	606,114
11	Amortization of Plant Acquisition Adjustment	1,189,690	540,672	91,545	185,581	15,824	319,821	24,277	6,675	133	5,161
12	Taxes Other than Income	20,940,293	11,518,901	1,279,645	3,123,711	136,916	4,343,957	181,630	105,934	1,997	247,602
13	SSCR (will be recovered w/ a Rider)	14,815,179	6,771,975	1,061,261	2,599,421	129,305	3,603,826	258,953	107,355	2,064	281,019
14	EECR (will be recovered w/ a Rider)	6,005,758	2,365,561	576,815	845,922	-	2,012,843	149,290	54,660	667	-
15	Less Credit to COS from Other Operating Revenue	(8,278,099)	(4,313,506)	(533,540)	(1,318,405)	(44,757)	(1,805,658)	(80,786)	(49,118)	(936)	(131,393)
16	**Total Cost of Service**	**563,749,493**	**246,696,430**	**42,946,239**	**96,070,024**	**7,669,302**	**150,975,890**	**9,598,911**	**3,480,305**	**65,703**	**6,246,695**
17	Less Present Revenue	596,853,414	250,098,239	46,736,829	96,599,501	11,061,296	166,588,860	13,381,097	3,773,720	79,482	8,534,390
18	**= Revenue Deficiency (Excess)**	**(33,103,921)**	**(3,401,809)**	**(3,790,590)**	**(529,477)**	**(3,391,994)**	**(15,612,970)**	**(3,782,186)**	**(293,415)**	**(13,779)**	**(2,287,695)**

Note: This Attachment was originally introduced as Exhibit VP-20 in the 2018 Rate Case.

Legend Consulting Group Limited

ENTERGY NEW ORLEANS, LLC
FORMULA RATE PLAN
Electric Utility Revenue Redetermination by Rate Class at Equal Rates of Return
ELECTRIC
Test Year Ending December 31, 2025

Line No.	Description	Total Company Adjusted	Residential	Small Electric	Municipal	Large Electric	High Load Factor	Master Metered	High Voltage	Large Interruptible	Large Municipal	Lighting
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]
1	Rate Base	1,211,061,492	704,222,604	177,056,791	18,343,556	60,887,851	223,402,244	1,145,467	8,184,592	5,858,185	2,166,875	9,793,326
2	ENO Required Rate of Return on Rate Base After taxes	7.45%										
3	ENO Required Rate of Return on Rate Base Including taxes	9.19%	3.81%	20.90%	10.02%	13.00%	14.82%	1.13%	17.04%	4.73%	14.28%	26.58%
4	Return on Rate Base including income taxes	111,325,048	26,857,744	37,012,602	1,837,923	7,916,187	33,103,843	12,892	1,394,723	276,915	309,419	2,602,801
5	Operation & Maintenance Expense	480,219,733	258,428,422	67,773,121	2,669,832	26,827,319	105,338,258	473,037	8,504,142	6,411,812	1,740,606	2,053,183
6	Gains from Disp of Allowances	-	-	-	-	-	-	-	-	-	-	-
7	Regulatory Debits & Credits	(18,939,824)	(11,089,288)	(2,778,054)	(255,698)	(934,436)	(3,433,511)	(17,398)	(143,825)	(101,033)	(38,120)	(148,461)
8	Interest on Customer Deposits	2,334,337	1,357,399	341,279	35,357	117,362	430,611	2,208	15,776	11,292	4,177	18,877
9	Other Credit Fees	57,196	33,259	8,362	866	2,876	10,551	54	387	277	102	463
10	Depreciation & Amortization Expense	80,774,099	47,784,232	11,848,711	1,069,507	3,912,576	14,291,050	70,269	581,045	409,315	148,631	658,762
11	Amortization of Plant Acquisition Adjustment	1,190,642	627,759	176,754	4,222	69,851	267,993	1,300	22,140	13,443	6,064	1,116
12	Taxes Other than Income	18,331,372	10,814,627	2,699,246	222,922	886,678	3,266,828	16,483	147,961	105,523	40,190	130,915
13	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	(1,304,515)	(334,047)	(364,503)	(25,690)	(111,171)	(412,230)	(1,392)	(16,083)	(10,318)	(4,877)	(24,203)
14	SSCR (recovered w/ a Rider)	-										
15	SSCR II (recovered w/ a Rider)	-										
16	SSCO (recovered w/ a Rider)	-										
17	EECR (recovered w/ a Rider)	-										
18	Less Credit to COS from Other Operating Revenue	(66,135,909)	(29,842,669)	(10,245,048)	(451,637)	(4,335,988)	(17,629,141)	(74,089)	(1,499,013)	(1,357,775)	(218,577)	(481,972)
19	**Total Cost of Service**	**607,852,181**	**304,637,438**	**106,472,471**	**5,107,605**	**34,351,253**	**135,234,250**	**483,365**	**9,007,253**	**5,759,451**	**1,987,615**	**4,811,479**
20	Less Present Revenue [1]	591,232,742	290,994,868	101,983,925	3,650,983	35,768,927	137,046,031	517,566	8,883,617	5,845,950	2,395,098	4,145,777
21	**= Revenue Deficiency (Excess)**	**16,619,439**	**13,642,570**	**4,488,545**	**1,456,622**	**(1,417,674)**	**(1,811,780)**	**(34,201)**	**123,635**	**(86,499)**	**(407,483)**	**665,703**
22	Percent Increase on Total Revenues	2.8%	4.7%	4.4%	39.9%	-4.0%	-1.3%	-6.6%	1.4%	-1.5%	-17.0%	16.1%

