

**RESOLUTION**

**NO. R-19-457**

**CITY HALL: November 7, 2019**

**BY: COUNCILMEMBERS MORENO, WILLIAMS, GIARRUSSO, BANKS AND  
BROSSETT**

**REVISED APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN  
ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194  
AND R-17-504 AND FOR RELATED RELIEF**

**RESOLUTION AND ORDER**

**DOCKET NO. UD-18-07**

**WHEREAS**, pursuant to the Constitution of the State of Louisiana and the Home Rule Charter of the City of New Orleans (“Charter”), the Council of the City of New Orleans (“Council”) is the governmental body with the power of supervision, regulation, and control over public utilities providing service within the City of New Orleans; and

**WHEREAS**, pursuant to its powers of supervision, regulation and control over public utilities, the Council is responsible for fixing and changing rates and charges of public utilities and making all necessary rules and regulations to govern applications for the fixing and changing of rates and charges of public utilities; and

**WHEREAS**, Entergy New Orleans, LLC (“ENO” or “Company”) provides retail electric service and gas within the City of New Orleans; and

**WHEREAS**, Council Resolution No. R-17-228 directed ENO to exclude certain costs and accounting entries related to its 2017 internal restructuring from its cost of service studies in its 2018 rate case filing (*i.e.*, the “Application”); and

**WHEREAS**, Council Resolution No. R-17-504 directed ENO to include in its 2018 rate case filing certain information, the provision of which as part of ENO’s filing, the Council expects may serve in the interest of economy, efficiency, and a reduction in regulatory costs as it reviews the Application; and

**WHEREAS**, Council Resolution No. R-18-97 directed ENO to include as part of its 2018 rate case filing (*i.e.*, the Application) a green pricing proposal under which customers may voluntarily choose to have some or all of their electricity supplied by renewable resources; and

**WHEREAS**, on July 31, 2018, ENO filed its initial *Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and For Related Relief* (“Initial Rate Filing”); and

**INITIAL RATE FILING**

**WHEREAS**, ENO’s Initial Rate Filing proposed a change in electric and gas rates and new rate schedules applicable to electric and gas service; and

**WHEREAS**, ENO’s Initial Rate Filing proposed electric rates that would overall decrease its revenues by approximately \$20 million per year and proposed gas rates that would overall decrease its revenues by approximately \$0.13 million per year; and

**WHEREAS**, according to the Company, the total net effects of the initially proposed electric rate changes on typical monthly electric bills are summarized in the following table:

Estimated Typical Monthly Electric Bill Summer (\$)					
Customer Type	Energy (kWh)	Demand (kW)	Present Rate	Proposed Rate	Difference
Residential – Legacy	1,000		\$122.11	\$126.57	\$4.46
Residential – Algiers	1,000		\$104.28	\$126.68	\$22.40
Small Electric – Legacy	10	1,825	\$242.69	\$257.62	\$14.93
Small Electric – Algiers	10	1,825	\$265.13	\$260.08	(\$5.05)
Large Electric – Legacy	250	91,250	\$9,552.67	\$8,916.46	(\$638.21)
Large Electric, HLF - Algiers	250	91,250	\$8,439.13	\$9,081.85	\$642.72

and

**WHEREAS**, with regard to the electric rate increase initially proposed for Algiers residential customers, the Council noted its disappointment and serious concern regarding ENO’s estimated bill impact on Algiers residential customers. One of the primary functions of the Council in its utility regulatory capacity is the establishment of just and reasonable rates. The Council’s initial reaction is that such a significant estimated increase will result in rate shock that is patently unacceptable and may be found to be unjust and unreasonable as filed without some form of viable mitigation measures. Accordingly, the Council indicated its intent to direct ENO to file a supplement to its Initial Rate Filing with proposed mitigation measures for the substantial Algiers residential rate increase; and

**WHEREAS**, in a letter dated August 15, 2018, Roderick K. West, Entergy Group President of Utility Operations, explained that ENO had decided to withdraw its Initial Rate Filing, explaining that the decision to withdraw the Initial Rate Filing was in “response to the thoughtful feedback that Entergy New Orleans has received from members of the Council of the City of New Orleans and the Council’s legal and technical Advisors, particularly with regard to the need to develop a better path toward a single rate structure for all customers of Entergy New Orleans, both those residing on the East Bank of New Orleans and those residing in Algiers” and noted that ENO would refile the rate case in September; and

## **ENO'S REVISED RATE APPLICATION**

**WHEREAS**, on September 21, 2018, ENO refiled its rate case, *Revised Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and For Related Relief* (“Revised Application”); and

**WHEREAS**, the Revised Application states that ENO’s request has three principal components: (1) a new combined electric rate structure, which realigns the revenue requirement associated with non-fuel capacity and long-term service agreements (“LTSA”) from certain riders to base revenue and will recover the cost of Advanced Metering Infrastructure (“AMI”); (2) contemporaneous cost recovery riders for investments in energy efficiency/demand response (also referred to as demand-side management or “DSM”), incremental changes in capacity/LTSA costs, grid modernization investments, and for Gas Infrastructure Replacement investments and related costs; and (3) Formula Rate Plans (“FRP”), one for Electric operations which incorporates a proposed decoupling mechanism as required by the Council, and one for Gas operations; and

**WHEREAS**, ENO’s Revised Application in this proceeding is a full base rate case with test years ending December 31, 2017 (Period I) and December 31, 2018 (Period II); and

**WHEREAS**, the Revised Application includes ENO’s request for a change in electric and gas rates and new rate schedules applicable to electric and gas service; and

**WHEREAS**, ENO’s Revised Application proposed electric rates would overall decrease its revenues by approximately \$20 million per year and proposed gas rates would overall decrease its revenues by approximately \$0.142 million per year; and

**WHEREAS**, according to the Company, the net effects of these proposed electric rate changes on typical monthly electric bills are summarized in the following table:

Estimated Typical Monthly Electric Bill (Summer) (\$)							
Customer Type	Energy (kWh)	Demand (kW)	Present Rate	Phase I Proposed Rate - August 2019	Difference	Phase II Proposed Rate - September 2021	Difference
Residential Legacy	1000		\$ 122.11	\$124.13	\$2.02	\$124.13	\$-0-
Residential Algiers	1000		\$ 104.28	\$107.93	\$3.65	\$111.69	\$3.76
Small Electric Legacy	1,825	10	\$ 242.69	\$252.62	\$9.93	\$252.62	\$-0-
Small Electric Algiers	1,825	10	\$ 265.13	\$247.27	(\$17.86)	\$247.27	\$-0-
Large Electric Legacy	91,250	250	\$9,552.67	\$9,213.95	(\$338.72)	\$9,213.95	\$-0-
Lg. Elec. - HLF Algiers	91,250	250	\$8,439.13	\$9,236.05	\$796.92	\$9,192.81	(\$43.24)

and

**WHEREAS**, according to the Company, the net effects of these proposed gas rate changes on typical monthly gas bills are summarized in the below table:

Estimated Typical Monthly Gas (Winter) (\$)				
Customer Type	Consumption	Present Rate	Proposed Rate	Difference
Residential	100 ccf	\$82.11	\$81.24	(\$0.87)
Commercial	50 mcf	\$428.66	\$414.00	(\$14.66)
Industrial	1,000 mcf	\$6,944.09	\$6,876.56	(\$67.53)

and

**ENO'S REQUEST FOR RELIEF**

**WHEREAS**, ENO requests the following relief in its Revised Application:

1. That the Council issue an order confirming that Entergy New Orleans' filing, including its Revised Application is in substantial compliance with the Minimum/Standard Filing Requirements;

2. That the Council direct that notice of all matters in these proceedings be sent to Gary E. Huntley and Alyssa Maurice-Anderson, as representatives of ENO;
3. That the Council find that the change in electric and gas rates described herein, but more particularly and specifically described in the testimony and exhibits of the witnesses attached hereto and made part hereof, is in the public interest, will result in just and reasonable rates and, subject to the terms and conditions to be established hereby, fully complies with Louisiana law and the ordinances of the Council;
4. That the Council take official action to grant the Company's request for a change in electric and gas rates, and such other specific requests for which the Company seeks approval herein, including but not limited to the following:
  - a. approving the Company's proposed depreciation rates so that the return of capital may be synchronized to the service life of the plant used to provide customers electric service;
  - b. approving the Company's proposed electric and natural gas formula rate plans;
  - c. approving the other new and revised riders proposed by ENO;
  - d. approving after receiving the Company's supplemental application, the new customer service and billing offerings proposed by the Company;
  - e. approving the withdrawal of certain rate schedules, as well as the new and modified rate schedules;
  - f. approving ENO's recovery of costs associated with the five grid modernization projects proposed in the filing for such projects closing to plant after December 31, 2019, and approves the regulatory review process proposed for use with future grid modernization projects;

- g. approving the Company’s proposed modifications to ENO’s Service Regulations  
Applicable to Electric and Gas Service;
5. That the Council adopt for application in this proceeding its Official Protective Order as set forth in Resolution No. R-07-432, or provide for such other appropriate protection for any confidential information to be produced in this proceeding;
6. That the Council approve the proposed procedural schedule allowing for ENO to provide supplemental information regarding its new offerings;
7. That the Council grant all other Orders and decrees as may be necessary, and for all general and equitable relief that the law and the nature of the case may permit; and

**MINIMUM FILING REQUIREMENTS**

**WHEREAS**, pursuant to Chapter 158 of the Code of the City of New Orleans (“City Code”), when a utility files an application to change rates or services, the application must satisfy certain Minimum Filing Requirements (“MFR”), which requirements provide the information necessary to permit a thorough analysis of the utility’s application; and

**WHEREAS**, ENO states that its Revised Application comports with the MFRs and requests an order confirming that ENO’s filing, including its Revised Application is in substantial compliance with the MFRs. However, out of abundance of caution, to the extent that the Council determines that ENO’s filing does not meet the referenced MFRs, pursuant to Section 158-48, of the City Code, the Company requests waiver of such requirements. Alternatively, ENO requests that a reasonable opportunity to remedy any such deficiencies be granted by the Council; and

**WHEREAS**, the Council, in Resolution No. R-18-434, stated that it wished for ENO to comply with the MFRs and will provide ENO a reasonable opportunity to remedy any deficiencies thereof. Further, the Council directed the parties to the instant docket to attempt to amicably

resolve any disputes as to whether the Revised Application is in compliance with respect to the MFRs; and

**PROCEDURAL MATTERS**

**WHEREAS**, Section 158-91 of the City Code establishes that the Council shall have 12 months from its acceptance of the utility’s filing within which to review the filing and to render a determination as to the proper rates to be charged by the utility and if the Council has not made this determination by 12 months plus one day after the date of acceptance, the rates as submitted by the utility in the accepted filing shall become effective subject to refund; and

**WHEREAS**, ENO addressed the Council’s concern that had ENO not withdrawn its initial rate filing and the case been determined within applicable time limits under Section 158-91 of the Code of the City of New Orleans, the proposed decrease in ENO’s rates would become effective with the first billing cycle of August 2019. In order to ensure that customers receive potentially lower rates at that same time but without compressing the Council’s twelve-month review period, ENO commits that rates ultimately approved by the Council in this proceeding will be effective as of the first billing cycle August 2019 even though a Council decision may not be issued by that time. The Council will direct ENO to make such necessary adjustments to customer bills to reflect the appropriate amounts due to reflect the approved rates retroactively to the first billing cycle of August 2019; and

**WHEREAS**, in Resolution No. R-18-434, the Council established a procedural schedule to allow the parties to this proceeding to rigorously investigate the Revised Application, conduct discovery, file testimony and otherwise establish a record upon which the Council may rely to render a determination as to the proper rates to be charged by ENO; and



**WHEREAS**, several parties timely intervened in the docket including the Alliance for Affordable Energy (“AAE”), Air Products and Chemicals, Inc. (“Air Products”), Building Science Innovators, LLC (“BSI”), City of New Orleans, Sewerage and Water Board of New Orleans (“SWB”), Crescent City Power Users Group (“CCPUG”), Justice and Beyond, Sierra Club, and 350 New Orleans; and

**WHEREAS**, numerous parties evaluated various aspects of the case by issuing hundreds of discovery requests, reviewing thousands of pages of responses, and conducting oral depositions of multiple experts; and

**WHEREAS**, ENO, AAE, Air Products, CCPUG, BSI, and the Council’s Advisors actively participated in the docket and a total of thirty-three (33) expert witnesses provided sworn pre-filed testimony in the case in support of their respective positions; and

**WHEREAS**, a five-day evidentiary hearing was conducted on June 17, 2019 through June 21, 2019, before the Honorable Jeffrey S. Gulin wherein parties were allowed to cross examine other parties’ witnesses and introduce additional evidence into the record; and

**WHEREAS**, several parties filed initial briefs and reply briefs outlining their positions and setting forth their legal arguments for the Council’s consideration; and

**WHEREAS**, the Council has reviewed ENO’s Revised Application, the positions of the parties and the evidence presented in the voluminous record certified in this proceeding and resolved the issues presented as follows; and

## RETURN ON EQUITY (“ROE”)

**WHEREAS**, in utility ratemaking, the primary objective is to allow the utility company sufficient revenues to meet its operating expenses, provide its shareholders with a reasonable rate of return (“ROR”), and attract new capital;<sup>1</sup> and

**WHEREAS**, the ratemaking process involves a complicated set of factors under which the regulator approves rate increases or requires rate decreases for each customer class. Retail rates should allow the utility the opportunity to recover prudently incurred operating and maintenance expenses, taxes, and a fair return on investment that is used and useful in providing utility services;<sup>2</sup> and

**WHEREAS**, the legal standard for determining what is a fair ROR was articulated in two seminal cases: *Federal Power Comm’n v. Hope Natural Gas Co.*<sup>3</sup> and *Bluefield Waterworks & Improvements Co. v. Public Service Commission of W. Virginia.*<sup>4</sup> In *Bluefield*, the Court observed:

What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to **all relevant facts**. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but **it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.** A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for

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<sup>1</sup> *Gordon v. Council of City of New Orleans*, 9 So. 3d at 73; citing *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm’n*, 508 So. 2d 1361, 1364 (La. 1987); *S. Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm’n*, 352 So. 2d 964, 967 (La. 1977).

<sup>2</sup> *Id.*

<sup>3</sup> *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944) (“*Hope*”).

<sup>4</sup> *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm’n of W. Va.*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923) (“*Bluefield*”).

investment, the money market and business conditions generally.<sup>5</sup> (Emphasis added).

In *Hope*, the Court reiterated these principles, stating:

**Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, ....**<sup>6</sup> (Emphasis added); and

**WHEREAS**, as a general proposition, these cases hold that the rate-making process rests on a balancing of interests between the investors and the consumers;<sup>7</sup> and

**WHEREAS**, the method used to balance the interests of the investors and the consumers is well established. The initial determination that must be made is the utility's future revenue requirement;<sup>8</sup> and

**WHEREAS**, as a guide to such a determination, data is generally gathered from some 12-month period taken as a "test year."<sup>9</sup> Customarily, the test year selected is the most recent annual period from which actual operating data is available. The data gathered is then used to calculate the following four variables:

1. The amount of *revenues* generated under the present rate structure.
2. The *operating expenses*, including maintenance, depreciation, and taxes, incurred to produce revenues.
3. The *rate base*, *i.e.*, the value of the property, plant, and equipment, (less accumulated depreciation) and related non-tangible assets, which provide the service, and on which a return should be earned.

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<sup>5</sup> *Id.* at 692-93, 43 S. Ct. at 679.

<sup>6</sup> *Hope*, 320 U.S. at 605, 64 S. Ct. at 289.

<sup>7</sup> *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d at 1365.

<sup>8</sup> *Id.*

<sup>9</sup> *Id.* citing *James C. Bonbright, et al., Principles of Public Utility Rates* 150, n.7 (1961).

4. The *rate of return*, a percentage figure which, when applied to the rate base, will generate revenues sufficient to cover costs and give investors a fair return on their investment;<sup>10</sup> and

**WHEREAS**, ENO's allowed return on investment can be regarded as its Weighted Average Cost of Capital ("WACC"), which is constituted as a weighting of the return on long term debt components and an allowed-ROE, which can be regarded as the WACC component allowing ENO a profit;<sup>11</sup> and

**WHEREAS**, accepted regulatory principles and the U.S. Supreme Court's *Hope* and *Bluefield* decisions provide that ENO be allowed a return on its investment that:

1. is comparable to that being earned by other companies with comparable risks,
2. is sufficient to assure confidence in its financial soundness, and
3. is adequate to maintain its credit worthiness and enable it to raise necessary capital;<sup>12</sup> and

**WHEREAS**, the Council is not obligated to employ any specific methodology when setting ENO's rates, however, both ENO in its Revised Application and the Advisors in their direct testimony calculate their respective proposed rates based on allowing the opportunity for recovery of prudently incurred operating costs, plus a fair return on investment to include a reasonable allowed-ROE, which is an accepted methodology;<sup>13</sup> and

**WHEREAS**, further, for many years, the Council has repeatedly acknowledged these ratemaking principles set forth in *Hope* and *Bluefield* in a variety of rate proceedings;<sup>14</sup> and

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<sup>10</sup> *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d at 1365.

<sup>11</sup> Initial Brief of the Advisors to the City Council of New Orleans, at 26, July 26, 2019 ("Advisors' Initial Brief").

<sup>12</sup> *Bluefield*, 262 U.S. at 692; and *Hope*, 320 U.S. 591.

<sup>13</sup> Advisors' Initial Brief at 27.

<sup>14</sup> Resolution Nos. R-03-272, at 11-12 (resolving rate case Docket No. UD-01-04), R-09-136, at 10 (resolving rate case Docket No. UD-08-03), and R-14-278, at 17-18 (resolving rate case Docket No. UD-13-01), all reference and accept these regulatory ratemaking principles regarding the appropriate allowed return on ENO's investments.

**WHEREAS**, these variables are then used to determine the “return” (*i.e.*, ROE) that is available to be distributed to the utility’s investors and the “actual rate of return” presently being earned by the utility.<sup>15</sup> The “return” or earnings is equal to the utility’s revenues less its operating expenses, exclusive of interest.<sup>16</sup> The ratio of the utility’s return to its rate base is equal to its actual ROR;<sup>17</sup> and

**WHEREAS**, as part of the Council’s ratemaking authority when setting ENO’s retail rates in this proceeding, the concept of ROR specifically means an appropriate WACC whose components are long-term debt total cost and ROE;<sup>18</sup> and

**WHEREAS**, in its Revised Application, ENO asserts that the Company’s ROE lies in the range of 10.25% to 11.25%.<sup>19</sup> Within that range, the Company considers 10.75% to be the best estimate of ENO’s Cost of Equity and recommends that the Council adopt a 10.75% ROE;<sup>20</sup> and

**WHEREAS**, ENO contends that Mr. Hevert is the only witness offering an opinion in this proceeding on ENO’s estimated ROE that performed a comprehensive analysis that fairly measured ENO’s risk;<sup>21</sup> and

**WHEREAS**, the Company contends that Mr. Hevert’s recommendation results from a balanced approach considering the relative strengths and weaknesses of multiple analytical methodologies as well as considerable empirical and qualitative information in analyzing and giving appropriate weight to their results;<sup>22</sup> and

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<sup>15</sup> *Bluefield*, 262 U.S. 692 and *Hope*, 320 U.S. 591.

<sup>16</sup> *Id.*

<sup>17</sup> *Id.*

<sup>18</sup> Advisors’ Initial Brief at 27.

<sup>19</sup> Post-Hearing Brief of Entergy New Orleans, LLC, at 44, July 26, 2019 (“ENO Initial Brief”).

<sup>20</sup> *Id.*

<sup>21</sup> *Id.* at 41.

<sup>22</sup> *Id.*

**WHEREAS**, Specifically, Mr. Hevert conducted analyses that included the Discounted Cash Flow (“DCF”) model, including the Constant Growth and Multi-Stage forms; the Capital Asset Pricing Model (“CAPM”); the Bond Yield Plus Risk Premium approach; and the Expected Earnings model;<sup>23</sup> and

**WHEREAS**, ENO argues that the opposing witnesses give considerable weight to the DCF method, even though it produces ROE estimates in some cases more than 150 basis points below the returns authorized for other electric utilities;<sup>24</sup> and

**WHEREAS**, ENO also proposed a Reliability Incentive Mechanism (“RIM”) Plan, which would affect the base rates to be set in this proceeding and afterwards through the proposed Electric FRP.<sup>25</sup> Under the RIM Plan, ENO proposed that the earnings component of its electric base rates be correlated to reliability performance through an adjusted ROE formula, included in the FRP that features a Reliability Adjustment.<sup>26</sup> Under the Company’s RIM Plan,<sup>27</sup> ENO is requesting that for the purpose of initially setting rates resulting from this proceeding that a ROE of 10.50% be implemented on its electric Cost of Service based on a negative adjustment of 25 basis points applied to the proposed ROE of 10.75% recommended by Company witness Robert B. Hevert.<sup>28</sup> Through the Company’s proposed electric FRP as described by Company witness Phillip B. Gillam, ENO seeks an opportunity to achieve enhanced returns commensurate with the 10.75% recommended by Mr. Hevert as ENO realizes increases in electric service reliability.<sup>29</sup> According

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<sup>23</sup> *Id.* at 42.

<sup>24</sup> *Id.*

<sup>25</sup> Ex. No. ENO-55 at 2.

<sup>26</sup> *Id.*

<sup>27</sup> Ex. No. ENO-2 at 23:1-30:5 (HSPM).

<sup>28</sup> Ex. No. ENO-55 at 21.

<sup>29</sup> *Id.* at 21-22.

to ENO, the Company should be allowed to earn more than its baseline ROE under the RIM Plan as a matter of fairness and maintaining a constructive regulatory environment;<sup>30</sup> and

**WHEREAS**, the Advisors recommend that the Council adopt an allowed-ROE of 8.93% for both electric and gas based on the comprehensive and persuasive testimony and multiple analyses of two expert witnesses in this proceeding;<sup>31</sup> and

**WHEREAS**, the Advisors' assert that their recommendation is based on the evaluation of market-based and accepted analytical methodologies that demonstrate that an 8.93% ROE represents a fair return to ENO;<sup>32</sup> and

**WHEREAS**, while an 8.93% ROE is in-line with the recommendations of the Intervenor witnesses (*i.e.*, 9.35%), the Advisors have pointed out that ENO's ROE proposal of 10.75% is an outlier among the other recommended ROEs in this proceeding;<sup>33</sup> and

**WHEREAS**, although the Company attempts to rely on numerous authorized ROEs in other jurisdictions to argue that the Advisors' and other Intervenors' recommendations are unreasonable, the Advisors argue that the ROEs cited in Mr. Hevert's testimony actually weakens ENO's argument for an authorized ROE of 10.75%.<sup>34</sup> The Advisors also argue that as evidenced in his own chart, the overwhelming majority of authorized ROEs represented in Mr. Hevert's testimony are significantly lower than ENO's requested ROE of 10.75% in this proceeding;<sup>35</sup> and

**WHEREAS**, ENO's claims that witness Hevert's "analysis indicated a range of 10.25% to 11.25% for equity investors' required ROE for investment in integrated electric utilities."<sup>36</sup> The

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<sup>30</sup> Ex. No. ENO-2 at 27:14-16 (HSPM).

<sup>31</sup> Advisors' Initial Brief at 31.

<sup>32</sup> *Id.*

<sup>33</sup> Ex. No. ADV-8 at 18:14-19:4.

<sup>34</sup> Advisors' Initial Brief at 28; ENO-29 at 6, Chart 2.

<sup>35</sup> *Id.*

<sup>36</sup> ENO Initial Brief at 44.

Advisors assert that this claim is largely untrue.<sup>37</sup> As shown by the Advisors, in Mr. Hevert's testimony, he prepared no-less than five ROE analyses, of which only one supported an upper range of 10.75%;<sup>38</sup> and

**WHEREAS**, Advisors' witness Watson conducted a two-step DCF analysis which sought to estimate the implied ROE of utilities comparable to ENO as a proxy for ENO's own appropriate allowed-ROE, which itself cannot be directly measured;<sup>39</sup> and

**WHEREAS**, Mr. Watson's DCF analysis is also based on objective market data such as dividend yields and professional analysts' opinions as to growth factors.<sup>40</sup> The results of witness Watson's two-step DCF ROE analysis establish, among proxy companies and unadjusted for risk and flotation costs, a range of implied ROEs of 5.74% to 10.64% with a median implied ROE of 8.09%;<sup>41</sup> and

**WHEREAS**, Advisors' witness Proctor performed a CAPM analysis that identifies an allowed-ROE of 7.57% (unadjusted for risk and flotation costs), which is less than Mr. Watson's two-step DCF ROE analysis result;<sup>42</sup> and

**WHEREAS**, however, the Advisors' assert that as a DCF ROE analysis and a CAPM ROE analysis are based on different financial concepts (*i.e.*, DCF is based on dividend yields and growth factors, while CAPM is based on market returns and correlations therewith), the relative concurrence in results between these analyses has probative value for the Council in the instant proceeding;<sup>43</sup> and

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<sup>37</sup> Reply Brief of the Advisors to the City Council of New Orleans at 4, Aug. 9, 2019 ("Advisors' Reply Brief").

<sup>38</sup> Ex. No. ADV-8 at 19-20, Table 2.

<sup>39</sup> Ex. No. ADV-7 at 13:1-7 (HSPM).

<sup>40</sup> *Id.* (HSPM).

<sup>41</sup> *Id.* at 44:1-4 (HSPM).

<sup>42</sup> *Id.* (HSPM).

<sup>43</sup> *Id.* at 44:14-45:2 (HSPM).



**WHEREAS**, according to the Advisors, Mr. Watson has reviewed Mr. Proctor's CAPM study, which is based on accepted methodologies and data, and he agrees with Mr. Proctor's analysis and results;<sup>44</sup> and

**WHEREAS**, Mr. Proctor discusses the ROE-related risk factors discussed by ENO witness, Mr. Hevert, and recommends the Council allow a risk-related ROE upward adjustment in this instant proceeding of 84 basis points;<sup>45</sup> and

**WHEREAS**, the Advisors adjusted their ROE findings for additional business risk ENO incurs largely as a result of its geographic location, its small size and its propensity to incur significant storm damage;<sup>46</sup> and

**WHEREAS**, according to the Advisors, Mr. Proctor's one standard-deviation adjustment methodology is objective and reflective of the variability of systemic risks among the Proxy Companies.<sup>47</sup> The Advisors also state that they specifically evaluated and addressed ENO's business risk<sup>48</sup> and Mr. Proctor's proposed 81 basis point adjustment was based on objective analysis and is reasonable, while ENO's arguments are general, subjective, and speculative;<sup>49</sup> and

**WHEREAS**, the Advisors made an additional adjustment to their recommended ROE for flotation costs which relate to incremental costs incurred from the issuance of common stock.<sup>50</sup> According to the Advisors, the costs are legitimately recoverable through utility rates either as a cost of equity or an operating expense;<sup>51</sup> and

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<sup>44</sup> *Id.* (HSPM).

<sup>45</sup> Ex. No. ADV-10 at 61:3-63:6 (HSPM).

<sup>46</sup> *Id.* at 61:3-10 (HSPM).

<sup>47</sup> Advisors' Initial Brief at 33.

<sup>48</sup> *Id.*

<sup>49</sup> *Id.*

<sup>50</sup> *Id.* at 34.

<sup>51</sup> *Id.*

**WHEREAS**, Mr. Watson presented the flotation cost-adjusted implied ROEs for the proxy companies, the median of such values is 8.12%, or approximately 3 basis points greater than the median of the non-flotation-adjusted proxy company implied ROEs.<sup>52</sup> His two-step DCF proxy company mean ROE analysis result of 8.09% plus these appropriate upward adjustments for business risks and flotation costs yields an allowed-ROE of 8.93%;<sup>53</sup> and

**WHEREAS**, the Advisors point out that the results of Mr. Proctor's CAPM ROE analysis are broadly consistent with those of Mr. Watson's two-step DCF ROE analysis and the Advisors recommend the Council take the results of Mr. Proctor's CAPM ROE analysis into account in the instant proceeding and adopt the Advisors' ROE recommendation;<sup>54</sup> and

**WHEREAS**, Intervenors, CCPUG and Air Products, also submitted testimony in this proceeding that included ROE recommendations to the Council; and

**WHEREAS**, CCPUG provided two methods of analysis for estimating a fair ROR for ENO, the DCF and CAPM analyses;<sup>55</sup> and

**WHEREAS**, based on these independent analyses, CCPUG concluded that a reasonable investor required ROE in the range of 8.70%-9.35% would be appropriate for ENO.<sup>56</sup> Employing these widely accepted financial methods for developing an ROE recommendation, CCPUG recommends that the Council adopt an ROE of 9.35%, which is on the high end of CCPUG's range;<sup>57</sup> and

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<sup>52</sup> Ex. No. ADV-7, Ex. No. BSW-4 (HSPM).

<sup>53</sup> Advisors' Initial Brief at 34.

<sup>54</sup> *Id.*

<sup>55</sup> Ex. No. CCPUG-3 at 15:15-24.

<sup>56</sup> *Id.* at 30:3-6.

<sup>57</sup> *Id.* at 30:6-7.

**WHEREAS**, with respect to evaluating and addressing ENO’s business risk for purposes of making an ROE recommendation, CCPUG approached the issue of risk by acknowledging that ENO’s business risk was considered by the credit rating agencies in their reports on ENO;<sup>58</sup> and

**WHEREAS**, according to CCPUG, Moody's and S&P mentioned these risks in various places in their reports which evaluated ENO’s credit profile, its risk associated with severe weather, its small size, and the effect of the TCJA.<sup>59</sup> CCPUG also observed that with regard to customer diversity, the S&P report cited by CCPUG’s witness Mr. Baudino noted that ENO’s customer mix was a credit strength, not a weakness;<sup>60</sup> and

**WHEREAS**, CCPUG also argues that after assessing these risks, as well as credit strengths possessed by ENO, S&P assigned credit ratings to ENO that were consistent with the proxy group and with the electric utility industry in general and therefore CCPUG concluded that no additional risk premium is necessary for ENO relative to the proxy group;<sup>61</sup> and

**WHEREAS**, according to CCPUG, ENO’s proposed 10.75% ROE far exceeds the average ROE awarded by regulators across the country in the last five years.<sup>62</sup> In fact, CCPUG urges, according to ENO’s own data, its requested ROE of 10.75% is higher than all but one ROE granted by a regulator to an electric and gas utility over the last five years;<sup>63</sup> and

**WHEREAS**, Air Products also provided extensive ROE testimony in this case utilizing several financial models to estimate ENO’s cost of common equity, including various forms of a DCF analysis, a Risk Premium analysis and a CAPM analysis similar to the financial models used by other ROE witnesses in the case;<sup>64</sup> and

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<sup>58</sup> Ex. No. CCPUG-3 at 46:22-47:1-10.

<sup>59</sup> *Id.*

<sup>60</sup> *Id.*

<sup>61</sup> *Id.*

<sup>62</sup> Initial Post-Hearing Brief of the Crescent City Power Users Group at 13, July 26, 2019 (“CCPUG Initial Brief”).

<sup>63</sup> *Id.* citing Ex. ENO-29 at 6:3, Chart 2.

<sup>64</sup> Ex. No. AP-1 at 17:5-10.

**WHEREAS**, based on comprehensive studies utilizing multiple industry accepted financial models, Air Products concluded that an ROE in the range of 9.0%-9.7% would be appropriate for ENO.<sup>65</sup> A recommended ROE for ENO of 9.35% was supported by Air Products as a reasonable midpoint;<sup>66</sup> and

**WHEREAS**, Air Products' witness Christopher C. Walters undertook an extensive analysis of the regulated utility industry's access to capital, credit rating trends and outlooks, the overall trend in authorized ROEs for electric utilities throughout the country, and the impact that the Federal Reserve's monetary policy actions have had on the cost of capital;<sup>67</sup> and

**WHEREAS**, according to Air Products, Mr. Walters fully evaluated the market's perception of ENO's investment risk and considered ENO's proposed capital structure;<sup>68</sup> and

**WHEREAS**, Mr. Walters then used several cost of equity estimation methods performed on proxy group of publicly traded electric utility companies with comparable risk to ENO, including (1) a constant growth DCF Model using the consensus of analysts growth rate projections, (2) a constant growth rate DCF model using sustainable growth rate estimates, (3) a multi-stage DCF model, (4) a Risk Premium model, and (5) a CAPM analysis;<sup>69</sup> and

**WHEREAS**, according to Air Products, based on Mr. Walters' extensive analysis, he estimated that ENO's current market cost of equity is in the range of 9.0% and 9.7%, with a mid-point estimate of 9.35%;<sup>70</sup> and

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<sup>65</sup> *Id.* at 49:5-8.

<sup>66</sup> *Id.*

<sup>67</sup> *Id.* at 2:15-20.

<sup>68</sup> *Id.* at 3:1-3 and 17:11-19:5.

<sup>69</sup> *Id.* at 3:4-6 and 17:3-10.

<sup>70</sup> *Id.* at 3:6-8.

**WHEREAS**, Mr. Walters presented Direct Testimony & Schedules demonstrating that ROEs for electric and gas utilities have been reasonably stable well below 10.0% for about the last six years;<sup>71</sup> and

**WHEREAS**, Air Products states that during this period of declining ROEs, there has been significant improvement realized in the electric utility industry's overall credit quality and the ability of regulated utilities to access significant amounts of capital to support record amounts of capital investments over at least the last ten years;<sup>72</sup> and

**WHEREAS**, as set forth by Air Products, Mr. Walters' analysis and recommendation for a 9.35% ROE for ENO took into consideration ENO's specific investment risk and proposed capital structure;<sup>73</sup> and

**WHEREAS**, after performing several analyses utilizing multiple ROE financial models, witness Walters recommended an overall ROE for ENO of 9.35%;<sup>74</sup> and

**WHEREAS**, a 9.35% ROE is within the range of reasonable ROE recommendations made in this docket by three parties that provided expert testimony on this issue, including the Advisors, CCPUG, and Air Products; and

**WHEREAS**, ENO's argues that the Federal Energy Regulatory Commission ("FERC") has changed the law as to which financial modeling should be used in setting an ROE.<sup>75</sup> The Advisors contend that the Company plainly mischaracterizes FERC's statements on this issue.<sup>76</sup> The Advisors also responded that FERC does not, as ENO suggests, **require** the use of four financial models in setting an ROE that results in just and reasonable rates.<sup>77</sup> FERC has simply

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<sup>71</sup> *Id.* at 4:4-10 and Figure 1.

<sup>72</sup> Air Products and Chemicals, Inc.'s Initial Post-Hearing Brief at 13, July 26, 2019 ("Air Products' Initial Brief").

<sup>73</sup> *Id.*

<sup>74</sup> *Id.* at 15.

<sup>75</sup> ENO Initial Brief at 38.

<sup>76</sup> Advisors' Reply Brief at 5.

<sup>77</sup> *Id.*

**proposed** that more than one model be used as opposed to relying on only one model.<sup>78</sup> The Advisors maintain that FERC has not issued any rule or requirement, but simply stated in that proceeding that it preferred to give consideration to the four financial models that were entered into the record of that case.<sup>79</sup> In fact, as noted by our Advisors, FERC has requested briefs from the parties in that proceeding to consider its proposal as it relates to financial modeling that should be used in evaluating and setting a ROE;<sup>80</sup> and

**WHEREAS**, the Advisors have submitted testimony from two expert witnesses in this case that do, in fact, include multiple sets of financial modeling data and results for the Council to consider.<sup>81</sup> Advisors' witness Mr. Watson employed the DCF analysis and Mr. Proctor used the Capital Asset Pricing Model CAPM analysis.<sup>82</sup> The Advisors state that both models are well accepted in the industry and they produce reliable results. Mr. Watson agreed with Mr. Proctor's CAPM modeling analyses and found that Mr. Proctor's results were reasonable.<sup>83</sup> Mr. Watson also recommends that the Council consider not only his DCF analysis, but also Mr. Proctor's analyses in making its decision to adopt a just and reasonable ROE.<sup>84</sup> Contrary to ENO's assertions, the Advisors utilized multiple models in conducting its ROE analyses and those modeling results fully support the Advisors' ROE recommendation,<sup>85</sup> and

**WHEREAS**, four ROE experts in this case, using multiple methodologies widely accepted in the utility industry, assert that ENO's proposed ROE is poorly supported by ENO's

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<sup>78</sup> *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118, at 34 (2018).

<sup>79</sup> Advisors' Reply Brief at 5.

<sup>80</sup> *Id.*

<sup>81</sup> *Id.*

<sup>82</sup> *Id.*

<sup>83</sup> Ex. No. ADV-7 at 45.

<sup>84</sup> *Id.* at 49.

<sup>85</sup> Advisors' Reply Brief at 5-6.

own testimony.<sup>86</sup> Mr. Hevert's updated DCF analyses in his rebuttal testimony produced results ranging from 8.34%-10.38% which clearly does not support his recommended 10.75% ROE.<sup>87</sup> Similarly, Mr. Hevert's revised CAPM ROE analyses presented in his rebuttal testimony produced a substantially lower range of results, from 8.25%-11.34%, placing his recommended 10.75% near the top of his revised range of results;<sup>88</sup> and

**WHEREAS**, the Council's Advisors have shown that ENO's updated analyses provide further support for the Advisors' and Intervenors' arguments that the Company's requested 10.75% ROE is unreasonable and not supported by the preponderance of evidence in the instant docket;<sup>89</sup> and

**WHEREAS**, the Council finds that the testimony provided by the Advisors' ROE witnesses, which was based on the utilization of more than one industry accepted financial method is well supported and convincing evidence in this proceeding; and

**WHEREAS**, the Council finds that the 8.93% ROE recommendation made by the Advisors is reasonable and supported by the Advisors analysis in this case; and

**WHEREAS**, the Council also finds that the ROE testimony provided by CCPUG and Air Products in this case, which was also based on the utilization of multiple industry accepted financial methods is similarly well supported and convincing; and

**WHEREAS**, the Council finds that the 9.35% ROE recommendation made by CCPUG and Air Products is also reasonable and supported by the analysis presented in this case; and

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<sup>86</sup> Advisors' Initial Brief at 28; Air Products' Initial Brief at 16; CCPUG Initial Brief at 32-35.

<sup>87</sup> Ex. No. ENO-29 at 144:1.

<sup>88</sup> *Id.*

<sup>89</sup> Advisors' Initial Brief at 28-29.

**WHEREAS**, the Council also acknowledges that the 9.35% ROE recommended by CCPUG and Air Products in this case is also within the scope of ROEs supported by Advisors' witness Watson's analysis which resulted in a range of implied ROEs of 5.74% to 10.64%; and

**WHEREAS**, the Council agrees with the Advisors, CCPUG and Air Products that ENO's proposed ROE of 10.75% is not convincingly supported by ENO's own testimony; and

**WHEREAS**, the Council agrees with the Advisors and Intervenors that ENO's updated analyses provide further support for the Advisors' and Intervenors' arguments that the Company's requested 10.75% ROE is unreasonably high and not supported by the preponderance of evidence in the instant proceeding; and

**WHEREAS**, considering all of the testimony and evidence presented related to the appropriate ROE for ENO in this proceeding, the Council finds that ENO's proposed ROE of 10.75% should be rejected and an ROE of 9.35% is reasonable and should be adopted; and

### **EQUITY RATIO**

**WHEREAS**, ENO has proposed that its actual equity ratio be employed for ratemaking purposes in this proceeding.<sup>90</sup> ENO witness Orlando Todd submitted testimony that ENO projects its capital structure as of December 31, 2018 will consist of 52.2% common equity, with the rest consisting of long-term debt;<sup>91</sup> and

**WHEREAS**, the Company used this estimated 52.2% equity ratio to calculate its WACC and revenue requirement in its cost of service studies in this proceeding;<sup>92</sup> and

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<sup>90</sup> *Id.* at 35.

<sup>91</sup> Ex. No. ENO-33 at 14:13-14.

<sup>92</sup> *Id.*



**WHEREAS**, the Advisors submitted testimony contending that ENO’s proposed capital structure, if adopted, would constitute inappropriate double leveraging;<sup>93</sup> and

**WHEREAS**, according to the Advisors, a useful meaning of “double leverage” for the purposes of the instant proceeding is the practice of maintaining a significantly higher common equity ratio at the utility operating company level (*i.e.*, ENO) than is maintained at the highest corporate level ultimately owning the utility (*i.e.*, Entergy Corp.);<sup>94</sup> and

**WHEREAS**, because the return on a utility’s investment component of its revenue requirement is customarily based on its WACC and the rate of the ROE component of WACC is typically at a higher rate than those of the debt components (especially on a pre-tax basis), our Advisors assert that a high common equity ratio tends to increase a utility’s WACC, and revenue requirement;<sup>95</sup> and

**WHEREAS**, our Advisors further argue that the effect of a utility that engages in double leverage is as if it borrows money at the top corporate level and places that money into its utility subsidiaries as common equity providing a potential return which is likely greater than its original borrowed cost;<sup>96</sup> and

**WHEREAS**, based on our Advisors’ analysis, ENO’s equity ratio is greater than those of Entergy Corp. as well as the average of the other Entergy Operating Companies (“EOCs”);<sup>97</sup> and

**WHEREAS**, according to testimony provided by our Advisors, ENO’s proposed equity ratio of 52.2% is 18.1% higher than that of Entergy Corp. as of December 31, 2018, while the average equity ratio of the other EOCs projected as of December 31, 2018, is only 15.5% higher

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<sup>93</sup> Ex. No. ADV-7 at 51:1-4 (HSPM).

<sup>94</sup> *Id.* (HSPM).

<sup>95</sup> *Id.* at 51:4-8 (HSPM).

<sup>96</sup> *Id.* at 51:8-11 (HSPM).

