

**BEFORE THE  
COUNCIL OF THE CITY OF NEW ORLEANS**

**REVISED APPLICATION OF ENTERGY )  
NEW ORLEANS, LLC FOR A CHANGE )  
IN ELECTRIC AND GAS RATES ) DOCKET NO. UD-18-07  
PURSUANT TO COUNCIL RESOLUTIONS )  
R-15-194 AND R-17-504 AND )  
FOR RELATED RELIEF )**

**INITIAL POST-HEARING BRIEF  
OF THE CRESCENT CITY POWER USERS GROUP**

**ROEDEL, PARSONS, KOCH, BLACHE,  
BALHOFF & McCOLLISTER**

Luke F. Piontek (Bar Roll #19979)  
J. Kenton Parsons (Bar Roll # 10377)  
Charles M. Pisano (Bar Roll # 19107)  
Christian J. Rhodes (Bar Roll # 31935)  
George W. Hardy, IV (Bar Roll # 38012)

8440 Jefferson Highway, Suite 301  
Baton Rouge, LA 70809  
Telephone: (225) 929-7033  
Facsimile: (225) 928-4925

- and -

1515 Poydras Street, Suite 2330  
New Orleans, Louisiana 70112  
Telephone: (504) 525-7086  
Facsimile: (504) 525-4991

*Counsel for Crescent City Power Users' Group*

## TABLE OF CONTENTS

TABLE OF AUTHORITIES .....	iv
INTRODUCTION .....	1
GLOSSARY OF IMPORTANT TERMS.....	2
EXECUTIVE SUMMARY .....	8
A. Purpose of CCPUG’s Intervention and Stated Objectives.....	8
B. CCPUG’s Consultants .....	11
C. Summary of Issues Addressed by CCPUG Consultants.....	12
1. Achieving the Lowest Reasonable Cost of Electricity for All Customer Classes .....	13
2. ENO’s Requested Return on Equity .....	13
3. Inappropriate Modification of Test Years and Inclusion of Projected Costs .....	14
4. Misallocation of EAI WBL and River Bend 30% PPA Capacity Costs.....	14
5. Underestimated Service Lives of Union Power Station and New Orleans Power Station .....	16
6. Electric and Gas Formula Rate Plan Riders are Reasonable <i>if</i> Appropriately Modified	16
7. ENO’s Requests for Approval of a Series of Unnecessary Riders .....	17
a. Reliability Incentive Mechanism Rider .....	17
b. Distribution Grid Modernization Rider .....	17
c. Gas Infrastructure Replacement Plan Rider.....	17
d. Purchased Power Capacity Acquisition Cost Recovery Rider .....	18
8. Removal of Capital Storm Costs from Plant and Reimbursement of the Costs from Storm Reserves.....	18
9. Algiers Residential Rate Transition Plan and Base Rate Adjustment Rider – Good News for Algiers Residential Customers; Bad News for ENO’s Commercial Customers .....	19
10. ENO’s Proposed Advanced Metering Infrastructure Rider – a Sliver of Good News...	19
LEGAL STANDARDS .....	20
1. Rates Must be Just and Reasonable .....	20
2. Rates must Provide Sufficient Revenues.....	20
3. Utilities have an Obligation to Minimize Costs to Customers .....	21
4. Customers may only be Charged for Investments that are Used and Useful .....	21
5. A Utility’s Rate Design must not Create Undue Discrimination.....	22

6. Upon a Finding of Unreasonableness, a Regulator can Employ a Hypothetical Capital Structure .....	23
7. The Regulator is not Bound by the Testimony of Witnesses.....	23
8. The Regulator’s Decision will be Afforded Deference <i>Unless</i> it is Arbitrary, Capricious, or not Based upon Evidence in the Record.....	23
ARGUMENT .....	24
I. KEY ISSUES ADDRESSED BY CCPUG.....	26
A. ENO’s Electric and Gas Operations .....	26
1. The Reduction in Overall Rates Should be Roughly \$51.7 Million; not \$20 Million....	26
2. ENO’s Return on Equity Should be set at 9.35% for Electric and Gas Operations .....	27
a. <i>ENO’s ROE Recommendation is Unsupported and Egregiously High</i> .....	27
i. Mr. Hevert’s Constant Growth DCF Analysis Produced ROEs Similar to Mr. Baudino’s Analysis, but He Disregarded those Results.....	30
ii. Mr. Hevert’s Multi-Stage DCF Analysis Results are Inflated, yet He Rejected them in Favor of even Higher Results .....	32
iii. Mr. Hevert’s CAPM Analysis is Unreliable, but He Based his ROE Recommendation on it, Nonetheless.....	34
iv. Mr. Hevert’s Bond Yield/Risk Premium Analysis is a “Blunt Instrument” not to be Relied Upon in the Presence of Other Acceptable Methodologies.....	35
v. Mr. Hevert’s “Business Risks” are Ill-Defined Regarding their Effect on ROE and Fail to Provide a Valid Reason for his Inflated ROE Recommendation .....	36
vi. Mr. Baudino Considered the DCF Analysis Results, the CAPM Results, and ENO’s Split Credit Rating in Setting the ROE; He also Updated his ROE Analyses.....	38
b. <i>Council Advisors’ ROE Recommendation</i> .....	43
3. ENO’s Manipulation of the Council’s Mandated Test Years Should be Rejected .....	44
4. The EAI WBL and River Bend 30% PPA Capacity Costs should be Allocated on an Equal Percentage Basis in Base Rates.....	51
5. Estimated Service Lives of UPS and NOPS are too Short, Allowing ENO to Inappropriately Accelerate the Recovery of Depreciation and Unnecessarily Inflate its Revenue Requirement.....	64
6. Electric and Gas Formula Rate Plans are Reasonable <i>if</i> Appropriately Modified .....	69
7. A Suite of ENO’s Requested Riders Should be Rejected as Unnecessary and Ripe for Abuse .....	70
a. Reliability Incentive Mechanism Rider .....	70
b. Distribution Grid Modernization Rider .....	71

<i>d. New Purchased Power Capacity Acquisition Cost Recovery Rider</i> .....	73
8. Capital Storm Restoration Costs Should be Removed from Plant and Reimbursed from Storm Reserves to Save Ratepayers Money .....	74
9. ENO’s Proposed Algiers Residential Rate Transition Plan Should be Approved, <i>but</i> with a Significant Modification .....	75
10. The AMI Charge Rider, as Proposed by ENO, Should be Approved .....	77
B. Tax-Related Issues .....	79
1. Remove (for Electric) and Reduce (for Gas) Asset Net Operating Loss Accumulated Deferred Income Taxes .....	79
2. Remove Asset Accumulated Deferred Income Taxes – Deferred Storm Costs .....	79
3. Remove 2019 Amortization of Protected Excess ADIT .....	80
4. Subtract FIN 48 Accumulated Deferred Income Taxes .....	81
C. ENO’s Gas Operations.....	81
II. REDUCTION OF CROSS-SUBSIDIES .....	83
III. OTHER ISSUES ADDRESSED BY CCPUG .....	90
A. Rate Base Issues - Correction of Cash Working Capital.....	90
B. Operating Expense Issues.....	91
1. Correction of Error in Patterson Solar Depreciation Rate and Expense .....	91
2. Extension of Amortization of Algiers Transaction Costs to 10 Years .....	92
3. Remove Algiers Migration Costs .....	92
4. Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years .....	93
C. Rate of Return Issues – Inclusion of Short-Term Debt in Capitalization .....	95
CONCLUSION.....	97



## TABLE OF AUTHORITIES

### Cases

<i>Baton Rouge Water Works Co. v. Louisiana Public Service Com'n</i> , 342 So.2d 609, 611 (La. 1977), cert. denied, 434 U.S. 827 (1977).....	23
<i>Bluefield Co. v. Public Serv. Comm'n</i> , 262 U.S. 679, 692-693, 43 S.Ct. 675, 678-679, 67 L.Ed. 1176.....	6, 21
<i>Central La. Elec. Co. v. Louisiana Pub. Serv. Comm'n</i> , 508 So.2d 1361, 1365 (La. 1987) .....	7, 21, 22, 50
<i>Central Louisiana Elec. Co., Inc. v. Louisiana Public Service Com'n</i> , 437 So.2d 278, 279 (La. 1983) .....	21, 23, 24, 59
<i>City of Evansville v. Southern Ind. Gas. &amp; Electric Co.</i> , 167 Ind.App. 472, 339 N.E.2d 562 (Ind.App. 2d Dist. 1975) .....	22, 50
<i>City of Plaquemine v. Louisiana Public Service Commission</i> , 282 So.2d 440, 442-43 (La. 1973).....	20
<i>CTS Enterprises, Inc. v. Louisiana Public Service Comm'n</i> , 540 So.2d 275 (La. 1989) .....	21, 23, 59
<i>Entergy Gulf States, Inc. v. Louisiana Public Service Com'n</i> , 98-1235, p. 2 (La. 4/16/99), 730 So.2d 890, 894-95.....	7, 8, 21, 50
<i>Gordon v. Council of City of New Orleans</i> , 2008-0929, pp. 12-13 (La. 4/3/09), 9 So.3d 63, 73 .....	20
<i>Gulf Power Co. v. Bevis</i> , 289 So.2d 401, 404 (Fla. 1974).....	7
<i>Gulf States Utilities Co. v. Louisiana Public Service Com'n</i> , 578 So.2d 71, 84 (La. 1991), cert. denied, 502 U.S. 1004, 112 S.Ct. 637, 116 L.Ed.2d 655 (1991) .....	23, 59
<i>Gulf States Utilities Co., v. Louisiana Pub. Serv. Comm'n</i> , 96-0345, p. 5 (La. 7/2/96), 676 So.2d 571,575.....	32
<i>Gulf States Utils. Co. v. Louisiana Pub. Serv. Comm'n</i> , 364 So.2d 1266, 1269 (La. 1978) .....	8, 21
<i>Hicks v. City of Monroe Utilities Commission</i> , 112 So.2d 635 (La. 1959) .....	22
<i>Liberty Rice Mill, Inc. v. City of Kaplan</i> , 95-1656, p. 3 (La.App. 3 Cir. 5/8/96), 674 So.2d 395, 397, writ denied, 96-1919 (La. 11/1/96), 681 So.2d 1263 .....	22
<i>Louisiana Power &amp; Light v. Louisiana Public Service Comm'n</i> , 523 So.2d 850 (La. 1988) .....	23, 59
<i>Oakland v. Key System Transit Lines</i> , 52 Cal.P.U.C. 779, 786 (1953) .....	6, 21
<i>Power Comm'n v. Pipeline Co.</i> , 315 U.S. 575, 590, 62 S.Ct. 736, 745, 96 L.Ed. 1037 (1942) .....	6, 21
<i>Re General Tel. Co. of Cal.</i> , 69 Cal.P.U.C. 601, 610 (1969) .....	6, 21
<i>South Central Bell Telephone Co. v. Louisiana Public Serv. Comm'n</i> , 594 So.2d 357, 359-60 (La. 1992) .....	6, 21, 23, 97
<i>South Central Bell Telephone Co. v. Louisiana Public Service Comm'n</i> , 352 So.2d 964, 967 (La.1977) .....	21, 23

<i>Southern California Edison Co. v. Public Utilities Comm'n,</i> 20 Cal.3d 813, 144 Cal.Rptr. 905, n. 8, 576 P.2d 945, n. 8 (1978) .....	6, 21
<i>State ex rel. Guste v. Council of City of New Orleans,</i> 309 So.2d 290, 294 (La. 1975) .....	20, 22

**Administrative Code and Council Resolutions**

Council Resolution R-03-272 .....	60
Council Resolution R-12-29 .....	58
Council Resolution R-15-194 .....	passim
Council Resolution R-17-504 .....	passim
Council Resolution R-18-224 .....	77
Council Resolution R-18-37 .....	77
Council Resolution R-18-434 .....	7, 45
New Orleans Administrative Code Section 158-41 .....	7, 8, 45
New Orleans Administrative Code Section 158-132 .....	45
New Orleans Administrative Code Section 158-133 .....	45

## INTRODUCTION

**NOW COMES** Crescent City Power Users' Group ("CCPUG"), through undersigned counsel, which respectfully submits its Initial Post-Hearing Brief, pursuant to the Order of Hearing Officer Gulin dated April 15, 2019. CCPUG is comprised of several large commercial customers taking service from Entergy New Orleans, LLC ("ENO"), including the City of New Orleans, the Sewerage and Water Board of New Orleans, New Orleans Cold Storage & Warehouse Co., Ltd., LCMC Health, and Tulane University Hospital & Clinic. Crescent City Power Users' Group intervened in this proceeding to analyze and address issues raised in the 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 on September 21, 2018 ("Revised Application").

ENO's Revised Application in this Combined Rate Case presents the classic "good news / bad news" story. The good news is that ENO proposes – and all parties agree – that an overall rate reduction should occur as the result of this proceeding. That means rates should go down for everyone. The bad news is that ENO's proposal would allow it to over-earn by (1) requesting an unreasonably high return on equity, (2) recommending unnecessary rate riders that will harm customers, and will afford ENO an opportunity to inflate earnings, and (3) minimizing the amount of rate reduction for certain groups of customers. It has been over 10 years since ENO's last base rate case. Consequently, the rates set by the Council in this proceeding could very well remain in effect for years to come and will directly affect household incomes as well as businesses' bottom lines.

CCPUG, through its consultants and attorneys, has participated fully in this proceeding by engaging in discovery (including propounding and analyzing significant amounts of discovery

materials), scrutinizing thousands of pages of pre-filed testimony, preparing two rounds of pre-filed testimony by its consultants, and partaking in the hearing on the merits of this matter held from June 17, 2019 through June 21, 2019. CCPUG appreciates the ability to contribute to the process in this important regulatory proceeding and respectfully submits its Initial Post-Hearing Brief for the Council's consideration.

### GLOSSARY OF IMPORTANT TERMS

*There will be numerous regulatory terms and principles used throughout this brief, as well as other parties' briefs, that play a prominent role in this case and, therefore, merit some discussion at the outset.*

**Cost Allocation:** Cost allocation is the method of dividing the costs a utility incurs to provide service to its customers among the various groups of customers. Cost-causation principles should drive the allocation.<sup>1</sup> “The allocation process for electric and gas apportions or distributes costs to the various customer groups, that is, rate classes, through the use of an ‘allocation factor.’ Generally, costs are allocated on the basis of a demand, energy, or customer relationship.”<sup>2</sup> Fixed costs (like investment in generating units or fixed costs associated with a long-term Purchase Power Agreement (“PPA”)) do not fluctuate with the amount of electricity produced and, therefore, are typically allocated on a demand basis.<sup>3</sup> Demand is measured in kilowatts or kW and demand charges are represented as \$ per kW.<sup>4</sup> Variable costs (such as fuel costs or energy

---

<sup>1</sup> Exh. ENO-45 (Revised Direct Testimony of Myra L. Talkington (“Talkington Revised Direct Testimony”) (ENO)), at 5:21 – 6:1.

<sup>2</sup> Exh. ENO-41 (Revised Direct Testimony of Phillip B. Gillam, adopted by Matthew S. Klucher (“Gillam / Klucher Revised Direct Testimony”) (ENO)), at 24:6-9.

<sup>3</sup> TR, June 18, 2019, (Cross Examination of Myra Talkington), at 48:6-12: “The demand-based cost is also referred to as a fixed cost. It’s typically – Examples of demand-based costs are production facilities, capacity costs, transmission plants. Usually the typical plant type fixed costs are usually allocated – are demand costs and allocated using a demand basis.”