Attachment B
Corrected Return on Rate Base
Calculation by Rate Class

Description	Line Item	Total Advisor Adjustments	Combined Total Company Adjusted	Residential	Small Electric	Municipal	Large Electric	High Load Factor	Master Metered	High Voltage	Large Interruptible	Large Municipal	Lighting
Rate Base	RBTOA: RATE BASE Total	8,375,898	1,219,437,390	693,581,430	181,697,582	17,994,018	65,258,249	226,351,540	1,355,140	8,337,685	5,896,227	9,254,193	9,711,030
ENO Required Rate Of Return On Rate Base Including Taxes	RORB IT	9.19%	9.19%	3.69%	20.79%	9.29%	12.88%	14.68%	1.01%	16.16%	4.73%	13.41%	26.58%
Return On Rate Base Including Income Taxes		769,942	112,094,991	25,560,586	37,765,842	1,671,644	8,406,993	33,229,023	13,650	1,347,045	278,713	1,240,564	2,580,929
Operation & Maintenance Expense	OMTOA: OPERATION & MAINTENANCE EXPENSE Total	2,054,566	482,274,299	254,090,126	69,687,438	2,697,055	27,677,403	104,935,497	554,466	8,512,358	6,543,938	5,653,713	1,922,287
Regulatory Debits & Credits	RDCTOA: REGULATORY DEBITS AND CREDITS Total	4,000,000	(14,939,824)	(8,843,205)	(2,166,602)	(237,573)	(749,936)	(2,587,854)	(15,307)	(70,466)	(55,631)	(66,037)	(147,233)
Interest on Customer Deposits	ICDTOA: INTEREST ON CUSTOMER DEPOSITS Total	0	2,334,337	1,319,301	336,768	34,746	129,074	442,340	2,754	16,166	11,290	22,830	19,070
Depreciation & Amortization Expense	DXTOA: DEPRECIATION AND AMORTIZATION EXPENSE To	(64,148)	80,709,951	46,901,172	11,971,585	1,055,105	4,136,886	14,331,888	81,993	578,467	403,921	593,969	654,978
Amortization of Plant Acquisition Adjustment	APAATOA: AMORTIZATION OF PLANT ACQUISITION ADJUS	0	1,190,642	598,930	175,286	4,672	73,850	271,628	1,530	22,568	13,412	28,393	372
Taxes Other than Income	TOTOA: TAXES OTHER THAN INCOME Total	(1,392,174)	16,939,199	9,828,581	2,657,674	200,420	841,165	2,929,246	17,118	130,380	93,929	124,439	116,260
FIN 48 and Bank Interest	OCFTOA: OTHER CREDIT FEES	30,314	87,510	49,458	12,625	1,303	4,839	16,583	103	606	423	856	715
Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	79,345	(1,225,170)	(313,729)	(342,333)	(24,128)	(104,410)	(387,156)	(1,307)	(15,105)	(9,690)	(4,581)	(22,731)
SSCR II (recovered w/ a Rider)													
SSCO (recovered w/ a Rider)													
Less Credit To COS From Other Operating Revenue:		0	(66,135,909)	(29,842,669)	(10,245,048)	(451,637)	(4,335,988)	(17,629,141)	(74,089)	(1,499,013)	(1,357,775)	(218,577)	(481,972)
Total Cost Of Service		5,477,846	613,330,026	299,348,553	109,853,236	4,951,608	36,079,876	135,552,052	580,911	9,023,006	5,922,531	7,375,570	4,642,675
Base Rate Revenue	REVOTH: Sales Revenue	-	409,389,302	200,506,599	72,796,026	2,543,959	24,584,313	93,566,362	439,832	5,584,082	3,635,973	1,792,980	3,939,175
Adjustment to LME Revenue	REVOTH: ADV07 LME Revenue	2,582,642	2,582,642	-	-	-	-	-	-	-	-	2,582,642	-
FRP Revenue	REVFRP: FRP Revenue	-	87,462,976	44,982,619	17,657,472	687,496	5,289,438	18,201,224	(26,110)	922,384	(153,907)	362,467	(460,108)
FAC Revenue	REVFAC: FAC Revenues	182,398	95,279,602	39,847,640	14,744,320	489,728	6,582,433	27,420,420	107,762	2,582,731	2,437,639	318,077	748,852
MISO Rider	REVMIS: MISO Revenues	13,747	2,065,569	961,682	332,629	6,709	144,021	523,193	2,668	43,642	35,482	15,545	(2)
LCFC Revenue	REVLCF: LCFC Revenue	(77,069)	(5,260,568)	(2,603,347)	(950,928)	(41,697)	(327,895)	(1,237,133)	(6,569)	(74,210)	-	(18,789)	-
Purchase Power Revenues	REVPPC: Purchase Power Capacity	(23,143)	(20,113,743)	(9,716,266)	(3,260,432)	(129,814)	(1,415,515)	(4,897,087)	(3,987)	(379,444)	(104,454)	(125,943)	(80,800)
	456200: Unbilled Revenue	-	-	-	-	-	-	-	-	-	-	-	-
EECR Revenue	REVEEC: EECR Revenue	2,060,082	24,565,620	18,609,940	739,619	103,504	1,003,405	3,821,761	4,468	227,195	-	55,728	-
Present Revenue		4,738,657	595,971,400	292,588,868	102,058,707	3,659,885	35,860,200	137,398,741	518,063	8,906,381	5,850,733	4,982,706	4,147,117
FRP Revenue Change		**739,188**	**17,358,627**	**6,759,685**	**7,794,529**	**1,291,723**	**219,676**	**(1,846,688)**	**62,848**	**116,625**	**71,799**	**2,392,864**	**495,557**
			2.91%	2.31%	7.64%	35.29%	0.61%	-1.34%	12.13%	1.31%	1.23%	48.02%	11.95%

