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July 16, 2025

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 *Advisors' Report Regarding Parties' Proposed Distributed Energy Resource Programs and Policies* on behalf of the Advisors to the Council of the City of New Orleans in the above-referenced matter. The Advisors submit this filing electronically and will submit the original and requisite copies as you direct. 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**

ADVISORS' REPORT REGARDING PARTIES' PROPOSED DISTRIBUTED ENERGY RESOURCE PROGRAMS AND POLICIES

July 16, 2025

I. INTRODUCTION

The Council has 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 and as a potential means of increasing grid resiliency. In Council Resolution No. R-24-624, the Council opened Utility Docket No. UD-24-02 dedicated to increasing the availability of DERs, battery storage, and related facilities, including any changes to related policies and funding mechanisms, as well as establishing a vendor-neutral program to facilitate these goals. In that resolution, the Council directed parties to submit proposals for changes to existing policies or programs, new programs, costs, and proposed funding mechanisms, including comments on whether SERI Credits[1] can and should be used to support these programs. The related procedural schedule also included convening two technical conferences and filing any responsive comments. The Advisors were directed to fully participate in the docket, conduct discovery, and to submit an Advisors' Report: (i) summarizing the comments received, (ii) recommending changes to existing Council policies, (iii) analyzing proposed funding mechanisms, and (iv) providing additional guidance to the parties on how to fulfill the Council's goals for this docket. The Advisors submit this Advisors' Report pursuant to that requirement.

Subsequent to the filing of this report the procedural schedule provides for parties to file comments regarding the report and submit revised proposals, after which the hearing officer will certify the record to the Council.

II. EXECUTIVE SUMMARY

The Advisors believe that several of the concepts of the parties' merit further Council consideration but that no individual proposal is supported or developed enough to approve as written. The two primary proposals targeting the near-term expansion of DERs are the proposals of TNO/AAE and ENO (collectively, "Direct Proposals"). Both Direct Proposals rely on a significant amount of SERI Credits expended upfront. However, as discussed below, the Advisors conclude that SERI Credits are not available for these purposes and that SERI Credits are intended for ongoing ratepayer relief. Therefore, the Direct Proposals lack appropriate funding to proceed. Although ENO's proposal utilizes only about one-third of the approximately $29 million in SERI Credits that TNO/AAE proposes, ENO's proposal should not be viewed as a significantly lower cost proposal for expanding DER's. Based on a review of the cost-effectiveness workpapers provided by the parties, over the next ten-years, implementation of either ENO's proposal or TNO/AAE proposal is expected to require approximately $30 million in ratepayer funds be provided as incentives.

The Direct Proposals both rely on the expansion of ENO's existing BESS pilot battery program, however the Advisors remain concerned about the definite near-term cost of the Direct Proposals compared to the speculative participation levels at any given incentive level, the uncertain impact

[1] The Council was a party in twenty dockets before the Federal Energy Regulatory Commission regarding System Energy Resources, Inc.'s recovery of costs under the Unit Power Sales Agreement, accumulated deferred income taxes, and the operation of Grand Gulf Nuclear Station. On May 2, 2024, the Council approved an Agreement in Principle ("AIP") to settle the dockets and to refund $116 million to ENO ratepayers. As part of the AIP, $32 million credits were retained by ENO pending further direction from the Council and subject to an annual cap of $10 million unless there is mutual agreement between ENO and the Council ("SERI Credits").

of a rapid expansion of DERs on ENO's distribution system, and the uncertain future costs and benefits. The Advisors believe that the Council should proceed toward the expansion of DERs, similar to the Council's approach in the resilience docket UD-21-03 that was, in part, the genesis for this docket. In that docket, the Council cautiously evaluated ENO's proposed $1.1 billion resilience plan, ultimately approving a $100 million two-year plan that could provide reliable data to inform future resilience decisions by the Council. Similarly, a measured DER approach could allow for expansion of DERs that could be accomplished through ENO's Energy Smart BESS pilot program, which both ENO and TNO/AAE have proposed to utilize.[2] This would allow the Council to gather critical information along the way 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 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. The Advisors note that RNO, PosiGen, and Enphase also support the expansion of the DERs through the Energy Smart program structure to expand the battery pilot.[3]

The Advisors believe that with good-faith collaboration and the willingness to compromise, the parties to this docket could develop a DER expansion program, conducted initially as a pilot, possibly through Energy Smart, that accomplishes the Council's goals while ameliorating the Advisors' concerns. This approach would also address the priorities and pitfalls noted by the parties. A DER expansion program should also have sufficient reporting and information gathering during the pilot program to support a permanent virtual power plant ("VPP") tariff. To that end, the Advisors recommend that the Council consider the development of a DER expansion pilot program based upon key elements from the input of the parties and the Advisors in this proceeding. The Advisors further recommend that the pilot program should include the following features:

- Upfront and ongoing incentive levels that bridge the significant difference in the parties' opinions. Ultimately, both the upfront and ongoing incentive levels should be set at a level that would likely be required to ensure long-term participation.
- Data-driven incentive levels or allocated funds for lower to moderate income ("LMI") customers such that significant LMI participation is expected.
- Be vendor neutral to promote the participation of both a significant number of BESS equipment manufactures, and energy service providers that may ultimately be funding projects installed for participants.
- An efficient, objective, and straightforward pre-approval process for third-party vendor participation and incentive disbursement.
- To the extent possible the initial pilot should leverage the use of ENO's existing BESS pilot program and supporting vendors.
- An identified funding source for the pilot program.
- Supported by a cost effectiveness analysis.
- Supported by a ratepayer bill impact calculation that identifies the expected timing and impact on customer bills.

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[2] Both TNO/AAE and ENO proposals require enrollment in ENO's Energy Smart BESS program or successor, but also propose significant expansion in near-term years.

[3] RNO Comments in Council Docket UD-24-02, December 20, 2024, p2; PosiGen Comments in Council Docket UD-24-02, March 31, 2025, p2; Enphase Comments in Council Docket UD-24-02, March 14, 2025, p 2.

- Sufficient reporting and data gathering such that a permanent VPP tariff could be developed.

III. BACKGROUND

The instant docket has its roots in earlier proceedings focused on the storm hardening and resiliency of the ENO grid. In Utility Docket UD-21-03 (resilience and storm hardening), Council Resolution No. R-23-74, addressed whether benefit-cost ratios of some resilience projects might have to be greater than 1.0 to merit approval. In Council Resolution No. R-24-73, CURO recommended that TNO work with ENO to explore further development of support for TNO's proposed resilience hubs. In Council Resolution No. R-24-625, the Council directed that microgrids be explored in a separate docket. On October 2, 2024, TNO/AAE proposed a "Plan For Distributed Community Resilience" that would apply $16 million of SERI Credits to Community Microgrids and $16 million of SERI Credits to "Residential Solar-Storage Aggregations."

Subsequently, in Council Resolution No. R-24-624, the Council established this instant docket, Docket No. UD-24-02.

ENO's current DER program, the Energy Smart BESS Pilot Demand Response Program was initiated following ENO's March 9, 2022, Request for Approval of a Demand Response Battery Storage pilot program for Program Year 12 of Energy Smart. That request originated in late 2021, when ENO and the third-party implementer for the Energy Smart Large Commercial DR program explored program ideas centered around utilizing smart solar battery systems to support the grid. A new pilot program was developed to allow residential customers with existing solar-connected smart battery systems to receive an incentive in exchange for participating in demand response events.

For Phase 1 of the BESS Pilot, the participating existing solar-connected smart battery systems were connected to the Distributed Energy Resource Management System ("DERMS") platform being used to administer the Large Commercial DR program. A separate DERMS and third-party implementer has been used for BESS Pilot Phase 2.

In this docket, parties were directed to submit proposals for changes to existing policies or programs, new programs, costs, and proposed funding mechanisms, including comments on whether SERI Credits can and should be used to support these programs. In December 2024 proposals and comments were filed in this proceeding by the Alliance for Affordable Energy ("AAE"), Together New Orleans ("TNO") and AAE (jointly, "TNO/AAE"), Solar United Neighbors ("SUN"), PosiGen, Resilience New Orleans ("RNO"), ProRate Energy ("PRE"), Recurve Analytics, Inc. ("Recurve"), and Entergy New Orleans, LLC ("ENO"). Two primary areas of discussion were addressed in the December 2024 filings:

1) comments on whether SERI Credits can and should be used to support the proposals, and
2) comments and proposals on the expansion of DERs in New Orleans.

Because several of the proposals in this docket rely on the use of SERI Credits, the Advisors will address the use of SERI credits prior to discussing the merits of the individual proposals and any guidance of the Advisors to the parties on how to fulfill the Council's goals for this docket.

IV. USE OF SERI CREDITS

The Council was a party in twenty dockets before the Federal Energy Regulatory Commission ("FERC") regarding System Energy Resources, Inc.'s ("SERI") recovery of costs related to the Unit Power Sales Agreement, accumulated deferred income taxes, and the operation of the Grand Gulf Nuclear Station. On May 2, 2024, the Council approved an Agreement in Principle ("SERI AIP") to settle the dockets and to refund $116 million to ENO ratepayers ("SERI Settlement").[4] As part of the AIP, $32 million credits were retained by ENO pending further direction from the Council and subject to an annual cap of $10 million unless there is mutual agreement between ENO and the Council ("SERI Credits") that, after considering ENO's financial condition, the cap could be exceeded.

In Council Resolution No. R-24-624 ("Initiating Resolution"), the parties were directed to submit proposals for changes to existing policies or programs, new distributed energy resource ("DER") programs, costs, and proposed funding mechanisms and to comment on whether the SERI Credits could and should be used to support any of the proposals.[5]

The SERI Settlement approved an "AIP to settle the dockets and to refund $116 million to ENO ratepayers". [6] (Emphasis added.) More specifically, the resolution noted that "$32 million credits [of the total SERI Settlement] was retained by ENO pending further direction from the Council and subject to an annual cap of $10 million unless there is mutual agreement between ENO and the Council…."[7] The resolution also noted that "regulatory law and policy generally require that credits such as these [$32 million credits] should be passed on to ratepayers."[8]

a. Parties' Comments on Use of SERI Credits

Solar United Neighbors ("SUN") filed its proposal for a distributed power plant ("DPP") program that "could be implemented in New Orleans after successful deployment of a pilot program funded through SERI credits."[9] SUN also stated that it supports the use of SERI Credits to "incentivize participation in a DPP program through payment credits or compensation for customer adoption of battery storage resources to couple with distributed energy rooftop solar systems."[10] SUN did not, however, provide any legal or regulatory basis for its conclusion that SERI Credits may be used to fund its proposal.