<sup>4</sup> Exh. ENO-41 (Talkington Revised Direct Testimony) (ENO), at 21:19 – 22:2.

purchased through a PPA), on the other hand, fluctuate with the production of electricity and are usually allocated on an energy basis.<sup>5</sup> Energy is measured in kilowatt-hours or kWh and energy charges are represented as \$ per kWh.<sup>6</sup> Finally, customer-specific costs (including the cost of the meter needed to provide the customer with service) are allocated on a customer-relationship basis.

**Cost-Causation Principle:** Cost causation refers to an “attempt to determine what, or who, is causing the costs to be incurred by the utility.”<sup>7</sup> The cost-causation principle provides that a customer or group of customers should bear financial responsibility for the costs that they cause the utility to incur to provide them with service.<sup>8</sup> The cost-causation principle drives the “allocation” of costs among the various customer classes in the Cost of Service Study. While ENO correctly allocated the costs necessary to provide service among the various customer classes in its Cost of Service Study, it strayed from that allocation with regard to certain costs when designing its rates in this proceeding without any valid justification.

**Cost of Service Study:** A Cost of Service Study is typically the starting point for a base rate case. A Cost of Service Study, as its name implies, is a study by a utility that breaks down all of the costs it incurs to serve its customers and assigns those costs among its various classes of customers.<sup>9</sup> Each customer class, therefore, will be responsible for a defined amount of costs that the utility incurs to provide service to that class. The Council directed ENO to conduct a “fully

---

<sup>5</sup> TR, June 18, 2019, (Cross Examination of Myra Talkington), at 48:14-17: “Energy-based costs are those costs that vary with the level of energy that’s produced and they typically allocate using an energy, E-N-E-R-G-Y, basis.”

<sup>6</sup> *Id.*

<sup>7</sup> Exh. CCPUG-5 (Direct Testimony of Stephen J. Baron (“Baron Direct Testimony”) (CCPUG)), at 11:14-16, quoting National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual (“NARUC Manual”), January 1992, Baron Exhibit\_(SJB-2), at 38-39.

<sup>8</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 11:5-9.

<sup>9</sup> Exh. ENO-41 (Gillam / Klucher Revised Direct Testimony) (ENO), at 24:6-9; Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 10:21 – 11:5.

allocated” Cost of Service Study in connection with its Application in this case.<sup>10</sup> ENO followed the Council’s directive and performed a fully allocated Cost of Service Study that no party seriously challenges. ENO’s fully allocated Cost of Service Study falls in the “good news” category. Unfortunately, however, ENO immediately departed from its Cost of Service Study when designing its proposed rates without any valid reason and in a manner which directly and significantly harms one group of customers in order to benefit another group of customers.

**Cross-Subsidization:** One consequence of violating the cost-causation principle and/or the used and useful principle, described below, is cross-subsidization. “Cross-subsidization occurs when one set of customers pays in excess of cost and another pays less than cost of service.”<sup>11</sup> In other words, cross-subsidization occurs when one customer or group of customers is forced to pay more than the cost the utility incurs to provide them with service. When this happens, the customer group paying more than the utility’s cost to serve them ends up paying a portion of the utility’s cost to serve a *different* group of customers. While there will likely always be some level of cross-subsidization among customer classes (because certain variables such as the amount of electricity usage in the future and usage patterns can never be predicted with absolute accuracy), an unreasonable level of cross-subsidization serves as nothing more than an unjustified tax on the subsidizing class of customers. Cross-subsidization lurks in ENO’s rate design like a villain hiding in the shadows. This is the bad news part of the story. ENO concedes that – under current rates – the customers in the commercial and industrial classes are paying approximately *\$45 million per year* in costs that are the responsibility of the residential customers, and – under ENO’s proposed rates – the commercial and industrial customers will *continue* paying approximately *\$35 million*

---

<sup>10</sup> See Resolution No. R-17-504, at 3-4.

<sup>11</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG)), at 13:2-4.

*per year* in costs that are the responsibility of the residential customers. There is no justification for imposing these massive subsidies on commercial customers.

**Gradualism:** Gradualism is a regulatory principle that counsels against dramatic rate changes. In particular, when rates to all customers or to a particular class of customers need to increase substantially to provide the utility with sufficient revenues, gradualism dictates that the increase should be phased in and rates increased as gradually as possible.<sup>12</sup>

**High Load Factor Customers:** From a technical perspective, a “load factor” is the “relationship between ... a customer’s usage at a given point in time compared to a longer period of time.”<sup>13</sup> In English, that means a load factor is the utilization rate or efficiency of electrical energy usage. A “high” load factor means that the customer’s power usage is relatively constant.<sup>14</sup> A customer or customer class with a high load factor typically consumes a large amount of energy (kWh) relative to the maximum amount of energy consumed over the same time period.<sup>15</sup> In other words, high load factor customers use large amounts of energy and their usage does not vary much over course of the day.<sup>16</sup> ENO has a group of high load factor customers – the Large Electric High Load Factor class.<sup>17</sup> If a utility has customers with high load factors, “the utility can spread out the fixed costs of capacity over more kWh units – thus, *lowering average system cost.*”<sup>18</sup> And lowering a utility’s average system cost should **lower costs for *all* customer classes**, not just the high load factor customer class.<sup>19</sup>

---

<sup>12</sup> See, generally, Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 8:17 – 9:2.

<sup>13</sup> TR, June 18, 2019, (Cross Examination of Myra Talkington), at 52:15-21.

<sup>14</sup> *Id.*, 53:4-7.

<sup>15</sup> *Id.*, at 54:6 – 55:8.

<sup>16</sup> *Id.*, at 53:4-7.

<sup>17</sup> *Id.*, at 53:8-12.

<sup>18</sup> *Id.*, at 53:13-54:1 (Italics added).

<sup>19</sup> *Id.*, at 54:2-5 (Emphasis and italics added).



Tossing aside the admitted benefits the Large Electric High Load Factor class provides to all of its customers, ENO has singled out the Large Electric High Load Factor class, along with other commercial classes, to pay substantial, unjustified subsidies.<sup>20</sup>

**Rate Design:** Rate design is the process of structuring a utility’s various rate schedules which it will use to charge its customers for service in a manner that recovers the utility’s revenue requirement.<sup>21</sup> Rate design should, to the extent possible, take into consideration cost causation.<sup>22</sup>

**Reasonable Return on Equity:** A return on equity is essentially a utility’s profit margin. The return on equity must be reasonable, and a utility is entitled to the *opportunity* to earn that reasonable return on equity, but *not* a guarantee.<sup>23</sup> No party disputes that ENO is entitled to the opportunity to earn a reasonable return on equity (often referred to as “ROE”); the disagreement here arises over what the reasonable return on equity should be. ENO claims that a 10.75% ROE is appropriate, but that return on equity is excessive. It is higher than *any other return on equity* for a utility awarded by a regulator in the United States – save for one – over the last five years.<sup>24</sup> The Advisors, on the other end of the spectrum, say 8.93% is a reasonable ROE. CCPUG’s

---

<sup>20</sup> TR, June 18, 2019, (Cross Examination of Myra Talkington), at 55:10 – 56:4, where Ms. Talkington admitted that the change in allocation of the EAI WBL and River Bend 30% PPA capacity costs to an energy basis will add costs to the roughly 1,000 customers on the Large Electric and Large Electric High Load Factor classes while reducing the costs that would otherwise be imposed on the Residential Class.

<sup>21</sup> Exh. ENO-45 (Talkington Revised Direct Testimony) (ENO), at 21:19 – 22:2.

<sup>22</sup> *Id.*, at 22:3-5.

<sup>23</sup> *South Central Bell Telephone Co. v. Louisiana Public Serv. Comm’n*, 594 So.2d 357, 359-60 (La. 1992) (citing, *Southern California Edison Co. v. Public Utilities Comm’n*, 20 Cal.3d 813, 144 Cal.Rptr. 905, n. 8, 576 P.2d 945, n. 8 (1978) (citing *Power Comm’n v. Pipeline Co.*, 315 U.S. 575, 590, 62 S.Ct. 736, 745, 96 L.Ed. 1037 (1942); *Bluefield Co. v. Public Serv. Comm’n*, 262 U.S. 679, 692-693, 43 S.Ct. 675, 678-679, 67 L.Ed. 1176; *Re General Tel. Co. of Cal.*, 69 Cal.P.U.C. 601, 610 (1969); *Oakland v. Key System Transit Lines*, 52 Cal.P.U.C. 779, 786 (1953))).

<sup>24</sup> See Exh. ENO-29 (Revised Rebuttal Testimony of Robert B. Hevert (“Hevert Revised Rebuttal Testimony”) (ENO)), at 6:3, Chart 2: “Vertically Integrated Authorized ROEs (2014 – 2019)”; TR, June 19, 2019 (Cross Examination of Robert Hevert), at 9:22 - 17:8.



consultants and, coincidentally, the consultant for Air Products and Chemicals, Inc. (“Air Products”) each determined that a 9.35% ROE is the most reasonable estimate.

**Revenue Requirement:** A revenue requirement is the total annual revenues a utility must collect from its customers to “meet its operating expenses, provide its shareholders with a reasonable rate of return, and attract new capital.”<sup>25</sup> “Mathematically, the utility’s revenue requirement is the sum of the utility’s operating expenses and its rate of return times the amount of its rate base.”<sup>26</sup>

**Test Year:** A test year is a recent historic time period, usually the most recent 12-month period, which regulators use as a benchmark for ratemaking decisions. By analyzing data from the test year, regulators can gain an understanding of the utility’s *actual* operational data and *actual* costs, and use that understanding to set rates for the future.<sup>27</sup> The use of a historic test year “allows the regulatory agency to analyze the dynamic interrelationships among the rate base, expenses, and revenues.”<sup>28</sup> That said, however, the test year is “merely a tool” and, *if* “it is apparent the test year data provides an inaccurate forecast of the future, adjustments should be made so as to provide a reasonably accurate estimate of future operating conditions.”<sup>29</sup>

For this Combined Rate Case, the Council specifically directed ENO to utilize two test year periods, with Period I ending December 31, 2017 and Period II ending December 31, 2018.<sup>30</sup> This directive was consistent with the Code of the City of New Orleans (“City Code”) Section 158-41, which defines “Period I” as the most recent 12 consecutive months, or the most recent calendar

---

<sup>25</sup> *Entergy Gulf States, Inc. v. Louisiana Public Service Com’n*, 98-1235, p. 2 (La. 4/16/99), 730 So.2d 890, 894-95, (citing *Central La. Elec. Co. v. Louisiana Pub. Serv. Comm’n*, 508 So.2d 1361, 1365 (La. 1987)).

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

<sup>27</sup> *Central La. Elec. Co. v. Louisiana Pub. Serv. Comm’n*, 508 So.2d 1361, 1368 (La. 1987) (citing 73B C.J.S. Public Utilities § 42, p. 248); see also, *Gulf Power Co. v. Bevis*, 289 So.2d 401, 404 (Fla. 1974).

<sup>28</sup> *Id.*, 508 So.2d at 1369.

<sup>29</sup> *Id.*

<sup>30</sup> Council Resolution R-18-434, at 4.

year, **for which actual data is available** and “Period II” as the 12 consecutive months immediately following the end of Period I. Instead of using these two, mandated historic test years to determine the revenue requirement, ENO modified the test years to include a *forecast* 2019 test year in each period.<sup>31</sup> It did so by including adjustments to reflect post-test year *projected* costs, which were neither actual nor known.

**Used and Useful Principle:** A corollary to the cost-causation principle is the “used and useful” principle. The used and useful principle is a well-settled ratemaking policy stipulating that ratepayers are only required to pay a utility company a fair return on facilities and invested capital actually used and useful for the provision of service to the ratepayers.<sup>32</sup> For example, customers should not pay the cost of a new generating unit until that unit becomes operational and provides service to them.

## EXECUTIVE SUMMARY

### A. PURPOSE OF CCPUG’S INTERVENTION AND STATED OBJECTIVES

As previously mentioned, CCPUG counts as its members the City of New Orleans (“City”), the Sewerage and Water Board of New Orleans (“S&WB”), New Orleans Cold Storage & Warehouse Co., Ltd. (“NOCS”), LCMC Health, and Tulane University Hospital & Clinic (“Tulane Health”), each of which takes service from ENO on commercial rates. The City and S&WB are two of ENO’s largest customers. NOCS is the oldest cold storage company in North America, and owns and operates two warehousing and docking facilities in New Orleans that are approved by federal and international authorities to handle, sort, inspect and blast freeze commodities including

---

<sup>31</sup> City Code Section 158-41.

<sup>32</sup> *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm’n*, 1998-1235, p. 28 (La. 4/16/99), 730 So.2d 890, 911 (citing, *Gulf States Utils. Co. v. Louisiana Pub. Serv. Comm’n*, 364 So.2d 1266, 1269 (La. 1978)).

poultry, meat, pork, seafood, and other products and prepare them for transport to all parts of the world.<sup>33</sup> LCMC Health is a New Orleans-based non-profit health system that offers five hospital locations, with four of those locations being within the City of New Orleans: Children’s Hospital, Touro Infirmary, University Medical Center New Orleans, and New Orleans East Hospital.<sup>34</sup> LCMC Health also offers a network of urgent care centers across the greater New Orleans area.<sup>35</sup> Tulane Health operates Tulane Medical Center, a hospital and emergency room in New Orleans that offers advanced medical care in Orleans Parish.<sup>36</sup>

Traditionally, the classes of customers represented by the CCPUG membership, which take service under commercial rates and include governmental bodies as ratepayers, typically do not participate in utility regulatory proceedings, leaving their interests and concerns underrepresented in cases such as this. CCPUG aims to change that. Our three primary objectives for its intervention in this case are as follows:

- Objective 1: **BE INVOLVED**

ENO’s last base rate case was over 10 years ago. ENO’s electric and gas rates represent significant expenses for the commercial classes of customers. Considering that this case may set rates for the foreseeable future, it was imperative that commercial customers be represented and contribute by participating in the process.

---

<sup>33</sup> See <https://www.nocs.com/>.

<sup>34</sup> See <https://www.lcmchealth.org/about-lcmc-health/>.

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

<sup>36</sup> See <https://tulanehealthcare.com/>.

- Objective 2: **STRIVE FOR REASONABLE RATES FOR ALL CUSTOMERS**

As CCPUG made clear in its opening statement during the hearing of this matter, it is *not* simply trying to lower rates for commercial customers and the interests of governmental bodies as ratepayers.<sup>37</sup> In fact, that is a secondary concern. CCPUG’s primary concern is the reliable provision of electric and natural gas service at the lowest reasonable cost for **all** of ENO’s customers. If it is true that a rising tide lifts all boats, then it is a fact that reasonable electric and gas rates coupled with reliable service will allow all of ENO’s customers – citizens of New Orleans – to prosper. Utility bills are a significant expense for every utility customer in the city. Consequently, it is imperative that electric and gas rates be reasonable. The flip side of the coin is that the rates must be reasonable to ENO and its shareholders. ENO must be able to attract capital at reasonable costs and to provide a reasonable level of return to its investors.

