BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC	))))	**DOCKET NO. UD-23-01**

ADVISORS' REPORT REGARDING THE ENTERGY NEW ORLEANS, LLC 2024 INTEGRATED RESOURCE PLAN

June 2, 2025

TABLE OF CONTENTS

I. Executive Summary

Pursuant to the procedural schedule set forth in Resolution No. R-23-254, the Initiating Resolution of the Entergy New Orleans Inc. ("ENO") 2024 Triennial Integrated Resource Plan ("IRP") proceeding, and the Electric Utility Integrated Resource Plan Rules ("IRP Rules"),[1] of the Council of the City of New Orleans (the "Council")the Advisors submit this Advisors' Report regarding ENO's 2024 Integrated Resource Plan ("2024 IRP Report").[2] Based on its analyses of its resource needs, ENO states in the 2024 IRP Report that the long-term (20-year) planning horizon will likely include additions of both renewable and energy storage technologies to ENO's resource portfolio.[3] As intermittent additions increase and ENO's legacy fleet deactivates, the 2024 IRP Report explains, ENO may also see increased value in additional flexible peaking and quick-response technologies such as solar and battery hybrid and standalone battery storage technology.[4] ENO states that it continues to be committed to exploring clean, alternative technologies to ensure the adaptability and longevity of these resources.[5] The analysis in the 2024 IRP Report indicates that ENO estimates it will begin needing to add new capacity resources by 2037[6] and begin needing to add new energy resources in 2041.[7]

The Advisors participated actively in the IRP stakeholder process, have completed a comprehensive review of the 2024 IRP process and ENO's Final 2024 IRP Report, have considered the comments submitted regarding it, and recommend that the Council accept the 2024 IRP Report as being in substantial compliance with the Council's substantive and procedural requirements of the IRP Rules and Initiating Resolution. As discussed in detail below, while the Advisors find that the 2024 IRP Report is complete and substantially complies with the IRP Rules, it does have a few shortcomings. However, given that ENO is currently not projecting new resources to be needed until approximately 2037 and that the analysis in the 2024 IRP Report and the changes seen over the last few IRP Reports indicate that updated analyses will be needed prior to the acquisition of any specific new resource, there is no need for the Council to either reject or approve the 2024 IRP Report after it is accepted as being in compliance. The Advisors recommend that if the Council accepts the IRP as in compliance with the IRP Rules, no further action is needed other than to follow through with the 2024 IRP Action Plan, including the three-year implementation of Energy Smart programs and three-year Renewable and Clean Portfolio Standard ("RCPS") Compliance Plan which are expected to be addressed in further proceedings. The Advisors also observed several update-related issues arising with the IRP Rules, as set forth below, that lead the Advisors to recommend that the Council consider making certain changes to the IRP Rules prior to the next iteration of the IRP, particularly with respect to the treatment of distributed energy resources ("DERs") under the IRP Rules.

The Advisors further recommend that the Council approve the Action Plan in ENO's 2024 IRP Report subject to the following caveats: (i) approval of the Action Plan does not constitute Council approval of any specific asset or resource acquisition - any such acquisition must still be submitted

[1] Resolution No. R-17-429, Attachment B.
[2] Entergy New Orleans, LLP, 2024 Integrated Resource Plan, Docket No. UD-23-01, Dec. 13, 2024.
[3] 2024 IRP Report at 21.
[4] *Id.*
[5] *Id.*
[6] *See id.* at 18-19.
[7] *Id.* at 19.

for Council approval consistent with the Council's rules and regulations; and (ii) Council acceptance of the 2024 IRP Report and approval the Action Plan, does not preclude the Council from considering and/or ordering further actions by ENO relative to resource planning and acquisition; in particular, acceptance of the Final 2024 IRP shall have no precedential impact upon the Council's considerations in the RCPS rulemaking docket (UD-19-01) or any other related docket.

The purpose of requiring a utility to complete an IRP generally is to ensure that the utility is making prudent decisions regarding long-term investments in supply-side resources, power purchase agreements and utility-managed demand-side resources, and to integrate non-utility-owned demand-side resources, to ensure reliable service at a reasonable cost while adhering to Council policies. To do so, an integrated planning process requires the utility to forecast its peak load and energy needs and then evaluate a wide array of resources available to meet the long-term needs identified -- the resource options including all forms of commercially viable generation, as well as demand-side resources for reducing load, both utility and customer-owned, and investments in the transmission and distribution system that can enable a wider variety of resources to reach and serve load. Ideally, a well-developed IRP, which integrates all utility and customer-owned resources, provides the Council and the public with some assurance that ENO is properly considering all resource options available to it as it makes decisions about how to service its load and grid requirements.

In developing the 2024 IRP Report, ENO engaged in substantial collaboration with the Intervenors in the docket, which included the Alliance for Affordable Energy ("AAE"), the Southern Renewable Energy Association ("SREA"), the Sewerage and Water Board ("SWB"), and Air Products and Chemicals, Inc. ("Air Products"). ENO held five Technical Meetings with the Intervenors, the Advisors and the Council Utilities Regulatory Office ("CURO") to discuss each stage of the IRP analysis and to get input and feedback from the parties.[8]

In response to IRP Rules Section 9.A.1. related to the opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with the Utility, the Advisors find that the Intervenors in the IRP proceeding were provided with a meaningful opportunity to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with ENO.

The IRP analyses included: (1) a load forecast representing ENO's prediction of how much energy and demand its customers will use over the 20-year period; (2) an analysis of ENO's existing resources and their expected retirement dates; (3) an identification of the types and costs of supply-side and demand-side resources anticipated to be commercially available over the 20-year planning period; (4) consideration of transmission and distribution options and impacts on the system; (5) resource portfolio modeling to determine what combination of resources would meet customer needs at the lowest reasonable cost in light of different possible future scenarios and policy strategies; (6) the development of a "scorecard" reflecting factors that cannot be easily quantified or evaluated through a software modeling program; and (7) risk analyses. Section 5.A.4 of the

[8] Technical Meeting #1 was held November 9, 2023, Technical Meeting #2 was held February 29, 2024, Technical Meeting #3 was held May 7, 2024, Technical Meeting #4 was held October 2, 2024 and Technical Meeting #5 was held February 27, 2025.

IRP Rules requires ENO to consider and identify all cost-effective demand-side resources through the development of a demand side management ("DSM") potential study. The DSM Potential Study included a rigorous analysis of input data for the energy efficiency ("EE") and demand response ("DR") components, calibrated the achievable potential Reference case to the historical ES program data, and provided a DSM supply curve as IRP input data, with EE impact load shapes and DR annual savings and levelized costs.

Section 5.A.3 of the IRP Rules requires ENO to consider DERs among the potential supply-side resources analyzed for the 2024 IRP Report. Note also that Section 4.A.2 of the IRP Rules refers to DER as demand-side resources, stating: "the details of the Load Forecast should identify the energy and demand impacts of customer-owned DERs and then existing Utility-sponsored DSM programs." The 2024 IRP Report included DERs in the load forecast, and although no specific DER Report was included in the 2024 IRP filing, the 2024 IRP Report did address ENO's DER integration studies.

To initiate the resource portfolio analysis, ENO created three Planning Scenarios[9] with the consensus of the Parties. Each Planning Scenario is a set of assumptions regarding what will occur with respect to various market-based factors that ENO has no control over during the 20-year planning period, such as the growth of ENO's load (customer base), natural gas prices, when non-ENO-owned fossil fuel-fired generators in the market will retire, whether a carbon tax will be imposed, market prices for energy, and the cost of capital to invest in renewables. No single Planning Scenario is expected to be an accurate prediction of the future, rather, the three different Planning Scenarios created were designed to bracket the range of possible different future market situations so that the portfolio analysis can demonstrate how different combinations of resources might perform in the different possible futures. Once the Planning Scenarios were developed, four Planning Strategies[10] were designed to represent different policies for resource acquisitions that ENO and the Council can implement, such as using least-cost resources or only resources that comply with the Council's RCPS policy, and so forth.

Working with the Intervenors, ENO developed the three Planning Scenarios and four Planning Strategies, the combinations of which resulted in 12 portfolios optimized through the AURORA modeling software program.[11] ENO then created two additional manual portfolios to model potential early deactivation dates for Union Power Station Power Block 1 ("UPS PB1"), ENO's largest generator, which is natural gas-fired and represents approximately 36% of ENO's

[9] IRP Rules Section 2.A 14 - "Planning Scenario"- refers to a distinct definition of a market outlook for the IRP Planning Period consisting of key parameters which are not controlled by the Utility or the Council. Several Planning Scenarios are constructed to identify the plausible futures of the IRP Planning Period.

[10] IRP Rules Section 2.A. - "Planning Strategy" - refers to the defining of distinct resource constraints, regulatory policies, or business decisions over which the Council, the Utility, or Intervenors have control. For example, a Planning Strategy can be traditional utility planning, Intervenors defining resource inputs, or a Planning Strategy reflecting Council policies.

[11] ENO, the Advisors, and the Intervenors agreed on three Planning Scenarios representing a range of market drivers and possible futures, and four Planning Strategies that informed or constrained the Portfolio development process consistent with defined objectives or policies.

generation capacity and approximately 75% of the expected unit deactivations over the planning period.[12]

The only resource that appeared in all fourteen resource portfolios was demand-side management,[13] indicating that energy efficiency, demand response, and other programs designed to reduce customer consumption or encourage customers to conserve power at key times is expected to be cost-effective and an important part of the portfolio under all reasonably possible future scenarios and planning strategies.[14] Wind generation appeared in thirteen of the fourteen portfolios, with the highest MW modeled in all but one of the thirteen portfolios, indicating that wind is also likely to be one of the lowest-cost resources included in an ENO resource portfolio under nearly all future conditions. Battery Energy Storage Systems ("BESS") appeared in ten of the fourteen portfolios,[15] indicating that utility-scale battery storage is also likely to be among the lowest-cost resources that perform well under most future conditions.

The 2024 IRP Report shows some interesting changes from the results of the 2018 and 2021 IRP Reports. While all three IRP Reports have consistently indicated that DSM, BESS, wind, and solar are resources likely to perform well in many future scenarios, natural gas-fired generators appeared in 9 of the 15 portfolios generated in the 2018 IRP Report,[16] disappeared completely in 2021, not being selected for any portfolio (the first time natural gas was not selected for any portfolio),[17] but then reappeared in the 2024 IRP Report in 5 of the 14 portfolios.[18] The timing of capacity needs, as well as the amounts and types of resources best suited to fill the needs, varied based on the Scenario and Strategy constraints imposed.[19] While the overall results from recent IRPs do seem to indicate that natural gas is less likely to perform well across many scenarios now than in the 2018 analysis, the reappearance of natural gas in the 2024 analysis indicates that there may still be some potential future scenarios where a natural gas generator could be a reasonable option. The fairly significant fluctuations over time regarding natural gas does underscore, however, the need for updated analyses regarding available alternatives prior to any future investment in generation resources.

Also of note is that while the 2018 IRP Report showed utility-scale solar being selected in a majority of portfolios[20] and the 2021 IRP Report showed utility-scale solar being selected for all portfolios,[21] in the 2024 IRP Report, utility-scale solar was only selected for 4 of the 14 portfolios, though it was forced-in for another two portfolios,[22] making it difficult to determine if it would

---

[12] UPS PB1 is 506.2 MW of ENO's total 1391.4 MW of capacity and that ENO estimates that over the 20-year planning period it will deactivate 675 MW of its existing capacity. 2024 IRP Report at 13. UPS PB1 will be one of the units anticipated to be deactivated during the planning period. *Id*. at 14.

[13] 2024 IRP Report at 59-60.

[14] DSM was "forced-in" for Planning Strategies 2 – 4, consistent with the defined objectives of those Strategies reflecting Council DSM goals and the stakeholder's planning strategy. DSM in Planning Strategy 1 was developed on a least-cost basis.

[15] The ten optimum resource portfolios in which batteries were included did not include one portfolio where the only battery resource was "forced-in" under the planning strategy constraints.

[16] 2018 IRP Report at 58.

[17] 2021 IRP Report at 65, and at 73.

[18] 2024 IRP Report at 59.

[19] 2021 IRP Report at 73.

[20] 2018 IRP Report at 58. Nine of the 15 optimized portfolios included utility-scale solar.

[21] 2021 IRP Report at 65.

[22] 2024 IRP Report at 59-60. Utility-scale solar was forced-in two portfolios as a result of planning strategy constraints.

have been selected for those two portfolios if it had not already been forced-in. However, the substantial change in successive IRP modeling results from having utility-scale solar included in all portfolios to being included in less than half of the portfolios does indicate that further analysis of utility-scale solar and alternatives should be performed prior to the acquisition of future utility-scale solar resources. Wind, in particular, may be a better alternative resource in some scenarios, given its strong showing in the 2024 IRP Report.

