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July 12, 2022

BY ELECTRONIC DELIVERY

Ms. Lora W. Johnson
Clerk of Council
Council of the City of New Orleans
City Hall, Room IE09
1300 Perdido Street
New Orleans, LA 70112

In Re: 2021 Triennial Integrated Resource Plan Of Entergy New Orleans, LLC,
CNO Docket No. UD-20-02

Dear Ms. Johnson:

Enclosed please find the *Advisors' Report Regarding the Entergy New Orleans, LLC 2021 Integrated Resource Plan* in the above referenced docket, which we are requesting be filed into the record along with this letter. The Advisors submit this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you direct.

Sincerely,

Jay Beatmann
Counsel

JAB/dpm
Attachment

cc: Official Service List for UD--20-02

BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC	)))))	**DOCKET NO. UD-20-02**

ADVISORS' REPORT REGARDING THE
<u>ENTERGY NEW ORLEANS, LLC 2021 INTEGRATED RESOURCE PLAN</u>

July 12, 2022

TABLE OF CONTENTS

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I. Executive Summary

Pursuant to the procedural schedule set forth Resolution No. R-20-257 as amended by Resolution No. R-21-73, and the April 7, 2021 Order of the Hearing Officer ("April 7 Order") in this proceeding, the Advisors submit this Advisors' Report regarding Entergy New Orleans, LLC's ("ENO" or the "Company") 2021 Integrated Resource Plan ("Final 2021 IRP"). As discussed in full below, the Advisors conclude that, despite ENO's failure to model the Stakeholder Strategy as requested by the Stakeholders, it did take steps to address Stakeholder concerns related to that failure and ENO has substantially met both the Council's procedural requirements and the requirements for the content of the IRP report. The Advisors therefore recommend that the Council accept ENO's Final 2021 IRP as filed in compliance with the Council's substantive and procedural requirements. The Final 2021 IRP is the first IRP submitted to the Council that shows no addition of new fossil-fueled resources to ENO's portfolio under any of the circumstances or strategies modeled. It generally indicates that adding some combination of renewable resources, battery storage, and demand-side management ("DSM") to ENO's portfolio is likely to be the least-cost pathway to meet the electric supply needs of New Orleans. The Final 2021 IRP is also the first IRP submitted to the Council that serves as a reference for the Renewable and Clean Portfolio Standard and its calculation of compliance costs.

The Advisors further recommend that the Council approve the Action Plan in ENO's 2021 Final IRP subject to the following caveats: (1) 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 (2) Council approval of the Final 2021 IRP, including 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, approval of the Final 2021 IRP shall have no precedential impact upon the Council's considerations in the Renewable and Clean Portfolio Standard rulemaking docket (UD-19-01) or any other related docket.

The Advisors do recommend a few changes for future IRPs that can be implemented in the Initiating Resolution for the next IRP cycle to improve the resulting analyses.

- To the extent that the Council determines that it will use its own independent expert to produce a DSM Potential Study in the next IRP cycle, it would be helpful if the Council provided instructions to ENO and the independent consultant as to how to make portfolios produced using inputs from different DSM Potential Studies more directly comparable.

- It would be helpful for IRP final reports to include more detail regarding how specific distributed energy resources ("DER"), such as growth in community solar, battery storage, and electric vehicles, impact the load forecast, with potential ranges of projected estimates.

- ENO should be directed to utilize AURORA's modeling capability for an economic analysis which optimizes retirement dates for ENO's existing assets rather than utilizing fixed retirement dates, and to continue modeling an early retirement date for Union Power Station Power Block 1 ("UPS PB1") in particular. While the Federal Energy Regulatory Commission ("FERC") rather than the Council may have jurisdiction to determine the extent to which ENO can terminate certain of its commitments and obligations, it would be informative to the Council to see the results of AURORA's analysis as to when it would be economic to retire ENO's various existing resources rather than programming in a specific retirement date for each resource.

- The issue of incorporating early retirements of existing resources simultaneously with optimizing an energy-based model solution should be considered by the Council before a procedural schedule is included in the Initiating Resolution of the next triennial IRP.

Finally, the Advisors recommend that the Council initiate a rulemaking proceeding, as discussed herein, to consider what further energy efficiency, conservation, and demand response policies and targets might be appropriate for New Orleans in light of the possible near-term attainment of the Council's 2% energy efficiency goal.

II. Background – IRP Rules and 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 generation resources and power purchase agreements 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, 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 provides the regulator and the public with some assurance that the utility is properly considering all options available to it as it makes decisions about how to service its load.

The Council has required the utilities subject to its jurisdiction to complete an IRP under a uniform set of rules since 2008.[1] Subsequent to its consideration of ENO's 2015 IRP, the Council determined that it would revise its IRP Rules,[2] which ultimately resulted in the Council's adoption of Resolution No. R-17-429, establishing the Electric Utility Integrated Resource Plan Rules of the Council of the City of New Orleans ("IRP Rules") in Council Docket No. UD-17-01.[3] 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

[1] Council Resolution No. R-08-295, Resolution Regarding Proposed Rulemaking to Establish IRP Components and Reporting Requirements for Entergy New Orleans, Inc., June 5, 2008.
[2] *See* Council Resolution No. R-17-32 (as corrected), Resolution and Order Establishing a Rulemaking Proceeding Regarding Integrated Resource Planning, January 6, 2017.
[3] The currently effective version of the IRP Rules are attached to Resolution No. R-17-429 as Attachment B, August 10, 2017.

> 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 development of a complete administrative record upon which informed Council decision-making can occur.[4]

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 Plan 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 second 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 distributed energy resources ("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.[5]

For the 2021 IRP, the Council issued its Initiating Resolution in August of 2020, Resolution No. R-20-257 ("Initiating Resolution"), which established a procedural schedule for the IRP in new Docket No. UD-20-02, addressed certain procedural matters, and set forth certain policy objectives to be incorporated into the IRP: (i) the adoption of a renewable and clean portfolio standard ("RCPS") for New Orleans in Council Docket No. UD-19-01; (ii) 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; (iii) the Energy Smart Program Years 10-12 budget and savings estimates approved in Resolution No. R-20-51 reflected in the data inputs and assumptions in all planning strategies; (iv) community solar as a potential DER for New Orleans in accordance with the treatment of DER as specified in the IRP Rules; and (iv) a scorecard template of quantitative and qualitative metrics to assist the Council in assessing the IRP in accordance with Section 7(1) of

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

the IRP Rules, including a metric of the extent to which the resource portfolios advance the goals set forth in the RCPS.[6]

Subsequent to the issuance of the Initiating Resolution, the Council decided to retain GDS Associates, Inc. to perform an independent DSM Study on behalf of the Council to assess the potential to reduce energy demand in the city through demand management measures.[7] 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, and directed ENO to include a report in the Final IRP filing containing its ongoing assessment of (1) its progress toward being able to determine how to integrate distributed generation and customer-owned DER into the distribution grid in a manner that supports grid reliability and sustainability; (2) any hardware, software or other equipment; (3) additional personnel; (4) personnel training; or (5) any other measures required to enable ENO to perform the requested analyses, including the estimated costs thereof, and any steps ENO has already taken toward acquiring this capability.[8]

The Initiating Resolution also addressed the Advisors' Suggestions for 2021 Triennial IRP Procedure[9] and the related filed comments:

i. The Council found it reasonable to require ENO to provide the parties with an estimate of the annual cost data for both supply-side resources and utility DSM programs for each optimized portfolio;[10]

ii. The Council stated a specific interest in evaluating the feasibility of a customer DER program whereby customers would receive an incentive to install energy storage facilities on their property controlled by the utility, such that the utility could direct when the storage units dispatch stored electricity onto the distribution grid, and directed ENO to include such a measure as one of the measures evaluated in the DSM potential study;[11]

iii. ENO was directed to work with the Advisors to ensure that the connections, including measure assumptions and metrics, between the IRP DSM Potential Study analysis and the implementation of Energy Smart DSM programs are clear and easily understood;[12]

iv. The Council required that the initial total supply costs from the capacity expansion module for all optimized portfolios be provided with supporting detail, and found that the energy-based nature of RCPS compliance may require a variation in the optimization methodology as compared to other planning strategies;[13]

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[6] Initiating Resolution at 4, 23-24.
[7] *See* Motion M-20-269 adopted Aug. 20, 2020 and Motion M-21-34 adopted Jan. 28, 2021.
[8] Initiating Resolution at 8.
[9] In the Advisors Report Regarding the Entergy New Orleans 2018 Integrated Resource Plan, the Advisors made eight suggestions for improvements to the IRP Procedure for the 2021 Triennial cycle. Initiating Resolution at 8.
[10] Initiating Resolution at 9.
[11] Initiating Resolution at 12.
[12] Initiating Resolution at 14.
[13] Initiating Resolution at 14-15.

v. The Advisors and ENO were directed to ensure that ENO's discussion of DER in the load forecast, distribution system, and workpapers of the IRP Report is sufficiently detailed to enable the Council and the parties to understand how DERs were accounted for in ENO's IRP analysis, and what the potential impacts upon the system of adoption of various amounts and types of DERs might be;[14]

vi. The Council clarified that, unless otherwise specified in a particular resolution, its objective is to be able to generally track the extent to which its energy policies as a whole change and impact the costs of each of the optimized portfolios through the IRP, rather than to examine the specific impact of individual Council policies;[15]

vii. The Council encouraged the parties to continue to work together to improve the scorecard with each Triennial IRP cycle;[16] and

viii. The Council clarified that while the Council would expect the reference planning strategy to include the current anticipated retirement dates of existing resources, the lowest cost option planning strategy should assume resources could be retired in the IRP optimization process when it becomes economic to retire them relative to the cost of new resources.[17]

The procedural schedule set forth in Resolution No. R-20-257 was amended in Resolution No. R-21-73 and later modified by the April 7 Order.

Interventions in the Docket were filed by the Alliance for Affordable Energy ("AAE"),[18] Air Products and Chemicals, Inc. ("Air Products"),[19] the Southern Renewable Energy Association,[20] Sustainable Energy Economy Solutions,[21] 350 New Orleans,[22] Gulf States Renewable Energy Industries Association,[23] and the National Audubon Society.[24] The Sierra Club participated as an Interested Party in the Docket.

Over the course of the proceeding, ENO held five technical meetings with the intervenors to discuss the details of the IRP analysis and get feedback from stakeholders on various components of the analysis, including a technical meeting to discuss the Energy Smart Implementation Plan.

[14] Initiating Resolution at 16.
[15] Initiating Resolution at 17.
[16] Initiating Resolution at 18.
[17] Initiating Resolution at 20.
[18] Alliance for Affordable Energy, *Petition for Intervention and Inclusion on Service List*, Docket No. UD-20-02, (Aug. 21, 2020).
[19] Air Products and Chemicals Inc., *Motion for Intervention and Inclusion on Service List*, Docket No. UD-20-02, (Sept. 3, 2020).
[20] Southern Renewable Energy Association, *Petition for Intervention and Inclusion on Service List*, Docket No. UD-20-02, (Sept. 29, 2020).
[21] Sustainable Energy Economy Solutions, *Petition for Intervention and Inclusion on Service List,* Docket No. UD-20-02, (Oct. 14, 2020)
[22] 350 New Orleans, *Petition for Intervention and Inclusion on Service List*, Docket No. UD-20-02, (Nov. 2, 2020).
[23] Gulf States Renewable Energy Industry Association, *Petition of Intervention and Inclusion on Service List*, Docket No. UD-20-02, (Nov. 2, 2020).
[24] National Audubon Society, *Petition to Intervene Out of Time and for Inclusion on Service List*, Docket No. UD-20-02, (Nov. 10, 2020).

ENO also held three public meetings regarding the development of the IRP and the IRP report to assist in informing the public of the IRP and obtaining public comment on it. ENO submitted its IRP to the Council on March 25, 2022 ("Final 2021 IRP").[25] AAE filed comments on the Final 2021 IRP with the Council[26] while 350 New Orleans circulated comments via email to the Service List.[27] ENO filed responsive comments on June 7, 2022.[28]

The Advisors participated actively in the stakeholder process, have considered the Final 2021 IRP 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 Final 2021 IRP 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).[29] 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.[30] 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.[31]

III. Whether the Report is In Compliance with the Council's Requirements

Section 10.E of the IRP Rules states in part:

> Provided the IRP fulfills the requirements contained herein and was developed in compliance with the procedural schedule established for the triennial IRP cycle, the Council shall accept the Utility's IRP as filed in compliance with the Council's substantive and procedural requirements. Failure of the utility to substantially comply with the provisions of these Rules may result in summary rejection of the Utility's IRP. Such rejection may be without prejudice to the refiling of the IRP once the utility has corrected the deficiencies.

In order to determine whether the Final 2021 IRP is in compliance with these requirements, the Advisors reviewed ENO's compliance with both the procedural requirements and the substantive requirements.