- Objective 3: **REDUCE CROSS-SUBSIDIZATION IMPOSED ON COMMERCIAL CLASSES**

ENO’s commercial customers have long paid rates that exceed ENO’s cost to provide service to them as a class. Conversely, ENO’s residential customers have paid *less* than the costs incurred by ENO to provide service. This cross-subsidization is wholly arbitrary and is calculated to reduce ENO’s political liability by burdening only commercial customers with rates in excess of those justified by their usage. ENO’s 181,500 residential customers contributed roughly \$250 million in revenues in test year 2018, while its 1,000 customers in the Large Electric and Large Electric High Load Factor classes, alone, contributed approximately \$213 million that same year.<sup>38</sup>

---

<sup>37</sup> References herein to “commercial customers” or customers in the “commercial classes” specifically include the City and S&WB as ratepayers of ENO.

<sup>38</sup> See Exh. ENO-56 (consisting of ENO’s workpapers), at “Schedule WP\_Statement AA-2\_REV\_E RevAllocation”, showing ENO has 181,500 residential customers, 333 customers in the Large Electric class and 606 customers in the Large Electric High Load Factor class. This workpaper was separately marked (but not admitted as substantive evidence) during cross-examination as Exh. CCPUG-9. (Row 1 shows the Residential class’ revenue contribution in 2018; Row 4 shows Large Electric class’ revenue contribution in 2018; and Row 5 shows the Large Electric High Load Factor class’ revenue contribution in 2018).

ENO admits that rates should be designed to move towards cost of service, yet the rates it proposes in this proceeding fall woefully short of that goal.

Subsidies under current rates have amounted to roughly \$45 million per year. In other words, ENO's residential customers are currently paying \$45 million per year *less than* the costs ENO incurs to serve that class of customers.<sup>39</sup> Two classes of ENO's commercial customers, the Large Electric and Large Electric High Load Factor classes, alone, contribute the bulk (58%) of this subsidy.<sup>40</sup> Perhaps more importantly, even under ENO's *proposed* rates, the commercial classes of customers will *continue* to be forced to pay substantial subsidies. The going-forward subsidies total more than **\$35 million per year** and those same two classes of commercial customers are expected to contribute **over 47%** of those annual subsidies.<sup>41</sup>

To be clear, CCPUG is *not* proposing that the Council eliminate these subsidies, although it certainly would be reasonable to do so. Rather, CCPUG is proposing that the Council *reduce* those subsidies. Being that this is an overall rate decrease case – and *not* a rate increase case – the Council has a unique (perhaps a once-in-a-generation) opportunity. Here, the Council can significantly reduce subsidies that have been, and are planned to be, forced upon commercial customers *while still maintaining a net decrease in residential rates*.

## **B. CCPUG'S CONSULTANTS**

In support of the group's objectives, CCPUG retained – at significant expense – some of the most well-regarded, highly-skilled and experienced regulatory experts in the United States. Lane Kollen (“Kollen”), Stephen J. Baron (“Baron”), and Richard A. Baudino (“Baudino”), of J.

---

<sup>39</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 7:14-17.

<sup>40</sup> *Id.*, at 17:1: Table 1, entitled, “Class Rates of Return and Subsidies at Present Rates”. See also TR, June 18, 2019, (Cross Examination of Myra Talkington), at 57:2-23.

<sup>41</sup> Exh. CCPUG-6 (Surrebuttal and Cross-Answering Testimony of Stephen J. Baron (“Baron Surrebuttal Testimony”)) (CCPUG), at 6:1-4.



Kennedy & Associates (“J. Kennedy”), served as CCPUG’s consultants in this case. J. Kennedy have served as regulatory consultants to numerous regulatory agencies, including the Louisiana Public Service Commission, Georgia Public Service Commission, and the New Mexico Public Service Commission.<sup>42</sup> J. Kennedy’s representation of various regulatory agencies spans more than 30 years.<sup>43</sup> J. Kennedy also has represented commercial customers, including hospitals, manufacturers, and retail customers in regulatory and utility rate matters for decades.<sup>44</sup>

It is important to point out that CCPUG did not retain J. Kennedy to address issues of concern only to the commercial classes; rather, they were hired to conduct a full analysis of ENO’s Revised Application and the issues raised therein. As a result of their review, Kollen, Baron and Baudino identified numerous errors, inconsistencies, and violations of crucial ratemaking principles in the Revised Application and supporting testimony, and developed recommendations to correct these flaws and conform ENO’s proposed rates, revenue requirements, and rate of return to the standard of reasonableness.

### **C. SUMMARY OF ISSUES ADDRESSED BY CCPUG CONSULTANTS**

CCPUG’s consultants have thoroughly analyzed ENO’s Revised Application, supporting testimony, exhibits and work papers, and have identified several requests by ENO that should either be corrected, modified, or rejected outright. The following are some of the more important issues identified by CCPUG’s consultants, each of which will be discussed more thoroughly in this brief.

---

<sup>42</sup> See Exh. CCPUG-1 (Direct Testimony and Exhibits of Lane Kollen (“Kollen Direct Testimony”) (CCPUG)), at Exhibit\_(LK-1), Resume of Lane Kollen; Exh. CCPUG-5 (Baron Direct Testimony), at Exhibit SJB-1, Expert Testimony Appearances of Stephen J. Baron; and Exh. CCPUG-3 (Direct Testimony and Exhibits of Richard A. Baudino (“Baudino Direct Testimony”) (CCPUG)), at Exhibit\_(RAB-1), Resume of Richard A. Baudino.

<sup>43</sup> *Id.*

<sup>44</sup> *Id.*

## 1. Achieving the Lowest Reasonable Cost of Electricity for All Customer Classes

ENO proposes an overall electric revenue (rate) decrease of approximately \$20.3 million,<sup>45</sup> and a decrease in its overall gas revenues (rates) of roughly \$0.142 million,<sup>46</sup> for a total overall rate reduction of just over \$20.4 million. While this is a sizeable sum, it is not nearly large enough given the evidence in this case. The Council's Advisors recommend an overall reduction in rates of roughly \$33 million in electric revenue and \$3.8 million in gas revenue for a total overall recommended reduction of \$36.8 million.<sup>47</sup> This, too, is a large decrease, but it is still not the correct amount. As a result of their thorough and detailed study of ENO's Revised Application, supporting testimony, work papers and extensive discovery in this matter, and through the application of well-accepted ratemaking principles, CCPUG's consultants determined that an overall rate decrease of over \$51 million (for electric and gas operations, combined) is well-documented, reasonable, and appropriate under the circumstances.<sup>48</sup>

## 2. ENO's Requested Return on Equity

ENO's requested return on equity of 10.75% is egregiously high and unsupported. It far exceeds the average ROE awarded by regulators across the country in the last five years.<sup>49</sup> In fact, according to ENO's data, its requested ROE of 10.75% is **higher than all but one** ROE granted

---

<sup>45</sup> ENO's Revised Application, at ¶ 17, stating that ENO is proposing a reduction in its electric revenue requirement of approximately \$20.3 million.

<sup>46</sup> *Id.*, at ¶ 18, explaining that ENO is proposing a reduction in its gas revenue requirement of approximately \$0.142 million.

<sup>47</sup> Exh. ADV-3 (Direct Testimony of Victor Prep ("Prep Direct Testimony") (Advisors)), at 2:10-11 and 6:1-4.

<sup>48</sup> See Exh. CCPUG-2 (Surrebuttal and Cross-Answering Testimony and Exhibits of Lane Kollen ("Kollen Surrebuttal Testimony") (CCPUG)), at 6:1, Table entitled, "Entergy New Orleans, LLC, Summary of CCPUG Revenue Requirement Recommendations – Surrebuttal and Cross-Answering Update, Docket No. UD-18-07, Period II test year Ended December 31, 2018, \$ Millions".

<sup>49</sup> Exh. ENO-29 (Hevert Revised Rebuttal Testimony) (ENO), at 5, fn 6: "The average authorized ROE for vertically integrated electric utilities (excluding limited issue riders) from January 1, 2014 to February 28, 2019 is 9.79 percent."

by a regulator to an electric and gas utility **over the last five years**.<sup>50</sup> CCPUG’s consultants have performed long-accepted analyses to determine the appropriate ROE for ENO and have determined that a 9.35% ROE (for both electric and gas operations) is reasonable and appropriate under the circumstances. Setting ENO’s ROE to 9.35% would save its customers approximately \$6.3 million per year.<sup>51</sup> The Council should reject ENO’s proposed 10.75% ROE and should adopt CCPUG’s recommended ROE of 9.35% instead.

### **3. Inappropriate Modification of Test Years and Inclusion of Projected Costs**

ENO violated Council Resolution Nos. R-15-194 and R-17-504, as well as applicable provisions of the City Code, when it modified the test years for Period I (which was to end December 31, 2017) and Period II (which was to end December 31, 2018) to include forecasted costs that will not be incurred until 2019.<sup>52</sup> The Council should spurn ENO’s attempt to include projected, future (2019) plant additions in its rate base as well as the related expenses. Such projected costs unnecessarily and inappropriately increased ENO’s rate base, upon which it earns a return. The Council should order ENO to remove the projected costs from its test years, the effect of which would be to correct the electric base revenue requirement and *lower* it by a total of \$10,384,000, and to likewise correct the gas base revenue requirement and *lower* it by a total of \$2,476,000.<sup>53</sup>

### **4. Misallocation of EAI WBL and River Bend 30% PPA Capacity Costs**

ENO pays certain non-fuel, fixed “capacity costs” in connection with Purchase Power Agreements (“PPAs”) through which it purchases electricity on a long-term basis. Two of those

---

<sup>50</sup> Exh. ENO-29 (Hevert Revised Rebuttal Testimony) (ENO), at 6:3, Chart 2: “Vertically Integrated Authorized ROEs (2014 – 2019)”.

<sup>51</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 39:15-21; Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 6:1, Table, showing, among other recommendations, “Reflect return on equity of 9.35% (Electric and Gas)”.

<sup>52</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 8:9-16.

<sup>53</sup> *Id.*, at 14:17-22 and 28:16-18.



contracts are the Entergy Arkansas, Inc. Wholesale Base Load PPA (“EAI WBL PPA”) and the River Bend 30% PPA. 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. ENO is realigning capacity costs associated with several PPAs, including, but not limited to the EAI WBL and River Bend 30% PPAs, from riders, such as the Fuel Adjustment Clause (“FAC”) Rider and Purchased Power Capacity Acquisition Cost Recovery (“PPCACR”) Rider to base rates. ENO also proposes to realign PPA capacity costs associated with the Ninemile 6 PPA and other similar costs from riders into its base rates *but* recommends that these costs be recovered through an *equal percentage base rate increase* to all customer classes.<sup>54</sup> This 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>55</sup> ENO allocates and recovers many other fixed costs on an equal percentage basis from each rate class; however, it abandons this established methodology with respect to the EAI WBL and River Bend 30% PPA capacity costs. ENO proposes to continue to recover (although such recovery will occur through the base rates) the EAI WBL and River Bend 30% PPA capacity costs on an *energy basis*, as opposed to an equal percentage basis. This radical departure from sound ratemaking principles is inconsistent with ENO’s recommended treatment of the Ninemile 6 PPA capacity costs (as well as the Algiers Transaction PPA capacity costs), violates cost-causation principles, and will continue the imposition of substantial unsupported subsidies on commercial customers in favor of residential customers. The Council should rebuff ENO’s attempt to harm its commercial customers and require it to allocate the capacity costs

---

<sup>54</sup> ENO proposes an overall, net revenue decrease in this case that is comprised of a *base revenue increase* of approximately \$135 million and a *net rider decrease* of approximately \$155 million.

<sup>55</sup> Exh. ENO-41 (Talkington Revised Direct Testimony) (ENO), 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.”

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.

#### **5. Underestimated Service Lives of Union Power Station and New Orleans Power Station**

ENO proposes service lives for Union Power Station, Power Block 1 (“UPS”) and New Orleans Power Station (“NOPS”) that are unsupported and unreasonably short.<sup>56</sup> ENO further proposes a negative salvage value for UPS for depreciation purposes without sufficient proof. In taking these unsubstantiated steps, ENO seeks to *accelerate* the recovery of depreciation on UPS and *artificially increase* the revenue requirement for NOPS in the Electric Formula Rate Plan (“E-FRP”) Rider. The Council should reject ENO’s unrealistically short service lives, fabricated negative salvage value, as well as the related depreciation expense, and should 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) in the E-FRP.

#### **6. Electric and Gas Formula Rate Plan Riders are Reasonable *if* Appropriately Modified**

CCPUG supports ENO’s proposals to implement Electric and Gas Formula Rate Plans (“FRPs”),<sup>57</sup> however, CCPUG is opposed to including projected costs in the electric and gas FRPs. The Advisors are in favor of including such projected costs in the FRPs. Inclusion of projected costs – which may or may not ever be incurred – undermines a utility’s incentive to operate efficiently. Allowing ENO to include a “wish list” of investments it may make in the coming year

---

<sup>56</sup> CCPUG is aware that Judge Piper Griffin entered a ruling on July 2, 2019, in Case No. 2018-3843, Div. “I”, Sec. 14, on the docket of the Civil District Court for the Parish of Orleans, Louisiana, that voided the Council’s decision in which it adopted Resolution No. R-18-65 approving the New Orleans Power Station. It is unclear how this ruling will affect the developments in this proceeding, therefore, CCPUG advances its arguments regarding NOPS based on the evidence in the record of this matter.

<sup>57</sup> For ease of reference, the electric FRP is sometimes referred to as the “E-FRP”, and the gas FRP is sometimes referred to as the “G-FRP”.

in its current rates is fraught with peril and ripe for abuse. The Council should reject the inclusion of projected costs and use of a forward-looking test year in the electric and gas FRPs and require the use of traditional, historical test years.

## **7. ENO's Requests for Approval of a Series of Unnecessary Riders**

### ***a. Reliability Incentive Mechanism Rider***

CCPUG recommends that the Council reject the Reliability Incentive Mechanism ("RIM") Rider, a proposal which would permit ENO to earn more than its authorized ROE if it met certain reliability criteria. This would amount to giving ENO a bonus for doing what it should do – *i.e.*, maintain and improve the reliability of its service to its customers. The proposed RIM Rider is also unnecessary – especially if the E-FRP is adopted. The RIM Rider will serve to remove ENO's incentive to operate efficiently and invest economically.

### ***b. Distribution Grid Modernization Rider***

ENO's proposed Distribution Grid Modernization ("DGM") Rider should likewise be rejected. Like the RIM Rider, the DGM Rider is unnecessary and provides accelerated and increased recovery to ENO through use of a forecasted test year instead of including the DGM costs in the E-FRP on a historic test year basis.<sup>58</sup> This proposed rider also provides a bonus to ENO for simply doing its job – which should include modernizing its distribution grid. In addition, the "streamlined process" ENO proposes to address the prudence and recovery of DGM projects is far too accelerated and presents the material risk of over-recovery.

### ***c. Gas Infrastructure Replacement Plan Rider***

CCPUG opposes ENO's requested Gas Infrastructure Replacement Plan ("GIRP") Rider. The proposed GIRP Rider is similar to the proposed DGM Rider and, as such, is unnecessary –

---

<sup>58</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 56:6-21.

especially if the G-FRP is adopted. The GIRP Rider will lead to inevitable, *quarterly rate increases*. The GIRP Rider will serve to remove ENO's incentive to operate efficiently and invest economically.