After the fourteen resource portfolios were generated, five downselected portfolios were selected for further analysis based upon a consensus among the parties that those five portfolios were reasonably representative of all fourteen portfolios.[23] The further analysis included DSM modeling, total relevant supply cost ("TRSC") base analysis, a TRSC stochastic assessment of risks, and the scorecard ranking of each portfolio for factors not easily incorporated into the portfolio modeling computer program. Of note in the further TRSC base analyses cross-testing of downselected portfolios, while this IRP's TRSC base analysis indicated that an earlier retirement of the USB PB1 unit in 2035, rather than in 2041, was projected with relatively lower TRSC across all three Planning Scenarios, the manual portfolios in the 2021 IRP that accelerated the deactivation of Union 1 resulted in TRSC values about 8% higher than the Least Cost Planning portfolio. The results of the manual portfolio analysis over the last two IRPs underscore the sensitivity of the TRSC results to input assumptions and the value of further analysis in future IRPs.[24]

The further TRSC base cross-testing analyses also indicated the Strategy 3/Scenario 3 portfolio, which consisted of wind, battery, and DSM in compliance with the Council's 2% Goal and RCPS, was the least TRSC under Scenarios 1 and 3 and the second-least TRSC under Scenario 2.[25] It also indicated the Strategy 4 (Stakeholder Strategy)/Scenario 2 portfolio, in which 800 MW of community solar, utility-scale solar, battery, wind and DSM were constrained in designated amounts, was projected to have the highest TRSC across all three Planning Scenarios. This further TRSC base analysis would seem to support a conclusion that caution should be used in evaluating any proposals that rely upon resources not supported by an updated, thorough long-term cost-benefit analyses. The comparative value of this IRP comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a **guide** for the future, **not** from focusing solely on the costs of one Portfolio versus another, particularly given that actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current, actual market costs.[26]

The 2024 IRP Report appears to indicate that while reliance upon particularly expensive renewables could be detrimental to the City, as long as reasonably-priced and cost-effective renewable resources are selected, it is likely possible to meet the long-term needs of the City at a reasonable cost over the planning period.

The further risk analysis of the five downselected portfolios indicated differences in TRSCs from the base results and indicate that portfolios that rely solely upon renewables, BESS, and DSM have higher TRSCs relative to the portfolios including a natural gas fired generator in future scenarios

[23] 2024 IRP Report at 61.
[24] *Id*. at 67-68.
[25] 2024 IRP Report at 67.
[26] *Id*.

where higher natural gas prices or lower CO2 prices occur.[27] Given how dependent the result of an IRP analysis of the TRSCs of the various portfolios appears to be on the assumptions made about the timing and cost of natural gas and the likelihood, timing, and level of a carbon tax over the 20-year planning period, it will be very important to ensure that an updated analysis is performed prior to the acquisition of any new resource of significant size. This also supports the value of continuing to perform the IRP analysis on its triennial cycle so that changes to the market, forecasts, and applicable policies can be accounted for with reasonable frequency.

In the Initiating Resolution, the Council discussed the interest of the Advisors and Intervenors in the modeling of energy-based solutions in addition to capacity-based solutions and optimizing the retirement dates of existing resources in addition to the current IRP portfolio modeling using fixed retirement dates. Based on discussions in the IRP Technical Meetings, the maximum seasonal reserve margin target (*i.e.* how much "extra" capacity a utility must have to ensure it can meet unexpected needs) that the AURORA model uses to judge whether a resource need exists was relaxed. This allowed the model to select more resources than needed to meet ENO's capacity requirements, if the energy revenue is projected to offset the additional cost under the assumptions of the relevant Planning Scenario and Planning Strategy combination. In other words, the model would allow ENO to acquire more resources than it needs to serve New Orleans if the model projects that ENO could make enough money selling its excess energy to justify the cost of acquiring those resources. And although the portfolio modeling did not include optimizing the early retirements of ENO's existing resources, the possibility of early retirements was addressed by altering the assumptions for two additional manually-created portfolios that included all of the inputs for Planning Strategy 1 and Planning Scenario 1, but with two different earlier deactivation dates for UPS PB1, ENO's largest generator representing a significant amount of the retirements expected during the planning period. A UPS PB1 earlier retirement date portfolio was included as a downselected portfolio for further evaluation.

The Advisors find that the IRP modeling complied with the Initiating Resolution with respect to energy-based solutions and optimizing the retirement dates of existing resources.

Evaluation of the downselected portfolios based on the scorecard results is inevitably somewhat subjective. The parties agreed to a set of 17 metrics to be included in the scorecard analysis, with each of the five downselected portfolios rated on a numerical grading scale. The 17 metrics were grouped under seven key scoring parameters of (i) utility costs related to the AURORA model portfolio optimization; (ii) cost impact on ENO revenue requirements; (iii) risk/uncertainty; (iv) reliability; (v) environmental impact; (vi) consistency with City policies/goals; and (vii) macroeconomic impacts. The grades required consideration of the inherent compositional differences among the portfolios, and were grouped into quartiles on an A-D basis with respect to their "performance" for each metric relative to the other portfolios.[28] As one approach to scorecard evaluation, if all of the 17 metrics are given equal weight and importance, then the two downselected portfolios relying upon renewables, BESS and DSM showed the highest grades, and Manual Portfolio 1b (early retirement of UPS PB1) came in third. A portfolio evaluation based on the scorecard would differ if one or more of the 17 specific scorecard metrics or seven key scoring parameters were considered to be of greater importance or weight than the other metrics

[27] *Id*. *at* 72.
[28] 2024 IRP Report at 73-76.

US_ACTIVE\130450395\V-1

or key scorecard parameters. This approach to IRP scorecard evaluation again underscores the need for an updated analysis that considers updated market conditions and the specific characteristics of a proposed resource prior to any new resource acquisition.

II. Background – IRP Rules and the Initiating Resolution

The purpose of requiring a utility to complete an IRP generally is to ensure that the utility is making prudent decisions regarding long-term investments in supply-side resources, power purchase agreements and utility-managed demand-side resources, and to integrate non-utility-owned demand-side resources, to ensure reliable service at a reasonable cost while adhering to the Council policies. To do so, an integrated planning process requires the utility to forecast its peak load and energy needs and then evaluate a wide array of resources available to meet the long-term needs identified -- the resource options including all forms of commercially viable generation, as well as demand-side resources for reducing load, both utility and customer-owned, and investments in the transmission and distribution system that can enable a wider variety of resources to reach and serve load. Ideally, a well-developed IRP, which integrates all utility and customer-owned resources, provides the Council and the public with some assurance that ENO is properly considering all resource options available to it as it makes decisions about how to service its load and grid requirements.

The purpose of the IRP is to inform and empower effective Council and utility decision-making, while augmenting utility resource planning and enhancing public awareness of the energy choices available to the utility. The IRP analysis performed under the Council's IRP Rules does not create a single resource plan to be approved by the Council, rather it is meant to ensure that as the utility is making resource decisions, it is performing a robust analysis of all available resource options in a process that is transparent and open to the Council and the public. The results of the analysis provide insight into what types of resources are likely to perform well across different potential future scenarios, and what factors might influence the choice of technologies over the 20-year planning period.

Any resource acquisition proposed by ENO, whether consistent with the results of the IRP analysis or not, must still be submitted to the Council for full review and approval. This is particularly important given that the IRP analysis is based in large part on national and regional average cost assumptions and characteristics of various types of resources rather than the specific costs and characteristics of a particular resource – when a specific resource is identified and proposed, it may cost more or less than the average figures underlying the 2024 IRP Report or may have unique characteristics that make it more or less suited to New Orleans than the average resource considered in the IRP. So, although the 2024 IRP Report provides a wealth of information regarding potential resource options for the utility, it is not determinative with respect to any particular future resource acquisition. Similarly, the analyses performed in the IRP also provide data that inform, but do not determine, the design of ENO's implementation plan for the next three years of the Energy Smart energy efficiency and demand response programs, and ENO's plan for compliance with the Council's RCPS for the next three years. The 2024 IRP is the second IRP submitted to the Council that serves as a reference for the RCPS and its calculation of compliance costs.

The analyses performed under the IRP Rules include: (1) a load forecast representing ENO's prediction of how much electric energy and demand its customers will use over the 20-year period; (2) an analysis of ENO's existing resources and their expected retirement dates to determine the difference between the resources ENO currently has and what will be needed in the future to meet the needs of the load forecast; (3) an identification of what types of resources (including different types electric generators, energy storage technologies such as batteries, and demand-side measures/resources that help customers reduce consumption, such as energy efficiency) are anticipated to be commercially available over the 20-year planning period and cost forecasts for them; (4) consideration of transmission and distribution options and impacts on the system; (5) portfolio modeling to determine what combination of resources would meet customer needs at the lowest reasonable cost in light of different possible future scenarios and policy strategies; (6) the development of a "scorecard" reflecting factors that cannot be easily quantified or evaluated through a software modeling program (such as environmental impacts, macroeconomic impacts like job creation, flexibility of the resources, and how well the portfolio complies with the Council policies); and (7) risk analyses.

In developing the 2024 IRP Report, ENO engaged in substantial collaboration with the Intervenors in the docket, which included the Alliance for Affordable Energy ("AAE"), the Southern Renewable Energy Association ("SREA"), the Sewerage and Water Board ("SWB"), and Air Products and Chemicals, Inc. ("Air Products"). ENO held five Technical Meetings with the Intervenors, the Advisors and the Council Utilities Regulatory Office ("CURO") to discuss each stage of the IRP analysis and to get input and feedback from the parties.

A. IRP Rules

The Council has required the utilities subject to its jurisdiction to complete an IRP under a uniform set of rules since 2008.[29] Subsequent to its consideration of ENO's 2015 IRP, the Council determined that it would revise its IRP Rules,[30] which ultimately resulted in the Council's adoption of Resolution No. R-17-429, establishing the IRP Rules in Council Docket No. UD-17-01.[31] In the IRP Rules, the Council states:

> These IRP Rules are intended to inform and empower effective Council and utility decision-making, while augmenting utility resource planning and enhancing public awareness of and input into the utility's energy choices. It is the Council's desire that a comprehensive IRP conducted in accordance with these IRP Rules provide a full picture of all reasonably available resource options in light of current and expected market conditions and technology trends, and generate an informed understanding of the economic, reliability, and risk evaluation of utility resource planning as well as the associated social and environmental impacts. Further, the Council wishes to encourage and enforce a transparent process that allows all interested constituents and stakeholders to participate and that fosters the

[29] Council Resolution No. R-08-295, Resolution Regarding Proposed Rulemaking to Establish IRP Components and Reporting Requirements for Entergy New Orleans, Inc.

[30] *See* Council Resolution No. R-17-32 (as corrected), Resolution and Order Establishing a Rulemaking Proceeding Regarding Integrated Resource Planning.

[31] The currently effective version of the IRP Rules is attached to Resolution No. R-17-429 as Attachment B, Aug. 10, 2017.

development of a complete administrative record upon which informed Council decision-making can occur.[32]

The IRP Rules establish an open and transparent process by which all electric utilities subject to the Council's regulatory jurisdiction develop and file IRPs. The IRP Rules set forth the procedural and substantive requirements for the development of an IRP and the required contents of an IRP Report submitted to the Council. The IRP Rules also require an Initiating Resolution to be adopted by the Council for each triennial IRP process that outlines the IRP process and timeline, Intervenor and public participation, policy objectives for consideration in the IRP and other matters as deemed necessary by the Council. This is the third triennial IRP performed under the new IRP Rules.

In the IRP Rules, the Council set forth specific objectives for the IRP, including, but not limited to:

(1) optimize the integration of supply-side resources and demand-side resources, while taking into account transmission and distribution, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;

(2) maintain the utility's financial integrity;

(3) anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;

(4) support the resiliency and sustainability of the utility's systems in New Orleans;

(5) comply with local, state and federal regulatory requirements and regulatory requirements and known policies (including policies identified in the Initiating Resolution) established by the Council;

(6) evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and DERs, among others;

(7) achieve a range of acceptable risk in the trade-off between cost and risk; and

(8) maintain the transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.[33]

B. Initiating Resolution

For the 2024 IRP, the Council issued its Initiating Resolution in June of 2023, Resolution No. R-23-254 ("Initiating Resolution"), which established a procedural schedule for the IRP in the new

[32] IRP Rules at 1.
[33] IRP Rules at Section 3.A, at 4.

