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August 6, 2026

BY E-MAIL

Clerk of Council
Council of the City of New Orleans
City Hall, Room IE09
1300 Perdido Street
New Orleans, LA 70112

Re: Resolution and Order Establishing a Docket and Procedural Schedule to Enhance Distributed Energy Resource Programs; NOCC Docket UD-24-02

Dear Clerk:

Attached please find the *Report Regarding ENO's Initial Plan and Supplemental Filings, TNO's Proposed Modifications, and Comments Addressing Each Submitted by the Council's Utility Advisors and the Council's DER Consultant* for filing in the above-referenced matter. Thank you.

Sincerely,

Jay Beatmann

/jb
Attachment
cc: Official Service List for UD-24-02

BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

RESOLUTION AND ORDER ESTABLISHING A DOCKET AND PROCEDURAL SCHEDULE TO ENHANCE DISTRIBUTED ENERGY RESOURCE PROGRAMS	)))))))))	**DOCKET NO. UD-24-02**

REPORT REGARDING
ENO'S INITIAL PLAN AND SUPPLEMENTAL FILINGS, TNO'S PROPOSED MODIFICATIONS, AND COMMENTS ADDRESSING EACH SUBMITTED BY THE COUNCIL'S UTILITY ADVISORS AND THE COUNCIL'S DER CONSULTANT

August 6, 2026

I. INTRODUCTION

The New Orleans City Council has long recognized the importance of expanding the availability of distributed energy resources ("DER") in response to a rapidly changing climate and increased demand on the electric grid. In Council Resolution No. R-23-74, pursuant to the recommendations of the Council Utilities Regulatory Office ("CURO") the Council recognized the need for a comprehensive and focused consideration of expanding DER and established an independent docket separate and apart from the ongoing system resilience docket, which resulted in the instant docket.

In addition, Council Resolution No. R-24-624 ("Initiating Resolution") established a procedural schedule to evaluate ways to increase the availability of DERs, battery storage, and related facilities, including any changes to ENO-related policies and funding mechanisms, and establishing a vendor-neutral program to facilitate these goals.

Pursuant to the Initiating Resolution, ENO submitted a copy of their current Distributed Energy Resource Standards for Distribution Interconnection. In addition, eight (8) parties submitted comments and proposals for changes to existing policies or programs, new programs, costs, and proposed funding mechanisms, including comments on whether the approximately $30 million System Energy Resources Inc. ("SERI") settlement credits can and should be used to support these programs.

In all, the parties filed six sets of comments and participated in two technical conferences. Several parties also submitted revised proposals including on the potential use of SERI credits and a range of other matters. Subsequently, the Council determined that no individual proposal was developed enough to approve and that the proposals were not supported by a cost-benefit analysis or an assessment of customer bill impacts related to each proposal. Accordingly, the Council extended the time for the initial Council utilities advisors' ("Advisors") report and ordered additional filings by ENO and TNO/AAE[1]. The Advisors filed their initial report in July 2025.

Among other conclusions the Advisors found that the record indicated that there were significant uncertainties associated with the cost-benefit analyses ("CBA") of both the ENO and the TNO/AAE proposals. The Advisors recommended that the Council approve a smaller scale pilot program before proceeding with the level of investment proposed. The Advisors also provided a legal analysis that concluded that the SERI funds could not be paid to unregulated third parties to implement a DER program as proposed by TNO/AAE. As an alternative the Advisors noted the possibility of a SERI-funded DER pilot implemented through and subject to the controls of the Council's Energy Smart Program. At the Council's direction the ENO and TNO/AAE submitted revised proposals in September 2025.

In Council Resolution No. R-25-669 ("DER Resolution") the Council found that the record supported a DER program implemented as a three-year phase three of the Energy Smart BESS Pilot Program ("BESS Phase 3") to be implemented consistent with the Council's features and findings described in the DER Resolution. The DER Resolution also confirmed the Council's hiring of two DER consultants, one of whom subsequently resigned from the engagement. The other consultant, Michael Goldman, of Apex Analytics L.L.C., has served in that role since the

[1] Together New Orleans ("TNO") and the Alliance for Affordable Energy ("AAE") filed jointly.

adoption of the DER Resolution and has participated with the Advisors continuously since (hereinafter “Advisors/Consultant”).

Additionally, the DER Resolution directed ENO, in consultation with CURO, the utility Advisors, and the Council’s DER Consultant, to file an implementation plan.

The Council directed ENO to file a DER Program Implementation Plan (“Initial Plan”) consistent with the Council’s findings in the DER Resolution. The Council largely adopted TNO/AAE elements and further directed that the Initial Plan include the following features:

a. Implementation under Energy Smart as BESS Phase 3 with costs recovered through the Energy Efficiency Cost Recovery rider (“EECR”).

b. Set a not-to-exceed amount of $28 Million for upfront incentives.

c. Propose the use of available SERI funds to mitigate any net increase in customer rates.

d. Earmark upfront incentives 50% for commercial customers and 50% for residential customers.

e. Earmark 40% of residential incentives for lower and moderate-income (“LMI”) customers.

f. Use TNO’s proposed upfront incentive levels but stated on a per kWh *installed* basis.

g. Include an upfront incentive LMI adder of 20%.

h. Use ENO’s ongoing incentive rates as used in BESS Phase 2.

i. Cap administrative costs at $2 Million for the initial 3-year period.

j. Require vendor neutrality.

k. Allow third-party ownership of batteries.

l. Establish appropriate periodic and annual reporting and data gathering requirements.

m. Require seven (7) years of participation for customers who received incentives.

n. Require appropriate claw back provisions for non-participation by incentive recipients.

The Council further directed that ENO’s proposed implementation plan include program design, eligibility criteria, incentive structures, budgets, performance requirements, administrative arrangements, deployment goals, and any other provisions necessary for implementation consistent with the DER Resolution.

ENO filed the Initial Plan, which generally complied with the Council’s directives; however, CURO, the Advisors, and the Council’s DER Consultant determined that it required additional details to ensure consistency with Council policy, ratepayer protections, and the public interest as required by the DER Resolution. Key elements of the Initial Plan included the following:

a. A 10-year implementation at a total cost of approximately $30 million using the upfront and ongoing incentive levels approved in the DER Resolution.

b. Administration costs for a third-party incentive administrator, DERMS provider fees, evaluation, measurement, and verification ("EM&V"), and a budget for system studies and/or upgrades if needed.

c. Most costs being offset by $29.2 million in available SERI funds with minimal ratepayer impact.

d. Allocation of $15.2 million in upfront incentives.

e. Participation estimates of 570 residential LMI customers, 690 non-LMI residential customers, and 120 commercial customers.

f. Capacity estimates of 18.2 MW.

g. Comments on the Initial Plan were filed by Together New Orleans ("TNO") asserting that it departed from the funding structure and budget approved in the DER Resolution; however, in addition, TNO proposed substantive changes to the DER program as approved in the DER Resolution ("TNO Modifications"). These changes largely related to increasing certain incentive levels and creating a new customer class, which had not previously been proposed nor supported in the record. The proposed changes could also potentially increase the bill impacts of the BESS Phase 3.

Key elements of the TNO Modifications included the following:

a. An assertion that $28 million be utilized for upfront incentives.

b. An assertion that based upon TNO's Customer Feasibility Analysis the incentive levels approved in the DER Resolution resulted in a "battery funding gap" for participants.

c. An assertion that the Initial Plan creates an unsupported disparity between ongoing incentive levels for residential versus commercial customers.

d. A recommendation of a special class for "commercial resilience" facilities.

e. A recommendation increasing upfront incentives for this new class to approximately double the rate for commercial customers as approved in the DER Resolution.

f. A recommendation increasing the upfront incentive rates approved in the DER Resolution for approved classes by approximately 30-70 percent.

g. A recommendation increasing both ongoing incentive rates and caps above what was approved in the DER Resolution.

h. Participation estimates of 459 residential LMI customers, 984 non-LMI residential customers, 277 commercial customers, and 119 commercial resilience customers.

i. Capacity Estimates of 22.8 MW.

Subsequently, in Council Resolution No. R-26-150 ("Extension Resolution"), the Council ordered a limited additional procedural schedule to provide an opportunity for parties to conduct discovery about, and comment on, TNO's proposed changes to the DER program as approved in the DER Resolution and to allow ENO to file a supplemental implementation plan addressing a list of details not sufficiently included in the Initial Plan. The Council made clear that the procedural schedule was crafted and ordered to "assure party participation…[and] provide the opportunity to provide comments on ENO's Proposed Plan [Initial Plan], TNO's proposed modifications, and ENO's supplemental filing."[2]

ENO's Supplemental Implementation Plan was filed on May 26, 2026 ("ENO Supplemental Plan"). Key elements of the ENO Supplemental Plan included the following:

a. A 10-year implementation at a total cost of approximately $27.2 million using the upfront and ongoing incentive levels approved in the DER Resolution.
b. Administration costs for a third-party incentive administrator, DERMS provider fees, evaluation, measurement, and verification ("EM&V"), and a budget for system studies and/or upgrades if needed.
c. DER programs costs being offset by $29.2 million in available SERI funds with minimal ratepayer impact.
d. Allocation of $13.4 million in upfront incentives.
e. Participation estimates of 507 residential LMI customers, 612 non-LMI residential customers, and 105 commercial customers.
f. Capacity estimates of 16.1 MW.