*d. Purchased Power Capacity Acquisition Cost Recovery Rider*

ENO proposes a new Purchased Power Capacity Acquisition Cost Recovery ("PPCACR") Rider. CCPUG objects to the proposed new PPCACR, because it would inappropriately allow near *automatic recovery* of new capacity costs and costs of newly-constructed generating assets without a full certification review by the Council.<sup>59</sup> The Council Advisors also oppose the new PPCACR on the basis that it will serve to prevent full certification review prior to plant investments being included in rates.

**8. Removal of Capital Storm Costs from Plant and Reimbursement of the Costs from Storm Reserves**

ENO's request to recover storm recovery costs by including them in its rate base instead of reimbursing itself for such costs from its two storm reserve accounts is (a) illogical – (the reserve accounts were established for this exact purpose), and (b) will **cost ratepayers more money** than if ENO reimbursed itself for such restoration costs from the reserve accounts. The Council should dismiss ENO's request to include the storm recovery costs in its rate base and should instead direct ENO to reimburse itself for such costs from its two storm reserve accounts, as it has done with other storm restoration costs in the past. Removal of the storm restoration costs from ENO's rate base will save its customers \$1.614 million and removing the related expenses will save \$0.565 million, for a total of roughly \$2.18 million per year.

---

<sup>59</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), 52:16 – 54:2.

**9. Algiers Residential Rate Transition Plan and Base Rate Adjustment Rider – Good News for Algiers Residential Customers; Bad News for ENO’s Commercial Customers**

CCPUG does not oppose the Algiers Residential Rate Transition Plan (“ARRT”) and accompanying Base Rate Adjustment Rider (“BRAR”); *however*, the Council should modify both the ARRT Plan and its corresponding BRAR. Under the ARRT and BRAR, Algiers residential customers will receive a reduction in the otherwise applicable rates in the amount of \$3.325 million, which amount will be funded almost exclusively by commercial customers. CCPUG understands the importance of the ARRT and supports the regulatory principle of gradualism when changing utility rates. That said, however, the goals of the ARRT must be balanced with the adverse effect it will have on other classes of customers. The Council should modify the ARRT and BRAR so that the first \$3.325 million of any overall rate reductions ordered in this proceeding *in excess of* the roughly \$20 million proposed by ENO be allocated to large customers to eliminate the subsidy they will pay the Algiers residential customers under the ARRT/BRAR.

**10. ENO’s Proposed Advanced Metering Infrastructure Rider – a Sliver of Good News**

ENO proposes to collect the cost of its Advanced Metering Infrastructure (“AMI”) program through a customer-specific charge rider.<sup>60</sup> This is the correct method by which to recover metering costs which are customer-specific. The Council Advisors recommended that the AMI program costs be socialized by including such costs in ENO’s rate base. CCPUG opposes this recommendation, because it defies cost-causation principles and shifts costs of the roughly

---

<sup>60</sup> See Revised Application, at ¶ 40, 38 (“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 so that a customer bears only the cost that the customer causes.”).

181,500 residential AMI meters to the approximate 1,000 commercial customers in the Large Electric and Large Electric High Load Factor classes.<sup>61</sup>

## LEGAL STANDARDS

### **1. Rates Must be Just and Reasonable**

The Louisiana Supreme Court long ago put it succinctly when it held, “The entire regulatory scheme, including increases as well as decreases in rates, is indeed in the public interest, designed to assure the furnishing of adequate service to all public utility patrons *at the lowest reasonable rates* consistent with the interest both of the public and of the utilities.”<sup>62</sup> More recently, the Court has reiterated that “in exchange for their favored status, furnishers of utility services submit to public regulation, which generally sanctions utility rates that provide *a limited but reasonable* return on the investment of the public utility. In effect, the public regulation acts as a substitute for competition.”<sup>63</sup> The utility’s base rates must be found to be reasonable in an “antecedent reasonableness review” before they may be charged to the utility’s customers.<sup>64</sup>

### **2. Rates must Provide Sufficient Revenues**

In setting a utility’s rates, “[T]he primary objective is to allow the company sufficient revenues to meet its operating expenses, provide its shareholders with a reasonable rate of return,

---

<sup>61</sup> See Exh. ENO-56 (consisting of ENO’s workpapers), at “Schedule WP\_Statement AA-2\_REV\_E RevAllocation”, showing ENO has 181,500 residential customers, 333 customers in the Large Electric class and 606 customers in the Large Electric High Load Factor class. This workpaper was separately marked (but not admitted as substantive evidence) during cross-examination as Exh. CCPUG-9.

<sup>62</sup> *City of Plaquemine v. Louisiana Public Service Commission*, 282 So.2d 440, 442-43 (La. 1973). (Emphasis and italics added).

<sup>63</sup> *Gordon v. Council of City of New Orleans*, 2008-0929, pp. 12-13 (La. 4/3/09), 9 So.3d 63, 73 (citing *State ex rel. Guste v. Council of City of New Orleans*, 309 So.2d 290, 294 (La. 1975)). (Emphasis and italics added).

<sup>64</sup> *Id.*, 2008-0929, pp. 13-14, 9 So.3d at 73-74. (Internal citations omitted).

and attract new capital.”<sup>65</sup> The regulator, in setting the rates of a utility at a level that the utility’s revenues will produce a fair rate of return, should “delineate and make explicit the basis upon which it has computed the utility’s fair rate of return.”<sup>66</sup>

That said, however, “A utility is entitled only to the opportunity to earn a reasonable return on its investment; the law does not insure that it will in fact earn the particular rate of return authorized by the Commission or indeed that it will earn any net revenues.”<sup>67</sup>

### **3. Utilities have an Obligation to Minimize Costs to Customers**

Utilities must make “*reasonable attempts to minimize costs* through prudent decision making, since ratepayers depend on only one monopolistic supplier.”<sup>68</sup> A regulator’s finding of unreasonableness, and therefore imprudence, will be upheld on appeal unless it is “based on an error of law or is one which the [regulator] could not have found reasonably from the evidence.”<sup>69</sup>

### **4. Customers may only be Charged for Investments that are Used and Useful**

It is well-settled ratemaking policy, adopted by the courts of this state, that “ratepayers are *only required to pay* a utility company a fair return on facilities and invested capital actually ‘*used and useful*’ for production of service to the ratepayers.”<sup>70</sup> “A facility or invested capital is used

---

<sup>65</sup> *Central Louisiana Electric Co. v. Louisiana Pub. Serv. Comm’n*, 508 So.2d 1361, 1364-65 (La. 1987) (citing, *South Central Bell Telephone Co. v. Louisiana Public Service Comm’n*, 352 So.2d 964, 967 (La.1977); Jones, *Judicial Determination of Public Utility Rates: A Critique*, 54 B.U.L.Rev. 873, 875 (1975)).

<sup>66</sup> *Central Louisiana Elec. Co., Inc. v. Louisiana Public Service Com’n*, 437 So.2d 278, 279 (La. 1983) (citing, *So. Cent. Bell Tel. v. L.P.S.C.*, 352 So.2d 964 (La.1977)).

<sup>67</sup> *South Central Bell Telephone Co. v. Louisiana Public Serv. Comm’n*, 594 So.2d 357, 359-60 (La. 1992) (citing, *Southern California Edison Co. v. Public Utilities Comm’n*, 20 Cal.3d 813, 144 Cal.Rptr. 905, n. 8, 576 P.2d 945, n. 8 (1978) (citing *Power Comm’n v. Pipeline Co.*, 315 U.S. 575, 590, 62 S.Ct. 736, 745, 96 L.Ed. 1037 (1942); *Bluefield Co. v. Public Serv. Comm’n*, 262 U.S. 679, 692-693, 43 S.Ct. 675, 678-679, 67 L.Ed. 1176; *Re General Tel. Co. of Cal.*, 69 Cal.P.U.C. 601, 610 (1969); *Oakland v. Key System Transit Lines*, 52 Cal.P.U.C. 779, 786 (1953))).

<sup>68</sup> *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm’n*, 1998-1235, p. 17 (La. 4/16/99), 730 So.2d 890, 904 (citing, *Gulf States Utils. Co. v. Louisiana Pub. Serv. Comm’n*, 1996-2046 (La. 2/25/ 97), 689 So.2d 1337, 1346 & n. 9). (Emphasis and italics added).

<sup>69</sup> *Id.*, (quoting, *CTS Enterprises, Inc. v. Louisiana Public Service Comm’n*, 540 So.2d 275 (La. 1989)).

<sup>70</sup> *Entergy Gulf States, Inc.*, 1998-1235, p. 28, 730 So.2d at 911 (citing, *Gulf States Utils. Co. v. Louisiana Pub. Serv. Comm’n*, 364 So.2d 1266, 1269 (La. 1978)). (Emphasis and italics added).



and useful if it is (1) in service, and (2) reasonably necessary.”<sup>71</sup> By definition, an investment that is not complete and, therefore, not in service, is not used and useful.<sup>72</sup>

##### **5. A Utility’s Rate Design must not Create Undue Discrimination**

The Louisiana Fourth Circuit Court of Appeal has held that “a utility’s rate structure *must be nondiscriminatory.*”<sup>73</sup>

A municipal utility has the same obligation to provide service to its customers at a “reasonable and nondiscriminatory rate” as a private utility company, and,

Although obligated to maintain a uniform and nondiscriminatory rate among its customers, a municipal corporation operating a public utility nevertheless has the right to make a reasonable classification of its customers, and to charge a different rate according to the classification, based upon such factors as the cost of the service, the purpose for which the service is received, the quantity or amount received, the different character of the service provided, the time of its use, *or any other matter which presents a substantial difference as a ground of distinction.*<sup>74</sup>

A municipal utility’s lower rate for large customers, designed to encourage such customers to “locate and remain in the community” is reasonable, under the rationale that such discounted rates will eventually benefit the entire community and all utility customers because of the attraction and retention of industry in the community.<sup>75</sup>

---

<sup>71</sup> *Id.* (citing, *Central Louisiana Electric Co. v. Louisiana Pub. Serv. Comm’n*, 508 So.2d 1361, 1367 (La. 1987) (citing *City of Evansville v. Southern Ind. Gas. & Electric Co.*, 167 Ind.App. 472, 339 N.E.2d 562 (Ind.App. 2d Dist. 1975))).

<sup>72</sup> *Id.*

<sup>73</sup> *State ex rel. Guste v. Council of City of New Orleans*, 309 So.2d 290, 294-95 (La. 1975) (finding that the classification at issue between customers by rate structure concerning a late charge was reasonable based on the difference between such customers (*i.e.*, customers who paid their bill late v. customers who paid their bill timely)). (Emphasis and italics added).

<sup>74</sup> *Liberty Rice Mill, Inc. v. City of Kaplan*, 95-1656, p. 3 (La.App. 3 Cir. 5/8/96), 674 So.2d 395, 397, writ denied, 96-1919 (La. 11/1/96), 681 So.2d 1263 (citing, *Hicks v. City of Monroe Utilities Commission*, 112 So.2d 635 (La. 1959)). (Emphasis and italics in original).

<sup>75</sup> *Id.*, 95-1656, p. 4, 674 So.2d at 397-98.



## **6. Upon a Finding of Unreasonableness, a Regulator can Employ a Hypothetical Capital Structure**

A utility's capital structure is the relative amount of debt capital to equity capital. Debt capital tends to be less expensive than equity capital. Thus, if a utility has too much equity in its debt-to-equity ratio in its capital structure, a regulator may find that unreasonable because it costs customers more than it should were there a proper amount of equity in the structure. The capital structure is crucial to determining the "cost of capital", which courts have held to essentially be the same as the "fair rate of return".<sup>76</sup> A regulator may choose to disregard a utility's actual capital structure and utilize a hypothetical capital structure (typically with a lower amount of equity capital), but the regulator must make a finding that "the utility's capital investments were imprudent *or that the capital structure resulting therefrom was unreasonable.*"<sup>77</sup>

## **7. The Regulator is not Bound by the Testimony of Witnesses**

As a general rule, a regulatory body may use its own judgment in evaluating evidence as to any matter within its expertise; it is not bound by even uncontradicted testimony of experts which amount to mere opinions on their part.<sup>78</sup>

## **8. The Regulator's Decision will be Afforded Deference *Unless* it is Arbitrary, Capricious, or not Based upon Evidence in the Record**

A regulator's decisions regarding ratemaking issues will be upheld "unless they are arbitrarily or capriciously rendered, or are not reasonably supported by the evidence."<sup>79</sup> Similarly,

---

<sup>76</sup> *South Central Bell Telephone Co. v. Louisiana Public Serv. Comm'n*, 594 So.2d 357, 359-60 (La. 1992) (citing, *South Central Bell Telephone Co. v. Louisiana Public Service Comm'n*, 352 So.2d 964, 970 (La.1977)).

<sup>77</sup> *Id.*, 594 So.2d at 366. (Emphasis and italics added).

<sup>78</sup> *Baton Rouge Water Works Co. v. Louisiana Public Service Com'n*, 342 So.2d 609, 611 (La. 1977), *cert. denied*, 434 U.S. 827 (1977) (citing 2 Davis, Administrative Law Treatise, Section 14.13 (1958)).

<sup>79</sup> *Gulf States Utilities Co. v. Louisiana Public Service Com'n*, 578 So.2d 71, 84 (La. 1991), *cert. denied*, 502 U.S. 1004, 112 S.Ct. 637, 116 L.Ed.2d 655 (1991) (relying upon *CTS Enterprises, Inc. v. Louisiana Public Service Comm'n*, 540 So.2d 275 (La. 1989), *Louisiana Power & Light v. Louisiana Public Service Comm'n*, 523 So.2d 850 (La. 1988), and *Central Louisiana Elec. Co., Inc. v. Louisiana Public Service Com'n*, 437 So.2d 278 (La. 1983)).

a regulator's order setting rates for a utility "will be upheld unless shown to be 'arbitrary, capricious, abusive of its authority, clearly erroneous, or unsupported by evidence.'"<sup>80</sup>

### ARGUMENT

Set forth below for the Council's convenience is a summary of the issues addressed by CCPUG, CCPUG's recommendation regarding each such issue, and the dollar amount of proposed reductions to ENO's base rates and overall rates associated with each of CCPUG's issues. The summary is included in the Surrebuttal and Cross-Answering Testimony and Exhibits of Lane Kollen, CCPUG's consultant.<sup>81</sup>

---

<sup>80</sup> *Id.* (quoting *Central Louisiana Elec. Co., Inc.*, *supra*).

<sup>81</sup> *See* Exh. CCPUG-2 (Kollen Surrebuttal Testimony) (CCPUG), at 6:1, Table entitled, "Entergy New Orleans, LLC, Summary of CCPUG Revenue Requirement Recommendations – Surrebuttal and Cross-Answering Update, Docket No. UD-18-07, Period II test year Ended December 31, 2018, \$ Millions".