ProRate filed its proposal to use up to $1 million per year "to conduct an international, expert-led analysis to develop a strategic, ongoing grid transition plan."[11] This proposal, according to ProRate, may be funded by SERI Credits since such credits "came indistinguishably from all New Orleans ratepayers, similar settlement precedents dictate that such funds must support programs to

[4] Council Resolution No. R-24-194 ("Approval Resolution").
[5] Council Resolution No. R-24-624 at 4.
[6] Council Resolution No. R-24-624 at 2; *See* also the *Agreement in Principle Regarding Resolution of Certain FERC Matters Related to SERI* at no.4, which describes the $116 million refund.
[7] Council Resolution No. R-24-624 at 2.
[8] *Id*.
[9] Solar United Neighbors' Proposal filed December 20, 2024 at 1.
[10] *Id*. at 4.
[11] Prorate Proposal dated December 20, 2024 at 2.

distribute benefits in an as effective and equitable process as possible to all ratepayers."[12] ProRate, like SUN, did not provide any legal or regulatory basis for its conclusion that SERI Credits may be used to fund its proposal.

Resilience New Orleans ("RNO") filed a proposal that provides a framework for accomplishing DER goals including expanding Energy Smart, incentivizing electrification, creating a time of use tariff, and developing a new funding source to help ratepayers cover the cost of new back-up battery systems.[13] RNO does not support the use of SERI Credits for programs developed and implemented by third-party developers or nonprofits.[14] According to RNO, "customer funds are not needed if the Council develops a new funding source like a carbon offset program to cover the costs of new battery programs."[15]

Recurve filed reply comments in the docket stating that it believes the Council has the authority to establish DER programs with SERI credits but did not provide any legal or regulatory basis for its conclusion.

Together New Orleans and the Alliance for Affordable Energy ("TNO/AAE") jointly submitted a proposal in the docket for their distributed energy resource program ("DERP") that includes the implementation of upfront incentives to accelerate the installation of behind-the-meter residential and small commercial battery energy storage systems.[16]

According to TNO/AAE, their proposal would allocate SERI Credits over a three-year period to applicants, "significantly increasing the availability of battery systems to support the Entergy New Orleans (ENO) distribution system."[17] TNO/AAE assert that the SERI AIP executed by the parties in the SERI Settlement, including SERI and the Council, provides the Council with broad discretion to utilize the SERI Credits to fund the TNO/AAE proposal.[18] TNO/AAE also argue that "there are no SERI refunds to customers in this matter" and that nothing in the SERI AIP or the resolution adopting the SERI AIP[19] "says that this matter is about SERI refunds to customers."[20]

TNO/AAE also cite the city's Home Rule Charter ("Charter") as support for using SERI Credits to fund the DERP TNO/AAE and posit a self-evident summary of the Council's authority under the Charter claiming that the Charter directs the Council to make certain that SERI Credits "are deployed in ways that maximize public interest and deliver meaningful, long-term benefits to ratepayers," which simply begs the question.[21]

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[12] *Id*.
[13] Resilience New Orleans Proposal dated December 20, 2024 at 1.
[14] *Id*.
[15] *Id*. at 4.
[16] TNO/AAE Proposal dated December 20, 2024 at 2.
[17] *Id*. at 2.
[18] *Id*. at 44.
[19] Council Resolution No. R-24-194.
[20] Comments of the Alliance for Affordable Energy dated March 14, 2025 at 1.
[21] TNO/AAE Proposal dated December 20, 2024 at 44, citing Home Rule Charter, City of New Orleans Section 3-130.

ENO's filed comments cite the language of the SERI AIP and the Approval Resolution noting that both specifically state that the primary purpose of the SERI AIP was to provide "expeditious benefits to ENO's customers in the form of credits and prospective rate reductions,"[22] arguing that the SERI AIP requires all of the SERI AIP funds to be returned to customers as follows: 1) $66 million would be returned to customers in "two tranches over long-term periods: $22 million over ten years and $44 million over twenty-five years;" and 2) a $32 million credit to be returned to customers in amounts not exceeding $10 million in any twelve-month period.[23]

ENO's comments also assert that "legal obstacles" prevent the Council from utilizing SERI Credits to fund programs proposed by third-parties, such as the TNO/AAE's DERP proposal.[24] ENO argues that the use of SERI Credits for programs such as TNO/AAE's DERP program is inconsistent with the plain language of the SERI AIP, and the Resolution No. R-24-194 approving the SERI AIP.[25] ENO also argued that an order directing SERI Credits to be used for DER programs may exceed the Council's regulatory authority and likely implicates the Council's taxing authority and constitutes the taking of private property.[26] Further, ENO claims that should the Council allow SERI Credits to be used for third-party DER programs the Council must indemnify ENO for any claims or further liability to customers for the amount of any SERI Credits provided for the proposed programs.[27] It should also be noted that although ENO opposes the use of SERI Credits for the TNO/AAE's DERP proposal, ENO submitted its own DER proposal that would be administered with the use of approximately $10 million in SERI Credits over five years.[28]

AAE responded that ENO's argument violates public policy and that ENO has no justiciable property interest in the SERI Credits and therefore has no basis for asserting a takings claim.[29] AAE also asserts that ENO's claim for indemnification is unnecessary and that the proposed programs pose "no credible risk of such legal action."[30] According to AAE, if the Council orders the use of SERI Credits for DER programs the order would be: (1) based on a record in this proceeding supporting the Council's conclusion that use of the funds is consistent with the public interest; (2) in consideration of public participation and comment as to the best way to advance the public interest; and (3) within the Council's discretionary authority to use the SERI credits in the manner proposed by TNO/AAE.[31]

Although TNO/AAE filed jointly, TNO filed, in the second round of comments, the following statement:

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[22] ENO Comments dated December 20, 2024 at 6. See also SERI AIP at 1.

[23] ENO Comments dated December 20, 2024 at 5. See also, SERI AIP at 2: "6a. ENO will retain a $32 million credit for customers: The $32 million in SERI credits will be retained by ENO pending further collaboration and direction from the Council. In the event that the Council desires to use more than $10 million of these credits in any given twelve month period, then CURO, the Council's Advisors and the Company shall collaborate on a mutually agreeable solution considering ENO's financial metrics."

[24] ENO Comments dated December 20, 2024 at 4.

[25] *Id.* at 2.

[26] *Id*.

[27] *Id.* at 4-5.

[28] ENO Comments dated March 14, 2025 at 2.

[29] AAE Comments dated March 14, 2025 at 1.

[30] *Id*. at 8.

[31] *Id*.

> Although we believe it is wholly within their authority, we are agnostic as to whether the Council opts to use SERI credits or other funds to expand DERs, but are frustrated that the argument over funding has successfully monopolized the conversation and prevented useful progress toward DER expansion. There's no reason why we can't be simultaneously working to refine the plan and figure out its funding source.[32]

Other legal arguments raised by ENO include the potential that ordering ENO to turn over the SERI Credits to third parties could be considered a tax or constitute an illegal taking.[33] This, too, according to ENO, would create the risk that an aggrieved customer may challenge both the interpretation of the SERI AIP and the Council's action to use the credits in a manner that is arguably inconsistent with the SERI AIP and other Council resolutions as an unconstitutional taking of ratepayers' private property.[34] ENO expressed concern that a successful legal challenge to a Council decision would also expose ENO to unreasonable financial risks that could ultimately adversely affect customers, including possible indemnification. Suffice it to say TNO/AAE stated their disagreement with these arguments in terms as general as ENO advanced them.

The Advisors conclude on the record that the SERI AIP, the Approval Resolution, and the Initiating Resolution all emphasize and assume that the objective is to return the SERI Settlement funds to ENO's customers. The Advisors also agree that the Council does have broad regulatory authority, but it is circumscribed by serious substantive and procedural legal constraints. Louisiana law places restrictions on the use of ratepayer refunds or credits that are the result of a Council-approved settlement in a regulatory proceeding. However, any deviation from the long-standing practice of returning refunds directly to customers would require regulatory justifications not supported in this record. Such a deviation clearly could result in costly legal challenges for diverting refunds away from direct customer compensation and as inconsistent with just and reasonable rates.

The Council's authority over ENO stems from its role as a utility regulator. The Council, via the Charter[35] (recognized by La. Const. art. VI, §5(E)), exercises full regulatory control over utilities within the city. That authority permits the Council to set just and reasonable rates and approve utility programs insofar as they benefit ratepayers and the utility service. It does not generally extend to using utility-derived funds as a general revenue source for unrelated public programs.[36] The Charter grants the Council the power to levy taxes and appropriate funds for public purposes, but only by ordinance and through proper legislative procedure (including mayoral approval). Louisiana statutes reinforce this authority – for example, La. Rev. Stat. § 45:1163.1 provides that when a utility implements a rate increase under bond and the final approved rate is lower, the

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[32] TNO Comments filed March 14, 2025 at 3 (unnumbered).
[33] ENO Comments filed December 20, 2024 at 4.
[34] *Id*. at 4 and 7.
[35] Home Rule Charter of the City of New Orleans ("HRC"), §3-101.
[36] *See e.g., Louisiana Power & Light Co. v. Louisiana Pub. Serv. Comm'n*, 369 So. 2d 1054, 1061 (La. 1979) (finding that a utility must refund overcharges when a Commission-approved rate is later found unlawful); *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n*, 98-1235 (La. 4/16/99), 730 So. 2d 890, 898 (finding that "[w]hen a [regulator] order adopts an agreement between a utility and the [regulator], this Court cannot unjustifiably disregard the parties' intentions or the plain language of the agreement to uphold the [regulator's] interpretation of the order, even though the [regulator's] interpretation of its own orders generally deserves great weight.").

utility must refund the excess (with interest) to the customers who paid it. This framework establishes that Louisiana regulators are responsible for ensuring that overcharges or improper collections are returned to the ratepayers rather than retained by the utility or diverted elsewhere.

The Advisors believe that technical legal issues and litigation posturing is not a productive path to deciding whether the SERI Credits can or should be used to fund either the Direct Proposals. An important consideration, both legal and practical, is the long-standing practice of the Council to presuppose that refunds like the SERI Credits should directly benefit the ratepayers by keeping rates and bills as low as possible, especially in times when everything seems to coincide to increase both. For decades the Council has very effectively managed refunds to mitigate, offset, and avoid tens of millions of dollars in rate and bill increases. The availability of hard-fought, or, at times, serendipitous refunds have allowed the Council to deal with natural disasters, storm hardening, needed grid upgrades, rising fuel costs, and even a pandemic without the staggering rate and bill impacts that would have otherwise occurred. Any deviation from this long-standing practice would require careful consideration and a clear demonstration of customer benefits not supported in this record. Refunds are a tool too critical to all customers to lose without demonstrated, compelling reasons.

While the Advisors are not "agnostic" about the use of the SERI Credits, we agree with TNO that "[t]here's no reason why we can't be simultaneously working to refine the plan and figure out its funding source." Therefore, the Advisors recommend that the SERI Credits be returned directly to ratepayers in the manner proven over decades to provide the maximum benefits to ratepayers. The Advisors also believe, however, that a measured DER program, which would fulfill the Council's goals for this docket, could proceed in accordance with the analysis and recommendations herein.