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[25] Entergy New Orleans, LLC, *2021 Integrated Resource Plan*, Docket No. UD-20-02, (March 25, 2022)
[26] Alliance for Affordable Energy, *Comments of the Alliance for Affordable Energy*, UD-20-02 (May 9, 2022) ("Alliance Comments").
[27] *See*, May 10, 2022 email from Marion Freistadt to the Service List in UD-20-02 conveying comments ("350 New Orleans Comments").
[28] Entergy New Orleans, LLC, *Entergy New Orleans, LLC's Reply Comments*, UD-20-02 (June 7, 2022) ("ENO Reply Comments").
[29] IRP Rules, Section 10.E, at 13-14.
[30] IRP Rules, Section 10.E, at 14.
[31] IRP Rules, Section 10.F, at 14.

A. Procedural Requirements

The IRP Rules, the Initiating Resolution, as modified by Resolution No. R-21-73 and the April 7 Order, set forth specific procedural requirements and a specific procedural schedule for the case. Below is a table summarizing ENO's procedural requirements through the date of this Report and whether and how ENO met each requirement:

IRP Rules Requirement *(IRP Rules Section 9 and Initiating Resolution as modified by R-21-73 and April 7 Order)*	**Action(s) Taken**	**Whether Requirement Was Met**
Initial public meeting (kickoff and educational meeting) no later than October 16, 2020	Meeting held October 14, 2020	Yes
Technical Meeting 1 of the parties between November 30, 2020 and December 11, 2020 (discussion of Planning Scenarios and Strategies)	Meeting held December 9, 2020	Yes
Completion of DSM Potential Studies by July 30, 2021	DSM Input Stakeholder Meeting held March 26, 2021; Filed July 30, 2021	Yes
Technical Meeting 2 of the parties (to confirm Scenarios and Strategies), between April 26 and April 30, 2021	Meeting held April 29, 2021 (date chosen with consensus of the parties)	Yes
Technical Meeting 3 of the parties (finalization of Scenarios and Strategies and lock down of inputs) between Aug. 9 and 13, 2021	Meeting held Aug. 12, 2021	Yes
Finalization of all IRP inputs, Aug. 15, 2021	Agreement among parties reached at Technical Meeting 3, Aug. 12, 2021	Yes
Completion of all optimized portfolio development and results, December 21, 2021	Completed on time, circulated to parties December 20, 2021, in advance of Technical Meeting 4	Yes
Technical Meeting 4 of the parties (to review the optimized portfolios and finalize scorecard metrics) between Jan. 5 and Jan. 20, 2022	Meeting held Jan. 20, 2022	Yes
2021 IRP Final Report filed March 25, 2022	Filed March 25, 2022	Yes
Second Public Meeting (present IRP Report) between Apr. 8 and Apr. 15, 2022	Meeting held Apr. 13, 2022	Yes
Third Public Meeting (to receive public comment on IRP Report) between Aug. 29 and May 6, 2022	Meeting held May 3, 2022	Yes

Technical Meeting 5 of the parties (to discuss Energy Smart Implementation Plan) between Apr. 29 and May 6, 2022	Meeting held May 3, 2022	Yes
Intervenor Comments filed May 9, 2022	Comments filed May 9, 2022	Yes
ENO Reply Comments filed June 7, 2022	Comments filed June 7, 2022	Yes

The Advisors conclude that ENO did meet the procedural requirements of the IRP Rules and the Initiating Resolution as modified by Resolution No. R-21-73 and the April 7 Order.

B. Required Report Content

The IRP Rules and Initiating Resolution set forth numerous substantive requirements for the IRP analysis and Report. As is required in the IRP Rules,[32] ENO included as Appendix A to its Final 2021 IRP a Rules Compliance Matrix setting forth each requirement and explaining how ENO met each requirement. The Advisors have reviewed ENO's Rules Compliance Matrix which is attached to this Report as Attachment A, and verified the information contained therein, and find that it is complete and does demonstrate to the Advisors' satisfaction that ENO has complied with the substantive requirements of the IRP Rules and Initiating Resolution as modified by Resolution No. R-21-73 and the April 7 Order.

The IRP Rules also require the Utility to include a reference Planning Scenario that represents the Utility's point of view on the most likely future circumstances as well as two alternative Planning Scenarios that account for alternative circumstances.[33] The IRP Rules require the Utility to seek to develop a position agreed to by the Utility, Advisors and a majority of the Intervenors regarding assumptions surrounding each of the Planning Scenarios and that if such consensus is not reasonably attainable, the Utility shall model a fourth Planning Scenario based upon input agreed to by a majority of the Intervenors.[34]

In this IRP Proceeding, the parties reached consensus that three Scenarios would sufficiently capture the range of reasonably likely possible futures, and a separate stakeholder Scenario was not necessary.

The IRP Rules then require that the utility develop two to four Planning Strategies which constrain the optimization process to achieve particular goals, regulatory policies and/or business decisions over which the Council, the Utility, or stakeholders have control.[35] The IRP Rules require a Planning Strategy that allows the optimization to identify the lowest cost option for meeting the needs identified in the IRP process, a reference Planning Strategy, agreed to by the Utility, Advisors and a majority of the Intervenors, and alternate Planning Strategies that reflect known utility regulatory goals of the Council.[36] The IRP Rules require that if the Utility, Advisors and a

[32] IRP Rules, Section 1 at 1..
[33] IRP Rules, Section 7.C.1, at 10.
[34] IRP Rules, Section 7.C.2, at 10.
[35] IRP Rules, Section 7.D, at 10.
[36] IRP Rules, Sections 7.D.1-7.D.3, at 10-11.

majority of the Intervenors do not agree to a single Reference Planning Strategy, the Utility shall model a separate Stakeholder Planning Strategy based upon input determined by a majority of the Intervenors.[37]

In this IRP proceeding the parties agreed to four Planning Strategies: Strategy 1, the least cost planning strategy; Strategy 2, the reference strategy (a "but-for RCPS" strategy); Strategy 3, an RCPS compliance strategy; and Strategy 4, the Stakeholder Planning Strategy.[38]

While ENO did model a Stakeholder Planning Strategy (Strategy 4), that Strategy did not fully adhere to the instructions provided by the stakeholders. In Technical Meeting 3, the stakeholders requested that to build the stakeholder Planning Strategy ENO should use Strategy 3 as a base, but make two changes – use the NREL 2020 ATB[39] LCOE values for the renewable resources and use the GDS High Case for the DSM Inputs. However, in addition to making these changes, ENO failed to include batteries in the input data set as a resource for the stakeholder Planning Strategy. The Advisors believe that this resulted in an incomplete input data set, and the stakeholders also expressed concern over this decision in Technical Meeting 4. ENO explained that it excluded batteries because the capacity expansion modeling was conducted using the inputs provided, and the Intervenors only provided alternative renewable inputs for solar and wind resources and did not include values for battery storage.[40]

The parties discussed the failure to include battery storage in the Strategy 4 in that Technical Meeting, and although 350 New Orleans argues in its comments that the failure was not corrected and should be corrected, including potentially re-running models,[41] it was the Advisors' understanding from the discussion in Technical Meeting 4 that rather than requiring ENO to re-run the Strategy 4 modeling (which would have taken weeks to months and required a delay of the procedural schedule), it was the preference of the majority of the Intervenors that ENO instead model Manual Portfolios 1a and 4a that would model the early retirement of UPS PB1, Manual Portfolio 3a that would model meeting the RCPS through capacity additions (rather than use of unbundled Renewable Energy Certificates ("RECs")), and Sensitivity 4b using even lower renewables costs. ENO did model those Manual Portfolios and Sensitivity and therefore it is the Advisors' assessment that although ENO failed to include battery storage in the modeling of the stakeholder Planning Strategy (Strategy 4), it worked with the stakeholders in good faith in the Technical Meetings to address the problem and develop additional alternate analyses that addressed many of the stakeholders' concerns. Therefore, the Advisors recommend that the IRP Report be accepted by the Council, notwithstanding the modeling issue of the Stakeholder Planning Strategy (Strategy 4) discussed above.

The Initiating Resolution also set forth certain specific requirements. It required that ENO include the Council's goal of increasing energy efficiency incremental annual kWh savings by 0.2% of sales per year until such time as incremental annual kWh savings reach 2% of annual sales into

[37] IRP Rules, Section 7.D.2, at 10.
[38] Final 2021 IRP at 58-59.
[39] NREL's Annual Technology Baseline using levelized costs of energy provides a consistent set of technology cost and performance data for energy analysis.
[40] ENO Reply Comments at 1-2.
[41] 350 New Orleans Comments.

the Planning Strategy that incorporates all effective Council utility regulatory policies.[42] ENO did meet this requirement by including the Council's Goal in Strategy 3 by forcing the selection of all energy efficiency and Demand Response ("DR") programs to meet the goal.[43] The Initiating Resolution also required ENO to include in that Planning Strategy the RCPS adopted by the Council in Docket No. UD-19-01.[44] ENO included the RCPS in Strategy 3 by excluding new capacity resources that would not be RCPS compliant, *i.e.*, fossil-fueled resources,[45] but not addressing the specified percentages of Retail Compliance Load in Section 3 of the RCPS. At the request of the Advisors and other parties in Technical Meeting 4, ENO also modeled a manual portfolio, Manual Portfolio 3a, based on Scenario 1/Strategy 3 that kept the UPS PB1 deactivation in 2033 while accelerating renewable resource additions to examine options for compliance with the annual mandates of the RCPS rules without procurement of additional unbundled RECs.[46] The Advisors are satisfied that between Strategy 3 and Manual Portfolio 3a, ENO has sufficiently modeled RCPS compliance to satisfy the Council's requirement.

C. The Final 2021 IRP is in Compliance with the Council's Requirements

The Advisors conclude that ENO has substantially met both the Council's procedural requirements and the requirements for the content of the IRP report, and therefore recommend that the Council accept ENO's Final 2021 IRP as filed in compliance with the Council's substantive and procedural requirements.

IV. Review of the Report

The purpose of an IRP developed under the Council's IRP Rules is not to develop a specific resource acquisition plan the utility is required or allowed to follow to the exclusion of other opportunities, but rather to provide the utility, the Council, and stakeholders with a well-rounded analysis of how various portfolios of resources are likely to perform over a range of possible future scenarios. This analysis provides insight into what type of resources and opportunities the utility should be seeking as it plans to meet the load of New Orleans customers. Because the data used in the analysis largely reflects what average prices of resources are projected to be over the next 20 years, rather than specific options that will actually be available to the utility, it serves only as a starting point and general guide as to which resources are likely to bring the most benefit to ratepayers. Because the costs associated with any specific resource or opportunity are likely to vary from projected costs, any specific resource acquisition by the utility must still be presented to the Council for full review and approval of that specific acquisition.

The second part of Section 10.E of the IRP Rules states:

> Further, after consideration of all the evidence entered into the record, the Council may approve the accepted Utility 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

[42] Initiating Resolution at 23, Ordering Paragraph 8.
[43] Final 2021 IRP at 58-59.
[44] Initiating Resolution at 24, Ordering Paragraph 8.
[45] Final 2021 IRP at 58-59.
[46] Final 2021 IRP at 59.

the accepted Utility IRP. Nothing in this provision limits the Council's ability to take any action with respect to the IRP that is within its authority, including the Council's ability to open a prudence investigation for noncompliance on the part of the Utility.

A. Advisors' Review

1. Participation by Parties in the Development of DSM Potential and the IRP

The Advisors commend all parties to the proceeding for continuing to collaborate productively and collegially on the IRP. Through the stakeholder process, the Advisors and Intervenors were able to work collaboratively with ENO to ensure that ENO's analysis would meet the Council's requirements and to ensure that the concerns of the stakeholders were identified early enough in the process for ENO to respond to the concerns in the IRP analysis.

Resolution No. R-20-257 directed ENO to work with all parties in the concurrent development of inputs and assumptions for the DSM Potential Study, and to include in the DSM measures evaluated, any measures proposed by the parties.[47] ENO provided the Council's DSM consultant with timely discovery responses, a complete set of the Business Plan 2020 inputs, other data files it had previously provided to its own consultant, as well as the measure list developed for the ENO DSM Potential study. In addition, the Company, the Advisors, Intervenors, and the two DSM consultants participated in an extended technical meeting[48] to discuss development of the DSM Potential Studies and to review the data provided in discovery. At that technical meeting, there was extensive collaborative discussion of the inputs and data sources among the parties in attendance.[49]

The Final 2021 IRP was developed with a stakeholder process that included a series of four technical meetings[50] over 16 months, building on constructive discussions concerned with the IRP inputs and analysis. Considering the depth of issues, conceptual differences among the parties, and the extent of the required analyses and modeling effort, acceptable compromises were achieved and the Final 2021 IRP presents the results of all reasonably available resource options based on the Planning Scenarios and Planning Strategies agreed on by all parties.