<sup>97</sup> *Id.* at 50:5-6 (HSPM).

than that of Entergy Corp.<sup>98</sup> As such, the revenue requirement effect of ENO's double leverage on New Orleans ratepayers is more pronounced than that for the average ratepayer of the other EOCs;<sup>99</sup> and

**WHEREAS**, ENO claims that that the Advisors have misinterpreted the other Entergy Operating Companies' equity ratios and argues that the Advisors' comparison of ENO's proposed equity ratio to the other Entergy Operating Companies "sheds no light on the issue;"<sup>100</sup> and

**WHEREAS**, despite ENO's claims to the contrary, the Advisors argue that comparing ENO's capital structure to that of the other EOCs is important for the Council's consideration because such a comparison serves as a guide for assessing the reasonableness of ENO's capital structure;<sup>101</sup> and

**WHEREAS**, analyzing these comparisons, according to the Advisors, provides the revenue requirement effect of ENO's proposed capital structure as compared to that of the other EOCs.<sup>102</sup> In fact, employing ENO's Period II External Models and changing ENO's equity ratio to be consistent with the non-ENO EOCs' average equity ratio of 49.6% as opposed to ENO's proposed 52.2% yields a \$1.5 million reduction in electric revenue and a \$0.3 million reduction in gas revenue;<sup>103</sup> and

**WHEREAS**, considering the arguments set forth by the Advisors regarding double leverage, the significance of ENO's equity ratio being higher than that of the average of the other EOCs and the impact of ENO's proposed equity ratio on ratepayers, the Advisors recommend that

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<sup>98</sup> *Id.* at 53:1-3 (HSPM).

<sup>99</sup> *Id.* at 53:3-5 (HSPM).

<sup>100</sup> ENO's Initial Brief at 60.

<sup>101</sup> Advisors' Initial Brief at 36.

<sup>102</sup> Advisors' Initial Brief at 36; Ex. No. ADV-7 at 52:20-53:5 (HSPM).

<sup>103</sup> Advisors' Initial Brief at 37; Ex. No. ADV-7 at 53:8-11 (HSPM).

the Council adopt an equity ratio of 50% in the instant proceeding for setting ENO's electric and gas rates;<sup>104</sup> and

**WHEREAS**, for setting rates as part of any FRP evaluations the Council approves in this case, the Advisors believe the Council should employ an equity ratio equal to the lesser of (a) ENO's then actual equity ratio properly excluding the effects of securitization bonds and cash, and (b) 50%;<sup>105</sup> and

**WHEREAS**, CCPUG asserts that ENO's capital structure must include short-term debt, because (a) it is abundantly available to ENO, (b) ENO routinely uses short-term debt for its operations, and (c) it is the lower-cost option for capital as compared to long-term debt and ENO's requested 10.75% ROE;<sup>106</sup> and

**WHEREAS**, according to CCPUG, ENO has available two sources of short-term debt.<sup>107</sup> The first source is the internal Entergy Money Pool whereby Entergy operating utilities that have a surplus of cash deposit it into the Money Pool and the Entergy operating utilities that need cash borrow it from the Money Pool.<sup>108</sup> The second source is an external Company-specific credit facility of \$25 million, which includes fronting commitments of up to \$10 million for the issuance of letters of credit against the borrowing capacity of the facility.<sup>109</sup> CCPUG also claims that ENO may borrow up to \$150 million from the Entergy Money Pool, other internal short-term borrowing arrangements, and external sources pursuant to FERC authorization;<sup>110</sup> and

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<sup>104</sup> Advisors' Initial Brief at 37; Ex. No. ADV-7 at 55:16-18.

<sup>105</sup> Advisors' Initial Brief at 37; Ex. No. ADV-7 at 55:16-56-1.

<sup>106</sup> Reply Post-Hearing Brief of the Crescent City Power Users Group at 21, Aug. 9, 2019 ("CCPUG Reply Brief").

<sup>107</sup> CCPUG Initial Brief at 95.

<sup>108</sup> *Id.*

<sup>109</sup> *Id.*

<sup>110</sup> *Id.*

**WHEREAS**, Mr. Kollen explained that ENO should use some amount of short-term debt in lieu of long-term debt and common equity to reduce its cost of capital and its revenue requirements;<sup>111</sup> and

**WHEREAS**, CCPUG witness Mr. Kollen testified it is not reasonable for ENO to exclude short-term debt from the capital structure and cost of capital, especially since short-term debt is available to ENO at a fraction of the cost of long-term debt and common equity;<sup>112</sup> and

**WHEREAS**, ENO relies heavily on a Louisiana Supreme Court decision to support its unreasonably high capital structure proposal;<sup>113</sup> and

**WHEREAS**, according to the Advisors, ENO claims that the Court in *South Central Bell* held very narrowly that the utility “is entitled to have its rates fixed on the basis of its actual cost of capital under its existing capital structure” absent a finding “that the actual capital structure of the utility resulted from unreasonable or imprudent investments;”<sup>114</sup> and

**WHEREAS**, the Company also claims that the Advisors have “not pointed to a single instance that the Company made an unreasonable investment or financing decision.”<sup>115</sup> However, ENO’s strict interpretation of the Court’s ruling on this issue is erroneous. *South Central Bell* plainly states that if the regulator finds that the utility’s proposed capital structure is unreasonable, it may adopt a reasonable alternative;<sup>116</sup> and

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<sup>111</sup> CCPUG Initial Brief at 96.

<sup>112</sup> *Id.* at 96-97, citing Ex. CCPUG-1 at 39:1-5.

<sup>113</sup> Ex. No. ENO-3 at 24:5-6; Ex. No. ENO-4 at 15:17-19; citing *S. Cent. Bell Tel Co. v. Louisiana Pub. Serv. Comm’n*, 594 So. 2d 357.

<sup>114</sup> Ex. No. ENO-4 at 15:19-16-1; citing *S. Cent. Bell Tel Co. v. Louisiana Pub. Serv. Comm’n*, 594 So. 2d 357.

<sup>115</sup> *Id.* at 16:1-2.

<sup>116</sup> *S. Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm’n*, 594 So. 2d at 363.

**WHEREAS**, specifically, the Court stated, “we conclude ... that the Commission must find a utility’s capital structure imprudent or unreasonable before disregarding it in ratemaking;<sup>117</sup> and

**WHEREAS**, the Advisors argue that the unreasonableness is, thus, not limited to investments made by the utility.<sup>118</sup> The unreasonableness that the Advisors explain primarily from, among other reasons, the effect of double leverage that exists as a result of Entergy Corporation having a significantly lower equity ratio than that of its subsidiary, ENO;<sup>119</sup> and

**WHEREAS**, CCPUG also maintains that ENO’s proposed capital structure is unreasonable because it fails to include short-term debt;<sup>120</sup> and

**WHEREAS**, a later Louisiana Supreme Court case, cited by the Advisors, supports the Advisors’ and CCPUG’s argument regarding the regulator’s ability to set aside the utility’s unreasonable capital structure in favor of a more equitable alternative;<sup>121</sup> and

**WHEREAS**, in the *Entergy Gulf States* case, the utility used the net proceeds of debt to determine the ratio of debt to equity capital in its capital structure.<sup>122</sup> The Commission, however, adjusted the Company’s filing by reducing its average weighted cost of capital to reflect the gross proceeds of debt in the company’s capital structure.<sup>123</sup> The sole capital structure problem presented to the Court was whether the Commission acted arbitrarily or capriciously by including the gross proceeds of debt, rather than the net proceeds of debt, in the Company’s capital

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<sup>117</sup> *Id.*

<sup>118</sup> Advisors’ Initial Brief at 38.

<sup>119</sup> *Id.*

<sup>120</sup> CCPUG Reply Brief at 21.

<sup>121</sup> *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm’n*, 730 So. 2d 890 (La. 1999).

<sup>122</sup> *Id.* at 915-16.

<sup>123</sup> *Id.*

structure.<sup>124</sup> In affirming the regulator’s authority to adopt a different capital structure than the one proposed by the utility, the Court stated:

The right of commissions to consider [capital structure] in setting rates cannot be questioned, since a commission has an obligation to protect the consumer from excessive wages, excessive pension provisions, excessive prices for purchased materials and supplies, and other such things, including excessive costs of capital<sup>125</sup>

and

**WHEREAS**, the Court also clearly found, in affirming the regulator’s adjustment to the utility’s proposed capital structure, that the utility had not demonstrated that the Commission had set unjust or unreasonable rates.<sup>126</sup> Orders of utility regulators in the State of Louisiana are “entitled to great weight” and “they should not be overturned absent a showing of arbitrariness, capriciousness, or abuse of authority by the Commission.”<sup>127</sup> Courts should also “be reluctant to substitute their own views for those of the expert body charged with the legislative function of rate-making;”<sup>128</sup> and

**WHEREAS**, the Advisors urge the Council to note that ENO routinely recommends utilizing a hypothetical capital structure in requesting rate recovery of costs incurred by the Company.<sup>129</sup> For example, the Company acknowledged in this proceeding that in Council Docket No. UD-15-01, ENO’s own witness recommended a hypothetical capital structure of 50% be used for ratemaking purposes for the recovery of costs associated with the acquisition of Union Power Block #1.<sup>130</sup> According to the Advisors, ENO also employed an “Assumed 50% Common Equity” even though ENO’s actual equity ratio was not 50% in Council Docket No. UD-17-02 related to

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<sup>124</sup> *Id.*

<sup>125</sup> *Id.* at 917, citing Paul J. Garfield & Wallace F. Lovejoy, *Public Utility Economics* at 130 (1964).

<sup>126</sup> *Id.*

<sup>127</sup> *Id.* at 897.

<sup>128</sup> *Id.*

<sup>129</sup> Advisors’ Initial Brief at 39.

<sup>130</sup> City Council Hearing Transcript, 120:5-9 (June 20, 2019).

the Company's Gas Infrastructure Rebuild Program.<sup>131</sup> The Advisors also point out that, in these instances, when recommended by the Company, a 50% equity ratio was not only reasonable but specifically proposed by ENO is its requests for cost recovery;<sup>132</sup> and

**WHEREAS**, the Council agrees with the Advisors and CCPUG that ENO's proposed equity ratio is unreasonable; and

**WHEREAS**, the Council also agrees that an unreasonably high equity ratio would constitute an inappropriate amount of double leveraging, result in an unreasonably higher equity ratio than those of Entergy Corp. as well as an equity ratio higher than the average of the other EOCs; and

**WHEREAS**, the Council also agrees with the Advisors and CCPUG that Louisiana Law allows a regulator to set aside the utility's unreasonable capital structure in favor of a more equitable alternative; and

**WHEREAS**, the Council finds that the inclusion of short-term debt in the calculation of ENO's allowed ROR (*i.e.*, WACC) is contrary to established Council ratemaking practices and is not supported by the preponderance of evidence in the instant proceeding; and

**WHEREAS**, as shown by the Advisors and CCPUG in sworn testimony and supporting analyses provided in this proceeding, ENO's proposed capital structure is unreasonably high and the Council rejects ENO's proposal in favor of a more reasonable equity ratio of the lesser of 50% or ENO's actual equity ratio for the purposes of this instant proceeding and for the FRP evaluations ordered in this resolution; and

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<sup>131</sup> Ex. No. ADV-7 at 54:18-55:3 (HSPM).

<sup>132</sup> Advisors' Initial Brief at 39.

## **DEPRECIATION RATES**

**WHEREAS**, ENO’s witness Donald J. Clayton sponsored new depreciation rates based on a study conducted by Tangibl, LLC, which was carefully reviewed by the Council’s Advisors.<sup>133</sup> The study states that it employs accepted depreciation study methodologies to create what is commonly referred to as *Iowa Curve* factors taking into account survivor curves, expected retirement dates, and salvage factors.<sup>134</sup> Mr. Clayton reports that ENO’s proposed depreciation rates would increase ENO’s depreciation expense by \$2.5 million and \$0.1 million for electric and gas respectively as compared to retaining ENO’s currently approved depreciation rates;<sup>135</sup> and

**WHEREAS**, the Advisors reviewed Mr. Clayton’s testimony and indicated that ENO’s proposed depreciation rates are based on accepted analytical methodologies and represent an incremental change to depreciation rates that ENO reports as having been in effect since 1980 and 2009 for electric and gas respectively.<sup>136</sup> Further, as depreciation represents recovery of ENO’s investments in plant, ENO’s requested overall increase in depreciation rates serves to slightly hasten the decline in ENO’s appropriate dollar return on rate base.<sup>137</sup> ENO’s proposed depreciation rates also appropriately provide for removing stranded costs (*i.e.*, related to a general plant reserve deficiency) from rate base over a 10-year period.<sup>138</sup> Accordingly, the Advisors recommended the Council adopt ENO’s proposed new depreciation rates;<sup>139</sup> and

**WHEREAS**, CCPUG argues that ENO’s proposed service lives for Union Power Station, Power Block 1 (“UPS”) and New Orleans Power Station (“NOPS”) are unsupported and

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<sup>133</sup> Ex. No. ADV-7 at 60:3-4 (HSPM).

<sup>134</sup> *Id.* at 60:4-6 (HSPM).

<sup>135</sup> Ex. No. ENO-35 at 16, Comparison table.

<sup>136</sup> Ex. No. ADV-7 at 61:7-17 (HSPM).

<sup>137</sup> *Id.* (HSPM).

<sup>138</sup> *Id.* (HSPM).

<sup>139</sup> *Id.* (HSPM).



unreasonably short.<sup>140</sup> In doing to, according to CCPUG, ENO seeks to accelerate the recovery of depreciation on these plants and to unnecessarily inflate its revenue requirement, respectively.<sup>141</sup> CCPUG urges the Council to reject ENO's unrealistically short service lives and the related depreciation expense and instead use a 40-year service life for UPS, and change the first-year revenue requirement to reflect a 50-year service life for NOPS (rather than a 30-year life);<sup>142</sup> and

**WHEREAS**, CCUPG witness Mr. Kollen examined publicly-available information from the Energy Information Administration which showed that similar combined cycle units were in service for 40 to 50 years before their retirements;<sup>143</sup> and

**WHEREAS**, ENO witness Mr. Clayton admitted that determining the service life of a generating unit for depreciation purposes and estimating salvage value is not an exact science.<sup>144</sup> Also according to Mr. Clayton, the retirement date of a plant is an important factor in determining its service life;<sup>145</sup> and

**WHEREAS**, the decision whether to retire a plant is driven by multiple factors according to ENO, such as repair costs, location of the plant, and environmental issues.<sup>146</sup> However, ENO provided the retirement date for UPS to Mr. Clayton, but did not provide him with any studies, analyses, or empirical data supporting that decision;<sup>147</sup> and

**WHEREAS**, according to CCPUG, Mr. Clayton attempted to dispute Mr. Kollen's use of similar plants to establish the service life for UPS by claiming that, because UPS (a combined cycle

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<sup>140</sup> CCPUG Initial Brief at 64.

<sup>141</sup> *Id.*

<sup>142</sup> *Id.*

<sup>143</sup> Ex. No. CCPUG-1 at 29:7-30:10.

<sup>144</sup> City Council Hearing Transcript, 138:23-139:5 (June 18, 2019).

<sup>145</sup> *Id.*, 140:3-11.

<sup>146</sup> *Id.*, 140:3-11.

<sup>147</sup> *Id.*, 141:20-142:7.

gas plant) was constructed after 2000, that the combined cycle gas plants Mr. Kollen referenced, which were constructed prior to 2000, were not comparable;<sup>148</sup> and

**WHEREAS**, however, CCPUG points out that Mr. Clayton offers no proof whatsoever that UPS' service life will, most likely, be shorter than a pre-2000 combined cycle plant;<sup>149</sup> and

**WHEREAS**, according to testimony provided by ENO, a major component replacement can extend the service life of a generating unit.<sup>150</sup> Mr. Breedlove opined that the combustion turbine rotors are a "major component" of UPS and have an estimated service life of roughly 19 years.<sup>151</sup> However, Mr. Breedlove did not recommend a 19-year service life for UPS; he recommended a 30-year life.<sup>152</sup> CCPUG asserts that to reach a 30-year life, UPS will most likely have to replace its combustion turbine rotors.<sup>153</sup> Although the service life of a plant is not determined by any one component, in CCPUG's view, the combustion turbine rotors are a major component that can greatly extend the life of the plant;<sup>154</sup> and

**WHEREAS**, Mr. Kollen recommends the use of a 40-year service life for UPS and estimates that the financial effect his recommendation would be a \$5.029 million reduction in ENO's electric base revenue requirement;<sup>155</sup> and

**WHEREAS**, in addition, CCPUG claims that ENO has no experience with retirements or net salvage value for UPS means that its actual experience is 0% net salvage<sup>156</sup> not negative 8% as ENO proposes. Mr. Kollen calculated that the effect of employing a 0% net salvage value for

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<sup>148</sup> *Id.*, 148:5-149:5.

<sup>149</sup> CCPUG Initial Brief at 66.

<sup>150</sup> Ex. ENO-48 at 5:4-12.

<sup>151</sup> *Id.* at 5:1-18; *see also*, City Council Hearing Transcript, 71:1-72:15 (June 19, 2019).

<sup>152</sup> CCPUG Initial Brief at 66.

<sup>153</sup> *Id.*

<sup>154</sup> *Id.*

<sup>155</sup> Ex. No. CCPUG-1 at 30:17-18.

<sup>156</sup> *Id.* at 31:7-15.

UPS for depreciation purposes would lead to a reduction of \$0.628 million in the electric base revenue requirement;<sup>157</sup> and

**WHEREAS**, with respect to NOPS, Mr. Kollen investigated publicly-available information on retirements of peaking unit plants, like NOPS, and found that similar units have been in operation for nearly 50 years or more;<sup>158</sup> and

**WHEREAS**, CCPUG asserts that the utility is made whole over time, because it will collect all of its depreciation, including consideration for salvage value; thus, the issue is whether ENO collects these costs over 30 years or 40 years or 50 years;<sup>159</sup> and

**WHEREAS**, Mr. Kollen recommends that a 9.35% ROE be used in the E-FRP, the first-year revenue requirement be reduced to reflect a 50-year service life, and ENO be ordered to reduce the revenue requirement for NOPS each year to reflect an additional year of depreciation and deferred income tax expense;<sup>160</sup> and

**WHEREAS**, Mr. Kollen then calculated the effect of his recommendations and concludes the first-year revenue requirement for NOPS should be reduced by \$4.073 million;<sup>161</sup> and

**WHEREAS**, the Council believes the CCPUG has made a compelling argument for extending the service lives for UPS and NOPS for the purposes of depreciation; and

**WHEREAS**, CCPUG has provided significant evidence in the record establishing that the service lives for these particular types of generating technology is considerably longer than ENO has proposed for purposes of calculating depreciation rates; and

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<sup>157</sup> *Id.* at 32:22-23.

<sup>158</sup> *Id.* at 47:1-19.

<sup>159</sup> CCPUG Initial Brief at 68.

<sup>160</sup> Ex. No. CCPUG-1 at 48:6-13.

<sup>161</sup> *Id.* at 48:15-20.

**WHEREAS**, the Council believes that ENO’s ratepayers will benefit from lower rates if the utility utilizes longer service life estimates for calculating depreciation rates; and

**WHEREAS**, the Council finds that CCPUG’s recommended 40-year service life for UPS and 50-year service life for NOPS shall be used by ENO in calculating depreciation rates in this proceeding; and

## **TAX ISSUES**

(1) *FIN 48 ADIT Liabilities*

**WHEREAS**, the Financial Accounting Standards Board’s Interpretation No. 48<sup>162</sup> (“FIN 48”) provides an interpretation of FAS No. 109 regarding the accounting for uncertainty in income taxes recognized in financial statements;<sup>163</sup> and

**WHEREAS**, in applying FIN 48, a determination is made by the taxpayer for specific transactions as to whether it is more likely than not that a tax position will be sustained upon examination, including resolution of appeals or litigation processes, based on the technical merits of the position. Then the tax position is measured at the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement. This amount is recognized as an Accumulated Deferred Income Tax (“ADIT”) liability for financial reporting purposes;<sup>164</sup> and

**WHEREAS**, ENO, through complying with normalization rules, records Deferred Income Tax (“DIT”) expense that is part of ENO’s cost of service and is recoverable in utility rates;<sup>165</sup> and

**WHEREAS**, ENO has proposed to remove from its electric and gas rate bases, the portion of various ADIT liabilities that it states are unlikely to produce cost-free capital due to the

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<sup>162</sup> Financial Accounting Series No. 281-B, June 2006, FASB Interpretation No. 48 of the FASB of the Financial Accounting Foundation.

<sup>163</sup> Advisors’ Initial Brief at 40.

<sup>164</sup> *Id.* at 40-41.

<sup>165</sup> *Id.* at 42.

aggressive tax positions taken by the Company in its filings with federal and state taxing authorities (FIN 48 ADIT),<sup>166</sup> with the specific proposed amounts by account to be so excluded;<sup>167</sup> and

**WHEREAS**, the Advisors disagree with ENO's proposed ratemaking treatment of FIN 48 ADIT liabilities. The Advisors evaluated the FIN 48 ratemaking issues in this proceeding in a two pronged approach: (1) how is the financial risk shared between ratepayers and shareholders with respect to the uncertainty of the income tax position taken by ENO; and (2) making the correct adjustment required for ratemaking purposes. With respect to issue of financial risk, the Advisors disagree with ENO's adjustment to eliminate FIN 48 ADIT liability balances from rate base for its electric and gas operations;<sup>168</sup> and

**WHEREAS**, the Advisors argue that ENO's recording of DIT expense and including it in its cost of service provides ENO a cost-free loan from the ratepayers which requires that the related FIN 48 ADIT liability also be included in rate base;<sup>169</sup> and

**WHEREAS**, ENO argues that its aggressive tax positions underlying the FIN 48 ADIT essentially have no effect on the level of income tax expense included in ENO's revenue requirement in its Period II Electric and Gas Cost of Service Studies, and a result, when considering income tax expense, a utility's customers are indifferent as to whether a utility uses aggressive tax positions on its tax return;<sup>170</sup> and

**WHEREAS**, ENO argues that FIN 48 ADIT is not cost-free capital in that ENO accrues interest expense on its aggressive tax positions, and that interest expense is borne by ENO and not recovered by ENO from customers in rates;<sup>171</sup> and

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<sup>166</sup> *Id.* at 41.

<sup>167</sup> Ex. No. ENO-1 at 71, Table 3 (HSPM).

<sup>168</sup> Advisors' Initial Brief at 41-42.

<sup>169</sup> *Id.* at 42.

<sup>170</sup> ENO Initial Brief at 147.

<sup>171</sup> *Id.*

**WHEREAS**, the Advisors support ENO’s recovery of prudently incurred interest expense attributed to ENO paying interest for tax underpayments to the federal government related to prudent FIN 48 positions it takes;<sup>172</sup> and

**WHEREAS**, the CCPUG recommends that that the Council authorize ENO to record a regulatory asset and seek recovery in a future ratemaking proceeding for the interest paid to the IRS related to FIN 48 ADIT calculated from the date when rates are reset in this proceeding;<sup>173</sup> and

**WHEREAS**, the CCPUG agrees with the Advisors that ENO’s proposed treatment of FIN 48 amounts to a cost-free loan from the ratepayers to ENO and that in this way, ENO pockets the carrying charge value on the savings that were funded by ratepayers. The CCPUG argues that the Council should subtract the FIN 48 ADIT amounts from rate base;<sup>174</sup> and

**WHEREAS**, the Advisors make certain recommendations regarding the recoverability of DIT in the event the Council approves ENO’s proposal to exclude FIN 48 ADIT from rate base; and

**WHEREAS**, the Council agrees with ENO that its aggressive tax positions underlying FIN 48 ADIT have no effect on its income tax expense as presented in its Period II electric and gas cost of service studies in the instant proceeding; and

**WHEREAS**, ENO’s argument that its aggressive tax positions underlying FIN 48 ADIT having no effect on income tax expense is supportive of its proposal to exclude FIN 48 ADIT from its rate base is unpersuasive, and the Council agrees with the Advisors and the CCPUG that such

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<sup>172</sup> Ex. No. ADV-13 at 63.

<sup>173</sup> Ex. No. CCPUG-1 at 26.

<sup>174</sup> CCPUG Initial Brief at 38.

proposed treatment provides ENO a cost-free loan from the ratepayers in which ENO pockets the carrying charge value of savings funded by ratepayers; and

**WHEREAS**, the Council finds that FIN 48 ADIT liabilities should be included in ENO's rate base; and

**WHEREAS**, any discussion as to the appropriate ratemaking treatment of DIT in the event FIN 48 ADIT liabilities are excluded from ENO's rate base is moot; and

**WHEREAS**, the Council finds that the FIN 48 ADIT liabilities ENO has proposed to exclude from its gas and electric rate bases as part of its electric and gas Period II cost of service studies in the Revised Application<sup>175</sup> should be included in ENO's gas and electric rate bases; and

**WHEREAS**, the Council agrees that prudently undertaken aggressive tax positions may involve prudently incurred related costs such as interest accruals or payments related to the period starting with the effective date of rates established herein; and

**WHEREAS**, the Council generally agrees that the CCPUG's recommended treatment of prudently incurred interest payments related to FIN 48 ADIT through a regulatory asset is reasonable, although the Council notes that it would authorize the creation of any such regulatory asset; and

**WHEREAS**, in future retail rate actions before the Council, ENO may propose for Council consideration a ratemaking mechanism for the recovery of prudently incurred costs related to FIN 48 ADIT liabilities that are included in ENO's rate base, such as interest accrued or paid, and related to the period starting with the effective date of rates established herein; and

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<sup>175</sup> Ex. No. ENO-1 at 71, Table 3 (HSPM).

(2) NOLCF ADIT Assets

**WHEREAS**, in any given year, when a company has more income tax deductions than taxable income, the excess of the income tax deductions over taxable income is called a net operating loss (“NOL”). This NOL represents a future income tax benefit that ENO may use, and is referred to as a net operating loss carry forward (“NOLCF”) and recorded as an ADIT asset;<sup>176</sup> and

**WHEREAS**, ENO proposes to include NOLCF ADIT asset balances attributable to accelerated tax depreciation in its rate base, citing two Private Letter Rulings (“PLR”) that ENO argues explain the income tax normalization rules that require the inclusion in its rate base of the NOLCF ADIT asset balance attributable to accelerated tax depreciation;<sup>177</sup> and

**WHEREAS**, ENO argues that the two PLRs it cites explain that the NOLCF ADIT asset balance must be included in ENO’s rate base to offset the credit ADIT by the amount for which no cost-free capital was received, otherwise a normalization violation of the IRS’s income tax rules could cause the IRS to prohibit ENO from using accelerated tax depreciation on its income tax return;<sup>178</sup> and

**WHEREAS**, through a response to discovery propounded upon ENO by the Advisors in the instant proceeding, ENO revised downward the amount of NOLCF ADIT it proposes to include in its electric and gas rate bases in the instant proceeding;<sup>179</sup> and

**WHEREAS**, the Advisors argue that the Council should not rely on the conclusions drawn in the two PLRs cited by ENO because it is impossible to compare the facts, as presented by the

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<sup>176</sup> Advisors’ Initial Brief at 45.

<sup>177</sup> *Id.* at 46.

<sup>178</sup> *Id.*

<sup>179</sup> ENO Initial Brief at 169; Post-Hearing Reply Brief of Entergy New Orleans, LLC at 120, Aug. 9, 2019 (“ENO Reply Brief”).



taxpayers in those cases, to this case as presented by ENO and note that there is no indication that the taxpayers that requested the PLRs stated that deferred income tax expense was reflected in their rates in prior periods, and without the benefit of this critical information, the Council is unable to rely on these PLRs as a basis for approving ENO's proposed ratemaking treatment of NOLCF ADIT asset balances;<sup>180</sup> and

**WHEREAS**, the Advisors also argue that, even if ENO's cited PLRs may be relied upon by the Council in the instant proceeding, ENO's NOLCF ADIT asset is not attributable to accelerated depreciation because the NOL cannot be tied to the excess depreciation over straight-line depreciation;<sup>181</sup> and

**WHEREAS**, the Advisors further argue that ENO's total income tax expense, for financial accounting purposes, includes a current provision payable to the government based on income tax law and a deferred provision based on financial accounting standards, and as such ENO was allowed recovery of all tax expenses, current and deferred, which constitutes taxable revenue;<sup>182</sup> and

**WHEREAS**, the Advisors argue that due to ENO's allowed recovery of all tax expenses, the NOL carried forward during the previous periods was less than it otherwise would have been by an amount equal to the deferred income taxes which were not paid to the government but were collected from ratepayers;<sup>183</sup> and

**WHEREAS**, the Advisors state that none of ENO's NOLCF ADIT assets are directly "attributable" to income tax timing differences, or the attributable balance of such is zero, and they

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<sup>180</sup> Advisors' Initial Brief at 46-47.

<sup>181</sup> *Id.* at 48.

<sup>182</sup> *Id.*

<sup>183</sup> *Id.* at 48-49.

recommend the Council deny ENO's proposal to add NOLCF ADIT asset balances to its rate bases;<sup>184</sup> and

**WHEREAS**, the Advisors discussed and made recommendations as to Council regulatory treatment of DIT should the Council allow ENO to include NOLCF ADIT asset balances in its rate bases;<sup>185</sup> and

**WHEREAS**, the Council finds persuasive the Advisors' argument that ENO has been allowed recovery of all of its book tax expenses, including DIT related to accelerated depreciation, and as such, the NOLCF ADIT asset balance attributable to accelerated depreciation is zero; and

**WHEREAS**, as the Council herein finds that any NOLCF ADIT asset amount properly includable in ENO's rate bases in the instant proceeding is zero, further consideration as to the probative value of ENO's two cited PLRs is not necessary at this time and any discussion of alternate regulatory treatment is moot; and

(3) Rider SSCO ADIT

**WHEREAS**, the Advisors recommend the Council direct ENO to employ its then current WACC when setting Rider SSCO's rates,<sup>186</sup> a recommendation that is not opposed by ENO<sup>187</sup> or any party to the proceeding; and

**WHEREAS**, the Council finds that ENO should employ its then current WACC, reflective of the provisions for a cap on ENO's equity ratio therein as ordered herein, when periodically setting Rider SSCO's rate; and

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<sup>184</sup> *Id.* at 49.

<sup>185</sup> *Id.* at 46.

<sup>186</sup> *Id.* at 149.

<sup>187</sup> ENO Reply Brief at 115.

**WHEREAS**, as part of ENO’s rebuttal testimony, ENO stated that in its Revised Application, it failed to make the entry to remove the balance of ADIT associated with Rider SSCO from the rate base in its cost of service studies,<sup>188</sup> as noted in ENO’s Post Hearing Brief;<sup>189</sup> and

**WHEREAS**, at Hearing, ENO offered a dollar revenue requirement effect of its stated failure to remove ADIT associated with Rider SSCO from its rate base,<sup>190</sup> as noted in ENO’s Post Hearing Brief;<sup>191</sup> and

**WHEREAS**, per the procedural schedule in the instant proceeding the Council-authorized period of discovery had expired prior to the Hearing; and

**WHEREAS**, the Council approved a procedural schedule in the instant proceeding calculated to afford parties to carefully inspect, validate, and rebut as necessary the proposals and claims of other parties; and

**WHEREAS**, due to the timing of ENO’s statements and disclosures, parties to the instant proceeding were not afforded the opportunity to inspect, validate, propound discovery related to, or rebut ENO’s claim as to the dollar amount of the revenue requirement effect of any such failure; and

**WHEREAS**, the Council finds that evidence in the Administrative Record is insufficient to support setting rates reflective of ENO’s stated dollar revenue requirement effect<sup>192</sup> related to ENO’s stated failure to remove ADIT related to Rider SSCO from its rate base; and

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<sup>188</sup> Ex. No. ENO-3 at 42-43.

<sup>189</sup> ENO Initial Brief at 170.

<sup>190</sup> City Council Hearing Transcript at 178-179 (June 17, 2019).

<sup>191</sup> ENO Initial Brief at 170.

<sup>192</sup> City Council Hearing Transcript at 178-179 (June 17, 2019).

(4) ADIT Related to Stranded Plant

**WHEREAS**, as part of the AMI deployment ENO must retire certain related existing plant, such as meters, prior to its full recovery through depreciation (“Stranded Plant”);<sup>193</sup> and

**WHEREAS**, the retirement of this Stranded Plant is associated with ENO’s per-book recording of ADIT liabilities; and

**WHEREAS**, the economic benefit to ENO of Stranded Plant ADIT in the form of cost-free capital is undisputed;<sup>194</sup> and

**WHEREAS**, in its Revised Application, ENO removed ADIT related to Stranded Plant from rate base;<sup>195</sup> and

**WHEREAS**, the Advisors argue that ENO’s rates should reflect the economic benefit it enjoys due to cost-free capital, such as ADIT related to Stranded Plant;<sup>196</sup> and

**WHEREAS**, ENO argues that allowing ADIT related to Stranded Plant in its rate base could constitute a “potential violation” of IRS normalization rules;<sup>197</sup> and

**WHEREAS**, out of an abundance of caution regarding ENO’s argument of a “potential violation” of IRS rules, the Advisors recommend the Council recognize the benefit to ENO of cost-free capital and direct ENO to create regulatory liabilities;<sup>198</sup> and

**WHEREAS**, ENO argues that the Council’s creating a regulatory liability to recognize ENO’s economic benefit related to cost-free capital amounts to “changing the name of the reserve or the book account of the reserve,” and does not negate the “potential” IRS normalization rules violation;<sup>199</sup> and

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<sup>193</sup> Advisors’ Initial Brief at 147.

<sup>194</sup> *Id.* at 148.

<sup>195</sup> Ex. No. ADV-6 at 57:1-3, Advisors Initial Brief at 147.

<sup>196</sup> *Id.*

<sup>197</sup> *Id.*

<sup>198</sup> *Id.*

<sup>199</sup> ENO Reply Brief at 74.

**WHEREAS**, ENO states that the Council should reject the Advisors’ recommendation to create a regulatory liability as it would result in a normalization violation and harm customers;<sup>200</sup> and

**WHEREAS**, the Council finds nothing in the record demonstrating that the Advisors are recommending the Council “change the name” or “book account” of any reserve; and

**WHEREAS**, the Council agrees that the Advisors’ recommendation to create a regulatory liability is to reflect the undisputed economic benefit to ENO of cost-free capital through Stranded Plant ADIT; and

**WHEREAS**, the Council notes its authority to set rates based in part on allowing ENO the reasonable opportunity to recover its prudently incurred costs; and

**WHEREAS**, the Council notes its authority to create regulatory liabilities as part of its ratemaking authority; and

**WHEREAS**, the Council finds that ENO should record a regulatory liability reflective of the economic benefit of cost-free capital through Stranded Plant ADIT, with such regulatory liability being a component of ENO’s electric and gas rate bases; and

**RESTRICTED STOCK INCENTIVE PLAN**

**WHEREAS**, the Advisors audited ENO’s affiliate transactions, and for the most part, found that ENO had properly treated its Billing Adjustments related thereto, with one exception.<sup>201</sup> Based on the Advisors’ review of ENO’s affiliated transactions during the test-year period, the Advisors recommend that the cost of ENO’s Restricted Stock Incentive Plan (“Plan”) should not be recovered in rates.<sup>202</sup> The Advisors assert that this recommendation would reduce ENO’s

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<sup>200</sup> *Id.*

<sup>201</sup> Ex. No. ADV-17 at 3:9-7:14.

<sup>202</sup> Ex. No. ADV-17 at 3:4-6.

revenue requirement related to its electric operations by \$648,314 and the revenue requirement related to its gas operations by \$145,211;<sup>203</sup> and

**WHEREAS**, ENO argues that this adjustment is unwarranted because the Advisors have not demonstrated that ENO's compensation plans are unreasonable.<sup>204</sup> However, the Advisors argue that incentive compensation plans and stock options may only be recovered in rates to the extent that the Company demonstrates that such plans benefit ratepayers.<sup>205</sup> Whether or not the Plan is reasonable, it is tied to the long-term performance of Entergy Corporation common stock, therefore the benefit of the Plan accrues solely to Entergy shareholders, and not to ratepayers, and therefore the costs thereof should not be recovered through rates.<sup>206</sup> The Advisors also point out that other jurisdictions have disallowed these costs from being recovered from customers for the same reasons that Advisors' witness Mr. Ferris cites in his testimony;<sup>207</sup> and

**WHEREAS**, the Council agrees with the Advisors that ENO has failed to provide support for its position regarding the inclusion of the Plan's costs in rates. Additionally, simply because a cost may be legitimate and prudent does not necessarily require those costs to be borne by ratepayers. The Council also notes that ENO incurs costs routinely that may be legitimate and prudent, but not recoverable from ratepayers. The Council further agrees with the Advisors that ENO has not provided any rational justification for recovering the costs of ENO's Restricted Stock Incentive Plan in rates. Accordingly, the Council finds that the Company has failed to meet its burden of showing that the Restricted Stock Incentive Plan benefits ratepayers and therefore, rejects ENO's proposal to include these costs in rates; and

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<sup>203</sup> Advisors' Initial Brief at 49, citing Ex. No. ADV-17 at 3:6-8.

<sup>204</sup> ENO Initial Brief at 163; Ex. No. ENO-3 at 50:14-17.

<sup>205</sup> Ex. No. ADV-18 at 4:5-7.

<sup>206</sup> *Id.* at 4:12-16.

<sup>207</sup> Ex. No. ADV-17 at 9:20-10:2 citing LPSC Order No. U-20925 (RRF 2004) and attached Recommendation on Contested Proposed Stipulated Settlement at 16.

## **ENO'S PREPAID PENSION ASSET ADJUSTMENT**

**WHEREAS**, ENO included an adjustment for its Prepaid Pension Asset as part of its rate base;<sup>208</sup> and

**WHEREAS**, the Advisors argue that ENO's inclusion of the Prepaid Pension Asset in rate base is conceptually correct;<sup>209</sup> and

**WHEREAS**, the Advisors took exception to ENO's calculation of the asset included in rate base because it is based on a forecasted balance for the year-end December 31, 2018.<sup>210</sup> Instead of using forecasted calculations, the Advisors recommend that the Pension Asset balance be based on the actual December 31, 2018 balances<sup>211</sup> when provided by ENO, which would more accurately reflect the market value of the Asset;<sup>212</sup> and

**WHEREAS**, ENO argued that the Advisors' reasoning was incorrect because the Prepaid Pension Asset's growth is not driven by the market value of the pension trust fund assets but by ENO's contributions to the pension trust fund;<sup>213</sup> and

**WHEREAS**, upon receipt of ENO's responses to the Advisors' discovery requests regarding ENO's Prepaid Pension Asset adjustment, the Advisors found that ENO's actual funded status of its pension funds at December 31, 2018 was significantly less than the amount forecasted by Entergy's actuaries, AON Hewitt.<sup>214</sup> Also, ENO's actual balance for its benefit obligations regulatory asset at December 31, 2018 was significantly larger than the amount forecasted by AON

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<sup>208</sup> ENO's Initial Brief at 150.

<sup>209</sup> Ex. ADV-9 at 63:9-10.

<sup>210</sup> *Id.* at 63:10-11.

<sup>211</sup> *Id.* at 63:11-14.

<sup>212</sup> The Advisors issued two discovery requests to ENO seeking information to determine the actual adjusted balance for the Pension Asset as of December 31, 2018. The two requests, CNO 12-2 and CNO 12-3 were outstanding at the time the Advisors were required to file direct testimony.

<sup>213</sup> ENO Initial Brief at 150.

<sup>214</sup> Ex. ADV-9 at 65:13-19.

Hewitt.<sup>215</sup> Further, AON Hewitt's overestimated funded status for ENO's pension funds and underestimated balance for ENO's benefit obligations regulatory asset at December 31, 2018, respectively, offset one another.<sup>216</sup> Therefore, the Advisors determined that as a result of this netting process, ENO's Pension Asset remains unaffected from differences between estimated and actual net gains and losses;<sup>217</sup> and

**WHEREAS**, in his Surrebuttal Testimony, Advisors' witness Mr. Proctor proposed that his recommendation for the Prepaid Pension Asset in rate base is also appropriate because it is supported by the lower historical five-year average year-end value of the Asset due to the growth of the Prepaid Pension Asset from recent financial market conditions and the amount of ENO's contributions;<sup>218</sup> and

**WHEREAS**, ENO responded that the Prepaid Pension Asset's growth is not driven by the market value of the pension trust fund assets but by ENO's contributions to the pension trust fund in excess of pension expense.<sup>219</sup> Contributions are tendered according to a plan provided by ENO's actuary setting forth the expected amount of the contributions and their timing.<sup>220</sup> Pension expense is generally determined at the beginning of the year by ENO's actuary.<sup>221</sup> ENO asserts that its discovery responses related to this issue show that the market value of the pension trust fund assets has no effect on the quantification of the Prepaid Pension Asset;<sup>222</sup> and

**WHEREAS**, the Council has considered the parties' positions related to ENO's Prepaid Pension Asset adjustment and concludes that the Asset should be included in rate base; and

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<sup>215</sup> *Id.*

<sup>216</sup> *Id.*

<sup>217</sup> Ex. ADV-9 at 66:14-16.

<sup>218</sup> *Id.* at 69:17-20.

<sup>219</sup> ENO Initial Brief at 151

<sup>220</sup> *Id.*

<sup>221</sup> *Id.*

<sup>222</sup> *Id.*



**WHEREAS**, the Council also believes that ENO has reasonably demonstrated that the market value of the pension trust fund assets does not have an effect on the quantification of the of the Prepaid Pension Asset for the purposes of inclusion of the Asset in base rates; and

**WHEREAS**, ENO’s Prepaid Pension Asset adjustment should be included in rate base and quantified as proposed by the Company in its Revised Application; and

**GAS INFRASTRUCTURE REPLACEMENT PROGRAM**

**WHEREAS**, on January 26, 2017, in Docket No. UD-07-02, the Council adopted Resolution R-17-38 which authorized ENO “to proceed with the replacement of gas infrastructure . . . at a rate of approximately 25 miles per year and approximately \$12.5 million in capital investment per year” until the resolution of the instant rate case docket;<sup>223</sup> and

**WHEREAS**, ENO proposes to establish a Gas Infrastructure Replacement Program (“GIRP”) to recover its costs related the replacement of aging natural gas infrastructure to ensure the safety and reliability of its gas distribution system. Specifically, ENO proposes to include GIRP investment made through the end of this proceeding in the costs collected through the proposed GIRP Rider;<sup>224</sup> and

**WHEREAS**, ENO specifically proposes to replace or abandon a total of 238 miles of low-pressure cast iron and steel and vintage plastic pipes at an estimated cost of \$119 million because, according to the ENO, cast iron and vintage plastic are two of the material types that the natural gas industry recognizes are prone to failure and recommends should be replaced.<sup>225</sup> ENO also argues that a gas distribution system that is entirely high-pressure also offers the benefit of

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<sup>223</sup> Ex. No. ENO-22 at 16:19-17:2.

<sup>224</sup> *Id.* at 17.