V. PARTIES'S PROPOSALS

With the exception of ENO, parties submitted their proposals in December 2024. ENO's proposal was submitted in March 2024 as part of its comments on the proposals submitted in December 2024.

a. The Alliance for Affordable Energy

AAE's comments were primarily limited to supporting the use of SERI credits for DER's. In its comments, AAE did not provide a proposal for changes to existing policies or programs or offer a new program to increase the availability of DERs. AAE did indicate that it looks forward to working with the other parties to this docket to finalize a program design.[37]

b. Solar United Neighbors

SUN states that it is a national nonprofit organization formed in 2007 and that it works in all 50 states, Washington, D.C., and Puerto Rico, to advance the interests of solar customers and other supporters by advocating for policies and programs that grow the solar market and support a clean, resilient, and equitable energy system.[38]

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[37] AAE Comments filed December 20, 2024 at 3 (unnumbered).
[38] SUN Comments filed December 20, 2024 at 1.

SUN indicated that it has developed a model Distributed Power Plant ("DPP") program for distribution utilities and provided its model tariff as an attachment to its comments to provide an example of a program that could be implemented in New Orleans. SUN highlights that the key principles of its DPP program include open access, energy equity, fair compensation, affordability and cost savings, facilitating electrification, and rapid development and scaling. SUN recognizes that the details necessary to implement a specific DPP tariff related to ENO and its customers will require further development through technical workshops.

SUN supports the use of the SERI Credits to incentivize participation in a DPP program and suggests that its model tariff could be implemented after successful deployment of a pilot program[39] funded through SERI Credits.

c. Resilience New Orleans

RNO states that it is a Louisiana-based nonprofit with a mission to advocate for sensible energy and electric policies to best ensure New Orleans remains a vital place to live and work. RNO seeks to ensure that New Orleans's has a resilient, reliable and clean power grid and that electricity is affordable to all customers.[40]

RNO references the success of ENO's Energy Smart Program and proposes that ENO's battery pilot program included within Energy Smart be expanded to incentivize purchases of battery systems to help more homeowners, and possibly business customers. RNO cautions that while allowing businesses to participate could help achieve carbon goals more quickly, commercial customers should not be allowed to deplete or expand the budget.

RNO states that the abuse of SERI Credits is a top concern and it does not support the use of SERI Credits for third party developers or nonprofits. RNO states that the Louisiana state solar tax credit was abused by third party solar developers and funds for a customer program should largely benefit customers. As an alternative to using customer funds, RNO proposes implementing a carbon offset program that would be marketed to eco-friendly tourists, festivals, conventions, hotels, and businesses. RNO states that if just 5% of New Orleans' 18 million annual visitors offset 1,000 lbs. of their carbon emissions at a cost of $4.99/1,000 lbs, it would raise $4,491,000 annually for the city's renewable energy goals.

Lastly, in its comments, RNO puts forth its support of facilitating electrification through Energy Smart and offering a time-of-use ("TOU") pricing tariff.

d. ProRate Energy

ProRate Energy states that it is a national nonprofit organization incorporated in Louisiana in 2020. ProRate Energy proposes using up to $1 million per year to conduct an international, expert-led analysis to develop a strategic, ongoing grid transition plan which will provide a roadmap to implement a decentralized, equitable, efficient, reliable, and resilient grid.[41]

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[39] Council Resolution No. R-15-599 and R-16-106 list the criteria for Council to approve a pilot program.
[40] RNO Comments filed December 20, 2024 at 1 (unnumbered).
[41] ProRate Energy Proposal filed December 20, 2024 at 5.

With respect to SERI Credits, Prorate Energy indicates that since SERI Credits came indistinguishably from all New Orleans ratepayers, similar settlement precedents dictate that such funds must support programs to distribute benefits in an effective and equitable process as possible to all ratepayers.

e. Recurve Analytics, Inc

Recurve states that it is an industry leader in providing software solutions to utilities and vendors to enable and enhance the short and long-term demand flexibility derived from distributed energy resources.[42]

Recurve proposed software solutions to manage load growth, enhance system resilience, and provide demand flexibility to utilities and vendors. Recurve states that its platform assists utilities and vendors in pinpointing the best locations to deploy distributed energy resources, monitors their performance, and facilitates market settlements between utilities and vendors based on the value provided.

f. PosiGen

PosiGen is a Louisiana-based solar, storage, and energy efficiency provider with a mission to provide "Solar for All." [43] PosiGen supports the proposal to use the SERI Credits to support the establishment of an energy storage program.[44]

PosiGen did not provide a specific proposal but recommended and elaborated on elements of program design for energy storage program. PosiGen recommend a program design with the following key elements:

- "Use of an upfront incentive that is calculated on either a $/kWh or $/kW basis.
- Enroll participating systems to provide demand reduction during events over at least a 3-year period.
- The program should be Original Equipment Manufacturer ("OEM") & installer-neutral to allow for a diversity of participation pathways, business models, and battery types.
- Set a low-income or equity-based participation target, track progress towards that target, and consider program changes to overcome barriers where they arise.
- Consideration of a low-income adder or how the program can work with other funding sources to increase low-income participation.
- Set clear and reasonable program terms regarding dispatch seasons, number of events, event timing, event duration, severe weather protections for consumers, and practical system and fleet performance measurement.
- Use of the SERI Settlement funding to start the energy storage program."[45]

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[42] Recurve Comments filed December 20, 2024 at 1.
[43] PosiGen Comments filed December 20, 2024 at 2.
[44] *Id.* at 6.
[45] *Id.* at 6.

PosiGen indicated that it looked forward to reviewing the proposals from other parties and ultimately working towards an innovative and cost-effective program design that will reduce electricity costs for all ratepayers.[46]

g. Together New Orleans and The Alliance for Affordable Energy

TNO/AAE refer to its proposal as the Distributed Energy Resource Program ("DERP"). In its proposal TNO proposes to implement an upfront incentive program to accelerate the installation of behind-the-meter residential and small commercial/institutional battery energy storage systems through allocating $32 million in SERI Credits to provide site-specific upfront incentives for solar-paired battery energy storage systems. DERP proposes building upon ENO's current BESS pilot by requiring enrollment in BESS program or its successor for a period of 3 years.

According to TNO/AAE: DERP "…aims to create a network of dispatchable, distributed battery storage systems to enhance grid reliability and foster resilience partnerships with local businesses, community organizations, and residents. These investments will strengthen resilience projects across the city…"[47] In addition to residential participation, DERP includes participation from the commercial and institutional sectors, including TNO Community Lighthouses. TNO states: "This initiative <u>can demonstrate</u> how such a fleet reduces <u>energy</u> costs while boosting resilience investments, all <u>without</u> <u>dismantling</u> existing programs or <u>implementing new rate increases</u>."[48] (underline added). Further, "TNO/AAE envision a decentralized network of batteries and solar installations that can function both as grid resources and as community resilience hubs. Their proposal is designed to deliver public benefits, including backup power for critical sites, emissions reduction, local economic development, and faster deployment."[49] Also, New Orleans' batteries should offer dual resilience and VPP roles, rewarding installations that deliver both grid capacity and onsite resilience.[50]

TNO/AAE propose to utilize approximately $32 million of the SERI Credits over a three-year period to provide site-specific upfront incentives for commercial/institutional and residential solar-paired battery energy storage systems. TNO/AAE propose to proceed in phases:

- Phase 1A: Use SERI funds to provide upfront customer incentives, driving rapid enrollment in the existing BESS Pilot program.
- Phase 1B: Assess program outcomes and evaluate virtual power plant capabilities to refine future approaches.
- Phase 2: Establish a permanent pay-for-performance retail demand response tariff that fully compensates the diverse benefits provided by distributed energy resources.[51]

Over the three-year, Phase 1 implementation period, TNO/AAE proposes to add a total of approximately 73.5 MWh. On a capacity basis, TNO's proposal would add a total of 51.1 MW of

[46] *Id.* at 18.
[47] TNO/AAE Proposal to Enhance Distributed Energy Resource Programs for New Orleans filed 20 Dec. 2024 at 2. The Proposal also referenced DERP as a "Distributed Energy Resilience Program."
[48] *Id.* at 3.
[49] TNO Reply Comments filed 31 March 2025 at 3.
[50] *Id.* at 6.
[51] TNO/AAE Proposal to Enhance Distributed Energy Resource Programs for New Orleans filed 20 Dec. 2024 at 6.

battery capacity based on the nameplate ratings of the installations. Table 1 presents more detail on TNO/AAE's Proposal.

Table 1 - Summary of TNO_AAE's DER Proposal features	
Issue Description	**Specific Application**
SERI Credits allocated to upfront incentives for new qualifying participants and related program administration costs.	$ 32 million over three years. ($ 29.1 million for upfront incentive costs, plus $2.9 million associated administrative costs related to upfront incentives).
Customers eligible to participate	Residential (LMI and Non-LMI). Commercial and Institutional customers.
Required Duration of Participation Required for Participants receiving upfront incentives.	Three years
Expected number of new participants (battery installations) by year three	2,120 (1,865 Residential and 255 Commercial/Institutional participants.) [Including 746 LMI Participants under Residential]
Cost of Upfront Incentives cumulative at year 3 (cost recovery proposed with SERI credits)	$29.1 million total over three years. (50% of upfront incentive funds for residential and 50% for commercial and institutional).
Proposal administrative costs cumulative by year 3	$3.0 million. $1 million per year for the first three-years with no administrative costs thereafter
Projected Installed MWh of Battery Capacity Enrolled (Cumulative - year 5)	63.8 MWh (TNO/AAE assumes lower participation levels after the initial three-years of upfront incentive payments)
Upfront Incentive rate	$1,000 per kW of deliverable capacity (with a 20% low-income adder incentive); Residential installations capped at $10,000; Commercial installations capped at $300,000)
Ongoing Incentive Rate	$15/kW-yr beginning in year 4
Battery Events	Not specified
Other participant available options/benefits	Ability to choose from several different major BESS manufacturers that are integrated with the DERMS contractor. Upfront incentive assignable by the participant to vendors and contractors (to assist with installed cost)

h. Entergy New Orleans, LLC

ENO's December 2024 comments were primarily focused on the use of the SERI Credits. ENO argued that nothing in the agreement in principle that established the SERI Credits suggests that third parties would receive the SERI Credits instead of customers. Further, ENO indicated that to the extent the Council may be inclined to allow third party entities to use the SERI Credits for their own non-utility programs, that would be inconsistent with the terms of the SERI Settlement and Resolution No. R-24-194, and also may exceed the Council's regulatory authority and likely implicates the Council's taxing authority and constitutes the taking of private property.

While ENO was designated as a party in the proceeding, ENO did not put forth a proposal in its December 2024 comments. Rather ENO, in its comments requested that the Council expand Resolution R-24-624 to consider utility-run programs and afford ENO the opportunity to present its own proposal. Subsequently, in its March 2025 comments, ENO submitted a proposal.