2. Treatment of DSM as a Resource

The impact of existing DSM was considered in developing the load forecast. The estimated cumulative savings volume in kWh of existing and previous years energy efficiency programs were added back to the monthly billed-sales to develop an estimate of kWh consumption without

[47] Resolution R-20-257, Directive 5.d and Directive 9, at 22, 24.
[48] Technical meeting March 26, 2021 to discuss responses to Advisors' Discovery Set 1, as well as inputs and assumptions to the DSM Potential Study.
[49] Response to Advisors' DR 2-6.
[50] Technical meeting 5 of the 2021 IRP discussed the Energy Smart three year Implementation Plan related to the IRP.

the effects of the existing and previous years' energy efficiency programs. From that estimate, the expected future levels of energy efficiency programs were subtracted from the forecast derived without including effects of energy efficiency programs to arrive at the net forecast levels.

DR programs were treated as a resource in the IRP modeling, and not incorporated into the load forecast. DR was assessed using the levelized real cost of a combustion turbine ("CT") based on ENO's revenue requirements, rather than capacity prices in the Midcontinent Independent System Operator, Inc. ("MISO") which are limited in term to the MISO planning year. DR programs sponsored by a DR Aggregator are included in the IRP only if the programs are included in a DSM Potential Study.

Where prospective DSM is not constrained in a portfolio to meet the Council's stated 2% goal (as is Planning Strategy 1),[51] the modeling selected the optimal amount of DSM to be included in the portfolios. The proposed DSM potential study programs were evaluated initially using the capacity expansion algorithm to identify those DSM programs that had capacity and energy benefits greater than their cost. The unselected DSM programs from the initial evaluation were redesigned to begin in later years with ENO's capacity needs, where AURORA's capacity expansion algorithm identified the lowest cost resource alternatives to meet ENO's capacity needs among the redesigned DSM programs and the available supply-side resource alternatives.

Once the DSM programs included in the optimized portfolios were identified, AURORA's production cost simulation algorithm was used in the model-configured MISO energy market to "dispatch" all of the resources in the portfolios to meet ENO's energy needs.

The Advisors had no dispute with the treatment of DSM as an IRP resource.

3. Treatment of Distributed Energy Resources (DER)

The aggregate effects of ENO-sponsored DER in each Planning Scenario were incorporated into the assumptions used in ENO's load forecast methodology. The impact of DER in the IRP optimized portfolios is reflected in the Planning Scenario load forecasts accounting for ENO-sponsored DER.

Similar to the treatment of ENO-sponsored DER, additional customer-owned solar installations are included as a monthly MWh decrement in the 2021 IRP load forecast. The projected years' behind-the-meter solar installations were estimated using models with a three-level approach similar to the DSM Potential Studies, based on (i) related assessments of the technical potential (from NREL Reports for each state), (ii) economic potential (using payback models with equipment costs and incentives), and (iii) market potential (with adoption levels derived from accepted Bass-diffusion adoption models). Assumptions included a declining solar capital cost curve and solar load profiles based on existing Net Metering policy and rate design, but not much emphasis on customer energy storage equipment. The Final IRP Report summarized that the long-term hourly load forecast, forecasted energy, forecasted peaks, and the forecasted customer class hourly profiles are calibrated together, and that typical load shapes for incremental solar and

[51] In Planning Strategies 2-4, DSM was specifically incorporated to meet the Council's stated 2% goal.

electric vehicle consumption allocate reduced or increased consumption to the appropriate hour of use.

While the IRP optimizes utility costs and customer impact, and does not evaluate a cost-benefit related to customers' installed DER, the avoided utility capital expenditures related to customer-owned distributed generation is reflected in the optimized resource portfolios based on ENO's load forecast net of the aggregate effect of customer-owned distributed generation.

While the treatment of DER in the IRP was consistent with the IRP Rules, requiring the utility to file updates to the potential ranges of projected estimates of specific DER, such as community solar, battery storage and EV, would be helpful to monitor DER between triennial IRP filings.

4. Defining Planning Scenarios and Planning Strategies

Future market conditions were adequately recognized in the IRP process through three different Planning Scenarios, defined by key market assumptions, and policy and planning objectives were adequately recognized by four different Planning Strategies. The three Planning Scenarios were agreed to by the parties as being representative of the different possible future outcomes. Planning Scenario 1 (Reference Scenario) was essentially a business-as-usual scenario that assumed moderate load growth, natural gas prices, and CO_2 prices, a low level of deactivations of coal and legacy gas deactivations and a moderate mix of new gas resources and renewable resources being added to MISO going forward.[52] Planning Scenario 2 is a scenario that is essentially favorable to the addition of traditional fossil generating resources, with high load growth, low natural gas and CO_2 prices, a moderate level of retirement of legacy resources, and a high mix of new natural gas in MISO relative to new renewables.[53] Planning Scenario 3 is a scenario that is essentially favorable to greater deployment of renewables and distributed energy resources, with low load growth, high natural gas and CO_2 prices, NREL 2020 ATB renewable resource costs, and the highest percentage of retirements of existing resources.[54] The Advisors concur with the parties that these three Planning Scenarios capture a reasonable range of possible future scenarios that could occur over the next twenty years. It should be noted that in all likelihood the actual future will not match any of the three scenarios precisely, but will likely fall somewhere within the range of futures the scenarios represent. The following summary of the Planning Scenarios is included below from IRP Public Meeting #2 presentation.

[52] Final 2021 IRP at 56-57.
[53] *Id.*
[54] *Id.*

2021 IRP Planning Scenarios

	Scenario 1	Scenario 2	Scenario 3
Description	**Reference**	**Decentralized Focus (DSM & renewables)**	**Stakeholder**
Peak / Energy Load Growth	Reference	Low	High
Basis of DR / EE / DER Additions (Adjustment to Load)	Entergy (Medium)	Entergy (High)	Entergy (High)
Natural Gas Prices (Levelized Real, 2021$/MMBtu)	Reference	Low	High
Market Coal Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
Legacy Gas Fleet Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
CO2 Tax Assumption (Levelized Real, 2021$/short ton)	Reference	Reference	High
New-Build Resource Alignment with MTEP Future #3	No, Aurora capacity expansion tool will be used	No, Aurora capacity expansion tool will be used	Yes, via a manual MISO market portfolio buildout
Renewable Resource Costs	Entergy Technology Assessment	Entergy Technology Assessment	NREL 2020 ATB

Scenario 1: Reference load growth and gas prices, DSM additions, and CO_2 reduction targets
Scenario 2: Low load growth and gas prices, high DSM additions, and moderately accelerated coal and legacy gas retirements. Aggressive DER and DSM contribute to lower peak load and energy projections. Continued political support for domestic gas production leads to sustained low gas prices.
Scenario 3: High load growth, gas prices, and DSM additions, as well as lower renewables costs. Social trends and corporate initiatives shift, demanding high penetration of DERs, DSM, and EE. Non-ENO coal and legacy plants are driven to retire earlier than anticipated resulting from stringent carbon mandates.

The four initial Planning Strategies agreed to by the parties (notwithstanding subsequent modifications which resulted in manual portfolios) were intended to represent the different objectives that could be achieved by various portfolios. Strategy 1 was designed to demonstrate the least cost portfolio that would result in a reliable power supply for the city across each of the three possible future scenarios.[55] Strategy 2 was designed to demonstrate a least cost portfolio that would also achieve the Council's 2% energy efficiency savings goal and provide reliable power across the three possible future scenarios.[56] Strategy 3 was designed to demonstrate a portfolio that was compliant with the RCPS, meet the 2% DSM savings goal, and exclude new resources that would not be RCPS compliant.[57] Strategy 4, the Stakeholder Strategy, was designed to achieve the level of achievable energy efficiency and demand response determined in the high case of the Council's DSM potential study, using only DSM and renewable resources while assuring reliable power across the three possible future scenarios.[58] The following summary of 2021 IRP Planning Strategies is included below from IRP Public Meeting #2 presentation. The summary also includes manual portfolios which are discussed below.

[55] Final 2021 IRP at 57-59.
[56] *Id.*
[57] *Id.*
[58] *Id.*

2021 IRP Planning Strategies

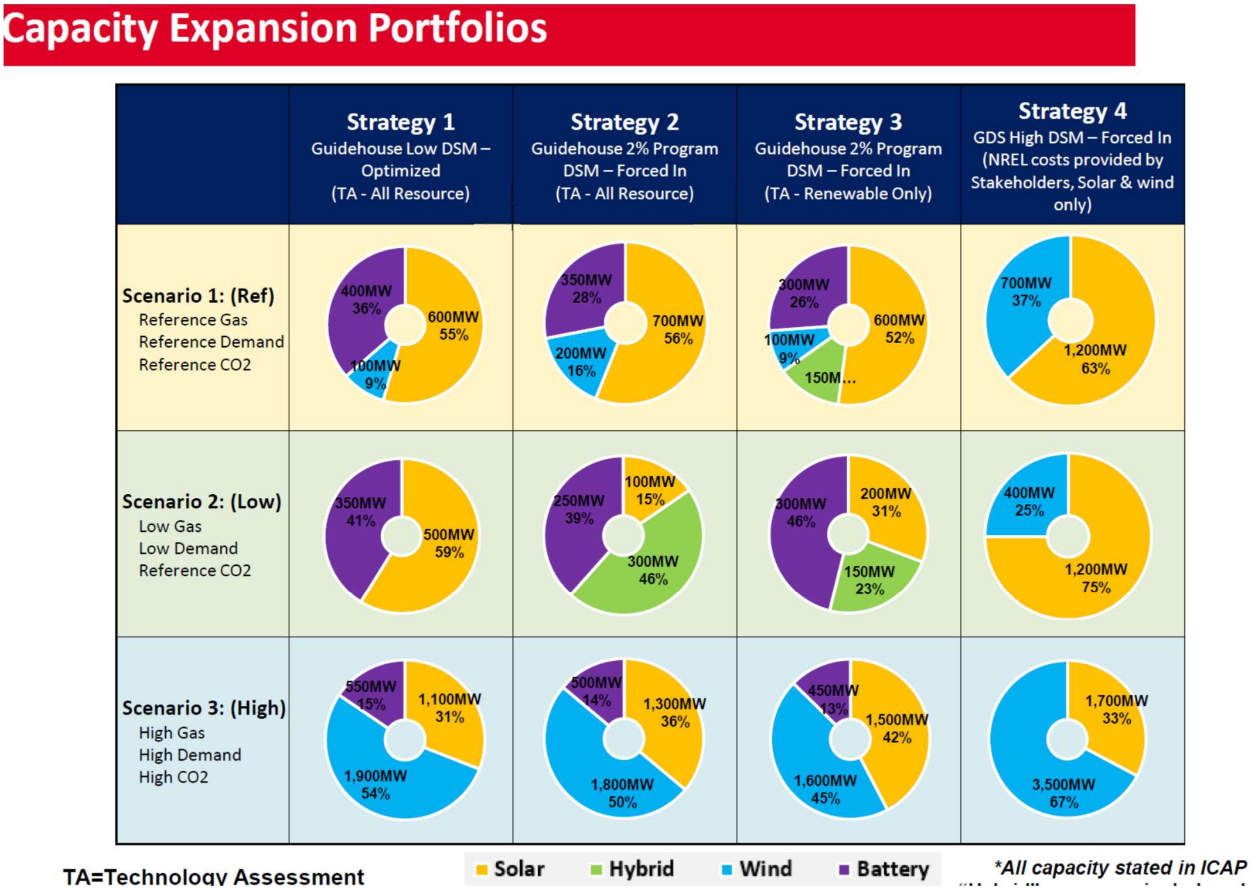
	Strategy 1	Strategy 2	Strategy 3	Strategy 4
Description	Least Cost Planning	But For RCPS (Reference)	RCPS Compliance	Stakeholder Strategy
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and meet long-term PRM target	Include a portfolio of DSM programs that meet the Council's stated 2% goal and meet long-term PRM target in compliance with RCPS policy goals	Include a portfolio of DSM programs that meet the Council's stated 2% goal and meet long-term PRM target in compliance with RCPS policy goals; NREL 2020 ATB LCOE values for renewables costs provided by Stakeholders
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.
DSM Input Case	Low Case (Guidehouse)	2% Program Case (Guidehouse)	2% Program Case (Guidehouse)	High Case (GDS)
Manual Portfolio	Alternative Deactivation – Union Power Station (2025) (Manual Portfolio 1a) [1]	N/A	Held Union 1 deactivation in 2033 and accelerated renewable generation additions to comply with near-term RCPS mandates (Manual Portfolio 3a) [2]	Alternative Deactivation – Union Power Station (2025) (Manual Portfolio 4a) [3]
Sensitivity	N/A	N/A	N/A	Lower renewables costs provided by Stakeholders (Sensitivity 4b) [4]

[1] An additional manual portfolio informed by the optimized portfolio developed under Strategy 1 and Scenario 1 ("Strategy 1a") was be developed.
[2] An additional manual portfolio informed by the optimized portfolio developed under Strategy 3 and Scenario 1("Strategy 3a") was be developed
[3] An additional manual portfolio informed by the optimized portfolio developed under Strategy 4 and Scenario 3 ("Strategy 4a") was be developed.
[4] A sensitivity using the alternative cost assumptions provided by the Stakeholders on the resources identified in the optimized portfolio developed under Strategy 4 and Scenario 3 ("Strategy 4b").