**Entergy New Orleans, LLC**  
**Summary of CCPUG Revenue Requirement Recommendations - Surrebuttal and Cross-Answering Update**  
**Docket No. UD-18-07**  
**Period II Test Year Ended December 31, 2018**  
**\$ Millions**

	Electric	Gas	Total
<b>Entergy New Orleans, LLC Requested Rate Change</b>			
ENO Request Based on Revised Period II Filing - Base Rates	135.092	(0.920)	134.172
ENO Computed Reduction to Realign Fuel and Purchased Energy Cost Recovery	(92.408)	-	(92.408)
ENO Reduction in Riders PPCACR, MISO, and NNCR	(76.313)	-	(76.313)
ENO Increase for AMI Electric and Gas Charge	7.145	0.777	7.923
ENO Increase for Interim EECR Rider	6.006	-	6.006
Sum Total of ENO Requested Rate Changes	<u>(20.478)</u>	<u>(0.143)</u>	<u>(20.620)</u>
<b>Effects on Increase of CCPUG Rate Base Recommendations</b>			
Remove Plant, A/D, and ADIT Proforma Adjustments Related to 2019 Additions	(3.482)	(1.486)	(4.968)
Remove Capital Storm Restoration Costs from Plant	(1.694)	(0.018)	(1.712)
Remove (Electric) or Reduce (Gas) Asset NOL ADIT	(0.605)	(1.315)	(1.920)
Remove Asset ADIT - Deferred Storm Costs	(0.565)	-	(0.565)
Remove Reduction to ADIT for Excess ADIT Amortization in 2019	(0.113)	(0.029)	(0.142)
Subtract FIN 48 Liability ADIT in Account 282	(0.326)	(0.004)	(0.329)
Correct Cash Working Capital to Include Dividend Component of Return on Equity	(0.206)	(0.032)	(0.238)
Remove Algiers Migration Costs Net of ADIT	(0.310)	-	(0.310)
<b>Effects on Increase of CCPUG Operating Income Recommendations</b>			
Remove Forecast 2019 Increases in Payroll and Related Expenses	(0.780)	(0.265)	(1.045)
Remove Depreciation Expense Related to 2019 Plant Additions	(3.684)	(0.692)	(4.376)
Remove Depreciation Expense Associated With Capital Storm Restoration Costs	(0.432)	(0.006)	(0.438)
Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1	(5.029)	-	(5.029)
Reduce Depreciation Expense – Use 0% Net Salvage for Union Power Block #1	(0.628)	-	(0.628)
Reduce Depreciation Expense – Correct Patterson Solar Depreciation Rate	(0.070)	-	(0.070)
Extend Amortization of Algiers Transaction and Migration Costs to 10 Years	(0.260)	-	(0.260)
Remove Amortization of Algiers Migration Costs	(0.862)	-	(0.862)
Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years	(0.514)	-	(0.514)
<b>Effects on Increase of CCPUG Rate of Return Recommendations</b>			
Reflect Short Term Debt	(1.112)	(0.155)	(1.267)
Reflect Return on Equity of 9.35% (Electric and Gas)	<u>(5.558)</u>	<u>(0.885)</u>	<u>(6.443)</u>
<b>Total CCPUG Recommendations</b>	<b>(26.230)</b>	<b>(4.886)</b>	<b>(31.116)</b>
<b>CCPUG Recommendation to Increase/(Decrease) Base Rates</b>	<u><b>108.863</b></u>	<u><b>(5.806)</b></u>	<u><b>103.057</b></u>
<b>CCPUG Recommendation to Decrease Overall Rates</b>	<u><b>(46.707)</b></u>	<u><b>(5.029)</b></u>	<u><b>(51.736)</b></u>

## I. KEY ISSUES ADDRESSED BY CCPUG

### A. ENO's Electric and Gas Operations

#### 1. The Reduction in Overall Rates Should be Roughly \$51.7 Million; not \$20 Million

ENO proposes a reduction in overall rates (revenue requirements) of approximately \$20.4 million.<sup>82</sup> The Council's Advisors recommend an overall reduction in rates of roughly \$33 million in electric revenue and \$3.8 million in gas revenue for a total overall recommended reduction of \$36.8 million.<sup>83</sup>

CCPUG's consultants, on the other hand, recommend much larger decreases in overall rates – a reduction of \$46.707 million in overall electric rates – as opposed to ENO's recommended reduction of \$20.30 million (*i.e.*, an *increase* in the reduction recommended by ENO of \$26.407 million) –and a reduction of \$5.029 million in overall gas rates – as opposed to ENO's proposed reduction of \$0.142 million (*i.e.*, an *additional* reduction of \$4.887 million).<sup>84</sup> As shown in the table above, CCPUG's consultants recommend a total (electric and gas) overall rate reduction of \$51.736 million<sup>85</sup> as opposed to ENO's total reduction of just over \$20.4 million.

For the reasons set forth below, CCPUG's recommended reductions to overall rates in addition to those suggested by ENO should be adopted by the Council in order to set ENO's rates at an appropriate level, while providing ENO the opportunity to earn a reasonable rate of return. CCPUG's recommendations also address an issue barely touched upon by other parties to this proceeding – ongoing and significant subsidies being forced upon customers in the commercial classes which require them to pay far more than the cost ENO incurs to serve them, all in order to

---

<sup>82</sup> See ENO's Revised Application, at ¶ 17, stating that ENO is proposing a reduction in its electric revenue requirement of approximately \$20.3 million and at ¶ 18 where it recommends a reduction in the gas revenue requirement of \$0.142 million.

<sup>83</sup> Exh. ADV-3 (Direct Testimony of Victor Prep ("Prep Direct Testimony") (Advisors)), at 2:10-11 and 6:1-4.

<sup>84</sup> See Exh. CCPUG-2 (Kollen Surrebuttal Testimony) (CCPUG), at 6:1, Table.

<sup>85</sup> See *id.*

provide rate relief to the residential class of customers. As stated in its opening statement at the hearing on the merits, CCPUG does *not* propose to eliminate the subsidies paid by the commercial classes of customers in favor of the residential class; rather, it proposes to reduce those subsidies which impinge upon the bottom lines of the members of the commercial classes. It also bears repeating that this particular case provides the Council with a rare opportunity to reduce those subsidies while still maintaining a rate *decrease* for residential customers. CCPUG encourages the Council to take advantage of this once-in-a-generation opportunity to reduce the crippling subsidies on the commercial classes of customers.

## **2. ENO's Return on Equity Should be set at 9.35% for Electric and Gas Operations**

### **a. ENO's ROE Recommendation is Unsupported and Egregiously High**

Estimating the appropriate rate of return for a utility is not an exact science. ENO's witness sponsoring testimony concerning its requested ROE, Robert B. Hevert, agreed with that statement under cross-examination.<sup>86</sup> He conceded it requires the use of informed judgment and, as such, reasonable minds can and do differ on the appropriate level of ROE for the same utility.<sup>87</sup> Mr. Hevert further agreed that his ROE recommendations are not always adopted by regulators.<sup>88</sup> In fact, while Mr. Hevert claimed that "some regulators" have disagreed with his ROE recommendations, he was presented with his own listing of expert testimonies at trial which shows that his ROE recommendations are *nearly always higher* than the ROEs adopted by regulators.<sup>89</sup>

---

<sup>86</sup> TR, June 19, 2019, (Cross Examination of Robert Hevert), at 10:2-5.

<sup>87</sup> *Id* at 10:10-25.

<sup>88</sup> *Id* at 10:2-5.

<sup>89</sup> *Id* at 10:16-25; 51:9-19 (where Mr. Hevert agreed that, over the last five years, in all of the cases in which he testified regarding ROE (which is well over 100), the regulator adopted an ROE *lower* than his recommendation in all but one case); and Exh. AP-5 (ENO's response to data request APC 2-14 containing the list of all cases over the last five years in which Mr. Hevert testified on ROE, his recommended ROE and the ROE adopted by the regulator, marked for cross-examination purposes only, and not admitted as substantive evidence).

One of the disappointing bad news plot lines in what should be a feel-good story about declining rates is ENO's desire to over-earn going forward. The evidence in this proceeding shows ENO's requested return on equity of 10.75% is unsupported and egregiously high.<sup>90</sup> Adopting an unreasonably high ROE going forward will undo much of the good accomplished through this rate decrease proceeding. If adopted, ENO's requested ROE would represent the **highest** ROE allowed by a regulator in the entire United States over the last 18 months.<sup>91</sup> Likewise, it far exceeds the average ROE awarded by regulators across the country in the last five years.<sup>92</sup> In fact, according to ENO's data, its requested ROE of 10.75% is **higher than all but one ROE** granted by any regulator in the entire United States to an electric and gas utility **over the last five years.**<sup>93</sup> The evidence in the record of this proceeding simply does not support awarding ENO the excessively high ROE it seeks.

CCPUG's consultants have performed thorough and well-accepted analyses to determine the appropriate ROE for ENO and have determined that a 9.35% ROE (for both electric and gas operations) is reasonable and appropriate under the circumstances.<sup>94</sup> CCPUG's consultant, Richard A. Baudino, performed long-accepted Discounted Cash Flow ("DCF") studies, as well as a Capital Asset Pricing Model ("CAPM") methodology, to estimate ENO's ROE.<sup>95</sup> Mr. Hevert testified that

---

<sup>90</sup> ENO has proposed in its Revised Application to temporarily structure its rates with a 10.50% ROE for electric operations which would increase to 10.75% over time and requested a 10.75% ROE for its gas operations. *See, e.g.*, Revised Application, at ¶¶ 23 – 26, and Exh. ENO-1 (Thomas Revised Direct Testimony) (ENO), at 6:11 – 7:5.

<sup>91</sup> *See* Exh. CCPUG-4 (Surrebuttal Testimony and Exhibits of Richard A. Baudino ("Baudino Surrebuttal Testimony") (CCPUG)), at 6:1, Surrebuttal Table 2, entitled, "2018 – 2019 Allowed ROEs, Rebuttal Exhibit (RBH-19)", listing the authorized ROEs across the country – as selected by Mr. Hevert – from January 2018 through February 2019 and revealing that the highest such ROE was 10.00%.

<sup>92</sup> Exh. ENO-29 (Hevert Revised Rebuttal Testimony) (ENO), at 5, fn 6: "The average authorized ROE for vertically integrated electric utilities (excluding limited issue riders) from January 1, 2014 to February 28, 2019 is 9.79 percent."

<sup>93</sup> *See id.*, at 6:3, Chart 2: "Vertically Integrated Authorized ROEs (2014 – 2019)"; Hearing Transcript, 6/19/2019 (Cross Examination of Hevert) at 25:8026:4.

<sup>94</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 3:3-12 and 30:2-7, and Exh. CCPUG-4 (Baudino Surrebuttal Testimony) (CCPUG), at 7:11-19 and 12:8 – 13:10.

<sup>95</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 3:3-12.

“[I]t is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach.”<sup>96</sup> That is exactly what CCPUG’s consultant, Mr. Baudino, did. On the other hand, Mr. Hevert failed to follow his own advice.

ENO’s witness, Mr. Hevert, claims that an ROE of 10.75% is reasonable, however, that ROE far exceeds any reasonable range of results of nearly all of the ROE analyses presented in this proceeding. In fact, Mr. Hevert’s ROE recommendation of 10.75% is **literally off of his own chart** of awarded ROEs across the country from 2014 through the third quarter of 2018.<sup>97</sup> Even more striking, according to that same chart (Chart 1) in Mr. Hevert’s Revised Rebuttal Testimony, the *highest* awarded ROE during that four-year time period was 10.20%, which is **55 basis points below** his recommended ROE in this case.<sup>98</sup> Mr. Hevert’s own evidence establishes that his recommended ROE is a lavish outlier.

The ROE estimate is derived using various analytical methods, such as the DCF and CAPM methodologies. As such, the results are only as reliable as the inputs. An ROE analyst, therefore, must be diligent and use only assumptions which are grounded in fact and most likely representative of future economic conditions. Otherwise, the results of the ROE analysis will be flawed and unreliable. Mr. Hevert failed to follow this standard, and his ROE analysis results should, therefore, not be relied upon. In actuality, what Mr. Hevert did here was to cherry-pick the **second highest range** of ROE results produced by only *one* set of assumptions in *one*

---

<sup>96</sup> Exh. ENO-26 (Revised Direct Testimony of Robert B. Hevert (“Hevert Revised Direct Testimony”) (ENO)), at 16:5-7.

<sup>97</sup> See Exh. ENO-29 (Hevert Revised Rebuttal Testimony) (ENO), at 5:3, Chart 1: “Authorized ROEs vs. DCF Estimates” showing the highest ROE awarded during the pertinent time period was 10.50%; TR, 6/19/2019 (Cross Examination of Hevert), at 17:5-8. See also Exh. CCPUG-4 (Baudino Surrebuttal Testimony) (CCPUG), at 4:17 – 5:6, noting that “Mr. Hevert’s [recommended] 10.75% ROE is, quite literally, off the chart given that the top ROE on his Chart 1 is 10.50%.”

<sup>98</sup> *Id.*, at 5:3, Chart 1.



methodology, while ignoring all of the results of his other analyses which produced significantly lower ranges.

As an initial matter, and as discussed by Mr. Baudino, Mr. Hevert's ROE range omits critically important information from the DCF model, resulting in greatly overstated investor required ROE for investment grade regulated utilities.<sup>99</sup> Mr. Hevert rejected the results of two of his four ROE methodologies, choosing to rely on the methodology that produced the second-highest range of ROE results.<sup>100</sup>

**i. Mr. Hevert's Constant Growth DCF Analysis Produced ROEs Similar to Mr. Baudino's Analysis, but He Disregarded those Results**

Mr. Hevert employed a Constant Growth DCF analysis, as did Mr. Baudino, in estimating ENO's ROE. The mean (average) results of Mr. Hevert's Constant Growth DCF analysis ranged from 9.16% to 9.29%<sup>101</sup> (a range that is similar to, but lower than, Mr. Baudino's). Below is Table 3 from Mr. Hevert's Revised Direct Testimony showing all of his results of his Constant Growth DCF analysis:<sup>102</sup>

**Table 3: Constant Growth DCF Results**

	<b>Mean Low</b>	<b>Mean</b>	<b>Mean High</b>
30-Day Average	8.45%	9.24%	10.12%
90-Day Average	8.49%	9.29%	10.16%
180-Day Average	8.37%	9.16%	10.03%

<sup>99</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 39:8-14.

<sup>100</sup> *Id.*, at 33:3-23.

<sup>101</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 22:16, Table 3: "Constant Growth DCF Results"; see also Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 32:6-8.

<sup>102</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 22:16, Table 3: "Constant Growth DCF Results".



Mr. Baudino employed two versions of a Constant Growth DCF analysis and discussed these in his Direct Testimony: “Method 1” Constant Growth DCF analysis (using average growth rates), which produced an ROE range from **8.71% to 9.36%**, and “Method 2” (using the median growth rates), which produced an ROE range from **8.52% to 9.36%**.<sup>103</sup> Mr. Baudino’s Constant Growth DCF results set forth in his Direct Testimony, therefore, are similar to Mr. Hevert’s, particularly his mean (average) results. As will be discussed below, Mr. Baudino updated his DCF analysis in his Surrebuttal Testimony and the updated results are lower than the results, mentioned above, set forth in his Direct Testimony. Nonetheless, Mr. Baudino continues to recommend the 9.35% ROE firmly established by his original DCF analysis due, in large part, to ENO’s split credit rating.<sup>104</sup>

Mr. Hevert testified that he performed the Constant Growth DCF methodology correctly.<sup>105</sup> Regardless, and although he claimed that he considered the results of his Constant Growth DCF analysis,<sup>106</sup> as can be seen from Mr. Hevert’s Table 3, all of his Constant Growth DCF analysis results are well below his recommended range of 10.25% to 11.25%,<sup>107</sup> indicating that he simply disregarded the results of his own analysis.