In ENO's March 2025 proposal, ENO proposes to significantly expand the existing Energy Smart VPP by using a portion of the existing SERI Credits. ENO describes the existing Energy Smart VPP as an aggregation of controllable demand response resources including smart thermostats and the BESS Pilot.[52] ENO describes its proposal as "… an effective program that supports local, distributed resilience and demand response."[53] ENO proposes to utilize approximately $9.2 million of the SERI Credits over a five-year period to provide upfront incentives to primarily target the retrofit of existing residential solar systems by encouraging the addition of a battery energy storage system.[54] ENO notes that there are approximately 10,000 net metered solar systems already installed throughout New Orleans. Recognizing that approximately 15% of all 2024 solar interconnection applications in New Orleans have included batteries, ENO also proposes to offer upfront incentives to support the inclusion of BESS on new residential solar installations. Over the five-year implementation period, ENO proposes to add approximately 11.5 MWh of battery capacity per year to the Energy Smart VPP, for a total of approximately 57.4 MWh. On a capacity basis, ENO's proposal would add a total of 28.7 MW of battery capacity.[55] Table 2 presents more detail on ENO's Proposal.

[52] Response to CNO-ENO 1-9.
[53] ENO Comments filed 14 March 2025 at 2.
[54] ENO Comments filed 14 March 2025, Exhibit 1. The $9.2 million does not include five years of ongoing/annual incentives.
[55] ENO Comments filed 14 March 2025, Exhibit1 at 2.

Table 2 - Summary of ENO's DER Proposal features	
Issue Description	**Specific Application**
SERI Credits allocated to upfront incentives for new qualifying participants, separate from ongoing annual incentives.	$10 million over five years. ($9.2 million for upfront incentive costs, plus associated administrative costs related to upfront incentives). Ongoing costs are separate.
Customers eligible to participate	Residential LMI and Non-LMI for retrofits or new installations. Commercial customers are limited to existing BESS Pilot.
Required Duration of Participation Required for Participants receiving upfront incentives.	Ten years. (includes a clawback provision if incentives are received, but the participant does not participate in program events)
Expected number of new participants (battery installations) by year five	4,250, which includes 1,000 LMI participants. (Projecting 850 new participants each year for 5 years.
Cost of Upfront Incentives cumulative at year 5 (cost recovery -SERI credits)	$9.2 million ($1.84 million annually over five years)
Proposal administrative costs cumulative by year 5	ENO provided a contractor's estimate. However, the total ENO administrative costs were not specified.
Projected Installed MWh of Battery Capacity Enrolled (Cumulative - year 5)	57.4 MWh (not including 2.1 MWh from existing BESS participants)
Upfront Incentive rate by participant type	Retrofit (LMI) $400 per kWh Retrofit (Non-LMI) $150 per kWh New Installation (LMI) $175 per kWh New Installation (Non-LMI) $75 per kWh – (Residential - all capped at 13.5 kWh; caps ranging from $1,000 to $5,400)
Ongoing Incentive Rate	Maximum of $600/yr per Participant
Battery Events (approx. 2 hr duration each)	Up to 60 events per year
Other participant available options/benefits	Ability to choose from several different major BESS manufacturers that are integrated with the DERMS contractor. Upfront incentive assignable by the participant to vendors and contractors (to assist with installed cost)

VI. DOCKET PROCEEDINGS

After the submission of the initial proposals, the parties participated in two technical conferences. The first on February 4, 2025, where each party was allowed equal time to present a summary of its proposal and provide their position on whether SERI Credits can and should be used to support proposals. The second technical conference was conducted on April 29, 2025. In the second technical conference, the agenda included: cost-benefit analyses, customer bill impacts, participant customer costs, regulatory framework, grid impact and associated costs, incentive levels and participation, and program commitment and event levels. Notably, during the second technical conference, it became evident that none of the parties had completed a cost-benefit analysis or an assessment of customer bill impact related to their proposals.

Between the first and second technical conferences the parties filed comments on the proposals on March 14, 2025, and reply comments on March 31, 2025.[56] To further understand the proposals, the Advisors issued discovery on each party that filed a proposal in the docket. The only other party to issue discovery was ENO, and it directed discovery solely to TNO/AAE.

On May 8, 2025, as a supplemental response to CNO-TNO/AAE 1-2, TNO/AAE submitted a benefit-cost analysis of its DERP proposal ("TNO/AAE Cost Effectiveness Workpapers"). Further, on June 2, 2025, TNO/AAE submitted a supplementary response to discovery titled "Impacts of the Distributed Energy Resources Program on Customer Rates and Customer Bills Resources Program in New Orleans."

On May 30, 2025, ENO submitted a cost-benefit analysis of its proposal and the proposal submitted by TNO/AAE ("ENO Cost Effectiveness Workpapers") and an "Independent Evaluator Review of Together New Orleans' May 8, 2025 Memorandum (Docket UD-24-02)." The Advisors issued discovery to both ENO and TNO/AAE on the submitted cost effectiveness workpapers.

VII. Direct Proposals (TNO/AAE Proposal and ENO Proposal)

Prior to discussing the Direct Proposals, the Advisors note that our review of the TNO/AAE Cost Effectiveness Workpapers showed upfront incentives totaling $30.4 million in contrast with TNO/AAE's stated assumption of $29 million in upfront incentives. The Advisors found and corrected apparent errors in the TNO/AAE model. Correcting the observed errors resulted in upfront incentives totaling approximately $29 million and a corresponding downward revision of the BESS storage capacity. To the extent any calculations in the TNO/AAE Cost Effectiveness Workpapers relied on the BESS storage capacity those calculations may be different as well in the corrected version of the model. The use of the word corrected should not be construed to mean that, after corrections, the Advisors are in agreement with the calculations in the TNO/AAE Cost Effectiveness Workpapers. In this report we rely on the information derived from the TNO/AAE Cost Effectiveness Workpapers, as corrected, and the ENO Cost Effectiveness Workpapers. Accordingly, the numbers presented herein may differ from what was presented by parties in their filings and responses to discovery.

a. Incentives and Participation Levels

TNO/AEE's DERP proposal has a three-year fixed $29 million upfront incentive budget. According to TNO the incentive structure is based on assumptions grounded in deployment data particularly from the Community Lighthouse project in New Orleans,[57] and is split evenly between residential and community sectors. Over the three years, the budget for upfront incentives ramps up to $14.5 million in year-three(3) for residential participants with an equal amount for commercial/institutional participants, where TNO/AEE estimates an average upfront incentive per site of $8,640 for residential and $55,529 for commercial sites.[58] TNO/AAE's proposed upfront

[56] On March 14, 2025, comments were filed by: PosiGen, AAE, RNO, Recurve, GSREIA, Enphase, ENO, TNO, SUN, and the Office of Resiliency and Sustainability. On March 31, 2025, reply comments were filed by: PosiGen, Enphase, ENO, TNO/AAE, and SUN.

[57] Response to CNO-TNO/AAE 1-1(d) at 5.

[58] Response to CNO-TNO/AAE 1-1(d) at 6. The Advisors note that in the assumptions in TNO/AAE Cost Effectiveness Workpapers assume an average upfront incentive per site $7,575. The Advisors further note that a

incentive of $1,000 per kilowatt (kW) of deliverable capacity[59] applies to all participants, and is based on Community Lighthouse deployment data.[60] TNO/AEE's proposal targets a three-year total of DER sites projected at 1,678 residential and 268 community/commercial for a total of 1,946 sites.[61] Residential and commercial site counts are based on average system sizes and the number of sites that can be supported within the annual upfront incentive budget. TNO/AAE's projected participation levels are based on the availability of SERI Credits, stating: "If SERI credits are redirected, the DERP Proposal would require major revision: reduced participation, diminished equity impacts, and a shift toward a slower and smaller rollout."[62] TNO further indicates that it does not recommend proceeding with the DERP Proposal if SERI Credits or similarly rate neutral funding is unavailable, and it does not recommend substituting it with a $32 million ratepayer-funded program.[63]

ENO's DER proposal was based on the decision to propose using approximately $10 million of SERI Credits to fund upfront incentives to residential participants for a period of five years, along with maintaining the current BESS Pilot Program of annual ongoing incentives for all participants. Citing approximately 10,000 customers (5% of ENO's customer base) already participating in net metering, ENO focused incentives and participation on the retrofit of existing residential solar, with retrofits expected to receive approximately 70% of the upfront incentive funding and LMI customers receiving approximately 40%. For these retrofits, ENO proposes upfront incentive levels of $400/kWh for LMI residential and $150/kWh for non-LMI residential participants. ENO contends that these upfront incentive levels are based upon the installed kWh duration of a battery. A BESS installation at an existing solar system for a qualifying LMI residential customer who installs a 13.5 kWh BESS would receive an upfront incentive in the amount of $5,400 (13.5 installed kWh x $400/kWh = $5,400).[64] The upfront incentives for new residential solar systems would be $175/kWh for LMI residential customers and $75/kWh for non-LMI residential customers. ENO stated that the proposed incentive levels were based on consultations with the current BESS implementer's national experience, reviews of incentive levels from other utility-led programs, and took into consideration pairing ENO's proposed incentives with the available 30% federal tax credit through the IRA/ITC.[65] At these upfront incentive levels, ENO projects 4,250 new DER participants over the next five years, including 2,500 retrofits.[66] ENO expects these incentive levels to generate their projected program uptake and participation among ENO

calculation based on the number of sites and the incentive costs results in an average upfront incentive per site of $7,013 for non-LMI residential, $8,416 for LMI residential and $58,174 for commercial sites.

[59] A DER's deliverable capacity is defined as the larger of 80% of usable battery storage over a two-hour event, or the battery inverter's output.

[60] No specific calculation was provided for the derivation of the $1,000/kW upfront incentive, except to state that the upfront incentive was intended to cover at least ~40% of the hardware cost of the battery (TNO/AAE 20 December 2024 DERP proposal, p. 23). TNO/AEE stated that cost estimates were sourced from NREL benchmarks, EnergySage marketplace pricing and vendor quotes from Community Lighthouse installations. See response to CNO-TNO/AAE 1-8.

[61] Response to CNO-TNO/AAE 1-1(d). A 20% higher demand was also projected for participation levels, and TNO/AAE's cost-effectiveness model submitted June 6, 2025 listed 1,865 residential and 255 community/commercial for a total of 2,120 sites.

[62] Response to CNO-TNO/AAE 1-6(b).

[63] Response to CNO-TNO/AAE 1-6(a).

[64] ENO Comments filed March 14, 2025 at 4.

[65] Response to CNO-ENO 1-7.

[66] ENO Comments filed March 14, 2025, Exhibit 1 at 1. "By the end of the five-year period, under ENO's proposal, approximately 25% of these existing [*10,000*] customers could add batteries to their existing residential solar systems."

customers and local solar and battery contractors.[67] ENO's proposal references a single Tesla Powerwall as the basis for the cap of 13.5 kWh per customer, based on the majority of residential NEM participants in the BESS Pilot having systems sized at or below 13.5 kWh, and making available a meaningful number of incentives.[68]

Not including the current BESS Pilot participant numbers, ENO projected an additional 850 participants annually for five (5) years at an ongoing annual incentive of $600 per participant, for an additional projected $7.65 million for the first five program years and projected that the annual incentive of $600 per participant would continue after program year 5 with no additional upfront incentives. For new DER participants, the projected incentive budget, including upfront and ongoing incentives, is approximately $16.85 million over the first five years.[69] ENO indicated: "If SERI credits were not available to fund ENO's program as proposed, ENO would consider alternative approaches such as funding upfront incentives through Energy Smart as part of Phase 3 of the current battery DR pilot program. In that case, ENO would consider modifications to its proposal such as number of years involved (i.e., three years instead of five to align with the term of the Energy Smart implementation plan) or amounts of incentives to be paid annually since these amounts would be collected from customers, presumably through the EECR rider."[70]

Table 3 compares the incentive levels for the Direct Proposals on a participant basis.