5. *Portfolio Results and Comparisons*

The total supply costs for the initial set of 12 optimized portfolios were provided in the AURORA capacity expansion module which included a useable estimate of variable supply costs based on an annual hours and operating costs of resources compared to the more detailed hourly production cost modeling which was applied to selected optimum portfolios. These optimized portfolios included different combinations of renewables, battery storage, and DSM programs based on specific planning assumptions. Each of the Strategy 1–3 Optimized Portfolios included a mix of solar and/or wind resources along with battery storage while Strategy 4 only included solar and wind resources because the cost and performance assumptions for battery storage were not provided.[59] The initial Scenarios and Strategies, without the modifications used to develop the manual portfolios, resulted in the following optimum resource portfolios, shown below, and as set forth in Figure 41 of the Final 2021 IRP.[60]

[60] Final 2021 IRP at 65, Figure 41.



Each of the initial twelve portfolios produced represents the least cost portfolio that could be employed under the assumptions contained in the relevant Planning Scenario and the strategy pursued under the relevant Planning Strategy. In addition to the Optimized Resource Portfolios shown above, three Manual Portfolios were developed based on specified Optimized Portfolios, with modifications. Manual Portfolio 1a, based on the Scenario 1/Strategy 1 Optimized Portfolio, and Manual Portfolio 4a, based on the Scenario 3/Strategy 4 Optimized Portfolio, both assumed an accelerated deactivation of UPS PB1 from 2033 to 2025. Manual Portfolio 3a,[61] based on Scenario 1/Strategy 3, kept the UPS PB1 deactivation in 2033 while accelerating renewable resource additions to examine options for compliance with the annual mandates set forth in the RCPS rules without procurement of additional unbundled RECs.

When looking at these results, it is important to note that based on current assumptions, the overall analysis shows that ENO will not have a need for new resources until 2033 (when UPS PB1 is expected to retire),[62] provided that RCPS compliance is maintained. The resource portfolios produced are essentially suggested resources to be added in the planning period, but there will be several more triennial IRP plans performed that will further inform future planning. The current

[61] Manual Portfolio 3a was agreed to among the parties at Technical Meeting #4 as an alternate RCPS strategy.
[62] Final 2021 IRP at 5. It is important to note that the Final 2021 IRP does assume that none of the current ENO resources would be retired or otherwise disposed of prior to the end of the life of the asset.

Final 2021 IRP is best used to inform the near-term Energy Smart Program design, and serve as a reference for RCPS cost compliance.

ENO notes that the various portfolios analyzed in the Final 2021 IRP indicate that once a capacity need arises for ENO, it can likely be met by a combination of renewable and storage resources rather than additional fossil generation. The Advisors agree with this conclusion.

This result is particularly notable because it is the first time in an IRP analysis that no optimized portfolio has shown any new fossil fueled resources. In ENO's 2018 IRP, the most recent IRP prior to the Final 2021 IRP, nine out of fifteen optimized portfolios included 346 MW of natural gas-fired capacity and only six portfolios showed all needs being met with solar, battery, wind, and DSM. As can be observed in the Capacity Expansion Portfolios figure provided on page 15 herein, solar and hybrid resources where a solar facility is paired with a storage facility, will most likely be a significant portion of generation resources acquired for ENO's portfolio under all Scenarios analyzed. Utility-scale battery storage, whether paired with a specific solar facility to make a hybrid facility or standing alone on the system appears in every portfolio except for those that resulted under Strategy 4 where battery storage was not included as discussed previously. In eleven of the twelve optimized portfolios, solar and battery storage combined account for 50% or more of the new resources to be acquired, with wind resources playing a lesser role. Also of particular note is that the portfolios under Strategy 4, where battery storage was not included in the analysis, added significantly greater amounts of renewable capacity than the Strategies that allowed battery storage to be selected. As can be seen in the Capacity Expansion Portfolios figure provided on page 15 herein, the portfolios created under Strategy 4 added on average over 800MW more of capacity than the portfolios created under the other three Strategies where battery storage was included as an input resource. Given that ENO's projected load at the end of the planning period is approximately 1350 MW, an 800 MW difference is particularly large, representing roughly 60% of ENO's load.

Overall, the Final 2021 IRP gives a strong indication that as the need for new capacity arises, it is most likely that under most of the currently anticipated possible future conditions, it would benefit New Orleans ratepayers for the utility to acquire some combination of solar and utility-scale battery storage, and, under some conditions, wind resources. The suitability of any specific resource acquisition, however, cannot be predicted based on these results, because it will depend heavily on the specific price the utility is able to negotiate for the resource as well as other attributes of the resource and system reliability and generation dispatch within MISO that cannot necessarily be predicted in the IRP process. Any specific resource ENO proposed to acquire would still need to be submitted to the Council for review and approval.

There are a few additional key takeaways that can be gleaned from looking at the total range of long term portfolios produced. First, DSM plays a significant role in every portfolio, ranging from 281 to 545 MW by 2041, which indicates that continuing to invest in and grow the Energy Smart Program is economically preferable based on the IRP assumptions. Second, while the ideal amount of battery storage varied across the scenarios, ranging from 250 MW to as much as 550 MW, the portfolio results indicated that an increasing amount of battery storage should be included in ENO's future resource portfolio. Third, renewable resources could be added to maintain RCPS compliance with reasonable cost difference relative to other optimum portfolios, even without considering the use of RECs within the allowed percentages.

The objectives related to identifying these specific three Planning Scenarios and four Planning Strategies were generally achieved through limiting the complete IRP modeling process and production cost calculations to five optimized resource portfolios. During a technical conference, the parties reviewed the initial set of twelve optimized portfolios and agreed that a subset of the five resource portfolios would be sufficiently representative to accomplish the planning objectives, since the remainder of the detailed supply cost analysis encompassed hourly production cost modeling.

The Total Relevant Supply Costs, present value ($2022) and annual costs, were provided in Appendix C for each of the subset five portfolios and for each of the three Planning Scenarios, exhibiting a revenue requirement range for the five subset resource portfolios. A range of results was also provided for four of the five subset portfolios related to changes in the input assumptions of natural gas price and CO2 price, as agreed upon by the parties. These ranges of results help to increase confidence in the IRP resource portfolios and their underlying assumptions.

6. Supporting RCPS Compliance

Section 4.d of the Renewable and Clean Portfolio Standard, Calculation of Compliance Costs, underscores the importance of the IRP in supporting RCPS compliance:

> 1. The RCPS Cost of Compliance is calculated as all incremental costs prudently incurred by the Utility in complying with RCPS Section 3, including, but not limited to, the incremental costs of new resources for compliance, the Incremental DSM costs, and other costs related to RCPS compliance. . . .
>
> 2. Incremental costs are the total electric utility revenue requirements associated with the Utility's operations in compliance with the RCPS, less the total electric utility revenue requirements associated with the optimized resource portfolio that may have been in place absent the requirements of the RCPS. The Utility's most recently filed Integrated Resource Plan shall inform the calculation of incremental costs as to the optimized resource portfolio that may have been in place absent the requirements of the RCPS.

The optimized resource portfolio developed under Planning Scenario 1 and Planning Strategy 2 represents the "but-for" IRP reference portfolio that may have been in place absent the requirements of the RCPS. It represents the resource plan that would comply with regulatory policies in New Orleans that existed before Council approval of the RCPS rules. ENO proposes to use the total relevant supply cost produced for this portfolio in the 2021 IRP analysis as the baseline for calculating incremental costs associated with its three-year RCPS compliance plan for 2023-2025.[63]

As a result of discussions among the Parties at IRP Technical Meeting 4, a Strategy 3a manual portfolio was developed to evaluate near-term compliance with the Council's RCPS through additional renewable energy production rather than through the purchase of unbundled RECs. The initial RCPS Planning Strategy 3 constrained resource additions to be renewables, but did not address the specified percentages of Retail Compliance Load listed in Section 3 of the Renewable

[63] Response to Advisors' DR 2-13.

and Clean Portfolio Standard. While this is not an unreasonable approach to RCPS compliance given the constraints of a capacity expansion model, the Advisors wished to see the result of complying with Section 3 of the RCPS solely through capacity additions, *i.e.*, no unbundled RECs or energy-only power purchase agreements. To that end, in the stakeholder process, the Advisors requested that ENO create Manual Portfolio 3a. Because there were already two Manual Portfolios modeling the early retirement of UPS PB1 in 2025, the Advisors requested that Manual Portfolio 3a assume that UPS PB1 remain in operation until 2033, but that ENO start adding the renewable capacity resources from the optimized portfolio created for Scenario 1/Strategy 3 gradually before UPS PB1 was deactivated in order to meet RCPS compliance entirely through capacity additions. The excess capacity generated by having both UPS PB1 and the new RCPS-compliant capacity resources in the portfolio simultaneously was assumed to be sold into the capacity market and the value of those sales included in the Total Relevant Supply Cost ("TRSC") analysis to reduce the cost of Manual Portfolio 3a.

The TRSC result for Manual Portfolio 3a showed that this was the highest cost portfolio relative to those analyzed for Scenario 1 (reference Scenario) and Scenario 3 (stakeholder Scenario) and was the second most expensive for Scenario 2 (low load growth, low natural gas prices, high energy efficiency, demand response and distributed generation). This result does support ENO's conclusion that prohibiting the use of unbundled RECs for RCPS compliance would increase costs to consumers. The Advisors would, therefore, expect ENO's RCPS implementation plan to incorporate the use of unbundled RECs as permitted under the RCPS in order to minimize costs to customers.

7. *Portfolio Optimization Methodology based on ENO Capacity Needs*

Resource additions are optimized using an iterative process in the IRP AURORA model. Fixed resource costs are derived from ENO's technology assessment installed cost, converted into an annual fixed cost revenue requirement including taxes and fixed Operation & Maintenance ("O&M"), and expressed as a levelized real $/MW-week fixed cost for the comparative analysis in AURORA's capacity expansion model. Resource variable costs are developed from technology assessment heat rates, variable O&M, and forecasted fuel and CO2 prices. For each Planning Scenario and Planning Strategy combination, and through an iterative analysis of alternative resource additions, the capacity expansion algorithm identified the lowest cost resource portfolios that met ENO's capacity needs based on fixed and variable costs net of the resource's capacity and energy value.

ENO did not consider capacity that does not clear the annual MISO Planning Resource Auction as a viable long-term planning IRP resource, noting the limited term related to the MISO planning year, potential unavailability, exposure to uncertain market clearing prices, and inability to convey IRP energy or energy-related benefits.[64] Similarly, ENO did not consider potential purchase power agreements as an alternative IRP resource, noting uncertain availability and terms that are unknowable.[65]

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[64] Response to Advisors' DR 2-7.
[65] Id.

The Advisors agree that capacity from the annual MISO Planning Resource Auction should not be considered as a viable long-term planning IRP resource. The Advisors also recognize that the terms and availability of potential purchase power agreements may not be known at the time an IRP is conducted. However, this does not preclude the ultimate use of purchase power agreements within ENO's Portfolio. For example, the IRIS solar facility was initially considered as a build-own-transfer and subsequently acquired through a purchased power agreement. The Advisors consider the modeling parameters utilized for new resources in the IRP to be representative of the costs associated with including a certain type of resource (natural gas fired, solar, wind, battery storage, etc.) within ENO's portfolio. While representative of the type of resource that is desirable in ENO's portfolio, the ultimate acquisition of that type of resource may take on a variety of forms ranging from an ENO self-build resource to a purchase power agreement.

8. Treatment of a Lower Cost Energy Resource Without ENO Capacity Needs

Notwithstanding the development of "manual-selected" portfolios, AURORA's capacity expansion algorithm does not select supply side resources for portfolios unless there is an ENO capacity need. To qualify that planning objective, ENO added: "AURORA's capacity expansion algorithm can be used to identify the resource alternatives that have capacity and energy benefits greater than their cost regardless of whether there is a capacity need; however, this approach is not used with the exception of DSM programs that begin before there is a capacity need because adding supply side resources in excess of the capacity need increases ENO's market risk."[66] ENO contends that adding resources beyond ENO's capacity needs increases market risk because the value of those excess resources is dependent on uncertain projected market prices of capacity and energy.[67] However, as ENO noted, DSM, as an energy-based solution, is included in the IRP resource selection. The fixed costs of an energy-based solution are converted into a levelized real $/MW-week fixed cost for the capacity expansion algorithm. The initial DSM programs were selected based on their capacity and energy benefits greater than their cost. Also, the "excess" renewable energy resources were treated in the Strategy 3a manual portfolio for the RCPS compliance strategy (assuming no early retirement of UPS PB1).

If early retirements of existing resources were simultaneously considered in optimizing an energy-based model solution, an increase in the IRP procedural schedule may be required to perform the several required engineering studies and associated capacity expansion simulations. The Advisors recommend that the Council consider this issue, and require technical discussion of this issue among ENO and the Parties, before a procedural schedule is included in the Initiating Resolution of the next triennial IRP.

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[66] Response to Advisors' DR 2-7

[67] Response to Advisors' DR 2-4.

