Leroy Nix
VP, Regulatory & Public Affairs
Entergy New Orleans, LLC
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1600 Perdido Street, New Orleans, LA 70112

May 12, 2025

Via Electronic Delivery
Clerk of Council
City Hall, Room 1E09
1300 Perdido Street
New Orleans, Louisiana 70112

Re: Entergy New Orleans, LLC's Eleventh Annual Post-MISO-Integration Monitoring Report
CNO Docket UD-11-01

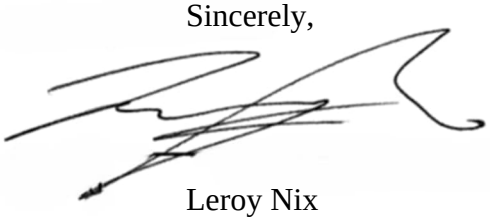
Dear Clerk of Council:

Please find enclosed for your further handling the Public Version of the Eleventh Annual Post-MISO-Integration Monitoring Report of Entergy New Orleans, LLC ("ENO" or the "Company").

In connection with the Company's filing, a Confidential Version of the Report bearing the designation "Highly Sensitive Protected Materials" is being provided to the Council's Advisors pursuant to the terms and conditions of the Official Protective Order adopted in Council Resolution R-07-432. Portions of the information included in the filing consist of or reflect competitively sensitive cost and market information, the disclosure of which may present a risk of harm to ENO's customers. In addition, portions of the filing may contain highly sensitive information of third parties to which an obligation of confidentiality is owed.

If you have any questions regarding this information, please contact me at (504) 670-3680.

Sincerely,



Leroy Nix

Enclosures

cc: Official Service List UD-11-01 *(via email)*

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

INVESTIGATION OF THE POTENTIAL COSTS AND BENEFITS OF ENTERGY NEW ORLEANS, LLC AND ENTERGY LOUISIANA, LLC JOINING A REGIONAL TRANSMISSION ORGANIZATION VERSUS CONTINUATION OF THE ENTERGY INDEPENDENT COORDINATOR OF TRANSMISSION WITH ENHANCEMENTS	**)**	**DOCKET NO. UD-11-01**

ENTERGY NEW ORLEANS, LLC'S ELEVENTH ANNUAL POST-MISO-INTEGRATION MONITORING REPORT

Pursuant to, and in compliance with, Council of the City of New Orleans Resolution R-15-139 dated April 9, 2015, Entergy New Orleans, LLC ("ENO" or the "Company")[1] submits its Eleventh Annual Post-MISO-Integration Monitoring Report ("Report") related to the integration of ENO into the Midcontinent Independent System Operator, Inc. ("MISO") regional transmission organization ("RTO") on December 19, 2013. The headings and sub-headings set forth below correspond to the headings and sub-headings contained in the Summary of Proposed Post-MISO-Integration Reporting Guidelines, in Exhibit 4 to the Agreement in Principle attached to Council Resolution R-15-139.

On December 14, 2017, the Council adopted Resolution R-17-627 in Docket No. UD-17-02 that found, among other things, that ENO's continued membership in MISO beyond December 19, 2018, is in the public interest at this time.[2] This Eleventh Annual Report follows the

[1] Effective December 1, 2017, Entergy New Orleans, Inc. underwent a Council-approved corporate restructuring to become a limited liability company. Accordingly, the utility formerly operating as Entergy New Orleans, Inc. is now operating as Entergy New Orleans, LLC.

[2] Resolution R-17-627, Ordering Paragraph #4. *See also* AIP, Paragraph 2.e., at page 4 ("ENO shall develop, in consultation with the Advisors, a detailed framework and content for future reporting that is better suited to assess the annual historic costs and benefits of MISO membership.").

streamlined framework and includes estimated benefits to ENO customers resulting from the Company's continued membership in MISO calculated as of the end of 2024 using the updated methodology discussed with the Advisors.

a. Resource Adequacy

1. The following related to resource adequacy in MISO for ENO[3] for the current Planning Year including:

i. The Results from MISO's Planning Resource Auction for the current Planning Year

MISO's Resource Adequacy Construct, including the Planning Resource Auctions ("PRAs"), are conducted on an annual basis coinciding with the MISO Planning Year, which begins on June 1 of a given year and concludes on May 31 of the following year. The PRAs are simultaneously conducted for each season within the upcoming MISO Planning Year. The Resource Adequacy Construct establishes capacity requirements for specific geographic areas, known as Local Resource Zones ("LRZs"), which can be met through participation in the PRA. ENO is located in LRZ 9, which covers Louisiana and Texas. In addition to owned and contracted resources in LRZ 9, ENO owns and has long-term contracts with generating resources located in LRZ 8 (Arkansas) and LRZ 10 (Mississippi). The PRAs result in clearing prices for each LRZ, which are used for both capacity purchases and capacity sales for auction participants within each

[3] Resolution 15-139 contemplated the "System Agreement Operating Companies," which included ENO and the other Entergy operating companies participating in the System Agreement at the time the resolution was issued (Entergy Louisiana LLC, Entergy Gulf States Louisiana, L.L.C., Entergy Texas, Inc., and Entergy Mississippi, Inc. (now Entergy Mississippi, LLC)). Because the Entergy System Agreement terminated on August 31, 2016, the information and data in this and each subsequent Report shall only be provided for ENO.

LRZ. The 2024-2025 PRAs resulted in clearing prices summarized by season and LRZ in HSPM Attachment 1 titled "24-25 PRA Results_ENO OC HSPM".

ii. A list of the capacity purchases, by amount and cost, made by ENO

Certain information responsive to this component of the filing has been designated as Highly Sensitive Protected Material ("HSPM"), has been redacted from the Public Version of this filing, and will be provided only to Reviewing Representatives authorized and designated under the confidentiality agreement executed in this docket.