<sup>225</sup> *Id.* at 15.

providing a form of “storm hardening,” as high-pressure operation prevents the infiltration of water into the system;<sup>226</sup> and

**WHEREAS**, under the assumption that the rates implemented as a result of this rate case include plant in service through December 31, 2019,<sup>227</sup> ENO proposes to recover its GIRP investment and expenses that are placed into service and/or expended from January 1, 2020 through March 31, 2020 through the GIRP Rider;<sup>228</sup> and

**WHEREAS**, ENO’s proposal contemplates that it will make a rate filing within 60 days of March 31, 2020 with new rates to become effective for bills rendered on and after the first billing cycle of July 2020.<sup>229</sup> The percent rate adjustment would be applied to each gas rate class (*i.e.*, Residential, Small General, Large General, Small Municipal, and Large Municipal) with the exception of the customers ENO describes as “Non-Jurisdictional.”<sup>230</sup> Further, ENO is proposing quarterly rate redeterminations, with quarterly filings that would be submitted within sixty days after each subsequent three-month period; and

**WHEREAS**, the Company proposes that the term of the GIRP Rider will be in effect through 2027, regardless of whether an FRP remains in place for ENO.<sup>231</sup> If this GIRP Rider is terminated before 2027, then the Company proposes that the GIRP Rider Rate then in effect would remain in effect until the Council approves an alternative recovery mechanism;<sup>232</sup> and

**WHEREAS**, none of the Intervenors addressed the proposed GIRP Rider; and

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<sup>226</sup> *Id.*

<sup>227</sup> *Id.*

<sup>228</sup> Ex. No. ENO-41 at 49.

<sup>229</sup> *Id.* at 49-50.

<sup>230</sup> Ex. No. ADV-6 at 80:4-7.

<sup>231</sup> *Id.* at 52.

<sup>232</sup> *Id.* at 52-53.

**WHEREAS**, Advisors’ witness Watson testifies that ENO’s proposed GIRP Rider is not necessary to allow ENO the opportunity to recover its related costs.<sup>233</sup> He states that “[t]hese GIRP-related costs are predictable and manageable by ENO.” As such, other ratemaking mechanisms exist to allow ENO the opportunity to recover such costs such as ENO’s proposed FRP.<sup>234</sup> Further, the Advisors note that “ENO witness Bourg testified, ‘ENO agrees that a properly structured FRP would provide an appropriate means to adjust ENO’s gas rates to allow it to recover its gas revenue requirements, including its GIRP-related costs and a reasonable return on its investment;’”<sup>235</sup> and

**WHEREAS**, Advisors’ witness Rogers testifies that although he agrees that the proposed scope of GIRP is consistent with industry trends to identify risks and replace aging infrastructure prior to failure and will provide customers with a safer, more reliable gas distribution system, he expressed his concern regarding the resulting rate impact on ratepayers,<sup>236</sup> and

**WHEREAS**, the Advisors note that the costs related to GIRP investment through 2019 are estimated to have a bill impact on a typical 100 ccf/month residential customer of approximately \$6.12/month with rates in the instant proceeding. The Advisors further note that the estimated costs related to GIRP investment after 2019 and the estimated costs related to address historical underground utility conflicts, the estimated bill impact on a typical 100 ccf/month residential customer peaks at approximately \$20.45/month in 2026;<sup>237</sup> and

**WHEREAS**, the Advisors assert that ENO has not shown that the proposed scope and pace of the GIRP plan adequately mitigates its rate impact.<sup>238</sup> In this regard, the Advisors argue ENO

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<sup>233</sup> Ex. No. ADV-6 at 81:9-10.

<sup>234</sup> *Id.* at 81:11-14.

<sup>235</sup> *Id.* at 82:6-9, citing Rebuttal Testimony of Michelle P. Bourg at 8, (Docket No. UD-07-02) (Sept. 5, 2017).

<sup>236</sup> Ex. No. ADV-6 at 39-40:17-10.

<sup>237</sup> Ex. No. ADV-6 at 39:18-40.

<sup>238</sup> Advisors’ Initial Brief at 90.

refrained from providing a specific estimate of the approximate number of miles of pipe that should be replaced annually to ensure the safety of the gas distribution system;<sup>239</sup> and

**WHEREAS**, ENO maintains its position for the original GIRP schedule presented in the Application;<sup>240</sup> and

**WHEREAS**, the Advisors make the following recommendations: (1) that the Council approve recovery of the GIRP infrastructure costs incurred as proformed through the end of 2019 as generally approved by Resolution No. R-17-38; (2) that the Council reject ENO's proposed GIRP Rider as it constitutes inappropriate single-issue ratemaking and any Council-authorized GIRP-related costs are more appropriately recovered in base rates as adjusted through the gas FRP evaluations; and (3) that ENO be required to identify potential measures to mitigate the identified impact on ratepayers; and

**WHEREAS**, the Advisors further recommend that given ENO's unwillingness to depart from its proposed pace of GIRP-related investments, the Council establish a that a working group composed of the Advisors, ENO, and Intervenors to explore appropriate cost mitigation measures;<sup>241</sup> and

**WHEREAS**, the Advisors have noted, and the Council is concerned that, ENO has changed the scope and cost budget for GIRP, including introducing a utility conflict survey cost in the instant proceeding and introducing abandonment of plant as a component of GIRP; and

**WHEREAS**, the Council believes that the safe operation of ENO's gas distribution system is the paramount concern but also remains concerned regarding the cost impact on ratepayers with respect to ENO's proposed gas infrastructure replacement program; and

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<sup>239</sup> *Id.*

<sup>240</sup> Ex. No. ENO-24 at 5:14-16.

<sup>241</sup> Ex. No. ADV-2 at 10:19-21.

**WHEREAS**, the Council agrees with the Advisors’ recommendations and (1) finds that the GIRP infrastructure costs through the end of 2019 should be approved so as not to disrupt the gas infrastructure replacement; (2) rejects ENO’s proposed GIRP Rider as it constitutes inappropriate single-issue ratemaking and finds that any Council-authorized GIRP-related costs are more appropriately recovered in base rates; and (3) requires ENO to identify potential measures to mitigate the cost impact of ENO’s proposed GIRP plan; and

**WHEREAS**, in light of the considerable need to ensure that ENO’s distribution gas pipeline operations are safe and reliable, the Council finds that ENO may continue to make prudent investments in gas distribution plant and incur prudent utility conflict survey costs as required to ensure the safe operation of ENO’s gas utility, and that a working group should be established to consider all appropriate measures to mitigate harmful GIRP-related ratepayer impacts, as proposed by the Advisors; and

**ALLOCATION OF CAPACITY COSTS ASSOCIATED WITH CERTAIN PURCHASE POWER AGREEMENTS**

**WHEREAS**, in proposing customer class revenue requirements, ENO allocated capacity costs associated with the Resource Plan Purchase Power Agreements (“PPAs”) using the relative percentage of energy sales (kWh) attributable to each rate class.<sup>242</sup> According to the Company, this allocation method decreases the capacity-related expenses allocated to the residential rate class and re-allocates those costs among the remaining customer classes.<sup>243</sup> According to ENO, the reallocation occurs as a matter of the Company’s proposed rate design and is not reflected in ENO’s electric cost of service study;<sup>244</sup> and

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<sup>242</sup> ENO Initial Brief at 81.

<sup>243</sup> *Id.*

<sup>244</sup> *Id.*

**WHEREAS**, Advisors’ witness Prep and CCPUG witness Baron object to the energy-based allocation of the Resource Plan PPAs capacity-related expenses; and

**WHEREAS**, specifically, for the allocation of capacity-related costs from Riverbend 30% PPA (“Riverbend 30”) and Entergy Arkansas, Inc. Wholesale Base Load PPA (“EAI WBL”), Advisors’ witness Prep used a production demand allocator, which is consistent with ENO’s own electric cost of service study, rather than ENO’s kWh/energy allocation of these fixed costs;<sup>245</sup> and

**WHEREAS**, CCPUG argues that ENO should allocate the capacity costs associated with the EAI WBL and River Bend 30% PPAs to each customer class on an equal percentage basis, just as it proposes to do with respect to the Ninemile 6 PPA and Algiers Transaction PPA capacity costs;<sup>246</sup> and

**WHEREAS**, CCPUG asserts that allocation of these costs on an equal percentage basis is a reasonable and well-accepted method to allocate and recover such fixed, non-fuel capacity costs, and ENO acknowledges that it is consistent with prior Council rate making decisions;<sup>247</sup> and

**WHEREAS**, CCPUG also points out that ENO proposes to treat the non-fuel, capacity costs related to the EAI WBL and River Bend 30% PPAs differently than it proposes to treat capacity costs associated with other PPAs, which are identical in nature;<sup>248</sup> and

**WHEREAS**, ENO argues, to the contrary, that the energy allocation not only is effective to address residential customer rate impacts, it is also founded on sound policy and cost causation principles;<sup>249</sup> and

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<sup>245</sup> Ex. No. ADV-3 at 28:2-4.

<sup>246</sup> CCPUG Initial Brief at 15-16.

<sup>247</sup> *Id.* at 15, citing Ex. No.. ENO-41 at 23:11-12. “[I]t has been the Council’s practice to adjust base rates by applying an equal percentage change to all classes.”

<sup>248</sup> *Id.* at 15.

<sup>249</sup> ENO Initial Brief at 82.

**WHEREAS**, the Council finds that CCPUG’s concerns regarding the effect of ENO’s proposed methodology to allocate these costs have merit; and

**WHEREAS**, the Council also concludes that Advisors’ witness Prep’s recommendation to require ENO to allocate these capacity costs on a production demand basis, as used in ENO’s electric cost of service study, is more consistent with the Council’s prior ratemaking decisions than ENO’s proposal and also similar to ENO’s treatment of other PPAs being realigned into base rates in this proceeding; and

**WHEREAS**, the Council disagrees with ENO’s proposal to allocate capacity costs related to the EAI WBL and River Bend 30% PPAs to each customer class on a percentage of energy (kWh) sales; and

**CCPUG’S PROPOSED RATE ADJUSTMENTS**

**WHEREAS**, CCPUG made a number of recommended rate adjustments in this proceeding that the Council declines to adopt, including;

- a. Remove Capital Storm Restoration Costs from Plant;
- b. Remove Depreciation Expense Associated With Capital Storm Restoration Costs;
- c. Remove Amortization of Algiers Migration Costs;
- d. Reduce Depreciation Expense – Correct Patterson Solar Depreciation Rate;
- e. Remove Reduction to ADIT for Excess ADIT Amortization in 2019;
- f. Remove Algiers Migration Costs Net of ADIT;
- g. Reduce Depreciation Expense – Use 0% Net Salvage for Union Power Block #1;
- h. Extend Amortization of Algiers Transaction and Migration Costs to 10 Years; and

**WHEREAS**, the Council has carefully considered each of these recommended adjustments and finds that they should not be adopted for various reasons; and

**WHEREAS**, with respect to the adjustment, Remove Capital Storm Restoration Costs from Plant and Remove Depreciation Expense Associated With Capital Storm Restoration Costs, the Council is unpersuaded by CCPUG's proposals regarding the recovery of storm related costs

and declines to alter the Council’s longstanding practice of allowing the recovery of such costs;  
and

**WHEREAS**, with respect to the adjustment, Remove Amortization of Algiers Migration Costs, Remove Algiers Migration Costs Net of ADIT and Extend Amortization of Algiers Transaction and Migration Costs to 10 years, the Council declines to modify its previously approved Algiers transaction and migration cost amortization period; and

**WHEREAS**, as for CCPUG’s proposed adjustment Reduce Depreciation Expense - Correct Paterson Solar Depreciation Rate, the Council is not persuaded that the Paterson Solar Project's depreciation rate as proposed by ENO is inappropriate since the project is reasonably viewed as a technology demonstration pilot project; and

**WHEREAS**, the Council also finds that the proposed adjustment, Remove Reduction to ADIT for Excess ADIT Amortization in 2019, would be inconsistent with the accepted ratemaking principle of allowing ENO the opportunity to recover its costs contemporaneously with their incurrence, including proforma costs that are known and measurable; and

**WHEREAS**, CCPUG’s proposed adjustment, Reduce Depreciation expense – use 0% Net Salvage for Union Power Block #1, should not be adopted because the Council is not persuaded that Union Power Block #1’s salvage will be 0%; and

**WHEREAS**, CCPUG did, however, make recommended rate adjustments that the Council believes should be adopted, including,

- a. Correct Cash Working Capital to Include Dividend Component of Return on Equity;
- b. Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1;
- c. Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years;
- d. Remove Forecast 2019 Increases in Payroll and Related Expenses; and



**WHEREAS**, with respect to the adjustment, Correct Cash Working Capital to Include Dividend Component of Return on Equity, the Council believes that this adjustment is reasonable and is consistent with the Council’s overall goal of reducing base rates to the greatest extent practicable; and

**WHEREAS**, with respect to the adjustment, Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1, the Council adopts the position of CCPUG as discussed in greater detail herein; and

**WHEREAS**, with respect to CCPUG’s adjustment, Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years, the Council believes that this adjustment is consistent with the Council’s decision to use a 40 year service life for Union Power Block #1 which has the effect of reducing ENO’s revenue requirement while maintaining ENO’s opportunity to recover its prudently incurred costs; and

**WHEREAS**, with respect to the adjustment, Remove Forecast 2019 Increases in Payroll and Related Expenses, the Council finds that this adjustment should be adopted since ENO did not provide documentation or otherwise establish that these proforma expenses are known and measurable; and

**WHEREAS**, CCPUG made some recommended rate adjustments that were opposed by the Advisors in testimony and that the Council chooses not to adopt, including,

- a. Remove Plant, A/D, and ADIT Proforma Adjustments Related to 2019 Additions;
- b. Remove Depreciation Expense Related to 2019 Plant Additions; and

**WHEREAS**, the Council finds that these adjustments are inconsistent with the Council’s decision in this resolution to generally allow ENO to include proforma costs that are known and measurable in rate base for the purpose of setting rates in this proceeding; and

## **COST ALLOCATION AND CUSTOMER CLASS REVENUE REQUIREMENTS**

**WHEREAS**, ENO proposes several steps in the way that its total cost of service/revenue requirement is allocated among customers classes. These steps impact the extent to which various customer classes see a rate increase or decrease as a result of the overall revenue decrease proposed by ENO; and

(1) Cost Allocation

**WHEREAS**, ENO argues that its proposed cost allocation methodologies have been historically used by the Company and are consistent with those traditionally approved by the Council. The significant characteristic of ENO's cost allocation is the fact that ENO limits its cost of service allocations to only costs recovered in base rates.<sup>250</sup> ENO's allocations of all other costs in the total revenue requirement are effectively determined by ENO's proposed rider tariff design for revenue recovery. For example, ENO proposed an allocation of AMI costs (through its proposed AMI Rider) on the basis of numbers of customers (which heavily weights the AMI cost recovery on residential ratepayers);<sup>251</sup> and

**WHEREAS**, Air Products concurred with the cost allocation methodologies employed by ENO in the development of its electric class cost of service study, specifically the 12 coincident peak ("12 CP") method for the allocation of generation-related fixed costs and PPAs.<sup>252</sup> CCPUG Witness Baron stated that ENO's 12 Coincident Peak class cost of service study is a reasonable basis to evaluate the cost of service for each of the Company's rate classes;<sup>253</sup> and

**WHEREAS**, the Advisors generally accepted ENO's cost allocation methodologies with few exceptions. The Advisors differed with ENO with respect to the allocations of AMI costs.

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<sup>250</sup> Ex. No. ENO-45 at 8: 14.

<sup>251</sup> Ex. No. ENO-41 at 6-7.

<sup>252</sup> Ex. No. AP-3 at 5.

<sup>253</sup> EX. No. CCPUG-5 at 14

Specifically, the Advisors recommend that the cost responsibility for AMI implementation should be based on the costs and benefits of AMI established in Docket No. UD-16-04;<sup>254</sup> and

(2) Customer Class Revenue Requirements

**WHEREAS**, ENO's class cost of service study shows the various customer class rates of return (limited to base rates rather than total costs of service) that result from present base rate revenues and the allocation of costs that ENO has identified as related to recovery with base rate revenues.<sup>255</sup> ENO's class cost of service study also shows how each customer class present base rate revenue differs from the customer class revenue that would provide a rate of return equal to that proposed by ENO<sup>256</sup>; and

**WHEREAS**, ENO's proposal for revenue changes by customer class does not follow its class cost of service allocation study filed in the Revised Application. Neither did ENO use its class cost of service study to show how its proposed revenue requirements by customer class changed the various customer class rates of return that correspond to present base rate revenues. Rather ENO proposed class revenue requirements based on an energy-based class allocation for its proposed cost allocation with regard to the capacity costs associated with Riverbend 30 ("RB30") and Entergy Arkansas, Inc. Wholesale Base Load ("EAI WBL") Purchased Power Agreements (PPAs"). ENO used the same approach to implementing the first step of its proposed Algiers Residential Rate Transition ("ARRT") plan. Next ENO applied a final class revenue adjustment pro-rated on present customer class base rate revenues;<sup>257</sup> and

**WHEREAS**, Air Products witness Brubaker proposed to adjust class revenues by first calculating the difference between the total revenues ENO requested and the total revenues

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<sup>254</sup> Ex. No. ADV-3 at 28: line 4.

<sup>255</sup> Revised Application, at MFR, COS, Period II, Section FF, Statement RR-1.

<sup>256</sup> *Id.*

<sup>257</sup> Revised Application at 26-30.

awarded by the Council, and then spreading that difference to only those customer classes whose revenues would be above cost of service under ENO's rate proposal.<sup>258</sup> Alternatively, CCPUG's witness Baron regarded the important issue in this case to be the extent to which the Council follows the cost of service results in its revenue allocation decision.<sup>259</sup> However, he then recommended that base rate revenues be increased by a uniform percentage amount,<sup>260</sup> with a cap on the total revenue change at a 2% increase level. CCPUG also proposed that the first \$3.325 million of Council approved revenue adjustments should be applied to eliminate the increases proposed for the four Large Industrial classes proposed by ENO to fund ENO's proposed Algiers residential mitigation plan;<sup>261</sup> and

**WHEREAS,** the Advisors' recommendation is to develop proposed customer class revenue requirements using ENO's class cost of service analysis to evaluate how each change to customer class revenue relates to changes in the customer class rates of return. The Advisors contend that the Council should be provided such specific information on the relative rates of return among the customer classes in its determination of the appropriate changes to the revenue responsibility of each customer class;<sup>262</sup> and

**WHEREAS,** as proposed by the Advisors, the cost of providing service is related to the established total revenue for each customer class. When class allocations are finalized for all other components of the cost of service except return, the class cost of service model provides the specific information related to discrete changes in present class revenues and rates of return. The Advisors used this information to make recommendations to the Council regarding individual

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<sup>258</sup> Ex. No. AP-3 at 15: 10.

<sup>259</sup> Ex. No. CCPUG-5 at 13-15.

<sup>260</sup> Ex. No. CCPUG-5 at 25.

<sup>261</sup> Ex. No. CCPUG-5 at 26, Table 6.

<sup>262</sup> Ex. No. ADV-3 at 30-32.

customer class revenue requirements while recognizing the disparity among the customer class rates of return and the impacts of changes to each customer class total present revenue.<sup>263</sup> Thus, based on the Council approved revenue requirement (cost of service) level for each customer class in this case, the resulting rates of return for each customer class would then be used in the subsequent FRP to calculate the return component of the FRP customer class revenue requirement and the decoupling revenue adjustment.<sup>264</sup> Any adjustments to the customer class relative rates of return should be movements towards the total utility rate of return; and

**WHEREAS**, the Council finds that the Advisors’ approach to setting customer class revenue requirements as indicated in Exhibits VP-20 and VP-21 is a preferred cost-based approach and provides the Council with information relating revenue changes to impacts on customer class rates of return; and

#### **REALIGNMENT OF RATE STRUCTURE**

**WHEREAS**, ENO proposes to eliminate two obsolete customer classes (Master Metered Residential and Experimental Interruptible) and to consolidate its Small Electric Service and Traffic Signal Service classes into a single class. ENO also proposes to consolidate all of its private area lighting services into a single customer class. ENO Witness Talkington addressed the proposed combination of Algiers non-residential rates with Legacy ENO rate classes. As a result, the Company’s electric cost of service studies are based on allocating costs to nine customer rate classes. ENO proposes to discontinue all existing Algiers rate schedules, except for the Market Valued Load Modifying Rider (“MVLMR”) and Market Valued Demand Response Rider

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<sup>263</sup> Ex. No. ADV-5 at 15.

<sup>264</sup> *Id.*

(“MVDRR”), which ENO proposes to available all ENO customers and qualified demand response aggregators of retail customers;<sup>265</sup> and.

**WHEREAS**, none of the Intervenors contested ENO’s realignment of rate classes and rate structures; and

**WHEREAS**, the Advisors do not oppose ENO’s proposal to eliminate and consolidate customer classes, including the existing Algiers electric tariffs, to be combined into nine electric customer rate classes;<sup>266</sup> and

**WHEREAS**, in light of the agreement of ENO and the Advisors regarding the elimination of the relevant obsolete customer classes and the consolidation, including the existing Algiers electric tariffs, into nine electric customer rate classes and the lack of opposition from any other party, the Council approves the proposed rate realignments; and

**NON-JURISDICTIONAL GAS CUSTOMERS**

**WHEREAS**, Non-Jurisdictional (“NJ”) customers are a subset of industrial customers for whom ENO provides interruptible gas service pursuant to negotiated special non-published contracts.<sup>267</sup> Advisor witness Prep notes that these customers were not included in ENO gas cost of service study and as such there is no basis under that approach to determine their allocated cost responsibility;<sup>268</sup> and

**WHEREAS**, ENO did not address this class of gas customers in its Revised Application or Direct Testimony. In response to the Advisors’ testimony, ENO takes issues with the Advisors’ recommendation that NJ customer rates should be reviewed and that, according to ENO, placing the existing NJ customers on the Large General Service rate would not be in the customer’s best

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<sup>265</sup> Ex. No. ENO-45 at 33.

<sup>266</sup> EX. No. ADV-4 at 64-65.

<sup>267</sup> Ex. No. ENO-25 at 27.

<sup>268</sup> Ex. No. ADV-3 at 50.

interest because it would likely result in a material increase in the cost for gas service for this class of customers. ENO argues that “[b]y offering interruptible service under special contracts to these customers, gas service should be able to remain competitive with the prices available to other similar industrial customers with whom the ENO industrial customers are in competition.”<sup>269</sup> ENO also notes that by continuing to serve NJ customers under special contracts also means that these interruptible gas customers will be served in a manner similar to the way gas service is provided to all other industrial customers throughout the state because the natural gas prices paid by customers classified as industrial are a confidential matter between the customers and the seller;<sup>270</sup> and

**WHEREAS**, none of the Intervenors addressed NJ gas customers’ rates; and

**WHEREAS**, the Advisors assert that ENO’s use of “NJ” to refer to these customers is a misnomer because the rates or charges applied to any person or entity receiving gas or electric service in New Orleans are subject to Council retail rate regulation. Since NJ customers receive gas service through the same gas distribution system mains as do all other ENO gas customers and all NJ customers are located in New Orleans, the Advisors contend that NJ customers are subject to Council retail rate regulation;<sup>271</sup> and

**WHEREAS**, although there is no NJ customer cost analysis, the Advisors argue that NJ customers’ rates and established business operations in New Orleans should not be modified without careful Council evaluation. Instead, the Advisors recommend: (1) that ENO should be required to provide a complete cost of service analysis in support of the NJ customers’ rates as part of future Council rate actions; (2) that the Council affirm that the terms under which ENO

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<sup>269</sup> Ex. No. ENO-25 at 30.

<sup>270</sup> *Id.*

<sup>271</sup> *Id.* at 52.

offers gas service to the NJ customers are subject to Council retail rate regulation; (3) that the Council direct ENO not to execute any new NJ contracts without express Council approval;<sup>272</sup> and

**WHEREAS**, the Council agrees that NJ customers are subject to the Council’s rate regulation authority and the Council finds that the Advisors’ argument that the Council in the exercise of that authority should carefully evaluate whether NJ rates are just and reasonable and in the public interest. Thus, we direct ENO to provide a complete cost of service analysis in support of the NJ customers’ rates as part of ENO’s 2020 gas FRP filing; and

### **NEW RIDERS FOR COST RECOVERY**

**WHEREAS**, ENO is proposing several new or revised riders, each of which would allow ENO contemporaneous and nearly exact recovery of its related cost. The riders include:

- Fuel Adjustment Clause rider (“FAC Rider”): recovery of fuel and energy costs, including the recovery of certain power purchase agreement (“PPA”) related capacity costs;<sup>273</sup>
- Purchase Gas Adjustment Clause Rider (“PGA Rider”): recovery of costs related to the provision of gas sold to ENO’s retail customers;<sup>274</sup>
- Midcontinent Independent System Operator, Inc. Rider (“MISO Rider”): recovery of costs charged to ENO pursuant to the MISO Open Access Transmission Energy and Operating Markets Tariffs that are not recovered via the Fuel Adjustment Clause;<sup>275</sup>

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<sup>272</sup> *Id.* at 55-56.

<sup>273</sup> Revised Application at 30

<sup>274</sup> *Id.* at 31.

<sup>275</sup> *Id.*



- Purchase Power and Capacity Acquisition Cost Recovery Rider (“PPCACR”): recovery of certain PPA-related capacity costs, Long-Term Service Agreement (“LTSA”) costs, and the non-fuel revenue requirement related to future constructed and/or acquired capacity additions;<sup>276</sup>
- Distribution Grid Modernization Rider (“DGM Rider”): recovery of costs related to certain distribution investments and O&M expenses characterized by ENO as relating to grid modernization;<sup>277</sup>
- Interim Energy Efficiency Cost Recovery Rider (“EECR Rider”): recovery of costs related to the Council’s Energy Smart program over an interim period;<sup>278</sup>
- Demand-Side Management Cost Recovery Rider (“DSMCR Rider”): recovery of costs related to the Council’s Energy Smart program upon the expiration of Interim EECR Rider;<sup>279</sup>
- Gas Infrastructure Replacement Program Rider (“GIRP Rider”): recovery of costs related to gas distribution investment beyond 2019 and recovery of utility conflict survey costs;<sup>280</sup>
- Advanced Metering Infrastructure (“AMI”) Charge for Electric Service (“AMICE Rider”)/Advanced Metering Infrastructure Charge for Gas Service (“AMICG Rider”): recovery of net costs

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<sup>276</sup> *Id.* at 32

<sup>277</sup> *Id.* at 34-36.

<sup>278</sup> *Id.* at 34.

<sup>279</sup> *Id.* at 33-34.

<sup>280</sup> *Id.* at 36.

related to AMI deployment beyond 2019 for electric and gas respectively;<sup>281</sup> and

**WHEREAS**, in support of these riders, ENO argues that utilities are currently undergoing a paradigm shift caused by the need for large new capital additions at a time of increasing costs and decreasing average usage per residential customer and that a regulatory environment that provides for contemporaneous cost recovery of large investments outside of the traditional rate case provides the utility the necessary opportunity to earn its allowed return while continuing to invest in the system and mitigate operational risks;<sup>282</sup> and

**WHEREAS**, in contrast, the Advisors urge caution in using riders as cost recovery mechanisms. To eliminate single-issue ratemaking, the Advisors recommend that the Council deny ENO's request for Council approval of certain riders that would provide exact cost recovery for their respective costs, *i.e.*, a near-guarantee that ENO will recover all of its costs contemporaneous with their incurrence or through a true-up mechanism involving carrying costs for any under collection balance; and

**WHEREAS**, the Advisors note that historically, riders were only approved by regulators in rare instances to address volatile and uncontrollable costs, such as the recovery of fuel and purchased power costs or natural gas commodity costs through a fuel adjustment rider or purchased gas adjustment rider. Advisor witness Rogers testifies that typically, riders are used for costs that can be significantly variable in nature and outside the control of utility. This is the case with respect to ENO's FAC, PGA, and MISO riders. At other times, riders may be used to provide for the recovery of significant costs incurred between full rate case proceedings that were not otherwise accounted for in base rates; and

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<sup>281</sup> *Id.* at 37-38.

<sup>282</sup> Ex. No. ENO-2 at 53.

## **SINGLE-ISSUE RATEMAKING**

**WHEREAS**, the Advisors raise significant concerns regarding ENO’s request for Council approval of riders that would provide exact cost recovery for their respective costs (*i.e.*, a near-guarantee that ENO will recover all of its costs contemporaneous with their incurrence or through a true-up mechanism involving carrying costs for any under collection balance). Specifically, the Advisors recommend that such riders should be rejected when they constitute inappropriate single-issue ratemaking. Advisor Witness Watson testifies that single-issue ratemaking is a deviation from the accepted regulatory ratemaking principle that rates should generally be based on a utility’s overall costs and risks.<sup>283</sup> The Supreme Court of Louisiana has found that “[s]ingle issue ratemaking occurs when a utility’s rates are altered on the basis of only one of the numerous factors that are considered when determining the revenue requirements of a regulated utility.”<sup>284</sup> Said differently, single-issue ratemaking occurs when particular portions of a utility’s revenue requirement are considered for recovery in isolation from the utility’s total costs and revenues;<sup>285</sup> and

**WHEREAS**, the Advisors also note that “[s]ingle-issue ratemaking is generally not appropriate because its application is contrary to the generally accepted regulatory ratemaking principle that a utility’s rates that produce its revenues should be based on a utility’s overall costs. Single-issue ratemaking may not capture the overall impact of the portion of a utility’s revenue requirement under special consideration by potentially not reflecting offsetting changes in other areas of the utility’s operations;<sup>286</sup> and

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<sup>283</sup> Ex. No. ADV-3 at 73-77.

<sup>284</sup> *Id.* at 75-76.

<sup>285</sup> *Id.* at 74.

<sup>286</sup> *Id.* at 75.

**WHEREAS**, single-issue ratemaking may have the adverse impact of reducing a utility's incentive to control its costs to the extent such ratemaking guarantees cost recovery through a true-up mechanism. As such, single-issue ratemaking is particularly inappropriate when other ratemaking mechanisms that are not subject to single-issue ratemaking deleterious effects are available, such as recovery of the same costs through base rates;<sup>287</sup> and

**WHEREAS**, it should be noted that the Advisors do not recommend an across-the-board prohibition on riders as recovery mechanisms, acknowledging that there may be valid and supportable reasons to use a rider to recover certain costs of service. The Advisors note that a rider may be acceptable if the specific costs are substantial, vary significantly and/or are unpredictable, or require periodic review by the Council. In those instances, the Advisors recommend that an appropriately selected Rider should generate revenue from each customer class based on the costs determined to be recovered from each customer class as reflected in the allocation of the total cost of service;<sup>288</sup> and

**WHEREAS**, the Advisors also note that a utility is entitled only to the opportunity to earn a reasonable return on its investment, and that the law does not insure that a utility will in fact earn the particular rate of return authorized by a Commission or even that it will earn any net revenues. ENO should be allowed a reasonable opportunity to recover its prudently incurred costs and earn a reasonable return on its investments. The reasonable return on investment is primarily influenced by the Council setting a ROE at a level that is comparable to that being earned by other companies with comparable risks, maintains ENO's financial integrity, and maintains ENO's ability to raise capital;<sup>289</sup> and

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<sup>287</sup> *Id.*

<sup>288</sup> *Id.* at 76-77.

<sup>289</sup> *Id.* at 77.

**WHEREAS**, in response to ENO’s argument that its proposed rider address the risk of undue regulatory lag, the Advisors note that if their recommendation for an annual electric and gas FRPs for a period of three years is approved the FRPs will help to mitigate ENO’s concerns related to regulatory lag because the FRP would provide for an annual adjustment to ENO electric and gas rates to reduce the time between regulatory base rate actions. Additionally, to further mitigate regulatory lag, the Advisors recommend that ENO be allowed to include prospective proforma adjustments for known and measurable capital additions budgeted for the 12-month period immediately following the FRP test year. Thus, ENO’s **known and measurable** costs that will occur in the rate effective period will be reviewed and considered for recovery in the annual FRP process; and

### **GRID MODERNIZATION**

**WHEREAS**, ENO contends that its grid modernization investments differ from grid maintenance investments in that the latter costs are typically incurred as part of a utility’s ordinary course of business and are required for a utility to continue to provide reliable service in the short term.<sup>290</sup> According to ENO, grid maintenance investments are typically reactive in nature and are incurred due to problems presented by existing equipment (*e.g.*, replacing damaged or aging assets, addressing compliance issues, etc.). In contrast, grid modernization investments are proactive investments designed to enhance the functionalities and services that grid infrastructure can provide to customers, while also changing the paradigm for evaluating and maintaining the reliability of the distribution system; and<sup>291</sup>

**WHEREAS**, ENO also notes that the five current grid modernization projects that were discussed in ENO’s Revised Application and testimony are expected to improve reliability by

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<sup>290</sup> Ex. No. ENO-6 at 34:13-35:5.

<sup>291</sup> *Id.*

reducing the number of customer interruptions by more than 53,000 per year and lowering the number of customer minutes of experienced interruptions by approximately 7.2 million per year.<sup>292</sup> The costs for these projects are estimated at \$59.3 million<sup>293</sup> through January 31, 2022, of this amount \$12.8 million is funded through ratepayer savings due to the effects of the TCJA.<sup>294</sup> Prudently-incurred costs related to the remaining \$46.5 million, would be appropriately recoverable through rates. Additionally, ENO proposes that the investment associated with the portions of the grid modernization projects expected to close to plant in service by December 31, 2019, be reflected in base rates adopted in this proceeding;<sup>295</sup> and

**WHEREAS**, with regard to portions of the above projects closing after December 31, 2019, and any future grid modernization projects, ENO is proposing that the Council, in this proceeding, approve Rider DGM as the cost recovery mechanism. As proposed, Rider DGM would consist of a charge based on a percentage of base rates that is incremental to base rates and would recover depreciation and return on grid modernization investments made in the applicable year. The rider would be updated on a quarterly basis to include any new investments made in the preceding three months for the grid modernization projects described above, or for future grid modernization projects;<sup>296</sup> and

**WHEREAS**, AAE and CCPUG oppose the proposed DGM rider. According to AAE, ENO did not provide any justification for this choice of rate structure.<sup>297</sup> Further, AAE asserts that the DGM rider “effectively increases the fixed customer charge, and therefore reduces consumer incentives for energy conservation.”<sup>298</sup> AAE also argues that ENO’s grid modernization

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<sup>292</sup> Ex. No. ENO-8 at 24:5-7.

<sup>293</sup> Ex. No. AAE-3 at 35:7-8.

<sup>294</sup> Tax Cuts and Jobs Act of 2017, Pub. L. 115-97, 131 Stat. 2054, December 22, 2017.

<sup>295</sup> Ex. No. ENO-41 at 54:1-2.

<sup>296</sup> Ex. No. AAE-3 at 35.

<sup>297</sup> Ex. No. AAE-3 at 36:4-13.

<sup>298</sup> *Id.*

investments are investments in the shared distribution system and do not encompass any customer-related functions or involve costs that otherwise vary directly with the number of customers on the system or connecting a customer to the system.<sup>299</sup> Thus, AAE states that the charge is unreasonable both from a perspective of public policy in support of energy efficiency, and from the perspective of cost causation,<sup>300</sup> and

**WHEREAS**, AAE's also contends that the charges to be recovered in Rider DGM should be aligned with how the Company charges for distribution service more generally, i.e., recovery through base rates. Noting that the current five projects target reliability improvements rather than demand growth, the charge associated with these investments should also be volumetric for non-residential customers,<sup>301</sup> and

**WHEREAS**, CCPUG argues that “[i]f the EFRP and GFRP are adopted, they likely will result in annual rate increases starting in 2020. If the DGM Rider and/or GIRP Rider are adopted, they will result in quarterly rate increases starting in 2020. These rider increases will be above and beyond any rate increases resulting from the electric and gas FRPs or any future base rate proceeding unless and until these riders are terminated”;<sup>302</sup> and

**WHEREAS**, the Advisors contend that the proposed DGM Rider would allow ENO quarterly rate adjustments to recover expected costs related to grid modernization investments and provides for an annual true-up of rider collections versus actual revenue requirements. As such, the DGM Rider constitutes guaranteed exact cost recovery of certain distribution investments that ENO has classified as grid modernization.<sup>303</sup> Moreover, the Advisor emphasize that these costs

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<sup>299</sup> *Id.*

<sup>300</sup> *Id.*

<sup>301</sup> *Id.* at 36-37.

<sup>302</sup> Ex. No. CCPUG-1 at 4:15-19.

<sup>303</sup> Ex. No. ADV-7 at 88:9-11 (HSPM).

are predictable and within ENO’s control, thus lacking the cost attributes (unpredictable and volatile) that generally require recovery through a Rider,<sup>304</sup> and

**WHEREAS**, the Council agrees with the Intervenors and the Advisors that ENO’s DGM Rider is unnecessary. As the Advisors correctly note that the DGM Rider constitutes inappropriate single-issue ratemaking because it sets a separate rate recovery mechanism for ENO’s incremental distribution investments.<sup>305</sup> Further, the DGM rider is not necessary to allow ENO the opportunity to recover its prudently-incurred costs, as other ratemaking mechanisms, i.e., base rates and FRP, are available to allow ENO recovery of its grid modernization-related costs;<sup>306</sup> and

### **ALGIERS RESIDENTIAL MITIGATION PLAN**

**WHEREAS**, the Advisors note that one goal of the Council to be implemented in this rate proceeding is to address the disparity between the revenues provided by the present rate tariffs for Algiers residential customers and Legacy ENO residential customers.<sup>307</sup> According to ENO’s Revised Application, the typical Algiers residential monthly bill (1,000 kWh/mo.) is \$104.28 as opposed to \$122.11 for customers on the East Bank.<sup>308</sup> The Council, in Resolution No. R-17-504, directed ENO to present one combined cost of service study and one combined set of rate schedules for the Legacy ENO and Algiers customers, “*unless significant rate shock could occur to single or multiple classes of customer[s]*;<sup>309</sup> and

**WHEREAS**, under the Company’s proposed combined residential rate without any rate mitigation, according to ENO’s Revised Application a typical residential Algiers monthly bill

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<sup>304</sup> *Id.* at 89:6-7 (HSPM).

<sup>305</sup> *Id.* at 86:20-21 (HSPM).

<sup>306</sup> *Id.* at 89:15-17 (HSPM).

<sup>307</sup> Advisors Initial Brief at 54.

<sup>308</sup> Ex. No. ENO-55, Statement A-5; Advisors’ Initial Brief at 54.

<sup>309</sup> Ex. No. ENO-55 at 27, quoting Resolution No. R-17-504.



would see a \$16.16 increase or 15.50%,<sup>310</sup> which the Advisors consider a wholly unacceptable impact.<sup>311</sup> In order to reduce the rate shock for Algiers residential customers that would otherwise result from a strict adherence to ENO's proposed residential revenue requirement and a combined residential rate, ENO proposed to phase-in the revenue increase to Algiers residential customers so that an Algiers residential customer's typical bill increases no more than 3.5% per year,<sup>312</sup> and

**WHEREAS**, as proposed by ENO, the first step of the phase-in will be implemented as a part of the rates ultimately approved by the Council in this case and Algiers bills would increase by 3.5%, or approximately \$3.65 on a typical residential bill.<sup>313</sup> The second step of the phase-in would be in September 2021, at the same time as the annual revenue adjustments that would be authorized under its proposed FRP.<sup>314</sup> ENO notes that the second step in 2021 foregoes an additional ARRT-related increase for Algiers customers in 2020, when the NOPS is tentatively scheduled to be included in ENO's rates.<sup>315</sup> As proposed, Algiers residential bills will increase in 2021 by another 3.5%, or \$3.76 on a typical residential monthly bill, moving them closer to parity with other Legacy ENO residential customers;<sup>316</sup> and

**WHEREAS**, in order to implement the ARRT plan proposed by ENO, the costs that Algiers residential customers would otherwise pay under the combined rate are paid for by four other participating rate classes - Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes, classes that would otherwise receive an overall bill reduction of 10% or more as a result of the proposed rates.<sup>317</sup> These industrial rate classes would see an

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<sup>310</sup> Ex. No. ENO-2 at 14:14-18.

<sup>311</sup> Ex. No. ENO-45, at Exhibit MLT-3; Advisors' Initial Brief at 54.

<sup>312</sup> Ex. No. ENO-45 at 30:8-17.

<sup>313</sup> *Id.* at 30:8-11, Exhibit MLT-3; ENO Initial Brief at 88.

<sup>314</sup> ENO-45 at 30:21-31:1.

<sup>315</sup> Ex. No. ENO-55 at 28.

<sup>316</sup> Ex. No. ENO-45 at 30:13-17, Exhibit MLT-3; ENO Initial Brief at 88.

<sup>317</sup> ENO Initial Brief at 88-89.

offsetting rate reduction in September 2021 when the second step increase is implemented for Algiers residential customers;<sup>318</sup> and

**WHEREAS**, ENO proposes a Base Rate Adjustment Rider to implement the ARRT plan. The rider contemplates two step changes in the rates of the Algiers residential customer and other four participating classes;<sup>319</sup> and

**WHEREAS**, Air Products, BSI and AAE do not address ENO's proposed ARRT plan; and

**WHEREAS**, CCPUG does not oppose ENO's ARRT Plan but argues that it should be modified such that the first \$3.325 million of any reduction in ENO's proposed base rate revenue requirement increase are designated for the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes that would bear the funding for ENO's ARRT proposal;<sup>320</sup> and

**WHEREAS**, the Advisors propose a residential combined rate adjustment for Algiers, which would be a revenue adjustment between Legacy ENO residential customers and Algiers residential customers and would be applied with each prospective annual rate action until parity was reached.<sup>321</sup> Instead of ENO's proposed 3.5% increase to Algiers residential customers, the Advisors propose that Algiers' residential customers would have no initial revenue change in the instant docket.<sup>322</sup> The Advisors propose that subsequent to the instant proceeding and under a combined residential rate, the adjustment could increase Algiers residential revenue 4%, with a corresponding adjustment to Legacy ENO customers such that the combined adjustment would reflect the revenue change for the total residential class.<sup>323</sup> If the total residential revenue increase

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<sup>318</sup> ENO Initial Brief at 88.

<sup>319</sup> Ex. No. ENO-45 at 31:14-20.

<sup>320</sup> CCPUG Initial Brief at 19.

<sup>321</sup> Advisors Initial Brief at 57.