The Alliance for Affordable Energy ("AAE"), Solar United Neighbors ("SUN"), GRID Alternatives ("GRID"), Gulf States Renewable Energy Industries Association ("GSREIA"), Finance New Orleans ("FNO"), and Enphase Energy ("Enphase") filed comments representing a variety of opinions about aspects of the TNO Modifications and the ENO Supplemental Plan, with general support for increasing residential LMI customers' incentive level. Few, if any, comments were made about the functional elements of the ENO Supplemental Plan. During the extension period several discovery requests were filed and answered and CURO convened a virtual discovery conference for parties to provide clarity and context around certain discovery responses.

The Extension Resolution also noted that the DER Resolution "erroneously referenced a $28 million budget for customer upfront incentives" and clarified that "the DER Program shall

[2] Council Resolution No. R-26-150 at 2.

include a not-to-exceed budget of $27.2 million for upfront incentives over the initial three-year program term, plus $2 million for ENO administrative costs."[3] Similarly, the Extension Resolution noted that the DER Resolution "did not specify a budget for ongoing incentives or clarify a cost recovery mechanism, which will be clarified in this proceeding."[4] Finally, the Extension Resolution directed the Advisors "to file a report addressing ENO's Proposed Plan [Initial Plan], ENO's supplemental plan [ENO Supplemental Plan], TNO's proposed substantive modifications [TNO Modifications], and comments received addressing each."[5]

II. EXECUTIVE SUMMARY

This report is submitted by the Council's Utility Advisors and the Council's DER Consultant ("Advisors/Consultant") in response to Council Resolution No. R-26-150 ("Extension Resolution") and after receiving comprehensive filings by the parties intended to assist the Council in approving a DER program implementation plan that will increase the availability of DERs in the City. The Advisors/Consultant recommend that the Council consider the key issues and recommendations made in this report and proceed with the DER program as Phase 3 of the Energy Smart BESS Pilot Program.

The two proposals under consideration differ significantly in cost and approach. ENO's Supplemental Plan proposes a 10-year DER program at a total cost of approximately $27.2 million, utilizing the Council-approved upfront and ongoing incentive rates, with an estimated installed capacity of 16.1 MW serving 507 residential LMI customers, 612 non-LMI residential customers, and 105 commercial customers. The TNO proposed substantive changes to the DER program include substantially higher incentives that would result in higher total program costs over ten years.[6] TNO estimates 22.8 MW of installed capacity serving 459 residential LMI customers, 984 non-LMI residential customers, 277 commercial customers, and 119 commercial resilience customers.

Another fundamental difference between the proposals relates to the use of the approximately $29.2 million Council-discretionary portion of the SERI Settlement funds. ENO proposes using $13.4 million for upfront incentives with the remainder offsetting ongoing incentive payments and administrative costs. TNO proposes allocating $28.0 million for upfront incentives, leaving $1.2 million to offset ongoing incentives and costs, which based on currently available information, would result in ratepayer impacts over the program's lifecycle.

The Advisors/Consultant have identified eight key issues, each discussed in greater detail below, requiring Council decision prior to DER program implementation: (a) the appropriate use of the Council-discretionary portion of the SERI Settlement funds; (b) consideration of TNO's

[3] Council Resolution No. R-26-150 at 3.
[4] *Id.*
[5] *Id.* at 5.
[6] TNO did not provide an analysis of its substantive changes over the 10-year period of BESS Phase 3. TNO did not provide an estimate of administrative and other non-incentive costs associated with its substantive changes. Utilizing costs TNO did provide and incorporating ENO's estimates of administrative and other non-incentive costs as a proxy, the TNO substantive changes are estimated to result in a total DER program cost of $74.2 million over 10 years. For additional detail see the table in section III of this report titled "Comparison of the ENO Supplemental Plan and the TNO Modifications Costs."

proposed new categories of participants; (c) the appropriate level of upfront incentive rates; (d) the appropriate level of upfront incentive caps; (e) the appropriate level of ongoing incentive rates and caps; (f) whether to increase administrative costs considering the TPIA's scope of work; (g) consideration of expected ratepayer impacts; and (h) whether to direct ENO to provide greater detail for DER program objectives.

Advisors/Consultant note for Council consideration: (1) proceeding with the DER program as Phase 3 of the BESS Pilot under Energy Smart with quarterly and annual reporting to allow for data-driven adjustments; (2) maintaining the Council-approved upfront incentive rates initially, with potential adjustments based on program performance data; (3) not creating an additional commercial-resilience class; (4) potentially increasing the administrative budget to accommodate the expanded scope of work for the third-party incentive administrator; (5) considering the ongoing incentive rates and caps for possible adjustment; and (6) requiring ENO to update its Utility Cost Test analysis to include a calculation of avoided transmission and distribution ("T&D") benefits; (7) considering using the information and data received during the actual operation of the DER Program, to determine if the ongoing incentive rates for residential/commercial customers should be equivalent; (8) requiring ENO to provide much greater detail and specificity to its operational objectives by which the Council can measure the direction, scope, and success of the DER program; and (9) reviewing and potentially strengthening customer protections regarding third-party owners.

The Advisors/Consultant note that higher upfront incentives might reduce the number of potential participants and total installed DER capacity given the available funding. The Advisors/Consultant continue to support the Council's original approach of establishing reasonable initial incentive levels and using actual program performance data to evaluate and adjust parameters over time, consistent with industry best practices.

III. SUMMARY COMPARISON OF THE ENO SUPPLEMENTAL PLAN AND THE TNO MODIFICATIONS

ENO in the ENO Supplemental Plan proposes a DER program implementing the Council approved upfront and ongoing incentive rates and proposes utilizing $13.4 million of the available $29.2 million in SERI settlement funds for upfront incentives with the remaining SERI settlement funds utilized to offset the ratepayer impact of the ongoing incentive payments and administration costs associated with the DER program. ENO estimates a total DER program installed energy storage capacity of 32,177 kWh. With respect to DER program participants, ENO estimates a total of 1,224 participants comprised of 507 residential low-to-moderate income (LMI) participants, 612 residential non-LMI participants, and 105 commercial participants.

TNO in the TNO Modifications proposes a DER program that substantially increases the Council approved upfront and ongoing incentive rates and proposes utilizing $28.0 million of the available $29.2 million in SERI settlement funds for upfront incentives leaving only $1.2 million in SERI settlement funds to offset the ratepayer impact of the ongoing incentive payments and administration costs associated with the DER program. TNO estimates a total DER program installed energy storage capacity of 45,504 kWh. With respect to DER program participants, TNO estimates a total of 1,839 participants comprised of 459 residential LMI participants, 984 residential non-LMI participants, and 396 commercial participants.

The tables below present comparisons of the ENO Supplemental Plan and the TNO Modifications. Over the approximately 10-year life of the DER program, ENO's DER program is estimated to cost $27.2 million as compared to TNO's Modifications with an estimated cost of $74.2 million. These costs will be offset, in part, through the utilization of the SERI settlement funds, avoided costs, and revenues reasonably expected from the DERs in MISO's capacity and energy markets which the Advisors/Consultant discuss in the Ratepayer Impact section of this report.

Comparison of the ENO Supplemental Plan and the TNO Modifications - Participation and Installed Energy							
	ENO Supplemental Plan[1]				**TNO Modifications[2]**		
Participant Class	**No. of Sites**	**Installed Storage Energy (kWh)**	**Deliverable Capacity[3] (MW)**		**No. of Sites**	**Installed Storage Energy (kWh)**	**Deliverable Capacity[3] (MW)**
Res. LMI	507	6,845	2.7		459	6,813	2.7
Res. Non-LMI	612	8,262	3.3		984	15,939	6.4
Commercial	105	17,010	6.8		396	22,752	9.1
Total	**1,224**	**32,117**	**12.8**		**1,839**	**45,504**	**18.2**

[1] ENO BESS Phase 3 Supplemental Implementation Plan Filing May 26, 2026

[2] TNO Response to CNO-TNO 3-4 (2026-03-29_New Orleans VPP Model_V8.xls)

[3] Deliverable Capacity (MW = Installed kWh * 80% /2hr /1000. Recognizing maximum 80% battery discharge and a 2-hour event)

Comparison of the ENO Supplemental Plan and the TNO Modifications Costs		
Cost Category	**ENO Supplemental Plan[1]**	**TNO Modifications[2,3,4]**
Upfront Incentives (Years 1-3)	$13,394,160	$28,000,000
Ongoing Incentives (10 Years)	$8,743,600	$41,173,920
Administrative and Other Non-Incentive Costs (Years 1-3)		
Energy Hub Fee (3 Years)	$797,840	$797,840
Third Party Incentive Administrator Fee (3 Years)	$2,000,000	$2,000,000
Evaluation, Measurement and Verification (EM&V)	$250,000	$250,000
System Study and Upgrade Budget	$2,000,000	$2,000,000
Administrative and Other Non-Incentive Costs (Years 4-10)	Not Available	Not Available
Total DER Program Costs	**$27,185,600**	**$74,221,760**

[1] ENO BESS Phase 3 Supplemental Implementation Plan Filing May 26, 2026

[2] TNO Response to CNO-TNO 3-4 (2026-03-29_New Orleans VPP Model_V8.xls)

[3] TNO Response to CNO-TNO 3-4 (2026-03-29_New Orleans VPP Model_V8.xls) included $ 4,575,196 per year in ongoing incentive payments, multiplying by 10 years yields $45.8 million, assuming an equal phase in of DER capacity over the first three years reduces these ongoing incentives to approximately $41.2 million.