The Constant Growth DCF method “utilizes verifiable public information with respect to investor return requirements for electric utilities.”<sup>108</sup> Likewise, “Current stock prices are the best indicators we have of investor expectations and analysts’ earnings and dividend growth forecasts may reasonably be assumed to influence investors’ required ROEs.”<sup>109</sup> The Constant Growth DCF

---

<sup>103</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 23:5-8.

<sup>104</sup> Exh. CCPUG-4 (Baudino Surrebuttal Testimony) (CCPUG), at 13:4-10.

<sup>105</sup> TR, June 19, 2019, (Cross Examination of Robert Hevert), at 20:20 – 21:4.

<sup>106</sup> *Id.*, at 19:12 – 20:8.

<sup>107</sup> Exh. ENO-29 (Hevert Revised Rebuttal Testimony) (ENO), at 4:8, Table 1: “Summary of ROE Recommendations”.

<sup>108</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 34:14-16.

<sup>109</sup> *Id.*, at 34:16-18.

model has been utilized for decades to estimate ROEs for electric utilities.<sup>110</sup> The fact that Mr. Hevert simply rejected the results of his own Constant Growth DCF analysis undermines the reliability of his recommended ROE.

**ii. Mr. Hevert’s Multi-Stage DCF Analysis Results are Inflated, yet He Rejected them in Favor of even Higher Results**

The mean (average) results of Mr. Hevert’s Multi-Stage DCF analysis range from 9.67% to 10.02%.<sup>111</sup> He presented the results of his Multi-Stage DCF analysis in Table 6 of his Revised Direct Testimony.<sup>112</sup>

**Table 6: Multi-Stage DCF Model Results<sup>30</sup>**

	<b>Mean Low</b>	<b>Mean</b>	<b>Mean High</b>
30-Day Average	9.40%	9.89%	10.42%
90-Day Average	9.53%	10.02%	10.55%
180-Day Average	9.19%	9.67%	10.21%

As can be seen from Table 6, only two results – both in the mean high column – are high enough to break into Mr. Hevert’s recommended ROE range of 10.25% to 11.25%. The results of Mr. Hevert’s own Multi-Stage DCF analysis, like those of his Constant Growth DCF methodology, cut sharply against his recommended ROE range and ROE determination of 10.75%.

Mr. Hevert’s selection of an ROE that exceeds the entire collection of results produced by his Multi-Stage DCF analysis is perplexing, especially given that the results of his Multi-Stage

<sup>110</sup> See, e.g., *Gulf States Utilities Co., v. Louisiana Pub. Serv. Comm’n*, 96-0345, p. 5 (La. 7/2/96), 676 So.2d 571,575 (affirming the LPSC’s adoption of Mr. Baudino’s ROE recommendation for Gulf States Utilities Co., Inc., and noting that the LPSC “had previously relied upon the DCF method when setting the equity return for GSU and other companies. It noted the constant growth form of DCF analyses is the method that has been historically used in regulatory proceedings, and the DCF analysis has been accepted by most state regulatory authorities over the years.”

<sup>111</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 30:7, Table 6: “Multi-Stage DCF Model Results”; see also Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 32:10-14.

<sup>112</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 30:7, Table 6: “Multi-Stage DCF Model Results”.

DCF method are inflated. In his Multi-Stage DCF analysis, Mr. Hevert relied upon a grossly elevated estimate of Gross Domestic Product (“GDP”) growth of 5.45%.<sup>113</sup> Mr. Hevert developed his GDP growth estimate by reviewing historical real GDP growth from 1929 through 2017 and a forecasted inflation rate.<sup>114</sup> An average of real GDP growth spanning from the Great Depression to recent history bears no relevance to future GDP growth estimates. Nonetheless, his use of an inflated GDP growth estimate still produced a mean (average) ROE range that is *entirely below* the 10.25% to 11.25% range he recommends in this proceeding and produced a set of results which is *entirely below* his recommended 10.75% ROE.

Mr. Baudino, on the other hand, relied upon two well-regarded, publicly-available forecasts for GDP growth that are commonly relied upon by the Federal Energy Regulatory Commission (“FERC”) produced by the Energy Information Administration and the Social Security Administration’s Trustees Report.<sup>115</sup> Mr. Baudino determined the GDP growth estimate to be 4.38%.<sup>116</sup> The introduction of such an inflated GDP growth estimate led Mr. Hevert’s DCF analysis to spew overstated ROE results. Even with its serious flaw, Mr. Hevert’s Multi-Stage DCF analysis produced mean (average) results in the range of 9.67% to 10.02%. When Mr. Baudino corrected Mr. Hevert’s erroneous GDP growth estimate in the Multi-Stage DCF analysis, the mean (average) results were in the range of **8.28% and 9.15%**,<sup>117</sup> a significant reduction from Mr. Hevert’s recommended 10.75% ROE. Mr. Hevert was wrong to completely discard the DCF model results, as the model “currently shows that investor required returns are considerably lower for utility stocks given their safety and security relative to the stock market as a whole.”<sup>118</sup>

---

<sup>113</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 40:15 – 41:10.

<sup>114</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 28:3-8.

<sup>115</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 40:16-20.

<sup>116</sup> *Id.*, at 41:7-10.

<sup>117</sup> *Id.*, at 41:11-17.

<sup>118</sup> *Id.*, at 34:21-23.

### **iii. Mr. Hevert's CAPM Analysis is Unreliable, but He Based his ROE Recommendation on it, Nonetheless**

Mr. Hevert conducted his CAPM analysis using the beta coefficients produced by Value Line and Bloomberg. The ROE results produced by the CAPM method using the average Value Line beta coefficient (11.66% to 12.28%), are “so unreasonably high [as compared to Mr. Hevert’s own historical data] that they should be rejected out of hand.”<sup>119</sup> Mr. Hevert, himself, did not rely on this extremely inflated range of ROE results. Mr. Hevert’s recommended range of ROEs (10.25% to 11.25%) is closest to – although not completely explained by – the results of his CAPM analysis using the Bloomberg beta coefficients.<sup>120</sup> It is somewhat of a mystery how Mr. Hevert arrived at the top end of his ROE range.

Mr. Hevert used two measures of the purported interest free rate: the current 30-day average yield on the 30-year Treasury bond and a projected 30-year Treasury bond. He did not consider any shorter maturity bonds, such as the 5-year Treasury note like Mr. Baudino considered.<sup>121</sup> As an initial matter, however, it is inappropriate to rely upon projected bond yields in the CAPM analysis, because current interest rates and bond yields embody all of the relevant market data and investors’ expectations including future changes.<sup>122</sup> To add projections regarding bond yields introduces an unwarranted layer of speculation to the analysis.

Mr. Hevert’s forecasted 30-year Treasury bond yield of 3.48% is higher than his current yield of 3.11%. This could only occur if investors today expect to incur significant losses in the value of their investments in long-term Treasury bonds,<sup>123</sup> because the price of a bond moves in the opposite direction of its yield; meaning that if the current bond price goes down, the yield on

---

<sup>119</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 33:19-23.

<sup>120</sup> *Id.*, at 34:2-7.

<sup>121</sup> *Id.*, at 42:1-5.

<sup>122</sup> *Id.*, at 42:12-15.

<sup>123</sup> *Id.*, at 43:5-14.

that bond will increase. In Mr. Hevert's example, the bond yield increases without the corresponding reduction in the assumed price of the bond. Mr. Hevert testified that "Classic valuation theory assumes that investors trade securities rationally, with prices reflecting their perceptions of value."<sup>124</sup> He likewise admitted under cross-examination that it would be *irrational* for an investor to invest in a bond expecting large losses.<sup>125</sup> Yet, that is exactly what he assumes in his methodology.

Mr. Hevert should have considered shorter-term Treasury yields, because theoretically, the risk-free rate in the CAPM analysis should have no interest rate risk.<sup>126</sup> The shorter the duration of a bond, the less interest rate risk there is, and, conversely, the longer the duration of a bond, the higher the inherent interest rate risk.<sup>127</sup> Mr. Hevert's use of only long-term bonds introduces interest rate risk when, according to the methodology, there should be none.

Mr. Hevert's CAPM results should, therefore, be rejected as unreliable and based upon irrational speculation as well as unreasonable reliance on only 30-year Treasury bond yields.

**iv. Mr. Hevert's Bond Yield/Risk Premium Analysis is a "Blunt Instrument" not to be Relied Upon in the Presence of Other Acceptable Methodologies**

Mr. Hevert developed, through a regression analysis, an estimate of a historical risk premium. His risk premium method yielded the resulting ROE range of 9.96% to 10.28%.<sup>128</sup> Bond yield plus risk premium is an imprecise approach that only offers general guidance on the current authorized ROE for an electric utility, because risk premiums can and do change substantially over

---

<sup>124</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 69:22-23.

<sup>125</sup> TR, June 19, 2019, (Cross Examination of Hevert), at 21:9-22.

<sup>126</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 43:22.

<sup>127</sup> *Id.*, at 42:20 – 43:3.

<sup>128</sup> *Id.*, at 45:8-15.



time.<sup>129</sup> The results of Mr. Hevert's bond yield/risk premium analysis are shown in Table 8 of his Revised Direct Testimony, reproduced below:<sup>130</sup>

**Table 8: Summary of Bond Yield Plus Risk Premium Results**

	<b>Return on Equity</b>
Current 30-Year Treasury (3.11%)	9.96%
Near-Term Projected 30-Year Treasury (3.48%)	10.03%
Long-Term Projected 30-Year Treasury (4.30%)	10.28%

As flawed and questionable as the bond yield/risk premium method is for estimating an appropriate ROE, the results of Mr. Hevert's analysis almost completely fall below his recommended ROE range of 10.25% to 11.25%. It is evident that he put very little weight on this method, as he did with regard to the DCF analyses.

**v. Mr. Hevert's "Business Risks" are Ill-Defined Regarding their Effect on ROE and Fail to Provide a Valid Reason for his Inflated ROE Recommendation**

In addition to his analytical methodologies, Mr. Hevert discusses, at great length, ENO's "business risks" that he says counsel in favor of a higher-than-average ROE.<sup>131</sup> These business risks are: "(1) ENO's planned capital investment program; (2) the Company's credit profile; (3) the geographic risk associated with severe weather; (4) the risks associated with the lack of customer diversity; (5) the Company's small size relative to the proxy group; (6) the effect of flotation costs; and (7) the effect of the TCJA."<sup>132</sup>

<sup>129</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 45:16-23.

<sup>130</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 37:10, Table 8: "Summary of Bond Yield Plus Risk Premium Results".

<sup>131</sup> See *id.*, at 38:1 – 66:10.

<sup>132</sup> *Id.*, at 38:5-10.

But, as Mr. Hevert testified at the hearing, ENO is in charge of its own capital investment program, and, therefore, is in complete control of this business risk.<sup>133</sup> Further, the Council has approved much of the capital investment program Mr. Hevert mentions, such as the NOPS station and the gas infrastructure repair and replacement program,<sup>134</sup> thus mitigating concerns regarding recoverability of such investments. Mr. Hevert does not quantify these business risks with respect to any corresponding increase or decrease to the recommended ROE for ENO.<sup>135</sup> Likewise, with regard to ENO's split credit rating, Mr. Hevert testified he did not quantify in terms of how many basis points should be added to the otherwise recommended ROE because of the split rating; rather he testified, "it was data that supports my view that it is proper to look toward the upper end of the range of results."<sup>136</sup> The other risks, including relative size, customer diversity, and geographic service territory, are long-standing, well-known factors that should not merit an oversized ROE. Finally, the effects of the TCJA have been addressed by the Council.

So, none of Mr. Hevert's purported business risks justifies an ROE that is higher than all but one awarded by a regulator in the United States over the last five years. In fact, for all of the testimony dedicated to these supposed business risks, Mr. Hevert declined to assign *any value* to *any of them* with respect to the relative increase or decrease in the recommended ROE for ENO. If Mr. Hevert possessed the courage of his convictions, he would have told us the relative effect on his recommended ROE for ENO associated with these allegedly serious business risks.

Mr. Hevert opposed the ROE recommendations of the Advisors, CCPUG and Air Products. He testified that all of their recommendations were "too low".<sup>137</sup> If that were the case, it should

---

<sup>133</sup> TR, June 19, 2019, (Cross Examination of Robert Hevert), at 39:13-20.

<sup>134</sup> *Id.*, at 39:21 – 41:9.

<sup>135</sup> *Id.*, at 41:10-20.

<sup>136</sup> *Id.*, at 43:10 – 44:9.

<sup>137</sup> *Id.*, at 44:21 – 45:2.



have been a relatively simple matter to say so. But, as Mr. Hevert admitted at the hearing, he spent over 250 pages of Revised Rebuttal Testimony, exhibits, and work papers attempting to discredit the work of the Advisors, CCPUG and Air Products.<sup>138</sup> The old saying, “Do not use a cannon to kill a mosquito”, comes to mind.<sup>139</sup> If the ROE recommendations sponsored by the Advisors, CCPUG and Air Products were simply erroneous and “too low” that should have been an easy mosquito to squash.

**vi. Mr. Baudino Considered the DCF Analysis Results, the CAPM Results, and ENO’s Split Credit Rating in Setting the ROE; He also Updated his ROE Analyses**

Like Mr. Hevert, Mr. Baudino performed the Constant Growth DCF analysis and CAPM methodology in determining ENO’s ROE. Unlike Mr. Hevert, Mr. Baudino used reasonable assumptions in his modeling and gave appropriate weight to the results of these two, well-accepted methodologies for setting ROEs when determining ENO’s ROE in this proceeding. With respect to prevailing economic and financial conditions in the U.S. economy, particularly, the recent increases in the federal funds rate, he noted,

Even with several recent increases in the federal funds rate, **the U.S. economy is still in a relatively low interest rate environment.** This environment has affected the common stocks of regulated utilities, which are interest rate sensitive due to their high concentration of fixed assets. Thus, as interest rates increase in the general economy, the prices of utility common stocks fall and their dividend yields rise. Alternatively, as interest rates fall, the dividend yields on utility common stocks tend to fall as their prices rise.<sup>140</sup>

After discussing the Federal Reserve’s “Quantitative Easing” program and subsequent targeted interest rate increases, Mr. Baudino explains that,

---

<sup>138</sup> TR, June 19, 2019, (Cross Examination of Robert Hevert), at 45:3 – 46:21.

<sup>139</sup> This quote is most often attributed to the Chinese philosopher, Confucius, although he died in 478 BC, roughly 1,400 years before gunpowder was believed to have been invented.

<sup>140</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 8:30 – 9:3. (Emphasis and italics added).

Despite recent increases in the general level of short-term interest rates since the second half of 2016, the U.S. economy continues to operate in a relatively low interest rate environment. It is important to realize that investor expectations of higher future interest rates, if any, **are already likely *already embodied in current securities prices***, which include debt securities and stock prices.<sup>141</sup>

As Mr. Baudino reported, utility stocks are doing just fine, despite the turbulent economic conditions prevailing in the years since 2008.<sup>142</sup> Even Mr. Hevert was forced to admit that the most common investors in utility stock are retirement systems and pension funds, which have an obligation to protect their funds' value.<sup>143</sup> Further, the Edison Electric Institute reports a quarterly credit ratings and rate review of the electric utility industry and, for the third quarter of 2018, its analysis showed that, of the 47 electric utilities included in the survey, the average Standard & Poor's credit rating was BBB+, with 55% of the utilities have credit ratings of BBB+/BBB.<sup>144</sup> Entergy Corporation was one of those utilities with a BBB+ credit rating.<sup>145</sup>

Similarly, ENO's current issuer credit rating is BBB+ from Standard & Poor's ("S&P").<sup>146</sup> As Mr. Hevert conceded, the S&P issuer credit rating of BBB+ is investment grade.<sup>147</sup> Meanwhile, as Mr. Baudino also explains, Moody's gives ENO a current long-term issuer rating of Ba1, with a first mortgage bond rating of Baa2.<sup>148</sup> Moody's credit rating for ENO, therefore, is below

---

<sup>141</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 9:24-28. (Emphasis and italics added).