<sup>322</sup> *Id.*

<sup>323</sup> *Id.*

was less than 4%, Algiers residential revenue would be increased 4% in subsequent rate actions and the increase to Legacy ENO residential would be moderated accordingly to reflect the total residential class increase. If a prospective ENO-wide residential revenue increase was greater than 4%, all residential customers, including Algiers, would receive the revenue change exceeding 4%,<sup>324</sup> and

**WHEREAS**, the Advisors explain that their Algiers proposal could be implemented in the context of a Rider applicable to the combined residential base rate tariff and would extend to future rate actions as necessary;<sup>325</sup> and

**WHEREAS**, the Advisors note that the CCPUG proposal would, in effect, transfer the funding of Algiers mitigation to all other customers except those four large industrial customer classes.<sup>326</sup> CCPUG argues, however, that it would simply eliminate the subsidy;<sup>327</sup> and

**WHEREAS**, ENO proposes to achieve the Algiers mitigation through implementation of a rider, while the Advisors propose a base rate tariff alternative.<sup>328</sup> ENO opposes implementing Algiers residential customer mitigation through changes to the existing residential base rate tariff arguing that it would add significant unnecessary complexity to the tariff design and billing of residential customers with the potential for unnecessary customer confusion.<sup>329</sup> ENO also opposes the alternative of making future AART rate changes in the context of the FRP, arguing that implementing the change through the larger context of the FRP dilutes the extent to which the annual adjustments address the disparity between residential customers and does not assure that the disparity will be eliminated in a reasonable time frame;<sup>330</sup> and

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<sup>324</sup> *Id.*

<sup>325</sup> *Id.* at 58.

<sup>326</sup> *Id.* at 56.

<sup>327</sup> CCPUG Reply Brief at 28.

<sup>328</sup> ENO Initial Brief at 91.

<sup>329</sup> *Id.*

<sup>330</sup> *Id.* at 92.

**WHEREAS**, ENO also opposes CCPUG’s proposal that the first \$3.325 million of any Council-approved revenue adjustment to ENO’s requested revenue requirements be used to eliminate ENO’s proposed Base Rate Adjustment Rider changes to large customers.<sup>331</sup> ENO argues that this proposal improperly intermingles the establishment of the overall revenue requirement with the class allocation of that revenue requirement;<sup>332</sup> and

**WHEREAS**, the Council agrees with ENO and the Advisors that under the new combined residential rate, it is necessary to mitigate the revenue related to Algiers residential customers. The Council agrees with the Advisors that since the majority of customers will receive a general rate reduction from the instant proceedings, the Algiers mitigation plan should have no change for Algiers residential revenue; and

**WHEREAS**, all parties appear to support rate mitigation for Algiers residential customers. The most significant difference between ENO’s mitigation proposal and the Advisors’ mitigation proposal is that ENO’s approach would reallocate revenues from the Algiers residential class to the classes that would otherwise receive the largest rate decreases of any of the customer classes, while the Advisors’ approach would reallocate revenues from the Algiers residential customers to the Legacy ENO residential customers which would reduce the amount of rate decrease they would otherwise receive in the instant docket under the combined rate; and

**WHEREAS**, while the Council appreciates that general ratemaking principles would suggest keeping all residential costs and revenues within the residential class, in light of the specific facts of this case, the Council finds that it serves the public interest better to reallocate the revenues to the classes that would otherwise receive the largest rate decrease. The Council finds that the Algiers mitigation will be funded from the Large Electric, Large Electric High Load

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<sup>331</sup> *Id.* at 93; ENO Reply Brief at 54.

<sup>332</sup> *Id.*; ENO Reply Brief at 54.

Factor, High Voltage, and Large Interruptible rate classes in proportion to their base rate revenue requirements; and

**WHEREAS**, the other primary difference between ENO's proposal and the Advisors' proposal is the timing and size of the increases to Algiers' rates. The Council finds that, consistent with the Advisors' recommendations, there will be no revenue change for Algiers residential customers in the initial rates set in this proceeding. Starting in 2021 with rates effective with that year's FRP evaluation, Algiers residential revenue will increase by a minimum of 4%, or equal to the residential class revenue increase when greater than 4%, until parity is achieved with the remainder of the residential rate class; and

**WHEREAS**, the Council agrees with the Advisors that the adjustment should be tied to the E-FRP. The Council finds that significant rate increases related to the E-FRP, if added to a 4% rate increase due to the Algiers residential mitigation plan could result in an unreasonable rate increase in a particular year; and

**WHEREAS**, the Council finds that subsequent to the final order designating the residential class revenue requirement, ENO should develop the combined residential rate tariff that provides the designated revenue impact to Legacy ENO residential as well as the revenue mitigation required to maintain Algiers residential revenue at present levels without an increase. The Council also finds that a specific rider tariff should be used to identify the amount of Algiers residential mitigation revenue required from each of the identified four rate classes based on the fixed cost portion of their customer class revenue requirements as designated in the final Order of this proceeding; and

## **ADJUSTMENTS TO FUEL ADJUSTMENT CLAUSE (“FAC”) RIDER**

**WHEREAS**, ENO proposes several changes to its FAC Rider. The first is to combine the separate FAC riders for Legacy ENO customers and Algiers customers into a single FAC Rider for all customers.<sup>333</sup> ENO also proposes: (1) to modify the recovery of the Resource Plan PPA capacity expenses to include recovery of the difference between estimated monthly capacity expenses and that amount recovered through base rates and, and the actual monthly capacity expenses; (2) elimination of the recovery of LTSA expenses, which ENO proposes to recover through base rates and the PPCACR Rider; (3) elimination of the Grand Gulf repricing mechanism for Algiers Customers, (4) elimination of the allocation to Legacy ENO customers of Union Power Block #1 fuel costs and wholesale revenues so that all customers are allocated these expenses and benefit from these revenues; (5) combination of the two over/under balances into a single over/under balance; and (6) use of per book rider revenue instead of calculated FAC collections;<sup>334</sup> and

**WHEREAS**, the Advisors state that the proposed combined FAC Rider is significantly simpler than the rider it is intended to replace and produces a single FAC Rider rate for both Legacy ENO Customers and Algiers Customers by eliminating the Geographic-Specific adjustments.<sup>335</sup> The Advisors believe this represents a significant improvement with respect to ease of calculation and understanding.<sup>336</sup> The Advisors did, however, note some errors in the formulas and references and also an inconsistency in the formulas in ENO’s Exhibit No. SMC-2 for the treatment of certain

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<sup>333</sup> Ex. No. ENO-55 at 30.

<sup>334</sup> *Id.* at 31; *see also*, Ex. No. ENO-44 at 5:1-6:12.

<sup>335</sup> Advisors’ Initial Brief at 95, citing Ex. No. ADV-1 at 23:7-9.

<sup>336</sup> *Id.*, citing Ex. No. ADV-1 at 23:9-10.

costs as compared to historical treatment and the treatment proposed in ENO's proposed PPCACR Rider for similar costs;<sup>337</sup> and

**WHEREAS**, ENO submitted no testimony in response to the errors noted by the Advisors, rather, ENO stated that there are no substantive disputes regarding the FAC Rider Schedule.<sup>338</sup> ENO stated that the only outstanding issue concerns which over and under collections, if any, should be included in the rider, which is dependent on the final resolution of allocation issues.<sup>339</sup> ENO proposes that this component of the rider be addressed in the compliance filing process.<sup>340</sup> The Advisors support this suggestion, and therefore recommend that the Council approve the proposed FAC Rider Schedule, as corrected by the Advisors;<sup>341</sup> and

**WHEREAS**, ENO supports the Advisors' corrections to the FAC Rider;<sup>342</sup> and

**WHEREAS**, in light of the agreement of ENO and the Advisors as to the corrections and the lack of opposition from any other party, the Council approves the proposed FAC Rider as corrected by the Advisors; and

### **PURCHASED GAS ADJUSTMENT RIDER**

**WHEREAS**, ENO proposes to use per book PGA Rider revenue instead of calculated PGA Rider collections in order to ensure a more accurate calculation by reflecting customer billing corrections recorded in the operations month;<sup>343</sup> and

**WHEREAS**, the Advisors note that the proposed combined PGA Rider is similar to the rider it is intended to replace.<sup>344</sup> The Advisors explain that ENO has proposed modifications from

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<sup>337</sup> Advisors' Initial Brief at 95, citing Ex. No. ADV-1 at 23:11-27:8.

<sup>338</sup> Ex. No. ENO-3 at 6:5-7; *see also*, ENO Post-Hearing Brief at 178.

<sup>339</sup> Ex. No. ENO-3 at 6:7-9; *see also*, ENO Post-Hearing Brief at 178-179.

<sup>340</sup> Ex. No. ENO-3 at 6:9-10.

<sup>341</sup> Advisors' Initial Brief at 96.

<sup>342</sup> ENO Reply Brief at 118-119.

<sup>343</sup> Advisors' Initial Brief at 96, citing Ex. No. ENO-55 at 31.

<sup>344</sup> *Id.*, citing Ex. No. ADV-1 at 28:1.

the previous rider to revise the formulas for calculating the over/under balance to utilize per book PGA Rider revenue.<sup>345</sup> A similar treatment is included in ENO's proposed FAC Rider, and the change in the source data for the calculation will not make a material difference in the rate charged under the FAC Rider or PGA Rider.<sup>346</sup> The Advisors did note some errors in the formulas of the proposed PGA Rider and recommend the Council approve the Rider as corrected for these errors;<sup>347</sup> and

**WHEREAS**, ENO recommends that the Council approve the proposed PGA Rider subject to the correction of the errors identified in Advisors' Exhibit No. JWR-5;<sup>348</sup> and

**WHEREAS**, in light of the agreement of ENO and the Advisors as to the corrections and the lack of opposition from any other party, the Council approves the proposed PGA Rider as corrected by the Advisors; and

### **PPCACR**

**WHEREAS**, ENO explains that, effective with new base rates from this proceeding, it will no longer recover the UPS and Ninemile 6 PPA costs exclusively through the Rider PPCACR.<sup>349</sup> ENO proposes to transfer current Rider PPCACR costs relating to the UPS acquisition and the Ninemile 6 PPA into base rates in this proceeding, and then reset the PPCACR Rider at zero.<sup>350</sup> On a going-forward basis, ENO then proposes to include three types of recoverable costs in revised Rider PPCACR: (1) the incremental difference between the estimated, approved PPA and LTSA costs in the new base rates and the actual PPA and LTSA costs incurred on a monthly basis; (2) costs related to newly constructed and/or acquired capacity; and (3) costs related to new PPAs the

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<sup>345</sup> *Id.*, citing Ex. No. ADV-1 at 28:1-3.

<sup>346</sup> *Id.*, citing Ex. No. ADV-1 at 5-7.

<sup>347</sup> *Id.*, citing Ex. No. ADV-1 at 28:8-29:6.

<sup>348</sup> ENO Post-Hearing Brief at 179; *see also* ENO Reply Brief at 119.

<sup>349</sup> Advisors' Initial Brief at 96.

<sup>350</sup> *Id.* at 96-97.



Company may enter into as approved by the Council.<sup>351</sup> ENO proposes to allocate the Rider PPCACR revenue requirement to the rate classes using the base rate revenue requirement allocation methodology approved by the Council in this proceeding.<sup>352</sup> Similar to the current PPCACR Rider, ENO proposes a cumulative over/under calculation that compares the cumulative over/under balance and the applicable monthly costs to the PPCACR Rider Revenue for that operations month.<sup>353</sup> Any prior period adjustments will be added or subtracted and an interest component will be applied based on the average of the beginning of the month and end of the month cumulative over/under balance for the operations month using that month's prime interest rate,<sup>354</sup> and

**WHEREAS**, Air Products supports the PPCACR Rider to allocate cost recovery as an equal percent of base rate revenue as reasonable in the absence of the utility to use a more specific cost-based allocation,<sup>355</sup> and

**WHEREAS**, CCPUG argues that it is inappropriate to allow ENO to include any and all revenue requirements for newly constructed or acquired capacity or the expenses related to new PPAs and new LTSAs ENO may enter into through a PPCACR Rider.<sup>356</sup> CCPUG argues that doing so would inappropriately allow ENO to include these costs without review or further action by the Council other than the initial estimated revenue requirement for newly constructed or acquired capacity.<sup>357</sup> CCPUG recommends that the proposed tariff be modified so that no revenue requirement for newly constructed to acquired capacity or no expenses for new PPAs or LTSAs may be included without action by the Council and without an opportunity for the Council to

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<sup>351</sup> *Id.* at 97.

<sup>352</sup> *Id.*

<sup>353</sup> *Id.*

<sup>354</sup> *Id.*

<sup>355</sup> Ex. No. AP-3 at 19:3-5.

<sup>356</sup> Ex. No. CCPUG-1 at 53:8-11.

<sup>357</sup> *Id.* at 53:11-14.

review the reasonableness of the transactions and agreements as well as setting forth a process to allow intervenors to review the transactions and agreements as well as the revenue requirements and expenses that will be included in the rider,<sup>358</sup> and

**WHEREAS**, the Advisors argue that while a rider to permit contemporaneous recovery of PPA and LTSA costs may be appropriate, the scope of the rider should not be so broad as to encompass any as-yet unknown non-fuel revenue requirements related to construction and/or acquisition of new capacity, new PPA, or new LTSA.<sup>359</sup> Proposed PPCACR Rider is not necessary to allow ENO a reasonable opportunity to recover its prudently incurred costs related to future ENO-owned capacity additions, because mechanisms exist to allow ENO the opportunity to recover such costs.<sup>360</sup> Such non-fuel costs for new acquisitions, once known and measurable, are more appropriately addressed in a general rate proceeding where all of ENO's cost categories and magnitude of costs are considered in total.<sup>361</sup> The PPCACR Rider would set a separate rate for incremental ENO-owned capacity additions and ensure ENO exact cost recovery, which constitutes inappropriate single-issue ratemaking;<sup>362</sup> and

**WHEREAS**, the Advisors argue that because the timing of any new construction and/or acquisition of new capacity, new PPA, or new LTSA is currently unknown as are the magnitude of any costs associated with the unknown future capacity additions, consideration in this instant base rate proceeding is not appropriate.<sup>363</sup> Additionally, the proposed PPCACR Rider allocates costs to rate classes using a Base Rate Revenue Requirement allocation factor, but since the costs proposed for recovery in this rider are non-fuel costs associated with production plant, a Production

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<sup>358</sup> *Id.* at 54:5-11.

<sup>359</sup> Advisors' Initial Brief at 98, citing Ex. No. ADV-1 at 32:3-6.

<sup>360</sup> *Id.*, citing Ex. No. ADV-6 at 86:9-11.

<sup>361</sup> *Id.*, citing Ex. No. ADV-1 at 32:6-10.

<sup>362</sup> *Id.*, citing Ex. No. ADV-6 at 17-7:2.

<sup>363</sup> *Id.* at 98-99, citing Ex. No. ADV-1 at 32:10-13.

Demand Allocation Factor would be more appropriate and consistent with how the costs would be anticipated to be allocated in a base rate proceeding;<sup>364</sup> and

**WHEREAS**, the Code of the City of New Orleans, Sec. 158-732(c) requires ENO to seek Council approval for taking an interest in a transmission or generation facility or for entering into a PPA whose costs generally exceed 2% of the rate making value of ENO's property.<sup>365</sup> ENO can reasonably request that the Council approve cost recovery relief as part of any such application; therefore, there is no need at this time for the Council to approve such currently unknown costs to be recovered through the proposed PPCACR Rider.<sup>366</sup> To that end, the Advisors recommend that (1) costs for non-fuel revenue requirements related to construction and acquisition of new capacity, fixed costs associated with new PPAs, and costs associated with new LTSAs not be provided automatic recovery in the proposed PPCACR Rider, and that the name of the rider be changed to the Purchase Power Cost Recovery Rider ("PPCR"); (2) that the new PPCR Rider collect the difference (positive or negative) between the estimated PPA capacity and LTSA expenses in the new base rates from this proceeding (Schedule A costs) and the actual PPA capacity and LTSA expenses incurred by ENO on a monthly basis; (3) costs recoverable in the PPCR Rider be limited to costs associated with ENO's existing PPAs and long term service agreements including: Grand Gulf UPSA, EAL Resource PPA, Riverbend PPA, Ninemile 6 PPA, Algiers Slice of System PPA, and LTSA Costs associated with the following facilities: UPS, Ninemile 6, Perryville 1 (Algiers SOS PPA), and Acadia (Algiers SOS PPA); (4) the Schedule A costs identified in the new PPCR be those costs identified in the HSPM Exhibit OT-2, broken down by month; (5) the new PPCR Rider allocate costs to rate classes using the Production Demand Allocation Factor determined in

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<sup>364</sup> *Id.* at 99, Ex. No. ADV-1 at 32:13-18.

<sup>365</sup> *Id.*, Ex. No. ADV-8 at 3-6.

<sup>366</sup> *Id.*, Ex. No. ADV-2 at 6-9.

this proceeding; and (6) the Council implement a new PPCR Rider that is based on the redline of ENO's proposed PPCACR Rider provided as Exhibit No. JWR-6 attached to Exhibit No. ADV-1;<sup>367</sup> and

**WHEREAS**, CCPUG objects that the proposed PPCACR Rider would inappropriately allow near automatic recovery of new capacity costs and costs of newly-constructed generating assets without full certification review by the Council.<sup>368</sup> CCPUG also argues that the PPCACR is also unnecessary as any new investment costs it would recover may be recovered through ENO's proposed E-FRP;<sup>369</sup> and

**WHEREAS**, CCPUG states it is not opposed to the Advisors' recommendations for the (to-be-renamed) Purchased Power Cost Recovery Rider ("PPCR");<sup>370</sup> and

**WHEREAS**, the Council agrees with the concerns stated by the Advisors and CCPUG; and

**WHEREAS**, the Council directs ENO to revise its proposed PPCACR Rider in accordance with the Advisors' recommendations for a PPCR Rider; and

### **MISO COST RECOVERY RIDER**

**WHEREAS**, consistent with the combination of Legacy ENO and Algiers customers, ENO proposes a combined MISO Cost Recovery Rider that for the most part mimics the current separate MISO Riders, though certain now inapplicable costs have been eliminated from the formula.<sup>371</sup> The combined MISO Cost Recovery Rider would be re-determined annually and subject to annual true-ups beginning in 2020.<sup>372</sup> ENO also proposed to use this combined rider in

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<sup>367</sup> *Id.* at 99-100, citing Ex. No. ADV-1 at 33:14-34:16.

<sup>368</sup> CCPUG Reply Brief at 30.

<sup>369</sup> *Id.*

<sup>370</sup> *Id.* at 31.

<sup>371</sup> Advisors' Initial Brief at 100, citing Ex. No. ENO-55 at 31; Ex. No. ENO-41 at 40:12-15.

<sup>372</sup> *Id.*, citing Ex. No. ENO-55 at 31; Ex. No. ENO-41 at 40:15-18.

the 2019 MISO Rider filing in order to facilitate the transition from the two current riders and two sets of rates to the combined rates expected to become effective in August 2019.<sup>373</sup> The general purpose of the MISO Cost Recovery Rider is to define the procedure by which ENO shall implement and adjust rates contained in the designated rate classes for recovery of the costs, including, but not limited to, costs charged to ENO pursuant to the FERC-approved MISO Open Access Transmission Energy and Operating Markets Tariffs that are not recovered via the FAC.<sup>374</sup> The Combined MISO Rider revenue requirement would reflect the following costs and revenues: (1) estimated Net MISO Charges or Credits (*i.e.*, MISO charges and credits for which recovery has not been requested separately through the FAC), and (2) a true up of actual revenues to actual costs, including carrying charges;<sup>375</sup> and

**WHEREAS**, the Advisors have reviewed the proposed rider and supporting testimony and did not find any reference errors or calculation errors.<sup>376</sup> The Advisors' analysis indicates that the proposed rider is consistent with the directions given to ENO by the Council in Resolution No. R-17-504 to develop a single set of proposed tariffs applicable to all customers, that its cost allocation is appropriate and that the cost categories and adjustment calculations that ENO removed are no longer necessary.<sup>377</sup> Therefore, the Advisors recommend that the Council approve the MISO Cost Recovery Rider as proposed by ENO;<sup>378</sup> and

**WHEREAS**, the Council approves the combined MISO Cost Recovery Rider as proposed by ENO; and

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<sup>373</sup> *Id.*, citing Ex. No. ENO-55 at 31-32.

<sup>374</sup> *Id.* at 101, citing Ex. No. ADV-1 at 29:10-15.

<sup>375</sup> *Id.*, citing Ex. No. ENO-41 at 40:23-41:3.

<sup>376</sup> *Id.*, citing Ex. No. ADV-1 at 29:18-19 and 30:13-14.

<sup>377</sup> *Id.*, citing Ex. No. ADV-1 at 3-13.

<sup>378</sup> *Id.*

## **ELECTRIC RESIDENTIAL CUSTOMER CHARGE**

**WHEREAS**, ENO’s proposes to increase the electric residential customer charge from the current \$8.07 to a proposed \$15.53 customer charge.<sup>379</sup> According to ENO, its cost of service study showed customer-related costs of service per residential customer to be \$21.07 a month.<sup>380</sup> ENO witness Talkington stated that customer-related costs that do not vary with monthly changes in a customer’s demand or energy usage should be recovered through a fixed monthly customer charge.<sup>381</sup> ENO witness Thomas added that higher fixed charges relative to volumetric rate structures provide more stability to ENO’s revenues;<sup>382</sup> and

**WHEREAS**, AAE urges the Council to reject ENO’s proposal to nearly double the level of the current residential customer charge and assert that a \$15.53 customer charge is “extreme” and fails to reflect the true nature of gradualism in utility ratemaking, as evidenced by national trends in residential fixed charges;<sup>383</sup> and

**WHEREAS**, Mr. Barnes asserted that ENO’s calculated customer unit cost is inflated by including numerous costs that bear little or no relationship with costs (i) associated with connecting a customer to the grid, or (ii) which vary directly with the number of customers being served.<sup>384</sup> Barnes also charged that a higher customer charge would lower the volumetric kWh rate, thus diluting customer incentives to use less energy;<sup>385</sup> and

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<sup>379</sup> Ex. No. ENO-45 at 26.

<sup>380</sup> *Id.*

<sup>381</sup> *Id.* at 23.

<sup>382</sup> Ex. No. ENO-2 at 62.

<sup>383</sup> Initial Brief of the Alliance for Affordable Energy and Sierra Club at 20, July 26, 2019 (“AAE/Sierra Club Initial Brief”).

<sup>384</sup> *Id.*

<sup>385</sup> *Id.* 15-19.

**WHEREAS**, AAE recommended a customer charge of \$8.13/month, “in order to properly reflect cost causation, avoid significant adverse impacts on customers with lower incomes, and support the Council’s policies on energy efficiency;”<sup>386</sup> and

**WHEREAS**, the Advisors’ recommended a \$10 per month electric customer charge, which is a relatively small increase that recognizes that costs have increased since the 2008 rate case but also minimizes the impact on low-use customers.<sup>387</sup> The Advisors expressed serious concern that ENO’s proposed \$15.21 electric customer charge is almost a 100% increase above the existing customer charge, and that large change would have a substantial adverse impact on low-use customers.<sup>388</sup> Advisors’ witness Prep recommended a small increase in the residential customer charge to moderate the bill impact on customers with lower or minimal usage.<sup>389</sup> Mr. Prep further testified that the remainder of that portion of the residential cost of service would be recovered through kWh usage;<sup>390</sup> and

**WHEREAS**, the Council shares the concerns expressed by AAE and the Advisors regarding the impact of ENO’s proposed customer charge on low income and low use customers; and

**WHEREAS**, the Council also finds that ENO’s proposal, which is an almost 100% increase above the existing customer charge, fails to reflect the concept of gradualism in ratemaking and is therefore, excessive; and

**WHEREAS**, the Council accepts AAE’s argument that an increase to the residential customer charge would reduce customers’ incentives to use less energy. Such a result would be

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<sup>386</sup> AAE/Sierra Club Initial Brief at 31.

<sup>387</sup> Ex. No. ADV-3 at 60.

<sup>388</sup> Advisors’ Initial Brief at 62.

<sup>389</sup> Ex. No. ADV-3 at 60.

<sup>390</sup> *Id.*

inconsistent with the Council's long-standing policy of supporting and increasing energy efficiency in New Orleans; and

**WHEREAS**, the Council finds that not altering the Company's current \$8.07 customer charge is consistent with addressing AAE's and the Advisors' concern regarding the potential for significant adverse impacts on low income customers and supportive of the Council's long-standing policy of supporting and increasing energy efficiency; and

**WHEREAS**, the Council rejects ENO's proposed customer charge of \$15.53 and finds that the Company's \$8.07 customer charge shall remain unchanged as a result of the evidence presented in this proceeding; and

#### **AMI CUSTOMER CHARGE**

**WHEREAS**, ENO proposes a customer charge for its costs in deploying and implementing ENO's Advanced Metering Initiative approved by the Council in Docket No. UD-16-04. Specifically, ENO proposes an electric AMI charge and a gas AMI charge to be collected through Rider AMICE and Rider AMICG, respectively;<sup>391</sup> and

**WHEREAS**, ENO contends that the number of customers ENO serves, in large part, drives the level of the costs associated with AMI. Therefore, these costs should be recovered through a customer charge (rather than base rates) so that a customer bears only the cost that the customer causes. The charges are intended to recover the net present value of the electric and gas AMI revenue requirements. Any differences in the revenue resulting from the customer charges and the actual costs of AMI would be reconciled through the proposed electric and gas FRPs. As proposed, the charges are intended to recover the net present value of the electric and gas AMI revenue

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<sup>391</sup> Revised Application at 37-38.



requirements. Any differences in the revenue resulting from the customer charges and the actual costs of AMI would be reconciled through the proposed electric and gas FRPs;<sup>392</sup> and

**WHEREAS**, both the gas and the electric AMI charges would change annually, beginning on January 1, 2020. The initial proposed monthly customer charges would be \$2.95 for electric customers and \$0.60 for gas customers. In January of 2020, the proposed monthly customer charges would be \$3.67 for electric customers and \$0.96 for gas customers;<sup>393</sup> and

**WHEREAS**, after 2020, the gas AMI charge would decline annually until 2029 when it terminates. Similarly, the electric AMI charge would decline annually until it terminates in 2035;<sup>394</sup> and

**WHEREAS**, AAE argues that ENO's proposed fixed monthly charge is unreasonable<sup>395</sup> because AMI is not "typical" metering.<sup>396</sup> AAE contends that "fixed customer charges should recover the cost of connecting a customer to the grid."<sup>397</sup> AAE argues that advanced metering and the associated incremental costs above traditional meters are not strictly necessary for the customer to be connected to the grid.<sup>398</sup> It also argues that a non-advanced meter and associated infrastructure can do so at lower costs, but AMI is used for much more than measurement of a customer's consumption for billing purposes;<sup>399</sup> and

**WHEREAS**, instead AAE recommends the Council adopt a volumetric rate design in order to support energy efficiency, protect the greater portion of lower income customers from disproportionate impacts, and distribute the costs and benefits of AMI more equitably;<sup>400</sup> and

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<sup>392</sup> *Id.* at 38.

<sup>393</sup> Ex. No. AAE-3 at 30, citing Ex. No. ENO-4, Exhibit JBT-9.

<sup>394</sup> Revised Application at 37-38.

<sup>395</sup> Ex. No. AAE-3 at 31-34.

<sup>396</sup> *Id.* at 31.

<sup>397</sup> AAE/Sierra Club Initial Brief at 42.

<sup>398</sup> *Id.*

<sup>399</sup> Ex. No. AAE-3 at 31.

<sup>400</sup> *Id.* at 34.

**WHEREAS**, AAE further notes that a volumetric AMI charge would cause lower usage customers to pay less towards AMI deployment, when those same customers act to reduce their energy consumption or peak period demands, higher usage customers still receive a greater portion of the benefits of the associated cost savings.<sup>401</sup> Therefore, according to AAE, while higher usage customers pay more under a volumetric design, they also receive more in return;<sup>402</sup> and

**WHEREAS**, the Advisors contend that ENO’s proposed per-customer charges in Rider AMICE and Rider AMICG are intended to allow ENO recover substantially all of its AMI-related costs through these riders rather than base rates.<sup>403</sup> The Advisors’ proposed allocation of AMI cost responsibility is based on the net benefits identified in AMI Docket No. UD-16-04 including “greater grid resiliency in the distribution network, improved outage and reliability performance, improved grid planning for modifications and improvements, DSM programs, time differentiated pricing, and specially designed customer options, among other system and customer benefits.”<sup>404</sup> The Advisors also assert that ENO’s proposed allocation of cost responsibility for AMI-related costs on a per-customer basis through a rider is inappropriate single-issue ratemaking.<sup>405</sup> Specifically, because the pace of AMI deployment is known, measurable, and reasonably within ENO’s control and related costs are similarly known and measurable, the use of a rider is unnecessary and singling-out AMI costs for recovery through riders constitutes inappropriate single-issue ratemaking.<sup>406</sup> Accordingly, the Advisors recommend the Council deny ENO’s request for Rider AMICE and Rider AMICG; and

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<sup>401</sup> *Id.*

<sup>402</sup> *Id.*

<sup>403</sup> Advisors’ Initial Brief at 94; *citing* Ex. No. ADV-6 at 83-84.

<sup>404</sup> Advisors’ Reply Brief at 20.

<sup>405</sup> Advisors’ Initial Brief at 94; *citing* Ex. No. ADV-6 at 83-84.

<sup>406</sup> *Id.*

**WHEREAS**, CCPUG argues against the Advisors’ recommended methodology for assigning responsibility among the rate classes for costs related to ENO’s AMI deployment. CCPUG favors ENO’s proposed per-customer methodology and labels the Advisors’ recommended benefits-based allocation methodology base rate “socialization.”<sup>407</sup> In contrast, the Advisors dispute that their recommendation is a form of cross-subsidization, asserting that it is based on a careful analysis of resulting net-benefits.<sup>408</sup> Moreover, the Advisors assert that the ENO/CCPUG proposal to recover AMI-related costs on a per-customer basis is flawed because ENO’s proposed allocation of AMI costs on the basis of numbers of customers weighs disproportionately on residential customers.<sup>409</sup> In addition, the ENO has long-asserted that AMI is intended to provide many functions and benefits beyond those of existing meters that serve the sole function of generating billing information.<sup>410</sup> Thus, the Advisors correctly note that a per-customer allocation of AMI-related costs would result in cross-subsidization benefiting large and industrial customers at the expense of residential and small commercial customers; and

**WHEREAS**, the Council agrees with the Advisors’ contention that the ENO/CCPUG proposal would result in cross-subsidization benefiting large and industrial customers at the expense of residential and small commercial customers and reject the ENO/CCPUG proposal to recover AMI-related costs on a per-customer basis because as ENO has argued since its initial proposal in Docket No. UD-16-04. AMI provides many functions and benefits beyond existing meters’ sole function to generate billing information.<sup>411</sup> As ENO has repeatedly made clear, the approximately \$80 million AMI capital investment is more than just new meters, as the benefits

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<sup>407</sup> CCPUG Initial Brief at 78.

<sup>408</sup> Ex. No. ADV-3 at 28:10-12.

<sup>409</sup> *Id.* at 28:10-19

<sup>410</sup> *Id.* at 28:13-16.

<sup>411</sup> Ex. No. AAE-5 at 31.

of AMI include greater resiliency in the distribution network, improved outage and reliability performance, improved grid planning for modifications and improvements, DSM programs, and time differentiated pricing. Moreover, as noted above, ENO agrees that the Advisors' proposed prospective treatment of known and measurable costs and attendant revenue change would mitigate the need for the proposed AMI Riders;<sup>412</sup> and

### **FORMULA RATE PLANS**

**WHEREAS**, ENO proposed electric and gas FRPs with an implementation date of 2020 and an initial term of three years that incorporates many features of the predecessor FRP approved by the Council in Resolution No. R-09-136, including the basic structure that evaluates whether the Company's rates fall within a bandwidth around the authorized ROE (midpoint) established by the Council, with annual evaluations that prospectively adjust rates to the midpoint;<sup>413</sup> and

**WHEREAS**, ENO also proposed several categories of FRP changes - for the E-FRP: (1) changes to the target Evaluation Period Cost of Equity ("EPCOE") to incorporate the proposed RIM Plan's adjusted ROE formula; (2) changes to accommodate the Energy Smart Program; (3) changes to implement the Decoupling Pilot Program (4) a new provision for an interim Rate Adjustment for NOPS non-fuel revenue requirement; (5) a new provision for changes in income tax rates; (6) a change to the "Extraordinary Cost Changes" provision related to the revenue trigger; and (7) a new provision for Rider PPCACR Transitional Items;<sup>414</sup> and for the gas FRP: (1) changing the filing date to April 30, with the initial rate adjustment to be effective for the first billing cycle in September; (2) the treatment of changes in the tax rate; and (3) increasing the

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<sup>412</sup> Ex. No. ENO-3 at 9:3-7; ENO Reply Brief at 48.

<sup>413</sup> Ex. No. ENO-55 at 20.

<sup>414</sup> Ex. No. ENO-41 at 29:11-21.

revenue requirement impact trigger to the Extraordinary Cost Changes section from \$750,000 in the previous FRP to \$1 million;<sup>415</sup> and

**WHEREAS**, both of ENO’s FRPs, which are based largely on the FRP’s previously approved by the Council, include, among others, the following features:

- Use of the previous calendar year as the Evaluation Period (*i.e.*, historic test year);
- Use of the authorized ROE set in this proceeding as the target Evaluation Period Cost of Equity (“EPCOE”);
- A deadband of plus or minus 50 basis points centered on the EPCOE, in which there would be no change in rates;
- A formula that adjusts the FRP revenue level for the Evaluation Period to prospectively earn the EPCOE, commonly referred to as “resetting to the midpoint,” if the Earned Rate of Return on Equity (“EROE”) is above or below the deadband;
- A seventy-five day review period;
- A specified dispute resolution procedure; and
- A three-year term;<sup>416</sup> and

**WHEREAS**, the use of an FRP mechanism and several aspects of ENO’s proposed FRP mechanism are undisputed by the parties. The Council finds that the undisputed elements of the FRP are reasonable and should be approved; and

**WHEREAS**, the following aspects of ENO’s proposed FRP mechanism are disputed by the parties: (1) whether total utility operating revenues and costs should be included in the FRP calculation; (2) whether forward-looking adjustments for known and measurable changes in the rate effective period should be included in the FRP calculation; (3) whether ENO’s proposed RIM should be included in the FRP; (4) whether ENO should update the inputs to the class cost of

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<sup>415</sup> Ex. No. ENO-55 at 21; Ex. No. ENO-41 at 48:15-22.

<sup>416</sup> Ex. No. ENO-41 at 28:14-29:7; Ex No. ENO-3 at 7:3-20.

service studies in the E-FRP decoupling adjustment and how rates are reset if ROE is outside the FRP bandwidth; and (5) whether and how costs related to NOPS should be included in the FRP mechanism; and

- (1) *Whether Total Utility Operating Revenues and Costs Should Be Included in the FRP Mechanism*

**WHEREAS**, the Advisors recommend that the Council should evaluate whether ENO is under-earning or overearning in the FRP by evaluating the total utility cost of service, including total ENO revenues and expenses, rather than limiting the FRP evaluation to base rate costs and revenues. That approach to evaluating total utility revenue requirements is consistent with the Advisors' approach establishing a fully allocated cost of service; and

**WHEREAS**, the Advisors concur with ENO's proposals to exclude Energy Smart costs, Lost Contributions to Fixed Costs ("LCFC"), and the utility incentive from the E-FRP mechanism,<sup>417</sup> and with ENO's proposed provisions regarding (i) the effect of any tax rate changes, (ii) increasing the revenue requirement trigger in the Extraordinary Cost Changes Section from \$2 million to \$6 million, and (iii) realigning future purchase power capacity recovered in the Advisors' proposed PPCR to the E-FRP;<sup>418</sup> and

**WHEREAS**, ENO opposes the inclusion of all revenues and expenses, including riders, in the Electric and Gas FRPs, similar to its approach in the Revised Application to use a cost of service limited to base rates. ENO argues that no evidence has been offered to show that any other regulator in the country requires utilities to include rider revenues and costs recovered through those riders when setting base rates.<sup>419</sup> ENO argues that the Advisors' proposed method would not change the level of ENO's base revenue requirement to be recovered in base rates, would not

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<sup>417</sup> Ex. No. ADV-3 at 76:3-4; Advisors' Initial Brief at 105.

<sup>418</sup> Ex. No. ADV-3 at 76:14-17; Advisors' Initial Brief at 105.

<sup>419</sup> ENO Initial Brief at 102.

give the Council a better understanding of ENO's financial performance, and could have the effect of shifting cost responsibility among the rate classes, although ENO's base revenue requirement from a total Company perspective would be unaffected;<sup>420</sup> and

**WHEREAS**, Air Products also opposes the Advisors' proposal to include total revenues and expenses in FRP evaluations, arguing that Riders should not be included because they have nothing to do with whether ENO is under-earning or over-earning.<sup>421</sup> Air Products believes a distortion is created: "...by including FAC revenues in the base revenue requirement used to adjust revenues after an FRP review has been conducted, then fuel revenues that recover cost that have made no contribution to the under- or over recovery will be part of the factor used to apportion any revenue changes, which will produce a distorted result;"<sup>422</sup> and

**WHEREAS**, the Advisors argue that to avoid single issue ratemaking, the total cost of service should be examined to adjust total revenues, not just to set base rates.<sup>423</sup> The Advisors argue that ENO's arguments are without merit, that base revenue requirement is only a portion of the total cost of service; the Council should evaluate ENO's financial performance and earned ROE based on its total cost of service; and a "shift" in cost responsibility is meaningless when the evaluation does not consider total costs. Moreover, the Advisors argue that decisions regarding cost recovery mechanisms, such as base rates and riders, follow the evaluation of the utility's total revenue requirement, therefore, no distortion is created.<sup>424</sup> Under the Advisors' proposal, allocations of fixed costs and variable costs and the cost responsibility supporting customer class

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<sup>420</sup> *Id.*

<sup>421</sup> Air Products' Initial Brief at 32.

<sup>422</sup> *Id.* at 26. (Emphasis added.)

<sup>423</sup> Advisors' Reply Brief at 32.

<sup>424</sup> *Id.* at 34.

revenue requirements are determined separately such that fuel costs and FAC revenues would not distort the fixed costs revenue requirement; and

**WHEREAS**, the Advisors argue that in an FRP filing, a comprehensive evaluation of the earned ROE compared to the Council-approved ROE requires that all costs and revenues be included.<sup>425</sup> The Advisors also argue that, contrary to the assertion of ENO that there would be double-counting of cost and revenues, as long as all costs and revenues are supported by the financial reports of the system accounts, and each program adjustment is supported with explanation and workpapers, double-counting of costs and revenues should be avoided.<sup>426</sup> In addition, the Advisors argue, Directive 6 of Resolution No. R-16-03 requires that all utility fixed costs should be included in the decoupling revenue adjustment, regardless of the revenue recovery mechanism used to recover any specific fixed (non-fuel) costs;<sup>427</sup> and

**WHEREAS**, the Council finds that in an FRP filing, a comprehensive evaluation of the earned ROE compared to the Council-approved ROE requires that all costs and revenues be included; and

(2) *Whether Forward-Looking Adjustments for Known and Measurable Changes Should be Included in the FRP Calculation*

**WHEREAS**, the Advisors also recommend an additional provision under FRP Attachment C, Evaluation Period Adjustments, paragraph 8. Other that would state: “ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP Evaluation Period;”<sup>428</sup> and

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<sup>425</sup> Ex. No. ADV-5 at 23:11-13; Advisors’ Initial Brief at 107; Advisors’ Reply Brief at 34.

<sup>426</sup> Ex. No. ADV-5 at 24:1-6; Advisors’ Initial Brief at 107; Advisors’ Reply Brief at 34.

<sup>427</sup> Ex. No. ADV-5 at 24:6-9; Advisors’ Initial Brief at 108; Advisors’ Reply Brief at 34.

<sup>428</sup> Ex. No. ADV-3 at 78:9-13; Advisors’ Initial Brief at 106; Advisors’ Reply Brief at 35.



**WHEREAS**, the Advisors also recommend that the FRP provision for an extraordinary cost change should be included as a proforma adjustment prospective to the FRP Evaluation Period pursuant to the Advisors’ proposed revision to Attachment C, Adjustments paragraph 8, if such occurs during the period.<sup>429</sup> Otherwise, the extraordinary costs may be considered for interim recovery, and included in the ROE bandwidth evaluation of the next FRP;<sup>430</sup> and

**WHEREAS**, ENO agreed with the Advisors’ position that incorporating forward-looking proforma adjustments to account for known and measurable costs (and attendant revenue changes) in the calendar year following the FRP evaluation period in a properly structured FRP would address ENO’s concerns regarding regulatory lag to a great degree.<sup>431</sup> ENO also agreed that the Advisors’ proposed prospective treatment of known and measurable costs and attendant revenue change would mitigate the need for the Electric and Gas AMI Charge Rider and the DGM Rider, although ENO witness Thomas argued for a provision to implement those riders in the event the FRP terminates after the initial three-year term;<sup>432</sup> and

**WHEREAS**, CCPUG opposes the Advisors’ proposal to include projected costs in the FRP, arguing that the inclusion of projected costs – which may or may not ever be incurred – undermines a utility’s incentive to operate effectively and economically.<sup>433</sup> CCPUG argues that allowing ENO to include a “wish list” of investments it may make in the coming year in its current rates is fraught with peril and ripe for abuse.<sup>434</sup>

**WHEREAS**, the Advisors argue that CCPUG ignores the requirement that projected costs be “known and measurable.”<sup>435</sup> The Advisors contemplate that in order to be known and

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<sup>429</sup> Ex. No. ADV-3 at 77:16-20; Advisors’ Initial Brief at 106; Advisors’ Reply Brief at 35.

<sup>430</sup> Ex. No. ADV-3 at 77:20-21; Advisors’ Initial Brief at 106; Advisors’ Reply Brief at 35.

<sup>431</sup> Ex. No. ENO-3 at 8:9-12; Ex. No. ENO-4 at 13:21-23; ENO Reply Brief at 48.

<sup>432</sup> Ex. No. ENO-3 at 9:3-7; ENO Reply Brief at 48.