ENO has been participating in MISO's Resource Adequacy process for the 2024-2025 Planning Year since June 1, 2024. For each season contained within the June 1, 2024 through May 31, 2025 Planning Year, ENO's purchases/sales are summarized in HSPM Attachment 1 titled "24-25 PRA Results_ENO OC HSPM".

b. Market Operations

1. **A breakdown of the energy mix used to supply ENO's customers, for the previous twelve month period, showing the MWh and average cost by month, as supplied by resources owned or controlled (through limited or long-term bilateral purchase power agreements) by ENO, and purchases from the MISO markets**

Please see HSPM Attachment 2 titled "ENO_Energy_Mix_2024 HSPM.xlsx" for a breakdown of the energy mix used to serve ENO's customers in 2024.

2. **The following related to congestion hedging for the System Agreement Operating Companies, collectively and individually:**

i. The allocation of Auction Revenue Rights ("ARRs") and Financial Transmission Rights ("FTRs") received by ENO

Please see HSPM Attachment 3 titled "ENO Annual ARR Allocation Results_PY2425_HSPM.pptx", which outlines the allocation of ARRs and FTRs to ENO for the 2024-25 Planning Year.

ii. The cost of any ARRs and FTRs purchased by ENO in the MISO market processes

The information responsive to this component of this filing has been designated as HSPM.

[redacted]

iii. The annual net congestion charges (net of congestion revenues which will be identified and quantified separately), if any, paid by ENO to MISO

The Company's net congestion charges are shown in the table below, with positive numbers reflecting net congestion charges and negative numbers reflecting net congestion revenues. Congestion charges represent the cost of delivering owned and contracted generation to load. This can be calculated by subtracting the Marginal Congestion Component ("MCC") of the Locational Marginal Price ("LMP") of the generator source from the MCC of the LMP of the load sink.

The HSPM table below reflects congestion charges (net of revenues from ARRs and FTRs) from resources owned or under contract by ENO prior to MISO integration on December 19, 2013 ("pre-MISO integration resources").[4] After the termination of the Entergy System Agreement on August 31, 2016, ENO modified its net congestion calculation. While the System Agreement was in effect, ENO was allocated a share of the total net congestion incurred by the System Agreement Operating Companies. This calculation included both Day-Ahead and Real-Time market effects, with the specifics of the calculation dictated by the System Agreement for purposes of allocating costs among the System Agreement Operating Companies. As a result of ENO operating as a standalone entity outside of the System Agreement, ENO is able to produce

[4] The pre-MISO integration resources include Ninemile Unit 6 because that resource was granted transmission service by the Independent Coordinator of Transmission prior to MISO integration.

a simplified congestion calculation that only includes Day-Ahead market effects. ENO has chosen to exclude the Real-Time market effects because: (1) FTRs hedge congestion incurred in the Day-Ahead market only, and (2) over 97% of ENO's load needs have been served through the Day-Ahead market since joining MISO. The following table reflects ENO's net congestion charges from its pre-MISO integration resources utilizing the Day-Ahead only methodology.

ENO's Net Congestion from Pre-MISO Integration Resources	
Period	**Net Congestion Charge/(Revenue)**
Jan. 1, 2024 – Dec. 31, 2024	[redacted]

3. Net Revenue Sufficiency Guarantee charges (net of any make whole payment revenues, which will be identified and quantified separately), if any, paid by ENO to MISO

The HSPM table below provides a summary of ENO's Revenue Sufficiency Guarantee ("RSG") charges and Make Whole Payments for the period from January 1, 2024 through December 31, 2024. Positive numbers reflect amounts paid to MISO, and negative numbers reflect amounts received from MISO.

Charge/Determinant Name	**Description**	**Charge/(Credit) to ENO (1/1/2024 – 12/31/2024)**
Day-Ahead RSG Distribution (DA_RSG_DIST)	The total Day-Ahead RSG Distribution amount obligation for an Asset Owner	[redacted]
Day-Ahead RSG Make Whole Payment (DA_RSG_MWP)	The total Day-Ahead Revenue Sufficiency Make Whole Payment credit for all assets of an Asset Owner	[redacted]
Real-Time First Pass RSG Distribution (RT_RSG_DIST1)	The charges related to funding first pass distribution of Real-Time RSGs	[redacted]
Real-Time Second Pass RSG Distribution (RT_RSG_DIST2)	The charges related to funding second pass distribution of Real-Time RSGs	[redacted]

Real-Time RSG Make Whole Payment (RT_RSG_MWP)	The total credits received for Real-Time RSG Make Whole Payments	[redacted]
Grand Total		[redacted]

4. A summary of the types of ancillary services purchased by ENO from MISO as well as those provided by ENO to MISO and the compensation received by ENO from such services

The HSPM table below provides a summary of ENO's charges and revenues related to MISO ancillary services from January 1, 2024 through December 31, 2024, with positive numbers reflecting amounts paid to MISO and negative numbers reflecting amounts received from MISO.

Charge /Determinant Name	Description	Charge/(Credit) to ENO (1/1/24-12/31/24)
Day-Ahead Regulation (DA_ASM_REG)	The total daily amount due to Asset Owners that own the Regulation Qualified Resources with Day-Ahead Schedules for Regulating Reserves.	[redacted]
Day-Ahead Spinning Reserves (DA_ASM_SPIN)	The total daily amount due to Asset Owners that own the Spin Qualified Resources with Day-Ahead Schedules for Spinning Reserves.	[redacted]
*Day-Ahead Short-Term Reserve Amount (DA_ASM_STR)	The total daily amount due an Asset Owner that clears Short-Term Reserve in the Day Ahead Market.	[redacted]
Day-Ahead Supplemental Reserves (DA_ASM_SUPP)	The total daily amount due to Asset Owners that own the Supplemental Qualified Resources with Day-Ahead Schedules for Supplemental Reserves.	[redacted]
Day-Ahead Ramp Capability Amount (DA_RC_AMT)	The total daily amount due to Asset Owners for Up Ramp Capability and/or Down Ramp Capability in the Day-Ahead Energy and Operating Reserve Market.	[redacted]
Contingency Reserve Deployment Failure Charge (RT_ASM_CRDFC)	The total daily net charge for an Asset Owner that owns Resources that was unable to deploy the specified amount of Contingency Reserve within the Contingency Reserve Deployment Period following a Contingency Reserve Deployment Instruction.	[redacted]