Docket No. UD-23-01, addressed certain procedural matters and set forth certain policy objectives to be incorporated into the IRP:

(i) the Council's goal, as originally set forth in Resolution No. R-17-100, of increasing the projected incremental annual kWh savings from the Energy Smart Program by 0.2% per year until such time as the program achieves annual incremental savings equal to 2% of annual kWh sales;

(ii) the inclusion of the 2% savings goal in the 2024 IRP, unless revised by the Council in Docket No. UD-22-04 before the final policy deadline;

(iii) the Energy Smart Program Years 13–14 budget and savings estimates approved in Resolution No. R-22-523, which are to be used as data inputs and assumptions in the DSM Potential Study and planning strategies for the IRP;

(iv) the treatment of Program Year 15 budget and savings estimates, with the Council directing that if it approves PY15 estimates before the policy issuance deadline, such approved estimates must be used; otherwise, ENO's proposed estimates for PY15 shall be used in the IRP planning inputs;

(v) the inclusion of community solar as a potential DER in the IRP, as authorized in Resolution No. R-19-111 and consistent with IRP Rules;

(vi) the incorporation of an RCPS for New Orleans in Council Docket No. UD-21-182 into the IRP planning strategy;

(vii) the development of a scorecard ranking resource portfolios by cost, risk, flexibility, environmental impacts, policy alignment, and economic impact, as required by IRP Rules § 7(1);

(viii) the inclusion of Council policy goals on renewables, storage, and demand-side resources, including any updated goals from Docket No. UD-22-04;

(ix) the use of broader benefit-cost analyses beyond the Toal Resource Cost ("TRC") and the ratepayer impact measure ("RIM"), including the Resource Value Test from the National Standards Practice Manual; and

(x) the application of multiple discount rates in the presentation of cost-effectiveness test results using both the societal discount rate and the utility's weighted average cost of capital, with nominal and present value comparisons.[34]

Subsequent to the issuance of the Initiating Resolution, the Council declined to retain an independent consultant to perform a DSM Potential Study for the 2024 IRP cycle, noting that while it had engaged consultants in the 2018 and 2021 IRP cycles, this decision carries no precedential effect for future proceedings. In accordance with the IRP Rules, the Council directed ENO to perform the DSM Potential Study and emphasized that Intervenors must be provided an

[34] Initiating Resolution at 3-7.

opportunity to participate in the concurrent development of DSM study inputs and assumptions. The Council also noted that other parties may procure their own DSM consultants to submit studies into the record.[35]

The Council reiterated that integration of distributed generation and customer-owned DER into the New Orleans electric grid in a manner that supports grid reliability and sustainability remains a key objective. Noting that the 2018 and 2021 IRPs reported progress of the measures taken to develop this capability, in the 2024 IRP ENO was directed to provide more detailed analysis and reporting required by the Rules for DER and integrated distribution planning, since by the time the 2024 IRP Report is submitted, over seven years will have passed since this requirement was adopted by the Council. Accordingly, in the Initiating Resolution the Council directed ENO to include a report in the Final IRP filing containing its ongoing assessment of:

(1) its progress toward integrating distributed generation and customer-owned DER into the distribution grid in a way that enhances reliability and sustainability;

(2) the analytical results provided from any hardware, software, or other equipment used to support this capability;

(3) how these analytical results were used to comply with these aforementioned specific sections of the Rules;

(4) the incremental costs of equipment, software and additional personnel and personnel training related to this capability, as well as an estimation of the incremental benefit;

(5) any other remaining measures required to enable ENO to comply fully with these aforementioned Sections of the Rules, including the estimated incremental costs and benefits thereof: and to which of these remaining measures ENO has already made commitments; and

(6) an estimated date by which ENO expects it will be able fully comply with the Rules and to implement such integrated distribution planning into the IRP.[36]

The Initiating Resolution also addressed the Advisors' Suggestions for 2024 Triennial IRP Procedure[37] and the related filed comments:

i. The Council directed the CURO to issue a request for qualifications for a DSM consultant pursuant to the Council Rules and stated that if a consultant is selected to perform a DSM Potential Study, CURO shall convene a technical conference so that any parties or consultants performing potential studies may agree to principles necessary to align input cases;[38]

[35] Initiating Resolution at 7-8.
[36] *Id*. at 8-10.
[37] In the *Advisors' Report Regarding the Entergy New Orleans 2024 Integrated Resource Plan*, the Advisors made four suggestions for improvements to the IRP Procedure for the 2024 Triennial cycle.
[38] Initiating Resolution at 11 and 18.

ii. The Council stated that greater detail, including workpapers and methodologies, regarding how specific distributed energy resources, such as growth in community solar, battery storage, and electric vehicles impact the load forecast with potential ranges of projected estimates would be useful in the evaluation of the IRP, and encouraged ENO to work with the stakeholders to identify other types of resources or additional information to be added;[39]

iii. The Council directed ENO to work with the Parties to develop additional modeling of manual portfolios, similar to the 2021 IRP analysis, for the 2024 IRP process. The Council stated that working sessions should be held prior to IRP Technical Meeting 1 to reach a consensus regarding how manual portfolios could be defined in planning strategies to provide sufficient information to evaluate early retirements;[40] and

iv. The Council instructed ENO to work toward evaluating certain energy-based solutions and developing an evaluation of early retirements of resources that is sufficient to provide meaningful information regarding energy-based impacts and that can be accomplished within the procedural schedule set forth in the Initiating Resolution.[41]

Interventions in the Docket were filed by AAE,[42] SWB,[43] Air Products,[44] and SREA.[45]

Per the Initiating Resolution and over the course of the proceeding, ENO was to hold four technical meetings with the intervenors to discuss the details of the IRP analysis and get feedback from stakeholders on various components of the analysis, and a fifth technical meeting to discuss the Energy Smart Implementation Plan. ENO was also to hold three public meetings regarding the development of the IRP and the 2024 IRP Report to assist in informing the public of the IRP and obtaining public comment on it. Per the Initiating Resolution, ENO was to submit its 2024 IRP Report to the Council by December 13, 2024;[46] The Parties in the docket were to file comments on the 2024 IRP Report with the Council by March 10, 2025;[47] and ENO was to file responsive comments by April 28, 2025.[48]

[39] Initiating Resolution at 12.
[40] *Id*. at 13.
[41] *Id*. at 14.
[42] Alliance for Affordable Energy, *Petition for Intervention and Inclusion on Service List*, Docket No. UD-23-01, (Aug. 29, 2023).
[43] Sewerage and Water Board of New Orleans, *Petition of Intervention*, Docket No. UD-23-01, (Oct. 2, 2023).
[44] Air Products and Chemicals Inc., *Motion for Late Intervention and Inclusion on Service List*, Docket No. UD-23-01, (Oct. 10, 2023).
[45] Southern Renewable Energy Association, *Petition for Intervention and Inclusion on Service List*, Docket No. UD-23-01 (Sept. 1, 2023).
[46] Entergy New Orleans, LLC, *2021 Integrated Resource Plan*, Docket No. UD-20-02, (Mar, 25, 2022).
[47] Alliance for Affordable Energy and the Office of Resilience & Sustainability, *Joint Comments of the Alliance for Affordable Energy and the Office of Resilience & Sustainability*, UD-23-01 (Mar. 10, 2025) ("AAE and ORS Comments").
[48] Entergy New Orleans, LLC, *Entergy New Orleans, LLC's Response to Comments of the Alliance for Affordable Energy and the Office of Resilience & Sustainability Regarding ENO's 2024 Integrated Resource Plan*, UD-23-01 (Apr. 28, 2025) ("ENO Reply Comments").

III. Whether the 2024 IRP Report is in Compliance with the Council's Requirements

The Advisors participated actively in the stakeholder process, have considered the 2024 IRP Report and the comments submitted regarding it, and now submit this Report to the Council. Under the IRP Rules, the Council makes two determinations. First, the Council determines whether or not the 2024 IRP Report is in compliance with the Council's IRP Rules and the procedural schedule established for this triennial IRP cycle; in which case the Council accepts ENO's IRP as filed in compliance with the Council's substantive and procedural requirements (if it is not in compliance with the requirements, it may be rejected without prejudice to the utility refiling the IRP once it has corrected the deficiencies). Second, after consideration of all of the evidence entered into the record, the Council may approve the accepted IRP, approve it subject to conditions or with modifications, approve it in part and reject it in part, reject it in its entirety, or choose to terminate the proceeding without either approving or rejecting the accepted IRP. The Council's approval of the IRP has no precedential effect with respect to the Council's evaluation of any application for approval of the acquisition, implementation, or deactivation of any supply-side or demand-side resource or program.

Under the IRP Rules if the IRP fulfills the requirements of the IRP Rules and was developed in compliance with the procedural schedule, the Council shall accept the IRP as filed in compliance with the Council's substantive and procedural requirements.[49] Failure to substantially comply with the provisions of these Rules may result in summary rejection of the IRP, which may be without prejudice to the refiling of the IRP once the utility has corrected the deficiencies.[50] Further, after consideration of all of the evidence entered into the record, the Council may approve the accepted IRP, approve it subject to stated conditions, approve it with modifications, approve it in part and reject it in part, reject it in its entirety, or choose to terminate the proceeding without either approving or rejecting the accepted IRP.[51]

A. Procedural Requirements

The procedural requirements for the Triennial IRP process are set forth in the IRP Rules, and a procedural schedule for each Triennial IRP process, as well as any further requirements for that cycle, are set forth by the Council in the Initiating Resolution for each cycle. Sections 4 through 8 of the IRP Rules set forth the analyses that must be performed as part of the IRP proceeding and Sections 9 and 10 set forth the procedural requirements for the development and submission of the 2024 IRP Report. Section 9 of the IRP Rules requires that, at a minimum, the IRP process include:

1. The opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with the Utility within the confines of the IRP timeline and procedural schedule.

2. At least four technical meetings attended by the parties in the Docket focused on major IRP components that include the Utility, Intervenors, CURO and the Advisors with structured comment deadlines so that meeting participants have the opportunity to present inputs and

[49] IRP Rules at § 10.E.
[50] *Id.*
[51] *Id.*

assumptions and provide comments, and attempt to reach consensus while remaining mindful of the procedural schedule established in the Initiating Resolution.

3. At least 3 public engagement technical conferences advertised through multiple media channels at a minimum of 30 days prior to the public technical conference.

    a. A public education and kickoff meeting that explains the following: the purpose of the IRP and the corresponding process; the IRP timeline as delineated in the Council's Initiating Resolution with respect to major process deadlines; the inputs and assumptions that are considered in the IRP process and summarized in the report; and ways in which public can remain informed throughout the IRP cycle (*e.g.*, online information resources that provide status updates, portal through which customers can submit questions or concerns to the Utility);

    b. A public presentation of the IRP; and

    c. A public hearing opportunity after presentation of the IRP report to give the public the opportunity to provide comment on the record.

4. CURO shall schedule, provide notice of, and conduct the public technical conferences. In addition to a live presentation, all public technical conferences should also be broadcast via the Council's website and archived for later viewing.

Section 10 of the IRP Rules contains both procedural and substantive requirements for the IRP Report. Procedurally, Section 10 requires that ENO make its IRP Report available for public review and file it with the Council.[52]

In addition to the IRP Rules procedural requirements, the Initiating Resolution set forth additional procedural requirements that:

1. a DSM Potential Study be submitted;

2. all IRP inputs be finalized by May 17, 2024;

3. the results of the optimized portfolios and workpapers be circulated to the parties;

4. a fifth technical meeting be held;

5. Intervenor Comments regarding the IRP Report should be filed;

6. ENO Reply Comments should be filed;

7. an Advisor Report regarding the IRP Report should be filed; and

[52] IRP Rules at §§ 10.A and B.

8. that an Energy Smart Implementation Plan for Program Years 16-18 of the program should be filed.[53]

In developing the 2024 IRP Report, ENO held five technical meetings with the Intervenors, the Advisors and CURO to discuss each stage of the IRP analysis and to get input and feedback from the parties. Technical Meeting #1 was held November 9, 2023, with the purpose of discussing the planning scenarios and planning strategies and begin working toward consensus regarding which scenarios and strategies should be included in the modeling. Technical Meeting #2 was held February 29, 2024, in order to further discuss the selection of planning scenarios and planning strategies, confirming that the Stakeholder Scenario and Stakeholder Strategy were being developed to be included in the modeling. The parties also had the opportunity at this meeting to raise any questions regarding the DSM Potential Study. Technical Meeting #3 was held May 7, 2024, to finalize the planning scenarios and planning strategies and lock down all IRP inputs and to begin the discussion of which metrics should be included on the scorecard. Technical Meeting #4 was held October 2, 2024, to discuss the optimized resource portfolios and downselection of portfolios for further analysis and cross-testing, finalize the scorecard metrics, and initiate a discussion of the next Energy Smart Implementation Plan. Technical Meeting #5 was held February 27, 2025 to discuss the targeted programs in the Energy Smart Implementation Plan for program years 16-18. In IRP Technical Meeting #5, ENO confirmed the June 16, 2025 filing date for the Energy Smart Implementation Plan for Program Years 16-18.