Table 3 - Direct Proposals Incentive Comparison per Participant[1]	
ENO Proposal	
Average Upfront Incentive/Participant	
BESS Retrofit Residential (LMI)	$5,400
BESS Retrofit Residential	$2,025
BESS New Installation Residential (LMI)	$2,363
BESS New Installation Residential	$1,013
Ongoing Annual Incentive Payments/ Participant[2]	
Residential	$600
TNO/AAE Proposal	
Average Upfront Incentive/Participant	
Residential Non-LMI	$7,013
Residential LMI	$8,416
Commercial	$58,174
Ongoing Annual Incentive Payments/ Participant[2]	
Residential	$105
Commercial	$873
Notes: 1)The numbers in this table were derived from the ENO Cost Effectiveness Workpapers and the TNO AAE Cost Effectiveness Workpapers as modified by the Advisors correction noted above.	

[67] Response to CNO-ENO 1-7.
[68] Response to CNO-ENO 1-8.
[69] ENO Cost Effectiveness Workpapers.
[70] Response to CNO-ENO 1-6.

2) The ENO ongoing incentive payments begin in year one of the proposal. The TNO/AAE incentive payments are in the form of a pay-for-performance tariff and begin in the fourth year of the DERP.

Table 3 shows the dramatic difference in the parties' positions on both upfront and ongoing incentives. Focusing on non-LMI residential customers, TNO/AAE's average upfront incentive per participant of $7,013 is nearly 3.5 times higher than that of ENO's $2,025 upfront incentive per participant in the residential retrofit category.

TNO/AAE comments that ENO's proposed upfront incentive is much lower than the incentives provided by other successful programs, and as such will not do enough to stimulate participation.[71] PosiGen comments that it believes ENO's incentive levels likely do not reflect the value that they would provide over 10 years of performing the program, particularly for non-LMI participants. For example, a non-LMI retrofit of a Tesla Powerwall would only receive $2,025 for 10 years of sustained and dispatchable demand reduction.[72] The Advisors note that PosiGen in its calculation of $2,025 for 10 years of sustained and dispatchable demand reduction fails to recognize that the participant, if called upon for demand reduction, would also receive up to $6,000 in ongoing incentive payments for a total of $8,025 for the ten-year period. For comparison purposes, the TNO/AAE proposal for a single Powerwall would receive $7,000 in upfront incentives and an additional $735 in pay for performance payments for a total of $7,735 for the ten-year period if that participant participated beyond the required three-year mandatory period required in the TNO/AAE proposal. This calculation demonstrates that the Direct Proposals are not that different in total incentives paid to a residential participant for a ten-year period based on the information provided in the TNO/AAE Cost Effectiveness Workpapers and ENO Cost Effectiveness Workpapers.

ENO argues that the TNO/AAE upfront incentive is too high and is not necessary to spur program adoption, does not serve the public interest, and creates an excessive benefit for the few ENO customers that would be able to participate each year and for the battery manufacturers and installers[73]. Enphase observed that the TNO/AAE upfront incentives would be among the strongest behind-the-meter battery incentives in the country and believes that the TNO/AAE level of upfront incentive would enable robust uptake among harder-to-reach customer segments.[74]

The TNO/AAE program offers upfront incentives for three years with no recurring/ongoing incentives for the first three-years, and a pay-for-performance incentive after the first three years with no mandatory participation after three years. The ENO program offers upfront incentives for five years and ongoing recurring incentives for the mandatory ten-year participation period. ENO's annual residential ongoing incentive is set at a maximum of $600 per participant per year. The residential ongoing incentive in TNO/AAE Cost Effectiveness Workpapers mirrors a pay-for-performance incentive of Rocky Mountain Power's Wattsmart VPP program and equates to roughly $105 per participant per year. TNO/AAE acknowledges that this is a placeholder value,

[71] TNO/AAE Comments filed March 31, 2025 at 5.
[72] PosiGen Comments filed March 31, 2025 at 9.
[73] ENO Comments filed March 31, 2025 at 4.
[74] Enphase Comments filed March 14, 2025 at 3.

and the actual value will be determined by value and performance analysis proposed in DERP Phase 1.

The Advisors are concerned about the vastly different ongoing incentives between the TNO/AAE proposal and the ENO proposal, especially since the TNO/AAE ongoing incentive is much lower than the ENO incentive and participation is not mandatory after three years. The Advisors note that to increase participation, ENO raised its incentive level from an ongoing participation incentive of $250 in BESS Pilot Phase 1 to an annually administered dollar cap for residential customers of $600 and $1,800 for commercial customers in Phase 2.[75] The $600 annual residential maximum in the ENO proposal is the same value employed in the BESS pilot. Without appropriate incentive levels, the participation and storage capacity under the TNO/AAE proposal could be dramatically reduced after the first 3-5 years of the program. Absent seeing the results for the most recent year of the current BESS pilot, the Advisors cannot conclude that the ENO proposed ongoing incentive level is the appropriate level.

A comparison of the incentive levels and corresponding participation levels between the TNO/AAE proposal and the ENO proposal highlights the differences between the parties' positions on the appropriate level and timing of incentives to entice participation. To easily compare the two incentive levels the Advisors evaluated the cost effectiveness workpapers provided by the parties to summarize the incentive levels on a comparable basis. Table 4 below presents a comparison of the incentive levels and participation extracted from the party's provided cost effectiveness workpapers. [76]

[75] BESS Pilot Phase 1 provided an ongoing participation incentive of $250, but it was noted that "incentive levels may be adjusted depending on the market reaction." (Phase 1 contractor- February 2, 2022). ENO's Report regarding BESS Pilot Phase 1 (December 1, 2023) noted challenges in getting battery manufacturers to participate - the implementers were only able to enroll 17 of the targeted 30 participants. By the end of Phase 1, there seemed to be less reluctance by OEMs to participate provided there is an adequate pay-for performance incentive for customers to participate. BESS Phase 2 participants were given increased ongoing annual pay-for-performance incentives with an annually administered dollar cap for residential customers of $600 and $1,800 for commercial customers.

[76] The Advisors noted that the TNO/AAE cost benefit analyses model showed upfront incentives totaling $30.4 million in contrast with TNO/AAE's stated assumption of $29 million in upfront incentives. The Advisors found and corrected apparent errors in the TNO/AAE model. Correcting the observed errors resulted in upfront incentives totaling approximately $29 million and a corresponding downward revision of the installed storage capacity. Additionally, the Advisors corrections resulted in revised cost benefit numbers when utilizing TNO/AAE's model to calculate benefits vs. costs.

Table 4 - Program Incentive and Participation Level Comparison						
	Cumulative 3-Years		Cumulative 5- Years		Cumulative 10- Years	
	TNO/AAE	ENO	TNO/AAE	ENO	TNO/AAE	ENO
Upfront Incentives Cost	$28,960,818	$5,518,125	$28,960,818	$9,196,875	$28,960,818	$9,196,875
Ongoing Incentive Cost	$0	$3,060,000	$759,970	$7,650,000	$2,769,807	$20,400,000
Total Incentives	$28,960,818	$8,578,125	$29,720,788	$16,846,875	$31,730,626	$29,596,875
Participants Useable Storage Capacity (kWh)	69,786	34,425	63,854	57,375	69,088	57,375
Residential Participants	1,865	2,550	1,706	4,250	1,846	4,250
Commercial Participants	255	-	233	-	252	-
Total Participants	2,120	2,550	1,940	4,250	2,099	4,250
Upfront Incentives per kWh of Capacity	$415	$160	$454	$160	$419	$160
Ongoing Incentives per kWh of Capacity	$0	$89	$12	$133	$40	$356
Total Incentives per kWh of Capacity	$415	$249	$465	$294	$459	$516

Table 4 presents three snapshots in time: after the TNO DERP buildout in three-years, after the ENO build out in 5-years, and after both proposals are in operation for ten-years. From a review of Table 4, it becomes evident that the proposed incentive cost in either the TNO/AAE DERP proposal or the ENO proposal after ten-years is roughly $30 million. The difference in the proposals is the level and timing of incentive payments.

Under the TNO/AAE DERP proposal the installed, useable capacity peaks in year 3 at 69,786 kWh; the ENO Proposal peaks in year 5 at 57,375 kWh. Thus, it appears that the TNO/AEE proposal results in 22% more useable energy, however the Advisors caution that if the TNO/AEE DERP proposal is implemented with an ongoing incentive level that is too low, the program could lose significant participation and the associated capacity after the mandatory three-year participation period. Alternatively, if the TNO/AEE DERP proposal is implemented with a higher ongoing incentive level, the program will result in higher costs than those presented and likely a reduced level of cost effectiveness.

PosiGen supports ENO's proposed commitment of ten-years, in part, because it considers what is closer to the lifespan of the resource.[77] When asked in discovery about the three-year minimum commitment for participants in the DERP, TNO/AAE responded that while most battery systems have a 10–15 year useful life, the three-year term strikes a balance between ensuring operational value for the grid during the early rollout period, and minimizing barriers to participation for low-income households, renters, or small businesses with uncertain site tenure.[78]

The Advisors believe more collaborative work among the parties in this area of upfront incentives, ongoing incentives, and mandatory participation timeframe would be appropriate prior to the establishment of a potential DER expansion pilot program.

b. Benefits vs. Costs

Although no benefits-costs-analyses ("BCA") were provided initially with the parties' proposals, and confirmed subsequently through responses to CNO's first set of discovery to all parties, at the second technical conference, TNO/AEE stated that their BCA was completed and would be filed within a week, and ENO said their BCA would be filed within the next several weeks. On May 8, 2025, as a supplemental response to CNO-TNO/AAE 1-2, TNO/AAE submitted a BCA of its DERP proposal. On May 30, 2025, ENO submitted a BCA of its proposal and the proposal submitted by TNO/AAE. Subsequently, TNO/AAE and ENO provided support for their BCAs in the form of MS Excel workpapers that the Advisors refer to as the TNO/AAE Cost Effectiveness Workpapers and ENO Cost Effectiveness Workpapers.

Cost effectiveness results are typically presented in the form of a benefit-cost ratio ("BCR"). A BCR greater than 1.0 suggests that the expected benefits outweigh the expected costs. Based on a ten-year program evaluation period, TNO/AAE presented the following cost effectiveness results:

Table 5 – Results of TNO/AAE Benefit-Cost Analyses

	TNO/AAE Proposal
Utility Cost Test (UCT)	1.37
Participant Cost Test (PCT)	6.25
Total Resource Cost Test (TRC)	3.96
TRC (excluding VOLL[79])	2.53
Societal Cost Test (SCT)	2.01

[77] PosiGen Comments filed March 31, 2025 at 8.
[78] Response to CNO- TNO/AAE 1-17.
[79] VOLL refers to Value of Lost Load.