Excessive/Deficient Energy Deployment Charge (RT_ASM_EXE_DFE_DEP)	The total daily Asset Owner charge associated with the Asset Owners that was unable to follow Setpoint Instructions and are assessed a share of the cost of procuring regulation service.	[redacted]
Real-Time Net Regulation Adjustment Amount (RT_ASM_NRGA)	Charges or credits to a Resource providing deployed Regulation Service such that the Resource is indifferent to deploying Energy above or below its Dispatch Target for Energy to provide the Regulation Service.	[redacted]
Real-Time Regulation (RT_ASM_REG)	The total daily net charge or credit for an Asset Owner that owns Regulation Qualified Resources with cleared hourly Real-Time Regulating Reserve delta MW.	[redacted]
Real-Time Regulation Cost Distribution (RT_ASM_REG_DIST)	The total daily charges or credits to an Asset Owner for Day-Ahead and Real-Time Regulating Reserve procurement costs.	[redacted]
Real-Time Spinning Reserves (RT_ASM_SPIN)	The total daily net charge or credit for an Asset Owner that owns Spin Qualified Resources with cleared hourly Real-Time Spinning Reserve delta MW.	[redacted]
Real-Time Spinning Reserve Cost Distribution (RT_ASM_SPIN_DIST)	The total daily charges or credits to an Asset Owner for Day-Ahead and net Real-Time Spinning Reserve procurement costs.	[redacted]
*Real-Time Short-Term Reserve Amount (RT_ASM_RST)	The total daily net charge or credit for an Asset Owner that owns Short-Term Reserve Qualified Resources with cleared Hourly Real-Time Short-Term Reserve delta MWs.	[redacted]
*Short-Term Reserve Cost Distribution Amount (RT_ASM_STR_DIST)	The total daily net charge or credit for an Asset Owner that owns Supplemental Qualified Resources with cleared hourly Real-Time Supplemental Reserve delta MWs.	[redacted]
Real-Time Supplemental Reserves (RT_ASM_SUPP)	The total daily net charge or credit for an Asset Owner that owns Supplemental Qualified Resources with cleared hourly Real-Time Supplemental Reserve delta MW.	[redacted]
Real-Time Supplemental Reserve Cost Distribution (RT_ASM_SUPP_DIST)	The total daily charges or credits to an Asset Owner for Day-Ahead and net Real-Time Supplemental Reserve procurement costs.	[redacted]

Real-Time Ramp Capability Amount (RT_RC_AMT)	The total daily charges or credits to an Asset Owners for Ramp Capability in the Real-Time Energy and Operating Reserve Market, net of Ramp Capability amounts in the Day-Ahead Energy and Operating Reserve Market.	[redacted]
Real-Time Ramp Capability Cost Distribution (RC_DIST)	The total daily charges or credits to an Asset Owners for Day-Ahead and net Real-Time Ramp Capability procurement cost.	[redacted]
Grand Total		[redacted]

*Short Term Reserves are exclusive to the New Orleans Power Station unit.

5. A summary of ENO's transmission charges and revenues from the previous twelve month period

The HSPM table below provides a summary of ENO's transmission charges and revenues from the previous twelve-month period.

Summary of ENO Transmission Charges and (Revenues)
From the previous 12-month period (January 2024 – December 2024)

[redacted]

[redacted]

6. Any changes approved by the ENO Operating Committee to the principles, practices, and protocols utilized to procure capacity and energy in MISO, including:

i. The manner of offering in generation and bidding and scheduling load into the Day-Ahead and Real Time Markets

The information responsive to this component of the filing has been designated as HSPM.

[redacted]

ii. ARR nominations

The information responsive to this component of the filing has been designated as HSPM.

[redacted]

iii. Other material aspects of any MISO-administered market interaction, if requested by the Advisors to the Council.

The Company is not aware of any further information requested by the Advisors to the Council.

7. Any unexpected material costs or market impediments that ENO is encountering within MISO

ENO has not encountered unexpected material market impediments since MISO integration. Starting on February 1, 2016, ENO has been billed monthly for JOA Settlement charges under Schedule 49—Cost Allocation for Available System Capacity Usage. For the period January 1, 2024, through December 31, 2024, ENO was billed approximately $193,391 pursuant to Schedule 49.

8. A list identifying any existing, enhanced and/or supplemental records series to be incorporated under the Entergy System Records Management and Retention Policy necessary to facilitate retention of data required to support SPO operations in MISO on behalf of ENO

No further record series have been added beyond those reported previously.

c. MISO's Transmission Expansion Planning Process

1. Any proposed transmission projects by ENO and directives received by ENO from MISO to construct transmission

The transmission projects planned and proposed by ENO are posted on the Company's OASIS page[5] and are generally updated on a monthly basis. The posted report includes the status of the projects in the MISO Transmission Expansion Planning ("MTEP") process.

On December 12, 2024, the MISO Board of Directors approved the MTEP24, Appendix A projects submitted by Transmission Owners, which contained one ENO asset renewal project.

In MTEP24, one Target Appendix A project was submitted by ENO to MISO in September 2023, and reviewed at the February 8, 2024, MTEP23 South Subregional Planning Meeting. MISO's presentations on this project and other projects in MISO South are posted with the meeting materials.[6] At this meeting, ongoing Generator Interconnection studies were also reviewed. As with MTEP23, there will be no formal Market Congestion Planning Study as part of MTEP24; rather, MISO is continuing to focus on the second tranche projects for the Long Range Transmission Planning ("LRTP") initiative for MISO North.