<sup>433</sup> CCPUG Initial Brief at 69; CCPUG Reply Brief at 34.

<sup>434</sup> *Id.*

<sup>435</sup> Advisors’ Reply Brief at 35.

measurable,<sup>436</sup> such costs either (i) would have already been presented to and approved by the Council prior to inclusion in an open and transparent proceeding that allows for public participation, such as ENO’s projected AMI costs, or (ii) that such costs would be clearly supported in ENO’s detailed budgeting process.<sup>437</sup> The Advisors argue that their proposal is by no means a blank check for ENO to simply include projected costs it would like to incur for projects that have not been reviewed and approved by the Council in a proceeding that allows all interested parties to have input.<sup>438</sup> As such, the Advisors recommend that the Council review such out-of-period proforma adjustments to ensure they were indeed accomplished.<sup>439</sup> The Advisors explain that if ENO were shown to have abused this ratemaking treatment, the Council could then take appropriate action.<sup>440</sup> Thus, the Advisors argue, the concerns raised by CCPUG that ENO will be able to collect a return on a “wish list” of investments that are never made are unfounded.<sup>441</sup> The Advisors recognize that ENO is undertaking a significant level of investment in its system and that regulatory lag could be a sufficient obstacle and believe that this proposal will sufficiently mitigate the impact of regulatory lag, without the need for unnecessary riders, while still providing ENO an incentive to be efficient and allowing the Council oversight of ENO’s investments;<sup>442</sup> and

**WHEREAS**, ENO argues that CCPUG’s assertion that new measures are unnecessary because traditional FRPs provide near real-time recovery of costs actually incurred is supported only by a vague conclusory statement in testimony that traditional FRPs eliminate much of the regulatory lag without any analysis to clarify what this statement means.<sup>443</sup> By way of contrast,

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<sup>436</sup> “Known and measurable” is discussed in the following testimony in this docket: Ex. No. ENO-41 at 2; Ex. No. CCPUG-2 at 9; Ex. No. ADV-1 at 2; Ex. No. ADV-2 at 11; and Ex. No. ENO-40 at 18.

<sup>437</sup> Ex. No. ADV-6 at 66:4-6; Advisors’ Reply Brief at 35-36.

<sup>438</sup> Advisors’ Reply Brief at 36.

<sup>439</sup> *Id.*

<sup>440</sup> *Id.*

<sup>441</sup> *Id.*

<sup>442</sup> *Id.*

<sup>443</sup> ENO Reply Brief at 48.

ENO argues, its own witness provided an analysis showing the cash flow effects of recovering a large, long-term capital project with multiple plant closings throughout the year;<sup>444</sup> and

**WHEREAS**, CCPUG witness Kollen argues that if the Council approves an E-FRP and/or GFRP implementation date of 2020 based on a calendar year 2019 Evaluation Period, it should require ENO to exclude all proforma adjustments for 2019.<sup>445</sup> If such proforma adjustments are not excluded for 2019, then CCPUG objects to an E-FRP implementation date of 2020 and recommends that it be delayed until 2021;<sup>446</sup> and

**WHEREAS**, ENO disagrees with the suggestion of CCPUG witness Kollen that the proposed FRPs should not use calendar year 2019 as the first evaluation period. ENO argues that to use 2019 as the first evaluation period would be consistent both with prior Council practice and LPSC practice;<sup>447</sup> and

**WHEREAS**, the Council finds that an electric and gas FRP should be implemented for a three-year period with an appropriate ROE and a bandwidth of +/- 50 basis points, to begin with a May 2020 filing covering a calendar year 2019 test year; and

**WHEREAS**, the Council finds that ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP Evaluation Period, during which the FRP rate adjustment would be effective and that an extraordinary cost change should be included as a proforma adjustment prospective to the FRP Evaluation Period, or be considered for interim recovery and included in the ROE bandwidth evaluation of the next FRP; and

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<sup>444</sup> *Id.* at 48-49.

<sup>445</sup> Ex. No. CCPUG-1 at 45:12-14; 51:12-26; Ex. No. CCPUG-2 at 25:1-7.

<sup>446</sup> Ex. No. CPPUG-1 at 45:14-15.

<sup>447</sup> Ex. No. ENO-3 at 12:12-20, citing Resolution Nos. R-03-272 and R-09-136; ENO Reply Brief at 51-52.

(3) Whether ENO's Proposed RIM Should Be Included in the FRP

**WHEREAS**, ENO proposes a RIM within its electric FRP. ENO states that it is proposing its RIM Plan because it recognizes that its reliability performance has not met the expectations of ENO, its customers, and the Council.<sup>448</sup> ENO's intention is to align the earnings component of its base rates to its distribution reliability performance.<sup>449</sup> ENO proposes that its electric ROE (which ENO proposes to be 10.75%) would be reduced by 25 basis points (to 10.5%) then, if ENO's performance improves, as measured through ENO's Distribution System Average Interruption Frequency Index ("SAIFI"), it would return to the baseline ROE (10.5%) and thereafter ENO's SAIFI based on the Evaluation Period data would then translate into a number of positive or negative basis points (maximum of 25) to be added to the baseline ROE.<sup>450</sup> ENO states that its expected year-end 2018 SAIFI score is expected to be 1.65.<sup>451</sup> ENO proposes that if its SAIFI improves to 1.24 the adjustment would be zero, a score of 1.40 or worse would warrant a 25 basis point decrease from 10.75%, and an improvement to 1.05 would warrant a 25 basis point increase from 10.75%.<sup>452</sup> ENO argues that this proposal directly addresses the reliability issue, balances the interests of stakeholders, is transparent, and is administratively straightforward to implement;<sup>453</sup> and

**WHEREAS**, CCPUG argues that the proposed RIM should be rejected by the Council.<sup>454</sup> CCPUG argues that given ENO's unacceptably poor electric system reliability over the last few years, the Council should not under any circumstances approve a regulatory incentive mechanism

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<sup>448</sup> Ex. No. ENO-1 at 23:3-6.

<sup>449</sup> *Id.* at 23:11-12.

<sup>450</sup> *Id.* at 24:1-26:2.

<sup>451</sup> *Id.* at 28:5-6.

<sup>452</sup> *Id.* at 28:3-16; Ex. No. ENO-41 at 31:2-23.

<sup>453</sup> *Id.* at 26:5-19.

<sup>454</sup> Ex. No. CCPUG-3 at 50:7-8.

that provides the possibility of ENO earning a higher ROE for improved system reliability.<sup>455</sup> CCPUG argues that reliable service is part and parcel of every utility company's duty, including ENO, under the Regulatory Compact.<sup>456</sup> In other words, in return for its monopoly status and the absence of competition, its power of eminent domain, and the opportunity to earn an almost guaranteed ROR, the utility's service must be reliable.<sup>457</sup> CCPUG also argues that ENO has admitted that it does not require an incentive to provide reliable service.<sup>458</sup> CCPUG argues that the Council should set base level performance attainment levels in this proceeding of 1.16 for SAIFI and 113.8 for SAIDI.<sup>459</sup> CCPUG suggests a 25 basis point reduction penalty for underperformance and no incentive for improved performance;<sup>460</sup> and

**WHEREAS**, Air Products also opposes the RIM, arguing that the mechanism is conceptually flawed because it would reward ENO for doing what it is supposed to be doing in the first place -- namely, providing reliable service.<sup>461</sup> Air Products urges the Council to reject the proposed RIM, or, in the alternative that the RIM should not apply to customers who take service at the transmission level;<sup>462</sup> and

**WHEREAS**, the Advisors argue that as a public service company, ENO should prudently manage its electric utility, including making prudent expenditures and investments, and SAIFI is one metric for ENO's performance.<sup>463</sup> They argue ENO should not require an incentive to act prudently and achieve reasonable results for stakeholders.<sup>464</sup> The Advisors also argue that even if

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<sup>455</sup> Ex. No. CCPUG-1 at 50:10-13.

<sup>456</sup> *Id.* at 50:13-14; CCPUG Reply Brief at 36.

<sup>457</sup> Ex. No. CCPUG-1 at 50:14-17.

<sup>458</sup> CCPUG Reply Brief at 36, quoting City Council Hearing Transcript, 122:2-8 (June 18, 2019).

<sup>459</sup> Ex. No. CCPUG-3 at 52:20-23.

<sup>460</sup> *Id.* at 52:14-18 and 53:2-5.

<sup>461</sup> Ex. No. AP-3 at 20:14-16; Air Products' Initial Brief at 36; Air Products' Reply Brief at 13-14.

<sup>462</sup> Ex. No. AP-2 at 21:5; Air Products' Initial Brief at 36; Air Products' Reply Brief at 14.

<sup>463</sup> Ex. No. ADV-1 at 15:2-4; Advisors' Initial Brief at 110.

<sup>464</sup> Ex. No. ADV-1 at 15:4-5; Advisors' Initial Brief at 110.

the Council were to decide to incentivize ENO to improve its reliability, the Advisors would not recommend the Council utilize an ROE adjustment to do so;<sup>465</sup> and

**WHEREAS**, the Advisors argue that there is not a direct relationship between ROE and distribution system performance and the ROE customarily affects ENO's return on all its investments, not just the investments in the distribution plant that is generally regarded as most closely related to many of ENO's reported service outages, which constitutes only 57.9% of ENO's net plant in service.<sup>466</sup> Moreover, they argue, the Council is currently investigating ENO's reliability performance in Council Docket No. UD-17-04, including consideration of what appropriate SAIFI and SAIDI standards should be as well as any appropriate incentives and penalty mechanisms related to those standards.<sup>467</sup> The Advisors argue that setting a target SAIFI level and incentive mechanism in this proceeding would be premature prior to the conclusion of the investigations being conducted in Docket No. UD-17-04.<sup>468</sup> Additionally, the Advisors note, the impacts on ratepayers of the proposed RIM are not insignificant. Under ENO's proposed RIM, they argue, if ENO were to succeed in improving its SAIFI performance sufficiently to allow its ROE to increase from 10.5% to 11.0%, the result would be that ENO is able to collect an additional approximately \$2.7 million from its ratepayers.<sup>469</sup> The Advisors recommend that the Council not approve ENO's proposed RIM; and

**WHEREAS**, in response to the Advisors' argument that any minimum reliability standard should be addressed in Council Docket No. UD-17-04, ENO responds that it would be amenable to the Council setting ENO's electric ROE at 10.50% in this proceeding and directing the details

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<sup>465</sup> Advisors' Initial Brief at 110.

<sup>466</sup> Ex. No. ADV-1 at 15:9-14; Advisors' Initial Brief at 110-111.

<sup>467</sup> Resolution No. R-17-427.

<sup>468</sup> Ex. No. ADV-1 at 16:10-17:2; Advisors' Initial Brief at 111.

<sup>469</sup> Ex. No. ADV-1 at 14:18-20; Ex. No. ADV-6 at 12:3-11; Advisors' Initial Brief at 111.

of a balanced financial incentive and penalty mechanism that would permit ENO's ROE to adjust above 10.50% be determined in Docket No. UD-17-04, which ENO anticipates would be resolved prior to the resetting of rates through the FRP;<sup>470</sup> and

**WHEREAS**, the Advisors argue that there is no need to consider ENO's proposed RIM further in Docket No. UD-17-04.<sup>471</sup> They argue that ENO's appropriate allowed-ROE will be established in this rate case, and the Council is considering whether or not to adopt minimum reliability performance standards in Docket No. UD-17-04.<sup>472</sup> The Advisors take the position that there is no need to consider ROE and minimum reliability performance standards in conjunction with each other,<sup>473</sup> because there simply is no direct relationship between the utility's ROE and distribution performance -- any adjustment to ROE would typically affect ENO's return on all of its plant, not just the distribution plant that is generally regarded as most closely related to many of ENO's reported service outages;<sup>474</sup> and

**WHEREAS**, ENO argues that its proposed RIM Plan is a transparent and straightforward approach towards achievement of certain reliability performance goals, making the earnings component of its rates contingent upon reliability performance.<sup>475</sup> ENO argues that a mechanism tying reliability performance to any financial outcome should be symmetrical and that if a financial value (*i.e.* penalty) can be ascribed to performance below the range, then a value exists for performance above the range.<sup>476</sup> ENO also argues that similar mechanisms have been implemented by regulators in other jurisdictions.<sup>477</sup> ENO writes:

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<sup>470</sup> Ex. No. ENO-3 at 19:20-20:3.

<sup>471</sup> Ex. No. ADV-2 at 4:11-15; Advisors' Initial Brief at 111.

<sup>472</sup> Ex. No. ADV-2 at 4:6-8; Advisors' Initial Brief at 111-112.

<sup>473</sup> Ex. No. ADV-2. at 4:8-9; Advisors' Initial Brief at 112.

<sup>474</sup> Ex. No. ADV-2 at 4:9-5:4; Advisors' Initial Brief at 112.

<sup>475</sup> ENO Initial Brief at 52.

<sup>476</sup> *Id.* at 53.

<sup>477</sup> *Id.* at 52.

Reliable service is ENO's goal, but providing reliable service comes at a cost; the question becomes what is the appropriate balance between the two. This is a tradeoff that regulators must factor into their decision-making on just and reasonable rates;<sup>478</sup>

and

**WHEREAS**, the Advisors argue that while ENO is correct that it is the job of the regulator to determine the point at which the incremental gains to be achieved by further increasing reliability are outweighed by the cost of doing so, reliable service is not merely a "goal" of the utility, rather, it is the fundamental purpose for which the utility exists.<sup>479</sup> They argue that ENO's attempt to extract further profit from ratepayers for merely improving its reliability to an acceptable level is distasteful at best.<sup>480</sup> The Advisors take the position that when coupled with ENO's proposal to change Section 11 Continuity of Service of ENO's Service Regulations,<sup>481</sup> and ENO witness Stewart's statement on the stand that she would not say ENO has a duty to provide safe and reliable electric service,<sup>482</sup> these arguments demonstrate a troubling attitude on ENO's part that reliability is somehow optional and the utility must be provided with an incentive to provide it;<sup>483</sup> and

**WHEREAS**, the Advisors oppose ENO's RIM proposal to tie its ROE to its reliability performance arguing that ENO's earnings component of its rates should not be contingent upon its reliability performance. They argue that the Council is not faced with a "tradeoff" and is not required to provide ENO with an incentive to increase reliability just because reliability comes with a cost, all of which will be recovered from ratepayers in any event;<sup>484</sup> and

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<sup>478</sup> *Id.* at 54-55.

<sup>479</sup> Advisors' Reply Brief at 37.

<sup>480</sup> *Id.*

<sup>481</sup> Ex. No. ENO-6, at Ex. No. MPS-8 at 18.

<sup>482</sup> City Council Hearing Transcript, 114:17-18 (June 18, 2019).

<sup>483</sup> Advisors' Reply Brief at 37.

<sup>484</sup> *Id.* at 38.



**WHEREAS**, Air Products urges the Council to reject the proposed RIM, or in the alternative, to find that the mechanism should not be applied to transmission-level customers such as Air Products.<sup>485</sup> Air Products argues that its witness, Brubaker, testified that the RIM mechanism is conceptually flawed because it would reward ENO for doing what it is supposed to be doing in the first place -- namely, providing reliable service.<sup>486</sup> In apparent agreement with the Advisors testimony,<sup>487</sup> Air Products also notes that ENO is proposing, through its Distribution Grid Modernization Rider, to charge customers for the cost of upgrading its distribution grid, which would in turn be expected to improve reliability -- thus, customers (not ENO shareholders) would have already paid for the improved reliability of ENO's distribution system.<sup>488</sup> Air Products also argues that to the extent the Council approves the RIM plan, it should not apply to customers who take service at the transmission level because they will not benefit from improvements in reliability on the distribution system since the entire focus of reliability improvement is at the distribution level;<sup>489</sup> and

**WHEREAS**, AAE and Sierra Club also oppose the RIM Plan, noting that ENO fails to even recognize its responsibility to provide reliable service to New Orleans ratepayers, and that ENO is effectively asking to be rewarded for operating its distribution system in the manner to which ratepayers are entitled, but have not been receiving for years.<sup>490</sup> AAE and Sierra Club argue that the Council should reject ENO's attempt to "do an end run" around the Council's ongoing investigation in UD-17-04.<sup>491</sup> In agreement with Advisors' testimony,<sup>492</sup> they also argue that

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<sup>485</sup> Air Products' Initial Brief at 35.

<sup>486</sup> *Id.*; Ex. No. AP-3 at 20:16-21:3.

<sup>487</sup> Ex. No. ADV-1 at 15:10-19.

<sup>488</sup> Air Products' Initial Brief at 35; Ex. No. AP-3 at 21:9-11.

<sup>489</sup> Air Products' Initial Brief at 35; Ex. No. AP-3 at 21:11-13 and 22:3-4.

<sup>490</sup> AAE/Sierra Club Initial Brief at 46-47.

<sup>491</sup> *Id.* at 48.

<sup>492</sup> Ex. No. ADV-1 at 15:10-19.

ENO's ROE affects its return on all investments, not just the distribution plant that is most closely related to many of ENO's reported service outages, and ROE is based on market performance of proxy companies, not SAIFI values, so the ROE is not the best mechanism to incentivize ENO's distribution-related performance given its broad impact on ENO's overall rates.<sup>493</sup> AAE and Sierra Club also allege that ENO has been overearning on its ROE for a number of years, and during that period had a dismal record regarding distribution system outages, so there is no reason to believe that allowing ENO to over-earn is the best way to incentivize the Company.<sup>494</sup> Finally, they note that FERC has declined incentives to utilities "for doing what it is supposed to do, *i.e.*, to adequately maintain its facilities in a prudent cost-effective manner," and argue that New Orleans ratepayers should not be required to pay extra for a service they are entitled to by virtue of ENO's status as the monopoly provider of electric service;<sup>495</sup> and

**WHEREAS**, the Council finds that ENO's proposed RIM Plan should be denied, and the issue of reliability standards and any penalties for failing to meet them should be taken up in Council Docket No. UD-17-04 rather than in this rate case; and

- (4) *Whether ENO Should Update the Inputs to the Class Cost of Service Studies in the E-FRP Decoupling Mechanism, and How Rates are Reset if ROE is Outside the FRP Bandwidth*

**WHEREAS**, the Advisors argue that the electric FRP decoupling revenue adjustment for each customer class should be determined by comparing the evaluation period fixed & variable revenue by class with the FRP evaluation period allocation of total ENO fixed and variable revenue requirement;<sup>496</sup> and

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<sup>493</sup> *Id.*

<sup>494</sup> *Id.*

<sup>495</sup> *Id.* at 48-49, quoting *New England Power Pool*, 97 FERC ¶ 61,093 at 61,477 (2001); *order on reh'g*, 98 FERC ¶ 61, 249 (2002), Reply Brief of the Alliance for Affordable Energy and Sierra Club at 19, Aug. 9, 2019 ("AAE/Sierra Club Reply Brief").

<sup>496</sup> Ex. No. ADV-3 at 78:6-8.

**WHEREAS**, Air Products also opposes the Advisors' proposal that whenever an E-FRP evaluation is conducted, the external allocation factors be updated, arguing that this would make the process unnecessarily complex, expensive, contentious and inefficient and would not prevent significant changes in rates for customers in rate classes with only a few customers as a result of decoupling,<sup>497</sup> and

**WHEREAS**, the Advisors explain that after determining the allocated (fixed and variable) cost responsibility from the total cost of service, the E-FRP adjustment by customer class can be determined by the difference between the evaluated customer class total cost of service and the customer class actual total revenue and there would be no issue of double recovery.<sup>498</sup> The Advisors argue that updating external allocation factors with current billing determinants is not complex and reflects changes in customer usage necessary to maintain fairness in the customer class decoupling revenue adjustments; and

**WHEREAS**, the Council agrees with the Advisors that the E-FRP decoupling revenue adjustment for each customer class should be determined by comparing the evaluation period fixed and variable revenue by class with the FRP evaluation period allocation of total ENO fixed and variable revenue requirement; and

**WHEREAS**, the Advisors recommend that the Council approve a three-year FRP with an appropriate ROE and a bandwidth of +/- 50 basis points,<sup>499</sup> to begin with a May 2020 filing covering a calendar year 2019 test year;<sup>500</sup> and

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<sup>497</sup> Ex. No. AP-4 at 12:3-11; Air Products and Chemicals, Inc.'s Post-Hearing Reply Brief at 22-23, Aug. 9 2019 ('Air Products' Reply Brief').

<sup>498</sup> Ex. No. ADV-3 at 24:9-12.

<sup>499</sup> *Id.* at 77:8-9.

<sup>500</sup> *Id.* at 77:9-11.

**WHEREAS**, Air Products opposes an FRP adjustment resetting rates to EPCOE<sup>501</sup> (the midpoint of the ROE bandwidth), but rather proposes that if the EROE is above the upper bandwidth, the revenue adjustment be only partially moved toward the upper bandwidth (60% of the way toward the upper bandwidth), such that ENO is able to retain some of the benefits of the efficiencies it gained.<sup>502</sup> When earnings are below the lower edge of the bandwidth, Air Products recommends that the adjustment be 60% of the way toward the lower bandwidth;<sup>503</sup> and

**WHEREAS**, ENO opposes this proposal and disagrees arguing that such a mechanism would result in ENO not having an opportunity to recover its costs and would always result in rate adjustments that set rates at a level below ENO's revenue requirement and provide ENO no opportunity to recover its costs;<sup>504</sup> and

**WHEREAS**, the Advisors oppose Air Products' proposal and support the complete reset of rates when the earned ROE falls outside the bandwidth.<sup>505</sup> The bandwidth is set at a reasonable range to allow ENO to keep a reasonable amount of value from efficiencies while protecting ENO against incurring too much risk from investing in and/or supporting and promoting energy efficiency, demand response, rooftop solar and the like.<sup>506</sup> Not allowing rates to be reset when they fall below the bandwidth would give ENO an incentive to oppose those programs, and allowing ENO to keep more of the profits of above-bandwidth revenues would provide ENO with too much incentive to increase kWh sales rather than to promote conservation;<sup>507</sup> and

**WHEREAS**, the Council agrees with the Advisors' assessment of Air Products' proposal and finds it should be rejected; and

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<sup>501</sup> Ex. No. AP-3 at 22:13-14.

<sup>502</sup> *Id.* at 23:13-21.

<sup>503</sup> *Id.* at 24:8-11.

<sup>504</sup> ENO Reply Brief at 52.

<sup>505</sup> Advisors' Reply Brief at 40.

<sup>506</sup> *Id.*

<sup>507</sup> *Id.*

(5) *Whether and How Costs Related to NOPS Should Be Included in the FRP Mechanism*

**WHEREAS**, ENO proposes to begin recovering the estimated first year revenue requirement associated with the NOPS in the first billing cycle of the month after the NOPS enters commercial operation.<sup>508</sup> ENO testified that it expects the NOPS to enter commercial operation in January 2020,<sup>509</sup> although that date has since been moved later into year 2020; and

**WHEREAS**, ENO also proposes to recover the estimate through an interim rate adjustment under ENO's proposed E-FRP.<sup>510</sup> Assuming that the Council approves an E-FRP, the Company requests that the Council confirm in this proceeding that an interim rate adjustment under ENO's proposed E-FRP is the contemporaneous cost recovery mechanism to be used to recover the NOPS first year revenue requirement;<sup>511</sup> and

**WHEREAS**, CCPUG argues that it is reasonable to include an interim rate adjustment in the E-FRP to recover the costs of NOPS, but that the costs included in the calculation of the interim rate adjustment are not reasonable for three reasons.<sup>512</sup> First, ENO's ROE is excessive – (ENO's proposed 10.5% ROE should be replaced by CCPUG proposed 9.35% ROE or whatever other ROE the Council authorizes.<sup>513</sup> Second, the NOPS depreciation rate and depreciation expense are excessive, and should be based on a CCPUG proposed service life of 50 years, instead of the Company's assumed service life of 30 years.<sup>514</sup> The third reason the costs included in the calculation of the interim adjustment are unreasonable is that CCPUG believes that ENO intends

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<sup>508</sup> Ex. No. ENO-2 at 67:11-13 (HSPM).

<sup>509</sup> *Id.* at 67:13-14 (HSPM).

<sup>510</sup> *Id.* at 67:18-19 (HSPM).

<sup>511</sup> *Id.* at 67:20-23 (HSPM).

<sup>512</sup> Ex. No. CCPUG-1 at 46:8-11.

<sup>513</sup> *Id.* at 46:13-20.

<sup>514</sup> *Id.* at 47:1-19.

to maintain the NOPS first year revenue requirement until the next general rate case, with no revenue requirement reduction due to greater accumulated depreciation and ADIT;<sup>515</sup> and

**WHEREAS**, in Council Docket No. UD-16-02, in which the Council approved NOPS, the Advisors proposed that the cost recovery of the NOPS investment be accomplished contemporaneously as a second step rate adjustment subsequent to the 2019 effective date of the revised rates from the instant docket.<sup>516</sup> Specifically, the Advisors believe that the NOPS interim rate adjustment could be a provision in the proposed FRP, providing contemporaneous recovery from the date of NOPS commercial operation (“COD”).<sup>517</sup> The Advisors have proposed that proforma adjustments be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP.<sup>518</sup> According to the Company, NOPS is expected to enter commercial operation in early 2020.<sup>519</sup> The Advisors argue that if the NOPS updated revenue requirement filing is not included as a prospective proforma adjustment in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS costs are included in the ROE bandwidth evaluation of the following FRP.<sup>520</sup> If the NOPS updated revenue requirement filing is included as a 2020 proforma adjustment in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment would be effective with the COD until the FRP rate adjustment is implemented in September 2020, at which time NOPS cost recovery would be included in the FRP rate adjustment,<sup>521</sup> and

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<sup>515</sup> *Id.* at 47:20-48:4.

<sup>516</sup> Resolution No. R-18-65 at 176.

<sup>517</sup> Advisors’ Initial Brief at 44.

<sup>518</sup> Ex. No. ADV-5 at 24:18-25:2.

<sup>519</sup> Ex. No. ENO-2 at 67:13-14.

<sup>520</sup> Ex. No. ADV-5 at 25:3-6.

<sup>521</sup> *Id.* at 25:4-10.

**WHEREAS**, ENO objects to Advisors’ witness Prep’s approach. The Company asserts that the potential exists that the bandwidth calculation may prevent ENO from recovering 100% of the NOPS costs.<sup>522</sup> ENO argues that “it would be illogical to permit 100% recovery of the NOPS costs in the interim rate adjustment but later reduce that recovery because of the FRP bandwidth mechanics.”<sup>523</sup> Therefore, the Company believes that the first-year revenue requirement should be reflected in its entirety in the FRP Rate Adjustment and any subsequent cost changes be subject to the bandwidth calculation,<sup>524</sup> and

**WHEREAS**, the Advisors urge the Council to adopt witness Prep’s recommendation regarding NOPS cost recovery and the inclusion of NOPS in the proposed FRP revenue adjustment.<sup>525</sup> The first-year revenue requirement associated with NOPS should be included in rates as an in-service rate adjustment, beginning with the month after NOPS enters commercial operation. The Advisors argue that this rate adjustment shall remain in place until NOPS costs are included in the costs of an FRP evaluation period and in the ROE bandwidth calculation.<sup>526</sup> The Advisors disagree with ENO’s argument that it should be permitted to recover the initial year of NOPS costs without being included in an ROE evaluation.<sup>527</sup> As with all other costs included in an FRP evaluation of earnings, ENO has the opportunity to earn its approved ROE rather than a guarantee that it will recover 100% of NOPS costs;<sup>528</sup> and

**WHEREAS**, the Advisors recommend that the interim Rate Adjustment for NOPS non-fuel revenue requirement be included under the proposed FRP Attachment C, paragraph 8, or in the following FRP within the bandwidth evaluation, depending on the commercial operation date,

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<sup>522</sup> Ex. No. ENO-3 at 48:5-6.

<sup>523</sup> *Id.* at 48:6-8.

<sup>524</sup> *Id.* at 48:8-10.

<sup>525</sup> Advisors’ Initial Brief at 45.

<sup>526</sup> *Id.* at 45.

<sup>527</sup> *Id.*

<sup>528</sup> *Id.*

and that the FRP provision include an allocation of NOPS costs based on the rate case production demand allocation factor, rather than total base rate costs;<sup>529</sup> and

**WHEREAS**, CCPUG argues that ENO’s proposal will lead to excessive recovery in the first year and every year thereafter until base rates are reset, because the ROR is excessive, the depreciation rate and depreciation expense are excessive, and the revenue requirement is generally at the maximum for the first year and then declines due to the accumulation of book depreciation and the tax savings from accelerated tax depreciation;<sup>530</sup> and

**WHEREAS**, CCPUG recommends ENO apply a 9.35% ROE to the E-FRP, that the first year revenue requirement for NOPS be reduced to reflect a 50-year service life, and that ENO be ordered to reduce the revenue requirement for NOPS each year to reflect an additional year of depreciation and deferred income tax expense;<sup>531</sup> and

**WHEREAS**, ENO suggested that the Council not determine the parameters for recovery of the NOPS revenue requirement in this proceeding, but wait until ENO makes its proposed rate filing prior to the in-service date of NOPS based on the estimated first NOPS revenue requirement.<sup>532</sup> CCPUG opposes this suggestion and argues that the Council should decide the issue in this case;<sup>533</sup> and

**WHEREAS**, AAE and Sierra Club oppose the NOPS adjustment in its entirety, arguing that because a presiding judge in Civil District Court issued a bench ruling voiding Resolution No. R-18-65, the construction of NOPS does not have the approval of the Council.<sup>534</sup> As AAE and Sierra Club are well aware, the Council appealed this ruling, and thus, that matter is not yet final.<sup>535</sup>

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<sup>529</sup> Ex. No. ADV-3 at 77:12-16.

<sup>530</sup> CCPUG Initial Brief at 68; Ex. No. CCPUG-1 at 46:8-48:4.

<sup>531</sup> CCPUG Initial Brief at 69; Ex. No. CCPUG-1 at 48:15-20.

<sup>532</sup> Ex. No. ENO-3 at 48.

<sup>533</sup> Ex. No. CCPUG-2 at 29:9-30:13.

<sup>534</sup> AAE/Sierra Club Initial Brief at 53.

<sup>535</sup> Advisors’ Reply Brief at 52.



The Advisors propose that to the extent that the matter has not yet become final at the time that the Council issues a resolution in this rate case, any NOPS adjustment approved by the Council should be conditioned upon the construction of NOPS and associated costs having been approved through a final judgment of the Council;<sup>536</sup> and

**WHEREAS**, after considering all of the arguments and evidence related to this issue, the Council agrees with the Advisors proposal that proforma adjustments should be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP.<sup>537</sup> The Council also finds that if the NOPS updated revenue requirement is included as a prospective proforma adjustment in the bandwidth evaluation of the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS cost recovery is included in the E-FRP revenue adjustment of the first FRP. The Council further finds that if the NOPS updated revenue requirement filing is not included as a prospective proforma adjustment in the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS costs are included in the ROE bandwidth evaluation of the following E-FRP;<sup>538</sup> and

**WHEREAS**, the Council finds that this course of action is consistent with the approach to evaluate the total utility cost of service and avoid single issue ratemaking; and

**WHEREAS**, the Council finds it reasonable to avoid future uncertainty and additional litigation costs by the parties not to defer consideration of the NOPS adjustment until a future date, but rather, as the Advisors suggest, to approve a NOPS adjustment with an instruction to ENO that

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<sup>536</sup> *Id.*

<sup>537</sup> Advisors' Initial Brief at 43-44; Ex. No. ADV-5 at 24:18-25:2.

<sup>538</sup> Advisors' Initial Brief at 44; Ex. No. ADV-5 at 25:3-6.

no actual costs should be flowed through that adjustment to ratepayers until such time as the construction of NOPS and the associated costs have been approved through a final judgment of the Council; and

**WHEREAS**, the Council finds that the interim Rate Adjustment for NOPS non-fuel revenue requirement be included under the proposed E-FRP Attachment C, paragraph 8, or in the following E-FRP within the bandwidth evaluation, depending on the commercial operation date; and

**WHEREAS**, the Council finds that the E-FRP provision should include an allocation of NOPS costs based on the rate case production demand allocation factor, rather than total base rate costs; and

### **DECOUPLING**

**WHEREAS**, the Advisors explain that in Resolution No. R-16-03, ENO was ordered to include in its next base rate case filing a proposal for an electric utility full decoupling mechanism as a three-year pilot program, to begin with the implementation of rate changes arising from the Combined Rate Case; and

**WHEREAS**, the Advisors also argue that Resolution No. R-16-03 requires that all utility fixed costs should be included in the decoupling revenue adjustment, regardless of the revenue recovery mechanism used to recover any specific fixed (non-fuel) costs;<sup>539</sup> and

**WHEREAS**, the Advisors argue that Resolution No. R-16-03 also requires (i) that the fixed cost revenue requirement should be determined on an allocated basis for each customer class, (ii) that the allocation methodology should be applied consistently on an annual basis to determine

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<sup>539</sup> Ex. No. ADV-5 at 24:6-9.

the decoupling revenue adjustments by customer class, (iii) and that the fixed-cost customer rate class allocation factor should be updated annually (with current billing determinants),<sup>540</sup> and

**WHEREAS**, ENO proposes a Decoupling Pilot Program within the electric FRP, through a four-step process to be applied only if a rate adjustment is necessary under the terms of the rider.<sup>541</sup> Under the decoupling proposal, the fixed and variable cost revenue requirements would be recovered from each rate class consistent with the allocation methodology used in the baseline rate case.<sup>542</sup> In the first step, the Baseline Fixed Cost Revenue Requirement and the Variable Cost Revenue Requirement would be determined.<sup>543</sup> The second step would be to allocate each Rate Class's Evaluation Period Base Revenue (and FRP Revenue, if any) between Fixed Revenue and Variable Revenue using the Baseline Revenue Requirement.<sup>544</sup> The third step would be to compute each rate class's Evaluation Period Fixed and Variable Revenue Deficiency or Excess.<sup>545</sup> The fourth and final step would be to calculate the Rate Adjustment for each rate class;<sup>546</sup> and

**WHEREAS**, under ENO's decoupling proposal, the revenue adjustments would be the difference between actual E-FRP evaluation period customer class base rate revenues and the E-FRP electric base rate revenue requirements allocated to customer classes using customer class base rate revenues approved by the Council in the instant docket; and

**WHEREAS**, under ENO's decoupling proposal, the E-FRP/decoupling base rate adjustment for each rate class would be calculated from each rate class's E-FRP evaluation period

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<sup>540</sup> *Id.*

<sup>541</sup> Ex. No. ENO-55 at 20-21; Ex. No. ENO-41 at 32:23-33:2.

<sup>542</sup> Ex. No. ENO-55 at 21.

<sup>543</sup> Ex. No. ENO-41 at 34:12-17.

<sup>544</sup> *Id.* at 36:6-8.

<sup>545</sup> *Id.* at 36:16-18.

<sup>546</sup> *Id.* at 37:3-7.

fixed and variable base rate revenue deficiency or excess, and applied as a percent of base rate revenue;<sup>547</sup> and

**WHEREAS**, ENO's decoupling proposal would not use cost allocation factors updated for each E-FRP evaluation period, and assumes the proportions of customer class fixed and variable base rate revenue requirements to be fixed (based on those values in the instant docket) for each of the E-FRP evaluation periods;<sup>548</sup> and

**WHEREAS**, AAE witness Morgan recommends four changes to ENO's decoupling proposal: (1) remove it from the effects of the FRP deadband; (2) clarify that it will only operate on either (a) revenues from customer billing charge billing determinants or minimum bill requirements in tariffs; or (b) revenues collected under tariff riders that are subject to full reconciliation; (3) clarify that the comparison is between the most recent approved revenues and the actual revenues, allocated to rate class/schedules per approved allocation factors, and not to a calculation of required allocated revenues that includes changes in costs during the decoupling period and (4) authorize ENO to calculate the difference between actual and authorized through-based revenues for fixed recovery on a monthly basis during any year, applying a Council-set carrying charge rate evenly to balances owed customers and owed ENO;<sup>549</sup> and

**WHEREAS**, AAE witness Morgan agrees that she did not participate in any of the Council's decoupling proceedings leading to the adoption of the Council's decoupling resolution, Resolution No. R-16-103.<sup>550</sup> She maintains, however, that decoupling should focus only on revenues, not expense, and that revenue decoupling is always backward looking - a true-up for

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<sup>547</sup> *Id.* at 36:16-18; 37:3-7.

<sup>548</sup> Ex. No. ENO-55 at 21; Ex. No. ENO-41 at 34:12-17.

<sup>549</sup> Ex. No. AAE-1 at 3:11-23; Ex. No. AAE-2 at 2:6-3:7, 9:16-21, 16:16-22; AAE Reply Brief at 16.

<sup>550</sup> Ex. No. AAE-2 at 3:15-4:1.

what actually happened compared to what was expected to happen.<sup>551</sup> AAE argues that any decoupling mechanism should operate separately from any FRP, be backward-looking in reconciliation, remove the need for any LCFC and ensure that there are no gaps that could penalize ENO for achieving the most energy efficiency it can,<sup>552</sup> and

**WHEREAS**, the Advisors recommend that the full decoupling mechanism should be approved for the three-year electric FRP term, that the total allocated costs of service for each customer class should be included in the decoupling revenue adjustment, and that the customer rate class allocation factors should be updated annually (with current billing determinants);<sup>553</sup> and

**WHEREAS**, the Advisors concur with ENO's recommendation that a decoupling adjustment be applied only if the E-FRP revenue adjustment is outside the bandwidth,<sup>554</sup> but recommend that the decoupling revenue adjustment be applied consistently to all customer classes based on the E-FRP evaluation period total revenue requirements of each customer class,<sup>555</sup> and

**WHEREAS**, the Advisors propose the following steps: (i) the "baseline" customer class revenue requirements in the instant Docket be updated with a new baseline of customer class fixed and variable revenue requirements in the E-FRP; (ii) the E-FRP fixed and variable total revenue requirements be determined for each customer class by an allocation of costs and a return component based on the rates of return corresponding to the customer class revenues set in the instant docket; (iii) the fixed and variable revenue deficiencies/excesses be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period total revenues; and (iv) the customer class decoupling

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<sup>551</sup> *Id.* at 4:14-15 and 5:8-9; AAE Reply Brief at 16.

<sup>552</sup> Ex. No. AAE-2 at 8:10-18.

<sup>553</sup> Ex. No. ADV-3 at 80:1-4.

<sup>554</sup> Ex. No. ADV-3 at 79:3-4.

<sup>555</sup> *Id.* at 79:4-7.

adjustments be applied within each customer class with updated billing determinants excluding the customer charge;<sup>556</sup> and

**WHEREAS**, ENO argues that its proposed decoupling approach is the only decoupling approach consistent with Resolution No. R-16-103 and accompanies by detailed explanatory testimony, a complete rate schedule setting forth the decoupling approach with exhibits, and a detailed example, and that no other party provided a proposal as comprehensive as ENO's;<sup>557</sup> and

**WHEREAS**, ENO argues (i) that the Advisors' assignment of the different required before-tax rates of return on rate base to each customer/rate class was done under no objective standard that can be replicated,<sup>558</sup> and (ii) that the proposed revenue by rate class approved in this proceeding be used to allocate ENO's revenue requirement in future FRP evaluation reports instead of developing customer/rate class revenue requirements from updated cost allocations and customer/rate class rates of return;<sup>559</sup> and

**WHEREAS**, ENO argues that there could be unintended consequences if a decoupling mechanism were to include all customer classes, particularly classes with few customers.<sup>560</sup> The Advisors argue, however, that concern of unintended consequences related to a customer class with few customers is without merit because updating allocation factors and billing determinants with each FRP will accommodate any shifts in customers and usage within these classes; and

**WHEREAS**, ENO also argues that it has significant concerns with the Advisors' proposal that the decoupling adjustment be performed by applying the same allocation methodology approved in this proceeding, and that ENO provide a new COS Study each year by updating the

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<sup>556</sup> *Id.* at 79:9-11 and 78:6-8.

<sup>557</sup> ENO Reply Brief at 94.

<sup>558</sup> Ex. No. ENO-42 at 20:6-21:9, *see also*, ENO Reply Brief at 94.

<sup>559</sup> Ex. No. ENO-42 at 22:3-4.

<sup>560</sup> Ex. No. ENO-13 at 2:8-15 and 4:11-13.

allocation factors for each customer class with then-current customer data.<sup>561</sup> ENO argues that it would substantially undermine the purposes and efficiencies of an FRP and there would be minimal benefit to be gained from developing updated allocation factors and presenting a fully developed COS Study each year.<sup>562</sup> ENO also argues that the Advisors' proposal would substantially undermine the purposes and efficiencies of an FRP by creating an inefficient use of resources and significant additional work.<sup>563</sup> ENO argues that FRP's streamline the rate setting process by eliminating the usual contentious debate around the allocation of the revenue requirement to the various rate classes and the rate design for three to five years, which is allowed because, typically, there are no substantial changes in operations from year to year that would materially affect cost allocations among customer classes.<sup>564</sup> ENO argues that it will be very labor intensive and require numerous resources for ENO to develop the allocation factors for the FRP that would be required under the Advisors' proposal,<sup>565</sup> and

**WHEREAS**, Air Products argues that the structure of ENO's and other parties' decoupling mechanisms poses a substantial risk of a highly disruptive change in revenues for customers in classes that have only a few customers (Master-Metered Nonresidential, Large Electric High Voltage and Large Interruptible Service) because the mechanism essentially would guarantee fixed cost recovery from those classes regardless of the level of purchases by customers in those classes.<sup>566</sup> According to Air Products, a modest change in the level of business operations, and hence the amount of power required from ENO, could cause a very disruptive increase to those customers;<sup>567</sup> and

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<sup>561</sup> Ex. No. ENO-42 at 14:16-15:3.

<sup>562</sup> *Id.* at 15:3-6.

<sup>563</sup> *Id.* at 15:3-20.

<sup>564</sup> *Id.* at 15:12-19.

<sup>565</sup> *Id.* at 16:9-21.

<sup>566</sup> Air Products' Initial Brief at 10.