[4] TNO in the TNO Modifications did not provide an estimate of Administrative and Other Non-Incentive Costs, ENO's estimates of Administrative and Other Non-Incentive Costs were utilized in this table for total cost comparison purposes.

IV. PARTIES COMMENTS ADDRESSING THE ENO SUPPLEMENTAL PLAN AND THE TNO MODIFICATIONS (07/20/2026)

a. Enphase Energy - Enphase did not provide any specific comments related to the ENO Supplemental Plan or the TNO Modifications but did comment that many cost-effectiveness models underestimate the actual value that battery VPPs[7] deliver, including improved reliability, operational flexibility, resilience, and customer engagement.

b. Solar United Neighbors – SUN accepts TNO's "affordability premise."[8] SUN believes the DER program with TNO proposals will save costs and increase energy equity.[9]

[7] DERs have often been characterized as virtual power plants ("VPPs"), which has been applied to the batteries in the BESS DER Program by comments in this docket.

[8] SUN comments, July 20, 2026 "…upfront incentive that will drive adoption of new distributed energy resources to create greater customer affordability and customer resiliency. As discussed in TNO's comments, the incentive level matters greatly for this deployment goal…" and "the incentives must create overall system affordability." at 2. "If batteries are not affordable, they will not be adopted…" at 4.

[9] *Id*. at 3.

Regarding "ongoing performance payments," SUN believes: "VPPs create energy affordability not just for participants, but for ratepayers in general. This cost savings is an especially critical component of any program for energy-burdened families…"[10] SUN does encourage consideration of the National Standards Practice Manual methodology to develop a benefit-to-cost ratio analysis for future review of the program.

c. Finance New Orleans – FNO commented that "The question before the Council is not whether battery storage creates value, but whether the program is structured to achieve meaningful deployment and long-term success. The ultimate measure of success should be whether the program delivers meaningful resilience and grid benefits at a scale that justifies public investment."[11] FNO supports high upfront incentives and appears to accept TNO's "affordability premise."[12] FNO also supports performance-based compensation structures, with compensation based on the value delivered to the grid. FNO expressed concern that interconnection study and upgrade requirements do not become barriers to participation for community-serving resilience facilities.[13]

d. AAE – comments that "qualified LMI households do not pay any cost upfront" (p.2). "This would mitigate the need for longer term-higher level performance incentives…" (p.3). AAE supports: (i) $28 million for upfront incentives, (ii) increased upfront incentive caps for all residential investments to $20,000 from $10,000, (iii) raising residential ongoing incentives per average kW delivered to $250 from $125, and (iv) escalating claw back provision compliance, beginning at 50% and escalating to 70%.

e. GSREIA – believes the program will reduce costs and improve reliability for homes and businesses. GSREIA describes the program as a "cost-effective energy procurement resource."

f. GRID – refers to TNO modifications built on "empirical evidence about what it takes to overcome relevant barriers to participation"[14] GRID states that "…both ongoing VPP participation and resilience against power outages have real benefits that demand valuation and consideration by the Council…"[15]. GRID contends that the funding stream for the ongoing incentives should be separate from the funding of upfront incentives.[16] GRID recognizes third-party owner ("TPO") models to access and monetize investment tax credits and applicable bonus credits but also identifies TNO's significant cost gap related to LMI upfront incentives.[17]

g. TNO – notes: (i) support for use of total available SERI credits to fund upfront incentives, (ii) asserts ENO's benefit-cost analysis is incomplete, and (iii) supports a not-to-exceed annual budget for ongoing performance payments, beginning at $5 million per year and reviewed annually. TNO argues that ENO's proposal to use a portion of the available SERI credits to fund program costs other than upfront incentives is in error, contending that the Council intended the program include the

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[10] *Id*. at 5.
[11] Finance New Orleans comments, July 20, 2026 at 2.
[12] *Id*. "…the critical issue is whether those incentives are sufficient to close affordability gaps…"
[13] *Id*. at 3.
[14] GRID comments, July 20, 2026 at 2.
[15] *Id*.
[16] *Id*. at 4.
[17] *Id*. at 5-6. "GRID recommends raising the upfront LMI incentive to a level that pencils while providing systems at no cost to the customer." ($850-$1,100/ kWh).

entire available SERI credits specifically for funding upfront incentives. TNO also argues that ENO's benefit-cost analysis Utility Cost Test (UCT)[18] and Ratepayer Impact Measure (RIM)[19] Test excluded several benefits that TNO included in its June 6, 2025 benefit-cost analysis.[20] TNO addresses the concern of limiting the total cost borne by nonparticipating customers by proposing an additional not-to-exceed budget of $5 million per year for ongoing incentive/performance payments.

h. ENO – noted that its Supplemental Plans use the $27.2 million of SERI credits over the full ten-year period of the DER program; in contrast, using the entire available SERI credits to only fund upfront incentives will result in increased ratepayer impacts to fund the remaining costs of the ten-year program, which include substantial costs of ongoing incentives and reasonable administrative costs.[21] ENO also noted that the uncapped annual ongoing incentives that TNO proposed for commercial installations would drive significant cost through the DER program over ten years.[22]

V. ADVISORS/CONSULTANT DISCUSSION OF ISSUES FOR COUNCIL DECISION

In preparing this report, the Advisors/Consultant examined ENO's filings, TNO's comments including proposed substantive modifications, other parties' comments and all discovery responses and cost effectiveness workpapers. The Advisors/Consultant recommend that the Council proceed with the DER program as a pilot program under Energy Smart as Phase 3 of the BESS Pilot. The Advisors/Consultant continue to recommend the approved quarterly and annual reporting framework to allow the Council to use the information and data received during the actual operation of the DER program to evaluate and adjust the DER Incentives and DER program parameters to achieve the Council's stated results from the DER program. The Advisors/Consultant have identified eight issues that they believe require Council decisions prior to ENO implementing a DER program.

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[18] 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.

[19] The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.

[20] Both the UCT and RIM tests capture the financial incentives paid to participants as a cost of the program, and exclude any benefits/costs incurred by participants, which TNO addresses as benefits in its comments. ENO did not include avoided transmission/distribution costs among program benefits, presumably because there were no supporting analyses performed consistent with the National Standards Practice Manual and Handbook for evaluating DER cost effectiveness.

[21] ENO June 22, 2026 comments, at 6: "By contrast, when accounting for the full costs of the DER Program that TNO outlines in its comments (including upfront incentives, annual incentives, and administrative payments to the DERMS provider), the DER program costs will total over $74 million over ten years in nominal terms – nearly three times the available funds from the SERI credits."

[22] *Id*. at 9.

a. Council-Discretionary Portion of the SERI Settlement
b. TNO Proposed New Categories of Participants
c. Upfront Incentive Rates
d. Upfront Incentive Caps
e. Ongoing Incentive Rates and Caps
f. Administrative Costs
g. Ratepayer Impact
h. DER Program Objectives

The Advisors/Consultant note the interaction of the individual parameters of the DER program require that changes should be considered in concert with each other. For example, increasing upfront incentive rates requires consideration of changing the upfront incentive caps to avoid rendering the increase ineffective. Additionally, a change in upfront incentive rates requires consideration of the ongoing incentive rates considering the total incentives provided to an individual participant for an additional DER resource and the value that resource provides. Further, increasing incentive rates and caps to increase participation will mathematically result in a lower number of customers potentially being able to participate and a corresponding lower amount of installed DER capacity, absent additional funds being allocated to the DER program.

The Advisors/Consultant also note that the Council recognized and anticipated that the DER program would require extensive ongoing data gathering and periodic adjustments based upon annual results, as noted in the DER Resolution:

> **WHEREAS**, to monitor the DER Program and potentially adjust incentive levels or reallocate budget based on the annual results of the DER Program, the Council finds that periodic reporting, on both a quarterly and annual basis, regarding the budget and operational progress is required, and that such reporting should have sufficient detail to allow the Council to adjust the program's spending.[23]

A. Council-Discretionary Portion of the SERI Settlement

In the DER Resolution, the Council directed that, to the extent practicable and subject to the annual $10 million application cap established in Resolution R-24-194, the remaining portion of the SERI Settlement, whose use is left to the Council's direction under the agreement-in-principle, be used to mitigate any net increase in customer rates resulting from the cost recovery of DER program costs through the EECR Rider, by providing bill credits or other rate offsets to ENO customers. The Council further ordered that the DER program shall include a not-to-exceed budget of $28 million for customer upfront incentives over the initial three-year program term, and

[23] DER Resolution at 10.

that these customer incentive costs, together with approved DER program implementation costs, shall be recovered through the EECR Rider.

