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May 30, 2025

VIA ELECTRONIC MAIL
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Re: Resolution and Order Establishing a Docket and Procedural Schedule to Enhance Distributed Energy Resource Programs (CNO Docket No. UD-24-02)

Dear Clerk of Council:

As the Council knows, a primary threshold question in this docket is whether SERI credits should be used for third party programs composed of non-utility projects when the Council previously decided to return the SERI credits to customers. The answer to that question is no, as Entergy New Orleans, LLC ("ENO") has discussed at length in prior comments.

Considering the legal and other obstacles in third party proposals, ENO presented its own proposal for consideration in this docket to the extent the Council is inclined to move forward with a BESS upfront incentive program using SERI credits. ENO's proposal is a measured, reasonable approach that would provide benefits and protections to all customers in accordance with regulatory law and policy.

Now, in compliance with the Order dated May 13, 2025, ENO submits a cost-benefit analysis of its proposal and the proposal submitted jointly by Together New Orleans ("TNO") and the Alliance for Affordable Energy ("AAE"). The analysis is contained in the following documents being filed:

a. ENO Cost Effectiveness Test Methodology and Assumptions (Attachment 1)
b. ENO Cost Effectiveness Test Results and Analysis (Attachment 2)
c. Independent Evaluator Review of Together New Orleans' May 8, 2025 Memorandum (Docket UD-24-02) (Attachment 3)

By way of summary, the ENO analysis uses both a Ratepayer Impact Measure ("RIM") and Utility Cost Test ("UCT") to consider the cost effectiveness of both ENO's and TNO/AAE's proposals. The results of the cost-effectiveness tests are:

	RIM Test	UCT Test
ENO Proposal	0.50	0.53
TNO/AAE Proposal	0.39	0.41

Both tests demonstrate that ENO's proposal is more cost effective than TNO/AAE's proposal. In fact, ENO's proposal supports more battery installations per year and in aggregate than the TNO/AAE proposal at approximately a third of the cost (with respect to the upfront incentives that would be funded through SERI credits). However, this analysis demonstrates that neither proposal passes the RIM or UCT 1.0 threshold.

Ultimately it is the Council's decision regarding how to proceed. To the extent the Council is inclined to move forward with a BESS upfront incentive program using SERI credits, ENO's proposal would be a more cost-effective option for customers than the TNO/AAE proposal.

ENO respectfully requests that the Advisors consider the analysis submitted by ENO in preparing their report. Should you have any questions or require additional information, please do not hesitate to reach out.

Attachment 2 contains information that is designated as Highly Sensitive Protected Materials ("HSPM"). An HSPM version of Attachment 2 is being produced only to those representatives who are authorized to review such information under the terms of the provisions of the Official Protective Order adopted pursuant to Resolution No. R-07-432 relative to the disclosure of Protected Materials.

Sincerely,

Leroy Nix

Attachment 1

ENO Cost Effectiveness Test Methodology and Assumptions

ENO Cost Effectiveness Test Results and Analysis

See the below for an explanation of the methodology and assumptions used in ENO's cost effectiveness tests.

1. **Results of cost-effectiveness tests**

	RIM Test	UCT Test
ENO Proposal	0.50	0.53
TNO/AAE Proposal	0.39	0.41

2. **Methodology and assumptions used for cost-effectiveness tests**

   a. **Study Period**

      i. ENO Proposal: 14 years. ENO's proposal requires that customers who receive an upfront/purchase incentive must participate in the ENO Energy Smart DR program for a 10-year period. Each battery that receives a purchase incentive is thus assumed to participate for exactly 10 years. Since the upfront battery incentives are provided over a 5-year period, the customers who receive an upfront incentive in year 5 are thus assumed to continue to participate in the program through year 14.

      ii. TNO/AAE Proposal: 10 years. This is consistent with the timeframe presented in the TNO/AAE analysis filed May 8, 2025.

   b. **Discount rate**

      7.28% is the weighted average cost of capital ("WACC") used in the analysis of both proposals. That value is equal to the benchmark return on rate base filed with ENO's Formula Rate Plan ("FRP") approved for the 2023 test year.

   c. **Applicable Cost-effectiveness Tests**

      ENO has only provided Ratepayer Impact Measure ("RIM") and Utility Cost Test ("UCT") tests for the two proposals. The other three main cost-effectiveness tests include the Participant Cost Test ("PCT"), Total Resource Cost ("TRC"), and Societal Cost Test ("SCT"). Based on industry standards for how these tests are performed, none of these three tests captures the financial incentives paid to participants as a cost of the demand response program being assessed. Since financial incentives paid to participants represent the vast majority of costs for a utility-managed demand response program such as those proposed in this docket, the PCT, TRC, and SCT tests do not provide a meaningful or relevant benchmark for this type of program. Therefore, ENO is only providing results for the two established cost-effectiveness tests that include financial incentives to participants as a measured cost of the program: RIM and UCT.