MISO continues to focus on the LRTP in MISO North, using updated resource mix and siting assumptions for futures, 1A, 2A and 3A, for Tranche 2 and potentially beyond. Tranche 2

[5] http://www.oasis.oati.com/EES/EESdocs/Construction_Plan.htm

[6] https://cdn.misoenergy.org/20240208%20SSPM%20Item%2003d%20Review%20of%20Proposed%20Reliability%20Projects%20LA631681.pdf

focuses on Future 2A, and MISO has not yet determined whether another Futures update will be necessary for Tranches 3 or 4. MISO's planned LRTP analysis of MISO South (*i.e.*, LRTP Tranche 3) is currently on hold and there is not currently a timeline to begin working on the MISO North/South Interface (Tranche 4). MISO has scheduled regular LRTP Workshops to discuss LRTP progress and has a dedicated page on its website for related materials and information.[7] ENO continues its active participation in MTEP25 and in the discussions and analyses that are ongoing for LRTP. As of the date of this report, ENO has not received any directives from MISO to construct transmission facilities as a result of planning studies, reliability assessments, or compliance requirements during the 2024 calendar year. ENO continues to monitor MISO's stakeholder activities, particularly through the Planning Advisory Committee ("PAC") and Planning Subcommittee ("PSC"), to assess potential future transmission needs that could result in project proposals or directives.

2. The status of developments within the MISO stakeholder process that could have a material effect on the allocation of MISO costs, including the cost of transmission investment included by MISO in its MTEP, to ENO.

Since ENO's monitoring report filed in May 2024, several key developments have arisen within the MISO stakeholder process with the potential to materially impact the allocation of transmission investment costs to ENO. MISO has implemented the Reliability-Based Demand Curve ("RBDC") in its Planning Resource Auction ("PRA") to better reflect the value of resource adequacy. The RBDC introduces a sloped demand curve, replacing the previous vertical demand curve, to provide more accurate price signals for capacity resources. This change aims to enhance reliability by incentivizing resource availability during peak demand periods. While RBDC

[7] https://www.misoenergy.org/planning/long-range-transmission-planning/

primarily affects capacity market pricing, it may indirectly influence transmission planning decisions and associated cost allocations.[8]

In May 2024, FERC approved MISO's Direct Loss of Load ("DLOL") accreditation filing which will be implemented in the 2028/2029 PY.[9] The approved DLOL-based methodology will be used by MISO both for accrediting resources participating in MISO's PRA and for calculating the Planning Reserve Margin Requirement ("PRMR") that Load Serving Entities ("LSE") participating in MISO must meet. Additionally, in April 2025, MISO submitted to FERC proposed tariff revisions related to demand response and emergency resources.[10] The proposed reforms are intended to improve real-time visibility and the efficient procurement and operation of Load Modifying Resources ("LMR"), Demand Response Resources ("DRR"), and other emergency-only resources.

MISO initiated the Expedited Resource Addition Study ("ERAS") process to accelerate the evaluation and integration of critical resource additions, such as new generation facilities, that address urgent reliability needs. ERAS allows for a streamlined study process, enabling a faster interconnection of resources that can mitigate reliability risks. The implementation of ERAS may lead to the identification of necessary transmission upgrades, potentially impacting cost allocations to ENO.[11]

The Entergy Regional State Committee ("ERSC") continues to provide collective state regulatory agency input on the operations and upgrades to the Entergy Transmission System. Recent ERSC meetings have focused on market performance in the MISO South subregion,

[8] https://cdn.misoenergy.org/20240306%20PAC%20Item%2005a%20RBDC%20Update631982.pdf
[9] FERC Docket Number: ER24-1638-000
[10] FERC Docket Number: ER25-1886-000
[11] https://cdn.misoenergy.org/20240424%20PAC%20Item%2007b%20Expedited%20Resource%20Addition%20Study%20Process632156.pdf

including discussions on price levels, congestion costs, and uplift payments. These discussions may influence future transmission planning and cost allocation decisions affecting ENO.[12]

The Regional Expansion Criteria and Benefits Working Group ("RECBWG") serves as a forum for stakeholders to discuss cost-shared transmission projects. Recent RECBWG meetings have addressed topics such as Targeted Market Efficiency Projects ("TMEPs") and transmission cost containment issues. Outcomes from these discussions may lead to changes in cost allocation methodologies that could impact ENO.[13]

MISO's 2024 Near-Term Congestion Study ("NTCS") focused on assessing the impacts of LRTP Tranche 1 construction outages on system congestion. The study utilized the Year 5 PROMOD model to analyze various outage scenarios, identifying potential congestion and curtailment issues. Findings from the NTCS may inform future transmission planning efforts and associated cost allocations to ENO.[14]

3. Material changes, if any, proposed by MISO or MISO stakeholders to MISO's governance structure or allocation principles for the cost of transmission investment

i. Regional Planning

Since the previous report, MISO has undertaken significant initiatives impacting transmission planning and cost allocation, notably through the approval of the LRTP Tranche 2.1 portfolio and updates to the Joint Targeted Interconnection Queue ("JTIQ") cost allocation methodology. In December 2024, MISO's Board of Directors approved the LRTP Tranche 2.1 portfolio, encompassing 24 projects with an estimated investment of $21.8 billion. These projects aim to establish a 765 kV transmission backbone across the MISO Midwest subregion. The