In the Extension Resolution, the Council noted an internal inconsistency in the budget apportionment language in the DER Resolution "which erroneously referenced a $28 million budget for customer upfront incentives, and hereby clarifies that the DER Program shall include a not-to-exceed budget of $27.2 million for upfront incentives over the initial three-year program term, plus $2 million for ENO administrative costs."[24] These total $29.2 million which is the total remaining amount of the Council's discretionary portion of the SERI Settlement.

To the extent the implemented DER program costs exceed $29.2 million over its 10-year lifecycle, the DER program will necessarily have a ratepayer impact, the amount of which could be reduced by revenues and avoidable costs resulting from the implementation of the program. The amount of any ratepayer impact will also be affected by whether the Council decides that virtually the entire SERI amount is committed to upfront incentives only, as proposed by TNO, or constitutes the entire program budget, as proposed by ENO.

The Extension Resolution also noted that the DER Resolution did not specify a budget for ongoing incentives or clarify a cost recovery mechanism, which will be determined in this proceeding. However, a reading of the DER Resolution suggests that the Council intended the DER program to be implemented under, and consistent with the goals of, Energy Smart, and found that the cost recovery for the DER program can be accomplished equitably and effectively through the EECR.[25] The Council in the DER Resolution did not specify a budget for ongoing incentives. How the Council chooses to clarify this issue also affects the level of ratepayer impacts.

B. TNO Proposed New Categories of Participants

To ensure that customer upfront incentives are widely available, the Council found that fifty percent (50%) of incentives should be earmarked for residential customers and fifty percent (50%) should be earmarked for commercial customers. To ensure opportunity for low-to-moderate income (LMI) participation in the DER program, the Council found that forty (40%) of the total residential customer upfront incentives should be earmarked for residential LMI customers. The Council's approved allocation of upfront incentives is consistent with TNO's recommendations.

The Council specifically found that these earmarks are "subject to periodic review and adjustment by the Council based upon data presented and evaluated regarding program demand."[26] To obtain this data, the Council established extensive quarterly and annual reporting requirements. The Council's provisions for potential future adjustment were consistent with the Advisors' report conclusion that the expansion of DERs could be accomplished through ENO's Energy Smart BESS pilot program. This approach would allow the Council to gather critical information to evaluate what incentive levels work best, how much participation is achieved at a given incentive level, what are the localized impacts on the distribution system, what are the identifiable benefits from

[24] Extension Resolution at 3.
[25] DER Resolution at 7.
[26] *Id*. at 8.

an annual review of the actual results of the program, how the program cost effectiveness could be improved, and what is the ratepayer impact of expanding the penetration of DERs.[27]

The TNO Modifications recommend two new categories of customers within the commercial category: i) commercial resilience facilities, ii) non-resilience commercial customers. TNO further proposes that the commercial resilience facilities receive an upfront incentive of $822 per kWh, which is more than double the $400 per kWh that TNO originally recommended for all participants except LMI, and what the Council ordered.[28]

The DER Resolution record did not include any proposals or evidence to establish a new category of participants limited to commercial resilience facilities. The TNO Modifications do not specifically support the creation of such a category or why a commercial resilience facility requires a higher upfront incentive than other commercial customers to be economically viable.

FNO indicates that community-serving resilience facilities deserve particular attention because they provide benefits that extend beyond any single customer.[29] FNO encourages the Council to adopt a DER framework that supports efficient commercial-scale and community-serving installations and prioritizes resilience facilities that provide critical services during outages.[30]

ENO urges the Council to evaluate any changes through the lens of the broader public interest. ENO urges the Council to refrain from using its regulatory authority to require ENO or its customers to subsidize private groups' preferred business structures or absorb the costs associated with making those ventures more profitable.[31]

To ensure that customer upfront incentives are widely available, the Council has earmarked funds for each category of participants. Should the Council decide to add a new category of participants within the commercial category, at a higher incentive rate, it would reduce the potential for a wider number of commercial participants given the limited funds available for upfront incentives, under either budget scenario. In effect, if the upfront incentive is doubled for the new category only half as many commercial customers could potentially participate. The Council should also consider that this would result in lower overall DER installed capacity and, given fewer participants, the DER facilities would likely not be dispersed as widely across the City diminishing potential broader benefits encouraged by the DER Resolution.

Although TNO and FNO support prioritizing commercial resilience facilities, nothing was added to the record in support of such a finding.

[27] Advisor Report at 34.
[28] In Resolution R-25-699, the Council accepted the TNO/AAE proposed incentive level for residential and commercial customers of $1,000/kW based upon delivered capacity for residential and commercial/ community battery systems; however, for implementation of the DER program, the Council found that establishing this incentive level on a per kWh installed basis was more straightforward. Restating the $1,000/kW delivered incentive on a per kWh installed basis results in an incentive level of $400 per kWh installed.
[29] FNO comments at 2.
[30] FNO comments at 3.
[31] ENO comments at 3.

C. Upfront Incentive Rates

In the DER Resolution, the Council found that the TNO/AAE proposed incentive level for residential and commercial customers of $1,000/kW based upon delivered capacity for residential and commercial/ community battery systems was supported by the record. However, for implementation of the DER program, the Council found that establishing this incentive level on a per kWh installed basis is more straightforward. Restating the $1,000/kW *delivered* incentive on a per kWh installed basis results in an incentive level of $400 per kWh *installed*. Accordingly, the Council found that an incentive level of $400 per kWh installed should be used for non-LMI residential and commercial customers. To facilitate and encourage residential LMI customer participation, the Council also found that the TNO/AAE proposed twenty (20%) "adder" for residential LMI customers is supported in the record and found that an incentive level of $480 per kWh installed would be used for residential LMI customers.

Consistent with the Council's findings throughout the DER Resolution, the Council found that these upfront incentive levels were the initial values for the DER program that would be evaluated by the Council based upon data presented and evaluated through the detailed quarterly and annual reports. Establishing initial incentive levels is admittedly not an exact science, hence the Council's insistence on ongoing data gathering and the flexibility to make adjustments as supported by data and experience.

The TNO Modifications assert that the upfront incentive levels it originally recommended, and the Council found were in the public interest, should now be increased. TNO originally stated their proposed upfront incentive levels were "grounded in market data and aligned with leading national VPP programs, ensuring broad accessibility without over-subsidization,"[32] The Council endorsed the original levels in the DER Resolution on December 18, 2025, and no objection was expressed by TNO until it filed their revised proposal on March 31, 2026.

The TNO Modifications assert that with the existing upfront incentive levels, batteries will not be affordable to New Orleans customers and recommends the following changes to upfront incentives:

- For non-LMI residential customers, TNO recommends increasing the upfront incentives from $400 per kWh to $527 per kWh (32 percent increase);

- For LMI residential customers, TNO recommends increasing the upfront incentives from $480 per kWh to $822 per kWh (71 percent increase);

- For non-resilience commercial customers, TNO recommends increasing the upfront incentives from $400 per kWh to $527 per kWh (32 percent increase);

[32] TNO March 31, 2025 comments.

- For commercial resilience facilities, TNO recommends increasing the upfront incentives from $400 per kWh to $822 per kWh (106 percent increase).[33]

In support, the TNO Modifications introduce the concepts of customer payback period and initial battery "funding gap." TNO evaluates both the ENO Initial Plan, which uses the Council ordered incentive rates, and the TNO Modifications that incorporate TNO's recommendations for upfront and ongoing incentives. The table below compares the payback periods and funding gaps from the MS Excel model of the TNO analyses that TNO provided in response to discovery request CNO/TNO 3-4.

[33] While the Council did not have a category for commercial resilience facilities as part of the DER Resolution, commercial resilience facilities would have received the commercial upfront incentive rate of $400 per kWh under the framework ordered by the Council.

Summary Table of TNO Analyses of Funding Gaps and Payback Periods				
ENO Supplemental Plan at the Current Incentive Rates Approved by the Council				
	Residential		**Commercial**	
	LMI	**Non-LMI**	**Resilience Facilities**	**Regular**
Incentive Values				
Upfront Incentive ($/kWh)	$480	$400	$400	$400
Upfront Incentive Cap ($)	$10,000	$10,000	$100,000	$100,000
Ongoing Incentive rate ($/avg kW/yr)	$125	$125	$250	$250
Ongoing Incentive Annual Cap per site ($/yr)	$600	$600	$1,800	$1,800
Battery funding gap, per site ($)	**$5,612**	**$7,160**	**$52,797**	**$52,797**
Upfront incentive as % of total project cost	36%	30%	19%	19%
Breakeven/Payback (years)	**15.5**	**25.7**	**30+**	**30+**
TNO Modifications with TNO's Recommended New Incentive Rates				
	Residential		**Commercial**	
	LMI	**Non-LMI**	**Resilience Facilities**	**Regular**
Incentive Values				
Upfront Incentive ($/kWh)	$822	$527	$822	$527
Upfront Incentive Cap ($)	$20,000	$20,000	$100,000	$100,000
Ongoing Incentive rate ($/avg kW/yr)	$250	$250	$250	$250
Ongoing Incentive Annual Cap per site ($/yr)	$1,200	$1,200	Unlimited	Unlimited
Battery funding gap, per site ($)	**$533**	**$5,102**	**$28,556**	**$45,502**
Upfront incentive as % of total project cost	61%	40%	40%	26%
Breakeven/Payback (years)	**0.5**	**5.2**	**4.8**	**8.6**

TNO indicates that its analysis is designed to identify the upfront battery incentive levels required to produce payback periods that can reasonably support customer participation. The TNO Modifications rest largely on its "customer feasibility analysis," which attempts to predict what level of affordability will cause customers to participate. The analysis does not provide any local or national data to support the conclusions.