CURO convened three public meetings, the first on August 23, 2023, to introduce the 2024 IRP process and proceeding, the second on January 21, 2025, for ENO to present the 2024 IRP Report to the public and take questions on it, and the third on February 26, 2025, to take public comment on the 2024 IRP Report.

In response to IRP Rules Section 9.A.1. related to the opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with the Utility, the Advisors find that the Intervenors in the IRP proceeding were provided with a meaningful opportunity to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with ENO.

ENO submitted its 2024 IRP Report to the Council by the deadline of December 13, 2024, set forth in the Initiating Resolution. AAE and the Office of Resilience & Sustainability ("AAE and ORS") filed joint comments regarding the 2024 IRP Report on March 10, 2025, and ENO submitted its reply comments on April 28, 2025.

As of the date of filing of this Advisors' Report, ENO has met all of the procedural requirements under the IRP Rules.

B. Required Report Content

The IRP Rules set forth over 70 specific substantive requirements for the IRP Report. As required under the IRP Rules,[54] ENO provided an Appendix A to the 2024 IRP Report detailing each requirement, which related to specific IRP Rules sections, and explaining how that requirement

[53] Initiating Resolution at 17-18.
[54] IRP Rules Section 1.C.

was met, by citing specific pages/sections of the 2024 IRP Report. The Initiating Resolution also set forth ten specific policy objectives to be incorporated into the IRP and directed that a DER report with six specific ongoing assessments be included in the Final 2024 IRP Report. The Advisors have reviewed the Final 2024 IRP Report content relative to the Appendix A compliance matrix and relative to the Initiating Resolution ten specific policy objectives to be incorporated into the IRP, and the required DER report. The Advisors' review confirmed that the ENO IRP was developed consistent with objectives articulated in Section 3 of the Council's IRP Rules, objective 5 of which states: "Comply with local, state, and federal regulatory requirements and known policies (including policies identified in the Initiating Resolution) established by the Council." While the Advisors' review finds that the 2024 IRP Report is in compliance with the Appendix A matrix and the Initiating Resolution policies, we note the following considerations relating to specific Requirements. Some of the following considerations are also the basis for specific Advisor findings and recommendations:

Requirement 8 – "*evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and DERs, among others.*" Utility-scale, utility-owned resources were evaluated in the cited 2024 IRP Report section, Capacity Resource Options, not customer-owned storage and other customer-owned DERs, some aspects of which were included in the development of the load forecast in Requirement 14. A more informative integrated resource plan would include analyses of the growing amount of customer-owned resources, including grid impact. Relative to this 2024 IRP Report, customer-owned DERs were to be included in a DER Report directed in the Initiating Resolution.

Requirement 14 – "*A detailed discussion of the forecasting methodology and a list of independent variables and their reference sources that were utilized in the development of the Load Forecast, including assumptions and econometrically evaluated estimates. The details of the Load Forecast should identify the energy and demand impacts of customer-owned DERs…*" The cited Report sections included a general discussion of the econometric-based sales forecast without a list of independent variables, using historic-based load profiles modified by rooftop solar, EV, and electrification. Analysis or details of other customer-owned DERs, including community solar, were not included. More detail related to probability distributions (uncertainty ranges) and statistical significance would be informative. The load forecast developed total utility energy/demand, and was not designed to project grid impacts or locational DERs.

Requirement 32 – "*With respect to potential supply-side resources, the Utility shall consider… technologies utilizing …energy storage technologies…and Distributed Energy Resources. . . .*" The Report cited the section Capacity Resource Options with ENO resources, but the IRP Rules Section 2.A.6 define DERs as "generation or energy storage facilities owned or leased by retail customers that are located on the customer side of the meter, that are primarily for the use and consumption of energy by the retail customer, and that are interconnected to and capable of delivering energy to the grid." This requirement is another example of the need to revise the IRP Rules with an objective of integrated resource planning to include more detailed analysis of customer-owned distributed energy resources.

Requirement 33 – "*The Utility should incorporate any known Council policy goals (including such policy goals identified in the Initiating Resolution) with respect to resource acquisition, including, but not limited to, renewable resources, energy storage technologies, and DERs.*" Also, Requirement 63 addresses alternate planning strategies to reflect regulatory policy goals of Council including those in Initiating Resolution. The Report cited planning strategies, which presently include the Council's energy efficiency goal of 2% of sales and the Renewable Clean Portfolio Standard. If prospective Council policy includes some aspects of DERs, more specificity will be needed with respect to the IRP Rules and development of planning strategies in subsequent IRPs.

Requirements 35- 41 address policy goals or targets related to demand-side resources. The issue to be clarified is whether DERs, as customer-owned resources, should be considered as supply resources or as an expanded definition of DSM. The current DSM Potential Study analyzes ENO-managed energy efficiency and demand response programs, so if DERs are considered as DSM or a demand-side resource, a delineation of DSM analysis would need to address DERs. A revision to the IRP Rules would also address the IRP treatment of DERs.

Requirement 45 – "*The utility shall explain how… the Utility's distribution system [is] integrated into the overall resource planning process to optimize the Utility's resource portfolio and provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.*" The cited Report section states that consideration must be given to the increased role that dispatchable resources may need to play in maintaining regional reliability as reliance on such inverter-based resources (solar PV) increase… Section 6.E. of the Council's IRP Rules requires that ENO evaluate the extent to which reliability of the distribution system can be improved through the strategic location of DERs or other resources identified as part of the IRP planning process. To the extent ENO does not currently have the capability to meet this requirement, it is required to demonstrate progress toward developing this capability in its 2024 IRP Report.[55] The 2024 IRP Report did include sections that explained various steps being undertaken to implement foundational systems, software, and processes that will be necessary for ENO to further develop the ability to evaluate locational and reliability benefits and impacts of DERs in the future.[56] The DER report required in the Initiating Resolution will be addressed further below.

Requirement 47 addresses major changes in the operation or planning of the transmission system and/or distribution system (including changes to accommodate the expansion of DERs) that are contemplated in the Planning Period. No such major changes were identified for the 20-year planning period, but more detail should be provided in prospective IRPs, with corresponding changes made in revisions to the IRP Rules.

Requirement 49 – "*It is the Council's intent that, as part of the IRP, the Utility shall evaluate the extent to which reliability of the distribution system can be improved through the strategic location of DERs or other resources identified as part of the IRP planning process. The Utility should provide an analysis, discussion, and quantification of the costs and benefits as part of the evaluation. To the extent the Utility does not currently have the capability to meet this requirement, the utility shall demonstrate progress toward accomplishing this requirement until such time as it acquires the capability*." This requirement also relates to the aforementioned DER Report required in the Initiating Resolution. Although no specific DER evaluation of benefits/cost

[55] 2024 IRP Report at 23.
[56] *Id*.

analysis was provided, the Final Report did provide sections discussing the progress made in the last two years to develop this capability.

Requirement 76 – "*The opportunity for Intervenors to participate in the* ***concurrent*** *development of inputs and assumptions for the major components of the IRP in collaboration with the Utility within the confines of the IRP timeline and procedural schedule*." (emphasis added) The stakeholder process and input was included in the several technical meetings, but there was no stakeholder participation in the concurrent development of the DSM Potential Study. In the Initiating Resolution, the Council declined to retain an independent DSM consultant and emphasized that Intervenors must be provided an opportunity to participate in the concurrent development of DSM study inputs and assumptions.

The Initiating Resolution set forth a policy objective to be incorporated into the IRP related to the use of broader benefit-cost analyses beyond the TRC and the RIM, including the Resource Value Test from the National Standards Practice Manual. Although the Resource Value Test was not specifically used in the IRP, there was adequate compliance with cost-effectiveness, although the broader benefit-cost analyses should be included in prospective IRPs.

While the Advisors believe that there were some shortcomings in the 2024 IRP Report, as set forth above, particularly with respect to the modeling of DERs, the Advisors acknowledge that the language of the current IRP Rules around DERs leaves some uncertainty as to how DERs are to be integrated into the IRP process. For that reason, and because ENO did include DERs in many elements of its analysis, the Advisors find that ENO substantially met the requirements of the IRP Rules and Initiating Resolution. However, as discussed in greater detail below, the Advisors recommend that, particularly in light of the Council's ongoing dockets around Community Solar, Distributed Energy Resources and ENO's battery storage pilot, it is important for the Council to consider revising the IRP Rules provisions around DERs to more accurately reflect the Council's policies established in those dockets and other recent developments on DERs and to provide greater guidance to the utility regarding the modeling of DERs.

C. The 2024 IRP Report is in Substantial Compliance with the Council's Requirements and Should be Accepted as Being in Substantial Compliance with the IRP Rules and Initiating Resolution

As described above, the Advisors find that the 2024 IRP Report contains sufficient required content and analyses and was developed in accordance with the procedural schedule set forth by the Council. Therefore, per IRP Rules Section 10.E, the Council should accept the 2024 IRP Report for filing as being submitted in substantial compliance with the Council's substantive and procedural requirements.

IV. Substantive Review of the Report

If the Council does accept the 2024 IRP Report as being in substantial compliance with the Council's substantive and procedural requirements, under Section 10.E of the IRP Rules, the Council then determines whether to approve the accepted IRP, approve it subject to stated conditions, approve it with modifications, approve it in part and reject it in part, reject it in its entirety, or to terminate the proceeding without either approving or rejecting the accepted IRP.

The Advisors provide the following substantive review of the report and recommendations to assist the Council in its determination.

A. Advisors' Review

1. Participation by Parties in the Development of the 2024 IRP Report

In developing the 2024 IRP Report, ENO is required to engage in substantial collaboration with the Intervenors to the proceeding. Through the Stakeholder Process, ENO is to strive to develop a position agreed to by the utility, the Advisors, and a majority of the Intervenors regarding the potential supply-side and potential demand-side resources and their associated defining characteristics (*e.g.* capital cost, operating and maintenance costs, emissions, DSM supply curve, etc.) for the Planning Strategies and the assumptions in the Planning Scenarios.[57] To the extent that consensus is not reached, the IRP Rules provide for the creation of a stakeholder Planning Strategy and a stakeholder Planning Scenario to model inputs chosen by a majority of the Stakeholders[58] As discussed above, in the 2024 Triennial IRP proceeding, ENO held five Technical Meetings with the Intervenors, the Advisors, and CURO to discuss each stage of the IRP analysis and to get input and feedback from the parties.

In the course of this collaboration, as ENO developed the strategies and scenarios to be incorporated into the portfolio modeling program, the Intervenors created their own Stakeholder Scenario and Stakeholder Strategy, both of which were incorporated into the portfolio modeling by ENO.[59] The Stakeholder Scenario (Scenario 3), as defined by the Intervenors, was characterized by high load growth, gas prices, and DSM additions, as well as low renewable capital cost assumptions.[60] The Stakeholder Strategy (Strategy 4), as defined by the Intervenors, did not allow for the optimization of resources for the entire portfolio by the portfolio modeling program; rather, it pre-determined/constrained specific amounts of new resources that would be added for the planning period, including the DSM Potential Study Societal High Case figures for DR and EE programs, and specified amounts of renewables chosen by the Intervenors including the amounts of behind-the-meter solar and community solar. The portfolio modeling program was then allowed to select the remaining resources needed for the optimized portfolios modeled for each planning scenario under the Stakeholder Strategy, which ranged from 1,550 MW to 4,200 MW based upon the assumptions used for each planning scenario.

In addition to the stakeholder input on the design of the planning scenarios and planning strategies, during the technical meetings, the parties had the opportunity to review and provide input to ENO on ENO's load forecasting methodology, the DSM Potential Study results, the optimized and manual portfolios and which of the portfolios should be downselected for further analysis, which metrics should be included in the scorecard matrix, and the Energy Smart program design, budgets and savings goals. The Advisors find that the Intervenors in the IRP proceeding were provided with a meaningful opportunity to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with the Utility, as required

[57] IRP Rules at §§ 5.B and 7C.2.
[58] *Id*.
[59] 2024 IRP Report at pages 51-52.
[60] *Id*. at 50.

under the IRP Rules.[61] As mentioned above, the Intervenors did not participate in the concurrent development of the DSM Potential Study.