3. **<u>Assumed Benefits</u>**

   a. **Avoided Capacity Value**

      i. For both proposals, the MISO-accredited amount of capacity for batteries was calculated by the following formula: installed kWh capacity of batteries x 80% x 25%. The 80% adjustment reflects that ENO's Energy Smart program will not dispatch batteries below 20% of the stored energy level of the battery. The 25% adjustment is needed to account for MISO's requirement that Load Modifying Resources ("LMRs") must be capable of being dispatched for at least a 4-hour period.

      ii. When considering the value of capacity for ENO, an important consideration is ENO's current capacity position. Consistent with analysis in ENO's most recent Integrated Resource Plan ("IRP"), the year that ENO is first projected to have a capacity shortfall is 2033. Therefore, from 2026 through 2032 (for both proposals), a short-term value of capacity is used, and a long-term value of capacity is used starting in 2033 (see additional explanations below).

         1. <u>Short-term capacity value</u>: in the near term when ENO has a capacity surplus, the value of capacity is based upon the MISO PRA. During this period, the recent PRA prices for the 2025/2026 MISO PRA were used as a baseline for 2025 value. More specifically, the average $/MW-day price of the four seasonal prices for MISO Zone 9 was multiplied by 365 and divided by 1,000 to convert to a $/kW-year value. For the remainder of the period that ENO has a capacity surplus (2026-2032), the average annual PRA price from the 2025/2026 Planning Year was escalated at an assumed annual inflation rate of 2% per year and multiplied by the MISO-accredited amount of capacity for batteries projected to be installed for each proposal in the relevant year.

         2. <u>Long-term capacity value</u>: in the long term and starting at the point that ENO has a need for new capacity, the value of capacity is based upon the avoided cost of generation (or more specifically, the company's estimate of the cost of a new combustion turbine facility from its Business Plan 2025 or "BP25"). Starting in 2033 and for the remainder of the applicable study period, the $/kW-year avoided cost of capacity is pulled from the Company's BP25 forecast (included here as HSPM Attachment 2) and multiplied by the MISO-accredited amount of capacity for batteries projected to be installed for each proposal in the relevant year.

   b. **Avoided Energy Value (including line losses)**

      i. Under both proposals, ENO assumes that the Energy Smart program would dispatch batteries for up to 120 hours per year (up to 60 times per year in 2-hour dispatches).

ii. Distribution line losses: 4.19%, consistent with the assumption used in recently performed Energy Smart evaluation analysis for 2024 programs.
iii. Transmission line losses: 1.90%, consistent with the average assumption used by MISO in the 2025/2026 PRA for MISO Zone 9. This value is also used in Other Benefits calculations, below.
iv. Marginal energy prices are estimated based on the top LMP prices in the MISO Day-Ahead market in 2024 for ENO's load zone.
v. Since energy dispatches are assumed to occur over 2-hour periods, the assumed amount of energy from the program is double the MISO-accredited amount of capacity for batteries projected to be installed for each proposal in the relevant year times the 120 hours per year, grossed up for T&D line losses and finally multiplied by the marginal energy price.

c. Other Benefits

i. In the MISO PRA, the registered amount of demand reduction capability for LMRs is ultimately grossed up for both transmission losses and a planning reserve margin ("PRM") before determining the total amount of zonal resource credits ("ZRCs") that each LMR provides in the PRA.
ii. This Other Benefit category captures the value of these transmission loss and PRM gross-ups for batteries.
iii. Under the current seasonal PRA construct, MISO applies different transmission loss and PRM assumptions for each season and each MISO Zone.
iv. Entergy New Orleans is located in MISO Zone 9.
v. For the 2025/2026 Planning Year, the average transmission loss across all seasons for MISO Zone 9 is 1.90%.
vi. For the 2025/2026 Planning Year, the average PRM across all seasons for MISO Zone 9 is 16.63%.
vii. The calculation of Other Benefits equals the MISO-accredited amount of capacity for batteries projected to be installed for each proposal in the relevant year x (1.90% + 16.63%) x the applicable avoided cost of capacity for that year (i.e., the relevant short-term value up to and through 2032 or the relevant long-term value from 2033 onward).