In response to discovery, TNO indicated that it did not conduct a separate New Orleans specific willingness-to-pay survey, a tool used in many jurisdictions to gauge potentially effective incentive levels.[34] Rather, TNO points to ENO's DSM planning framework and asserts that it shows that long payback periods suppress adoption.[35] However, the conclusions TNO draws are largely subjective.

Absent a discrete payback acceptance curve for batteries, it can be assumed that an individual participant would likely be more inclined to proceed with a project if the payback period is shorter and solely based on the economics of the program. However, if the participant perceives there is value to the battery system to avoid outages during roughly 305 days a year (80% of the year) when the battery is not being utilized by ENO, the participant may be inclined to accept a longer payback period or initial funding gap. This is likely the case for the residential and commercial customers that already have installed batteries on their own and are participating in ENO's existing BESS Phase II without any upfront incentives. The Advisors/Consultant note that the record does not demonstrate that the concept of a "payback period" is a common metric used by residential customers when deciding on a purchase and its relevance is speculative.

In the June 29, 2026, Evaluation, Measurement & Verification of Program Year Fifteen Energy Smart Programs prepared for ENO by QUALUS, an email survey of participants participating in ENO's battery storage pilot program found that 12.9% of respondents said the battery storage pilot played only a minor role in their decision to install a battery, while most indicated the program had no bearing on their choice. Instead, their decisions were driven by practical and financial considerations: having backup power during outages (29.5%), storing power generated on site (23.2%), saving money on electric bills (19.0%), and supporting clean energy (17.9%) were the most commonly cited reasons for installing a battery.[36]

FNO's point is well taken that no stakeholder can perfectly predict customer adoption or market response. If participation falls short of expectations – or if demand exceeds expectations in certain customer segments – the Council should have the flexibility to adjust program parameters to improve deployment and ensure public resources achieve their intended resilience outcomes.[37]

The Council should consider that until the additional information that will be gained from ENO's implementation of the program and reported to the Council is available, it is difficult to determine whether the increased upfront incentive levels proposed by TNO would effectively increase participation without diminishing the stated benefits of the DER program. Support for the Council's decision to adopt the currently approved upfront incentive levels was based in part on

[34] CNO-TNO 3-8.b

[35] CNO-TNO 3-8.b

[36] EM&V Program Year Fifteen report at 268 and 269.

[37] FNO comments at 3.

TNO's representation that those levels were based on market data and aligned with leading national VPP programs and at a level that ensured broad accessibility without over-subsidization.[38]

Over-subsidization is a critical concern in DER program design because under either proposed budget the Council has limited funds to provide upfront incentives. Higher upfront incentives, if unnecessary to promote participation, will result in a lower number of customers being able to participate and a corresponding lower amount of installed DER capacity to benefit all customers.

The Council's original approach of setting upfront incentives at a reasonable initial level and using the information and data received during the actual operation of the DER program to evaluate and adjust the incentives and program parameters is supported by the record and continues to be consistent with the Council's public interest determination. Similarly, FNO suggests that the DER program should be designed to adapt as the market develops based on periodic reviews to recalibrate incentive levels, compensation structures, and customer-segment allocations based on actual program performance.[39]

It is also helpful to note that adjusting incentives based on ongoing data is a standard practice in developing DER programs. For example, GRID Alternatives reports a similar approach from their experiences in the California Self-Generation Incentive Program ("SGIP") battery storage plan where incentives were adjusted upward based upon experience in enrollments. GRID notes that they were able to build low-income BESS projects under both iterations of the program.[40]

1. LMI upfront Incentive

Notwithstanding the Council's original findings, TNO concludes from its analysis that for LMI customers the TNO calculated funding gap of $5,612 could discourage LMI customer participation.

The TNO calculated funding gap for LMI customers is based on a reasonable assumption, albeit on the higher end, of initial purchase and installation costs.[41] In considering whether the Council should adjust the LMI incentive it should be aware of the fuller picture of how an LMI customer will likely participate in the DER program. Based upon the information in the record and discovery responses presented, it is highly unlikely that most potential participants, particularly LMI, will be purchasing battery systems outright and have significant out-of-pocket expenses.

As of December 31, 2025, the federal tax credit for battery installations is no longer available to residential battery purchasers, however, it is still available to third-party owners (TPO) of residential systems. The more likely scenario is that customers will lease batteries or have an

[38] TNO March 31, 2025 comments at 1; "The proposed $1,000/kW incentive and $10,000 cap are grounded in market data and aligned with leading national VPP programs, ensuring broad accessibility without over-subsidization."
[39] FNO comments at 2.
[40] CNO-GRID 1-9.
[41] In response to CNO-TNO 4-6, regarding battery installation costs within New Orleans, TNO provided cost data from EnergySage Louisiana-specific residential batteries, Community Lighthouse local project cost data, and recent city permit-reported project values of average cost per battery from recent projects in New Orleans.

agreement with a TPO who is still able to take advantage of the federal tax credits. TPOs can offer systems at lower costs and spread remaining costs over multi-year agreements with customers. In discovery TNO stated: "A residential customer may be able to obtain value through a TPO structure if the TPO can claim or monetize an applicable business clean-energy investment credit and pass value through to the customer;" and: "A typical residential TPO structure may include no or limited upfront payment; a monthly lease, service, or PPA payment; assignment or direct payment of the upfront utility incentive to reduce customer cost;" and: "The relevant implementation question is whether those terms leave the customer with an affordable payment."[42]

To further understand how a TPO agreement might be structured, the Advisors/Consultant issued discovery to TNO, ENO, and Grid Alternatives. The parties were unable to provide signed contracts or information to provide a reasonable estimate of how upfront costs for batteries would be reasonably translated to a customer lease payment. However, in response to discovery, GRID Alternatives did provide a model "GRID Services Solar Agreement" that calculated a $45,000 system over ten (10) years as zero cost to the customer.[43]

Regardless, it can be generally understood that an LMI customer participating through a TPO that can capitalize on the benefits of the tax credits and other incentives will not likely experience the full TNO calculated upfront funding gap and will more likely experience a considerably smaller lease payment. Nevertheless, the economics of the project from the TPO's perspective will affect the ultimate level of the lease payment that the TPO is willing to offer to an LMI customer. However, the negative side of TPO arrangements is that they present very serious risks of consumer protection and financial exploitation including high interest rates and "aggressive and unfavorable terms."[44] The Advisors/Consultant recommend that the Council address these issues in future directives in this docket.

In its comments, GRID Alternatives suggests that the Council should close the LMI funding gap with a larger upfront incentive to provide no-cost battery energy storage systems for LMI customers and that the appropriate upfront incentive to accomplish that would be $850 per kWh - $1100 per kWh.[45] Similarly, AAE in its comments indicates that BESS for LMI customers must be a no-cost option, in the same way the current Energy Smart Income Qualified program does not require an investment or financing from the LMI household.[46]

ENO's Energy Smart Program historically provides higher incentives to assist low-income customers, and the Council could attempt to reduce the burden on LMI DER program participants through higher upfront incentives, which may ultimately result in lower TPO lease payments. However, it should be noted that any increase in LMI upfront incentives will mathematically result in fewer overall LMI customers that will be able to participate and a corresponding lower amount of overall DER installed capacity. Replacing the Council approved LMI upfront incentive rate of $480 per kWh with the TNO proposed upfront incentive rate of $822 per kWh would reduce the

[42] CNO-TNO 4-11.
[43] CNO-GRID 1-7 part g, and attachment Exhibit B.
[44] GRID Alternatives comments at 6.
[45] GRID Alternative comments at 6 and 7.
[46] AAE comments at 3.

potential number of LMI participants and installed LMI capacity by 42%, assuming the overall budget for LMI customers remains the same.

D. Upfront Incentive Caps

To ensure that customer upfront incentives are available widely, the Council found that it was appropriate to establish a cap on the amount of upfront customer incentives that an individual customer receives and established a $10,000 residential customer cap and a commercial customer cap of $100,000. The Council indicated that these caps would also be evaluated and, if necessary, adjusted based upon data presented in quarterly and annual reports.

ENO applied these caps in both its Initial Plan and ENO Supplemental Plan. The TNO Modifications recommend that the commercial customer cap of $100,000 remain unchanged but that the residential customer cap be doubled to $20,000 without providing a reason for the increase.[47] AAE encourages the Council to direct ENO to increase upfront incentive caps for all residential investments from $10,000 to $20,000 to ensure the costs are covered.

While not explicitly stated, the Advisors/Consultant believe that this proposed change is primarily due to TNO's higher proposed incentive rates and the fact that some residential customers may choose to install more than one standard battery to meet the capacity needs of their home. Implicit in the TNO Modifications is an estimate that for residential LMI customers only 10% will have more than one battery and for residential non-LMI customers only 20% will have more than one battery.