2. The DSM Potential Study and Treatment of DSM as a Resource

Section 5.A.4 of the IRP Rules requires ENO to consider and identify all cost-effective demand-side resources through the development of a DSM potential study, and that all DSM measures with a TRC Test value of 1.0 or greater shall be considered cost-effective for DSM measure screening purposes. Section 5.A.4 requires that:

a. The DSM potential study shall include, but not be limited to: identification of eligible measures, measure life expectancies, baseline standards, load reduction profiles, incremental capacity and energy savings, measure and program cost assumptions, participant adoption rates, market development, and avoided energy and capacity costs for DSM measure and program screening purposes.

b. The principal reference document for the DSM potential study shall be the New Orleans Technical Reference Manual ("TRM").

c. In the development of the DSM potential study, all four California Standard Practice tests (*i.e.*, TRC, RIM, Program Administrator Cost Test, and Participant Cost Test) will be calculated for the DSM measures and programs considered.

d. The Utility should incorporate any known Council policy goals or targets (including such policy goals or targets identified in the Initiating Resolution) with respect to demand-side resources.

e. The cost-effective DR programs should include consideration of those programs enabled by the deployment of Advanced Meter Infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer classes.

f. Data supplied as part of the Utility's IRP filing should include: a description of each potential demand-side resource considered, including a description of the resource or program; expected penetration levels by planning year, hourly load reduction profiles for each DSM program utilized in the IRP process; and results of appropriate cost-benefit analyses and acceptance tests, as part of the planning assumptions utilized within the IRP planning process.

g. The Council will decide on, and announce in the Initiating Resolution, whether it will procure an independent consultant to perform a DSM Potential Study. In the event the Council does not procure an independent contractor, ENO shall provide a DSM Potential Study.

In the Initiating Resolution, the Council directed CURO to issue a request for qualifications for an independent consultant to perform a DSM Potential Study, but noted that if the Council did not

[61] IRP Rules at Section 9.A.1.

select a consultant prior to September 15, 2023, ENO would provide the DSM Potential Study.[62] The Council also noted that other parties may procure their own DSM consultants to submit studies into the record.[63] The Council did not select a DSM Potential Study consultant prior to the deadline, and ENO submitted its DSM Potential Study on February 1, 2024. No other party submitted a DSM Potential Study. The Initiating Resolution directed ENO to include the budget and kWh/kW savings estimates in developing the DSM Potential Study data inputs and assumptions for Program Years ("PY") 13 and 14 for the planning strategies and to also include the approved budgets and savings estimates for PY 15 if the Council approved them by the deadline for the issuance of Council Policies that must be included in the IRP, or to include ENO's proposed budgets and savings estimates if the Council did not act prior to that deadline.[64]

In Resolution No. R-23-553, the Council directed ENO to include cost-effectiveness scores for Energy Smart programs using both the weighted average cost of capital ("WACC") and a pre-determined societal discount rate in the DSM Potential Study.[65]

The DSM Potential Study included a rigorous analysis of input data for the EE and DR components, calibrated the achievable potential Reference case to the historical ES program data, and provided a DSM supply curve as IRP input data, with EE impact load shapes and DR annual savings and levelized costs. Each DSM Potential Study measure was mapped to one or more DSM programs, then developed into a program load shape representing the aggregate hourly energy savings for the group of measures included in the program over the 20-year planning period. This input data is aligned with the Council's IRP rules, which request that the data supplied include a description of each demand side resource considered, including a description of resource expected penetration levels by year, hourly load reduction profiles for each DSM program, results shown using both the utility's WACC and the societal discount rate, and results of all four standard cost-effectiveness tests were calculated.[66]

The EE market characterization used datasets from the 2022 Residential Appliance Saturation Survey ("RASS") conducted for ENO, and the ENO Business Plan 2024 ("BP24") forecast sales and customer counts. Customer segments were selected with assumptions about the stock, electricity sales, end-use breakdown, and energy use intensity. The payback acceptance curves for ENO were developed based on the results of customer surveys. The DSM measure list focused on technologies likely to have the highest feasible, cost-effective contribution to savings potential. The TRC measure screening threshold for all measures was 0.9, with most of the viable measures implemented into Energy Smart programs exceeding that level. To achieve the two percent (2%) savings target, incentive levels were assumed up to 100%, and the TRC measure screening threshold was relaxed to 0.75 from 0.9.[67] The high case assumed no TRC measure screening threshold, with every measure passed on to the achievable potential analysis. EE savings over the 20 years ranged from 1,000 GWh to over 2,000 GWh,[68] slowing by 2031 due to increasing saturation of the existing set of measures. Peak demand savings over the 20-year period rose to

---

[62] Initiating Resolution at 18.
[63] Init*Id*. at 7-8.
[64] *Id*. at 4 and 18.
[65] Resolution No. R-23-553 at 13 (Dec. 14, 2023).
[66] 2024 IRP Report, Appendix D, DSM Potential Study, at 113.
[67] *Id*. at 13.
[68] *Id*. at 14.

levels ranging from 400 MW to 700 MW.[69] The estimated cost of incentives varies significantly between the low and high DSM cases, with the respective 20-year total incentive costs ranging from $56 million to $1,439 million in nominal dollars.[70] The total DSM investment costs over the 20-year period are estimated to range from $152 million for the low DSM case to $1,613 million for the high DSM case.

The DR programs selected to evaluate included those enabled by the deployment of advanced meter infrastructure, direct load control and DR dynamic pricing programs for both Residential and Commercial customer classes. Residential Solar-paired battery storage and EV managed charging were also selected as DR programs to evaluate. The cost-effective DR options passed the benefit-cost threshold of 1.0. Achievable peak demand reduction potential from DR was estimated to grow from 15 MW in 2024 to 75 MW in 2043, approximately 8.4% of ENO's peak demand in 2043.[71] Of the total cost-effective DR potential by 2043, C&I curtailment (most with Auto-DR HVAC control) was projected at a 51% share, direct load control ("DLC") of residential thermostats at 22% share, dynamic pricing at a 20% share, and solar-paired battery storage at a 7% share.[72] The two added DR options – Peak Time Rebate and EV Managed Charging were analyzes as both not cost-effective and were therefore not included in the achievable DR potential results.

The 2024 DSM Potential Study results were benchmarked against the 2021 results with the few differences noted. It is important to note that programs found to be cost-effective in the DSM Potential Study are evaluated as DSM inputs in the IRP process, and modeled with other resources over the planning period. DSM programs are selected in the optimization of IRP portfolios, related to the planning scenarios and planning strategies. Also, the long-term achievable DSM potential identified for the IRP 20-year planning period is inherently different from the short-term DSM savings potential that is identified through a DSM program portfolio design effort targeting the 3-year period implementing the next Energy Smart programs. However, the IRP DSM Potential Study is an important element to consider in Energy Smart program design.

The DSM Potential Study team provided several suggestions: (i) review and update the TRM for high impact measures; (ii) consider including dynamic pricing DR options; (iii) analyze the merits of time of day usage as it aligns to grid-based energy resources (*i.e.*, DERs) and their associated costs; and (iv) explore cost-effective opportunities, pricing structures, and research on additional benefits to behind-the-meter ("BTM"), including battery storage.

The Advisors find that the DSM Potential Study has met the Council's requirements. The Advisors note the merit of the suggestions from the DSM team, and will reference such for consideration in the Findings section of this Report.

3. Treatment of DER

Section 5.A.3 of the IRP Rules requires ENO to consider DERs among the potential supply-side resources analyzed for the 2024 IRP Report. The Initiating Resolution directed ENO to the greatest

[69] *Id*. at 15.
[70] *Id*. at 17.
[71] *Id*. at 22.
[72] *Id*. at 23.

extent feasible to include Community Solar as a potential DER for New Orleans in accordance with the treatment of DER as specified in the IRP Rules.[73]

In the IRP Rules and the Initiating Resolution, the Council stated that integration of distributed generation and customer-owned DER into the New Orleans electric grid in a manner that supports grid reliability and sustainability remains a priority.[74] Thus far, the IRP process and Reports have addressed the integration of resources, with less focus on grid impacts and grid reliability with respect to providing service to customers from the integrated resources. And while the 2018 and 2021 IRPs reported progress of the measures taken to develop the capability of integrating distributed generation and customer-owned DERs into the grid, in the 2024 IRP Initiating Resolution, ENO was directed to provide more detailed analysis and reporting for DER and integrated distribution planning as required by the IRP Rules. Specifically, ENO was instructed to include a DER Report containing its ongoing assessment of:[75]

(1) its progress toward being able to determine how to integrate distributed generation and customer-owned DERs into the distribution grid in a manner that supports grid reliability and sustainability;

(2) the analytical results provided from hardware, software or other equipment related to this capability;

(3) how these analytical results were used to comply with these aforementioned specific sections of the IRP Rules;

(4) the incremental costs of equipment, software and additional personnel and personnel training related to this capability, as well as an estimation of the incremental benefit; and

(5) any other remaining measures required to enable ENO to comply fully with these aforementioned Sections of the Rules, including the estimated incremental costs and benefits thereof: and to which of these remaining measures ENO has already made commitments.

(6) an estimated date by which ENO expects it will be able fully comply with the Rules and to implement such integrated distribution planning into the IRP.

Although no specific DER Report was included in the 2024 IRP filing, the 2024 IRP Report did address ENO's DER integration studies.[76] The recently formed Advanced Network Planning Department performs Feasibility Studies and System Impact Studies for customers requesting interconnection of commercial-scale (300 kW and above) DERs to ENO's distribution grid. Such studies have provided more insight into potential limitations of the distribution system and led to more collaboration with ENO's Power Delivery Planning and Grid Technology departments to develop better planning forecasts and improved technology solutions to support the growing demand of DERs. Many process improvements related to DERs have been implemented over the

[73] Initiating Resolution at 5.
[74] *Id*. at 8.
[75] *Id*. at 9.
[76] 2024 IRP Report at 25.

past two years, such as: (i) revisions to DER Interconnection Standards; (ii) DER interconnection guidelines leading to faster DER request processing times; (iii) a recent Grid Unity online interconnection portal has provided a digital intake tool for DER application requests and interconnection review processing; (iv) incorporating existing DERs into power flow models for planning and interconnection studies; (v) development of initial technical screening review criteria for DER requests; (vi) building a team of five in-house engineers to perform detailed interconnection impact studies for DER projects; (vii) analyzing solar generation penetration by feeder and identifying feeders with penetration greater than 15% of feeder peak capacity, where new DER requests could trigger additional studies and/or upgrades; and (viii) mapping known DER technologies (smart thermostats, EV chargers, and solar connected batteries) by feeder.

ENO lists essential components of their DER integration capability as the smart infrastructure of AMI and distribution automation-enabled devices, the smart operational systems of DMS/OMS, enhanced DER analysis, and interconnection process improvements.

4. The Optimization Process and Planning Scenarios and Planning Strategies

Section 7 of the IRP Rules sets forth the requirements for the portfolio optimization process to be used in the IRP analysis. The Initiating Resolution directed ENO to include the Council's goal of increasing the projected incremental annual kWh savings from the Energy Smart Program by 0.2% per year, until such time as the program generates incremental annual kWh savings at a rate equal to 2% of annual kWh sales ("2% Goal") in the 2024 IRP modeling unless the Council set a new goal prior to the deadline for the issuance of Council Policies that must be included in the optimization process (April 15, 2024).[77] In Resolution No. R-23-553, the Council made a determination to keep the 2% Goal in place through the end of PY 15 and to reconsider the 2% Goal based upon the outcome of the DSM Potential Study for the 2024 IRP.[78] Therefore, the Council did not change the 2% Goal prior to the deadline and ENO was required to include it in the modeling.

The Initiating Resolution also directed ENO to incorporate compliance with the Council's RCPS into the planning strategy, reflecting known utility regulatory policy goals of the Council.[79]

The power generation technologies included in the portfolio modeling were those projected to be commercially available to ENO in its region during the 20-year planning period and included five types of natural gas generators, including a type of generator that can be fueled with natural gas mixed with hydrogen (up to 30% of the mix being hydrogen); on shore wind; utility-scale solar; and lithium-ion BESS with a 4-hour duration.[80] In addition to power generation technologies, demand-side management measures were included in the modeling. The IRP process began with assumptions and inputs developed for ENO's Business Plan 2024 ("BP24").

To initiate the resource portfolio analysis, ENO created three Planning Scenarios with the consensus of the Parties. Each Planning Scenario is a set of assumptions regarding what will occur with respect to various market-based factors that ENO has no control over during the 20-year

[77] Initiating Resolution at 4 and 18.
[78] R-23-553 at 11.
[79] Initiating Resolution at 5.
[80] 2024 IRP Report at 40.

planning period, such as the growth of ENO's load (customer base), natural gas prices, when non-ENO-owned fossil fuel-fired generators in the market will retire, whether a carbon tax will be imposed, market prices for energy, and the cost of capital to invest in renewables. No single Planning Scenario is expected to be an accurate prediction of the future; rather, the three different Planning Scenarios created were designed to bracket the range of possible different future market situations so that the portfolio analysis can demonstrate how different combinations of resources might perform in the different possible futures.