d. Additional benefits assumed by TNO/AAE that are NOT included in ENO analysis

i. TNO included several other benefits in their analysis that were not assumed in the ENO cost-effectiveness test analysis: Avoided Regional Network Service ("RNS") Charges, Avoided Demand Response ("DR") Program Costs, Avoided T&D Costs, and Resilience/Value of Lost Load ("VOLL") Benefits.
ii. None of these additional benefits assumed by TNO/AAE are included in cost-effectiveness tests for Energy Smart programs (see Attachment 3, a

memorandum from ADM, the Third-Party Evaluator that conducts Evaluation, Measurement, and Verification ("EM&V") of the Energy Smart program).

iii. As noted in Attachment 3, cost-effectiveness test analysis for Energy Smart programs includes avoided T&D line losses (which are captured in the ENO analysis), but do not include the costs of avoided T&D infrastructure in the manner that the TNO/AAE analysis included. To quantify avoided T&D costs for the purpose of a battery DR program would require location-specific analysis.

iv. Some of these additional benefits also appear duplicative, such as the Avoided DR Program Costs and Avoided Capacity Costs. DR programs are generally recognized for helping avoid the need for new generation resources and Avoided Capacity Costs are a key part of benefits quantified in cost-effectiveness test analysis for DR programs. Assuming that Avoided Capacity Costs are captured as a quantified benefit, it would not be reasonable to also quantify an additional benefit regarding the avoided need for DR programs, particularly when such DR programs are largely justified by their avoidance of future generation capacity.

4. <u>Assumed Costs</u>

a. Program Administration Expense

Program Administration Expenses were estimated based on information provided by Energy Hub (EH).

b. Annual Incentives to Participants

i. Under the ENO proposal, current Energy Smart Phase 2 battery pilot DR annual incentive levels (capped at $600 per residential system and $1,800 per non-residential system) are assumed to continue at the current level. The ENO analysis assumes that current participants in the pilot (~85 residential customers and ~15 non-residential customers) continue to receive these incentives for the full study period. In addition, customers who receive an upfront incentive are assumed to participate for a ten-year period.

ii. Under the TNO proposal, annual incentives are included at $40/kW-year in years 4-10, consistent with the assumption provided on the Benefit-Cost Analysis Worksheet (page 2) of TNO's supplemental filing on May 8, 2025. This annual incentive amount is applied to the projection of "Deliverable Capacity" by year.[1]

[1] There are several discrepancies in the assumptions/inputs provided by TNO on May 8, 2025, including with the annual incentive inputs. ENO has attempted to reconcile by using the number of installations per year, the average installed kWh of battery capacity – a.k.a. "BESS Energy" as defined by TNO – for residential (non-LMI), residential (LMI) and community/non-residential systems, MISO accreditation rules, TNO's assumed participation rates for

c. **Upfront/Purchase Incentives to Participate**
   - **i.** ENO's analysis used projections filed by each party regarding total upfront incentives. ENO projections were included in its proposal filed on March 14, 2025.
   - **ii.** TNO's projections were taken from figures provided on page 4 of the Benefit-Cost Analysis Worksheet as part of TNO's Supplementary Response submitted on May 8, 2025. In addition, the total upfront incentive costs for residential customers was split into two categories: 40% of the residential incentives is assumed to be LMI customers and the remainder is non-LMI, consistent with TNO's statements (e.g. on page 2 of TNO's Supplementary Response submitted on May 8, 2025).

d. **Lost Contribution to Fixed Costs (LCFC; only applicable for RIM test)**
   - **i.** Similar to the Avoided Energy Value calculations, since energy dispatches are assumed to occur over 2-hour periods, the assumed amount of energy from the program is double the MISO-accredited amount of capacity for batteries projected to be installed for each proposal in the relevant year times the 120 hours per year.
   - **ii.** To calculate LCFC, the applicable amount of energy is multiplied by the energy charges in the applicable base rate schedule and (1 + applicable FRP adjustment). The applicable base rate for residential customers is the ENO RES-25 rate schedule. For non-residential customers, the average base energy charge from the ENO SE-25 and ENO LE-25 rate schedules, and the average FRP adjustment for the small electric and large electric rate classes, were used.