Attachment C

Advisor Adjustments to ENO's Proposed Ratemaking Treatment by Account	
ENO Account(s)	**Adjustment DR/(CR)**
ADV01 – Rider Revenues	
RSRREECR: 440-445 SALES–RETAIL - Energy Smart	($2,060,082)
RSRRFAC: 440-445 SALES–RETAIL - FAC	($182,398)
RSRRMIS: 440-445 SALES–RETAIL - MISO	($13.747)
RSRRPPC: 440-445 SALES–RETAIL - PURCHASED POWER CAPACITY	$23,143
OMCS908: 908 CUSTOMER ASSISTANCE EXP	$2,054,566
PGA Rider Revenue	
FTCALC: FEDERAL INCOME TAX	$35,427
CITTOA: CURRENT INCOME TAXES	$9,819
ADV02 – FIN48 ADIT	
ADFIT283: 283 - FEDERAL 283225: Section 475 Adjustment-Fed	($[redacted])
ADSIT283: 283 - STATE 283226: Section 475 Adjustment-St	($[redacted])
ADV03 – LCFC	
RSRRLCF: 440-445 SALES–RETAIL - LCFC REVLCF: LCFC Revenue	$77,069
FITAESI: ESL CURRENT FEDERAL TAXES 409112: Income Taxes-Util Op Inc – Fed	$15,294
SITAESI: ESL CURRENT STATE TAXES 409114: Income Taxes-Util Op Inc-State	$4,239
ADV04 – Storm Proforma Costs	
PLD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 1010AM: Electric Plant In Service	($27,448)
PLD362: 362 STATION EQUIPMENT (DS-DD-TO) 1010AM: Electric Plant In Service	($652,381)
PLD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 1010AM: Electric Plant In Service	($623,877)
PLD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 1010AM: Electric Plant In Service	($985,539)
PLD368: 368 LINE TRANSFORMERS (DX-DD-TO) 1010AM: Electric Plant In Service	($139,879)
PLD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 1010AM: Electric Plant In Service	($19,879)
DXD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 4030AM: Depreciation Expense	($270)
DXD362: 362 STATION EQUIPMENT (DS-DD-TO) 4030AM: Depreciation Expense	($7,294)
DXD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 4030AM: Depreciation Expense	($19,563)
DXD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 4030AM: Depreciation Expense	($31,214)