[12] https://cdn.misoenergy.org/20250224%20ERSC%20Item%2006%20IMM%20South%20680764.pdf
[13] https://cdn.misoenergy.org/20250527%20RECBWG%20Item%2001c%20Minutes%2020250415692972.pdf
[14] https://cdn.misoenergy.org/20241030%20PSC%20Item%2004b%20MTEP%20Near-Term%20Congestion%20Studies%20%28PAC-2021-1%29656111.pdf

benefit-to-cost ratios for these projects range from 1.8 to 3.5, indicating a substantial value for investment. Cost allocation for Tranche 2.1 follows the existing Multi-Value Project ("MVP") methodology, applying a subregional postage stamp approach.[15][16]

ii. **Interregional Planning**

MISO and the Southwest Power Pool ("SPP") have revised the cost allocation framework for JTIQ projects, which are designed to address interconnection challenges along the MISO-SPP seam. The updated methodology allocates 100% of engineering and construction costs to interconnection customers, aligning with Generator Interconnection cost allocation practices. Operations and maintenance costs are recovered from the constructing transmission owner's zone. This reflects adjustments due to DOE Grid Resilience and Innovation Partnership ("GRIP") funding.[17]

iii. Stakeholder Engagement and Future Considerations

These developments have prompted discussions among stakeholders regarding fairness and transparency. Concerns have been raised about potential disproportionate financial burdens on generators. MISO has indicated that cost allocation for future projects will be determined based on specific analyses.[18]

d. Interim Cost-Benefit Analysis

Please see Attachment 4 titled "2024 MISO Savings_ENOL_Final.pptx", which provides the calculation of MISO energy- and capacity-related savings through 2024. Also, please see

[15] https://www.misoenergy.org/planning/long-range-transmission-planning/
[16] https://www.misoenergy.org/planning/transmission-planning/mtep/
[17] https://cdn.misoenergy.org/20240123%20RECBWG%20Item%2002a%20Cost%20Allocation%20Update631435.pdf
[18] https://www.misoenergy.org/engage/stakeholder-feedback/2024/pac-recbwg-jtiq-new-language-20240618/

Attachment 5 titled “2023 MISO Savings_ENOL_Final.pdf”, which provides the calculation of MISO energy- and capacity-related savings through 2023. This analysis was not complete at the time the Tenth Post-MISO Integration Report was filed last year and is being submitted here.

1. **Identification of any material changes to ENO’s generation portfolio, such as the retirement or addition of a long-term resource, and an estimate of the impact of that change (if any) on the savings identified in the Interim Cost-Benefit Analysis**

There were no material changes (long-term resource retirements or additions) to ENO’s generation portfolio in 2024.

Respectfully Submitted:

By: _____

Edward R. Wicker, Jr., Bar No. 27138
639 Loyola Avenue, Mail Unit L-ENT-26E
New Orleans, Louisiana 70113
Telephone: (504) 576-6571
Facsimile: (504) 576-5579

ATTORNEY FOR
ENTERGY NEW ORLEANS, LLC

CERTIFICATE OF SERVICE
CNO Docket UD-11-01

I hereby certify that the foregoing pleading was served on all parties of record listed on the Official Service List through electronic delivery.

New Orleans, Louisiana, this 12th day of May 2025.

Edward R. Wicker, Jr.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

INVESTIGATION OF THE POTENTIAL COSTS AND BENEFITS OF ENTERGY NEW ORLEANS, LLC AND ENTERGY LOUISIANA, LLC JOINING A REGIONAL TRANSMISSION ORGANIZATION VERSUS CONTINUATION OF THE ENTERGY INDEPENDENT COORDINATOR OF TRANSMISSION WITH ENHANCEMENTS	**)**	**DOCKET NO. UD-11-01**

ATTACHMENT 1
(Attachment 1_24-25 PRA Results_ENO OC HSPM)

HIGHLY SENSITIVE PROTECTED MATERIALS

INTENTIONALLY OMITTED

MAY 2025

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

INVESTIGATION OF THE POTENTIAL COSTS AND BENEFITS OF ENTERGY NEW ORLEANS, LLC AND ENTERGY LOUISIANA, LLC JOINING A REGIONAL TRANSMISSION ORGANIZATION VERSUS CONTINUATION OF THE ENTERGY INDEPENDENT COORDINATOR OF TRANSMISSION WITH ENHANCEMENTS	)))))))))	**DOCKET NO. UD-11-01**

ATTACHMENT 2
(Attachment 2_ENO_Energy_Mix_2024 HSPM)

HIGHLY SENSITIVE PROTECTED MATERIALS

INTENTIONALLY OMITTED

MAY 2025

BEFORE THE

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ATTACHMENT 3
(Attachment 3_ENO Annual ARR Allocation Results_PY2425_HSPM)