9. *Treatment of Resource Deactivations*

IRP Rules Section 1.D states: "Each Utility IRP is intended to serve as a general resource planning tool to the Utility and the Council, rather than a forum for the approval of the acquisition, implementation, or deactivation of any supply-side or demand-side resource."

There was considerable discussion among the parties on the issue of how to evaluate existing resource retirements in the IRP planning process. While existing resource retirement dates may be fixed for a number of reasons, the IRP planning process does represent an avenue to explore alternate possibilities related to resource retirement, including various economic based analyses, and AURORA's modeling capability can accommodate an economic analysis of retirement.

The issue of whether possible deactivation opportunities could be identified in the IRP modeling process if the projected MISO market hourly Locational Marginal Pricing ("LMP") were substantially lower than specific generating units in ENO's existing fleet was addressed in the IRP technical discussions. While the IRP model "objective function" is to identify long-term capacity to meet ENO's long-term capacity planning needs, the IRP analysis factors in MISO market hourly LMP prices and other factors, such as the fixed and variable cost of resource alternatives, to determine optimized portfolios.

10. *ENO's Union Power Station Power Block 1 (UPS PB1) Potential Early Retirement*

ENO reported that the process to optimize UPS PB1 deactivation dates could not be accommodated within the 2021 IRP schedule because of the time required to perform the several required engineering studies and associated capacity expansion simulations.[68] However, ENO stated[69] that it could run a limited manual portfolio sensitivity analysis that assessed an alternate deactivation date of UPS PB1, in time to run the production cost within the 2021 IRP schedule.

The economic analysis of an alternate UPS PB1 retirement date in the 2021 IRP used the incremental cost to maintain and operate the unit relative to a baseline date. The reference deactivation date of UPS PB1 is 2033, and it was chosen to evaluate the earlier deactivation date of 2025. An engineering study estimate of the cost to maintain UPS PB1 through 2025 was required, with the cost delta between the two retirement dates equal to the estimated incremental cost to maintain the unit from 2025 through 2033. That incremental cost was converted into a levelized $/MW-week metric for inclusion in the AURORA Capacity Expansion model to determine which of the deactivation date scenarios was more economic for customers, when considering both non-fuel fixed costs and variable supply cost. It should be noted that this economic (incremental) analysis did not incorporate the sunk costs or fixed costs that may remain from the initial UPS PB1 investment related to early deactivation.

[68] Response to CNO 2-1.
[69] In Technical Meeting 3, the manual portfolio of UPS PB1 retirement was discussed.

ENO states that the IRP analysis indicates that it is more beneficial to customers for ENO to operate UPS PB1 until 2033 instead of deactivating it early in 2025.[70] While the Advisors agree that this specific statement is supported by the IRP analysis, the Advisors do not believe that the analysis supports eliminating the early retirement of UPS PB1 as a future possibility. The Advisors note that the only analysis performed was to compare the Stakeholders' proposal of retiring UPS PB1 in 2025 to ENO's assumption that the unit would be retired in 2033 based on the expected average life of similar units. No analysis was performed on the merits of retiring UPS PB1 in any of the years between 2025 and 2033.

While the TRSC analysis performed did show that retiring UPS PB1 in 2025 increased costs to ratepayers versus retiring UPS PB1 in 2033, the difference in cost was relatively minor. Comparing, for example, the TRSC results of the Strategy 1, Scenario 1 portfolio with Manual Portfolio 1a, which was the same portfolio of resources, but acquired beginning in 2025 rather than in 2033 to reflect the retirement of UPS PB1 in 2025, resulted in an increase in cost due to the early retirement of UPS PB1 of only 2.6%-13.0%, with the lowest impact in Scenario 3. Scenario 3 was the Stakeholder Scenario that assumed high load growth, high natural gas prices and high DSM, along with lower costs for renewables. Given how close this cost difference is, current social and corporate trends toward electrification, and volatility in natural gas prices due to global conflicts, it is well within the realm of possibility that while retiring UPS PB1 in 2025 does not currently appear to benefit customers, future developments could cause it to be beneficial to customers to retire UPS PB1 some time before 2033. Therefore, the Advisors recommend that the Council require ENO to continue to evaluate the possible retirement of UPS PB1 prior to 2033 in future IRP proceedings.

11. Incorporating Two DSM Potential Studies.

Since DSM is recognized as an important supply-side resource, the four planning strategies enabled the evaluation of two separate DSM potential studies as inputs to the IRP process -- one DSM potential study from ENO and a separate DSM potential study performed by an independent consultant retained by the Council. The parties agreed on assignments of DSM input cases from both DSM Potential Studies to each of the four Strategies analyzed in the IRP modeling. The comparative results of proposed programs between the two DSM potential studies were also extended to the IRP scorecard. Since the IRP represents a principal DSM source to inform the implementation of Energy Smart DSM programs in the City over the next few years, the triennial DSM cost benefit analysis and selection of DSM programs by the independent Energy Smart Third Party Administrator and Third Party Evaluator in turn represent valuable reference sources for IRP DSM inputs. Notwithstanding the increased complexity of the analysis with DSM inputs from two DSM potential studies, it was beneficial for the IRP process to consider the range of energy and demand reductions and associated costs represented by differing credible DSM sources. The Advisors note that the prospective three-year Energy Smart Implementation Plan is expected to include DSM program reductions and costs that differ from each of the two DSM potential studies used as IRP DSM inputs. The Energy Smart Third Party Administrator developing the Implementation Plan for the next three years will necessarily focus on more near term impacts

[70] Final 2021 IRP at 5.

from DSM measures and with more confidence in DSM metrics than considered in the twenty year planning horizon of the IRP DSM potential study.

12. Council DSM-related directive to evaluate customer-owned storage controlled by the utility

Council Resolution No. R-20-157, Directive 9, states: "the Council specifically directs ENO to include in the measures to be evaluated in the study a customer DER program whereby customers would receive an incentive to install energy storage facilities on their property controlled by the utility such that the utility could direct when the storage units dispatch stored electricity onto the distribution grid." In compliance, ENO's DSM Potential Study evaluated a DER program where customers would receive incentives from ENO for the purchase/installation of battery storage systems interconnected with the distribution grid in return for the customers' commitment to ENO to have the battery capacity available and controlled by ENO for dispatch during peak system times. The customer incentives included ENO sharing a portion of the upfront installed battery storage cost (50% for residential and 20% for C&I customers), plus customers would receive a $/kW basis for the dispatched kW capacity. The program assumptions of dispatch frequency and duration, kW size, inverter cost, method of dispatch, and customer incentive were reasonably constructed. However, the DER program, as designed, was analyzed and determined to be not cost-effective, and therefore was not included in the IRP analysis as an annual peak load reduction. The GDS DSM Potential Study also found that demand response control of battery storage is currently not cost-effective.[71]

The Advisors believe that applying the current Residential, Small Electric Service and Large Electric Service retail tariffs and rates did not reflect the time-differentiated nature of the costs related to this battery storage program, and could have significantly changed the benefit to cost ratio of the evaluated program. Any DSM/DER measure involving storage should be evaluated with rates that reflect the time-differentiated periods of high and low energy costs. Further, the Advisors note that ENO currently has a proposal before the Council for a battery storage pilot program that would collect data regarding the benefits to ENO of being able to dispatch existing customer batteries installed at the customer's expense. Although this IRP analysis found that a program allowing the utility to dispatch customer-owned battery systems in exchange for an incentive is not cost effective, the Advisors recommend that the Council instruct ENO to include this analysis again in the next IRP proceeding, informed by the results of the pilot program and assuming time-differentiated rates.

13. The impact of AMI included in the IRP

The ENO DSM Potential Study included a dynamic pricing DR program, enabled by AMI, as an opt-in, critical peak pricing offer to all customers with a 6:1 critical peak to off-peak price ratio. As with all cost-effective DSM programs, the hourly impacts were included in the IRP analysis as a reduction or increase to forecasted load consistent with the term of the program. It was indeterminate if the operational benefits related to AMI, including energy and peak reduction, as claimed in ENO's Application in Docket No. UD-16-04, such as an annual electric usage reduction

[71] City Council Of New Orleans 2021 DSM Potential Study, prepared by GDS Associates, Section 3.2.4, (TRC of 0.06 to 0.15), adding that the potential for demand response control of battery storage would be lower if customers do not want the utility to have control of the battery.

of 1.75% and a peak capacity reduction of 2.125% for residential and commercial customers, were recognized in the load forecast and IRP.

14. IRP Scorecard

The Final 2021 IRP did include a scorecard, agreed upon by the parties, to assist the Council in assessing the IRP portfolio results. The scorecard included several aspects of the Resource Portfolios, including social and environmental impacts, some of which could only be evaluated on a subjective basis. The Final 2021 IRP's statements regarding the IRP scorecard noted the difficulty inherent in trying to compare resource portfolios based on different assumptions and subjective and objective characteristics. Starting from the Scorecard developed for the 2018 IRP, the parties affirmed the continued use of several metrics and agreed on updated metrics that focused on reliability (a "Relative Loss of Load Expectation" metric) and compliance with the Council's RCPS rules (the average annual percent of a portfolio's clean energy targeted to align with Schedule 3.A. of the RCPS). Based on the thirteen scorecard metrics, the five down-selected Portfolios were assigned a grade determined by how the given Portfolio performed in relation to the others. ENO commented that due to differing Scenario and Strategy characteristics, a review of the scorecard grades requires consideration of the inherent compositional differences among the Portfolios.[72] The Advisors found this second attempt to employ an IRP scorecard to be a valuable tool in comparing the various optimized resource portfolios and assisting the Council in assessing the results of the overall 2021 IRP analysis. A qualitative comparison of the key metrics of utility cost, risk/uncertainty, reliability, environmental impact, and RCPS compliance is facilitated for the optimized portfolios with the scorecard rankings using a quartile basis.

B. <u>Comments of the Parties</u>

While many of the parties were active participants in the technical meetings and public hearings, only AAE and 350 New Orleans filed written comments regarding the Final 2021 IRP.

1. AAE Comments

AAE stated: "This IRP does not include portfolios with any [Demand Side Management]. This is a departure from the 2018 IRP which included DSM within each portfolio modeled, ranging from 187-278 MW of capacity 'additions' through demand-side efforts."[73] However, this statement was not supported by IRP workpapers related to DSM. AAE commented that the Council could open a new docket to consider a DSM rule, which would include both an energy savings target as well as a peak demand reduction target. Furthermore, this docket could operate independently from the IRP.[74] AAE also suggested a new DSM docket, to include new programs directing more support to parts of the city that suffer both extreme energy burdens and severe heat island impacts. AAE stated that independent DSM docket could generate models using a more appropriate discount rate, rather than the high 8% discount rate used in both IRP DSM Potential Studies.[75]

[72] IRP Final Report, Page 78. The results of the scorecard are outlined in Table 16.
[73] Comments of the Alliance For Affordable Energy, May 9, 2022, Page 2.
[74] Comments of the Alliance For Affordable Energy, May 9, 2022, Page 3.
[75] Id.

AAE commented positively that the IRP indicated no need for additional fossil fuel generation, but criticized the IRP's conservative projections of the cost of natural gas, as likely to unreasonably extend reliance on existing fossil resources and delay further deployment of DSM and large-scale renewable energy. Specifically, AAE noted that the Henry Hub spot price for natural gas was currently around $8/MMBtu, a price that even the IRP high cost scenario does not anticipate until after 2040.[76] AAE recommended the Council direct ENO to model an additional sensitivity analysis to better understand the impacts of volatile natural gas prices on the portfolios, using an average of the last six months of Henry Hub spot prices to create a new cost-curve for future gas costs. AAE concluded that the Council must exercise its extraordinary power to ensure that the IRP process produces results in line with the Council's goals for climate and resilience, such as the Renewable and Clean Portfolio Standard (Docket No. UD-19-01) and Resolution No. R-21-401 initiating the storm hardening and resilience docket. It was left to interpretation as to exactly how the IRP results should be "in line" with the referenced dockets.