<sup>142</sup> *Id.*, at 12:9-25, quoting the Value Line Investment Survey's December 14, 2018 report on the Electric Utility (Central) Industry, which concluded, in part, that, "Utility equities attract income-oriented investors for their above average dividend yields, and their defensive characteristics are appealing to many investors in times of market turbulence." The report continues, acknowledging that several large utility companies' stock prices were "up" 22%, 18% and 11%.

<sup>143</sup> TR, June 19, 2019, (Cross Examination of Robert Hevert), at 13:11 – 16:3, noting that 70-80% of utility stocks are owned by institutional investors, such as pension or benefit fund managers, which have obligations to their beneficiaries to prudently manage their funds.

<sup>144</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 13:1-5.

<sup>145</sup> *Id.*, at 13:5-6.

<sup>146</sup> *Id.*, at 14:1-3.

<sup>147</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 44:10-11; *see also* TR, 6/19/19, (Cross Examination of Robert Hevert), at 42:6-17.

<sup>148</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 14:4-6.

investment grade.<sup>149</sup> Even so, Mr. Hevert acknowledges that Moody’s credit metrics for ENO “*indicated a higher rating*”, but for its concentrated service territory that is vulnerable to storm activity.<sup>150</sup> Mr. Baudino reports that both S&P and Moody’s have a stable credit outlook for ENO.<sup>151</sup> Further, ENO is affiliated with Entergy Corporation; it is not a stand-alone utility. Therefore, its credit and risk profiles benefit from the association with its parent, and its ROE should fully reflect the association as well.<sup>152</sup>

Put simply, there is no evidence in the record that ENO’s equity investors are poised to flee, despite its split credit rating. Utility stocks are safe investments; that is why retirement and pension funds invest in them. Utility companies do not require – nor should they be awarded – exorbitant returns to attract capital and provide a reasonable rate of return to investors. Recall that, “in exchange for their favored status, furnishers of utility services submit to public regulation, which generally sanctions utility rates that provide *a limited but reasonable* return on the investment of the public utility.”<sup>153</sup>

In his Constant Growth DCF analysis, Mr. Baudino used the *same proxy group* of 22 utilities that Mr. Hevert used.<sup>154</sup> He then utilized the “standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, Yahoo! Finance, and Zacks.”<sup>155</sup> These three major sources of analysts’ forecasts for growth are the same sources Mr. Baudino typically uses in estimating growth for the DCF model.<sup>156</sup> Mr. Baudino

---

<sup>149</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 44:2-5.

<sup>150</sup> *Id.*, at 44:5-8. (Italics added).

<sup>151</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 14:6.

<sup>152</sup> *See id.*, at 31:3-12.

<sup>153</sup> *Gordon v. Council of City of New Orleans*, 2008-0929, pp. 12-13 (La. 4/3/09), 9 So.3d 63, 73 (*citing State ex rel. Guste v. Council of City of New Orleans*, 309 So.2d 290, 294 (La. 1975)). (Emphasis and italics added).

<sup>154</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 15:15-19.

<sup>155</sup> *Id.*, at 15:19-21.

<sup>156</sup> *Id.*, at 21:1-4.

carefully studied the various types of risks faced by utility companies in performing his ROE analyses.<sup>157</sup> The results of Mr. Baudino's "Method 1" Constant Growth DCF analysis (using average growth rates), range from 8.71% to 9.36%, and for "Method 2" (using the median growth rates), range from 8.52% to 9.36%.<sup>158</sup>

Mr. Baudino also employed the CAPM method using both a forward-looking and historical (for reference purposes) data.<sup>159</sup> As he testifies, the results of his CAPM analysis tend to support the reasonableness of the results of his DCF analysis.<sup>160</sup> The CAPM method assumes that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio.<sup>161</sup> The CAPM analysis focuses on two types of risks for a security – company-specific risk and market risk.<sup>162</sup> Under the CAPM methodology, the expected return for a security is equal to the risk-free rate plus a risk premium that is proportional to the security's market.<sup>163</sup> The analyst employing the CAPM method also must consider the utility stock's "beta coefficient", which is the measure of volatility of that stock relative to the overall market for securities. A stock with a beta coefficient of 1.0 means that the stock will rise 15% if the overall market also rises 15%.<sup>164</sup>

Mr. Baudino noted that there is some controversy surrounding the use of the CAPM methodology, due to evidence that beta is not the primary factor in determining the risk of a security.<sup>165</sup> Similarly, there is a significant amount of judgment required to estimate the required return for the "overall market."<sup>166</sup> Mr. Baudino conducted his ROE determination using average

---

<sup>157</sup> See, Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 17:1-23.

<sup>158</sup> *Id.*, at 23:5-8.

<sup>159</sup> *Id.*, at 15:21-22.

<sup>160</sup> *Id.*, at 15:22-24.

<sup>161</sup> *Id.*, at 23:10-12.

<sup>162</sup> *Id.*, at 23:14-21.

<sup>163</sup> *Id.*, at 24:1-3.

<sup>164</sup> *Id.*, at 24:3-11.

<sup>165</sup> *Id.*, at 25:7-13.

<sup>166</sup> *Id.*, at 25:15-21.

growth rates, as well as median growth rates in his CAPM analysis, because, “[u]sing median growth rates is likely a more accurate approach to estimating the central tendency of Value Line’s large data set compared to the average growth rates.”<sup>167</sup>

Mr. Baudino determined the risk-free rate for the CAPM analysis by using the average yields on the 30-year Treasury bond and the five-year Treasury note over the six-month period from July through December 2018.<sup>168</sup> Mr. Hevert, on the other hand, *only* relied upon the 30-year Treasury bond yield for his risk-free rate.<sup>169</sup> The results of Mr. Baudino’s CAPM analysis (using average growth rates), range from 9.34% to 9.47%.<sup>170</sup>

After conducting his analyses, Mr. Baudino recommends a range of ROEs for ENO of 8.70% to 9.35%, based primarily on his DCF analysis.<sup>171</sup> Considering ENO’s split credit rating, Mr. Baudino recommends the upper end of his ROE range as the recommended ROE for ENO of 9.35%.<sup>172</sup>

Mr. Baudino testifies that he *updated* his ROE analyses in his Surrebuttal Testimony and sets forth the results of this updated analyses in Surrebuttal Table 3.<sup>173</sup> His updated DCF methodology produced results ranging from **8.39%** to **9.30%**, and his updated CAPM analysis produced results ranging from **8.16%** to **8.35%**.<sup>174</sup> As previously noted, these ranges are lower than Mr. Baudino’s original range of ROE estimates in this proceeding. Nonetheless, as he states,

The updated results are *slightly lower than* the results I presented in my Direct Testimony. I believe this reflects the market’s expectation of stable short and long term interest rates, a much different expectation than the one that existed when I prepared my Direct Testimony. Given these results, **it would not be unreasonable**

---

<sup>167</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 27:1-4.

<sup>168</sup> *Id.*, at 28:14-20.

<sup>169</sup> Exh. ENO-26 (Hevert Revised Direct Testimony) (ENO), at 32:6-9.

<sup>170</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 29:7-10.

<sup>171</sup> *Id.*, at 30:2-7.

<sup>172</sup> *Id.*, at 30:9 – 31:2.

<sup>173</sup> Exh. CCPUG-4 (Baudino Surrebuttal Testimony) (CCPUG), at 12:8-13, and Surrebuttal Table 3.

<sup>174</sup> *Id.*

to *reduce my recommended 9.35% ROE for ENO. However*, given the Company's **split credit rating** from S&P and Moody's, with Moody's being below investment grade, I will leave my recommendation at 9.35% at this time.<sup>175</sup>

Setting ENO's ROE at the appropriate and reasonable level of 9.35% would save its customers approximately **\$6.3 million per year**.<sup>176</sup>

Based on the foregoing, the Council should *reject* ENO's proposed 10.75% ROE and should adopt CCPUG's recommended ROE of 9.35% for both electric and gas operations instead.

**b. Council Advisors' ROE Recommendation**

While the Council's Advisors have recommended a lower ROE (8.93%) for ENO's electric and gas operations than CCPUG's consultants, they used "judgmental" allocation factors to select class rate of returns which effectively departed from standard, well-accepted class cost allocation methodologies. Mr. Baron explained that he does not quarrel with the Advisors' use of a 12CP methodology for cost allocation purposes, but he demonstrates how the Advisors' use of judgmental allocation factors result in the commercial customers being assigned a drastically higher rate of return than the residential customers:

**Q. Do you have any concerns with the Advisors' methodology?**

A. Yes. While I do not have any specific concerns with the Advisors' cost allocation methodology itself (for example, the using a 12 CP production demand allocation method), the use of judgmental factors to select a proposed class rate of return effectively departs from standard, well-accepted class cost allocation methodology. While Mr. Prep's Exhibit VP-9 Amended indicates that the proposed revenue requirement for each rate class is based on cost of service, in actuality it is a departure from cost of service because of the use of different proposed class rates of return.

---

<sup>175</sup> Exh. CCPUG-4 (Baudino Surrebuttal Testimony) (CCPUG), at 13:4-10. (Emphasis and italics added).

<sup>176</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 39:15-21; Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 6:1, Table, showing, among other recommendations, "Reflect return on equity of 9.35% (Electric and Gas)" which is a \$6.248 million reduction in the electric and gas revenue requirements.

**Q. Can you give an example of this departure from cost of service?**

A. Yes. Exhibit VP-9 Amended shows that the **overall ENO ROR recommended by the Advisors**, including income taxes, **is 8.48%**. *However*, the Advisors are recommending that the **residential class ROR**, including taxes, **be set at only 1.60%**. Since the weighted sum of the RORs for all rate classes must equal the retail average of 8.48%, all other ENO rate classes must have substantially higher RORs. **The Large Electric High Load Factor rate class**, for example is **being assigned an ROR of 15.79%**, almost *twice* the retail average and almost 10 times larger than the residential class ROR. Other rate classes are paying RORs even higher than this.<sup>177</sup>

The use of such judgmental allocation factors in selecting class rates of return, therefore, results in the continued undue discrimination against large commercial customer classes in the ratemaking process. If the Council adopts the Advisors' recommended ROE, it should reject the use of such judgmental allocation factors and allocate on the basis proposed by CCPUG.

**3. ENO's Manipulation of the Council's Mandated Test Years Should be Rejected**

ENO violated Council Resolution Nos. R-15-194 and R-17-504, as well as applicable provisions of the City Code, when it modified Period I (which was to end December 31, 2017) and Period II (which was to end December 31, 2018) to include forecasted costs that will not be incurred until 2019.<sup>178</sup> The forecasted costs include additions to plant; increases in accumulated depreciation and accumulated deferred income taxes; increases in depreciation expense, insurance expense and property tax expenses related to increases in plant; and increases in certain operating and maintenance costs.<sup>179</sup> Violating the Council's resolutions is not a harmless error. Adding in the significant projected costs unnecessarily and inappropriately increased ENO's rate base, upon which it earns a return, and its revenue requirement.<sup>180</sup> ENO proposes to include \$64.4 million of

---

<sup>177</sup> Exh. CCPUG-6 (Baron Surrebuttal Testimony) (CCPUG), at 3:4-21. (Emphasis and italics added).

<sup>178</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 8:9-16.

<sup>179</sup> *Id.*, at 8:17 – 9:2. *See also*, TR, June 17, 2019, (Cross Examination of Laura Beauchamp), at 163:3-10.

<sup>180</sup> *See* Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 10:1-3, stating that the effect of including forecast costs after the end of Period I and Period II "is to substantially increase the revenue requirement for both periods."



electrical operations investments and \$25.7 million of gas operations investments that are expected to close *after* the prescribed Period I and Period II test years in its rates in this case.<sup>181</sup> The Council should spurn ENO’s attempt to include projected, future (2019) plant additions in its rate base as well as the related expenses.

The Council specifically directed ENO to utilize two test year periods, with Period I ending December 31, 2017 and Period II ending December 31, 2018.<sup>182</sup> This directive was consistent with the Code of Ordinances of the City of New Orleans (“City Code”) Section 158-41, *et seq.* Section 158-41 (Definitions) defines “Period I” and “Period II”:

*Period I* means the most recent 12 consecutive months, or the most recent calendar year, **for which actual data is available**, the last day of which is no more than nine months prior to the date of the filing of the application.

*Period II* means the 12 consecutive months **immediately following** the end of Period I.<sup>183</sup>

Meanwhile, other sections of the City Code build upon the definitions of Period I and Period II set forth in Section 158-41. For example, Section 158-132 (Revenue Requirements) of the City Code specifies certain summary information a utility must provide when filing an application regarding revenue requirements, operating income, rate base, the actual earned rate of return and proposed rate of return utilizing the test years defined as Period I and Period II in Section 158-41.<sup>184</sup> Similarly, Section 158-133 mandates that a utility filing a rate case application supply information regarding its plant in service, accumulated depreciation, construction work in progress, and multiple other categories of information for Period I and Period II as defined in Section 158-41.<sup>185</sup> As such, the regulatory framework for rate cases under the City Code and this

---

<sup>181</sup> TR, June 17, 2019, (Cross Examination of Laura Beauchamp), at 168:3 – 169:2.

<sup>182</sup> Resolution No. R-18-434, at 4.

<sup>183</sup> City Code, Section 158-41. (Emphasis and italics added).

<sup>184</sup> City Code Section 158-132.

<sup>185</sup> City Code Section 158-133.

Council's originating resolutions requires historical test years, the actual information from which is employed in structuring base rates, revenue requirements and rate of return. A departure from this historical test year requirement erodes the reliable foundation on which the entire rate case process is grounded.

The Council's directive was clear, as ENO's witnesses acknowledged.<sup>186</sup> ENO put up weak resistance when cross-examined concerning its deviation from the Council's mandated use of historical test years. The best its witnesses could muster was to say that Resolution Nos. R-15-194 and R-17-504 don't prohibit ENO from including future, projected costs in the test years.<sup>187</sup> Ms. Laura Beauchamp, who adopted Orlando Todd's Revised Direct Testimony, testified she could not point to any Council resolution or order that permitted ENO to include costs beyond December 31, 2018 in its Period I and Period II test years in this case.<sup>188</sup> ENO was to use historical test years in this rate case.

The use of historical test years is crucial, because it provides known data – *i.e.*, the costs and expenses actually incurred by the utility in providing service – in setting rates for the future. While the Council's Resolution No. R-17-504 does states that “ENO may annualize and/or normalize (e.g., weather normalize) certain customer, cost, revenue, and balance sheet values *in* Period I and Period II for regulatory ratemaking treatment.”<sup>189</sup> In other words, the Resolution

---

<sup>186</sup> TR, June 17, 2019, (Cross Examination of Laura Beauchamp), at 155:1 – 156:3, where Ms. Beauchamp agreed Resolution No. R-15-194, at 4, dictated that this rate case be based upon a Period I test year that ended December 31, 2017. *See id.*, at 156:14 – 158:1, at which Ms. Beauchamp conceded Resolution No. R-17-504, at 8-9, dictated the use of Period II for this case that ended December 31, 2018.