Planning Scenario 1 was a reference scenario that assumed the current trends in load growth, natural gas prices, plant deactivations, carbon taxes, and renewable capital costs carry forward through the entire 20-year planning period.[81] In Planning Scenario 2, the reference assumptions were used for load growth, natural gas prices, carbon taxes, and renewable capital costs, but deactivations of coal and natural gas plants were assumed to be accelerated in order to comply with proposed changes to the Clean Air Act Section 111(d), with new resources being built to comply with those changes.[82] Planning Scenario 3 included assumptions of high load growth, high natural gas costs, early deactivations of coal and natural gas generators, high carbon taxes and low renewable capital costs.[83]

Once the Planning Scenarios were developed, four Planning Strategies were designed to represent different policies for resource acquisitions that ENO and the Council can implement, such as using least-cost resources or only resources that comply with the Council's RCPS policy, and so forth.

In Planning Strategy 1, AURORA met the long-term capacity needs with the least-cost resource portfolio of supply and DSM resources. In Planning Strategy 2 AURORA included DSM programs that met the Council's stated 2% Goal, then optimized the remaining resources on a least-cost basis to meet long-term capacity requirements. In Planning Strategy 3, AURORA included DSM programs to meet the Council's 2% Goal and then optimized resources to meet the remaining long-term capacity requirements on a least-cost basis using only renewable resources that comply with the Council's RCPS requirements.[84] In Planning Strategy 4, AURORA included all DSM from the DSM Potential Study Societal High Case, 800 MW of renewables by 2030, including 200 MW of behind-the-meter solar (such as customer-owned rooftop solar) and 55 MW of Community Solar, and optimized resource additions to the remaining capacity requirements on a least-cost basis using only renewable resources.

A Stakeholder Scenario (Planning Scenario 3) and Stakeholder Strategy (Planning Strategy 4) were defined by the Intervenors.[85] The Stakeholder Planning Scenario was characterized by high load growth, gas prices and DSM additions, as well as low renewable capital cost assumptions.[86] The Stakeholder Planning Strategy (Strategy 4) constrained the optimization modeling of resources by pre-determining specific MWs of new renewable resources, including behind-the-meter solar and community solar, and the DSM Potential Study Societal High Case DR and EE IRP inputs, to be added over the planning period. The portfolio modeling program selected the

[81] 2024 IRP Report at 51.
[82] *Id*.
[83] *Id*.
[84] Note that the RCPS annual compliance is based on kWh sales, and not meeting capacity requirements.
[85] 2024 IRP Report at pages 51-52.
[86] 2024 IRP Report at 50.

remaining resources needed for each Planning Scenario that was modeled with the Stakeholder Strategy, which ranged from 1,550 MW to 4,200 MW based upon the assumptions used for each Planning Scenario.

Once the three Planning Scenarios and four Planning Strategies were developed, ENO put each combination of scenario and strategy into the AURORA software modeling system to generate twelve lowest-cost ("optimized") portfolios of future resources to meet ENO's capacity requirements over the 20-year planning period. To address the possibility of early retirements of existing resources, two additional "manual" portfolios were created that included all of the inputs for Planning Strategy 1 and Planning Scenario 1, but with two different earlier deactivation dates for UPS PB1.[87] ENO's planning assumption, based on a recent evaluation of the plant, is that UPS PB1 would be deactivated in 2041, the two manual portfolios (identified as Portfolio 1a and Portfolio 1b) would be modeled as retiring that unit in 2032 and 2035, respectively.[88]

The analysis of the four Planning Strategies across the three Planning Scenarios resulted in twelve optimized portfolios, plus the two additional Manual Portfolios, for a total of fourteen portfolios. Based on our review of the development of the fourteen portfolios, the Advisors find that ENO has complied with the requirements of the IRP Rules and Initiating Resolution with respect to portfolio optimization and the consideration of early retirement of resources.

Further Portfolio Analysis

After the fourteen resource portfolios were generated, five were downselected for further, more detailed, analysis and evaluation based upon a consensus among the parties that those five portfolios were reasonably representative of all fourteen portfolios.[89] The further analysis included hourly production cost modeling, DSM modeling, TRSC modeling, a stochastic assessment of risks related to fluctuations in natural gas prices and CO2 prices, and the scorecard ranking of each portfolio for factors not easily incorporated into the portfolio modeling program. For each of the five downselected portfolios, annual capacity expansion results and annual DSM capacity over the planning period were evaluated, and the AURORA production cost model results for the relevant Planning Scenario were combined with other spreadsheet-based fixed cost components to produce a TRSC. Downselected portfolios built under specific Planning Scenarios were *also "cross-tested" for TRSC results under the other two Planning Scenarios, but not adjusted, and therefore saw greater reliance on the MISO market to meet energy demand. The comparati*ve value of the cross-testing TRSC analyses comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing solely on the estimated costs of one Portfolio versus another, particularly given that actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current, actual market costs.[90]

[87] 2024 IRP Report at 13 indicates that UPS PB1 is 506.2 MW of ENO's total 1391.4 MW of capacity, and that ENO estimates that over the 20-year planning period it will deactivate 675 MW of its existing capacity. The 2024 IRP Report at 14 indicates that UPS PB1 will be one of the units anticipated to be deactivated during the planning period.
[88] 2024 IRP Report ay 14.
[89] *Id*. at 61.
[90] *Id*. at 66.

5. Portfolio Results and Comparisons

The only resource that appeared in all fourteen resource portfolios was DSM, indicating that energy efficiency, demand response, and other programs designed to reduce customer consumption or encourage customers to conserve power at key times is expected to be cost-effective and an important part of the portfolio under all reasonably possible future scenarios and planning strategies. Wind generation appeared in thirteen of the fourteen portfolios, with the highest MW modeled in all but one of the thirteen portfolios, indicating that wind is also likely to be one of the lowest-cost resources included in an ENO resource portfolio under nearly all future conditions. BESS appeared in ten of the fourteen portfolios, indicating that utility-scale battery storage is also likely to be among the lowest-cost resources that perform well under most future conditions.

The 2024 IRP Report shows some interesting changes from the results of the 2018 and 2021 IRP Reports. While all three IRP Reports have consistently indicated that DSM, BESS, wind, and solar are resources likely to perform well in many future scenarios, natural gas fired generators appeared in 9 of the 15 portfolios generated in the 2018 IRP Report,[91] disappeared completely in 2021 resource portfolios (the first time natural gas was not selected for any portfolio),[92] but then re-appeared in the 2024 IRP Report in 5 of the 14 portfolios.[93] The reappearance of natural gas in the 2024 analysis indicates that there may be potential future scenarios where a natural gas generator could be a reasonable option.

Also of note is that while the 2018 IRP Report showed utility-scale solar being selected in a majority of portfolios[94] and the 2021 IRP Report showed it being selected for all portfolios,[95] in the 2024 IRP Report, utility-scale solar was only selected for 4 of the 14 portfolios, though it was forced in for another two portfolios,[96] making it difficult to determine if it would have been selected for those two portfolios if it had not already been forced in. However, the swift change from having utility-scale solar included in all portfolios to being included in less than half of the portfolios does indicate that further analysis of utility-scale solar and alternatives to it should be performed prior to the acquisition of future utility-scale solar resources. Wind, in particular, may be a better alternative in some scenarios, given its strong showing in the 2024 IRP Report. The various portfolios analyzed in the 2024 IRP indicate that the optimal combination of resource additions will depend on ENO's capacity need and the market forces and regulations in place at the time of the proposed capacity addition. The fairly significant fluctuations over time regarding resource selections in the IRPs does underscore the need for updated analyses regarding available alternatives prior to any future investment in generation resources.

Of note in the additional TRSC analyses cross-testing of the downselected portfolios, while this IRP's TRSC base analysis indicated that an earlier retirement of the USB PB1 unit in 2035, rather than in 2041, was projected with relatively lower TRSC across all three Planning Scenarios, the manual portfolios in the 2021 IRP that accelerated the deactivation of USB PB1 resulted in TRSC

[91] 2018 IRP Report at 58.
[92] 2021 IRP Report at 65.
[93] 2024 IRP Report at 59.
[94] 2018 IRP Report at 58.
[95] 2021 IRP Report at 65.
[96] 2024 IRP Report at 59.

values about 8% higher than the Least Cost Planning portfolio. The results of the manual portfolio analysis over the last two IRPs underscore the sensitivity of the TRSC results to input assumptions and the value of further analysis in future IRPs.

Also, the Strategy 3/Scenario 3 portfolio, which consisted of wind, battery, and DSM in compliance with the Council's 2% Goal and RCPS, was projected with the lowest TRSC in Scenarios 1 and 3 and the second-lowest TRSC under Scenario 2.[97] Strategy 4 (Stakeholder Strategy)/Scenario 2 portfolio, in which 800 MW of renewables, including community solar, utility-scale solar, battery, wind and DSM, were constrained into the portfolio in designated amounts, was projected with the highest TRSC across all three Planning Scenarios. These projected TRSC results would seem to support a conclusion that caution should be used in evaluating any proposals to rely upon resources not supported by thorough long-term cost-benefit analyses.

The Advisors also note that, based on the Strategy 3/Scenario 3 portfolio projected to have the lowest TRSC in cross-testing with all Planning Scenarios, the resources added during the planning period would be wind generation, BESS, or DSM. The relatively high TRSC projected for Planning Strategy 4 in cross-testing across Planning Scenarios therefore should not be seen as an indication that a portfolio that only includes new generation from renewable resources and BESS could not be successful. The comparative value of this IRP comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing solely on the costs of one Portfolio versus another, particularly given that actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current, actual market costs. The 2024 IRP Report appears to indicate that as long as reasonably priced and cost-effective renewable resources are selected, it is likely possible to meet the long-term needs of the City at a reasonable cost over the planning period by adding only renewables, BESS and DSM to ENO's portfolio of resources.

The IRP Rules (Sec. 3.A.3) list as a specific objective to be accomplished in the IRP planning process –"to anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors." In compliance with this IRP objective, the analysis was conducted with a "stochastic" risk assessment to provide a more complete picture of the potential range of portfolio costs compared to assuming fixed values for uncertain price inputs over the planning period. A stochastic risk assessment acknowledges that real-world cost results are not always predictable when a range of input prices are assumed. For the five downselected Portfolios, a random probability distribution or pattern of input prices was used to evaluate the range of probable portfolio costs to changes in two main input assumptions—natural gas prices and CO2 prices. This stochastic risk assessment gave an indication of the variability of each portfolio's costs relative to changes in assumptions for natural gas prices and CO2 emission prices. Specifically, 30 price distributions were generated for Henry Hub natural gas prices and CO2 emission prices as price inputs over the 20-year planning period, and assigned to randomized runs for each of the five downselected portfolios. The resulting range of each potential portfolios' costs provides insights representing the sensitivity of each portfolio to gas and CO2 prices.

[97] 2024 IRP Report at 67.

The stochastic risk analysis of the five portfolios indicated differences in TRSCs from the base results. After stochastic distributions were generated for future natural gas and CO2 prices, the Henry Hub gas prices and CO2 emission prices were randomized and assigned for 150 stochastic runs. From the resulting ranges of TRSCs for each of the 5 downselected portfolios the difference in TRSC between the base results and the stochastic results was due to the difference in gas price and CO2 price produced under the specific modeled Planning Scenario compared to the price ranges in the stochastic runs. The stochastic risk analysis of the five portfolios indicated that the two downselected portfolios that rely solely upon renewables, BESS, and DSM are projected to have higher TRSC relative to the portfolios including a natural gas fired generator in future scenarios where there are lower CO2 and natural gas prices, which tend to make natural gas-fired generation more cost effective compared to renewables.[98] Given how dependent the results of the TRSC and stochastic risk analyses of the various portfolios appear to be on the assumptions made related to the cost of natural gas and the likelihood, timing, and level of a carbon tax over the 20-year planning period, it is important to ensure that an updated analysis is performed prior to the acquisition of any new resource of significant size. This conclusion also supports the value of continuing to perform the IRP analysis on its triennial cycle so that changes to the market, forecasts, and applicable policies can be evaluated with reasonable frequency.