Assuming a standard TESLA battery installation with a nameplate rating of 13.5 kWh, using the Council approved $400 per kWh upfront incentive rate, a non-LMI residential customer installing a TESLA battery would receive $5,400. Under the TNO proposed $527 per kWh upfront incentive rate, that same non-LMI residential customer would receive $7,145. An LMI customer using TNO's proposed $822 per kWh, with a 13.5 kWh installation would have a calculated incentive of $11,097, but would be capped and only receive $10,000.

Further, under TNO's proposed upfront incentive rates a residential customer, either LMI or non-LMI, that installs two 13.5 kWh batteries would reach the $10,000 Council approved cap and would not receive the full per kWh incentive for their installed capacity. If the Council does decide to increase incentive rates, either now or after receiving additional data from the implementation of the DER program, the Council should consider adjusting the incentive caps accordingly so that the cap does not limit the upfront incentive with the installation of one or two batteries at a residential site.[48]

E. Ongoing Incentive Rates and Caps

The Council maintained consistency with ENO's current (Phase 2) BESS Pilot and found ENO's proposed ongoing incentive payments were appropriate for all enrolled residential

[47] TNO comments at 3.

[48] If the Council decides not to increase upfront incentive rates, the Advisors/Consultant recommend that the Council consider whether this would discourage residential customers from installing two standard batteries and consider whether increasing the residential customer cap accordingly is appropriate.

customers at the rate of $125 per average kW delivered across all events, capped at $600 per year, and for all enrolled commercial customers at the rate of $250 per average kW delivered across all events, capped at $1,800 per year. The Council indicated that these ongoing rates and caps are initial values and they may be evaluated and adjusted based on the annual results of the DER program.

ENO used the Council-approved ongoing incentives and incentive caps in both its Initial Plan and supplemental filing. TNO argues that the record does not support compensating different customers at different rates if they are providing the same service and that the annual caps independently distort compensation and suppress efficient deployment. TNO proposes a uniform ongoing payment of $250 per average kW across customer classes, with a residential annual cap of $1,200 and no commercial cap. In its comments, TNO further recommends an initial not-to-exceed budget of $5 million per year for ongoing incentives.[49] TNO suggests that the Council should review the cap annually, based on a filing by ENO and recommendations from the Council's Advisors and may increase, reduce, or maintain it based on customer participation and battery deployment; verified battery performance; realized grid and capacity benefits; and the level of compensation needed to sustain participation.

AAE encourages the Council to standardize this performance incentive across all participating customers and raise the residential ongoing incentive rate from $125 per average kW delivered to $250 per average kW delivered.[50] AAE further recognizes that the DER Resolution allows for these values to be adjusted and encourages the use of EM&V to consider future changes or "right sizing" of the ongoing incentive as appropriate.

The ongoing incentives and incentive caps established by the Council in the DER Resolution were based upon the record presented and represent the reasonable judgment of the Council. They also reflect practices employed in some form nationally. Should the Council consider revising its findings it should also consider that unlimited caps at the inception of the program could lead to unnecessarily high incentive payments and incrementally larger bill impacts for non-participating customers, including many non-participating LMI customers. Alternatively, increasing ongoing incentives and their corresponding caps may be revisited once the Council collects and evaluates the reporting data gathered in the periodic reports. If the program underperforms as a result of inadequate ongoing incentives and cap levels, the Council can increase those incentives and caps in an attempt to improve participation.[51]

While TNO argues that the record does not support compensating different customers at different rates if they are providing the same service, the record that the Council based its decision on included DER proposals from both TNO and ENO that both proposed that residential customers be compensated at the ongoing incentive rates that the Council ultimately approved: $125 per average kW delivered for residential customers and $250 per average kW delivered for commercial customers. In the Energy Smart program, for various measures that would be implemented similarly for residential, LMI, and small commercial customers, the incentives that reimburse the

[49] TNO July 21,2026 comments at 3.
[50] AAE comments at 3 and 4.
[51] Consistent with the Advisors/Consultant's recommendation on increasing residential upfront incentive caps to avoid possibly discouraging the installation of two standard batteries at a residential site, the Advisors/Consultant recommend that the Council consider increasing the ongoing incentive cap accordingly.

participants for measure cost are often different for each type of customer, dependent on expected energy savings, value experienced from the measure by the customer, and other considerations.

BESS Phase 1 was offered to residential customers only and targeted 30 residential customers who owned batteries and had solar installed. Participants were offered an upfront incentive of $300 and a fixed $250 annual ongoing incentive.[52] Based on the 4.5 average kW delivered per site, the $250 annual ongoing incentive equated to $55.56 per kW delivered.

A BESS Phase 1 Report for May through September 2023, indicated 17 participants were enrolled. BESS Phase 2 targeted up to 140 participants and was offered to residential and commercial customers (125 residential customers and 15 small commercial customers) who owned batteries and had solar installed. To increase enrollment in BESS Phase 2, the ongoing residential incentive for residential customers was increased by changing from a fixed annual amount to an ongoing incentive of $125 per kW delivered. Commercial customers were offered an ongoing incentive rate of $250 per kW delivered.

BESS Phase 2 with an approved extension was "re-launched" in September 2025. With the increased incentives, an additional 78 participants were enrolled within three months. In 2025, BESS Phase 2 had 121 participants enrolled (which included 109 residential and 12 commercial).[53]

TNO/AAE in their December 2024 "Proposal to Enhance Distributed Energy Resource Programs for New Orleans" emphasized "...the DERP proposal is to create more pathways to access one program, not to create multiple programs. The simplicity of the program must include a continuation of PFP [pay for performance] design for all customers enrolled in the ENO BESS Pilot via the DERMS program with EnergyHub. Therefore, the existing PFP payment ($125/kW for residential customers and $250/kW for commercial customers) should continue to be paid out to existing and new customers. We caution that creating multiple participation compensation approaches, or attempting to bifurcate the customers who enroll through the upfront incentive or otherwise, creates risk and complexity that has proven to stifle participation and market growth in other states and even prevented more competition in hardware availability and installer participation."[54] With respect to ongoing incentive rates the Council based its finding on the parties' proposals in the record of this docket and decided, at least for the initial implementation of the program, to maintain consistency with ENO's current (Phase 2) BESS Pilot.

More importantly, the Council found that these were initial values and that they may be evaluated and adjusted based on the annual results of the DER program. Enphase Energy stressed that "… program success should be measured by actual participation and delivered performance—not by enrollment statistics alone. A program with thousands of enrolled batteries provides little value if only a fraction of participants remain active or respond during grid events. The true measure of success is the amount of dependable capacity that is available when needed and the percentage of customers who continue participating over time. High participation rates, consistent

[52] ENO Battery Report, BESS Phase 1, December 1, 2023.
[53] Energy Smart Program Year 15 Semi-Annual Report, September 12, 2025.
[54] TNO/AAE December 2024 Proposal at 42.

event performance, and long-term customer retention are the metrics that ultimately determine whether a VPP can be counted on as a reliable grid resource."[55]

The Council established detailed annual and quarterly requirements to measure actual participation and delivered performance and adjust program incentives based on the demonstrated performance of the DER program. Nonetheless, the Council may choose to revisit this issue, now or using the information and data received during the actual operation of the DER Program, to determine if the ongoing incentive rates for residential/commercial customers should be equivalent to better achieve the Council's desired results from the DER Program.

F. Administrative Costs

To keep the DER program implementation and administration costs from becoming excessive, the Council found that a not-to-exceed implementation and administration budget of $2 million over the initial three-year program term is a reasonable and supportable target budget. To allow the Council to monitor the DER program's administrative costs, the Council found that the DER program should include a requirement for ENO to inform the Council if its administrative costs are expected to exceed the $2 million budget and to request Council approval prior to collecting any additional costs from ratepayers.

In ENO's supplemental filing ENO provides an estimate of administrative and non-incentives costs that exceeds the $2 million amount over the first 3-years. ENO's estimate is presented in the following table.

ENO Estimated Administrative and Other Non-Incentive Costs	
Energy Hub Fee (3 Years)	$ 797,840
Third Party Incentive Administrator ("TPIA") - ICF International Fee (3 Years)	$ 2,000,000
EM&V	$ 250,000
System Study and Upgrade Budget	$ 2,000,000
Total	**$ 5,047,840**

The TNO Modifications did not include an estimate of the administrative costs associated with the implementation of its proposal. No party chose to opine in their comments regarding ENO's estimate of administrative costs. However, AAE agrees that a third-party incentive administrator ("TPIA") is appropriate for upfront incentives and other elements outlined in ENO's potential scope of work for the TPIA. Additionally, TNO in response to a discovery request

[55] Enphase Energy comments at 1.

indicated that it does not accept ENO's $5,047,840 estimate of administrative and non-incentive costs without further support.[56]

The Advisors/Consultant note that the $2 million in System Study and Upgrade Budget is a place holder for distribution system studies and distribution system upgrade costs that may or may not be necessary. However, no additional detail was provided in ENO's supplemental filing to support the estimate. In a discovery response in which ENO was asked to provide a detailed explanation, with supporting workpapers, for the estimated $2 million portion of the budget proposed for residential interconnection studies, ENO responded: "Until the specific systems are submitted to ENO for review, it is not possible to provide detailed information or workpapers substantiating this estimate."[57]

Although ENO has incorporated this placeholder as part of the DER program, they are not directly administrative costs of the DER program. Accordingly, the estimated administrative costs for the initial 3-years of the DER program are approximately $3,047,840, or roughly $1 million more than the Council originally targeted. The majority of these administrative costs are associated with the TPIA.