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years 4-10, and TNO's definition of "Deliverable Capacity" to determine the amount of "Deliverable Capacity" in the model. Ultimately, ENO understands "Deliverable Capacity" is double the amount of "Projected MW-years Accredited/Registered with MISO (based on demand reduction capability without ZRC gross-ups)" provided in the "TNO-AAE Input Assumptions" tab of ENO's workpapers.

Attachment 2

ENO Cost Effectiveness Test Results and Analysis (Public version of spreadsheet attached)

Attachment 3

Independent Evaluator Review of Together New Orleans' May 8, 2025 Memorandum (Docket UD-24-02)

INDEPENDENT EVALUATOR REVIEW OF TOGETHER NEW ORLEANS' MAY 8, 2025 MEMORANDUM (DOCKET UD-24-02)

SUBMITTED TO:

DEREK MILLS, ENTERGY NEW ORLEANS

ROSS THEVENOT, ENTERGY NEW ORLEANS

SUBMITTED BY:

ZEPHANIAH DAVIS, DIRECTOR, ADM ASSOCIATES, INC.

ROBERT OLIVER, PRINCIPAL, ADM ASSOCIATES, INC.

SUBMITTED ON: MAY 30, 2025

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INTRODUCTION

ADM Associates, Inc. (ADM) is the Third-Party Evaluator (TPE)[1] for Entergy New Orleans' (ENO) Energy Smart Programs. At ENO's request, the TPE provides this memorandum regarding industry best practices for determining benefits when performing cost-effectiveness testing for demand response (DR) programs.

COST-EFFECTIVENESS BENEFITS FROM DEMAND RESPONSE

The California Standard Practice Model[2] was used as a guideline for the calculations, along with guidance from the ENO TRM V7.0, National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources[3] and the SEE Action Guide for States: Evaluation, Measurement, and Verification Frameworks—Guidance for Energy Efficiency Portfolios Funded by Utility Customers[4]. Methods described in these manuals provide a variety of options for claiming benefits for demand response (DR) programs. These benefits are typically considered the “avoided electricity cost” and consist of the avoided costs of generation capacity (the avoided capacity costs), avoided costs of the saved energy (avoided energy costs), and avoided costs of transmission and distribution. These avoided costs comprise the major benefit of most demand response programs and are similar to the avoided costs of other demand-side management activities such as energy efficiency and distributed generation.

With respect to Docket UD-24-02, the TPE has reviewed a May 8, 2025 memorandum from Together New Orleans (TNO) and the Alliance for Affordable Energy (AAE). TNO/AAE propose to add benefits from Avoided DR[5] and Avoided Regional Network Service (RNS)[6] in cost-effectiveness (CE) calculations for BESS Battery DR.

- The proposed Avoided DR benefit attempts to quantify the monetary savings from reducing the need for regular DR programs. This is inconsistent with best industry practices while also double-counting regular DR program benefits when comparing the TNO/AAE analysis to the TPE's cost-effectiveness analyses for the whole Energy Smart portfolio of EE and DR programs.
- The proposed Avoided RNS benefit is not a form of double-counting, per se, but it is not a standard component in best industry practices for CE calculations.

The TPE's CE analyses for the Energy Smart portfolio include avoided T&D costs that are calculated from line loss factors (i.e., 4.19% and 4.66% for energy and demand, respectively) that are applied to all EE and DR programs. However, calculating avoided T&D costs specific to the BESS Battery DR would optimally take into consideration location-specific attributes at the interconnection of individual battery installations. Considerably more information from substations, circuits and feeders would be needed to accurately quantify the location-specific benefits.

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[1] ADM has been the TPE for ENO’s Energy Smart Programs since 2015, or ‘PY5.’

[2] https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf

[3] https://www.nationalenergyscreeningproject.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf

[4] https://www.energy.gov/sites/default/files/2021-07/EMV-Framework_Jan2018.pdf

[5] The proposed Avoided DR benefit attempts to quantify the monetary savings from reducing the need for regular DR programs. This is inconsistent with best industry practices while also double-counting regular DR program benefits when comparing the TNO/AAE analysis to the TPE's cost-effectiveness analyses for the whole Energy Smart portfolio of EE and DR programs.