2. 350 New Orleans Comments

350 New Orleans' comments expressed disappointment regarding battery storage excluded from Stakeholder Strategy 4, but did not reference the parties agreement that no further modeling efforts were necessary. 350 New Orleans also advocated that UPS PB1 be shut down in 2025, not 2033, for reasons of devastating climate effects. 350 New Orleans noted that Manual Portfolios 1a and 4a do not show an equivalent 1,980 MW being substituted with renewables. 350 New Orleans concluded with the recommendation that the EV charging station infrastructure, approved in 2018, needs to be given a high priority to get many more, if not hundreds, around the city within a year or two.[77]

3. ENO Comments

ENO submitted Reply Comments responsive to the 350 New Orleans and AAE Comments. Regarding 350 New Orleans' comments related to the exclusion of battery storage in Strategy 4, ENO noted the agreement among the Stakeholders, ENO, and the Advisors to include the three manual portfolios in the total relevant supply cost analysis, and that this approach would produce a suitable range of results for Council consideration within the time allowed by the procedural schedule, and without the need for re-running the capacity optimization with another Stakeholder input set that included battery storage.[78] Regarding 350 New Orleans' comments related to Manual Portfolios 1a and 4a not showing an equivalent 1,980 MW being substituted with renewables, ENO noted that 350 New Orleans seems to be suggesting that the analysis should have considered not just the early deactivation of UPS PB1, but also the other three Union units as well, which combined with UPS PB1 would represent an overall capacity amount of approximately 1,980 MW, which is not a valid consideration since the other three Union units are not owned by ENO.[79] The Advisors note that of the 1,980 MW of total capacity at the Union site, ENO owns only Power Block 1, representing 500 MW, and that the remaining 1,480 MW of Union capacity is committed

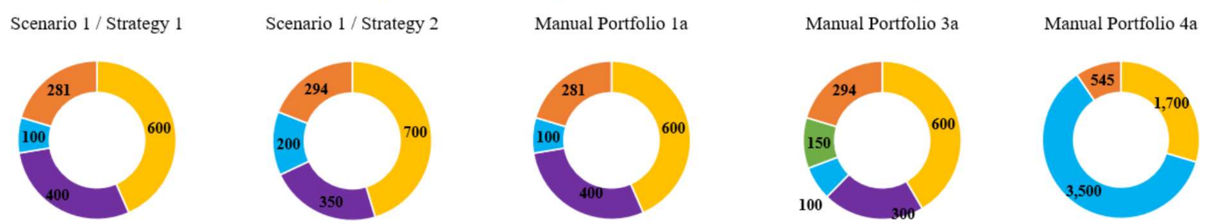
[76] Comments of the Alliance For Affordable Energy, May 9, 2022, Page 4.
[77] 350 New Orleans Comments re: 2021 IRP Final Report. May 9, 2022.
[78] ENO Reply Comments, Page 2
[79] Id.

to customers of other utilities. Therefore, the Advisors agree that it is only appropriate to include ENO's 500 MW of Union capacity in the IRP analysis.

Regarding 350 New Orleans' comments related to the EV charging station infrastructure public charging pilot, ENO referenced its June 2, 2022 presentation to the Council's Climate and Sustainability Committee and its expectation to complete installation of at least a portion of the chargers under the pilot program this year and the remainder in 2023.[80] ENO also referenced its filing with the Council in January 2022 in Docket No. UD-18-07 seeking regulatory changes that would encourage the expansion of electric vehicle charging infrastructure in New Orleans, and stated that it will seek to develop other proposals to the Council that would expand public access to Direct Current fast chargers and Level 2 chargers and foster greater adoption of EVs in the city.[81]

Regarding AAE's comment regarding the lack of DSM in the IRP portfolios, ENO replied: "This comment is puzzling since AAE should be aware that all of the portfolios developed for the 2021 IRP included significant amounts of DSM, with avoided capacity values ranging from 245 MW to 474 MW."[82] ENO noted that the effects of DSM on the total relevant supply costs are explained in detail on pp. 46-53 and pp. 69-74 of the IRP Report, and included a chart in its Reply Comments which shows the amounts of DSM included in each of the five portfolios down-selected for inclusion in the full total relevant supply cost analysis. That chart is also included below.

2041 New Capacity (ICAP) with DSM (incl. Transmission Losses & Reserve Margin)



Scenario 1 / Strategy 1	
Resource	Capacity (MW)
Solar	600
Battery	400
Wind	100
Hybrid	-
DSM	281

Scenario 1 / Strategy 2	
Resource	Capacity (MW)
Solar	700
Battery	350
Wind	200
Hybrid	-
DSM	294

Manual Portfolio 1a	
Resource	Capacity (MW)
Solar	600
Battery	400
Wind	100
Hybrid	-
DSM	281

Manual Portfolio 3a	
Resource	Capacity (MW)
Solar	600
Battery	300
Wind	100
Hybrid	150
DSM	294

Manual Portfolio 4a	
Resource	Capacity (MW)
Solar	1,700
Battery	-
Wind	3,500
Hybrid	-
DSM	545

■ Solar ■ Battery ■ Wind ■ Hybrid ■ DSM

ENO offered that a similar chart could be included in future IRP reports to make clear the amount of DSM included in each portfolio, and the Advisors concur that such chart should be so included.

As to AAE's recommendation that the Council direct ENO to model an additional sensitivity analysis to better understand the impacts of volatile natural gas prices, ENO suggests that any such additional analysis is not appropriate or necessary as part of the 2021 IRP, since the IRP is by definition a 20-year planning study that draws on NYMEX Henry Hub forward prices as well as other third-party forecasts. ENO added: "If the high gas prices seen recently in the market persist

[80] ENO Reply Comments, Page 3.
[81] ENO Reply Comments, Page 4.
[82] Id.

and drive forecasts of higher prices over the long term, those trends will be captured as appropriate in the input cases developed for the 2024 IRP." The Advisors concur with that conclusion. The Council requires a new IRP to be developed every three years to update the long-term point of view based on recent assumptions, such as those related to natural gas prices. The Advisors note that current high gas prices are driven in part by geopolitical conflict which may or may not have a long-term impact on natural gas prices over the 20-year planning period. The IRP inputs for the next planning cycle should be finalized by early- to mid-2024, which will provide all parties with a better ability to project the long-term impacts of the current geo-political conflict.

Related to AAE's suggestion for a new rulemaking to consider a "DSM Rule," ENO pointed to the Energy Smart program is in its 12th year, and the Council's standing 2% energy savings goal has been in place for several years now, modeled in both the 2018 and 2021 IRPs.[83] ENO also referred to the increasing participation in demand response programs among ENO's customers and the recent completion of the AMI implementation, and stated that it would be appropriate for the Council to consider adding a demand reduction goal in connection with demand response programs to the next three years of Energy Smart, 2023-2025.[84]

ENO also commented that there is no merit to AAE's suggestion that a new DSM docket is necessary to create programs to support low income customers or neighborhoods since such programs already exist and are well documented in Energy Smart; any additions or modifications could be considered under the existing plan review process.[85] In its final Reply Comments, ENO argued against AAE's belief that a 2-3% discount rate is "more appropriate," and AAE's conclusion that "a high discount rate tends to disfavor DSM options such as battery storage because of their up-front costs," adding that a new DSM docket would serve only to slow down the implementation of Energy Smart and add additional regulatory costs for customers.

The DSM potential studies indicate that the Council's 2% energy efficiency goal could be achieved as early as 2025, and may decline thereafter, as savings decrease over time.[86] Incremental annual savings would be expected to decline over time in part due to the success of the program and to increasing governmental efficiency standards – as the base level of technology in New Orleans becomes more efficient due to measures previously implemented and improved efficiency standards, such as the phasing out of incandescent light bulbs, the amount of savings from switching to a new technology is likely to be smaller. For example, switching from an incandescent light bulb to a Compact Fluorescent Lamps ("CFL") light bulb reduces energy use by about 75%, however, changing from a CFL light bulb to a light-emitting diode ("LED") bulb does not result in a significant energy savings, LED bulbs are about the same as CFLs, 75% more energy than incandescent bulbs (but have a much longer life span). Further, if a consumer does not have the option to buy an incandescent bulb at the store, then an incentive for either CFLs or LEDs does not actually create savings – the customer would have to use a CFL or LED whether the incentive is present or not. It should be noted, however, that the 2% goal is relevant only to the incremental (*i.e.*, new) energy savings added by the Energy Smart Program every year. The cumulative savings of the program are much greater than 2% of energy sales every year. The

[83] ENO Reply Comments, Page 6.
[84] Id.
[85] Id.
[86] Final 2021 IRP at Appendix D, Guidehouse DSM Potential Study at xvii, Table 3; and Appendix E, GDS 2021 Potential Study at 4, Table ES-2.

Council's consultant, GDS, found in its potential study that over the 20-year time frame studied, the cumulative result of the energy efficiency programs could be range from 21-29% of total energy sales.[87]

In light of the possibility that the Council's energy efficiency goal of increasing annual incremental energy savings through the program by 0.2% per year until it reaches 2% could be met in the Program Year 13-15 compliance period for which ENO will be filing the implementation plan later this month, the Advisors recommend that the Council open a new rulemaking proceeding to consider what goal should be set to replace the 2% goal for Program Years 16 and beyond. Such a rulemaking could consider a broad range of issues beyond simply what an appropriate energy efficiency goal would be – it could also consider issues such as whether a peak demand reduction goal should be included as well as an energy sales goal, as suggested by the AAE in its comments.[88] It could also consider other aspects of energy efficiency program design, such as whether new programs should target specific geographic areas of the city to address heat islands or towards customers facing particularly severe energy burdens, as also suggested by the AAE.[89] It could also consider the impact of the programs on customer bills and whether customer incentives funded through energy bills are the most appropriate way to achieve all forms of energy efficiency or whether it might be more cost effective to achieve energy efficiency through regulatory measures such as improved building efficiency standards.

To the extent that the Council sets a procedural schedule for the 2024 IRP similar to that utilized in this case, the deadline for finalization of any Council policies to be included in the IRP would most likely occur in the second quarter of 2024, with DSM Potential Studies (which would be heavily impacted by any new Council rule on energy efficiency) being conducted from approximately the fourth quarter of 2023 through the first quarter of 2024. Therefore, in order to allow any new Council rule to be in place in time to be properly taken into account in the DSM Potential Studies to be utilized in the 2024 IRP proceeding as well as in the program design for Energy Smart Program Years 16-18 (2026-2028), the Advisors recommend that the Council conduct an energy efficiency rulemaking docket beginning in the third quarter of 2022 and concluding no later than the third quarter of 2023.

V. Advisor Findings and Recommendations

The Advisors believe that the 2021 IRP does provide a credible planning perspective to consider options for meeting forecasted utility electrical energy and demand over the 20-year planning period, assuming a range of expected market conditions in MISO. Contrary to IRPs previous to 2018, which offered a "preferred portfolio," the revised IRP Rules and resulting Final IRP Report represents the second attempt to provide a useful planning tool for the Council to assist in evaluating future resource options. The Final 2021 IRP did present an acceptable summary of ENO's ongoing efforts related to the current status towards optimizing distributed energy resources on the distribution grid, including the current implementation of AMI and several

[87] Final 2021 IRP at Appendix E, GDS 2021 Potential Study at 20, Figure 2-5.
[88] AAE Comments at 3.
[89] AAE Comments at 3.

associated software systems, and the ongoing progress of distribution reliability and grid modernization projects.[90]

The Advisors agree that the recent two IRPs developed under the new IRP Rules have proven to result in a more collaborative and efficient process with a less contentious result than prior IRP cycles under previous rules. The Advisors also agree that while the Final 2021 IRP provides interesting insight into long-term resource planning, the most immediate applications of the Final 2021 IRP should be: (i) informing the Implementation Plan for Energy Smart Program Years 13-15, which is due to be filed by ENO on July 19, 2022; and (ii) providing the total relevant supply cost produced for the "but-for" portfolio in the Final 2021 IRP analysis as the baseline for calculating incremental costs associated with ENO's three-year RCPS compliance plan for 2023-2025.

While the Advisors find that the Final 2021 IRP Result is in compliance with the Council's requirements, the Advisors do recommend a few changes that can be implemented in the Initiating Resolution for the next IRP cycle that we believe would improve the resulting analyses.

- First, to the extent that the Council determines that it will use its own independent expert to produce a DSM Potential Study in the next IRP cycle, it would be helpful if the Council provided instructions to ENO and the independent consultant as to how to make portfolios produced using inputs from different studies more directly comparable. This could include the use of survey techniques to improve the estimation of saturation and adoption rates for specific DSM measures and the use of comparable references regarding the technology available for projected DSM measures.

- Second, future IRP final reports should include more detail 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.

- Third, the Advisors recommend that ENO be directed to utilize AURORA's modeling capability for an economic analysis which optimizes retirement dates for ENO's existing assets rather than utilizing fixed retirement dates and to continue modeling an early retirement date for UPS PB1. While the Advisors do recognize that with respect to certain resources, the FERC and not the Council has the jurisdiction to determine the extent to which ENO can terminate its commitments and obligations, however, the Advisors believe it would be informative to the Council to see the results of AURORA's analysis as to when it would be economic to retire ENO's various existing resources rather than programming in a specific retirement date for each resource.

- Fourth, the Advisors recommend that the issue of incorporating early retirements of existing resources simultaneously with optimizing an energy-based model solution should be considered by the Council before a procedural schedule is included in the Initiating Resolution of the next triennial IRP.

[90] Final 2021 IRP Report, Page 22.