TNO/AAE indicated that across all four tests, the benefit-cost ratios indicate strong economic viability.[80]

In its May 30, 2025 filing, ENO presented the results of its BCA for both the ENO proposal and the TNO/AAE proposal. ENO evaluated its proposal over 14 years to accommodate its proposed five-year build out and minimum ten-year participation requirement. Consistent with the information provided by TNO/AAE, ENO evaluated the TNO/AAE proposal over a ten-year period. ENO indicated:

> "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."

ENO's evaluation of both the TNO/AAE proposal and its own proposal presented the following cost effectiveness results:

Table 6 – Results of ENO Benefit-Cost Analyses		
	ENO Proposal	**TNO/AAE Proposal**
Utility Cost Test (UCT)	0.53	0.41
Ratepayer Impact Measure (RIM)	0.50	0.39

ENO indicated that its analysis demonstrates that neither proposal passes the RIM or UCT 1.0 threshold.

Since ENO and TNO/AAE each provided results for the UCT, the Advisors will focus our discussion on the UCT for comparison purposes. The UCT includes the benefits and costs experienced by the utility. Sometimes the UCT is also called the Program Administrator Cost Test (PACT).

<u>Program Costs Considered in the UCT</u>

With respect to the UTC in the area of costs, both TNO/AAE and ENO included categories for upfront incentives, ongoing incentives, and administrative costs. While the incentive costs represent the majority (approximately 90%) of Program Costs under the ENO and TNO/AAE

[80] Supplemental Response to CNO-TNO/AAE 1-2 filed May 8, 2025 at 3.

proposals, the administrative costs in each proposal are less straight forward, vastly different between the two proposals, and appear to not encompass to the totality of administrative costs associated with the proposals. TNO/AAE included an estimate of the administrative costs totaling $1.0 million annually for the first three years, and nothing for administrative costs for the next phase of their DERP after year 3. In response to discovery, TNO/AAE indicated that "TNO/AAE's Benefit-Cost Analysis does not anticipate significant new administrative costs for Phase 2 (Years 4–10) of the DER Program because, from an operational standpoint, this phase is largely continuation of ENO's existing battery storage pilot."[81] TNO/AAE further acknowledged that scaling up participation in the pay-for-performance phase may entail modest marginal administrative costs and provided a planning-level estimate for Phase 2 administrative costs of approximately $300,000 annually.[82] ENO appears to have included only the administrative costs associated with its DERMS provider. The Advisors could not resolve through discovery ENO's estimate of total costs to administer the programs. While changes in the assumptions regarding administrative costs are not likely to drive a significant change in the calculated BCRs, the Advisors believe the Council would benefit from the parties working together to develop a complete and more refined estimate of the administrative costs associated with the proposals.

A larger concern of the Advisors is that both proposals rely on a rapid expansion of DERs in New Orleans yet neither of the CBAs included an estimated cost associated with distribution network upgrades that might be required to accommodate the rapid expansion of DERs. Regarding the costs of upgrades to ENO's distribution system that may be required to accommodate DERS under the DERP Proposal, TNO/AEE responded that (i) ENO has not indicated that its current Energy Smart BESS demand response pilot requires any upgrades to the distribution system, and (ii) no public documentation from ENO suggests that scaling the current program to the 2,000 system levels contemplated in Phase 1 of DERP would inherently require physical grid upgrades.[83] We are unaware of any request from TNO/AEE to ENO for an initial or preliminary evaluation of the DERP proposal in terms of grid impacts, including 268 community/commercial sites not in the existing BESS Pilot.

TNO/AEE objected to the Advisors' interrogatory (CNO-TNO/AAE 1-3) requesting an estimate of distribution system upgrades required to TNO/AAE's DERP proposal to the extent it assumes that the burden lies with non-utility parties to quantify distribution upgrade needs or costs resulting from DER adoption; rather contending that it is ENO—not stakeholders or customers—who is in the position to disclose whether and under what conditions it anticipates system upgrade costs in response to DER deployment.[84] DER penetration is monitored by ENO on a feeder basis, as is industry practice, and DR penetration in excess of a given percent of feeder peak capacity can cause distribution level issues and is the trigger for ENO's engineering staff to undertake a detailed feasibility study to determine what, if any, impacts additional DERs may have on a given feeder. Based on the available capacity on the feeder in question, as well as the specific location of the new DER, ENO's engineering staff may determine a feasibility study is required and that upgrades to the distribution system may be required as a result of the feasibility study.

[81] Response to CNO-TNO/AAE 2-3b.
[82] *Id.*
[83] Response to CNO-TNO/AAE 1-3.
[84] Response to CNO-TNO/AAE 2-6.

In response to CNO-ENO 1-4, ENO indicated that distribution upgrade costs relating to ENO's proposal have not been estimated. In response to CNO-ENO 1-16, and with respect to the rapid expansion of DERs on the distribution system, ENO indicated that it anticipates changes to the distribution grid would be required, but would require guidance from the Council as to the recommended funding source and/or recovery mechanism for potential distribution upgrade costs triggered due to additional DER penetration incented through an upfront battery incentive program. If upgrades to the distribution grid are likely as a result of implementing either the ENO proposal or TNO/AAE proposal, the Advisors recommend that the Council be made aware of these potential costs and that the estimated costs be included, as appropriate, in any cost effectiveness calculations regarding the Direct Proposals.

<u>Program Benefits Considered in the UCT</u>

A large difference in the parties' calculations of the UCT BCR results from both the categories considered on the benefits side and differences in the assumptions utilized to quantify benefits.

Table 7 – UCT Test Categories of Benefits Considered		
	ENO Benefit-Cost Analyses	**TNO/AAE Benefit-Cost Analyses**
Avoided Capacity Costs	Included	Included
Avoided Energy Costs	Included	Not- Included
Avoided Transmission & Distribution	Not- Included	Included
Avoided Demand Response	Not- Included	Included
Avoided Regional Network Service Charges	Not- Included	Included

While the TNO/AAE BCA fails to quantify Avoided Energy Costs, the TNO/AAE BCA includes three additional categories of benefits that were not included in the ENO BCA. Although the benefit of Avoided Transmission & Distribution costs included in the TNO/AAE BCA was based on national benchmarks, its inclusion as a benefit is generally consistent with best industry practices. With Respect to the Avoided Demand Response benefit and the Avoided Regional Network Service Charges, the Advisors are less certain about their appropriateness for inclusion in TNO/AAE's BCA.[85]

On May 30, 2025, ENO submitted, as an attachment to its 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 is the Third-Party Evaluator ("TPE") for ENO's Energy Smart Programs. In addition to presenting industry best practices for determining benefits when performing cost-effectiveness testing for DR programs, the memorandum commented on the use of the Avoided Demand Response and Avoided Regional Network Service Charges, commenting:

[85] The TNO/AAE proposed Avoided Demand Response benefit appears to quantify the monetary savings from reducing the need for implementing DR programs. The TNO/AAE proposed benefit of Avoided Regional Network Service Charges refers to the ability to defer the need for network transmission upgrades or expansions by implementing non-wire alternatives or other DSM.

"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."[86]

The Advisors note that in the TNO/AAE Cost Effectiveness Workpapers, for the TNO/AAE Proposal the UCT benefit cost ratio was calculated as 1.37 with all claimed benefits. Removing the two benefits of concern, the Avoided Regional Network Service Charges and the Avoided Demand Response from the TNO/AAE workpapers results in a UCT benefit cost ratio of 0.74.

The Advisors also note that a significant difference exists in the calculations of Avoided Capacity Cost Benefits between the TNO/AAE BCA and the ENO BCA. TNO/AAE calculations of Avoided Capacity Cost for the TNO/AAE proposal are significantly higher than ENO's Avoided Capacity Cost calculated for the TNO AAE Proposal. The TNO/AAE BCA relies on a fixed capacity price estimate for the ten-year period, while ENO's BCA utilizes estimates of MISO planning reserve auction ("PRA") through 2032, the year in which a capacity shortfall was indicated in ENO's 2024 integrated resource plan. After 2032, ENO switches to a significantly higher levelized cost of a new combustion turbine. Avoided Capacity Cost benefits are the largest single benefit in the ENO BCA and TNO/AAE BCA, the Advisors believe that the parties should collaborate and determine an accurate and consistent value for evaluating the cost effectiveness of any program proposed to the Council.

Whether any of the parties' DER proposals are considered as a new DSM program, or as a pilot program, cost-effectiveness must be an important part of the evaluation. The Council developed the following criteria to determine whether any particular DSM program should be included in the Energy Smart Program:[87] (1) cost effectiveness of such action (all programs, with the exception of low-income weatherization and domestic solar water hearing programs were required to be determined cost-effective under the Total Resource Cost ("TRC") Test and the Program Administrator Cost ("PAC") Test as defined in the California Standard Practice Manual); (2) the

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[86] Independent Evaluator Review of Together New Orleans' May 8, 2025 Memorandum (Docket UD-24-02), May 30, 2025 at 2.

[87] Council Resolution No. R-09-136, 2009 AIP:46.b; 2009 AIP: 43 "All programs approved by the Council, with the exception of low income weatherization and domestic solar water heating programs, prior to implementation, must be determined to be cost-effective under the industry accepted testing criteria of the Total Resource Cost ("TRC") Test and the Program Administrator Cost ("PAC") Test as defined in the California Standard Practice Manual"

maintenance of customer commercially sensitive or confidential information; (3) feasibility; (4) other criteria that may be identified by Entergy and determined appropriate by the Council.

The Council subsequently re-emphasized the importance of cost-effectiveness tests in implementing energy efficiency and demand response by restricting those programs to those that demonstrated TRC cost-effectiveness ratios greater than 1, except for the low income and other specific programs previously exempted from the cost-effectiveness test by this Council.[88] In Council Resolution No. R-16-106, the Council listed the Advisors' recommendations that proposals for pilot programs should include: 1) what data is to be collected; 2) how it will be collected; 3) draft tariff provisions to implement such a pilot program, and 4) the anticipated costs and rate impact of such a pilot program.

Consistent with Council policy, cost-effectiveness tests have long been an evaluation criterion in dockets considering applications for approval of investments. The requirement of a cost effectiveness analysis with supporting documentation before committing large funds for a project has been an important consideration for the Council.

Consequently, the Advisors are concerned that the cost effectiveness of the proposed programs, as presented in the TNO/AAE BCA and the ENO BCA, may not capture the full cost of the proposed programs impact on the distribution grid and may not capture the complete cost of program administration. Increases to these costs will lower the projected CBRs for the proposals potentially resulting in proposals that do not meet the benefit-cost ratio threshold of 1.0.