ENO's estimate of the TPIA costs is $2 million. As of the filing date of the Initial Plan, ENO was in the process of selecting a TPIA that would carry out the TPIA-related tasks identified in the DER Resolution. The Initial Plan included the "placeholder" of $2 million for TPIA costs. In ENO's supplemental filing, ENO indicates that it has selected ICF International ("ICF") as the TPIA, and that it requests Council approval of the selection. ENO's supplemental filing included as Attachment 2, a "DER Program Support Scope Outline" developed by ICF. In an additional supplemental filing ENO provided the following details for the TPIA costs.

ENO Battery Program Implementation Cost—ICF				
Price Category	**Year 1**	**Year 2**	**Year 3**	**Total**
Delivery	$363,397	$311,781	$321,835	$997,014
IT	$264,468	$210,965	$216,235	$691,669
Marketing	$94,365	$73,730	$75,855	$243,950
Customer Care	$26,294	$18,715	$19,524	$64,534
Total	**$748,525**	**$615,192**	**$633,450**	**$1,997,166**

The "DER Program Support Scope Outline" developed by ICF encompasses more than just administrating the incentives and includes the following identified tasks: Task 1 - Program Governance, Startup, and Management; Task 2: Program Design, Operational Goals, and

[56] CNO-TNO 3-9, e.
[57] CNO 3-11.

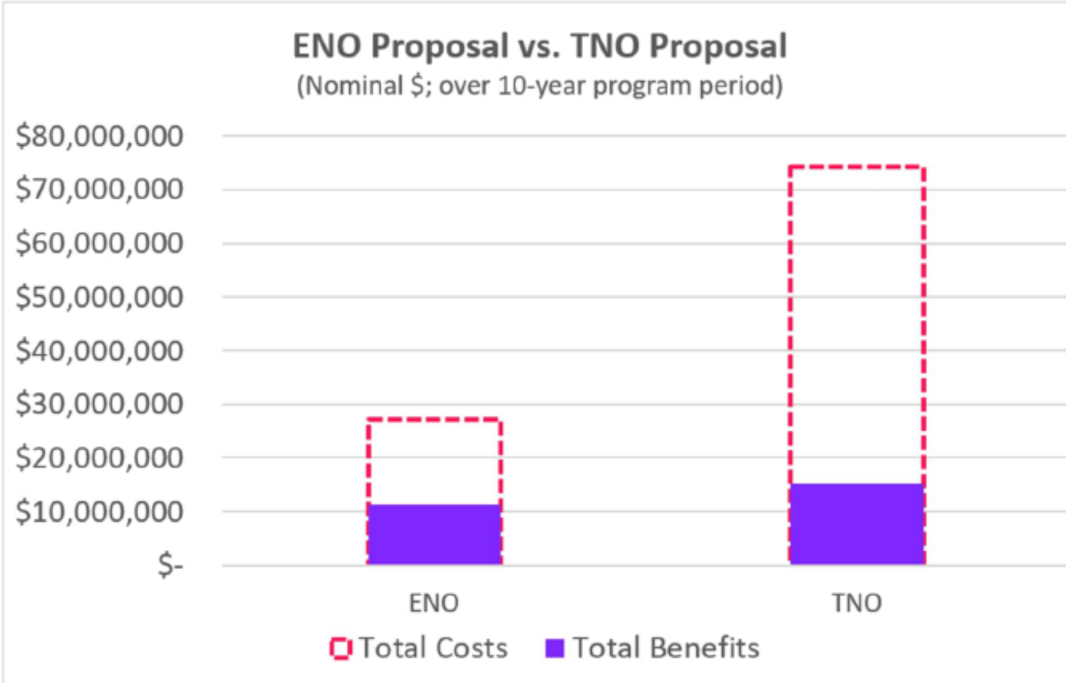
Implementation Timeline; Task 3: Customer and Technology Eligibility Administration; Task 4 - Customer Acquisition and Outreach Implementation; Task 5 - Application Intake, Reservation Queue, and Enrollment Workflow; Task 6 - Fund Reservation Administration; Task 7 - Incentive Processing and Payment Administration; Task 9 - Installer and OEM Management Task 10 - QA/QC and Installation Verification; Task 11 - Terms and Conditions and Consumer Protections; Task 12 - Customer Care and Complaint Resolution - Task 13 - EnergyHub Coordination, Event Monitoring, and Performance Reporting; Task 14 - Budget Tracking and Financial Controls; Task 15 - Program Reporting.

With a contractor tasked with doing more of the work associated with administering the DER program, the administration costs of the DER program could be higher than if ENO performed the work. However, the expanded scope of work and cost for the TPIA may result in a better DER program and reduced conflict among the stakeholders. The Advisors/Consultant believe that ICF has the experience and resources to complete the scope of work and none of the parties have objected to the cost estimate or scope of work developed by ICF. Therefore, the Advisors/Consultant believe the Council could reasonably decide to increase the not-to-exceed implementation and administration budget of $2 million over the initial three-year program term to a level that accommodates the increased scope of work of the TPIA.

G. Ratepayer Impact

As attachment 4 to its ENO's Supplemental Plan, ENO provided a cost benefit analyses of both ENO's Supplemental Plan and the TNO Modifications. ENO concludes that "…while neither program proves to be cost-effective under the Ratepayer Impact Measurement ("RIM") or Utility Cost Test ("UCT") test, ENO's Plan results in cost-effectiveness test results of 0.29 to 0.30, whereas TNO's proposed changes result in scores of just 0.15 to 0.16 (with cost-effectiveness being represented by a result ≥ 1.0)."[58] Additionally ENO provides a figure comparing ENO's plan with TNO's proposed changes as reproduced below: [59]

[58] ENO comments at 7.
[59] *Id*.



TNO in its comments asserts that ENO's results are "… implausibly low when compared with the benefits quantified in TNO's analysis. The federal investment tax credit alone is projected to attract approximately $31 million in additional investment in grid-connected battery assets—more than two and a half times the total benefits reflected in ENO's stated ratios. ENO reaches its result by excluding most of the benefits quantified by TNO, including the benefits from the investment tax credit ($31 million), avoided Regional Network Service charges, ($4.96 million), avoided demand-response costs ($16.72 million), deferred transmission and distribution investments ($7.74 million) and resilience benefits during outages ($57.48 million). In total, ENO's analysis excludes approximately $118 million in quantified benefits."[60]

Because the Council has already decided to proceed with the DER program implemented and operated under Energy Smart as Phase 3 of the BESS Pilot Program, the information contained in these recent cost-effectiveness tests is more useful at this juncture for estimating the impact on rates.

Prior to discussing the impact on rates, the Advisors/Consultant note that two of the benefits TNO mentions: benefits from the investment tax credit, and resilience benefits during outages, would not be benefits that flow through to all New Orleans ratepayer's rates. Additionally, on May 30, 2025, ENO submitted, as an attachment to its earlier cost-benefit analysis, an "Independent Evaluator Review of Together New Orleans' May 8, 2025 Memorandum (Docket UD-24-02)." At ENO's request, the memorandum was developed by ADM Associates, Inc. (ADM). ADM was the third-party evaluator ("TPE") for ENO's Energy Smart Programs through program year 15. In addition to presenting industry best practices for determining benefits when

[60] TNO July 21, 2026 comments at 2-3.

performing cost-effectiveness testing for demand response ("DR") programs, the memorandum commented on the use of the Avoided Demand Response and Avoided Regional Network Service Charges, commenting:

> 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 DRs and Avoided Regional Network Service (RNS) 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 calculation.[61]

TNO also contends that ENO excluded from its cost effectiveness tests deferred transmission and distribution investments. This category of benefits would flow through to New Orleans ratepayer's rates. While ENO included some avoided transmission and distribution benefits in the form of reduced line losses, ENO did not include a benefit amount for this category in its cost effectiveness tests.