6. Evaluation of Energy-Based Solutions, Resource Deactivations and early Retirements and ENO's Union Power Station Power Block 1

In the Initiating Resolution, the Council discussed the interest of the Advisors and Intervenors in the modeling of energy-based solutions and optimizing the retirement dates of existing resources in addition to the current IRP portfolio modeling for capacity needs and using fixed retirement dates.[99] The Council noted that the modeling of manual portfolios with early retirement dates for UPS PB1 was informative and useful to the Council and directed ENO to work with the Parties to develop similar modeling for the 2024 IRP process.[100] Recognizing that the AURORA modeling is based on capacity solutions, in the Initiating Resolution, the Council directed ENO to work with the Stakeholders and Advisors toward evaluating certain energy-based solutions and to develop an evaluation of early retirements of resources that is sufficient to provide meaningful information regarding energy-based impacts that can be accomplished within the procedural schedule.[101]

Discussions at the IRP technical meetings pointed out that an energy-based approach and investing above ENO's capacity need could possibly lower customer costs by generating excess energy market revenues, but that such an approach could also increase customer costs if future energy market conditions vary from the IRP modeling assumptions and the additional resources do not produce enough energy revenue to cover their costs. Based on those discussions, the maximum seasonal reserve margin target that the Aurora model uses to judge whether a resource need exists was relaxed, allowing the model to select more resources than needed to meet ENO's capacity requirements if the energy revenue is projected to offset the additional cost under the assumptions of the relevant Planning Scenario and Planning Strategy combination.[102] This approach provided additional insight regarding the types of resources the planning model could select, even without

[98] 2024 IRP Report at 72.
[99] Initiating Resolution at 12-14.
[100] *Id*. at 13.
[101] *Id*. at 14.
[102] 2024 IRP Report at 69.

a need for capacity, while executing a capacity-based resource planning analysis that aligned with the IRP Rules. As an example of this approach, the Strategy 3/Scenario 3 allowed the Aurora model to select significant renewable capacity above the reserve margin requirements.

Although the portfolio modeling did not include optimizing the early retirements of ENO's existing resources, the possibility of early retirements was addressed by altering the assumptions for two additional manually-created portfolios that included all of the inputs for Planning Strategy 1 and Planning Scenario 1, but with two different earlier deactivation dates for UPS PB1, ENO's largest generator representing a significant amount of the planning years retirements. A UPS PB1 earlier retirement date portfolio was included as a downselected portfolio for further evaluation.

The Advisors find that the IRP modeling complied with the Initiating Resolution with respect to energy-based solutions and optimizing the retirement dates of existing resources.

7. Report of ENO's Progress Toward Integrating DERs Into the Distribution Grid

The Initiating Resolution required ENO to include in the 2024 IRP Report a report containing its ongoing assessment of (1) its progress toward being able to determine how to integrate distributed generation and customer-owned DERs into the distribution grid in a manner that supports grid reliability and sustainability; (2) the analytical results provided from hardware, software or other equipment related to this capability; (3) how these analytical results were used to comply with the IRP Rules; (4) the incremental costs of equipment, software and additional personnel and personnel training related to this capability, as well as an estimation of the incremental benefit; and (5) any other remaining measures required to enable ENO to comply fully with the IRP Rules, including the estimated costs and benefits thereof, and to which of these remaining measures ENO has already made commitments.[103] The Initiating Resolution also required that the 2024 IRP Report should also contain an estimated date by which ENO expects it will be able to fully comply with the Rules and to implement such integrated distribution planning into the IRP.[104]

As discussed previously, although no specific DER Report was included in the 2024 IRP filing, the 2024 IRP Report did address ENO's DER integration studies, including a recently-formed Advanced Network Planning Department which performs DER Feasibility Studies and System Impact Studies, and eight DER-related process improvements that have been implemented over the past two years.[105] Although analytical results and incremental costs related to this DER capability have not yet been provided, more DER-related information is anticipated in Docket UD-24-02 and as more transmission/distribution planning is integrated into current and revised IRP Rules and the triennial IRP process.

The Advisors find that ENO has complied with the DER-related requirements of the IRP Rules in the 2024 IRP.

[103] Initiating Resolution at 9-10 and 18.
[104] *Id*.
[105] 2024 IRP Report at 25.

8. IRP Scorecard

The IRP Rules at Section 7.I require ENO to develop and include a scorecard template or set of quantitative and qualitative metrics to assist the Council in assessing the IRP based on the Resource Portfolios. The scorecard should rank the resource portfolios bey how well each portfolio achieves each metric. Such metrics should include but not necessarily be limited to: cost; impact on the Utility's revenue requirements; risk; flexibility of resource options; reasonably quantifiable environmental impacts (such as national average emissions for the technologies chosen, amount of groundwater consumed, etc.); consistency with established, published city policies, such as the City's sustainability plan, and macroeconomic impacts in New Orleans. In the Initiating Resolution, the Council directed ENO to include in its scorecard all of the metrics listed in the IRP Rules, including consistency with the RCPS adopted in Council Docket No. UD-19-01.[106]

The parties agreed to a set of 17 metrics to be included in the scorecard analysis, with each of the five downselected portfolios rated on a numerical grading scale. The 17 metrics were grouped under seven key scoring parameters of (i) utility costs related to the Aurora model portfolio optimization; (ii) cost impact on ENO revenue requirements; (iii) risk/uncertainty; (iv) reliability; (v) environmental impact; (vi) consistency with City policies/goals; and (vii) macroeconomic impacts. The grades required consideration of the inherent compositional differences among the portfolios, and were grouped into quartiles on an A-D basis with respect to their "performance" for each factor metric relative to the other portfolios.

Evaluation of the downselected portfolios based on the scorecard results is inevitably somewhat subjective. As one approach to scorecard evaluation, if all of the 17 metrics are given equal weight and importance, then the two downselected portfolios relying upon renewables, BESS and DSM showed the highest grades, averaging a B+ for the Strategy 3/Scenario 3 portfolio (wind, BESS and DSM) and a B for the Strategy 4/Scenario 2 portfolio (various renewables, BESS and DSM). Manual Portfolio 1b (early retirement of UPS PB1) followed in grading averaging a B-; however, it was graded higher than the top two portfolios with respect to Risk/Uncertainty and tied with Strategy 3/Scenario 3 with respect to Utility Costs Impact on ENO's Revenue Requirements. A portfolio evaluation based on the scorecard would differ if one or more of the 17 specific scorecard metrics or seven key scoring parameters were given higher priority. If, for example, utility costs were considered to be of greater importance or weight than the other metrics or key scorecard parameters (such as expected value, reliability, environmental impact, consistency with City policies/goals and macroeconomic impacts), Manual Portfolio 1b could be considered to perform better than the Strategy 3/Scenario 3 and Strategy 4/Scenario 2 portfolios. The approach to scorecard evaluation again underscores the need for an updated analysis that considers updated market conditions and the specific characteristics of a proposed resource prior to any new resource acquisition.

9. 2024 IRP Action Plan

ENO described various actions that it intends to pursue following the submission of the 2024 Integrated Resource Plan.

[106] Initiating Resolution at 18.

(i) RCPS Compliance Plan- ENO will develop and file its three year RCPS compliance plan for 2026-2028.

(ii) DSM/DR Program Implementation- File Implementation Plan for Energy Smart Program Years 16-18 as required by Resolution R-23-254 and work with the Advisors and Stakeholders towards Council review and approval.

(iii) Bring Your Own Battery ("BYOB") DR Pilot Expansion- ENO will pursue continuation of the BYOB DR pilot that was conducted in 2023 and 2024 and seek further expansion of the program through the DER Programs docket (UD-24-02).

(iv) System Resiliency and Storm Hardening Plan- Building on the resilience projects approved through Resolutions R-24-73 and R-24-625, ENO will develop plans detailing additional investments and projects to support further system resiliency and storm hardening.

(v) DER Programs docket (UD-24-02)- Actively participate in docket to help shape policy and program outcomes.

(vi) Community Solar rulemaking (UD-18-03)- Continue active participation to help shape policy, rules, and processes for program administration.

(vii) Federal Funding- Identify and pursue additional opportunities for available federal grants and/or loans to support utility infrastructure projects and reduce project costs.

The Advisors support the actions that ENO has expressed its intention to pursue, and recommend that the Council approve the 2024 IRP Action Plan as presented.

B. Comments of the Parties

While many of the parties were active participants in the technical meetings and public hearings, only AAE and ORS filed joint comments regarding the 2024 IRP Report.

1. AAE/ORS Comments

AAE and ORS stated: "ENO's modeling indicates that its compliance with the city's Renewable and Clean Portfolio Standard is the least-cost option for generation planning."[107] AAE and ORS asserted that under all three planning scenarios, the RCPS compliance strategy produced the lowest TRSCs.[108] However, as noted previously in this report, the comparative value of the cross-testing TRSC analyses comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a <u>guide</u> for the future, <u>not</u> from focusing solely on the estimated costs of one Portfolio versus another

AAE and ORS recommended strengthening the RCPS by including a 10% carveout for locally generated renewable energy, which would support distributed generation and community solar, build a local clean energy workforce, improve air quality, and reduce emissions.[109] AAE and ORS also urged the Council to enforce the implementation of consolidated billing for community solar under Docket No. UD-18-03, noting that ENO's opposition was based on concerns that it would make community solar "too successful."[110] The Advisors note that amendments to the RCPS and

[107] AAE and ORS Comments at 1.
[108] *Id*. at 2.
[109] *Id*.
[110] *Id*.

Community Solar Rules are outside the scope of the IRP proceeding. In the Advisors' RCPS Report (3 Sept. 2019), the Advisors noted that to the extent that the Council wishes to prioritize certain resources under the RCPS without creating a mandatory carve-out, providing a multiplier would give such resources an economic advantage in RCPS compliance. Rather than creating a mandatory carve-out for certain types of renewables to meet this standard, the Advisors recommended multipliers for "tiers" of resources.

AAE and ORS commented that robust DSM programming is essential and must be structured to give service providers the certainty needed to deliver services.[111] AAE and ORS encouraged ENO to file a three-year DSM implementation plan by June 2025 to ensure full program launch in January 2026, aligning with Council policies to scale energy and demand savings.[112] To strengthen DSM, AAE and ORS recommended that the Council: (1) require that 15% of total DSM portfolio savings benefit income-qualified customers; (2) adopt improved data protocols, including a citywide benchmarking ordinance for large commercial buildings; (3) require program enhancements for low-to-moderate income customers that leverage Inflation Reduction Act tax credits and rebates; and (4) establish a formal DSM Working Group.[113] The Advisors note that the Initiating Resolution specifies that the Energy Smart Implementation filing for Program Years 16-18 shall be filed not later than June 16, 2025 and that further procedural deadlines related to that filing will be set in a future resolution.[114] It is the Advisors' expectation that such further procedural deadlines would provide opportunity for comments and reply comments on the design elements of the Energy Smart Implementation Plan such as those discussed by AAE and ORS in their comments. Also, residential and commercial battery storage were included in the 2024 IRP forecast of customer loads. Other dockets, such as UD-24-02 (DER) will include residential and commercial battery storage, and should correlate with the amounts included in the first three years of the 2024 IRP 20-year forecast. Neighborhood-targeted programming is not included in the analysis of the Integrated Resource Plan, but is being addressed in other dockets, such as UD-24-02, and should also be included in the forecast of distribution grid loads under distribution system planning.

AAE and ORS further suggested that the Council, as in prior IRP cycles, commission its own DSM Potential Study to complement ENO's analysis and identify additional energy-saving opportunities.[115]

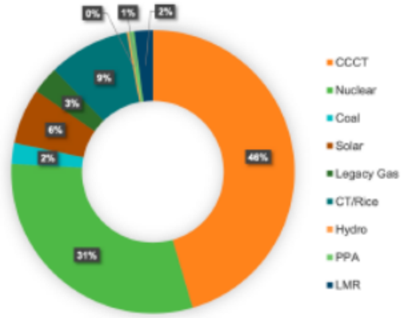
AAE and ORS stated that ENO's reliance on fossil gas remains a major concern, noting that Combined Cycle Combustion Turbine ("CCCT") and Combustion Turbine Reciprocating Internal Combustion Engine ("CT-RICE") units collectively make up 58% of ENO's generating capacity.[116]

---

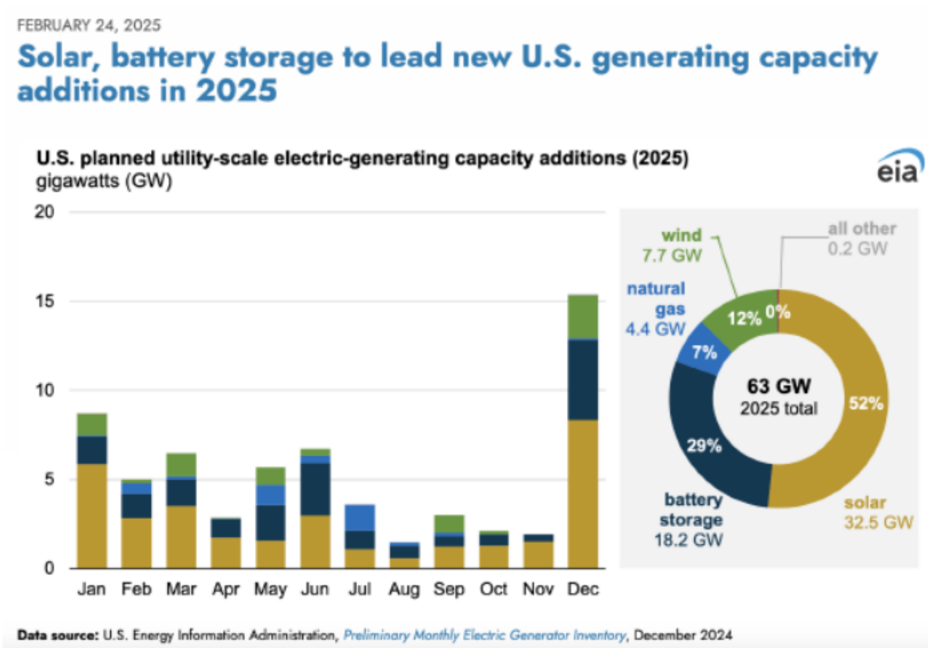
[111] *Id*.
[112] *Id*. at 3.
[113] *Id*.
[114] Initiating Resolution at 18.
[115] AAE and ORS Comments at 4.
[116] *Id*. at 4-5.