Further, the Advisors are concerned that certain benefits included in the BCAs may erroneously lead to the conclusion that a given proposal meets the cost-effectiveness threshold when, in practice, the program will fall short of being cost-effective. The concern lies less in getting an accurate cost effectiveness analysis and more in avoiding additional costs on ratepayers' bills if either the TNO/AAE proposal or ENO proposal is implemented at the scale proposed, if the proposal proves to be not cost effective. The Council is presented with two proposals that will increase the penetration of DERs on ENO's distribution system. Roughly 90 percent of the total cost of either of the Direct Proposals will require approximately $30 million in ratepayer funds to be paid out in either upfront or ongoing incentives over the next ten-years. Given the uncertainties associated with each party's submitted CBA the Advisors recommend that the Council proceed on a smaller scale as a pilot program before proceeding to the levels of investment required by either the TNO/AAE proposal or the ENO proposal.

c. Program Administration, Leveraging of Federal Incentives and Third-Party Ownership, and Vendor Neutrality

The Advisors believe that the parties are closer together on these aspects of the proposals than parties previously believed.

[88] Council Resolution No. R-14-509, directive 5.a.(i).

Program Administration

With Respect to a Program Administration, TNO/AAE propose an Incentive Administrator that would:

> …in Phase 1A of the program, running for three Program Years from some time beginning in 2025-26 through 2027-28, an Incentive Administrator will tranche the available funds into three award cycles and disburse the funds to battery owners (Program Applicants) that have successfully enrolled their batteries in the Phase II (and subsequent phases required) of the Entergy New Orleans Battery Storage Demand Response Pilot Program ("BESS Pilot"). The Administrator's primary role is to ensure a seamless integration of enrolled batteries into the existing BESS Pilot via the existing utility-facing DERMS (Program Implementer, or EnergyHub) and to ensure that the Program Applicant is paid the incentive in a timely fashion upon program enrollment success. On the front end, the Incentive Administrator works with Program Applicants to verify eligibility of the site(s) in question, and on the back end, EnergyHub validates for the Incentive Administrator that the site has successfully enrolled –which qualifies the Program Applicant for its payment. The proposal requires that the Incentive Administrator is responsible for designing and carrying the weight of soliciting, educating, enrolling, and ensuring ongoing compliance of Program Applicants who benefit from the upfront incentive and are obligated under contract to remain enrolled in the Entergy BESS Pilot for the requisite minimum 3-year period."[89]

TNO/AAE further proposed two options for the Incentive Administrator: Option A – Entergy New Orleans and, Option B – a City-Contracted Third Party.[90]

RNO stated its opposition to creating a new Incentive Administrator stating that it believes that "…creating unnecessary bureaucracies that increase costs and reduce efficiency is not the best path", and that it "…will be easier, quicker, and cheaper to leverage Energy Smart, which already has proven infrastructure for program administration and 3rd party contracting." RNO emphasized that the "…City Council has a long history of regulatory oversight over Entergy and will continue to do so."[91]

The Advisors believe employing TNO's Option A with ENO as the Incentive Administrator under any expansion of the DER program is the best way to satisfy the parties and for the Council to maintain its oversight over ratepayer funds that may be required for any DER program approved by the Council. To mitigate any concerns regarding participation enrollment or disbursement of incentives, the Advisors recommend that the Incentive Administrator employ an efficient, objective, and straightforward participation approval process and incentive disbursement process that fosters vendor neutrality through competition and participation while assuring the safety and reliability of the grid. While TNO/AAE's proposal for an Incentive Administrator was identified

[89] TNO/AAE Proposal filed December 20, 2024 at 45.
[90] *Id.*
[91] RNO Comments filed March 14, 2025 at 1.

for the three-year term of upfront incentives, the Advisors note that incentives will have to be administered throughout the duration of the full term of a DER program or VPP tariff that includes ongoing incentives.

Leveraging of Federal Incentives and Third-Party Ownership

In comparing the TNO/AAE Proposal and the ENO Proposal, TNO/AAE claims that the ENO proposal "… results in a higher cost to ratepayers due to lack of federal tax credit monetization (as a regulated utility) and that the ENO Proposal "…does not leverage IRA incentives." Further, TNO/AAE comments that its proposal structure "… allows full use of IRA incentives, significantly reducing the cost burden on ratepayers by 30% to 50%."[92]

With respect to third party ownership of DERs, the TNO/AAE proposal allows for third-party ownership of DERs by allowing the party of record with registered electric utility services provided by ENO to directly apply for the incentive or work with its partnering installer (Energy Service Partner) to apply or assign the incentive.[93]

In comparing the TNO/AAE Proposal and the ENO Proposal, TNO/AAE claims that the ENO proposal employs "[u]tility-owned and controlled batteries. ENO retains operational control and likely earns a regulated return on capital investments, creating shareholder value." TNO/AAE comments that under its proposal it provides for "[c]ommunity or third-party owned assets, potentially using public-private partnerships or Energy Services Agreements (ESAs) and it "[e]mphasizes ratepayer and public benefit, not utility shareholder profit." [94]

However, ENO in its proposal does not propose they own the batteries or prevent third-party ownership of the DERs. Similar to the TNO/AAE proposal the ENO proposal provides for third-party ownership to "help facilitate low-to-moderate income participation and support different financing options, ENO intends to make the upfront incentive assignable by the customer to the vendors and contractors selling and installing the battery systems."[95] The Advisors do not see a distinction between the two proposals with respect to ownership of the DERs. As such, both the TNO/AAE proposal and the ENO proposal should be able to access and utilize any available federal incentives.

Vendor Neutrality

With respect to vendor neutrality the advisors believe that if the Council adopts a DER program, that the program should be OEM and installer-neutral to allow for a diversity of participation pathways, business models, and battery types.

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[92] TNO/AAE Comments filed March 31, 2025 at 3.
[93] TNO/AAE Proposal filed December 20, 2024 at 14.
[94] TNO/AAE Comments filed March 31, 2025 at 3.
[95] ENO Comments filed March 14, 2025, Exhibit 1 at 2.

One of the key objectives listed in the TNO/AAE proposal was the adoption of vendor-neutral and applicant-neutral frameworks to accelerate incentive disbursement and operationalize assets for system-wide benefit.[96]

ENO state in its proposal that "[p]articipants have the ability to choose from several different major BESS manufacturers to qualify for the incentive, including current partners Tesla and Enphase, and additional partners Franklin WH, Solar Edge, and any other residential BESS manufacturers that are integrated with EnergyHub.[97]

Given that each of the programs appear to contain the same access for federal incentives, participation that allows for third-party ownership, support multiple financing options, and propose to utilize a diverse group of BESS manufacturers, the Advisors believe that the differences in the two proposals with respect to program administration, leveraging of federal incentives, and third-party ownership are small. Accordingly, the Advisors believe that the Council could adopt a potential DER program that could satisfy the parties with respect to vendor neutrality.

d. Program Commitment and Event Levels

TNO/AAE's proposal commits participants to three years with acceptance of the upfront incentives. Recognizing the three-year commitment impact on continued participation, the cost-effectiveness analysis of TNO/AAE estimates a ten percent reduction in participation in year 4. ENO's proposal requires that participants commit to ten years of the program with acceptance of the upfront incentives, that commitment being consistent with the expected battery life of the asset being incentivized. ENO expects that there would be no difference in treatment between existing participants in the BESS Pilot and new participants under its proposed program. BESS Pilot participants would be rolled into the new program, and all participants would be bound by the same terms and conditions and incentive levels. Customers who receive incentives and do not participate in DR program events will be subject to claw backs which will be detailed in the terms and conditions for participation. The terms and conditions for participation in the proposed program have not yet been formalized, but claw backs would only occur following some reasonable level of non-performance by the customer.[98]

ENO's Proposal includes that participants should expect up to 60 events per year related to the DER battery, with each event duration being approximately 2 hours. TNO/AAE's Proposal is not specific regarding events that may occur during each annual period.

e. LMI Participation

Both the ENO proposal and TNO/AEE proposal included specific recognition of LMI participation. Each of the proposals incorporate higher upfront incentives for LMI participation, but do not appear to include dedicating an amount of incentive funding specifically for LMI customers.

[96] TNO/AAE Proposal filed December 20, 2024 at 10.
[97] ENO Comments filed March 14, 2025, Exhibit 1 at 2.
[98] Response to CNO-ENO 1-12.

For LMI residential participants, the ENO proposal includes upfront incentive levels of $400/kWh for retrofit installations and $175/kWh for the inclusion of BESS on new residential solar installations. The ENO proposal assumes that LMI customers will receive approximately 40% of the proposed upfront incentive funding.[99] Under the ENO proposal the upfront incentive to LMI participants reaches 1,000 customers.

TNO/AAE's proposal provides a 20% adder to the upfront incentive of $1,000/kW. TNO/AAE's proposal provides for incentive prioritization for sites located in LMI neighborhoods or areas identified with high social vulnerability indexes. TNO/AAE targets 746 LMI sites of the total 1,865 residential sites by Year 3. Based on the TNO/AAE Cost Effectiveness Workpapers, LMI customers will receive approximately 22% of the proposed upfront incentive funding.

To ensure participation by LMI customers, PosiGen recommends we recommend that Council establish explicit LMI participation targets.

f. Bill Impacts

The TNO/AAE proposal does not include a modeled projection of how the program would affect ENO's revenue requirements or customer bills on an annual basis, since it would require access to utility-side cost data, billing models, cost-of-service accounting, and regulatory assumptions that are not publicly available. TNO/AAE states: "By recommending the use of settlement funds to support the program launch, the proposal seeks to "kickstart" DER deployment without new surcharges or collections from ratepayers." [100] TNO/AAE recommends that the Council direct Entergy New Orleans—working with the Council's technical advisors or a retained expert—to conduct modeling of DERP-related impacts on revenue requirements and ratepayer bills, accounting for (i) program administration and delivery costs, (ii) avoided cost and system-value benefits of customer-sited battery participation, and (iii) rate design implications for long-term DER compensation. [101]

Similarly, ENO, as part of its proposal, did not provide information on how the ENO proposal would affect ENO's revenue requirements or customer bills. In response to CNO-ENO 1-2, ENO indicated that the annual impact by year on ENO typical bills has not been calculated. After ENO submitted the ENO Cost Effectiveness workpapers, the Advisors issued further discovery seeking any available calculations of the impact on ratepayers' bills that would result from the implementation of either the TNO/AAE proposal or the ENO proposal. In response to that discovery, ENO indicated that bill impact calculations have not been performed for any proposals submitted in this docket.[102]

On June 2, 2025, TNO/AAE submitted a supplementary response to discovery titled "Impacts of the Distributed Energy Resources Program on Customer Rates and Customer Bills Resources Program in New Orleans." In the supplementary response, TNO/AAE estimates a $0.32 per month bill reduction for non-participating customers. The Advisors note that TNO/AAE's estimate of bill impacts is based on the calculated ten-year benefits from its calculation of the UCT cost

[99] ENO Comments filed 14 March 2025, Exhibit 1 at 3.
[100] Response to CNO-TNO/AEE 1.e, at 7.
[101] *Id.* at 8.
[102] Response to CNO-ENO 2-11.

effectiveness test. Given the advisors concerns regarding the TNO/AAE UCT cost effectiveness calculation and the relatively rudimentary way in which TNO/AAE calculated the bill impact, the Advisors do not consider the TNO/AAE estimate to be robust or sufficient for Council consideration.