ENO's 2021 IRP Action Plan appears reasonable. In its Action Plan ENO represented that it will: (i) seek to identify a suitable small project to help it meet or exceed the 100 MW renewables commitment; (ii) engage with the Council and City stakeholders to discuss possible offerings for a City Clean Power Plan responsive to Resolution No. R-22-11; (iii) develop and file its first three year RCPS compliance plan for 2023-25 within 90 days after submission of the IRP Report; (iv) continue to work towards completion of the 25 site Public Charging pilot approved through the 2018 Rate Case, and seek to develop proposals to the Council that would expand public access to Direct Current Fast Chargers and Level 2 chargers; (v) work with the Bring Your Own Battery Pilot program implementer to execute the program during Energy Smart PY12 and develop experience to possibly inform a similar program during PY 13-15; (vi) file an Implementation Plan for Energy Smart Program Years 13-15 as required under Resolution No. R-20-257; (vii) evaluate a possible expansion of the current Green Power Option program to accommodate larger usage offsets; (viii) consider solutions offered to residential and commercial customers which could include make ready infrastructure and other equipment that would facilitate the safe and quick installation of temporary backup generation in response to storm events; and (ix) file a Plan detailing investments and projects to support system resiliency and storm hardening as required by Resolution No. R-21-401.

The Advisors recommend that the Council approve ENO's 2021 IRP Action Plan subject to the following caveats: (1) consistent with Section 1.D of the IRP Rules, 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 (2) Council approval of the 2021 IRP does not preclude the Council from considering and/or ordering further actions by ENO relative to resource planning and acquisition; in particular, approval of the Final 2021 IRP shall have no precedential impact upon the Council's considerations in the Renewable Portfolio Standard rulemaking docket (UD-19-01) or any other related docket. The Advisors also note that there are various related proceedings, such as the RCPS Docket (UD-19-01) that may impact resource choices and should inform future IRP cycles.

VI. Conclusion

As discussed herein, the Advisors recommend that the Council accept the Final 2021 IRP as being in compliance with the Council's requirements, approve the Final 2021 IRP, subject to certain caveats and provide certain instructions to the parties in the Initiating Resolution for the next IRP cycle.

RESPECTFULLY SUBMITTED:

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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-20-02 via electronic mail and/or U.S. Mail, postage properly affixed, this 12th day of July, 2022.

J. A. "Jay" Beatmann, Jr.

ATTACHMENT A

Attachment "A" to Final IRP Report

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX A

2021 IRP RULES COMPLIANCE MATRIX

MARCH 2022

Requirement No.	Section No.	Page No.	Key phrase or Issue	Excerpt	Response and/or Citation to IRP Report
1	1.C.	1	Rules Matrix	*Each Utility IRP shall include a matrix of these rules, the corresponding section of the IRP responsive to that rule, and a brief description of how the Utility complied with the rules.*	**Appendix A**
2	3.A.	4	Specific Objectives	*The Utility shall state and support specific objectives to be accomplished in the IRP planning process, which include but are not limited to the following:*	
3	3.A.1.	4	Integration of Supply Side and Demand Side Resources	*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;*	**Pg 7: Planning Objectives; Pg 17: Transmission; Pg 19: Distribution; Chapter 4: Modeling Framework**
4	3.A.2.	4	Maintain Financial Integrity	*maintain the Utility's financial integrity;*	**Pg 7: Planning Objectives**
5	3.A.3.	4	Mitigate Risks	*anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;*	**Pg 75: Stochastic Assessment of Risks**
6	3.A.4.	4	Support Resiliency and Sustainability	*support the resiliency and sustainability of the Utility's systems in New Orleans;*	**Pg 17: Transmission; Pg 19: Distribution; Pg 78: Scorecard Metrics and Results**
7	3.A.5.	4	Comply with Requirements and Council Policies	*comply with local, state and federal regulatory requirements and regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;*	**Pg 57: Planning Strategy Overview; Pg 78: Scorecard Metrics and Results**
8	3.A.6.	4	Evaluate Incorporation of new technology	*evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and DERs, among others;*	**Pg 38: Generation Technology Assessment**
9	3.A.7.	4	Acceptable Risk	*achieve a range of acceptable risk in the trade-off between cost and risk;*	**Pg 75: Stochastic Assessment of Risks**
10	3.A.8.	4	Transparency and Engagement	*maintain 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.*	**Technical Meeting #1: 12/9/20; DSM Input Stakeholder Meeting: 3/26/21; Technical Meeting #2: 4/29/21; Technical Meeting #3: 8/12/21; Technical Meeting #4: 1/20/22;**
11	3.B.	4	Efforts to Achieve Objectives	*In the IRP Report, the Utility shall discuss its efforts to achieve the objectives identified in Section 3A and any additional specific objectives identified in the Initiating Resolution.*	**Pg 7: Planning Objectives; Chapter 4, Modeling Framework**
12	4.A.	5	Reference Load Forecasts and alternatives	*The Utility shall develop a reference case Load Forecast and at least two alternative Load Forecasts applicable to the Planning Period which are consistent with the Planning Scenarios identified in Section 7C. The following data shall be supplied in support of each Load Forecast:*	**Pg 24: Load Forecasting Methodology**

13	4.A.1.	5	Forecast of Demand and Energy by Customer Class	*The Utility's forecast of demand and energy usage by customer class for the Planning Period;*	**Pg 24: Load Forecasting Methodology; Appendix B**
14	4.A.2.	5	Methodology	*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 and then existing Utility-sponsored DSM programs;*	**Pg 24: Load Forecasting Methodology**
15	4.A.3.	5	Independent Variables	*Forecasts of the independent variables for the Planning Period, including their probability distributions and statistical significance;*	**Pg 24: Load Forecasting Methodology**
16	4.A.4.	5	Expected Value of forecast	*The expected value of the Load Forecast as well as the probability distributions (uncertainty ranges) around the expected value of the Load Forecast;*	**Pg 24: Load Forecasting Methodology; Appendix B**
17	4.A.5.	5	Line Losses	*A discussion of the extent to which line losses have been incorporated in the Load Forecast.*	**Pg 33: Load Forecasts for IRP Planning Scenarios**
18	4.B.	5	Composite Customer Hourly Load Profiles	*The Utility shall construct composite customer hourly load profiles based on the forecasted demand and energy usage by customer class and relevant load research data, including the factors which determine future load levels and shape.*	**Pg 24: Load Forecasting Methodology; Appendix B**
19	4.C.	5	Demand and Energy data for 5 preceding years	*Concurrent with the presentation of the Load Forecasts to the Advisors, CURO, and stakeholders, the Utility shall provide historical demand and energy data for the five (5) years immediately preceding the Planning Period. At a minimum, the following data shall be provided:*	**Appendix B**
20	4.C.1.	5	Monthly energy consumption by class	*monthly energy consumption for the Utility in total and for each customer class;*	**Appendix B**
21	4.C.2.	5	Monthly CP for utility and classes	*monthly coincident peak demand for the Utility and estimates of the monthly coincident peak demand for each customer class;*	**Appendix B**
22	4.C.3.	5	Monthly peak demand by class	*estimates of the monthly peak demand for each customer class;*	**Appendix B**
23	4.D.	5	Section 4 data in attachment	*The data and discussions developed pursuant to Section 4A and Section 4B, and Section 4C shall be provided as an attachment to the IRP report and summarized in the IRP report.*	**Pg 24: Load Forecasting Methodology; Appendix B**
24	4.E.	6	Known cogen and >300kW DER resources	*The Utility shall also provide a list of any known co-generation resources and DERs larger than 300 kW existing on the Utility's system, including resources maintained by the City of New Orleans for city/parish purposes, (e.g. Sewerage and Water Board, Orleans Levee District, or by independent agencies or entities such as universities, etc.).*	**New Orleans Solar Power Project; Sites constructed under Commercial Rooftop Project (UD-17-05)**
25	5.A.	6	Identification of resource options	*Identification of resource options. The Utility shall identify and evaluate all existing supply-side and demand-side resources and identify a variety of potential supply-side and demand-side resources which can be reasonably expected to meet the Utility's projected resource needs during the Planning Period.*	**Appendix D and E: Guidehouse and GDS Studies; Pg 38: Generation Resource Assessment**
26	5.A.1.	6	Existing supply side resource costs	*Existing supply-side resources. For existing supply-side resources, the Utility should incorporate all fixed and variable costs necessary to continue to utilize the resource as part of a Resource Portfolio. Costs shall include the costs of any anticipated renewal and replacement projects as well as the cost of regulatory mandated current and future emission controls.*	**Appendix C--Variable Supply Cost reflects the optimized run time of existing units**

27	5.A.1.a.	6	Changes to resource mix	*The Utility shall identify important changes to the Utility's resource mix that occurred since the last IRP including large capital projects, resource procurements, changes in fuel types, and actual or expected operational changes regardless of cause.*	**Pg 10: Figure 4 and Table 1**
28	5.A.1.b.	6	Supply side resource info	*Data supplied as part of the Utility's IRP filing should include a list of the Utility's existing supply-side resources including: the resource name, fuel type, capacity rating at time of summer and winter peak, and typical operating role (e.g. base, intermediate, peaking).*	**Pg 11: Table 2**
29	5.A.2.	6	Load reductions from existing DSM resources	*For existing demand-side resources, the Utility should account for load reductions attributable to the then-existing demand-side resources in each year of the Planning Period. Each existing demand-side resource will be identified as either a specific energy efficiency program or DR program with an individual program lifetime and estimated energy and demand reductions applicable to the Planning Period, or as a then-existing Utility owned or Utility-managed distributed generation resource with energy and demand impacts that are estimated for applicable years of the Planning Period. Data supplied as part of the Utility's IRP filing should include:*	**Pg 24: Load Forecasting Methodology; Pg 46: Demand-Side Management; Pg 81: Action Plan; Appendix H**
30	5.A.2.a.	6	Projected reductions	*Details of projected kWh/kW reductions from existing DSM programs based on quantifiable results and other credible support derived from Energy Smart New Orleans, or any successor program, using verified data available to the Utility from prior DSM program implementation years.*	**Pg 30: Demand Side Management**
31	5.A.2.b.	6	Existing DSM resources	*A list categorizing the Utility's existing demand-side resources including anticipated capacity at time of summer and winter peak.*	**Pg 30: Demand Side Management**
32	5.A.3.	6	Potential SS resources	*With respect to potential supply-side resources, the Utility shall consider: Utility-owned and purchased power resources; conventional and new generating technologies including technologies expected to become commercially viable during the Planning Period; technologies utilizing renewable fuels; energy storage technologies; cogeneration resources; and Distributed Energy Resources, among others.*	**Pg 38: Generation Resource Assessment**
33	5.A.3.a.	7	Incorporate known policy goals	*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.*	**Pg 57: Planning Strategies; Pg 68: Action Plan**
34	5.A.3.b.	7	Required data for resources	*Data supplied as part of the Utility's IRP filing should include: a description of each potential supply-side resource including a technology description, operating characteristics, capital cost or demand charge, fixed operation and maintenance costs, variable charges, variable operation and maintenance costs, earliest date available to provide supply, expected life or contractual term of resource, and fuel type with reference to fuel forecast.*	**Pg 38: Generation Resource Assessment**
35	5.A.4.	7	Potential DSM Resources	*Potential demand-side resources. With respect to potential demand-side resources, the Utility should consider and identify all cost-effective demand-side resources through the development of a DSM potential study. All DSM measures with a Total Resource Cost Test value of 1.0 or greater shall be considered cost effective for DSM measure screening purposes.*	**Appendix D and E: Guidehouse and GDS Studies**
36	5.A.4.a.	7	DSM Potential Study	*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.*	**Appendix D and E: Guidehouse and GDS Studies**
37	5.A.4.b.	7	N.O. TRM	*The principal reference document for the DSM potential study shall be the New Orleans Technical Reference Manual.*	**Appendix D and E: Guidehouse and GDS Studies**
38	5.A.4.c.	7	CA Standard Practice Tests	*In the development of the DSM potential study, all four California Standard Practice Tests (i.e. TRC, PACT, RIM and PCT) will be calculated for the DSM measures and programs considered.*	**Appendix D and E: Guidehouse and GDS Studies**
39	5.A.4.d.	7	Known policy goals re: DSM	*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.*	**Pg 57: Planning Strategy Overview; Pg 78: Scorecard Metrics and Results**
40	5.A.4.e.	7	Cost effective DR programs	*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.*	**Appendix D and E: Guidehouse and GDS Studies**