Existing Fleet Capability

Fuel Type	Summer Rating MW
CCCT	632.9
Nuclear	423.1
Coal	32.9
Solar	88.9
Legacy Gas	43.0
CT/Rice	129.1
Hydro	3.3
PPA	8.8
LMR	29.4
Total	**1391.4**



AAE and ORS criticized ENO's IRP presentation for obscuring this dependence and warned that ratepayers bear the cost of volatile gas prices through direct fuel pass-throughs.[117] Citing a February 2025 report from the Energy Information Administration showing that 52% of new utility-scale capacity additions for 2025 will be solar and 29% battery storage, they recommended that the Council require ENO to submit a plan aligned with current industry standards for clean and cost-effective generation.[118]



AAE and ORS expressed skepticism regarding ENO's hydrogen modeling assumptions, stating that ENO failed to disclose data on hydrogen fuel sourcing or cost.[119] AAE and ORS noted that ENO simply used Henry Hub natural gas prices in place of hydrogen-specific inputs, likely understating the total costs of portfolios that include hydrogen co-firing.[120] AAE and ORS

---

[117] *Id*. at 5.
[118] *Id*.
[119] *Id*. at 6.
[120] *Id*.

cautioned that ENO's use of hydrogen modeling could be used to justify new gas-fired generation that is less cost-effective than available renewable and storage alternatives.[121] AAE and ORS urged the Council to closely scrutinize ENO's hydrogen-related proposals and prioritize more affordable clean energy technologies.[122]

AAE and ORS concluded that the Council must exercise its authority to ensure the IRP produces outcomes consistent with its climate and resilience policy objectives, including the RCPS and Resolution No. R-21-401, which initiated the storm hardening and resilience docket.[123] However, the comments did not specify exactly how the IRP should align with those dockets.

2. ENO Reply Comments

ENO submitted Reply Comments responsive to the AAE and ORS Joint Comments. Regarding AAE/ORS's claim that the RCPS compliance strategy produced the lowest TRSC under all planning scenarios, ENO clarified that this is not accurate.[124] ENO explained that while the RCPS portfolio (Strategy 3/Scenario 3) was lowest in its optimized scenario, it was not the least-cost option under Scenario 2, where Manual Portfolio 1b had the lowest TRSC.[125] ENO emphasized that the TRSC results are highly dependent on the underlying scenario assumptions and that the RCPS portfolio performed less favorably when stochastic price simulations were applied, showing heightened risk due to oversupply and reduced market revenues.[126] ENO cautioned that selectively citing favorable TRSC values does not justify modifying the Council's RCPS policy.[127]

Regarding the Energy Smart Program Years 16–18 Implementation Plan, ENO responded to four specific recommendations from AAE and ORS. First, in response to the request that 15% of total DSM savings benefit income-qualified customers, ENO noted that its Revised PY15 Implementation Plan, approved by Resolution R-24-570, already dedicates approximately 18.5% of the kWh savings target to income-qualified programs, not including additional contributions from behavioral and school kit initiatives.[128] ENO expects similar levels of participation in the PY16–18 plan.[129]

Second, on the matter of improved data collection and reporting, ENO explained that it has already implemented many of the protocols recommended in Docket UD-22-04.[130] These include tracking projects by zip code and census tract and collecting deferral data.[131] ENO is also testing an automated process for providing whole-building energy use data to owners through the EPA's Portfolio Manager platform.[132]

---

121 *Id*.
122 *Id*. at 6-7.
123 *Id*. at 7.
124 ENO Reply Comments at 2.
125 *Id*. 2.
126 *Id*. 2.
127 *Id*. at 2-3.
128 *Id*. at 3.
129 *Id*.
130 *Id*. at 3-4.
131 *Id*.
132 ENO Reply Comments at 4.

Third, in response to recommendations that Energy Smart programs be coordinated with Inflation Reduction Act ("IRA") rebates and tax credits, ENO stated that it is in regular contact with state and local entities responsible for IRA implementation.[133] ENO expressed support for working collaboratively to align Energy Smart and IRA resources, although it noted that the continued availability of IRA funds remains uncertain.[134]

Fourth, regarding the suggestion to form a formal DSM Working Group, ENO reiterated the position it expressed in Docket UD-22-04: that it "supports the creation of a DSM Working Group to the extent that the DSM Working Group's efforts do not inhibit or in any way become a hindrance to implementation of the program."[135] However, ENO questioned the necessity of a new working group, citing existing collaboration through IRP technical meetings, Technical Reference Manual update meetings, and active dockets such as UD-22-04 and UD-24-02.[136]

With respect to hydrogen generation, ENO disputed AAE and ORS's claim that the IRP modeled optimistic hydrogen co-firing scenarios.[137] ENO clarified that hydrogen was not modeled in its production cost or capacity expansion analyses.[138] Instead, hydrogen was discussed in the IRP as a long-term decarbonization option, and the IRP clearly outlined the technical limitations and market uncertainties associated with its use.[139] ENO emphasized that it has no immediate plans to deploy hydrogen and is merely monitoring developments in turbine technology and fuel availability.[140]

ENO reiterated that the 2024 IRP includes several initiatives aligned with Council goals, including: (i) the forthcoming Energy Smart PY16–18 Implementation Plan; (ii) the RCPS Compliance Plan for 2026–2028; (iii) pursuit of federal infrastructure funding; and (iv) system resiliency and storm hardening efforts.[141]

V. Advisor Findings

The Advisors find that the DSM Potential Study has substantially met the Council's requirements, and note the merit of the following suggestions from the IRP DSM team for further consideration: (i) review and update the New Orleans TRM for high impact measures; (ii) consider including dynamic pricing DR options; (iii) analyze the merits of time of day usage as it aligns to grid-based energy resources (*i.e.*, DERs) and their associated costs; (iv) explore cost-effective opportunities, pricing structures, and research on additional benefits to BTM, including battery storage. The Advisors also note that that there was no stakeholder participation in the concurrent development of the DSM Potential Study.

---

133 *Id*.
134 *Id*.
135 ENO Reply Comments at 4 (citing ENO's Reply Comments, UD-22-04, Jan. 12, 2023).
136 *Id*. at 4-5.
137 *Id*. at 5.
138 ENO Reply Comments at 5.
139 *Id*.
140 *Id*.
141 *Id*. at 5-6.

Based on our review of the development of the fourteen portfolios, the Advisors find that ENO has complied with the requirements of the IRP Rules and Initiating Resolution with respect to portfolio optimization and the consideration of early retirement of resources.

The Advisors find that the IRP modeling complied with the Initiating Resolution with respect to energy-based solutions. While the Advisors find that the 2024 IRP Report is complete and substantially complies with the IRP Rules and Initiating Resolution, it does have a few shortcomings, as set forth in detail above.

In particular, although the Advisors find that ENO has generally complied with the DER-related requirements of the IRP Rules in the 2024 IRP, the following paragraphs discuss areas where more DER detail is needed, as well as inconsistencies of DER treatment in the IRP Rules making 2024 IRP Report compliance difficult.

Some aspects of customer-owned storage and other customer-owned DERs were included in the development of the load forecast, but only Utility-scale, utility-owned resources were evaluated in the 2024 IRP Report section, Capacity Resource Options, referring to the IRP Rules requirement to "*evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and DERs, among others.*"

The IRP load forecast was developed for total utility energy/demand, and was not designed to project grid impacts or locational DERs. The IRP Rules also require a detailed discussion of independent variables and their reference sources in the load forecast, including DER impacts. However, analysis or details of customer-owned DERs, including community solar, in the IRP load forecast was limited to rooftop solar, EVs and electrification.

Section 6.E. of the Council's IRP Rules requires that ENO evaluate the extent to which reliability of the distribution system can be improved through the strategic location of DERs or other resources identified as part of the IRP planning process. In response to the Initiating Resolution's requirement of a DER with specific assessments, the 2024 IRP Report did include sections that explained various steps being undertaken to implement foundational systems, software, and processes that will be necessary for ENO to further develop the ability to evaluate locational and reliability benefits and impacts of DERs in the future.

The Advisors note that other ongoing Council dockets, such as UD-18-03 regarding Community Solar and UD-24-02 regarding DERs are likely to implement changes to Council policies around DERs that will impact IRP analyses, and that technological and market changes regarding DERs have occurred since the Council's current IRP Rules were adopted.

Section 5.A.3 of the IRP Rules groups DERs with consideration of supply-side resources, which the 2024 IRP Report cited as ENO resources. Yet Section 2.A.6 of the IRP Rules defines DERs as customer-owned. The issue to be clarified is whether DERs, as customer-owned resources, should be considered as supply resources or as an expanded definition of DSM. If DERs are considered as DSM or a demand-side resource, a delineation of DSM analysis in the IRP would need to address DERs. This IRP Rules requirement is another example of the need to revise the IRP Rules with an objective of integrated resource planning to include more detailed analysis of customer-owned distributed energy resources.

If prospective Council policy includes some aspects of DERs in addition to RCPS and the Energy Smart 2% savings goal, more specificity will be needed with respect to the IRP Rules and development of planning strategies in subsequent IRPs.

Integrated resource planning should include more detail regarding the delivery of cost-effective, reliable integrated resources, i.e. more analyses on that requirement of the distribution system. The related dockets, UD-24-02 to enhance the availability of DERs, UD-18-03 Community Solar, UD-22-03, Battery Storage DR Pilot, among others, should be coordinated in reasonable fashion, with the IRP process.

If the Energy Smart three-year Implementation Plan for PY 16-18 (2026-2028) is filed in compliance with the Initiating Resolution and procedural schedule, there should be sufficient time for Stakeholder comments and Council review to provide for any revisions and adequate time for Energy Smart contractors to prepare for the start of PY 16.

VI. Recommendations

Based on our comprehensive review of the 2024 IRP process and ENO's Final 2024 IRP Report, the Advisors recommend that the Council accept the 2024 IRP Report as being in substantial compliance with the Council's substantive and procedural requirements of the IRP Rules and Initiating Resolution, and terminate the proceeding with no further action.

The Advisors also recommend that the Council consider opening a proceeding to evaluate revising the IRP Rules with respect to how DERs are included in both the DSM potential study and the IRP analyses to reflect these recent developments. The IRP Rules were last amended in 2017 in Resolution R-17-429, and the Advisors recommend that the Council now consider reviewing the IRP Rules with input from all Stakeholders, particularly with respect to the definition of DER as a supply-side or demand-side resource, and the specific analyses required to evaluate DERs.

The Advisors further recommend that the Council approve the Action Plan in ENO's 2024 2024 IRP Report subject to the following caveats: (i) approval of the Action Plan does not constitute Council approval of any specific asset or resource acquisition- any such acquisition must still be submitted for Council approval consistent with the Council's rules and regulations; and (ii) Council acceptance of the 2024 2024 IRP Report and approval the Action Plan, does not preclude the Council from considering and/or ordering further actions by ENO relative to resource planning and acquisition; in particular, acceptance of the Final 2024 IRP shall have no precedential impact upon the Council's considerations in the RCPS rulemaking docket (UD-19-01) or any other related docket.

RESPECTFULLY SUBMITTED:

J. A. "Jay" Beatmann, Jr. (#26189)
Basile J. Uddo (#10174)
Dentons US LLP
650 Poydras Street, Suite 2850,

New Orleans, LA 70130
Telephone: (504) 524-5446
Facsimile: (504) 568-0331
Email: jay.beatmann@dentons.com

Clinton A. Vince
Emma F. Hand
Presley R. Reed, Jr.
1900 K Street, N.W.
Washington, D.C. 20006
202-408-6400 (Telephone)
202-408-6399 (Facsimile)

Advisors to the Council of the City of New Orleans

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served upon the Official Service List in UD-23-01 via electronic mail and/or U.S. Mail, postage properly affixed, this 2nd day of June, 2025.

J. A. "Jay" Beatmann, Jr.