<sup>567</sup> *Id.*

**WHEREAS**, Air Products' witness Mr. Brubaker recommended that one of two solutions be applied to address the consequences that a decoupling adjustment could have on rate classes with only a few customers.<sup>568</sup> Either customer classes with only a few customers should be excluded from any decoupling mechanism, or there should be a maximum change of 10% in the average charge per kWh between rate cases to customers in those classes;<sup>569</sup> and

**WHEREAS**, the first recommendation of Mr. Brubaker is to exclude from the decoupling mechanism those classes with only a few customers.<sup>570</sup> As Mr. Brubaker points out, the revenues of these rate classes with only a few customers amount to less than 3% of total base rate revenues, so this exclusion would not materially impact the operation of a decoupling mechanism;<sup>571</sup> and

**WHEREAS**, in the alternative, Air Products asserts that should the Council not want to exempt any customer rate classes from the decoupling mechanism, it should adopt Mr. Brubaker's recommendation to cap the percentage change in average revenue per kWh between rate cases that result from the application of the decoupling mechanism to 10% for individual customers in rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, which would greatly reduce the potential for highly disruptive changes in these classes rates;<sup>572</sup> and

**WHEREAS**, Air Products requests that customer classes with few customers, including rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, either be exempt from the decoupling adjustment or have their exposure to changes in rates between rate cases resulting from the decoupling adjustment capped at 10%;<sup>573</sup> and

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<sup>568</sup> *Id.* at 41.

<sup>569</sup> *Id.* at 11.

<sup>570</sup> *Id.*

<sup>571</sup> *Id.*

<sup>572</sup> *Id.* at 42.

<sup>573</sup> *Id.* at 43.



**WHEREAS**, the Advisors argue that the decoupling mechanism should operate within the E-FRP, and should apply to proforma revenue requirements and billing determinants in the FRP rate effective period to reduce regulatory lag and remove the need for LCFC;<sup>574</sup> and

**WHEREAS**, the Advisors also argue that the concern of unintended consequences related to a customer class with few customers is largely without merit because updating allocation factors and billing determinants with current customer data in each E-FRP will accommodate any shifts in customers or usage within these classes, and the customer class rates of return determined by the customer class revenues set by the Council in the instant Docket would be the basis for the customer class return component in the FRP.<sup>575</sup> Consequently, ENO's argument regarding no objective standard that can be replicated for the different ROR on rate base for each customer/rate class is without merit; and

**WHEREAS**, the Advisors maintain that updated allocation factors are necessary to reflect the change in usage patterns related to increased energy efficiency, distributed energy resources, renewables including solar, new products and equipment, and other current impacts affecting usage that were not as much of a concern in years previous;<sup>576</sup> and

**WHEREAS**, the Advisors also argue that implementing the Advisors' decoupling recommendations will not require a level of effort comparable to a cost allocation study in a general rate case, since using the same methodologies and models, with no requirement for two test periods or weather normalization, minimal updating of weighting factors, and no change to the use of the external and internal allocation factors in the cost of service model will not undermine the efficiencies of the E-FRP;<sup>577</sup> and

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<sup>574</sup> Ex. No. ADV-5 at 29:3-30:4.

<sup>575</sup> *Id.* at 27:17:2.

<sup>576</sup> *Id.* at 27:6-10.

<sup>577</sup> *Id.* at 25:25:16-19 and 26:18-27:1.

**WHEREAS**, despite its assertion that its proposal is the only one that complies with Resolution No. R-16-103,<sup>578</sup> ENO proposes that it not be required to meet the requirement of Resolution No. R-16-103 that it recalculate a fixed-cost customer rate class allocation factor or factors each year consistent with the cost allocation methodology used in this proceeding and use those factors to allocate the FRP evaluation period electric revenue requirement to each rate class.<sup>579</sup> ENO argues that (1) strictly following the rate class cost allocation from the cost of service study allocation factors would cause a disruptive increase in cost responsibility for the Residential Rate Class, and (2) the Council had not adopted such a rate class cost allocation in its last two rate cases.<sup>580</sup> Instead, ENO proposes that the FRP Evaluation Period electric revenue requirement be allocated consistent with the relative allocation of the base electric revenue among the rate classes approved by the Council, absent some material change that indicated that relative allocation should be modified,<sup>581</sup> and

**WHEREAS**, the Advisors argue that ENO’s claim regarding a “disruptive increase in cost responsibility for the Residential Rate Class” is not supported by any analysis. If the cost allocation methodologies accepted by the Council in this docket are simply updated with current billing determinants, a disruptive increase in cost responsibility is implausible, as is defining “some material change” in ENO’s decoupling proposal; and

**WHEREAS**, the Council finds that it thoroughly examined the issue of decoupling in a transparent docket open to all interested parties, and in which the AAE actively participated in Docket No. UD-08-02. The outcome of that examination was the adoption by the Council of a decoupling mechanism in Resolution No. R-16-03. Thus, the Council finds that the appropriate

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<sup>578</sup> ENO Reply Brief at 94.

<sup>579</sup> ENO Initial Brief at 100.

<sup>580</sup> *Id.*

<sup>581</sup> *Id.* at 100-101.

consideration in this rate case is whether or not ENO's decoupling proposal complies with the Council's instructions in Resolution No. R-16-03; it is not an appropriate proceeding for parties to take "another bite at the apple" as to what the appropriate structure of the decoupling mechanism is. That was decided in Resolution No. R-16-03, and the Council finds that no party has raised a sufficient reason for the Council to re-open the decisions made in Resolution No. R-16-03 in this proceeding; and

**WHEREAS**, while AAE urges the Council to reject the concept that stakeholders who failed to participate in a previous process should "be forever barred from weighing in on an issue,"<sup>582</sup> that is not what is at issue in this proceeding. The Council must strike a balance between striving to continually make improvements to its regulations and providing sufficient stability in its regulations that regulated entities can understand what they must do to comply with the Council's regulations. It is not beneficial to any party for the Council's regulations to be a constant "moving target." Under the facts presented in this case, the Council finds that the AAE and other interested parties had sufficient opportunity to advocate for their desired decoupling structure in Docket No. UD-08-02 and have not offered sufficient cause for the Council to take the unusual step of altering its regulations through a rate case; and

**WHEREAS**, the Council finds that a full decoupling mechanism should be filed with each electric E-FRP evaluation, with total allocated costs of service for each customer class included in the decoupling revenue adjustment, and the customer rate class allocation factors be updated annually with current billing determinants; and

**WHEREAS**, the Council finds that the decoupling adjustment be applied to all customer classes if the E-FRP revenue adjustment is outside the bandwidth; and

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<sup>582</sup> AAE Reply Brief at 17.

**WHEREAS**, the Council has carefully considered Air Products' arguments and alternative proposals with respect to the potential impact of ENO's proposed decoupling mechanism on rate classes with only a few customers and believe that Air Products' concerns are valid; and

**WHEREAS**, the Council finds that some protection should be provided for those rate classes (Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service) having only a few customers to mitigate the potential exposure of those rate classes to highly disruptive changes in rates that may occur as a result of the decoupling mechanism approved in this case; and

**WHEREAS**, for rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, a decoupling revenue adjustment cap of 10% shall apply to each of the three annual FRP evaluation period revenue adjustments provided that the total electric utility FRP revenue adjustment for that evaluation period does not exceed 10%; and

**WHEREAS**, the Council finds that a new baseline of customer class fixed and variable revenue requirements be determined in each E-FRP from an allocation of costs and a return component based on the rates of return corresponding to the customer class total revenues set in the instant docket. Any adjustments that may be needed to the relative rates of return will be such that those adjustments move the relative customer class rates of return toward the utility's rate of return based on the weighted average cost of capital; and

**WHEREAS**, the Council finds that the revenue deficiencies/excesses be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period total actual revenues, with the decoupling adjustments applied within each customer class using updated billing determinants excluding the customer charge; and

**WHEREAS**, the Council finds that the decoupling adjustment should apply to proforma revenue requirements and billing determinants in the E-FRP rate effective period, based on updated allocation factors and billing determinants in each E-FRP; and

**WHEREAS**, to the extent any undisputed element of ENO’s decoupling proposal is not addressed herein, the Council has reviewed it and found it reasonable, and it is approved as proposed by ENO; and

**GREEN POWER OPTION**

**WHEREAS**, ENO proposed a “green pricing proposal” in this case pursuant to Resolution No. R-18-97.<sup>583</sup> Under ENO’s proposed Green Power Option (“Rider GPO”), a voluntarily enrolled customer would be able to match some or all (*i.e.*, 100%) of their electricity usage with renewable energy certificates (“RECs”) sourced from renewable energy sources like wind and solar,<sup>584</sup> and

**WHEREAS**, a REC represents the environmental benefits of 1 MWh of renewable energy.<sup>585</sup> ENO argues that by purchasing and pairing RECs with their electricity service, retail customers can use and receive the benefits of that renewable electricity.<sup>586</sup> ENO argues that RECs are used across the country as a low-risk option to support renewable energy and meet renewable energy usage goals;<sup>587</sup> and

**WHEREAS**, ENO’s proposed Rider GPO would be open to all customers and allow them the option of matching 100%, 50%, or 25% of their electricity usage each month with RECs.<sup>588</sup> ENO explains that nationally, demand for green pricing options provided by utilities has increased

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<sup>583</sup> Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 41:4-16.

<sup>584</sup> Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 40:9-11.

<sup>585</sup> Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 40:13-15.

<sup>586</sup> Ex. No. ENO-55 at 41.

<sup>587</sup> Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 40:18-41:2.

<sup>588</sup> Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 43:15-17.

substantially in recent years, and that, according to surveys conducted by ENO, approximately 36% of ENO’s customers have expressed interest in participating in a green power option;<sup>589</sup> and

**WHEREAS**, under the proposal, ESI’s System Planning and Operations Organization (“SPO”) would acquire and retire the RECs associated with the Green Power Option.<sup>590</sup> ENO proposed that the offering be certified by “Green-e”, which, ENO explains, is an independent consumer protection organization that offers certification and verifies the integrity of RECs through the entire chain of custody, so customers can be confident in their purchase,<sup>591</sup> and

**WHEREAS**, ENO’s proposed green power option would be available to all customer classes and there will be no limit on the number of customers that can participate.<sup>592</sup> Under ENO’s proposal, there would be no minimum contract term for participation, though customers who withdraw would not be eligible to return until after the seventh month following their withdrawal.<sup>593</sup> Customers would be allowed to change their election no more than one time in any six-month period;<sup>594</sup> and

**WHEREAS**, ENO’s proposed price for the Green Power Option would incorporate REC prices (as driven by the national market), a small contingency to account for fluctuations in REC prices and vendor support costs related to customer enrollment, customer education/marketing, and Green-e certification.<sup>595</sup> ENO proposed the following charges for each of the three options:<sup>596</sup>

<b>Option</b>	<b>GPO Election</b>	<b>Rate (per kWh)</b>
Tier One Option	25%	\$0.015 per kWh

<sup>589</sup> Ex. No. ENO-19 at 41:17-42:12.

<sup>590</sup> *Id.* at 47:3-9.

<sup>591</sup> *Id.* at 44:1-4.

<sup>592</sup> *Id.* at 44:18-21 and 45:18.

<sup>593</sup> *Id.* at 46:6-10.

<sup>594</sup> *Id.* at 46:13-14.

<sup>595</sup> *Id.* at 47:12-21.

<sup>596</sup> *Id.* at 48:6-10.

Tier Two Option	50%	\$0.0125 per kWh
Tier Three Option	100%	\$0.01 per kWh

**WHEREAS**, the options would be priced at different amounts in order to encourage customers to choose to offset more of their usage with renewable energy.<sup>597</sup> ENO’s proposed pricing is based on assumptions regarding participation levels over the first three years, and to the extent that actual participation levels and costs are significantly different than ENO’s assumptions and/or change over time, ENO would seek pricing adjustments, though ENO does not anticipate that adjustments would be needed frequently;<sup>598</sup> and

**WHEREAS**, the Advisors estimate that under ENO’s proposed rate, a 1,000 kWh per month customer (which is approximately the average residential customer) who chose the 100% Green Power Option would experience a surcharge on their bill of approximately \$10/month.<sup>599</sup> The Advisors calculate that ENO would profit from Rider GPO, but not materially or over the long term, and conclude that the estimated O&M costs related to the GPO Rider do not constitute a substantial risk to ratepayers should ENO’s actual costs be less.<sup>600</sup> The Advisors state that any collections in excess of actual expenses would be corrected for prospectively as part of any FRP evaluation;<sup>601</sup> and

**WHEREAS**, BSI opposes the Green Pricing Proposal because BSI believes it will neither lower rates, nor contribute to improving New Orleans’ local economics nor its local

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<sup>597</sup> *Id.* at 48:12-14.

<sup>598</sup> *Id.* at 49:6-11.

<sup>599</sup> Ex. No. ADV-6 at 71:13-14.

<sup>600</sup> *Id.* at 71:16.

<sup>601</sup> *Id.* at 71:18-72:1.

environmental footprint, and proposes that all Green Pricing funds be invested in CLEP instead;<sup>602</sup> and

**WHEREAS**, ENO argues BSI’s claims that CLEP is superior to the Green Power Option are unsupported by any testimony and should be rejected;<sup>603</sup> and

**WHEREAS**, the Council observes that there are no funds set aside for the Green Power Option, rather, customers would on an individual basis, decide whether to participate, thus there are no “funds considered for Green Pricing” that can be directed to another purpose in the absence of a Green Power Option; and

**WHEREAS**, the Advisors recommend that the Council approve Rider GPO because it presents a valuable option for ratepayers who wish to offset the environmental impact of their electricity consumption while imposing substantially no costs or risks to non-participants.<sup>604</sup> The Advisors also recommend that the Council evaluate the programs’ actual costs of operation as part of future rate actions, such as FRP evaluations, and take any further appropriate action at that time, including adjustments to Rider GPO’s rates;<sup>605</sup> and

**WHEREAS**, AAE and the Sierra Club argue that ENO’s proposed Rider GPO should be modified in two ways: (1) rather than using Green-e certified RECs to verify that green power is used, the Council should direct ENO to define explicitly green energy as actual clean resources, *i.e.*, solar, wind, and battery storage; and (2) the Council should direct ENO to include language in the Rider GPO tariff that expressly states that any costs or expenses not recovered from participants may not be recovered from ratepayers;<sup>606</sup> and

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<sup>602</sup> Building Science Innovators, LLC Post Hearing Brief at 25, July 26, 2019 (“BSI Initial Brief”).

<sup>603</sup> ENO Reply Brief at 118.

<sup>604</sup> Ex. No. ADV-6 at 72:6-9.

<sup>605</sup> *Id.* at 72:12-15.

<sup>606</sup> AAE/Sierra Club Initial Brief at 52-53.



**WHEREAS**, with respect to the first point, AAE and Sierra Club argue that Green-e is not regulated by the Council and the Council has no control over what resources are designated as green resources.<sup>607</sup> They argue that this is a problem because some states may include energy generated from black liquor or waste to energy facilities in their renewables portfolio standards that ultimately determine whether a resource is “green” within that state or not. AAE and Sierra Club view these types of resources “unclean” and only want solar, wind, and battery storage resources to be included;<sup>608</sup> and

**WHEREAS**, ENO argues in response to the AAE and Sierra Club that Resolution No. R-18-97 simply required ENO to make a “proposal under which customers may voluntarily choose to have some or all of the electricity supplied by *renewable resources*” and did not otherwise define “renewable resources.”<sup>609</sup> ENO argues that AAE submitted no testimony or evidence in support of its argument that the scope of allowed resources should be narrowed; and

**WHEREAS**, the Advisors note that the Council currently has an RPS rulemaking docket open, Council Docket No. UD-19-01, where the issue of what energy resources the Council would deem as eligible to be considered “renewable resources” is being actively considered.<sup>610</sup> Therefore, the Advisors believe it is premature for the Council to rule in this rate case what should and should not be considered an “eligible” resource for the Green Power Tariff.<sup>611</sup> The Advisors also argue that it would be unnecessarily burdensome for ENO to comply with and the Council to enforce two separate definitions of “renewable energy,” one for the Rider GPO and different one

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<sup>607</sup> *Id.* at 52.

<sup>608</sup> *Id.*

<sup>609</sup> ENO Reply Brief at 116, citing Resolution No. R-18-97, at P 9 (emphasis added).

<sup>610</sup> Advisors’ Reply Brief at 53.

<sup>611</sup> *Id.* at 53-54.

for the RPS.<sup>612</sup> The Advisors agree, however, that only RECs that would otherwise satisfy the Council's definition of renewable resources are appropriate for inclusion in the program;<sup>613</sup> and

**WHEREAS**, ENO argues that Green-e is an independent consumer protection organization that verifies that the RECs procured by the Company are (a) sourced from facilities that meet quality criteria that has been endorsed by diverse stakeholder group; (b) marketed transparently and honestly; and (c) delivered exclusively to the purchaser of the REC, *i.e.*, that the renewable attribute of the generation is not used toward a state renewable energy mandate or otherwise double-counted.<sup>614</sup> ENO notes that Green-e has specific minimum criteria related to: facility online date, REC vintage, and eligible resource types, yet it also allows flexibility in design;<sup>615</sup> and

**WHEREAS**, the Advisors also argue that any program based upon RECs must utilize some method of certifying the RECs as green resources to ensure that the source of the REC is known and that the REC is not double-counted (*i.e.* both sold to ENO and used to satisfy the RPS requirement in the state in which it was generated, or sold to more than one customer).<sup>616</sup> Green-e is a nationally known and widely used service that performs such tracking and certification.<sup>617</sup> Therefore, the Advisors believe that use of Green-e certification, or a similar certification, for any RECs purchased by ENO for the Rider GPO would be appropriate.<sup>618</sup> Therefore, the Advisors recommend that the Council put in a requirement that RECs used for the Rider GPO must both (1) be certified by Green-e; and (2) conform to the definition of renewable resources ultimately

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<sup>612</sup> *Id.* at 54.

<sup>613</sup> *Id.*

<sup>614</sup> ENO Reply Brief at 116.

<sup>615</sup> *Id.*

<sup>616</sup> Advisors' Reply Brief at 54.

<sup>617</sup> *Id.*

<sup>618</sup> *Id.*

adopted by the Council in Docket No. UD-19-01.<sup>619</sup> To the extent that there is not a final Council decision in Docket No. UD-19-01 prior to the implementation of the Rider GPO, the Advisors recommend that ENO be allowed to utilize any Green-e certified RECs until such time as the Council renders a decision in Docket No UD-19-01, at which point, ENO must conform its use of RECs to the Council's definition of renewable resources on a going-forward basis,<sup>620</sup> and

**WHEREAS**, the Advisors are concerned about the proposal to include storage as a renewable resource because storage is not inherently a renewable form of electricity.<sup>621</sup> The Advisors note that (1) storage does not actually generate any electricity, it merely stores electricity generated by a generator until a more advantageous time to utilize that electricity and (2) the electricity from any given storage battery may or may not have originally been generated by a renewable resource.<sup>622</sup> The Advisors note, for example, that although many home batteries are coupled with a rooftop solar unit, there is no requirement that they be, and homeowners can easily install a home battery that is simply charged with electricity from the local utility, which is a mix of any number of renewable and non-renewable resources.<sup>623</sup> Therefore, while the Advisors would not exclude from eligibility any RECs originally from an energy source that have passed through a storage battery, the Advisors recommend that any such REC be able to demonstrate that the original source from which the electricity was generated was in fact a renewable resource and that the REC be Green-e certified so that the renewable properties of the electricity cannot be double-counted;<sup>624</sup> and

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<sup>619</sup> *Id.*

<sup>620</sup> *Id.*

<sup>621</sup> *Id.*

<sup>622</sup> *Id.* at 54-55.

<sup>623</sup> *Id.* at 55.

<sup>624</sup> *Id.*

**WHEREAS**, with respect to AAE and Sierra Club’s second proposed modification, that ENO be required to include express language in the Green Power Option tariff that expressly states that any costs or expenses not recovered from participants may not be recovered from ratepayers, ENO argues that Resolution No. R-18-97 requires that “[t]he green pricing proposal should reflect *to a reasonable extent* ENO’s incremental net cost to provide this option to customers.”<sup>625</sup> ENO argues that its testimony demonstrates that the pricing has been designed such that it is “reasonably assured” that the price of the RECs and incremental costs of offering the product will be recovered from participants.<sup>626</sup> ENO also states that actual participation levels and costs will be monitored, and ENO will seek adjustments, subject to Council approval, if warranted,<sup>627</sup> and

**WHEREAS**, the Advisors advise the Council that AAE and Sierra Club’s recommendation that ENO be required to include express language in the Green Power Option tariff that expressly states that any costs or expenses not recovered from participants may not be recovered from ratepayers is inconsistent with the regulatory doctrine that the utility must be allowed sufficient revenues to meet its operating expenses, provide its shareholders with a reasonable ROR and attract new capital.<sup>628</sup> The Advisors explain that such costs must be recovered from the utility’s customers, either the customers participating in the program or the non-participating customers.<sup>629</sup> It is the Advisors’ expectation that there will be enough interest in the program that there will be a sufficient number of participating customers to cover the program’s costs, and that in the event that there are not, the costs would be *de minimis* as testified

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<sup>625</sup> ENO Reply Brief at 117, citing Resolution No. R-18-97.

<sup>626</sup> *Id.*, citing Ex. No. ENO-19 at 48.

<sup>627</sup> ENO Reply Brief at 117, citing Ex. No. ENO-19 at 49.

<sup>628</sup> Advisors’ Reply Brief at 55, citing *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm’n*, 508 So. 2d at 1364-65, citing *So. Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm’n*, 352 So. 2d at 967.

<sup>629</sup> Advisors’ Reply Brief at 55.

to by ENO witness Owens.<sup>630</sup> The Advisors argue that because there is value to customers in being given an option, such as the Rider GPO, even if those customers do not take advantage of it, it would be reasonable for non-participating customers to bear such *de minimis* costs in the event the program does not prove to be popular,<sup>631</sup> and

**WHEREAS**, the Advisors, however, would not endorse a blank check to ENO to pass through any and all costs, whether reasonable or not, or to run an unsuccessful program indefinitely, because it would provide ENO with no incentive to design the program well or negotiate for reasonably priced RECs, etc.<sup>632</sup> Therefore, the Advisors recommend that the Council require that, in the instance where there are not enough customers participating in the Green Power Option to bear the costs of the program fully, ENO should be allowed to recover costs from non-participating ratepayers, but only after submitting such costs to the Council for review and demonstrating to the Council’s satisfaction that the costs were prudently incurred, along with a request to either terminate or alter the program.<sup>633</sup> The Advisors argue that this solution would uphold the requirements of *Hope* and *Bluefield*, while preserving the Council’s ability to protect ratepayers from having to bear imprudently incurred expenses and providing ENO with an incentive to run the program well,<sup>634</sup> and

**WHEREAS**, having considered the arguments of the parties, and considering that Council Docket No. UD-19-01 is ongoing and is actively considering both what resources should be defined as “renewable resources” under the Council’s rules and regulations and what certifications

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<sup>630</sup> *Id.*, citing City Council Hearing Transcript, 118:22-23 (June 19, 2019).

<sup>631</sup> Advisors’ Reply Brief at 55-56.

<sup>632</sup> *Id.* at 56.

<sup>633</sup> *Id.*

<sup>634</sup> *Id.*

would be required for RECs from such resources, the Council finds that ENO's Green Pricing Proposal should be approved with the following modifications:

- to the extent that the Council establishes a definition of "renewable resources" in Docket No. UD-19-01, RECs used for the Green Power Option must originate from sources meeting that definition;
- to the extent the Council adopts a requirement in Docket No. UD-19-01 that RECs be certified and/or tracked through a particular program(s), such as Green-e, then RECs used for the Green Power Option must be certified and/or tracked in the same manner, however, if the Council does not establish such a requirement in Docket No. UD-19-01, then RECs shall be certified through Green-e (or such other certification as the Council may approve in the future); and
- ENO's pricing proposal is approved but shall be modified to clarify that in the instance where there are not enough customers participating in the Green Power Option that the participating customers could reasonably be expected to bear the full costs of the program under the approved pricing structure, ENO should be allowed to recover remaining costs from non-participating ratepayers after submitting such costs to the Council for review and demonstrating to the Council's satisfaction that the costs were prudently incurred, along with a request for Council authorization to either alter the program to ensure that there is reasonable assurance that costs of the program will be paid by participating customers going forward, or a request to terminate the program; and

**WHEREAS**, the Council agrees with the Advisors' suggestion that to the extent that there is not a final Council decision in Docket No. UD-19-01 prior to the implementation of the Green Power Option, ENO be allowed to utilize any Green-e certified RECs until such time as the Council renders a decision in Docket No. UD-19-01, at which point, ENO must conform its use of RECs to the Council's definition of renewable resources and certification and/or tracking requirements on a going-forward basis; and

### **COMMUNITY SOLAR**

**WHEREAS**, ENO and BSI both propose some form of community solar program or pricing in this case. ENO proposes its Community Solar Offering ("Schedule CSO") while BSI proposes its CLEP community solar rate; and

(1) ENO Proposal

**WHEREAS**, ENO proposes a new community solar offering whereby participants voluntarily pay for a specific allocation of offsite solar PV projects, and in return for an upfront or ongoing payment, the participant receives a credit on his or her monthly electric bill, tied to the actual output of the solar PV project.<sup>635</sup> ENO proposes to use both its existing ~1 MW<sub>AC</sub> solar project located at the Paterson site along with the recently approved 5 MW<sub>AC</sub> rooftop solar project.<sup>636</sup> ENO argues that using existing projects allows interested customers to sign up for a program based on real-life systems as opposed to having to wait until enough interest has been expressed before ENO can move forward with constructing a resource to support community solar,<sup>637</sup> and

**WHEREAS**, ENO's proposed program would be open to both residential and non-residential customers on non-lighting rate schedules, subject to a few limitations.<sup>638</sup> ENO has designed its proposal as a "pay-as-you-go" model to maximize participation.<sup>639</sup> The monthly charge ENO proposes would be fixed for the duration of the offering and is set at \$15.00 per kW<sub>AC</sub> based on the customer's allocated share in kW.<sup>640</sup> ENO designed this rate to cover the incremental costs associated with using an outside vendor to get ENO's community solar offering up and running, as well as the monthly bill credits that customers receive for participating; it is not meant to cover the upfront and ongoing costs of the solar assets that underpin the offering - those costs will be reflected in overall rates that all customers pay.<sup>641</sup> ENO proposes that the credit rate that is applied to the customer's allocated share of the actual output of the solar systems

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<sup>635</sup> Ex. No. ENO-55 at 39.

<sup>636</sup> Ex. No. ENO-10 at 41:16-18.

<sup>637</sup> *Id.* at 41:20-42:3.

<sup>638</sup> *Id.* at 42:15-17.

<sup>639</sup> Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 43:19-20.

<sup>640</sup> Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 44:1-3.

<sup>641</sup> Ex. No. ENO-10 at 44:10-22.

that underpin the community solar offering be based on two components: the historic embedded value of generation, which is adjusted from time to time, and the current FAC value.<sup>642</sup> ENO states that any verified RECs produced by the solar systems that underpin the offering would belong to ENO, would be retired each year, and would not be transferred in any manner to subscribing customers,<sup>643</sup> and

**WHEREAS**, the Advisors argue that one of the principles established by the Council with regards to community solar programs was the principle of a level playing field.<sup>644</sup> In Resolution No. R-18-223, the Council specifically indicated that:

In order to ensure a level playing field, to the extent that ENO chooses to become a community solar developer, it must offer the same privileges it allows itself to all other developers. ENO may not give itself preferential treatment as a developer of a community solar project and may not use ratepayer funding for its community solar projects in any manner not available to other developers;<sup>645</sup> and

**WHEREAS**, the Advisors argue that ENO's proposed Community Solar Offering may result in preferential treatment for ENO that may discourage other Community Solar developers from developing projects in New Orleans under the Council's Community Solar Rules, because, it is ensured to recover its prudently incurred costs of any solar projects, regardless of the number of subscribers its Community Solar Offering has, or whether the fees and credits for its participants fully offset the costs of the projects;<sup>646</sup> and

**WHEREAS**, this guarantee that ENO would fully recover their costs even if it is not able to attract a sufficient number of subscribers or charge a high enough price, the Advisors argue, is an advantage that other community solar developers will not have.<sup>647</sup> The Advisors express doubt

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<sup>642</sup> Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 45:3-8.

<sup>643</sup> Ex. No. ENO-10 at 49:11-13.

<sup>644</sup> Advisors' Initial Brief at 129.

<sup>645</sup> Resolution No. R-18-233 at 3.

<sup>646</sup> Advisors' Initial Brief at 129, citing Ex. No. ADV-1 at 44:12-15 and 44:16-20.

<sup>647</sup> *Id.*



that that approving ENO's Community Solar Offering could bring community solar to New Orleans faster than allowing the market to form naturally under the Council's Community Solar Rules, and argue that it may permanently impair the market by preventing competing developers from being able to compete with ENO;<sup>648</sup> and

**WHEREAS**, the Advisors also argue that ENO's proposed Community Solar Offering monthly charge is designed to recover only the incremental administrative and marketing costs and the cost of providing solar credits to all potential participants at the retail rate, while the Community Solar Rules clearly state that the capital and operating costs of a community solar garden facility will not be recovered from ratepayers, but rather those costs are the responsibility of the developer/owner of the community solar garden to be recovered from the participants in it.<sup>649</sup> The Advisors argue that ENO's proposal violates this, by requiring ENO ratepayers to pay for a portion of the facilities' fixed costs;<sup>650</sup> and

**WHEREAS**, in addition, the Advisors argue that ENO's proposed credit for community solar is valued differently than the credit in the Council's Community Solar Rules, and that it would be preferable to have only one methodology for determining the appropriate credit for community solar offerings;<sup>651</sup> and

**WHEREAS**, ENO acknowledges that its proposed Community Solar Offering Rider does not comply with the Council's Community Solar Rules, but argues that it has sought approval despite those variances and demonstrated with undisputed evidence why Rider CSO can bring greater benefits to customers than if it were modified to conform to the Council's Rules;<sup>652</sup> and

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<sup>648</sup> *Id.*

<sup>649</sup> *Id.*, citing Ex. No. ADV-3 at 72:4-6 and 72:17-73:1.

<sup>650</sup> *Id.*, citing Ex. No. ADV-3 at 73:1-9.

<sup>651</sup> *Id.*, citing Ex. No. ADV-1 at 45:2-9 and 45:9-10.

<sup>652</sup> ENO Initial Brief at 168.

**WHEREAS**, ENO also argues that it has attempted to justify its Community Solar Offering in this proceeding and that ENO is entitled to an adjudication on the merits of its proposal in this proceeding based on any regulatory requirements that existed at the time the proposal was filed.<sup>653</sup> ENO argues that customers who enroll in its program would be able to switch to other developers later without any penalties if the Council’s community solar initiative ultimately attracts any, and would allow ENO to gain experience with the administration of a community solar offering before the Council’s initiative gets under way.<sup>654</sup> ENO also argues that it may reduce the incremental costs of administering the Council’s program, thus benefitting those customers as well.<sup>655</sup> ENO argues that its proposal will bring greater benefits than the Council’s Community Solar Rules because (1) it will not require the Council or CURO to create additional regulatory mechanisms for the oversight of ENO’s proposed rider; (2) it provides the opportunity for customers to participate in “Utility-Scale” offerings that could help to offset the revenue requirements associated with ENO’s commitment to add up to 100 MW of renewable energy to its generation portfolio; (3) it would mean that customers have a community solar option in a more timely manner.<sup>656</sup> ENO argues that it would be counterproductive and wasteful for the Council to reject ENO’s proposal,<sup>657</sup> and

**WHEREAS**, ENO argues that the evidence about the potential benefits of ENO’s proposed CSO is undisputed and that the Advisors’ criticisms and recommendations lack any foundation in evidence submitted in this proceeding.<sup>658</sup> ENO argues that its proposal can be viewed as complementary to, but deliberately designed to be separate from, the Council’s

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<sup>653</sup> Ex. No. ENO-12 at 39:6-9; Ex. No. ENO-13 at 12:12-13:18.

<sup>654</sup> Ex. No. ENO-12 at 39:16-22.

<sup>655</sup> *Id.* at 39:22-40:3.

<sup>656</sup> *Id.* at 41:9-42:8.

<sup>657</sup> *Id.* at 44:12-13.

<sup>658</sup> ENO Initial Brief at 166-167.

program.<sup>659</sup> ENO also argues that its proposal has the potential to be available much sooner than any offerings developed through the Council’s framework;<sup>660</sup> and

**WHEREAS**, the Advisors argue that ENO misrepresents the Advisors’ primary concern.<sup>661</sup> The Advisors argue that the Council must still review ENO’s proposal and make sure it is just and reasonable and while compliance with the Council’s Community Solar Rules would create a presumption that it is just and reasonable, the fact that formal community solar rules were not in place prior to ENO’s proposal does not mean that the Council is obligated to accept whatever community solar project ENO proposes;<sup>662</sup> and

**WHEREAS**, the Advisors do not believe that the potential near-term benefits of having some form of community solar available to ratepayers more quickly and allowing ENO to gain some experience administering a community solar program will be significant enough to offset the potential damage to the long-term market;<sup>663</sup> and

**WHEREAS**, AAE and the Sierra Club argue that the Council should reject ENO’s specific community solar tariff because the Company failed to establish that the proposal would bring greater benefits.<sup>664</sup> They argue that both of the benefits ENO claims its proposed structure would bring — being able to be in service more quickly and being able to offer it on a “pay-as-you-go” basis without long-term commitments — stem from ENO’s status as a regulated utility, and its ability to provide the offering from solar projects that are fully supported by all ratepayers in ENO’s rates.<sup>665</sup> They argue that this advantage places other solar developers at a clear and substantial disadvantage and, as a result, such developers may choose not to participate in the

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<sup>659</sup> *Id.* at 167.

<sup>660</sup> *Id.*

<sup>661</sup> Advisors’ Reply Brief at 56.

<sup>662</sup> *Id.* at 56-57.

<sup>663</sup> Ex. No. ADV-5 at 37:11-19.

<sup>664</sup> AAE/Sierra Club Initial Brief at 49.

<sup>665</sup> *Id.* at 49-51.

New Orleans market.<sup>666</sup> Thus, AAE and Sierra Club argue, ENO’s community solar offering does not meet the standard established by the Council in Resolution No. R-19-11 of demonstrating that the offering provides greater benefits than would a proposal conforming to the Council’s recently adopted Community Solar Rules.<sup>667</sup> To the contrary, they argue, ENO’s proposal creates the risk of real harm to the nascent community solar market without presenting any real benefits to New Orleans ratepayers, and should therefore be rejected;<sup>668</sup> and

**WHEREAS**, ENO claims that the Advisors’ recommendation expresses a general concern<sup>669</sup> that is unsubstantiated by any analyses, however, the Advisors argue that with significant concerns having been raised by the Advisors, AAE and Sierra Club, ENO bears the burden of demonstrating that its proposal is just and reasonable.<sup>670</sup> Had the proposal been in conformance with the Community Solar Rules, the Advisors argue, a presumption of reasonableness would have been in place, but it is not in conformance, and the Advisors do not believe that ENO has demonstrated that the benefits it claims from bringing community solar to New Orleans faster and allowing a “pay-as-you-go” model (which others may or may not also be able to offer) would outweigh the damage caused to the development of a competitive market for community solar in New Orleans;<sup>671</sup> and

**WHEREAS**, the Advisors argue that ENO has not made its case in this proceeding that its proposed community solar program is just and reasonable or in the public interest.<sup>672</sup> Nevertheless, the Advisors recommend that the Council reject ENO’s proposal in this proceeding without prejudice to ENO and being permitted to re-file either the same proposal or a modified

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<sup>666</sup> *Id.* at 51.

<sup>667</sup> *Id.*

<sup>668</sup> *Id.*

<sup>669</sup> ENO Initial Brief at 167.

<sup>670</sup> Advisors’ Reply Brief at 59.

<sup>671</sup> *Id.*

<sup>672</sup> *Id.*

proposal in the Community Solar docket with more support as to the issue of whether ENO's proposed structure would bring greater benefits than would a proposal that conforms to the Council's Community Solar Rules.<sup>673</sup> While ENO argues that requiring an additional filing would create "administrative waste,"<sup>674</sup> the Advisors disagree, writing that the Council needs more information to consider the potential benefits and adverse impacts of ENO's proposal, apart from the focus of the ratemaking decisions of the instant docket;<sup>675</sup> and

**WHEREAS**, ENO argues that the Advisors' and AAE's concerns about the potential market effect of ENO's Community Solar Offering are exaggerated.<sup>676</sup> ENO argues that AAE had not previously filed any testimony or otherwise previously taken a position on Community Solar.<sup>677</sup> ENO states that the concerns on the impact on the market are exaggerated because its Community Solar offering is limited to 6 MW of solar capacity and that any future community solar offerings made by the Company would be in accordance with the Council's new rules that were implemented after ENO made this rate case filing;<sup>678</sup> and

**WHEREAS**, the Council is pleased that ENO has been developing a community solar offering for its customers and encourages ENO to continue developing interesting new offerings for its customers; and

**WHEREAS**, the Council shares the Advisors' concerns that an improperly structured community solar offering could impede the development of a local community solar market; and

**WHEREAS**, the Council rejects ENO's Community Solar Offering as proposed in this case, without prejudice to ENO proposing a revised Community Solar Offering in the future; and

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<sup>673</sup> *Id.* at 59-60.

<sup>674</sup> ENO Initial Brief at 167.

<sup>675</sup> Advisors' Reply Brief at 60.

<sup>676</sup> ENO Reply Brief at 101.

<sup>677</sup> *Id.*

<sup>678</sup> *Id.* at 101-102.

(2) BSI Community Solar Proposal

**WHEREAS**, BSI proposes a CLEP solar rate where the customer would receive the sum of the monthly kWh produced by the customer's share of the community solar project multiplied by ENO's cost of energy plus the customer's CLEPm payment or charge plus the monthly sum of the customer's CLEP5 payments and charges;<sup>679</sup> and

**WHEREAS**, the Advisors observe that this would be instead of the community solar payments set by the Council's Community Solar Rules.<sup>680</sup> However, the Advisors argue, while BSI admits that its proposal would not be consistent with the Council's Community Solar Rules, BSI fails to demonstrate to the Council why its Community Solar proposal would provide greater benefits than a proposal that complies with the Council's rules.<sup>681</sup> In addition, the Advisors argue, the CLEP community solar proposal is too complex to be easily understood or implemented by customers;<sup>682</sup> and

**WHEREAS**, in adopting its Community Solar Rules, the Council explicitly left open the opportunity for parties to propose community solar projects that do not directly conform to the Council's rules and set forth a requirement that parties proposing such a program demonstrate why the alternative proposal brings greater benefits than a proposal conforming to the Community Solar Rules would bring.<sup>683</sup> However, the Advisors argue that BSI has not demonstrated that its community solar proposals provide greater benefit to ratepayers than a community solar project structured under the Council would.<sup>684</sup> Therefore, the Advisors do not recommend that the Council implement CLEP community solar;<sup>685</sup> and

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<sup>679</sup> Ex. No. BSI-1 at 17:16.

<sup>680</sup> Advisors' Initial Brief at 130, citing Ex. No. BSI-1 at 18:3-6.

<sup>681</sup> *Id.* at 130.

<sup>682</sup> *Id.* at 130-131.

<sup>683</sup> *See* Resolution No. R-18-538 at 30-31.

<sup>684</sup> Advisors' Initial Brief at 131.

<sup>685</sup> *Id.*

**WHEREAS**, while BSI argues that its CLEP proposal generally meets several Council objectives, it provides little description of how the CLEP Community Solar proposal would provide greater benefits to ratepayers than a program designed consistently with the Council’s Community Solar Rules, other than that CLEP payments would exceed payments to community solar participants under the Council’s Community Solar rules;<sup>686</sup> and

**WHEREAS**, BSI explains in Appendix 1 of its Reply Brief that it estimates that the CLEP Community Solar price would pay 17% more to participating customers than the retail cost of electricity.<sup>687</sup> BSI also notes in its Initial Brief that CLEP is helpful to community solar by paying 10% higher than retail.<sup>688</sup> However, BSI fails to explain why requiring ENO to pay community solar participants far more per kWh for the electricity they produce than ENO pays for the power it already provides ratepayers will bring more benefits to New Orleans ratepayers than the Council’s Community Solar Rules, which endeavor to balance the interests of participating and non-participating customers; and

**WHEREAS**, BSI argues that CLEP is superior to the Council’s Community Solar Rules adopted in Resolution No. R-19-111 because those rules assume that the primary way community solar will be implemented is through utility ownership, but treating Community Solar Farms as private enterprises moots most of the issues addressed in Resolution No. R-19-111.<sup>689</sup> However, the characterization of Resolution No. R-19-111 demonstrates a complete misunderstanding of that Resolution. Resolution No. R-19-111 and the Community Solar Rules adopted therein clearly

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<sup>686</sup> Building Science Innovators, LLC Reply Brief at 19, Aug. 9, 2019 (“BSI Reply Brief”).

<sup>687</sup> *Id.* at Appendix 1.

<sup>688</sup> *Id.* at 5.

<sup>689</sup> BSI Initial Brief at 24-25.

contemplates that a Community Solar facility could be owned either by the utility or by any other for-profit or not-for-profit entity or organization;<sup>690</sup> and

**WHEREAS**, in light of BSI’s apparent misunderstanding of the Community Solar Rules, the Council gives no weight to BSI’s arguments as to how CLEP benefits exceed those of the Community Solar Rules; and

### **COST RECOVERY FOR THE ENERGY SMART PROGRAM EECR/DSMCR**

**WHEREAS**, as the Advisors explain, the Council has long recognized energy efficiency and demand response offerings (collectively “demand-side management” or “DSM”) as high-priority resources for serving ENO’s customers, and in 2009, established the Energy Smart program to encourage the development of such resources in New Orleans by offering various programs and incentives for customers wishing to implement DSM measures to reduce their energy use;<sup>691</sup> and

**WHEREAS**, the Energy Smart Program is now nearing the end of Program Year 9, and has been funded through a variety of mechanisms over the first nine years of its existence.<sup>692</sup> The program has been highly successful, having received the U.S. Environmental Protection Agency’s Partner of the Year Award in both 2014 and 2016, a Pro 3 award from the Southeast Energy Efficiency Alliance and a first-in-the-nation ranking in an American Council for an Energy-Efficient Economy study with respect to the kWh savings per participant for low-income customers.<sup>693</sup> The program, however, has lacked a stable and predictable funding source;<sup>694</sup> and

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<sup>690</sup> Resolution No. R-19-111, Appendix A at II, Definition of Community Solar Generating Facility.