HIGHLY SENSITIVE PROTECTED MATERIALS

INTENTIONALLY OMITTED

MAY 2025

MISO Historical Benefits Calculation

Results of 2024 ENOL Analysis

Summary

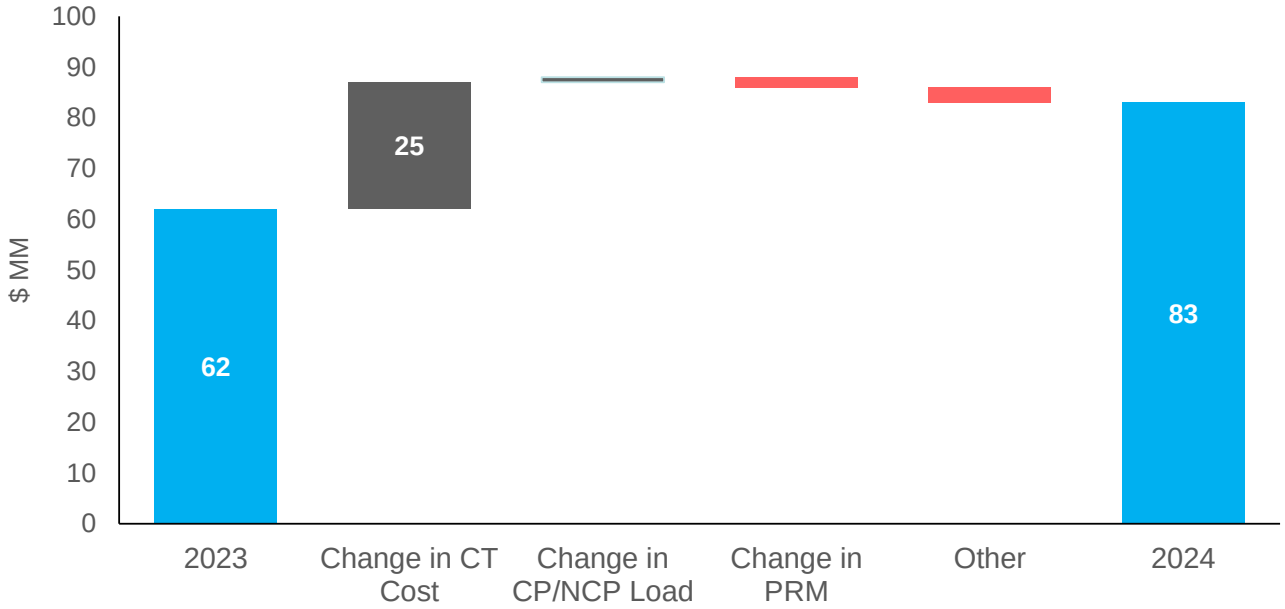
- The results of the 2024 MISO savings calculation indicate that ENOL continues to experience meaningful benefits from MISO participation -- $86 million of benefits in 2024 compared to standalone BA operations
- ENOL's 2024 benefits are higher than those estimated for 2023, primarily due to a change in capacity-related benefits
  - ENOL's energy-related benefits changed by a relatively small amount (an increase of $1 million)
  - ENOL's capacity-related benefits increased by $21 million due to changes in the cost of long-term capacity
  - The net effect of all changes is an increase in benefits of $22 million compared to 2023
- The following slides discuss the change in capacity-related benefits in more detail.

Highlights of the capacity-related cost/benefit calculation

- ENOL's capacity-related cost/benefit calculation is based on two main items:
  - First, a comparison of the MW of long-term planning reserves required in MISO versus what would have been required had ENOL not joined an RTO
  - Second, an estimate of the value of this difference in MW -- the avoided cost of the additional planning reserves -- based on the long-term cost of capacity
- ENOL's capacity-related benefits increased between 2023 and 2024 due to changes in the second item
  - ENOL estimated that fewer MW of long-term planning reserves were avoided by participating in MISO due to changes in the PRM[1]
  - However, ENOL's updated estimate of the long-term cost of capacity -- which is based on the cost of a new CT -- increased
  - The impact of the second item was bigger than the first, resulting in a $21 million net increase in benefits.

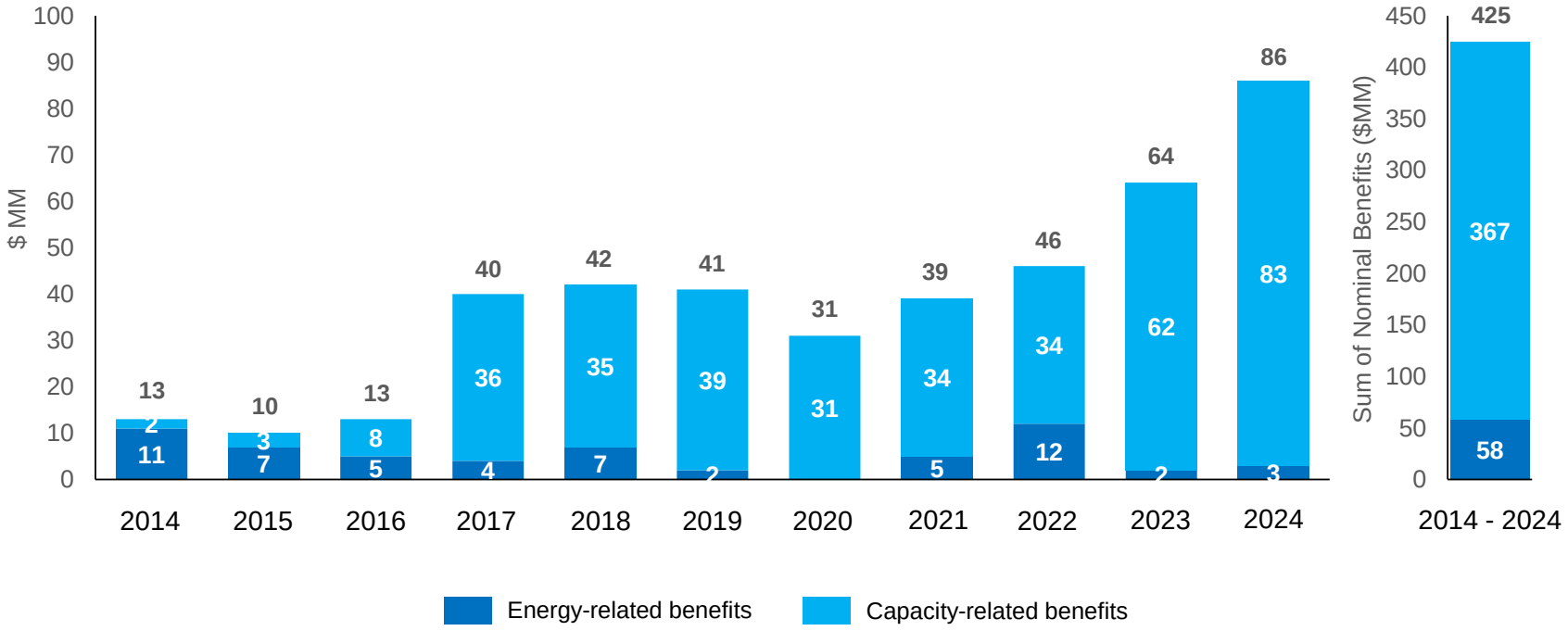
[1] The estimated PRM in MISO increased between 2023 and 2024; the estimated PRM in a standalone BA decreased slightly. Higher requirements in MISO and slightly lower requirements in a standalone BA translate to fewer MW of long-term planning reserves avoided by MISO participation.