41	5.A.4.f.	8	Required data for DSM analysis	*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.*	**Appendix D and E: Guidehouse and GDS Studies; Pg 46: Demand-Side Management**
42	5.B.	8	Stakeholder process	*Through the Stakeholder Process, the Utility shall 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.).*	**Consensus among parties reached at Technical Meeting #3**
43	5.B.1.	8	Reference Planning Strategy	*To the extent such a consensus can be achieved among the Utility, the Advisors, and a majority of the Intervenors, the resulting collection of potential supply-side and demand-side resources and their associated defining characteristics will be utilized in the reference Planning Strategy developed pursuant to Section 7D.*	**See #44, below**
44	5.B.2.	8	Stakeholder Strategy	*To the extent such a consensus cannot be achieved, the Utility shall model, in coordination with the requirements in Section 7D, two distinct Planning Strategies: a reference Planning Strategy and a stakeholder Planning Strategy. The reference Planning Strategy will be based on the Utility's assessment of the collection of potential supply-side and demand-side resources and their associated defining characteristics. The stakeholder Planning Strategy will be determined by a majority of the Intervenors and modeled by the Utility based on inputs provided to the Utility describing the collection of potential supply-side and demand-side resources and their associated defining characteristics. To maintain consistency in the modeling process, the Advisors will work with the Intervenors and the Utility to ensure that input that is provided for the stakeholder Planning Strategy can be accommodated within the framework of the existing model and software.*	**Consensus among parties reached at Technical Meeting #3 regarding set of four Planning Strategies**
45	6.A.	8	Integration of T&D planning into IRP	*The Utility shall explain how the Utility's current transmission system, and any planned transmission system expansions (including regional transmission system expansion planned by the RTO in which the Utility participates) and the Utility's distribution system are 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.*	**Pg 17: Transmission; Pg 19: Distribution Planning**
46	6.B.	9	Planned transmission topology	*Models developed for the integrated resource planning process should incorporate the planned configuration of the Utility's transmission system and the interconnected RTO during the Planning Period.*	**Pg 17: Transmission**
47	6.C.	9	Major changes to T&D systems	*To the extent major changes in the operation or planning of the transmission system and/or distribution system (including changes to accommodate the expansion of DERs) are contemplated in the Planning Period, the Utility should describe the anticipated changes and provide an assessment of the cost and benefits to the Utility and its customers.*	**Pg 17: Transmission; Pg 19: Distribution Planning**
48	6.D.	9	Transmission solutions for reliability	*To the extent that new resource additions are selected by the Utility for a Resource Portfolio based on reliability needs rather than as a result of the optimized development of a Resource Portfolio, the Utility shall identify reasonable transmission solutions that can be employed to either reduce the size, delay, or eliminate the need for the new reliability-driven resource additions and provide economic analyses demonstrating why the new reliability-driven resource addition was selected in lieu of the transmission solutions identified.*	**N/A**
49	6.E.	9	Evaluation of DERs	*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.*	**Pg 19: Distribution Planning**
50	7.A.	9	IRP Modeling parameters	*The integrated resource planning process should include modeling of specific parameters and their relationships consistent with market fundamentals, and as appropriate for long-term Portfolio planning. This overall modeling approach is an accepted analytic approach used in resource planning considering the range of both supply-side and demand-side options as well as uncertainty surrounding market pricing. To represent and account for the different characteristics of alternative types of resource options, mathematical methods such as a linear programming formulation should be used to optimize resource decisions.*	**Chapter 4, Modeling Framework**

51	7.B.	9	External Capacity sales	*The optimization process shall be constrained to mitigate the over-reliance on forecasted revenues from external capacity market sales and external energy market sales driving the selection of resources.*	**Pg 60: Market Modeling; Pg 65: Optimized and Manual Portfolios**
52	7.C.	9	Planning Scenarios	*The Utility shall develop three to four Planning Scenarios that incorporate different economic and environmental circumstances and national and regional regulatory and legislative policies.*	**Consensus among parties reached at Technical Meeting #2**
53	7.C.1.	10	Reference and Alternative Scenarios	*The Planning Scenarios should include a reference Planning Scenario that represents the Utility's point of view on the most likely future circumstances and policies, as well as two alternative Planning Scenarios that account for alternative circumstances and policies.*	**Consensus among parties reached at Technical Meeting #2**
54	7.C.2.	10	Scenario Assumptions	*In the development of the Planning Scenarios, the Utility should seek to develop a position agreed to by the Utility, Advisors, and a majority of Intervenors regarding the assumptions surrounding each of the Planning Scenarios. To the extent such a consensus is not reasonably attainable regarding the Planning Scenarios, the Utility shall model a fourth Planning Scenario which is based upon input agreed to by a majority of the Intervenors.*	**Consensus among parties reached at Technical Meeting #2**
55	7.C.3.	10	Data for Scenarios	*For each IRP Planning Scenario, data supplied as part of the Utility's IRP filing should include:*	
56	7.C.3.a.	10	Fuel Price Forecast	*a fuel price forecast for each fuel considered for utilization in any existing or potential supply-side resource;*	**Pg 54: Natural Gas Price Forecast**
57	7.C.3.b.	10	Hourly Market Price Forecast for Energy	*an hourly market price forecast for energy (e.g. locational marginal prices);*	**Pg 64: Average Annual MISO LMPs**
58	7.C.3.c.	10	Annual Capacity Price Forecast	*an annual capacity price forecast for both a short-term capacity purchase (e.g. bilateral contract or Planning Resource Credit) and a long-term capacity purchase (e.g. long-run marginal cost of a new replacement gas combustion turbine);*	**Appendix F--Macro Inputs Workbook**
59	7.C.3.d.	10	Other Price Components	*forecasts of price for any other price related components that are defined by the Planning Scenario (e.g. CO2 price forecast, etc.).*	**Pg 55: CO2 Price forecast**
60	7.D.	10	Strategies	*Distinct from the Planning Scenarios, the Utility shall identify two to four Planning Strategies which constrain the optimization process to achieve particular goals, regulatory policies and/or business decisions over which the Council, the Utility, or stakeholders have control.*	**Consensus among the parties reached at Technical Meeting #3**
61	7.D.1.	10	Lowest Cost Strategy	*The Utility shall develop a Planning Strategy that allows the optimization process to identify the lowest cost option for meeting the needs identified in the IRP process.*	**Pg 57: Planning Strategies**
62	7.D.2.	10	Reference Strategy	*The Utility shall develop a reference Planning Strategy agreed to by the Utility, Advisors, and a majority of the Intervenors. To the extent such a consensus cannot be reasonably achieved, the reference Planning Strategy shall reflect the Utility's point of view on resource input parameters and constraints, and the Utility shall model a separate stakeholder Planning Strategy based upon input determined by a majority of the Intervenors.*	**Consensus among the parties reached at Technical Meeting #3 regarding Strategy #2 as the Reference and "But For RCPS" Strategy**
63	7.D.3.	11	Alternate Strategies	*As necessary, the Utility shall develop alternate Planning Strategies to reflect known utility regulatory policy goals of the Council (including such policy goals or targets identified in the Initiating Resolution) as established no later than 30 days prior to the date the Planning Strategy inputs must be finalized.*	**Consensus among the parties reached at Technical Meeting #3 regarding Strategy #3 as the "RCPS Compliance" Strategy**
64	7.E.	11	Finalization of Scenario and Strategy Parameters	*Prior to the development of optimized Resource Portfolios, the parameters developed for the Planning Scenarios and Planning Strategies shall be set, considered finalized, and not subject for alteration during the remainder of the IRP planning cycle. The IRP Report shall describe the parameters of each Planning Scenario and each Planning Strategy, including all artificial constraints utilized in the optimization modeling.*	**Pg 56: Planning Scenarios; Pg 57: Planning Strategies**

65	7.F.	11	Portfolio Optimization	*Resource Portfolios shall be developed through optimization utilizing the Utility's modeling software. The Utility shall identify the least-cost Resource Portfolio for each Planning Scenario and Planning Strategy combination, based on total cost. Resource Portfolios shall consist of optimized combinations of supply-side and demand-side resources, while recognizing constraints including transmission and distribution.*	**Pg 65: Optimized and Manual Portfolios**
66	7.G.	11	Results of Scenario&Strategy combinations	*The Utility shall provide a discussion and presentation of results for each Planning Scenario/Planning Strategy combination, the annual total demand related costs, energy related costs, and total supply costs associated with each least-cost Resource Portfolio identified under each Planning Scenario/Planning Strategy combination, a load and capability table indicating the total load requirements and identifying all supply-side and demand-side resources included in the Resource Portfolio (including identifying the impacts of existing demand-side resources on the total load requirements), and a description of the supply-side and demand-side resources that are planned and, if applicable, their principal rationale for selection (i.e., supply peak demand, supply non-peak demand or operational constraints, achieve more economical production of energy, etc.).*	**Pg 71: Total relevant supply Cost Results; Appendix C**
67	7.G.1.	11	Annual and Cumulative portfolio costs	*Data supplied as part of the Utility's IRP filing shall include a cumulative present worth summary of the results as well as the annual estimates of costs that result in the cumulative present worth to enable the Council to understand the timing of costs and savings of each least-cost Resource Portfolio.*	**Pg 71: Total relevant supply Cost Results; Appendix C**
68	7.H.	11	Discussion of Portfolio Results	*The IRP report's discussion and presentation of results for each Resource Portfolio should identify key characteristics of that Resource Portfolio and significant factors that drive the ultimate cost of that Resource Portfolio such that the Council may understand which factors could ultimately and significantly affect the preference of a Resource Portfolio by the Council.*	**Pg 71: Total relevant supply Cost Results**
69	7.I.	11	Scorecard template	*The Utility will 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 by 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.*	**Pg 78: Scorecard Metrics and Results**
70	8.A.	12	Cost/Risk Analysis	*The Utility shall develop a cost/risk analysis which balances quantifiable costs with quantifiable risks of the identified least-cost Resource Portfolios. The risk assessment must be presented in the IRP to allow the Council to comprehend the robustness of each Resource Portfolio across the cost/risk range of possible Resource Portfolios.*	**Pg 75: Stochastic Assessment of Risks**
71	8.A.1.	12	Assessment of social and environmental costs	*In quantifying Resource Portfolio costs/risks, the IRP shall assess any social and environmental effects of the Resource Portfolios to the extent that: 1) those effects can be quantified and have been modeled for a Resource Portfolio, including the applicable Planning Period years and ranges of uncertainty surrounding each externality cost, and 2) each quantified cost must be clearly identified by the portion which relates to the Utility's revenue requirements or cost of providing service to the Utility's customers under the Resource Portfolio.*	**Pg 78: Scorecard Metrics and Results**

72	8.A.2.	12	Probabilities of outcomes	*It is the Council's intent that, as part of the IRP, a risk assessment be conducted to evaluate both the expected outcome of potential costs as well as the distribution and potential range and associated probabilities of outcomes. To the extent the Utility believes the risk assessment described herein is beyond the current modeling capabilities of the Utility or that the risk assessment cannot be accomplished within the procedural schedule set forth in the Initiating Resolution, the Utility shall so inform the Council and meet with the Intervenors and Advisors to agree upon an alternative form of risk analysis to recommend to the Council.*	**Pg 75: Stochastic Assessment of Risks**
73	8.A.2.a.	12	Cost/MWh in future years	*The risk assessment shall include the expected cost per MWh of the Resource Portfolios in selected future years, along with the range of annual average costs foreseen for the 10th and 90th percentiles of simulated possible outcomes.*	**Pg 75: Stochastic Assessment of Risks**
74	8.A.2.b.	12	Supporting Methodology Included	*The supporting methodology shall be included, such as the iterations or simulations performed for the selected years, in which the possible outcomes are drawn from distributions that describe market expectations and volatility as of the current filing date.*	**Pg 75: Stochastic Assessment of Risks**
75	9.A.	12	IRP Process Requirements	*At a minimum, the IRP process shall include, but not be limited to, the following elements:*	
76	9.A.1.	12	Collaboration on IRP inputs	*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.*	**Stakeholder process conducted in accordance with IRP Rules and Initiating Resolution**
77	9.A.2.	12	Four Technical Meetings	*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 assumptions and provide comments, and attempt to reach consensus while remaining mindful of the procedural schedule established in the Initiating Resolution.*	**Technical Meeting #1: 12/9/20; DSM Input Stakeholder Meeting: 3/26/21; Technical Meeting #2: 4/29/21; Technical Meeting #3: 8/12/21; Technical Meeting #4: 1/20/22; Technical Meeting #5: TBD**
78	9.A.3.	13	Three Public Meetings	*At least 3 public engagement technical conferences advertised through multiple media channels at a minimum of 30 days prior to the public technical conference.*	**Public Meeting #1: 10/14/20; Public Meeting #2: 4/13/22; Public Meeting #3: 5/3/22**
79	10.A.	13	Public Review of IRP	*The Utility shall make its IRP available for public review subject to the provisions of the Council Resolution initiating the current IRP planning cycle and referenced in Section 1B.*	**Public IRP Available on ENO IRP Website**
80	10.B.	13	Filing of IRP	*The Utility shall file its IRP with the Council consistent with and subject to the provisions of the Council Resolution initiating the current IRP planning cycle referenced in Section 1B.*	**IRP Report Filed: 3/25/22**
81	10.C.	13	Discussion of Stakeholder engagement	*The IRP report should discuss the stakeholders' engagement throughout the IRP process; the access to data inputs and specific modeling results by all parties; the consensus reached regarding all demand-side and supply-side resource inputs and assumptions; specific descriptions of unresolved issues regarding inputs, assumptions, or methodology; the formulation of the stakeholder Planning Scenario and/or stakeholder Planning Strategy as needed; and recommendations to improve the transparency and efficiency of the IRP process for prospective IRP cycles.*	**Pg 4: Executive Summary; Pg 56: Scenario- and Strategy-Based Approach**
82	10.D.	13	Action Plan	*The IRP shall include an action plan and timeline discussing any steps or actions the Utility may propose to take as a result of the IRP, understanding that the Council's acceptance of the filing of the Utility's IRP would not operate as approval of any such proposed steps or actions.*	**Pg 81: Action Plan**