<sup>691</sup> See Resolution No. R-09-136. See also, Resolution Nos. R-07-600 and R-09-483; Advisors’ Initial Brief at 67.

<sup>692</sup> Advisors’ Initial Brief at 67.

<sup>693</sup> Ex. No. ENO-10 at 9:18-24, citing <http://aceee.org/sites/default/files/low-income-baseline-0717.pdf>.

<sup>694</sup> *Id.* at 11:1-3.



**WHEREAS**, in this case ENO proposes a new model for cost recovery related to DSM initiatives offered through Energy Smart.<sup>695</sup> ENO’s model would use a rider for Energy Smart funding, incorporating a regulatory asset that would earn a return and be amortized over three years, to recover the costs of each Program Year (“PY”) of Energy Smart.<sup>696</sup> Under ENO’s proposal the return and ROR that ENO would earn on the regulatory asset would function as an incentive mechanism for achieving the savings goals established during the Integrated Resource Plan (“IRP”) process.<sup>697</sup> The rider would also recover the LCFC, but would not include those dollars as part of the regulatory asset.<sup>698</sup> ENO argues that its proposed model would fulfill the Council’s directive that demand-side resources should be on an equal financial footing with traditional supply-side resources,<sup>699</sup> and

**WHEREAS**, ENO argues that cost recovery for DSM offerings must fairly address (1) direct and indirect costs of DSM offerings;<sup>700</sup> (2) LCFC and (3) some form of incentive, and that these three elements will “level the playing field” between DSM and supply-side alternatives and will increase the likelihood that a utility will maximize the utilization of cost-effective DSM to meet customer needs;<sup>701</sup> and

**WHEREAS**, ENO is proposing implementation of two separate riders as funding mechanisms -- one to continue funding for Energy Smart through the end of PY 9, the Interim Energy Efficiency Cost Recovery Rider (“Interim EECR”), and another mechanism intended to be

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<sup>695</sup> *Id.* at 3:10-12.

<sup>696</sup> *Id.* at 3:12-17.

<sup>697</sup> *Id.* at 3:17-211; ENO Initial Post-Hearing Brief at 111.

<sup>698</sup> Ex. No. ENO-10 at 3:20-4:1; ENO Initial Post-Hearing Brief at 111.

<sup>699</sup> Ex. No. ENO-10 at 5:8-11.

<sup>700</sup> Such costs would include direct incentives paid to customers and other direct costs, ENO labor costs and indirect costs necessary to develop and administer the DSM offerings and provide reporting, and amount paid to ENO’s vendors for development and administration of DSM offerings as well as separate EM&V services. *Id.* at 21:9-15.

<sup>701</sup> Ex. No. ENO-10 at 18:11-18; *see also* Ex. No. ENO-55 at 33.

applied for PY10 and beyond, the Demand-Side Management Cost Recovery Rider (“Rider DSMCR”);<sup>702</sup> and

### **INTERIM ENERGY EFFICIENCY COST RECOVERY RIDER**

**WHEREAS**, ENO designed the Interim EECR to contemporaneously recover the Council-approved funding for Energy Smart from customers for the period of August 2019 until December 2019<sup>703</sup> (the period between when the new rates go into effect and the end of PY9). ENO proposes that it would serve as an interim universal funding mechanism for both the Legacy ENO and Algiers Energy Smart offerings approved in Resolution No. R-17-623.<sup>704</sup> ENO states that the Council approved a similar Interim EECR in Resolution No. R-17-623 that was never implemented due to the availability of funding from another source<sup>705</sup> and that ENO’s proposed Interim EECR Rider in this proceeding utilizes the allocation factors that the Council approved in Resolution No. R-17-623.<sup>706</sup> ENO does not propose to implement the Interim EECR Rider as a line item on customers’ bills;<sup>707</sup> and

**WHEREAS**, the Advisors support the use of the Interim EECR,<sup>708</sup> and no party opposes the Interim EECR; and

**WHEREAS**, the Council finds the use of the Interim EECR to be reasonable; and

### **DSM COST RECOVERY RIDER**

**WHEREAS**, the second mechanism ENO proposes for recovery of its costs associated with DSM, its Rider DSMCR, is for PY 10 and beyond.<sup>709</sup> ENO proposes Rider DSMCR in

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<sup>702</sup> Ex. No. ENO-10 at 14:3-5; ENO Initial Brief at 112.

<sup>703</sup> Ex. No. ENO-10 at 14:17-19.

<sup>704</sup> *Id.* at 14:10-12.

<sup>705</sup> Resolution Nos. R-17-623 and R-18-227.

<sup>706</sup> Ex. No. ENO-10 at 15:1-2.

<sup>707</sup> *Id.* at 15:5-7.

<sup>708</sup> Ex. No. ADV-3 at 9:11-13, 68:3-13.

<sup>709</sup> Ex. No. ENO-10 at 15:11-14.

response to the Council Resolutions aimed at identifying a permanent funding mechanism for DSM customer offerings (Resolution Nos. R-17-504, R-17-623, and R-17 176).<sup>710</sup> ENO argues that running DSM costs through a rider allows the Council, its Advisors, and other stakeholders to specifically identify and track the level of ENO's investments in DSM and the recovery of those investments and that the use of a rider provides greater stability and facilitates planning by providing a long-term mechanism for helping to ensure that funding will be available, and a rider was clearly identified in Resolution No. R-17-623 as the preferable long-term approach.<sup>711</sup> ENO also argues that use of a rider that is updated annually provides a clearer path for the Council to incorporate changes to Energy Smart, or add other DSM offerings to ENO's demand-side portfolio, which would allow for greater flexibility in responding to customer needs.<sup>712</sup> ENO is not proposing that the rider appear on the customer's bill, rather that it be included within another line item such as the Energy Charge.<sup>713</sup> ENO's proposed Rider DSMCR would have four components;<sup>714</sup> and

**WHEREAS**, the first component would be the total balance associated with the DSM investment.<sup>715</sup> ENO's Rider DSMCR would utilize regulatory asset-based cost recovery model to allow DSM investment to be treated more equivalently to traditional supply-side and other investments in capital assets.<sup>716</sup> ENO argues this treatment would also initially help mitigate higher bill impacts that would otherwise occur with full contemporaneous cost recovery.<sup>717</sup> ENO proposes to amortize its total DSM investments over a three-year amortization period;<sup>718</sup> and

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<sup>710</sup> Ex. No. ENO-55 at 33.

<sup>711</sup> Ex. No. ENO-10 at 16:21-17:11, *see also* Ex. No. ENO-55 at 33.

<sup>712</sup> *Id.* at 17:11-15.

<sup>713</sup> Ex. No. ENO-10 at 17:19-21.

<sup>714</sup> *Id.* at 19:16-18.

<sup>715</sup> *Id.* at 19:11-12.

<sup>716</sup> *Id.* at 19:4-6 and 23:13-15; Ex. No. ENO-14 at 24:17-23.

<sup>717</sup> Ex. No. ENO-10 at 19:6-8; Ex. No. ENO-14 at 25:1-4.

<sup>718</sup> Ex. No. ENO-10 at 22:6-18; ENO Initial Brief at 111.

**WHEREAS**, AAE opposes the Rider DSMCR rate design. AAE urges the Council to reject ENO’s proposal to effectively “rate base” DSM expenses.<sup>719</sup> AAE also argues that the percentage of bill-based design effectively increases the fixed charge that a customer pays each month, which dampens the energy conservation price signal.<sup>720</sup> Additionally, AAE argues it is inappropriate because the objective of avoiding future energy supply costs and potentially distribution infrastructure costs does not have a customer-specific component or any other relationship to costs associated with connecting a customer to the grid.<sup>721</sup> AAE argues that a volumetric charge should be used for Rider DSMCR.<sup>722</sup> AAE recommends the following modifications to the Rider DSMCR: (1) a meaningful minimum savings threshold below which ENO recovers expenses but receives no return on those expenses and is subject to a penalty equivalent to the value of foregone cost savings for failing to achieve the minimum threshold; (2) a more granular formulaic incentive calculation system in place of the large “steps” in ENO’s proposal; and (3) a cap on total incentive awards;<sup>723</sup> and

**WHEREAS**, in response to AAE’s argument that the Council should reject any DSM cost recovery that allows ENO to “rate base” DSM, ENO argues that this ignores the Council’s goals of aligning the incentives equally for DSM and supply-side resources and providing a comparable earnings opportunity;<sup>724</sup> and

**WHEREAS**, ENO argues that in order to level the playing field between supply-side and demand-side investments, incentive mechanisms should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset;<sup>725</sup> and

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<sup>719</sup> AAE/Sierra Club Initial Brief at 32.

<sup>720</sup> Ex No. AAE-3 at 53:19-54:1.

<sup>721</sup> *Id.* at 53:1-5.

<sup>722</sup> *Id.* at 54:19-20.

<sup>723</sup> Ex. No. AAE-5 at 14:18-15:5.

<sup>724</sup> ENO Reply Brief at 78.

<sup>725</sup> *Id.* at 80.

**WHEREAS**, the Advisors believe it would be reasonable to use the proposed EECR Rider as the permanent mechanism to recover the costs (which have all been expenses and not capital investment) of the Energy Smart program for both Legacy ENO customers and Algiers customers, and that the Rider DSMCR should not be implemented.<sup>726</sup> The Advisors also recommend that prospective Energy Smart costs beyond 2019 be included in each FRP evaluation;<sup>727</sup> and

**WHEREAS**, AAE and Sierra Club support the Advisors' proposal to reject the proposed DSMCR Rider and make Interim EECR Rider proposed by ENO the permanent cost recovery method, and they propose removing language referencing LCFC from the EECR Rider and instead addressing the LCFC with the Advisors' proposal to allow for pro forma adjustments to evaluation period filling determinants for the twelve months subsequent to the FRP evaluation period;<sup>728</sup> and

**WHEREAS**, while ENO argues that Rider DSMCR would initially have a lower impact on customers, the Advisors argue that customers will pay less in total costs by recovering Energy Smart costs contemporaneously as expenses, rather than by deferring expenses and treating them as a regulatory asset.<sup>729</sup> Moreover, the Advisors argue, ENO is not proposing a true regulatory asset treatment, because ENO makes no attempt to match the term of the deferral of the payment of costs to the life of the DSM measures being funded, which is typically more in the 10-20 year range than in the three-year range.<sup>730</sup> Thus, the Advisors conclude, Rider DSMCR does not propose a true leveling of the playing field between DSM and traditional supply-side assets;<sup>731</sup> and

**WHEREAS**, the Advisors also argue that regulatory asset treatment is appropriate if a large, non-recurring cost is recovered over several future years, whereas Energy Smart costs recur

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<sup>726</sup> Ex. No. ADV-3 at 68:7-13; Advisors' Initial Brief at 71.

<sup>727</sup> Ex. No. ADV-3 at 68:10-11; Advisors' Initial Brief at 71.

<sup>728</sup> AAE/Sierra Club Reply Brief at 11-12.

<sup>729</sup> Ex. No. ADV-3 at 69:4-7; Advisors' Initial Brief at 71-72.

<sup>730</sup> Advisors' Initial Brief at 72.

<sup>731</sup> *Id.*

every year, and are only likely to increase as the program pursues the Council’s goal of increasing savings until it reaches 2% of annual sales.<sup>732</sup> The Advisors note that ENO witness Dr. Faruqui argues that while it is true DSM costs would not typically be recovered as a regulatory asset, the traditional regulatory paradigm can act as a road block to encouraging aggressive and effective DSM, and ENO has proposed a progressive solution to encourage innovation.<sup>733</sup> The Advisors, however, are not persuaded that a “progressive solution” that requires ratepayers to pay more in nominal dollars than they otherwise would for DSM in order to allow the utility to earn a return on DSM investment (as deferred expenses) is a solution that benefits ratepayers in the long term;<sup>734</sup> and

**WHEREAS**, the Advisors argue that while ENO performed and presented an analysis comparing net present values of funding options to demonstrate that ratepayers will ultimately save money with the proposed DSMCR Rider,<sup>735</sup> ENO’s Net Present Value calculations hinge on ENO’s assumptions regarding the time value of money -- essentially how much benefit a customer receives by being able to make use of their money over the time period for which payment is deferred.<sup>736</sup> The Advisors explain that, as ENO’s witness Owens conceded at hearing, ENO’s calculations of the value customers receive by being able to spread the costs over three years rather than by paying the costs up front are essentially based on the assumption that on average, customers could earn a return on their money of 7.78% over the time that the customer is able to keep the money.<sup>737</sup> The Advisors argue that this is an overly optimistic expectation of what customers, on average, would be able to achieve in the market or other investment vehicles if they

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<sup>732</sup> Ex. No. ADV-3 at 68:1-3 and 69:4-10; Advisors’ Initial Brief at 72.

<sup>733</sup> Ex. No. ENO-14 at 10:18-11:10; Advisors’ Initial Brief at 72.

<sup>734</sup> Advisors’ Initial Brief at 72.

<sup>735</sup> Ex. No. ENO-12 at 18:9-22:4.

<sup>736</sup> Advisors’ Initial Brief at 72.

<sup>737</sup> *Id.* at 72-73, citing City Council Hearing Transcript, 137:20-138:16 (June 19, 2019). *See also*, Ex. No. ENO-12 at 19:21-23 demonstrating the average cost of capital utilized was 7.78%.

could invest the amounts they defer paying to ENO, and therefore, the Advisors dispute ENO's claim that the analyses demonstrate that Rider DSMCR will actually have less of an effect on customers than Rider EECR;<sup>738</sup> and

**WHEREAS**, the Advisors argue that regulatory asset treatment is typically approved for non-recurring costs, like the construction of a power plant, while recurring and increasing annual costs, like those associated with the Energy Smart program, are typically treated as expenses and paid as they are incurred.<sup>739</sup> The Advisors point out that ENO concedes that ratepayers would pay substantially more in nominal dollars under the Rider DSMCR than under the EECR Rider, and ENO's net present value analysis attempting to demonstrate that customers are better off in the long term was based on an unreasonable assumption regarding the time value of money;<sup>740</sup> and

**WHEREAS**, while the Advisors express appreciation for ENO's stated intent to create a level playing field between supply-side and demand-side resources, they argue if ENO truly desired to create a level playing field, it would amortize the costs of each DSM program year over the life of the DSM resource (typically 10-20 years) rather than only for a three-year period;<sup>741</sup> and

**WHEREAS**, ENO argues that while the EECR arguably meets the goal of providing stable and predictable funding, it falls well short of meeting the Council's other goals.<sup>742</sup> ENO also argues that the EECR lacks a mechanism for recovery of LCFC and a reasonable performance incentive commensurate with the expected investments in Energy Smart.<sup>743</sup> ENO argues that the DSMCR proposal is the best cost recovery method proposed in this case because it provides the

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<sup>738</sup> Advisors' Initial Brief at 73.

<sup>739</sup> *Id.* at 81.

<sup>740</sup> *Id.*

<sup>741</sup> *Id.* at 80-81.

<sup>742</sup> ENO Reply Brief at 75.

<sup>743</sup> ENO Initial Brief at 115.

stable and predictable source of funding and it aligns incentives equally for DSM and supply-side resources and provides the opportunity to earn a comparable return;<sup>744</sup> and

**WHEREAS**, ENO argues that the company proposed a three-year amortization period rather than a life-of-measure amortization period because it ties directly to the Council's practice of approving portfolios and budgets for DSM programs in three-year cycles as part of the IRP process.<sup>745</sup> ENO notes, however, in its Reply Brief that it would be willing to extend the amortization period to up to 10 years, and that this would still result in Rider DSMCR having a lower rate impact on an NPV basis than the Advisors' proposed EECR;<sup>746</sup> and

**WHEREAS**, ENO argues that the Advisors' argument that 7.78% is an overly optimistic assumption of what the average ratepayer could earn in the market if they were able to keep and invest the money over the amortization period is unsupported speculation and that the 7.78% is the same discount rate ENO has historically used when comparing resource alternatives and is appropriate if demand-side and supply-side resources are to be evaluated on an equal footing.<sup>747</sup> ENO argues that the Rider DSMCR is the better cost recovery mechanism for pursuing the Council's aggressive DSM goals and implementing its long-term vision, and has a lower rate impact on customers;<sup>748</sup> and

**WHEREAS**, the Council agrees with the Advisors that DSM expenditures would not typically meet the requirement for being treated as a regulatory asset; and

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<sup>744</sup> ENO Reply Brief at 75.

<sup>745</sup> *Id.*, quoting Ex. No. ENO-10 at 22.

<sup>746</sup> *Id.* at 76.

<sup>747</sup> *Id.* at 77.

<sup>748</sup> *Id.* at 78.



**WHEREAS**, the Council finds that in light of the concerns raised by the parties, ENO has not presented sufficient evidence of the benefits to customers of its proposal to rate base DSM expenditures; and

**WHEREAS**, the second component to be recovered through proposed Rider DSMCR would be a utility performance incentive that would involve taking the resulting balance corresponding to the total amount of the investment (as deferred expense) in DSM offerings for a given PY and the Company being allowed to earn a return at ENO's pre-tax WACC based on its allowed ROE, subject to a performance adjustment;<sup>749</sup> and

**WHEREAS**, AAE argues that it is relatively uncommon for a utility to earn a ROR on DSM expenses, and that rather than being a trend for regulators to grant such treatment, it is merely a trend in what utilities want to get.<sup>750</sup> AAE does support the use of utility performance incentives as a method for encouraging energy efficiency, but states that the Council should be cautious and only reward truly good performance.<sup>751</sup> AAE also prefers an energy efficiency resource standard ("EERS") as a better option than a performance incentive.<sup>752</sup> AAE argues that ENO's proposed performance incentives are too rich and will provide shareholders a return regardless of the amount of savings achieved relative to target;<sup>753</sup> and

**WHEREAS**, AAE suggests a meaningful minimum savings threshold below which no additional earnings are received, such as 80% of the annual target with penalties for poor performance; a more graduated incentive with more granular steps; and a cap on total incentive awards;<sup>754</sup> and

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<sup>749</sup> Ex. No. ENO-10 at 19:19-23; Ex. No. ENO-14 at 26:12-14.

<sup>750</sup> Ex. No. AAE-3 at 39:14-40:7.

<sup>751</sup> *Id.* at 47:18-48:4.

<sup>752</sup> *Id.* at 48:4-7.

<sup>753</sup> *Id.* at 48:8-19.

<sup>754</sup> *Id.* at 49:15-50:5; AAE/Sierra Club Initial Brief at 40.

**WHEREAS**, the AAE and Sierra Club also argue that the Council should directly state what performance incentive will be used going forward, and state that they do not object to the performance incentive proposed by the Advisors in the Advisors’ March 1, 2018 Energy Smart Plan Recommendations for Program Years 7-9;<sup>755</sup> and

**WHEREAS**, ENO argues that AAE recommends an unnecessarily punitive performance incentive mechanism that does not recognize the Council’s Energy Smart framework already in place.<sup>756</sup> ENO argues that to level the playing field, the incentive mechanism should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset.<sup>757</sup> ENO also argues that AAE’s proposal to penalize ENO by limiting recovery solely to Energy Smart investments below a predetermined savings threshold, and additionally to impose a second-step penalty equivalent to the value of foregone cost savings for failing to achieve the minimum threshold is unreasonable, absent a finding of imprudence in light of the fact that it is ultimately the Council’s decision as to what ENO implements.<sup>758</sup> ENO is, however, amenable to a more granular framework with smaller “steps.”<sup>759</sup> In its rejoinder testimony, ENO proposes changing the framework such that achieving between 90% and 110% of targeted Energy Smart savings in a given year would not result in any ROE adjustment while ROE is reduced by 5 basis points for every 1% below 90% that is achieved, and increased by 5 basis points for every 1% above 110% that is achieved, with a maximum of up to 100 basis points.<sup>760</sup> ENO also states that there will be a cap on the performance incentive that is used,<sup>761</sup> and

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<sup>755</sup> AAE/Sierra Club Reply Brief at 12, citing Advisors Recommendations for Council Consideration Pursuant to Resolution R-17-623 Re: Unresolved Issues for Energy Smart Program Years 7-9, Docket No. UD-08-02 (Mar. 1, 2018).

<sup>756</sup> ENO Initial Brief at 121.

<sup>757</sup> Ex. No. ENO-12 at 29:11-13.

<sup>758</sup> Ex. No. ENO-13 at 10:2-11.

<sup>759</sup> *Id.* at 10:21-22.

<sup>760</sup> *Id.* at 10:22-11:4.

<sup>761</sup> *Id.* at 33:4:7.

**WHEREAS**, ENO argues that it makes no sense to defer the incentive mechanism structure, particularly with no guidelines at all around its potential future form, because this would not provide ENO with the certainty necessary to make DSM a core part of its business or put DSM on a level playing field with supply-side resources.<sup>762</sup> ENO urges the Council to determine the appropriate incentive procedure in this docket and not to delay consideration until the Council considers the specific goals and budgets for future years of Energy Smart in the IRP docket;<sup>763</sup> and

**WHEREAS**, the Advisors argue that while it is appropriate for a utility performance incentive to be included in ENO's compensation for the Energy Smart program, it is more appropriate for such mechanisms to be determined along with the Energy Smart program designs, budgets and savings goals than in a rate case, and the Advisors continue to recommend that the performance incentive be addressed in that proceeding rather than in this case.<sup>764</sup> The Advisors argue that ENO's argument that the Council should determine the appropriate utility incentive procedure in this Docket and not delay consideration is without merit, since the Council will be considering the implementation plan for the next Energy Smart program years in the third quarter of this year;<sup>765</sup> and

**WHEREAS**, the Council agrees that the appropriate performance incentive for the Energy Smart program is best considered in the Energy Smart docket alongside the targets and budgets set for the program; and

**WHEREAS**, in light of the anticipated timing of the Council's consideration of the Energy Smart docket, the Council finds that uncertainty regarding the performance incentive is unlikely to exist for an unreasonably long period of time; and

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<sup>762</sup> ENO Initial Brief at 117.

<sup>763</sup> Ex. No. ENO-12 at 23:6-9.

<sup>764</sup> Advisors' Initial Brief at 82.

<sup>765</sup> *Id.*

**WHEREAS**, the third component to be recovered through Rider DSMCR would be LCFC, adjusted each year based on the incremental (or decremental) change to ENO's DSM investment and resulting projected energy savings.<sup>766</sup> ENO proposes to calculate projected annualized LCFC amounts the same way that LCFC has been calculated historically, albeit with updated values reflecting the outcome of the rate case.<sup>767</sup> ENO proposes to calculate the total projected annualized LCFC amount for the upcoming year, which would be recovered concurrently through the Rider DSMCR (but not through the regulatory asset) and would be subject to a true-up relative to actual results that would occur in the following year.<sup>768</sup> ENO argues that it is important to provide recovery of LCFC in order to put DSM offerings and more traditional, supply-side resources on more equal footing;<sup>769</sup> and

**WHEREAS**, AAE opposes ENO's proposal to collect LCFC, and argues that a utility that has a decoupling mechanism will automatically recover the net effect of any energy or demand reduction resulting from its program, along with changes in energy and demand resulting from matters outside its influence or control, and therefore ENO does not need LCFC.<sup>770</sup> AAE also argues that an LCFC is not necessary to level the playing field between demand-side and supply-side resources because demand-side resources are more appealing than supply side resources due to the lack of any need for the utility to have any ongoing role in maintenance or operation of those resources.<sup>771</sup> AAE recommends that the Council reject the LCFC in favor of a simple decoupling mechanism that AAE proposes<sup>772</sup> and arguing that a full decoupling mechanism is a superior

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<sup>766</sup> Ex. No. ENO-10 at 20:1-6.

<sup>767</sup> *Id.* at 28:3-5.

<sup>768</sup> *Id.* at 28:8-12; Ex. No. ENO-14 at 25:11-18.

<sup>769</sup> *Id.* at 28:18-20.

<sup>770</sup> Ex. No. AAE-1 at 30:21-31:4; AAE/Sierra Club Initial Brief at 33.

<sup>771</sup> Ex. No. AAE-1 at 33:6-34:21.

<sup>772</sup> *Id.* at 38:16-17.

mechanism to a lost revenue adjustment.<sup>773</sup> AAE and Sierra Club also point out that ENO has failed to explain several aspects of its LCFC proposal, including the definition of adjusted gross margin and how reconciliation will occur;<sup>774</sup> and

**WHEREAS**, AAE also points out that lost revenues are not themselves equivalent to under-recovery of fixed costs for the utility because other factors, such as weather, customer growth, economic growth, or off-system sales may provide a balancing effect.<sup>775</sup> AAE also argues that there is strong evidence that decoupling is generally associated with better energy efficiency outcomes than LCFC;<sup>776</sup> and

**WHEREAS**, the Advisors oppose the inclusion of LCFC in any cost recovery mechanism,<sup>777</sup> noting that ENO's own witness, Dr. Faruqi states:

To address the issue of LCFC, regulators in many states allow utilities to recover the LCFC that is specifically associated with reduced energy sales due to the utility's DSM investments. Recovery of DSM-specific LCFC is most commonly achieved concurrently through a dedicated DSM rider based on a forward-looking period. In some states, regulators have **instead** chosen to fully decouple the utility's revenues from its energy sales (known as "full revenue decoupling.") (Emphasis Added),<sup>778</sup>

**WHEREAS**, in Resolution No. R-16-103, the Council directed ENO to file a proposal for full decoupling in this Combined Rate Case.<sup>779</sup> Therefore, the Advisors argue, the inclusion of LCFC in a DSM-specific rider is not appropriate, rather, any erosions in fixed costs should be considered in the annual FRP review and Decoupling mechanism;<sup>780</sup> and

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<sup>773</sup> Ex. No. AAE-3 at 39:8-13; AAE/Sierra Club Initial Brief at 34-35.

<sup>774</sup> AAE/Sierra Club Initial Brief at 36-37.

<sup>775</sup> Ex. No. AAE-3 at 42:15-18.

<sup>776</sup> *Id.* at 44:8-46:7.

<sup>777</sup> Ex. No. ADV-3 at 76:5-6.

<sup>778</sup> Ex. No. ENO-14 at 12:17-13:2.

<sup>779</sup> Resolution No. R-16-103 at 21.

<sup>780</sup> Ex. No. ADV-3 at 76:6-7; Advisors' Initial Brief at 78.

**WHEREAS**, Air Products, however, argues that to the extent the Council allows ENO to recover any LCFC costs, those costs should be recovered as part of the EECR or DSMCR mechanism and not as part of the FRP and decoupling mechanisms in order to keep those costs associated with the programs and customers that cause them.<sup>781</sup> Air Products notes that if the Advisors' proposal is to include LCFC in FRP evaluations and decoupling mechanism using the same allocation used by the EECR, it may address Air Products' concern;<sup>782</sup> and

**WHEREAS**, Air Products also argues that energy efficiency programs increase the utility's average cost of supplying service, resulting in an increase in rates, and that such programs can only be regarded as beneficial to nonparticipants if the end result were to be rates lower than they otherwise would have been, as evidenced by a Ratepayer Impact Measure test of 1.0 or greater.<sup>783</sup> Air Products argues that such an outcome is rare, and there is no evidence to support the RIM test results for the energy efficiency program being in excess of 1.0, therefore nonparticipants do not benefit from the energy efficiency programs;<sup>784</sup> and

**WHEREAS**, ENO argues Air Products' comments regarding the cost-effectiveness of energy efficiency are misplaced, because the Council has established rules and a process for assessing the cost effectiveness of each PY's portfolio of DSM offerings and their associated budgets;<sup>785</sup> and

**WHEREAS**, ENO emphasizes that it is undisputed that LCFC needs to be addressed, it is just a matter of where, but agrees with the Advisors that if the final design of the FRP incorporates features that ENO believes adequately address LCFC, then the Company would not need to recover

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<sup>781</sup> Ex. No. AP-4 at 12:13-13:14; Air Products' Initial Brief at 34; Air Products' Reply Brief at 5.

<sup>782</sup> Air Products' Initial Brief at 34.

<sup>783</sup> Ex. No. AP-4 at 13:15-21.

<sup>784</sup> *Id.* at 14:1-4.

<sup>785</sup> Ex. No. ENO-13 at 12:7-9.

LCFC amounts in Rider DSMCR or through some other cost recovery mechanism other than the FRP.<sup>786</sup> ENO witness Owens stated in his rebuttal testimony that the Advisors' proposal to make proforma adjustments to address timely recovery of demand-side management costs could present a workable solution to the LCFC issue, contingent on agreeing on the specific FRP language.<sup>787</sup> ENO does not, however, believe that the AAE's decoupling proposal could adequately address LCFC because it would delay recovery of the lost revenues by at least a year.<sup>788</sup> ENO opposes methods of cost recovery that would cause ENO to be always a year or more behind in the recovery of fixed costs attributable to Energy Smart-related DSM investments;<sup>789</sup> and

**WHEREAS**, the Council agrees with the Advisors that the erosion of any fixed costs is best considered in the annual FRP review and Decoupling mechanism; and

**WHEREAS**, finally, the fourth component included in ENO's proposed Rider DSMCR would be an adjustment resulting from a true-up that will occur once a year based on prior year actual results.<sup>790</sup> ENO proposes that Rider DSMCR rates be set only once a year and take effect at the beginning of each PY with the first billing cycle.<sup>791</sup> ENO also argues that the EECR may over or under-recover Energy Smart costs if it does not include some form of annual true-up mechanism within the EECR Rider, because of EECR revenues in any given year were less than the amount of Energy Smart program costs, but the FRP evaluation results were within the bandwidth, no rate adjustment would occur, and ENO would not recover all of the Energy Smart costs for that year;<sup>792</sup> and

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<sup>786</sup> Ex. No. ENO-12 at 10:13-18.

<sup>787</sup> Ex. No. ENO-13 at 7:10-11; *see also*, ENO Reply Brief at 80.

<sup>788</sup> Ex. No. ENO-13 at 7:17-8:5.

<sup>789</sup> Ex. No. ENO-12 at 11:4-11 and 12:11-19.

<sup>790</sup> Ex. No. ENO-10 at 20:16-18.

<sup>791</sup> *Id.* at 20:18-19.

<sup>792</sup> Ex. No. ENO-12 at 23:10-17.

**WHEREAS**, the Advisors recommend that the EECR Rider be utilized as the long-term funding mechanism for the Energy Smart program and argue that ENO has failed to demonstrate that its proposed Rider DSMCR would be more beneficial to ratepayers than the EECR Rider.<sup>793</sup> The Advisors argue that compared to ENO's arguments for its proposed DSMCR, the EECR (i) does represent a permanent funding mechanism, (ii) can track DSM investments and cost recovery through annual filings, (iii) provides stability by ensuring funding will be available, (iv) provides a clear path and flexibility to incorporate changes to DSM, (v) does not have to appear as a separate line item on customers' bills, and (vi) represents less of a financial burden to ratepayers than DSMCR, since the nominal cost to ratepayers with DSMCR would be higher including ENO's return on the regulatory asset;<sup>794</sup> and

**WHEREAS**, the Advisors assert that the EECR Rider will provide ENO with a reasonable opportunity to recover its DSM investments and<sup>795</sup> that lost revenues due to the Energy Smart program should be addressed through the decoupling and FRP mechanisms, rather than the proposed DSMCR rider.<sup>796</sup> The Advisors argue that the purpose of allowing lost revenue recovery is not to guarantee that the utility earns exactly as much money as it would if DSM was not implemented, rather it is to ensure that the utility has a fair and reasonable opportunity to earn its authorized revenue requirement.<sup>797</sup> Further, the Advisors state, to the extent that increased sales due to weather or other factors offsets revenues lost due to the implementation of energy efficiency measures, there is simply no need to further compensate ENO;<sup>798</sup> and

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<sup>793</sup> Advisors' Initial Brief at 80.

<sup>794</sup> *Id.*

<sup>795</sup> *Id.* at 81.

<sup>796</sup> *Id.*

<sup>797</sup> *Id.*

<sup>798</sup> *Id.*



**WHEREAS**, the Council finds that the EECR Rider is the appropriate long-term funding mechanism for the Energy Smart program; and

**DEMAND RESPONSE MECHANISMS**

**WHEREAS**, both ENO and BSI propose rates that would allow customers to be paid for actively reducing their load during key times; and

- (1) *ENO Proposal - Extend MVLMR and MCDRR to All Customers*

**WHEREAS**, ENO proposes to extend two of the riders previously in effect in the Algiers territory to all of its customers, the Market Valued Load Modifying Rider (“MVLMR”) and the Market Valued Demand Response Rider (“MVDRR”).<sup>799</sup> ENO explains that these riders provide the opportunity for qualified retail customers, or qualified aggregators of retail customers, to act as a load modifying resource (MVLMR) or a demand response resource (MVDRR), consistent with MISO-prescribed standards and requirements;<sup>800</sup> and

**WHEREAS**, the Advisors note that demand response and load modifying resources are important facets of the Council’s policy to expand demand side management in New Orleans,<sup>801</sup> and because these riders have already been implemented in Algiers, and ENO has experience administering the Riders; the Advisors support ENO’s proposal to expand the MVLMR and MVDRR to ENO’s full service territory.<sup>802</sup> The Advisors recommend, however, that because many customers will be unable to perform a cost benefit analysis of the investment they make by volunteering in the riders, ENO should provide support, such as providing a cost estimate from the

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<sup>799</sup> Ex. No. ENO-55 at 30.

<sup>800</sup> Ex. No. ADV-3 at 64:13-18.

<sup>801</sup> Ex. No. ADV-3 at 64:18-20.

<sup>802</sup> Advisors’ Initial Brief at 120-121.

MISO tariff and other related information regarding cost, to customers to help them make more informed decisions as to whether to voluntarily participate;<sup>803</sup> and

**WHEREAS**, the AAE and Sierra Club also support the extension of the MVLMR and MVCRR riders to its full service territory.<sup>804</sup> They support the suggestion that ENO be required to provide some kind of support to potential participants, including a cost-estimate so potential customers understand the programs and know what they are getting into.<sup>805</sup> AAE and Sierra Club also propose, for the first time in their Reply Brief, that the MVLMR rider be amended to (a) make it a multi-year commitment so that it is a useful planning resource for ENO; (b) increase the compensation towards long-term avoided costs to recognize the fact that it is a useful planning resource, and (c) allow customers to participate through aggregators of retail customers;<sup>806</sup> and

**WHEREAS**, no party opposes the extension of ENO's MVLMR and MVDRR riders to ENO's full service territory; and

**WHEREAS**, the Council notes that AAE and Sierra Club's proposed changes are not supported by any evidence in the record and were proposed for the first time in their Reply Brief such that no other party has had opportunity to probe or respond to the proposals; and

**WHEREAS**, the Council agrees that the expansion of the demand response riders supports the Council's policy to expand demand-side management in New Orleans; and

**WHEREAS**, the Council finds it reasonable to require ENO to add a component of customer support, including the provision of cost estimates to customers to be reasonable; and

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<sup>803</sup> Ex. No. ADV-3 at 65:4-9; Advisors Initial Brief at 121.

<sup>804</sup> AAE/Sierra Club Reply Brief at 21-22.

<sup>805</sup> AAE/Sierra Club Reply Brief at 22.

<sup>806</sup> *Id.* at 22.

(2) BSI CLEP Proposal

**WHEREAS**, BSI proposes the adoption of three Customer Lowered Energy Pricing (“CLEP”) rates, a CLEP residential rate, a CLEP non-residential rate, and CLEP community solar.<sup>807</sup> CLEP community solar is discussed above along with ENO’s community solar proposal. Under the proposed CLEP rates, a customer either earns a payment or incurs a charge every five minutes (called “CLEP5”).<sup>808</sup> The customer earns a CLEP5 payment for each five minute period in which either (a) the customer purchases electricity from ENO when the current MISO price of energy is lower than ENO’s cost to produce energy; or (b) the customer sells electricity to ENO when the current MISO price of energy is higher than ENO’s cost to produce energy.<sup>809</sup> Conversely, the customer would incur a CLEP5 charge within each five-minute period that the customer either (a) purchases electricity from ENO when the MISO price for electricity is higher than ENO’s cost to produce energy or (b) sells electricity to ENO when the current MISO price for energy is lower than the ENO’s cost to produce electricity;<sup>810</sup> and

**WHEREAS**, customers would also earn monthly payments or incur monthly charges (called CLEPm) for providing or demanding power at nearly the same times the utility experiences its annual peak demand.<sup>811</sup> The CLEP5 payments and charges are summed monthly and added to the CLEPm payment or charge to produce a credit or charge on the customer’s monthly bill.<sup>812</sup> It does not replace and otherwise has no effect on the customer’s regular monthly bill under the

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<sup>807</sup> Ex. No. BSI-1 at 6:13-16.

<sup>808</sup> Ex. No. BSI-1 at 12:1-9.

<sup>809</sup> Ex. No. BSI-1 at 12:1-9.

<sup>810</sup> Ex. No. BSI-1 at 12:9-13.

<sup>811</sup> Ex. No. BSI-1 at 12:17-19.

<sup>812</sup> Ex. No. BSI-1 at 16:11 and 17:1.

customer's regular rate.<sup>813</sup> If CLEP results in a payment to the customer that exceeds the charges the customer owes on its monthly bill, the customer receives a monetary credit;<sup>814</sup> and

**WHEREAS**, BSI states that CLEP payments benefit non-CLEP customers because "Every CLEP transaction will include a 5% service charge to be collected by the utility. Thereafter, some portion of the 5% service charge can be distributed to all ENO customers after deducting ENO's administrative costs according to the Council's rulemaking."<sup>815</sup> BSI also states that appropriate use of the CLEP rate by a customer will lower the average cost of electricity ENO incurs, while a CLEP customer that fails to modify their behavior and makes purchases or sales at the wrong time will only cause an increase in their own electricity bill;<sup>816</sup> and

**WHEREAS**, BSI argues that its CLEP rate would lower ENO's true cost of service to supply power, enhance reliability, appropriately assign demand charges to customers with higher than usual demand, correctly reflects residential customers' impact on demand and energy use, account for entities with a peak that differs from ENO's peak, provide economic benefit to customers who have heavily invested in storage, provide credits to EV owners who charge off peak, provide a financial incentive to install batteries, and generally cause customers to make choices that will lower demand;<sup>817</sup> and

**WHEREAS**, the Advisors argue that whether the CLEP proposal will actually produce these benefits is uncertain.<sup>818</sup> In addition, the Advisors find the design of CLEP to be extremely complicated and not one that customers will easily be able to navigate.<sup>819</sup> The Advisors believe customers are unlikely to be able to determine the relative positions of ENO and MISO's costs of

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<sup>813</sup> Ex. No. BSI-1 at 14:17-22.

<sup>814</sup> Ex. No. BSI-1 at 15:15-17.

<sup>815</sup> Ex. No. BSI-1 at 22:9-12.

<sup>816</sup> Ex. No. BSI-1 at 22:18-23:4.

<sup>817</sup> Ex. No. BSI-1 at 23:16-26:4.

<sup>818</sup> Advisors' Initial Brief at 122.

<sup>819</sup> Advisors' Initial Brief at 122-123.

producing electricity in five-minute increments.<sup>820</sup> The Advisors point out that BSI is clear that CLEP customers who fail to successfully adapt their behavior to change as the relative positions of ENO and MISO's costs change would see an increase in their electricity bills.<sup>821</sup> ENO opposes the CLEP proposal and argues that it appears to be substantially the same as to the proposal already rejected by the Council in Resolution Nos. R-16-106 and R-17-100.<sup>822</sup> The Advisors believe that the most likely outcome of implementing CLEP would be that most CLEP customers experience difficulty in managing their energy use and production in five minute increments, resulting in increased electricity bills and frustration.<sup>823</sup> Therefore, the Advisors do not recommend that CLEP be adopted by the Council, particularly in light of the demand response opportunities available under Riders MVLMR and MVDRR;<sup>824</sup> and

**WHEREAS**, the Advisor argue that as BSI notes, there are two primary ways that a customer can benefit from CLEP, the first would be by investing in programmable appliances and programming those appliances to run in a manner that takes advantage of CLEP pricing.<sup>825</sup> The second would be by hiring an aggregator to assist them.<sup>826</sup> The Advisors agree with BSI that, at least initially there will be few, if any, aggregators able to provide such a service,<sup>827</sup> and the Advisors note that it will take an extensive level of expertise in both ENO's pricing structure and MISO markets and will require access to real-time information about the price differentials between the two, in five-minute increments, as well as fairly extensive control over the consumer's

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<sup>820</sup> Advisors' Initial Brief at 122-123.

<sup>821</sup> Advisors' Initial Brief at 123.

<sup>822</sup> Ex. No. ENO-12 at 50:7-11.

<sup>823</sup> Advisors' Initial Brief at 123.

<sup>824</sup> Advisors' Initial Brief at 123.

<sup>825</sup> Advisors' Reply Brief at 60, BSI Initial Brief at 36.

<sup>826</sup> Advisors' Reply Brief at 60, BSI Initial Brief at 36.

<sup>827</sup> Advisors' Reply Brief at 60, BSI Initial Brief at 36.

consumption of electricity in five-minute increments, for an aggregator to effectively help customers make money by participating in CLEP;<sup>828</sup> and

**WHEREAS**, the Advisors argue that as to the use of programmable appliances, BSI posits that programming them to always run at the same time of day would be sufficient to allow a customer to profit from CLEP, but while this may generally work under average circumstances, it may not be able to shield customers from being penalized under CLEP when there are unexpected developments in the MISO market, such as unanticipated generator outages or capacity shortages.<sup>829</sup> Thus, the Advisors note, there is no guarantee that a customer will only get payments from CLEP and not incur occasional penalties.<sup>830</sup> As BSI notes, the electricity bill of a customer participating in CLEP could either go up, go down, or hardly change.<sup>831</sup> The Advisors note that as homes become increasingly automated over time and the grid becomes modernized and smarter, it is possible that at some point in the future a CLEP-like model could be adopted that allows smart devices and Artificial Intelligence to effectively manage energy use for the customer so that customers can benefit from CLEP with much less effort and investment, and at such time, it may make sense for the Council to consider such a model.<sup>832</sup> However, the Advisors argue, that time has not yet come, as matters stand today, the CLEP model is impractical to implement, and should be rejected by the Council;<sup>833</sup> and

**WHEREAS**, ENO supports the Advisors' arguments in favor of rejecting the BSI CLEP proposal.<sup>834</sup> ENO also points out that while CLEP participants would be engaging in energy transactions every 5 minutes, the data from AMI meters is recorded and transmitted in 15-minute

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<sup>828</sup> Advisors' Reply Brief at 60-61.