Attachment C

Advisor Adjustments to ENO's Proposed Ratemaking Treatment by Account	
ENO Account(s)	**Adjustment DR/(CR)**
DXD368: 368 LINE TRANSFORMERS (DX-DD-TO) 4030AM: Depreciation Expense	($5,195)
DXD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 4030AM: Depreciation Expense	($612)
ADV05 – FIN 48 Interest	
OCFBL: BANK LOANS & FIN48 - INTEREST EXP	$30,314
ADV07 – Prospective LME Rate Class Revenues	
RSRRT: 440-445 SALES-RETAIL	($2,582,642)
409112: Income Taxes-Util Op Inc - Fed	$512,525
409114: Income Taxes-Util Op Inc-State	$142,045
ADV09 – Corporate Franchise Tax	
TOSLFTLA: 408.158 FRANCHISE TAX-LOUISIANA	($1,392,174)
Regulatory Asset Related to FERC Order	
AAA115: 115 AMORT ACQUISITION ADJUSTMENT	$16,000,000
RCASB: 407.425 REGULATORY CREDITS - ARO - ASBESTOS REMOVAL	$4,000,000
ADITSTOA: ACCUMULATED DEFERRED STATE INC TAXES	($4,055,200)

Attachment D

Entergy New Orleans, LLC
Formula Rate Plan
Earned Rate of Return on Common Equity Formula
Electric
For the Test Year Ended December 31, 2025

Line No.	Description		ENO Adjusted Amount	Advisor Adjusted Amount
	TOTAL COMPANY			
1	RATE BASE	Att B, P 2, L 23	1,211,061,492	1,219,437,390
2	BENCHMARK RATE OF RETURN ON RATE BASE	Att D, L 4, Col D	7.45%	7.45%
3	REQUIRED OPERATING INCOME	L 1 * L 2	90,181,694	90,805,405
4	NET UTILITY OPERATING INCOME	Att B, P 3, L 26	78,191,696	77,639,308
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	11,989,998	13,166,097
6	REVENUE CONVERSION FACTOR (1)		1.3861	1.3184
7	REVENUE DEFICIENCY/(EXCESS)	L 5 * L 6	16,619,439	17,358,627
	PRESENT RATE REVENUES			
8	ULTIMATE CUSTOMERS	Att B, P 3, L 1	591,232,742	595,971,400
9	REVENUE REQUIREMENT	L 7 + L 8	607,852,181	613,330,026
10	PRESENT RATE BASE REVENUES	Att B, P 3, L 1	591,232,742	595,971,400
11	REVENUE DEFICIENCY/(EXCESS)	L 9 - L 10	16,619,439	17,358,627
12	REVENUE CONVERSION FACTOR (1)	L 6	1.3861	1.3184
13	OPERATING INCOME DEFICIENCY/(EXCESS)	L 11/L 12	11,989,998	13,166,097
14	RATE BASE	Att B, P 2, L 23	1,211,061,492	1,219,437,390
15	COMMON EQUITY DEFICIENCY/(EXCESS) (%)	L 13/L 14	0.99%	1.08%
16	WEIGHTED EVALUATION PERIOD COST RATE FOR	Att D, L 3, Col D	5.14%	5.14%
17	WEIGHTED EARNED COMMON EQUITY RATE (%)	L 16 - L 15	4.15%	4.06%
18	COMMON EQUITY RATIO (%)	Att D, L 3, Col B	55.00%	55.00%
19	EARNED RATE OF RETURN ON COMMON EQUITY (%)	L 17/L 18	7.55%	7.39%