The Advisors believe that ENO is likely in the best position to develop calculations regarding the timing and level of expected bill impacts. Prior to the Council implementing an expanded DER Program as proposed herein, or as a pilot program, the Advisors believe that ENO should provide a bill impact calculation that can be reviewed by the parties.

VIII. Other Proposals

a. Development of a Master Plan

Parties' proposals did focus on one component of a DER Master Plan by citing reference to the existing BESS Demand Response Pilot Program, and although several aspects of a substantial increase in the BESS Demand Response Pilot Program were discussed in detail, other components of a DER Master Plan were deferred or not addressed, such as impacts of substantial DER growth on the distribution grid, supporting new tariffs with New Orleans data and the associated regulatory timetable for implementation, developing alternative funding sources, and mitigating near term ratepayer impacts.

ProRate Energy proposes using up to $1 million per year to conduct an international, expert-led analysis to develop a strategic, ongoing grid transition plan which will provide a roadmap to implement a decentralized, equitable, efficient, reliable, and resilient grid. When asked in discovery to compare ProRate Energy's proposal to other proposals offered thus far in the instant docket, ProRate Energy responded: "The point we are making by way of further explanation is that while installation of a few tangible assets can provide value to consumers we suggest that a broader approach that looks at the entire system holistically can accomplish more long term changes by providing for a roadmap to regulatory, structural and operational changes that encourage the purchase of assets by consumers rather than subsidize a few assets."[103]

Although there could be some agreement with the "broader approach" concept espoused by ProRate, undertaking the three-year proposed analysis with a $1 million annual budget to cover expert analysis, stakeholder engagement, and technical assessments does not evoke sufficient confidence to represent a DER master plan relative to the positive attributes of all other parties' proposals for expanding DERs.

In terms of recommending implementation of a specifically defined DER master plan at this time, the Advisors feel that there are several issues that have been raised thus far that would benefit from a longer timeline to evaluate DER growth, with more time needed for the Parties to collaborate, collect and analyze results based on New Orleans data, improve the DER cost-effectiveness, and insure an acceptable impact on ratepayer bills.

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[103] Response to CNO-ProRate 1-1.

b. Time of Use Rates

In the rate case docket, UD-18-07[104], RCPS Docket No. UD19-01,[105] resilience/storm-hardening docket UD-21-03,[106] and in Docket UD-22-04 to consider modifications to DSM and customer-owned DERs, the Council declined to consider time-of-use (time-differentiated) rate structures, rather deferring consideration of such rate structures to a separate docket.

The Advisors' Report in Docket UD-22-04[107] offered the following guidance: "create a long-term timetable, as recommended by the Parties in this docket, for further proceedings to develop proposals (i) for time-differentiated rate designs that could capture the potential for kW savings related to such programs identified in the DSM Potential Studies, and (ii) for programs for customer-sited distributed energy resources and battery storage." Also, in ENO's responsive comments to the parties' proposals in UD-22-04, ENO further requested, with respect to innovative pricing structures regarding ENO's Peak Time Rebate and off-peak electric vehicle DR programs approved for implementation in Energy Smart this year, that ENO be allowed sufficient time to operate to understand customer response, effectiveness, and overall desirability.[108]

In the instant docket, RNO has proposed a voluntary Time-of-Use (TOU) pilot tariff designed to complement DER adoption by providing pricing signals that incentivize battery use, solar exports, and load shifting.[109] Although there have been several previous time-of-use rate structure proposals, the Council has indicated in the aforementioned resolutions that the adoption of time-of-use rates and evaluating what form of time-of-use rates would be most beneficial to New Orleans would be most properly considered in a separate rulemaking docket.

c. Carbon offset program

RNO proposed a "New Orleans Carbon Offset" program as a way to potentially pay for renewable energy goals, including storage.[110] RNO proposes implementing a carbon offset program that would be marketed to eco-friendly tourists, festivals, conventions, hotels, and businesses. RNO

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[104] In Council Resolution No. R-19-457, Building Science Innovators' Community Solar proposals and CLEP proposals with time-differentiated rate structures were rejected.

[105] The Energy Futures New Orleans Coalition proposal to incentivize Beneficial Electrification through time-of-use rates or critical peak pricing (EFNO RCPS Reply Comments July 15, 2019 at 5) was not included in the Council's RCPS.

[106] In Council Resolution No. R-22-411 the Council noted that the CLEP rate design proposed by ProRate appeared to be a form of time-of-use rates stating: "The Council is interested in considering the adoption of time-of-use rates and evaluating what form of time-of-use rates would be most beneficial to New Orleans. However, because time-of-use rates are primarily a demand response measure rather than a storm hardening and storm resiliency measure, the Council finds that time-of-use rate proposals would be most properly considered in the new rulemaking docket the Council is establishing concurrently with the issuance of this Resolution rather than in this proceeding;"

[107] Council opened Docket No. UD-22-04 to consider modification of the Energy Smart energy efficiency and conservation program, demand response, other demand side management ("DSM"), customer-owned distributed energy resources ("DER") and energy storage, as well as potential Council policy impacts with respect to proposed modifications.

[108] The Advisors note that 2024 IRP ENO DSM Potential Study included a dynamic pricing DR program, enabled by AMI, as an opt-in, critical peak pricing offer to all customers, but this pricing program was not proposed for the E.S. three-year implementation plan for PY16-PY18.

[109] Response to CNO-RNO 1-3.

[110] RNO Comments filed December 20, 2024 at 2.

states that if just 5% of New Orleans' 18 million annual visitors offset 1,000 lbs. of their carbon emissions at a cost of $4.99/1,000 lbs. it would raise $4,491,000 annually for the city's renewable energy goals.

In response to Advisors' discovery, CNO-RNO 1-2, RNO provided information several states and cities that have implemented carbon offset programs. Additionally, RNO provided a sample ordinance for establishing a New Orleans carbon offset program. The sample ordinance incorporates the following features: (i) a city-managed carbon offset program to fund climate resilience, energy efficiency, and DER initiatives; (ii) verified carbon credits (carbon offset certificates) could be generated through solar and battery deployment, local environmental projects, including urban reforestation, and energy retrofits – any project that quantifiably reduces carbon emissions; (iii) the verified carbon offsets would offsets may be sold to: corporations seeking voluntary offsets, government entities meeting climate mandates, event organizers, tourists, or local residents via opt-in programs; (iv) proceeds from the sales of verified carbon offsets would support: expansion of Energy Smart programs, local climate adaptation projects, and workforce development in green infrastructure and energy sectors.

While the development of the RNO proposed New Orleans Carbon Offset project likely extends to parties outside the participation in this docket, the Advisors believe that this is a concept that the Council may want to explore as a source of funds.

IX. Conclusions

The Advisors believe that several of the concepts of the parties merit further Council consideration but that no individual proposal is supported or developed enough to approve as written. The two primary proposals targeting the near-term expansion of DERs are the proposals of TNO/AAE and ENO (collectively, "Direct Proposals"). Both Direct Proposals rely on a significant amount of SERI Credits expended upfront. However, as discussed below, the Advisors conclude that SERI Credits are not available for these purposes and that SERI Credits are intended for ongoing ratepayer relief. Therefore, the Direct Proposals lack appropriate funding to proceed. Although ENO's proposal utilizes only about one-third of the approximately $29 million in SERI Credits that TNO/AAE proposes, ENO's proposal should not be viewed as a significantly lower cost proposal for expanding DER's. Based on a review of the cost-effectiveness workpapers provided by the parties, over the next ten-years implementation of either ENO's proposal or TNO/AAE proposal is expected to require approximately $30 million in ratepayer funds to be provided as incentives.

The Direct Proposals both rely on the expansion of ENO's existing BESS pilot battery program, however the Advisors remain concerned about the definite near-term cost of the Direct Proposals compared to the speculative participation levels at any given incentive level, the uncertain impact of a rapid expansion of DERs on ENO's distribution system, and the uncertain future costs and benefits. The Advisors believe that the Council should proceed toward the expansion of DERs, similar to the Council's approach in the resilience docket UD-21-03 that was, in part, the genesis for this docket.[111] In that docket, the Council cautiously evaluated ENO's proposed $1.1 billion resilience plan, ultimately approving a $100 million two-year plan that could provide reliable data to inform future resilience decisions by the Council. Similarly, a measured DER approach could allow for expansion of DERs that could be accomplished through ENO's Energy Smart BESS pilot program, which both ENO and TNO/AAE have proposed to utilize.[112] This would allow the Council to gather critical information along the way 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 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. The Advisors note that RNO, PosiGen, and Enphase also support the expansion of the DERs through the Energy Smart program structure to expand the battery pilot.[113]

The Advisors believe that with good-faith collaboration and the willingness to compromise, the parties to this docket could develop a DER expansion program, conducted initially as a pilot, possibly through Energy Smart, that accomplishes the Council's goals while ameliorating the Advisors' concerns. This approach would also address the priorities and pitfalls noted by the parties. A DER expansion program should also have sufficient reporting and information gathering during the pilot program to support a permanent virtual power plant ("VPP") tariff. To that end, the Advisors recommend that the Council consider the development of a DER expansion pilot program based upon key elements from the input of the parties and the Advisors in this proceeding. The Advisors further recommend that the pilot program should include the following features:

- Upfront and ongoing incentive levels that bridge the significant difference in the parties' opinions. Ultimately, both the upfront and ongoing incentive levels should be set at a level that would likely be required to ensure long-term participation.
- Data-driven incentive levels or allocated funds for lower to moderate income ("LMI") customers such that significant LMI participation is expected.
- Be vendor neutral to promote the participation of both a significant number of BESS equipment manufactures, and energy service providers that may ultimately be funding projects installed for participants.
- An efficient, objective, and straightforward pre-approval process for third-party vendor participation and incentive disbursement.
- To the extent possible the initial pilot should leverage the use of ENO's existing BESS pilot program and supporting vendors.
- An identified funding source for the pilot program.
- Supported by a cost effectiveness analysis.

[111] In docket UD-21-03, Resolution R-23-74 addressed whether benefit-cost ratios of some resilience projects may have to be greater than 1.0. In R-24-73, CURO recommended that TNO work with ENO related to support for resilience hubs. R-24-625 directed that microgrids be in a separate docket. On October 2, 2024, TNO/AAE proposed a "Plan For Distributed Community Resilience" which would apply $16 million of SERI credits to Community Microgrids and $16 million of SERI credits to "Residential Solar-Storage Aggregations."

[112] Both TNO/AAE and ENO proposals require enrollment in ENO's Energy Smart BESS program or successor but also propose significant expansion in near-term years.

[113] RNO Comments in Council Docket UD-24-02, December 20, 2024, p2; PosiGen Comments in Council Docket UD-24-02, March 31, 2025, p. 2; Enphase Comments in Council Docket UD-24-02, March 14, 2025, p. 2.

- Supported by a ratepayer bill impact calculation that identifies the expected timing and impact on customer bills.
- Sufficient reporting and data gathering such that a permanent VPP tariff could be developed.