Additional details of changes in capacity-related benefits



ENOL's estimated benefits from MISO participation

- ENOL continues to experience meaningful benefits from MISO participation -- $86 million of benefits in 2024 compared to standalone BA operations.



Notes:
- Benefits reflect the impact of incremental administrative costs in MISO.
- 2017 – 2022 capacity-related benefits reflect the impact of forced outage rates on MISO requirements but not on standalone requirements.

MISO Historical Benefits Calculation

Results of 2023 ENOL Analysis

Summary

- The results of the 2023 MISO savings calculation indicate that ENOL continues to experience meaningful benefits from MISO participation -- $64 million of benefits in 2023 compared to standalone BA operations
- ENOL's 2023 benefits are higher than those estimated for 2022
  - ENOL's energy-related benefits decreased by $10 million primarily as a result of lower gas prices and LMPs in 2023 compared to 2022
  - ENOL's capacity-related benefits increased by $28 million due to a number of changes including changes in the MISO PRM
  - The net effect of all changes is an increase in benefits of $18 million compared to 2022
- The following slides discuss the 2023 results in more detail.

Highlights of the energy-related cost/benefit calculation

- An important difference between MISO and standalone BA operations involves the commitment of flexible resources to meet needs
- The methodology used for estimating “flex savings” identifies whether MISO’s commitment of ENOL’s resources is sufficient to meet standalone BA flexibility requirements
  - If the MISO commitment is sufficient, the analysis assumes no flex savings attributed to MISO participation
  - If the MISO commitment is not sufficient, the analysis estimates the cost of the additional flexibility required based on the opportunity cost of operating units for flex as opposed to operating them at their preferred level given the LMP
- As such, the additional cost of flex, and therefore flex savings, can change when:
  - The estimate of standalone BA flex requirements changes, the amount of flex committed by MISO changes, and/or gas prices and LMPs change
- Flex savings decreased by $7 million between 2022 and 2023
  - This decrease, and the overall $10 million decrease in energy-related benefits, was driven by significant decreases in gas prices and LMPs.[1]

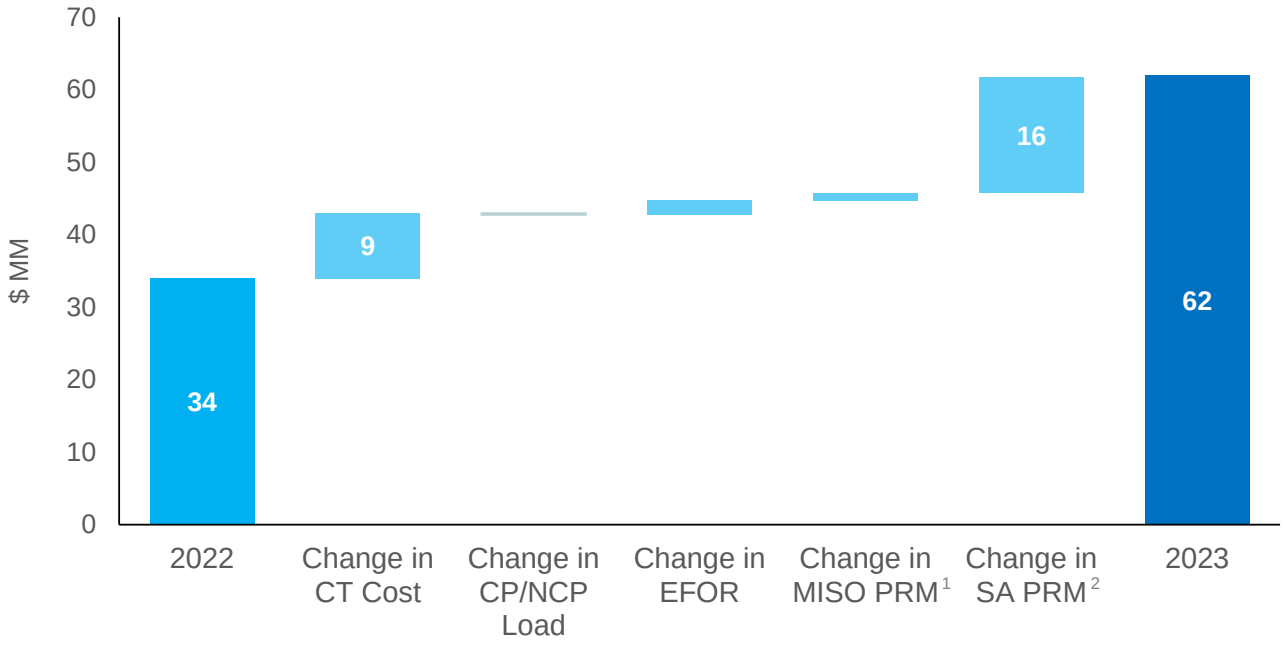
[1] While changes in flex represented the largest portion of the total change in energy-related benefits, changes in ENOL purchase and sale benefits and changes in administrative costs also contributed to the total $10 million decrease.

Highlights of the capacity-related cost/benefit calculation

- ENOL's capacity-related cost/benefit calculation is based on two main items:
  - First, a comparison of the MW of long-term planning reserves required in MISO versus what would have been required had ENOL not joined an RTO
  - Second, an estimate of the value of this difference in MW -- the avoided cost of the additional planning reserves -- based on the long-term cost of capacity
- ENOL's capacity-related benefits increased between 2022 and 2023 due to changes in both items
  - ENOL estimated that more MW of long-term planning reserves were avoided by participating in MISO due to changes in the PRM[1]
  - ENOL's updated estimate of the long-term cost of capacity -- which is based on the cost of a new CT -- also increased
  - These changes resulted in a $28 million increase in benefits.