[6] The proposed Avoided RNS benefit is not a form of double-counting, per se, but it is not a standard component in best industry practices for CE calculations.

The TNO/AAE analysis regarding resilience benefits, such as the value of lost load, attempt to quantify the value of batteries allowing households and institutions to maintain power during outages, avoiding economic losses, health risks and disruption to critical services. Notably, however, cost-effectiveness evaluations of the Energy Smart programs do not currently include any quantified benefits related to resilience.

TEST AND INPUTS CURRENTLY USED BY THE TPE

The cost-effectiveness analysis methods that are used in the analysis of the Energy Smart Energy Efficiency (EE) and Demand Response (DR) portfolios are among the set of standard methods used in this industry and include the Utility Cost Test (UCT)[7], Total Resource Cost Test (TRC), Ratepayer Impact Measure Test (RIM), and Participant Cost Test (PCT). All tests weigh monetized benefits against costs. These monetized amounts are presented as Net Present Value (NPV) evaluated over the lifespan of the measure. The benefits and costs differ for each test based on the perspective of the test. The definitions below are taken from the California Standard Practice Manual.

The TRC measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The UCT measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

The PCT is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills would go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

A common misperception is that there is a single best perspective for evaluation of cost-effectiveness. Each test is useful and accurate, but the results of each test are intended to answer a different set of questions. The questions to be addressed by each cost test are shown in the table below.[8]

Table 1. Questions Addressed by the Various Cost Tests

Cost Test	Questions Addressed
Participant Cost Test (PCT)	▪ Is it worth it for the customer to install energy efficiency?
	▪ Is it likely that the customer wants to participate in a utility program that promotes energy efficiency?
Ratepayer Impact Measure (RIM)	▪ What is the impact of the energy efficiency project on the utility's operating margin?
	▪ Would the project require an increase in rates to reach the same operating margin?
	▪ Do total utility costs increase or decrease?

[7] The UCT is also referred to as the Program Administrator Cost Test (PACT).

[8] https://19january2017snapshot.epa.gov/sites/production/files/2015-08/documents/understanding_cost-effectiveness_of_energy_efficiency_programs_best_practices_technical_methods_and_emerging_issues_for_policy-makers.pdf

Cost Test	Questions Addressed
Utility Cost Test (UCT)	▪ What is the change in total customer bills required to keep the utility whole?
Total Resource Cost Test (TRC)	▪ What is the regional benefit of the energy efficiency project (including the net costs and benefits to the utility and its customers)?
	▪ Are all of the benefits greater than all of the costs (regardless of who pays the costs and who receives the benefits)?
	▪ Is more or less money required by the region to pay for energy needs?

Overall, the results of all four cost-effectiveness tests provide a more comprehensive picture than the use of any one test alone. The TRC cost test addresses whether energy efficiency is cost-effective overall. The PCT, UCT, and RIM address whether the selection of measures and design of the program are balanced from the perspective of the participants, utilities, and non-participants. The scope of the benefit and cost components included in each test are summarized in the table below.[9] Note that only UCT and RIM include incentives as a cost, while others do not.

Table 2. Benefits and Costs Included in each Cost-Effectiveness Test

Test	Benefits	Costs
PCT (Benefits and costs from the perspective of the customer installing the measure)	▪ Incentive payments	▪ Incremental equipment costs
	▪ Bill Savings	▪ Incremental installation costs
	▪ Applicable tax credits or incentives	
UCT (Perspective of utility, government agency, or third party implementing the program	▪ Energy-related costs avoided by the utility	▪ Program overhead costs
	▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Utility/program administrator incentive costs
TRC (Benefits and costs from the perspective of all utility customers in the utility service territory)	▪ Energy-related costs avoided by the utility	▪ Program overhead costs
	▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program installation costs
	▪ Additional resource savings	▪ Incremental measure costs
	▪ Monetized non-energy benefits as outlined by the TRM.	
RIM (Impact of efficiency measure on non-participating ratepayers overall)	▪ Energy-related costs avoided by the utility	▪ Program overhead costs
	▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Lost revenue due to reduced energy bills
		▪ Utility/program administrator incentive costs

[9] *Ibid.*