ENO in response to an Advisors/Consultant's discovery request that "…it is not possible at this time to provide further analysis of transmission and distribution benefits. ENO indicates that, without knowing where specific deployments will occur on the distribution grid, ENO (or any other party) cannot know whether deployments would reduce or increase ENO's required investments in the distribution grid."[62]

Further, ENO responded: "As to transmission, an analysis for ENO would not produce similar benefits to those that may be seen in other jurisdictions (under either the tests ENO used or those described in the 2022 Handbook[63]) since ENO is located within its own Transmission Pricing Zone ("TPZ"). The analysis submitted by TNO assuming savings of $50/kW-yr is not supported and speculative. ENO's distribution costs are not largely driven by constraints on the gird, but rather by the age of ENO's equipment and exposure to extreme weather conditions and unique vegetation constraints. ENO's transmission costs are not driven by constraints on the system, as projects constructed outside of ENO's TPZ largely address those issues."[64]

ENO in response to Advisors/Consultant's discovery indicates that: "To fully perform the analyses recommended by the Handbook, however, would require months of intensive,

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[61] Independent Evaluator Review of Together New Orleans' May 8, 2025 Memorandum (Docket UD-24-02), May 30, 2025 at 2.
[62] CNO-ENO 3-6.
[63] https://naseo.org/Data/Sites/1/media/tknaseo/methods-tools-resources-handbook_6-3-22.pdf
[64] CNO-ENO 3-6, Addendum 1.

collaborative evaluation to develop appropriate quantification methods for potential benefits beyond what is assessed in the UCT, many of which do not actually reflect savings on customers' bills. Moreover, it is not possible, at this time, to more specifically analyze potential distribution benefits, or costs, without knowing where specific projects will be installed. Depending on the conditions on the feeders where projects may reside, additional costs may be incurred to accommodate the installations. Similarly, an ENO-specific analysis of potential transmission savings would likely produce less benefits than seen in other jurisdictions because ENO resides within its own Transmission Pricing Zone and because many projects that do provide reliability benefits to ENO are funded by other utility companies in Louisiana."[65]

The Advisors/Consultant agree with TNO that avoided transmission and distribution benefits should have been included as an accepted component of a UCT cost effectiveness test analysis. This category of benefits will flow through to New Orleans ratepayer's rates. The Advisors/Consultant recommend that the Council require ENO to update its UCT cost effectiveness test for the DER program with an estimate of these benefits.

ENO, with respect to its Initial Plan and TNO with respect to its TNO Modifications, were asked in discovery to provide estimated bill impacts for DER Program years 1-3 and DER Program years 4-10. In response, TNO indicated that it has not independently prepared a full ten-year utility revenue requirement or bill impact model and that ENO controls the billing determinants, cost-recovery assumptions, rider mechanics, administrative cost data, and implementation cost data needed to perform that calculation.[66]

1. Bill impact of ENO Supplemental Plan

In response to discovery, ENO asserts that "[i]n terms of bill impacts, ENO (in compliance with the December 2025 Resolution) designed the ENO Supplemental Plan to be entirely funded by the amount allocated to the program in the December [DER] Resolution. While this is not a cost-effective use of those funds, it still eliminates the potential for additional bill impacts from the program. The TNO framework not only is less cost effective than ENO's Plan but also will produce significant incremental bill impacts for customers over the life of the program."[67]

2. Bill impact of TNO Modifications

TNO presented the following estimates: $28 million in upfront incentives, and $4.6 million per year in annual ongoing incentives, which when multiplied by the 10-yr duration results in $45.8 million. TNO did not include any program administration costs.[68]

Using ENO's estimate of $5.0 million as a proxy for the TNO Modifications administrative costs results in a total nominal 10-year cost of approximately $79 million. In ENO's cost effectiveness model of the TNO Modifications ENO modeled costs slightly lower at approximately

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[65] CNO-ENO 3-4, Addendum 1.
[66] CNO-TNO 3-9, b.
[67] CNO-ENO 3-6, Addendum 1.
[68] CNO-TNO 3-4.

$74.2 million due primarily to ENO phasing in the TNO estimated installations over 3-years and reducing the ongoing incentive costs for first three years.

Considering benefits associated with the TNO Modifications ENO, in its cost effectiveness analyses and in response to Advisors' discovery, provided the following benefits computation associated with the TNO Modifications, totaling approximately $15.2 million.[69]

[69] CNO-ENO 3-6.

Program Benefits - TNO Modifications				
Year	**Avoided Capacity Costs**	**Avoided Energy Costs**	**Transmission Line Loss & PRM Adjustment for MISO Capacity Value**	**Total Benefits**
2026	$135,548	$42,294	$23,084	$200,926
2027	$276,518	$84,588	$47,091	$408,197
2028	$423,072	$126,882	$72,049	$622,003
2029	$431,533	$126,882	$73,490	$631,905
2030	$440,164	$126,882	$74,960	$642,006
2031	$448,967	$126,882	$76,459	$652,308
2032	$457,947	$126,882	$77,988	$662,817
2033	$3,064,000	$126,882	$521,799	$3,712,681
2034	$3,125,280	$126,882	$532,235	$3,784,397
2035	$3,187,786	$126,882	$542,880	$3,857,547
Total	**$11,990,815**	**$1,141,937**	**$2,042,036**	**$15,174,787**

The Advisors/Consultant note that Avoided Capacity Costs represent a proxy for potential MISO Planning Resource Auction revenues, and the Avoided Energy Costs represent a proxy for potential MISO energy revenues for dispatching the DER resources and selling the energy into the market when energy prices are at some of their highest levels.

Based on the information presented above, and consistent with ENO's cost effectiveness analyses, ENO provided the following annual ratepayer impacts associated with the TNO Modifications. ENO notes the ratepayer impact is based on an annual incremental bill impact analysis performed for residential customers using 1000, 1500, and 2000 kWh per month. Further, ENO notes that its bill impacts presented do not include impacts to customers in the Small Electric and Large Electric classes, whose bills also are impacted by the EECR, which is the expected cost recovery mechanism for these additional costs.[70]

Program Ratepayer Impacts - TNO Modifications			
Year	**1000 kWh**	**1500 kWh**	**2000 kWh**
2026	$10.57	$14.95	$19.34
2027	$8.09	$11.45	$14.81
2028	$11.48	$16.24	$21.01
2029	$10.09	$14.27	$18.46
2030	$10.06	$14.23	$18.41
2031	$10.03	$14.20	$18.36
2032	$10.01	$14.16	$18.31
2033	$2.21	$3.12	$4.04
2034	$2.02	$2.86	$3.70
2035	$1.83	$2.60	$3.36
Total	**$76.38**	**$108.08**	**$139.78**

In calculating these bill impacts, ENO notes "…that the figures above take into account the potential benefits of the program identified in ENO's analysis, as well as application of the SERI settlement credits during the first three years of the program. Even accepting these potential benefits as given, which they are not, TNO's permutation of the program will cost each household in New Orleans a significant amount of money over the life of the program, not to mention the amount small and large businesses customers will pay."[71]

The Advisors/Consultant note that ENO's calculations result from the $29.8 million net cost of the TNO Comments, which is calculated as approximately $74.2 million less $29.2 million in the Council-discretionary portion of the SERI Settlement less the $15.2 million in ENO calculated benefits.

The Advisors/Consultant further note the lack of inclusion of any avoided T&D benefits in ENO's ratepayer impact calculation assuming that any avoided T&D benefits would be realized as revenue requirement reductions impacting ratepayers. TNO asserts that the avoided T&D benefit is approximately $7.74 million. While ENO strongly disagrees with this estimate, if it were factored into ENO estimates, the net cost of the TNO Modifications would be reduced from $29.8 million to $22.0 million, and the corresponding ratepayer impact of the TNO Modifications would be reduced to approximately 74% of the ratepayer impact estimated by ENO.

The Council should also consider that not all benefits will impact ratepayer bills. Based on a reasonable assessment of benefits from MISO revenues for the DER program capacity and energy, TNO's estimate of avoided T&D benefits, and ENO's other identified avoided cost benefits, it cannot be resolved that the benefits will exceed the ongoing incentive and administrative costs associated with the TNO Modifications. Thus, based upon the currently available information in the record and assumptions for some calculable benefits not yet determined, the benefits and expected MISO revenues will not be sufficient to avoid bill increases

[70] CNO-ENO 3-6.
[71] *Id*.

over the life of the program. While there will be other benefits as a result of the implementation of a DER program, those benefits have not been demonstrated to have an impact on rates and are not expected to directly reduce those increases.

H. DER Program Objectives

ENO's Initial Plan lacks clarity in explaining program objectives. ENO stated in its filing of the Initial Plan: that "Collectively, the batteries will help form a Virtual Power Plant ("VPP") under Energy Smart that can be dispatched to provide support to the local distribution grid, and that can be registered by ENO with the Midcontinent Independent System Operator ("MISO") as a resource that provides additional market revenues to ENO customers."[72] However, in the plan itself, ENO did not elaborate or provide details of how the DERs will support the local distribution grid or generate the additional MISO market revenues.

In subsequent filings, and in responses to Advisors/Consultant discovery requests, ENO failed to explain how it would use the DERs to support the local distribution grid or generate the additional MISO market revenues. Program objectives are central to the program, including specific plans, operational goals, timelines, and anticipated annual revenue from each MISO program, including additional use cases related to distribution planning/operation and value streams such as avoiding T&D upgrade costs.

Because ongoing reporting and evaluation are critical to the findings and mandates of the DER Resolution the Council should require ENO to provide much greater detail and specificity to its operational objectives by which the Council can measure the direction, scope, and success of the DER program.

In addition, the Council should update the reporting requirements to include data on program objectives and BESS program Phase 3 additional use cases related to distribution planning and operations.

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[72] ENO proposed Initial Plan of March 2, 2026 at 1.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Report Regarding ENO's Initial Plan and Supplemental Filings, TNO's Proposed Modifications, and Comments Addressing Each Submitted by the Council's Utility Advisors and the Council's DER Consultant* has been served upon "The Official Service List" via electronic mail and/or U.S. Mail, postage properly affixed, this 6th day of August, 2026.

/s/ J. A. Beatmann, Jr.

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J. A. Beatmann, Jr.