[1] The 2023 estimate of long-term planning reserves in MISO is based on a determination of the binding seasonal requirement corresponding with MISO's seasonal reliability construct. MISO estimated that the PRMR of the overall market would be highest in the Summer season. MISO's 7.4% summer PRM_{UCAP} requirement is 1.3% lower than MISO's 2022 PRM_{UCAP} requirement of 8.7%. Similarly, the 2023 estimate of long-term planning reserves in a standalone BA is based on a determination of the binding seasonal requirement corresponding with a seasonal reliability construct applied to a Standalone ENOL BA. ENOL's analysis, using SERVM, estimated that Summer was the season with the highest PRMR. ENOL's updated SERVM analysis -- which reflects updated load profiles, cold weather outages, and other changes -- resulted in a higher ENOL Standalone BA requirement than the 2022 analysis which was based on a 2017 SERVM analysis.

Additional details of changes in capacity-related benefits

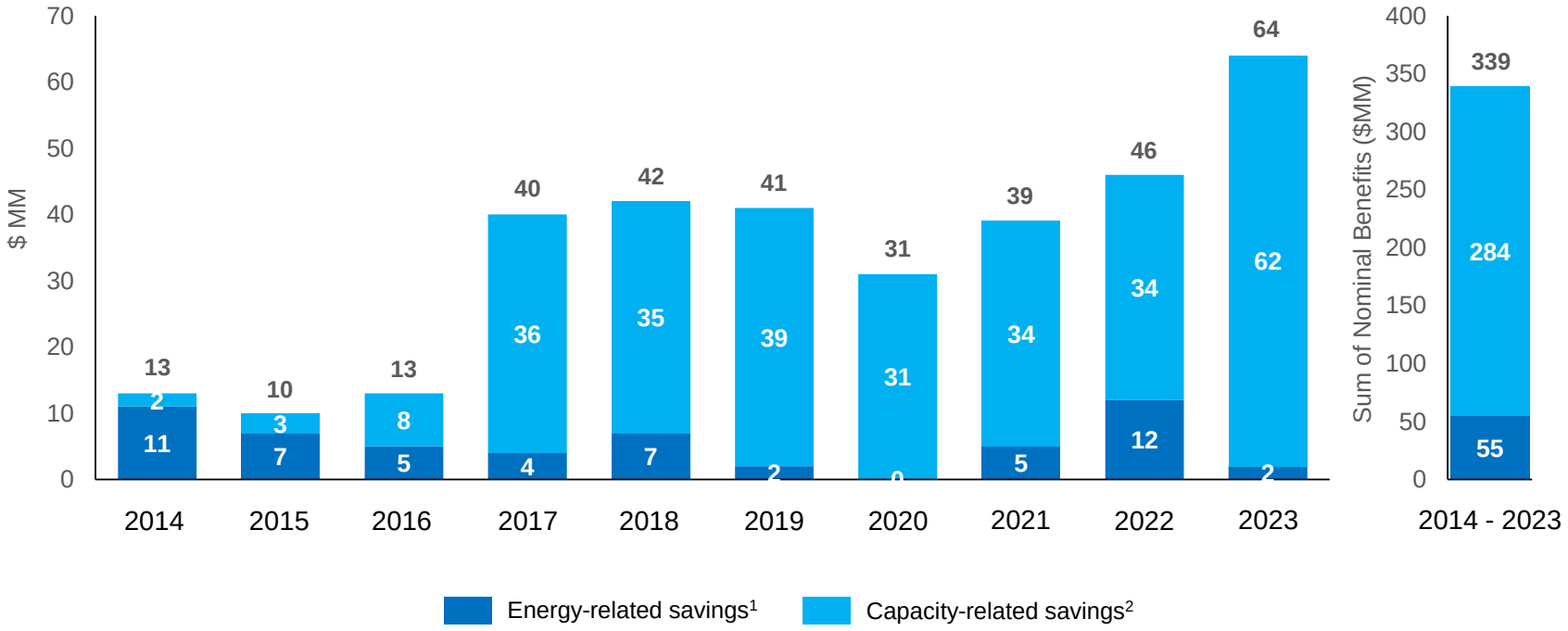


[1] MISO estimated that the PRMR of the overall market would be highest in the Summer season. ENOL's PRMR in MISO was based on the Summer even though its PRMR in the Winter was estimated to be slightly higher. It was assumed that ENOL would not build to the Winter requirement given the amount of excess capacity expected in the overall MISO market in the Winter. The "Change in MISO PRM" million value includes the estimated impact of short-term purchases and sales, at the MISO clearing price, for seasonal differences from the Summer PRMR.

[2] ENOL's PRMR in a Standalone BA was based on the Summer season which was estimated to be the season with the highest PRMR. The "Change in SA PRM" value includes the estimated impact of short-term sales for seasonal differences from the Summer PRMR at the MISO clearing price (if ENOL had excess MW in the standalone BA, the analysis assumes that excess could be sold into the MISO Planning Resource Auction, subject to the requirements for participation in the PRA of external resources and possibly incremental transmission costs). ENOL's updated SERVM analysis of standalone BA requirements -- which reflects updated load profiles, cold weather outages, and other changes -- resulted in a higher requirement than the previous (2017) SERVM analysis.

ENOL's estimated benefits from MISO participation

- ENOL continues to experience meaningful benefits from MISO participation -- $64 million of benefits in 2023 compared to standalone BA operations.



[1] Energy-related benefits include incremental administrative costs.
[2] 2017 – 2022 capacity-related benefits reflect the impact of forced outage rates on MISO requirements but not on standalone requirements.