<sup>829</sup> Advisors' Reply Brief at 61.

<sup>830</sup> Advisors' Reply Brief at 61.

<sup>831</sup> BSI Initial Brief at 35.

<sup>832</sup> Advisors' Reply Brief at 61.

<sup>833</sup> Advisors' Reply Brief at 61.

<sup>834</sup> ENO Reply Brief at 84-85.

increments, thus, it does not appear that it is possible to implement CLEP without significantly altering the configuration of AMI deployment, which is presently underway;<sup>835</sup> and

**WHEREAS**, BSI also requests that the Council appoint a Load Flexibility and Time-of-Use Rate-Design Working Group to begin work immediately in designing and implementing CLEP that would include key stakeholders, ENO, the Council's utility Advisors, residential, commercial, municipal, water utility, and industrial customers, environmental justice and conservation communities and nationally recognized experts on load flexibility, and time of use rates, and that the Council should hire an independent consultant to advise the Working Group as well;<sup>836</sup> and

**WHEREAS**, although BSI argues that CLEP fulfills nearly every regulatory purpose and goal of the Council as well as addressing Global Warming and Sea Level Rise and will lower rates to all customers, the Council finds these claimed benefits to be speculative in nature and the overall design of CLEP to be overly complicated for consumers to understand while requiring a considerable amount of either programmable equipment, or skill and expertise either by the customer or an aggregator to be practical to implement at this time; and

**WHEREAS**, having rejected the CLEP proposal, the Council also rejects as moot BSI's request for the establishment of a working group to design and implement the CLEP proposal; and

### **EV CHARGING INFRASTRUCTURE**

**WHEREAS**, ENO proposes two different concepts designed to expand access to EV charging infrastructure in New Orleans and which would complement an offering currently

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<sup>835</sup> ENO Reply Brief at 85.

<sup>836</sup> BSI Reply Comments at 8.

available to residential customers.<sup>837</sup> ENO also proposes a separate initiative involving rebates for customer-owned EV charging infrastructure;<sup>838</sup> and

(1) *Rider Schedule Electric Vehicle Charging Infrastructure (“EVCI”)*

**WHEREAS**, the first concept, available to non-residential customers, would involve ENO constructing, owning, and operating EV charging infrastructure on customer-owned property.<sup>839</sup> In return, the customer would pay a fixed amount each month tied to a percentage specified under the proposed Rider Schedule EVCI and the installed cost of the equipment, less (1) the value of a 30% tax credit available from the State of Louisiana and (2) an estimated level of near-term, non-fuel revenue.<sup>840</sup> ENO argues that there are several benefits to non-participating customers: (1) new revenues from charging usage helps recover fixed costs on ENO’s system and other costs, and thus helps control rates for all of ENO’s customers; (2) only the participating customer is paying for the dedicated EV charging facilities; (3) to the extent the customer uses the program to provide public EV charger access (such as at a shopping mall or parking lot), non-participants who live in New Orleans and own or lease an EV would benefit from increased access; and (4) expanding access to EV charging infrastructure would provide important environmental and other public policy benefits.<sup>841</sup> ENO states that customers who take advantage of this program will be able to provide access to the chargers to their employees, customers, and/or tenants without issue, including being able to charge a fee for use of the charger;<sup>842</sup> and

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<sup>837</sup> Ex. No. ENO-55 at 40.

<sup>838</sup> Ex. No. ENO-10 at 58:5-7.

<sup>839</sup> Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 58:8-14.

<sup>840</sup> Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 59:9-12.

<sup>841</sup> Ex. No. ENO-10 at 60:18-61:4.

<sup>842</sup> Ex. No. ENO-10 at 64:19-21.



**WHEREAS**, the Advisors state that ENO’s Rider EVCI proposal is properly constructed.<sup>843</sup> The Advisors find that the rider would be entirely voluntary to ratepayers and would not impose any material costs on non-participant ratepayers.<sup>844</sup> The proposed Rider EVCI is consistent with the theory underlying Rider AFC, which the Council has already approved.<sup>845</sup> There appears to be no reason to expect that Rider EVCI would prevent ratepayers from funding their own EV charging stations; a commitment under Rider EVCI is entirely voluntary; however, the Council may wish to make clear to ENO that similar new meter installations are appropriate for ratepayer-funded EV charging stations, subject to all of ENO’s service standards.<sup>846</sup> The Advisors recommend that the Council approve Rider ECVI-1 as proposed by ENO, and specifically note that it is not to be applied prejudicially to ratepayers who choose to construct EV charging stations outside of Rider EVCI in terms of vendor selection, provision of related electric service, and financing services;<sup>847</sup> and

**WHEREAS**, no party opposes Rider EVCI; and

**WHEREAS**, the Council finds EVCI to be reasonable; and

(2) Public EV Charging Infrastructure Offering

**WHEREAS**, ENO’s second proposal would be available to public institutions and would involve ENO constructing, owning, and operating EV charging infrastructure solely for public use at a handful of key locations in New Orleans.<sup>848</sup> ENO would collaborate with City officials to determine optimal locations for the EV chargers, which could include downtown City-owned

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<sup>843</sup> Advisors’ Initial Brief at 135, Ex. No. ADV-6 at 94:10-11.

<sup>844</sup> Advisors’ Initial Brief at 135, Ex. No. ADV-6 at 94:11-12.

<sup>845</sup> Advisors’ Initial Brief at 135, Ex. No. ADV-6 at 94:12-14.

<sup>846</sup> Advisors’ Initial Brief at 135, Ex. No. ADV-6 at 94:19-95:1.

<sup>847</sup> Advisors’ Initial Brief at 135-136, Ex. No. ADV-6 at 95:19-96:2; Ex. No. ADV-2 at 50:6-8.

<sup>848</sup> Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 58:15-15-17.

right-of-way, public libraries and schools, parks, and other recreational areas.<sup>849</sup> ENO is proposing to invest up to \$500,000 over the next 24-30 months to build out EV charging infrastructure on public property that would be made accessible to electric vehicle drivers.<sup>850</sup> ENO is proposing to recover the capital investment and related expenses in retail rates through the normal ratemaking process,<sup>851</sup> and

**WHEREAS**, ENO is proposing that no additional fee or charge be levied on any EV driver for using the charging equipment regardless of where the EV charger is located relative to a customer's meter.<sup>852</sup> ENO explains that the City or other public entity that owns the property may charge for parking, but ENO would not impose an additional fee or charge related to using the EV charger or the electricity dispensed by the equipment used to charge the EV's battery.<sup>853</sup> ENO anticipates that the cost of the electricity provided in this manner would be small, and for locations where the charging equipment is not behind the customer's meter, ENO proposes that the value of electricity not being billed to the EV drivers would be reflected in ENO's FAC in the same way that unaccounted-for energy from line losses and other forms of non-technical losses are treated today;<sup>854</sup> and

**WHEREAS**, the Advisors support EV charging stations installed behind the ratepayer meter, where the ratepayer pays ENO for the electricity consumed and then makes a decision as to whether and how much to charge users of the EV charging stations to charge their cars.<sup>855</sup> The Advisors support the ability of such ratepayers to offer amenities, such as free EV charging, that

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<sup>849</sup> Ex. No. ENO-55 at 40-41; Ex. No. ENO-10 at 58:17-20.

<sup>850</sup> Ex. No. ENO-55 at 41; Ex. No. ENO-10 at 58:22-23.

<sup>851</sup> Ex. No. ENO-55 at 41; Ex. No. ENO-10 at 67:16-19.

<sup>852</sup> Ex. No. ENO-10 at 68:3-5.

<sup>853</sup> Ex. No. ENO-10 at 68:5-8.

<sup>854</sup> Ex. No. ENO-10 at 68:8-15.

<sup>855</sup> Advisors' Initial Brief at 137, Ex. No. ADV-6 at 100:12-15.

the ratepayer deems valuable to their business or purpose, and do not view free EV charging offered in this context as anti-competitive;<sup>856</sup> and

**WHEREAS**, the Advisors, however, do believe that ENO’s proposal to build some charging stations in front of the customer meter (where use is not measured or paid for) and to offer charging for free to EV drivers with the costs rolled into ENO’s rates and borne by all ratepayers could be problematic.<sup>857</sup> First, the Advisors argue, the generally accepted regulatory ratemaking principle of cost causation does not support socializing one ratepayer group’s (*i.e.*, EV charging station users) costs among other groups (*i.e.*, all other ratepayers), even if the subsidy is small, it is not appropriate to require other ratepayers to pay for an EV charger customer’s electricity.<sup>858</sup> Second, free EV charging offers an incentive for EV owners to avoid charging where energy is not free, such as at home.<sup>859</sup> Further, the Advisors express concern that since EV owners reasonably could be expected to prefer free EV charging stations over those that charge a fee, non-ENO EV charging station providers could be deterred from installing EV charging stations near an ENO free EV charging station;<sup>860</sup> and

**WHEREAS**, the Advisors argue that adding EV charging stations is consistent with the Council’s goals and policies regarding Smart Cities and environmental benefits for New Orleans; however, rather than having the Council decide an issue that could have such a significant impact upon the market for EVs in New Orleans as part of this rate case, the Advisors initially recommend that the issue of whether ENO should install EV chargers and/or offer free charging to the public should be taken up in the EV Docket, UD-18-01, where stakeholders with an interest in

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<sup>856</sup> Ex. No. ADV-6 at 100:12-15.

<sup>857</sup> Advisors’ Initial Brief at 137.

<sup>858</sup> Advisors Initial Brief at 137, Ex. No. ADV-6 at 99:4-7. Advisors’ witness Watson calculates the amount to be socialized in this manner as possibly being as high as \$64,432, ENO witness Owens argues that it would be only a fraction of that amount. Ex. No. ENO-12 at 46:3-21.

<sup>859</sup> Advisors’ Initial Brief at 137, Ex. No. ADV-6 at 99:7-9.

<sup>860</sup> Advisors’ Initial Brief at 138, Ex. No. ADV-6 at 100:8-10.

encouraging EVs in New Orleans will have better opportunity to participate in the discussion;<sup>861</sup>  
and

**WHEREAS**, with respect to the Advisors' proposal that the issue be considered not in this proceeding, but in UD-18-01, ENO proposes that the issue of ENO's investment be separated from the issue of where to locate the EV chargers, and that Docket UD-18-01 might be the forum in which ENO, the City and the stakeholders could collaborate as to where to locate the estimated 30 to 50 Level 2 chargers that ENO would construct and operate.<sup>862</sup> The Advisors agree with ENO's proposal and recommend that ENO be allowed to proceed with its proposed \$500,000 investment with siting of the charging stations to be considered as part of Council Docket No. UD-18-01.<sup>863</sup>

**WHEREAS**, the Advisors explain that the proposal to authorize ENO to invest up to \$500,000 in public EV charging infrastructure in the instant proceeding and then use Council Docket No. UD-18-01 to engage stakeholders where best to cite ENO's proposed EV chargers is reasonable and mitigates the Advisors' concerns, particularly in light of Council's stated interest in promoting environmental benefits, the limited scope of ENO's specific investment proposal, and the minimal amount of socialized costs.<sup>864</sup> The Advisors, therefore, recommend that the Council authorize ENO's proposed investment of up to \$500,000 in public EV charging infrastructure that would provide free EV charging services at roughly 30-50 locations and consider any stakeholder input as to the siting of such locations in Council Docket No. UD-18-01,<sup>865</sup> and

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<sup>861</sup> Advisors Initial Brief at 138, Ex. No. ADV-6 at 100:16-102:3.

<sup>862</sup> ENO Initial Brief at 181, and Ex. No. ENO-12 at 48:1-11.

<sup>863</sup> Advisors Initial Brief at 138-139, Ex. No. ADV-8 at 51.

<sup>864</sup> Advisors Initial Brief at 139, Ex. No. ADV-8 at 51:9-14.

<sup>865</sup> Advisors Initial Brief at 139, Ex. No. ADV-8 at 51:18-52:3.

**WHEREAS**, the Council finds the compromise proposed by ENO and the Advisors to be reasonable; and

(3) *Rebate for EV Charger Installation*

**WHEREAS**, ENO also proposes to continue with its Electric Technology initiative (“eTech”) under which it provides a \$250 rebate to qualifying customers to partially offset the costs they incur to install Level 2 EV chargers at their home or business.<sup>866</sup> ENO argues that the program is beneficial, because it allows ENO to know which of its customers have installed a Level 2 charger, and to periodically get data about impacts on electric load including hours of the day, possible frequency of charging, and so forth.<sup>867</sup> Knowing where EV chargers are located on its system and being able to perform analysis could help with grid planning and maintain reliability and also help inform how grid modernization can help to accommodate increased penetration of EVs.<sup>868</sup> ENO could also periodically survey participating customers to better understand their real-world experience as EV drivers in New Orleans, what actions they would like to see taken by ENO and/or the City to expand access, etc.;<sup>869</sup> and

**WHEREAS**, the Advisors also support ENO’s proposed EV charger rebate program.<sup>870</sup> A Level 2 charger may be considered a load-modifying resource when used off-peak, which can generate benefits for all ratepayers reflected in MISO charges and credits.<sup>871</sup> Because Level 2 chargers can be viewed as DSM and, when used off-peak, are likely to utilize less carbon-intensive production resources, the Advisors believe that encouraging Level 2 EV chargers through a rebate program is consistent with the Council’s policies on energy efficiency and environmental

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<sup>866</sup> Ex. No. ENO-10 at 69:9-12.

<sup>867</sup> Ex. No. ENO-10 at 69:16-19.

<sup>868</sup> Ex. No. ENO-10 at 69:19-70:2.

<sup>869</sup> Ex. No. ENO-10 at 70:3-70:6.

<sup>870</sup> Advisors Initial Brief at 140.

<sup>871</sup> Ex. No. ADV-6 at 96:16-97:1.

benefits.<sup>872</sup> The Advisors also believe that because EV chargers may be considered energy efficiency or DSM measures, it would be most appropriate to fund them through the Energy Smart Program, going forward, but recognizing that the earliest such a mechanism would be in place would be for Energy Smart Program Year 2020, the Advisors recommend that in the interim, the Council authorize ENO to continue its \$250 per Level 2 charger rebate program, and that any related cost recovery proposal be considered through the FRP mechanism;<sup>873</sup> and

**WHEREAS**, ENO argues that the eTech efforts are efforts at electrification (conversion of equipment that uses fossil fuel to electric), which ultimately increases electricity usage, and therefore should not be considered energy efficiency measures and funded through the Energy Smart program.<sup>874</sup> ENO argues that the costs should be recovered through normal ratemaking;<sup>875</sup> and

**WHEREAS**, ENO and the Advisors appear to be in agreement that the eTech program should continue, no party opposes it, and it is consistent with the Council's interest in fostering EV adoption in New Orleans. The Council finds that the eTech program should continue; and

**WHEREAS**, the Council finds that it may be advantageous to ENO's customers to have the eTech offering conveniently included within the Energy Smart program, and so agrees with the Advisors that the eTech rebate should be part of that program. However, the Council appreciates ENO's concern that the measure could increase a customer's overall energy use, rather than decrease it. To that end, the Council finds that it would be reasonable in the consideration of the design of the Energy Smart Implementation Plan for PY 10-12, for the parties to develop a method of evaluating the success of the eTech program separate and apart from the kWh savings

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<sup>872</sup> Ex. No. ADV-6 at 97:1-4.

<sup>873</sup> Ex. No. ADV-6 at 97:6-98:5.

<sup>874</sup> Ex. No. ENO-12 at 49:3-16.

<sup>875</sup> Ex. No. ENO-12 at 49:16-18.

goals of the other Energy Smart program measures, such that increases energy usage related to the eTech program does not count against ENO's ability to achieve the kWh and any kW savings goals established for Energy Smart PY 10-12; and

### **SERVICE REGULATION AMENDMENTS**

**WHEREAS**, ENO proposes certain minor modifications to its Service Regulations to reflect current practices, add new definitions, requirements and modifications necessary to reflect the changing nature of service (such as AMI, and the new offerings).<sup>876</sup> ENO states that such minor modifications include changes such as updating listings for ENO's website, updating hours of Customer Service centers, and job titles for certain employees, updating certain definitions to reflect AMI deployment, and language that separately references East Bank and West Bank customers, and eliminating outdated or duplicative language, as well as changes reflecting changes to the nature of service due to AMI deployment, broadening the definition of "written Communications" to reflect digital communications, and various other modifications reflecting the changing nature of utility service and new customer offerings;<sup>877</sup> and

**WHEREAS**, most of these proposed changes are unopposed by the parties. The Council finds the unopposed proposed changes to be reasonable; and

**WHEREAS**, one proposed change was objected to by the Air Products and the Advisors, specifically, the proposed change to Section 11 Continuity of Service, which would have changed ENO's responsibility for loss or damages caused by the failure or other defects of service, which both Air Products and the Advisors objected to as inappropriate;<sup>878</sup> and

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<sup>876</sup> Ex. No. ENO-6 at 59:4-9.

<sup>877</sup> Ex. No. ENO-6 at 59:18-62:6.

<sup>878</sup> Ex. No. AP-3 at 25:18-19, Air Products Initial Brief at 44, Advisors Initial Brief at 144.

**WHEREAS**, in its Reply Brief, ENO stated that it does not object to Air Products' recommendation that ENO's proposed change to the Continuity of Service provision in the Service Regulations not be adopted (though ENO objected to the Advisors' characterization of the effect of the provision);<sup>879</sup> and

**WHEREAS**, the Council finds the proposed changes to the Service Regulations, except for the proposed change to Section 11 Continuity of Service, to be reasonable. The Council rejects the proposed change to Section 11 Continuity of Service; and

### **CITY OF NEW ORLEANS BILLING ISSUES**

**WHEREAS**, CCPUG witness Baron recommends that the Council require ENO to establish a working group, following completion of the rate case to address billing issues. ENO opposes this recommendation, noting that CCPUG did not identify the aspects of billing that the City claims to be at issue, and recommends that instead the City work with its account representative to address any billing issues. The Advisors agree that a working group likely is not necessary to resolve the City's concerns and are willing to work with the City and ENO to assist in resolving these concerns to the City's satisfaction. CCPUG is supportive of the Advisors' suggestion, but still urges the formation of a working group; and

**WHEREAS**, the Council finds it unnecessary to establish a formal working group to address the City's issues at this time, but directs its Advisors to work with the City and with ENO to resolve the City's billing issues; and

### **TAX BENEFITS RELATED TO AMI**

**WHEREAS**, as part of the AMI deployment ENO must retire certain related existing plant, such as meters, prior to its full recovery through depreciation ("Stranded Plant").<sup>880</sup> The Advisors

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<sup>879</sup> ENO Reply Brief at 118.



note that the retirement of this Stranded Plant is associated with ENO's per-book recording of ADIT liabilities.<sup>881</sup> In its Revised Application, ENO incorrectly removed ADIT related to Stranded Plant from rate base in the amounts of \$6,227,006 and \$823,146 for electric and gas respectively.<sup>882</sup> Intervenors did not comment on ENO's exclusion of this ADIT from its rate base; and

**WHEREAS**, the Advisors recommend that ENO's rates should reflect the economic benefit it enjoys due to cost-free capital. Out of an abundance of caution for ENO's unspecified "potential violations" of IRS normalization rules, an appropriate mechanism to recognize ENO's cost-free capital is a regulatory liability.<sup>883</sup> As the economic benefit to ENO of Stranded Plant ADIT is undisputed, the Advisors recommend the Council recognize the benefit to ENO of cost-free capital and direct ENO to create regulatory liabilities in the amount of \$6,227,006 and \$823,146 for electric and gas respectively and include those liabilities in ENO's regulatory rate base;<sup>884</sup> and

**WHEREAS**, the Council finds that the Advisors' proposal is reasonable; and

**MISCELLANEOUS ISSUES**

(1) *Error in ENO's Calculation of Electric Taxes*

**WHEREAS**, in response to discovery in the instant proceeding, ENO has acknowledged an error in its calculation of electric taxes, which the Advisors estimate and present correcting adjustments in the below table;

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<sup>884</sup> Ex. No. ADV 8 at 37:10-13, Advisors Initial Brief at 148.

<b>Advisor Adjustment ADV06 Period II</b>		
<b>Account</b>	<b>Debit</b>	<b>Credit</b>
410101	\$141,633	
190221		\$141,633
410120	\$22,872	
190222		\$22,872

**WHEREAS**, the Council finds that ENO should correct for this error as part of its compliance filing; and

(2) *ENO's \$1/Year Per Gas Meter Gas Research and Development Charge*

**WHEREAS**, ENO has proposed a \$1 per year per gas meter gas research and development charge to fund ENO's participation in certain industry technology development groups; and

**WHEREAS**, the Advisors testified that, while such expenditures may involve energy efficiency and environmental benefits, and thus are indicative that they may be prudently incurred costs, ENO's proposed per meter charge is not necessary, would constitute single-issue ratemaking, and such costs should instead be recovered through ENO's gas base rates; and

**WHEREAS**, the Council is persuaded by the Advisors' arguments and finds that, while ENO's participation in the groups it discusses may be prudent, a special per-meter charge is not justified; and

**OTHER MISCELLANEOUS ISSUES**

**WHEREAS**, ENO is proposing that the Council approve of certain modifications to the Service Regulations Applicable to Electric and Gas Service by ENO.<sup>885</sup> The proposed modifications vary in purpose: addressing minor modifications necessary to reflect the changing

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<sup>885</sup> Ex. No. ENO-55 at 45.

nature of service due to innovations such as the impending deployment of AMI and new customer offerings and billing options the Company proposes to make available to customers<sup>886</sup> as well as the combination of the Algiers and Legacy ENO service territories into a single territory; and

**WHEREAS**, the Advisors reviewed and had no objection to and no other party objected to ENO's proposed changes related to Datalink and other related riders changing due to AMI;<sup>887</sup> the updates to fees for certain service schedules;<sup>888</sup> and the discontinuation of certain schedules;<sup>889</sup> and

**WHEREAS**, in light of the lack of objection to these proposals by any party, including the Council's Advisors, the Council finds these proposals to be reasonable; and

### **WITHDRAWN PROPOSALS**

**WHEREAS**, ENO proposed a Pre-pay Electric Service ("PES") Option and Pre-pay Gas Service ("PGS") Option (Schedules PES and PGS) which are prepaid billing options for residential customers.<sup>890</sup> ENO's proposal would be a voluntary billing option enabled by AMI and supporting technology.<sup>891</sup> The Advisors support the development of a pre-pay option for ENO customers.<sup>892</sup> However, in its rejoinder testimony, ENO suspended its request for approval of the pre-pay option due to delays and increased complexity in the integration of the AMI customer web portal with the Company's legacy IT and billing systems.<sup>893</sup> ENO states that the expected additional integration and IT development efforts to fully deploy pre-pay service are more complex than were originally

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<sup>886</sup> Ex. No. ENO-55 at 45-46.

<sup>887</sup> Advisors' Initial Brief at 141-142.

<sup>888</sup> Advisors' Initial Brief at 144-146.

<sup>889</sup> Advisors' Initial Brief at 146-147

<sup>890</sup> Ex. No. ENO-55 at 42.

<sup>891</sup> Ex. No. ENO-55 at 42-43; Ex. No. ENO-19 at 4:20-5:2.

<sup>892</sup> Advisors' Initial Brief at 124.

<sup>893</sup> Ex. No. ENO-13 at 14:4-8.

envisioned.<sup>894</sup> Because ENO has suspended this request, the Council will not consider ENO's pre-pay proposal at this time; and

**WHEREAS**, in its Revised Application, ENO proposed a voluntary fixed billing option for residential customers under which, in exchange for paying a premium over what the standard residential service rate would be, customers receive a monthly fixed bill that will not change over the contract period.<sup>895</sup> However, in response to the Advisors' testimony, ENO withdrew this proposal in its Rebuttal Testimony.<sup>896</sup> Therefore, the Fixed Billing proposal also will not be addressed by the Council at this time; and

### **COMPLIANCE FILING**

**WHEREAS**, the Revised Application discusses ENO's making a compliance filing resulting from a decision from this proceeding; and

**WHEREAS**, this resolution does not and is not intended to specify ENO's exact revenue requirements or exact rates that would allow ENO to collect such revenue amounts; and

**WHEREAS**, this resolution directs ENO to make numerous adjustments to its proposed revenue requirements and rates; and

**WHEREAS**, it is not practical for the Council to calculate with precision the rates ENO should be allowed to implement to comply with each aspect of this resolution; and

**WHEREAS**, the Council desires for its Advisors to confer with ENO as soon as practicable to share with ENO the Advisors' opinion as to the revenue requirement and rate class impacts of this resolution; and

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<sup>894</sup> Ex. No. ENO-13 at 14:10-12.

<sup>895</sup> Ex. No. ENO-55 at 44.

<sup>896</sup> Ex. No. ENO-21 at 2:10-11.

**WHEREAS**, in a motion in the instant proceeding filed before the Hearing Officer on July 11, 2019, ENO stated that it maintained its commitment that the effective date of the rates approved by the Council will be the first billing cycle of August; and

**WHEREAS**, in the same motion in the instant proceeding filed before the Hearing Officer on July 11, 2019, ENO discussed that a Council determination in the instant proceeding by September would allow ENO to implement rates with the first billing cycle of November; and

**WHEREAS**, the Council desires for ENO to demonstrate how it will comply with each provision of this resolution by making a compliance filing within 30 calendar days of the adoption of this resolution providing all relevant documents for each of electric and gas, including,

1. Total company retail revenue requirements subtotaled by rate class (for electric, each of the nine customer classes identified in the Revised Application).
  - a. A detailed set of work papers demonstrating that such revenue requirements are in full compliance with each provision of this resolution and do reflect costs not approved by the Council.
2. A computation of each fee, charge, rate, proscribed credit, or other mechanism by which ENO receives revenue or credits against revenue requirement, that, when applied to ENO's Period II billing determinants, would allow ENO to collect its revenue requirement for each rate class.
3. A computation of all credits and charges appropriate and required for ENO's new rates to be effective as of the first billing cycle of August 2019.
4. Interim rate adjustment riders for each of electric and gas to provide required credits by rate class consistent with the excess revenues collected from each rate class from

the first billing cycle of August 2019 through the last billing cycle before new rates go into effect.

- a. The allocation of credits among the rate classes shall, to the extent practicable, reflect the allocation method employed to collect excess revenues (*e.g.*, volumetric, demand, base rate).
  - b. The calculation of credits shall reflect carrying charges reflective of the source of excess collections (*e.g.*, excess collections through the FAC shall accrue carrying charge credits at the FAC's over/under rate). For excess collections received from sources not having an over/under provision (*e.g.*, base rates), the FAC's over/under rate shall apply.
  - c. For any rider having a true-up mechanism and which under-collected its approved revenue requirement through July 31, 2019, a provision to first apply over collections from August 1, 2109 to the under-collection balance.
  - d. For electric, and to the extent reasonably practicable, a mechanism to return over collections according to service area (*i.e.*, the east and west bank of the Mississippi River).
  - e. The interim rate adjustment rider may itself have a true-up provision.
  - f. The interim rate adjustment rider may return over collections over a reasonable period of time not to exceed three months.
5. Copies of all documents, such as service schedules, riders (including the E-FRP and GFRP riders), or terms affecting ENO's service and rates that are required to be altered to comply with this resolution, with rates presented therein.

6. For each ratemaking treatment ordered herein that is not consistent with ENO's Revised Application, a description of how ENO has implemented such treatment and in which workpaper or other document its implementation may be mathematically reviewed; and

**WHEREAS**, the Council does not seek to permit ENO to include adjustments as part of its compliance filing that are not ordered herein that ENO may regard as ancillary consequences of this resolution's ratemaking directives or treatments; and

**WHEREAS**, the Council desires for ENO and the Advisors to work together to ensure ENO's compliance filing reflects every aspect the orders in this resolution; and

**WHEREAS**, the Council desires for the Advisors to review ENO's compliance filing and to have all relevant information required for such a review made available by ENO; and

**WHEREAS**, the Council desires for the Advisors to have fifteen (15) business days to review ENO's compliance filing for accuracy, compliance with this resolution, and consistency with established Council ratemaking practices; and

**WHEREAS**, should the Advisors identify any error or deficiency in ENO's compliance filing, or require additional information to validate any part of ENO's compliance filing, the Council desires for the Advisors to identify and report to ENO such error or deficiency along with any documentation and proposed correction, and then for ENO and the Advisors to work together to resolve all issues; and

**WHEREAS**, the Council desires for the Advisors to, at the conclusion of their review of ENO's compliance filing, to state whether ENO's compliance filing complies fully with this resolution and is appropriate in all material aspects or to identify any remaining deficiencies; and

**WHEREAS**, the Council desires that, unless the Advisors conclude that ENO's compliance filing results in rates that are wholly inappropriate, that retail rates in compliance with this resolution be affected, as soon as practicable by ENO notwithstanding any unresolved issues; and

**WHEREAS**, the Council desires that, in the event there are disputes regarding ENO's compliance filing that cannot be resolved through good faith efforts by ENO and the Advisors, the Advisors should report such issues, along with documentation and the Advisors' recommended correction, to the Council for the Council's evaluation; and

**WHEREAS**, the Council desires that any corrections to ENO's compliance filing that are resolved after new rates are affected be made effective as of the first billing cycle of August through the interim rate adjustment rider's true-up mechanism; and

**WHEREAS**, the Council has reviewed ENO's Revised Application and the record and considered all arguments raised therein, to the extent that any specific argument is not herein addressed, the Council has reviewed such argument and found that it was duplicative, cumulative, or otherwise did not have sufficient impact on the Council's decision to warrant discussion herein;

**NOW THEREFORE**

**BE IT RESOLVED BY THE COUNCIL OF THE CITY OF NEW ORLEANS**

**THAT:**

1. ENO's ROE shall be set at 9.35% and shall operate as a bandwidth midpoint for purposes of the formula rate plan approved in this proceeding.
2. ENO's WACC shall be based on an equity ratio equal to the lesser of ENO's actual equity ratio or 50% and shall be used for all rate ratemaking purposes.
3. ENO's proposed depreciation rates are approved, except:
  - a. ENO shall employ a 40-year depreciable life schedule for UPS effective August 1, 2019.



- b. ENO shall employ a 50-year depreciable life schedule for NOPS.
  - c. ENO shall amortize the general plant reserve deficiency over a 20-year period.
4. ENO's proposal to exclude FIN 48 ADIT liability balances from its rate bases is denied.
  5. ENO's proposal to include NOLCF ADIT asset balances in its rate bases is denied.
  6. ENO shall employ its then current WACC with each calculation of Rider SSCO's rate.
  7. ENO is directed to create regulatory liabilities in the amount of \$6,227,006 and \$823,146 for electric and gas respectively and include those liabilities related to Stranded Plant ADIT in ENO's regulatory rate base.
8. ENO's proposal to recover Restrictive Stock Incentive Plan costs is denied.
  9. ENO's proposed pension asset adjustment is approved.
  10. ENO's proposed GIRP rider is denied.
    - a. ENO's GIRP infrastructure costs incurred as proformed through the end of 2019 and generally approved by Resolution R-17-38 are approved for cost recovery through base rates.
    - b. Within 120 days from the date of this order, ENO is directed to propose, for Council consideration, a rate of gas distribution pipe installation and dollar investment that is required to maintain the safe operation of ENO's gas system including potential measures to mitigate the identified impact on ratepayers.
    - c. Within 120 days from the date of this order, ENO is directed to convene a working group composed of the Advisors, ENO, and Intervenors to explore appropriate cost mitigation measures.
    - d. ENO's recovery of utility conflict survey costs is approved and ENO is directed to recover its related costs through base rates.
  11. ENO's proposal to allocate certain PPA costs on a volumetric basis is denied.
  12. The Council denies CCPUG's recommendations to:
    - a. Remove Capital Storm Restoration Costs from Plant
    - b. Remove Depreciation Expense Associated With Capital Storm Restoration Costs
    - c. Remove Amortization of Algiers Migration Costs
    - d. Reduce Depreciation Expense – Correct Paterson Solar Depreciation Rate
    - e. Remove Reduction to ADIT for Excess ADIT Amortization in 2019
    - f. Remove Algiers Migration Costs Net of ADIT

- g. Reduce Depreciation Expense – Use 0% Net Salvage for Union Power Block #1
  - h. Extend Amortization of Algiers Transaction and Migration Costs to 10 Years
  - i. Remove Plant, A/D, and ADIT Proforma Adjustments Related to 2019 Additions
  - j. Remove Depreciation Expense Related to 2019 Plant Additions.
13. The Council approves CCPUG’s recommendations to,
- a. Correct Cash Working Capital to Include Dividend Component of Return on Equity
  - b. Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1
  - c. Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years
  - d. Remove Forecast 2019 Increases in Payroll and Related Expenses
14. The utility’s total revenue requirements, as determined by compliance with each of the Council’s directives in this Resolution, will be recovered from each customer class on the basis of the Advisors’ proposal for customer class revenue requirements as indicated in Advisors’ Exhibits VP-20 and VP-21 for the electric and gas utilities respectively.
15. ENO’s proposal to eliminate and consolidate customer classes, including the existing Algiers electric tariffs, to be combined into nine electric customer rate classes is approved.
16. ENO is directed to provide a complete cost of service analysis in support of the NJ customers’ rates as part of future Council rate actions. ENO is further directed not to execute any new NJ contracts without express Council approval.
17. ENO’s DGM Rider is rejected and ENO is directed to recover its costs related to grid modernization through base rates.
18. The AART Plan shall be adjusted consistent with the Advisors recommendations except that instead of the mitigation plan being funded by the Legacy ENO residential customers, it shall be funded by the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes in proportion to their base rate revenue requirements.
19. ENO’s proposed FAC Rider is approved as corrected by the Advisors.
20. ENO’s proposed PGA Rider is approved as corrected by the Advisors.
21. ENO shall revise its proposed PPCACR Rider in accordance with the recommendations made by the Advisors for a PPCR Rider.
22. The MISO Cost Recovery Rider is approved as proposed.

23. The Company's \$8.07 electric residential customer charge shall remain unchanged.
24. ENO's proposed AMI Riders and customer charges are denied.
25. The Council approves ENO's proposed electric and gas FRP mechanisms with the following modifications:
  - a. Total utility cost of service, including total ENO revenues and expenses shall be utilized in the FRP evaluation;
  - b. The Advisors' proposed provision that "ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP evaluation Period" shall be add to FRP Attachment C, Evaluation Period Adjustments, paragraph 8.
  - c. ENO's proposed RIM is rejected.
  - d. The electric FRP decoupling revenue adjustment for each customer class should be determined by comparing the evaluation period fixed and variable revenue by class with the FRP evaluation period allocation of total ENO fixed and variable revenue requirement.
  - e. No NOPS costs shall be included in the FRP mechanism until such time as the construction of NOPS and associated costs have been approved through a final judgment of the Council. To the extent that the Council's judgment becomes final, the proforma adjustments related to NOPS shall be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP. If the NOPS updated revenue requirement is included as a prospective proforma adjustment in the bandwidth evaluation of the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS cost recovery is included in the E-FRP revenue adjustment of the first FRP. If the NOPS updated revenue requirement filing is not included as a prospective proforma adjustment in the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS costs are included in the RPE bandwidth evaluation of the following E-FRP. The E-FRP provision should include an allocation of NOPS costs based on the rate case production demand allocation factor, rather than total base rate costs.
26. ENO's decoupling proposal shall be modified such that a full decoupling mechanism shall be filed with each electric E-FRP evaluation, with total allocated costs of service for each customer class included in the decoupling revenue adjustment, and the customer rate class allocation factors be updated annually with current billing determinants. The decoupling adjustment shall be applied to all customer classes if the E-FRP revenue adjustment is outside the bandwidth. However, ENO shall, for rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, implement a decoupling revenue adjustment cap of 10% which will apply to each of the 3 annual E-FRP evaluation period revenue adjustments provided that the total electric utility FRP revenue adjustment for that evaluation does not exceed 10%. A new baseline of customer class fixed and variable revenue requirements shall be determined in each E-FRP from an

allocation of costs and a return component based on the rates of return corresponding to the customer class total revenues set in the instant docket. Any adjustments that may be needed to the relative rates of return will be such that those adjustments move the relative customer class rates of return toward the utility's rate of return based on the weighted average cost of capital. The revenue deficiencies/excesses shall be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period total actual revenues, with the decoupling adjustments applied within each customer class using updated billing determinants excluding the customer charge. The decoupling adjustment shall apply to proforma revenue requirements and billing determinants in the E-FRP rate effective period, based upon updated allocation factors and billing determinants in each E-FRP.

27. ENO's Green Pricing Proposal is to be approved with the following modifications:

- a. to the extent that the Council establishes a definition of "renewable resources" in Council Docket No. UD-19-01, RECs used for the Green Power Option must originate from sources meeting that definition;
  - b. to the extent the Council adopts a requirement in Council Docket No. UD-19-01 that RECs be certified and/or tracked through a particular program(s), such as Green-e, then RECs used for the Green Power Option must be certified and/or tracked in the same manner, however, if the Council does not establish such a requirement in UD-19-01, then RECs shall be certified through Green-e (or such other certification as the Council may approve in the future);
  - c. ENO's pricing proposal is approved with the modification that in the instance where there are not enough customers participating in the Green Power Option that those customers could reasonably be expected to bear the full costs of the program under the approved pricing structure, ENO should be allowed to recover remaining costs from non-participating ratepayers after submitting such costs to the Council for review and demonstrating to the Council's satisfaction that the costs were prudently incurred, along with a request for Council authorization to either alter the program to ensure that there is reasonable assurance that costs of the program will be paid by participating customers going forward, or a request to terminate the program; and
  - d. to the extent that there is not a final Council decision in Docket No. UD-19-01 prior to the implementation of the Green Power Option, ENO shall be allowed to utilize any Green-e certified RECs until such time as the Council renders a decision in UD-19-01, at which point, ENO must conform its use of RECs to the Council's definition of renewable resources and certification and/or tracking requirements on a going-forward basis.
28. Both ENO's and BSI's Community Solar proposals are rejected.
29. The Interim EECR Rider is approved.
30. The proposed Rider DSMCR is rejected. In its place an EECR Rider consistent with the Advisors' proposal is approved. LCFC shall be addressed through the decoupling process and shall not be included in the EECR Rider.

31. ENO's proposal to extend its MVLMR and MCDRR to its full service territory is approved. ENO is directed to add customer support to the program, including the provision of cost estimates to interested customers to encourage understanding of and participation in the program.
32. BSI's CLEP proposal is rejected, as is BSI's request that the Council form a working group to implement CLEP.
33. ENO's proposed Rider EVCI is approved.
34. ENO is authorized to invest of up to \$500,000 in public EV charging infrastructure that would provide free EV charging services at roughly 30-50 locations and shall consider stakeholder input as to the siting of such locations in Council Docket No. UD-18-01.
35. ENO is authorized to continue with the eTech program of rebates for the installation of EV chargers, with the program to be included in the Energy Smart Implementation Plan for PY 10-12. In the proceeding considering that Implementation Plan, the parties should develop a method of assessing the success of the eTech program separate and apart from the kWh and any kW savings goals established in the Implementation Plan for PY10-12 such that increased usage related to the success of the eTech plan does not negatively impact ENO's ability to achieve the savings goals related to other measures.
36. The proposed changes to the Service Regulations, except for the proposed change to Section 11 Continuity of Service, are approved. The proposed change to Section 11 Continuity of Service is rejected.
37. ENO shall correct tax errors in its Revised Application related to FERC Accounts 410 and 190.
38. ENO shall create a regulatory liability and enter such liability's balance in its rate base to reflect the economic benefit of cost free capital related to retired meters.
39. ENO's proposed \$1/yr. per gas meter research and development charge is denied.
40. ENO shall make a compliance filing with the Council within 30 calendar days of the adoption of this resolution providing all relevant documents for each of electric and gas, including,
  - a. Total company retail revenue requirements subtotaled by rate class based on Period II (for electric, each of the nine customer classes identified in the Revised Application).
    - i. A detailed set of work papers demonstrating that such revenue requirements are in full compliance with each provision of this resolution and do reflect costs not approved by the Council.
  - b. A computation of each fee, charge, rate, proscribed credit, or other mechanism by which ENO receives revenue or credits against revenue requirement, that, when applied to ENO's Period II billing determinants, would allow ENO to collect its revenue requirement for each rate class.
  - c. A computation of all credits and charges appropriate and required for ENO's new rates to be effective as of the first billing cycle of August 2019.
  - d. Interim rate adjustment riders for each of electric and gas to provide required credits by rate class consistent with the excess revenues collected from each rate class from

the first billing cycle of August 2019 through the last billing cycle before new rates go into effect.

- i. The allocation of credits among the rate classes shall, to the extent practicable, reflect the allocation method employed to collect excess revenues (*e.g.*, volumetric, demand, base rate).
  - ii. The calculation of credits shall reflect carrying charges reflective of the source of excess collections (*e.g.*, excess collections through the FAC shall accrue carrying charge credits at the FAC's over/under rate). For excess collections received from sources not having an over/under provision (*e.g.*, base rates), the FAC's over/under rate shall apply.
  - iii. For any rider having a true-up mechanism and which under-collected its approved revenue requirement through July 31, 2019, a provision to first apply over collections from August 1, 2109 to the under-collection balance.
  - iv. For electric, and to the extent reasonably practicable, a mechanism to return over collections according to service area (*i.e.*, the east and west bank of the Mississippi River).
  - v. The interim rate adjustment rider may itself have a true-up provision.
  - vi. The interim rate adjustment rider may return over collections over a reasonable period of time not to exceed three months.
- e. Copies of all documents, such as service schedules, riders (including the E-FRP and GFRP riders), or terms affecting ENO's service and rates that are required to be altered to comply with this resolution, with rates presented therein.

41. For each ratemaking treatment ordered herein that is not consistent with ENO's Revised Application, a description of how ENO has implemented such treatment and in which workpaper or other document its implementation may be mathematically reviewed.
42. To the extent not otherwise modified in this Resolution, ENO's remaining proposals are approved as filed by ENO.
43. The Council's Utility Advisors are directed to work with the City and ENO to resolve the City's outstanding billing issues.

**THE FOREGOING RESOLUTION WAS READ IN FULL, THE ROLL WAS CALLED ON THE ADOPTION THEREOF, AND RESULTED AS FOLLOWS:**

**YEAS:**

**NAYS:**

**ABSENT:**

**AND THE RESOLUTION WAS ADOPTED.**