<sup>187</sup> *Id.*, at 158:22 – 159:7: Ms. Beauchamp testified she was “I guess reading this [resolution] -- I'm not sure that I would necessarily understand sitting here today whether or not it was absolute prescriptive at 12/31/18”. *See also*, TR, June 17, 2019, (Cross Examination of Matthew Klucher), at 185:23 – 186:12, where Mr. Klucher testifies that he is aware of no Council resolutions or orders that “permit or prohibit” ENO from including forecasted costs for 2019 in its test years in this proceeding.

<sup>188</sup> *Id.*, at 159:11-23.

<sup>189</sup> Resolution No. R-17-504, at 5, third Whereas paragraph. (Emphasis and italics added).

expressly allows the Company to make adjustments to annualize or normalize costs *in* the test year, but it does not authorize the Company to make adjustments to reflect cost levels that are expected in 2019 and that will not be incurred until *after* the end of the test year.<sup>190</sup> Contrary to ENO witness, Joshua Thomas's testimony, costs expected in 2019 are not "known and measurable"; such costs are not known and measurable until they are incurred.<sup>191</sup>

On the other hand, Resolution No. R-17-504 allows ENO to normalize for weather and to annualize certain costs incurred during the test years for changes that are actually known and measurable.<sup>192</sup> While cost projections and forward-looking test years are used in certain jurisdictions, they are used according to the rules and regulations governing utility rate cases in those jurisdictions. Here, ENO can point to no support for its use of projected costs in its test years.

More importantly, requiring the use of historical test years guards against turning the regulatory process into ENO's ATM machine. As Ms. Beauchamp admitted under cross-examination at the hearing, if ENO's FRP riders are approved but its use of projected costs in its test years is rejected and it makes future investments in plant, it will have the opportunity to recover such future investments and related expenses through such FRP mechanisms.<sup>193</sup> Mr. Thomas testified that ENO proposed to implement the FRPs in its Revised Application using historical test years and that ENO believes the use of historical test years in the FRPs is appropriate and reasonable.<sup>194</sup> This testimony, standing alone, proves the inclusion of projected costs in the test years (which, as explained, is fraught with peril) is also completely unnecessary. Further, if ENO

---

<sup>190</sup> See Exh. CCPUG-2 (Kollen Surrebuttal Testimony) (CCPUG), at 9:3-9, quoting Resolution No. R-17-504.

<sup>191</sup> See *id.*, at 9:11-15 and 10:1-8.

<sup>192</sup> *Id.*, at 10:10-15.

<sup>193</sup> TR, June 17, 2019, (Cross Examination of Laura Beauchamp), at 166:3 – 167:7.

<sup>194</sup> TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 79:11-18. Of course, Mr. Thomas was elusive on this point, as he was on others, stating that the historical test year would be reasonable and appropriate only if all of ENO's other riders were approved.

truly believed the use of projected test years in its FRP riders was reasonable and necessary it would have proposed such, but it did not.

Consider the testimony of Advisors' witness, Victor Prep, at the hearing. He acknowledged ENO proposed the use of historical evaluation periods (test years) in its FRP riders;<sup>195</sup> however, *the Advisors recommended* that ENO include a projected test year for the calendar year following the most recently completed year. Mr. Prep testified that he was involved in the last proceeding before the Council in which ENO's use of formula rate plan riders was approved – which utilized historic test years – and that he did not recommend the use of projected test years as he has in this proceeding.<sup>196</sup> Importantly, Mr. Prep conceded that if ENO includes a projected cost in its rates through the FRP but never incurs the cost and its earnings fall within the FRP's bandwidth for that calendar year, **the cost collected from ratepayers but never actually incurred is *never returned to ratepayers***. In particular, he testified at the hearing as follows:

Q. So let's talk about your proposal with a forward-looking test year. Let's say Entergy New Orleans includes a projected cost in the forward-looking test year but never incurs that cost. Okay? And let's assume further that in the review following that rate affected [sic: effective] period, the earnings fall within the bandwidth. Is there any return of that cost to the ratepayers?

A. If the earnings fell within the bandwidth with all of the costs considered and no adjustment would be required, then with your example the update would -- all things being considered and included in the composite, no adjustment would be required because other items might have countered the previous example that you mentioned.<sup>197</sup>

Mr. Prep conceded he has no analytical proof that the use of a projected test year in an FRP rider is necessary for ENO to recover its cost of service or earn its return.<sup>198</sup> He likewise testified

---

<sup>195</sup> TR, June 20, 2019, (Cross Examination of Victor Prep), at 205:12-16.

<sup>196</sup> *Id.*, at 205:17 – 206:1.

<sup>197</sup> *Id.*, at 208:11 – 210:2.

<sup>198</sup> *Id.*, at 206:2-11 and 206:22 – 207:1.

he has no proof that ENO's cost of debt or equity will increase without the use of a projected test year in the FRP.<sup>199</sup> He also agreed that an FRP mechanism that utilizes a historic test year reduces regulatory lag for the utility.<sup>200</sup>

This brief exchange illuminates the perils of allowing a utility to include projected costs in its rates. Even if one were to believe that the scenario discussed with Mr. Prep at the hearing would be a remote occurrence (of which there is no guarantee), the destruction of a utility's incentive to conduct its operations efficiently and economically – that will result from its being allowed to project its operating costs – is all but certain. Allowing a utility to include projected costs in a test year is bad news for ratepayers. As Mr. Kollen explains, there are several compelling reasons to reject the inclusion of projected costs in the test years.

First, Mr. Kollen testifies that, “Unlike a historic test year, a forecast test year is largely untethered to actual revenues and costs and necessarily is based on assumptions about the future and estimates of revenues and costs based on those assumptions.”<sup>201</sup> Second, Mr. Kollen conveys that “a forecast test year is inappropriate because the revenues and costs are not known and measurable; they are the result of assumptions and estimates, any and all of which cannot be verified and are subject to bias and manipulation.”<sup>202</sup> Actual costs can be verified for prudence much more readily than estimated costs because the regulator will have the advantage of *actual* experience and *actual* available alternatives that are absent when estimating costs. Third, Mr. Kollen testifies that,

[T]he Company's proposal results in a *fundamental mismatch* of revenues and costs, thus **ensuring that the Company will recover revenues that exceed its costs**. More specifically, the Company's forecast costs for 2019 include plant

---

<sup>199</sup> TR, June 20, 2019, (Cross Examination of Victor Prep), at 207:2-13.

<sup>200</sup> *Id.*, at 206:12-21.

<sup>201</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 11:21 – 12:3.

<sup>202</sup> *Id.*, at 12:4-6.

additions through December 31, 2019, depreciation expense and other plant related expenses based on the plant additions through December 31, 2019, and payroll and payroll-related expenses based on costs at December 31, 2019. However, the Company's rates will be reset in this proceeding on or about August 1, 2019, a date some five months before any of the forecast costs after that date will be incurred.<sup>203</sup>

In other words, ENO will be permitted to include in its rates, and earn a return upon, costs it has not yet incurred. This would violate the used and useful principle. Under the used and useful principle, ratepayers should only pay for facilities and investments that are used and useful in providing them with service. Such facilities are considered used and useful if they are (1) in service, and (2) reasonably necessary.<sup>204</sup>

Finally, Mr. Kollen provides the imperative ratemaking rationale for the use of a historic test year,

To the extent that certain fixed costs are recovered based on a historic test year, this ratemaking structure provides an equitable and balanced behavioral ratemaking incentive to constrain the growth in costs. The use of a historic test year promotes good management and a focus on efficiencies, thus restraining cost increases and limiting rate increases.<sup>205</sup>

Making ENO's inclusion of projected costs in the test years more unreasonable is the fact that it has requested approval of its Formula Rate Plan Riders. As discussed above, ENO proposes that the Council approve its E-FRP and G-FRP, each of which calls for an annual review of its earnings and provides a mechanism to adjust rates accordingly should expenses or other factors cause earnings to dip below the bandwidth. The use of such FRPs drastically reduces uncertainty

---

<sup>203</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 12:7-15. (Emphasis and italics added).

<sup>204</sup> *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n*, 1998-1235, p. 28 (La. 4/16/99), 730 So.2d 890, 911 (citing, *Central Louisiana Electric Co. v. Louisiana Pub. Serv. Comm'n*, 508 So.2d 1361, 1367 (La. 1987) (citing *City of Evansville v. Southern Ind. Gas. & Electric Co.*, 167 Ind.App. 472, 339 N.E.2d 562 (Ind.App. 2d Dist. 1975))).

<sup>205</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 12:17-22.

and regulatory lag, as the utility will have to wait - *at most* - 20 months between cost-incurrence and recovery through rates, again, assuming earnings travel outside the bandwidth.<sup>206</sup>

Were the Council to reject ENO's inclusion of projected costs in its test years, the effects would be as follows: (a) a reduction of **\$9.604 million** in the electric base revenue requirement and a reduction of **\$2.211 million** in the gas base revenue requirement due to removing the 2019 forecast costs from the electric and gas rate base and the related depreciation expense,<sup>207</sup> and (b) a reduction of **\$0.780 million** in the electric base revenue requirement and a reduction of **\$0.265 million** in the gas base revenue requirement as a result of removing the Company's proposed adjustments to increase payroll expense based on 2019 forecast costs.<sup>208</sup> The Council should reject ENO's inclusion of projected costs in its test years and order the aforementioned reductions in revenue requirements for electric and gas rates.

#### **4. The EAI WBL and River Bend 30% PPA Capacity Costs should be Allocated on an Equal Percentage Basis in Base Rates**

As previously discussed, ENO prepared a fully allocated Cost of Service Study in connection with this proceeding. A Cost of Service Study is a study through which a utility breaks down all of the costs it incurs to serve its customers and assigns those costs among its various classes of customers.<sup>209</sup> Each customer class, therefore, will be responsible for a defined amount of costs that the utility incurs to provide service to that class. The Council directed ENO to conduct a "fully allocated" Cost of Service Study in connection with its Revised Application in this case.

---

<sup>206</sup> TR, June 17, 2019, (Cross Examination of Laura Beauchamp), at 167:5 – 168:2: Testifying that the regulatory lag under ENO's proposed FRP riders for an investment made in October would be roughly the following September, or less than one year. Since the FRP evaluation period (test year) is the most recently-completed calendar year, an investment made in January would be eligible for recovery the following September, for a maximum regulatory lag of 20 months.

<sup>207</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 14:17-22.

<sup>208</sup> *Id.*, at 28:16-18.

<sup>209</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 10:21 – 11:5.



ENO followed the Council's directive and performed a fully allocated Cost of Service Study that no party seriously challenges.<sup>210</sup> ENO's performance of the fully allocated Cost of Service Study is good news. Almost on cue, however, the bad news quickly enters the scene as ENO immediately discards its Cost of Service Study in designing rates to be charged to its customers without any valid reason and in a manner which directly and significantly harms one group of customers in order to benefit another group of customers. ENO's Revised Application concedes, "Though ENO's filing presents the fully allocated class cost of service for informational purposes, **its proposed class cost allocation for purposes of establishing rates is *not* strictly based on cost of service principles.**"<sup>211</sup>

As previously mentioned, ENO is realigning capacity costs associated with several PPAs, including, but not limited to the EAI WBL and River Bend 30% PPAs, from riders, including the FAC Rider and PPCACR Rider, to base rates. ENO also proposes to realign PPA capacity costs associated with the Ninemile 6 PPA and other similar costs into its base rates *but* recommends that these costs be recovered through an *equal percentage base rate increase* to all customer classes. This is a reasonable and well-accepted method to allocate and recover such fixed, non-fuel capacity costs. Unfortunately, however, ENO flips the script and abandons this well-accepted methodology with respect to the EAI WBL and River Bend 30% PPA capacity costs by proposing to continue to recover such capacity costs on an *energy basis*, as opposed to an equal percentage basis that it recommends for all other base rate increase amounts.

---

<sup>210</sup> See Exh. ENO-41 (Gillam / Klucher Revised Direct Testimony) (ENO), at 13:2 – 14:3, testifying that, "The objective of preparing a cost of service study for either electric or gas operations is **to determine the portion of a utility's costs**, as measured by its revenue requirement, **for which each of the various rate classes is responsible.**" (Emphasis added).

<sup>211</sup> Revised Application, at ¶ 32. (Emphasis and italics added).

It is important to point out at this juncture that ENO receives 100% of the revenues associated with the PPAs (including the capacity costs) under *either* allocation method (equal percentage increase basis or energy basis);<sup>212</sup> therefore, the issue is not one of making the utility whole. The issue, rather, is how such costs should be allocated among the various customer classes.

ENO witness, Joshua Thomas, agreed that rates should reflect the underlying costs of the utility in providing service.<sup>213</sup> Mr. Thomas further agreed that rates should be **just and reasonable**;<sup>214</sup> rates should *not* be **unduly discriminatory between customers**;<sup>215</sup> and, in designing rates, customers should pay their ‘**fair share**’ of **common costs**.<sup>216</sup> Mr. Thomas further confirmed that, in preparing fully allocated Cost of Service Study in this case, ENO classified fixed costs of various Purchase Power Agreements (PPAs) – including the Grand Gulf, Ninemile 6, EAI WBL and the River Bend 30% PPAs – as **demand-related** (*i.e., not* energy-related).<sup>217</sup> ENO’s Cost of Service Study provides important information to the Council regarding the relationship between rates paid by each rate class and cost of providing service to that class.<sup>218</sup> Mr. Thomas acknowledged that, when ENO filed its original application in this case, it allocated the capacity costs associated with the EAI WBL and River Bend 30% PPAs in its rate design so that they would be recovered in base rates *on an equal percentage basis* from all rate classes.<sup>219</sup>

Yet, despite all of this seemingly reasonable testimony, ENO proposes to single out the fixed capacity costs associated with the EAI WBL and River Bend 30% PPAs to allocate on an energy (kWh) basis in its recommended base revenue increases to each rate class. The nonfuel

---

<sup>212</sup> TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 60:14-23.

<sup>213</sup> *Id.*, at 43:23 – 44:4. *See also* Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 12:9-10.

<sup>214</sup> TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 44:9-11.

<sup>215</sup> *Id.*, at 44:12-15.

<sup>216</sup> *Id.*, at 44:16 – 45:7.

<sup>217</sup> *Id.*, at 46:7-15. *See also* Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 13:18-23.

<sup>218</sup> *See* Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 15:13-16.

<sup>219</sup> TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 46:16 – 47:10.

costs related to the EAI WBL and the River Bend 30% PPAs amount to *\$62.71 million per year*, so the effect on customers of the recovery mechanism for these costs is significant.<sup>220</sup> The pertinent capacity costs were allocated in ENO's Cost of Service Study (and in its original application) on a demand basis, following cost-causation principles. The switch to allocating these costs on an energy basis ignores cost-causation principles. Ms. Talkington testified that rate design should, to the extent possible, take into consideration cost causation.<sup>221</sup>

ENO's witnesses freely admit that the allocation of the EAI WBL and River Bend 30% PPA capacity costs does *not* follow cost-causation principles or even its own Cost of Service Study.<sup>222</sup> ENO also does not shy away from the spotlight regarding its intended purpose in piling a discriminatory amount of the EAI WBL and River Bend 30% PPA capacity costs onto commercial customers' bills – it is being proposed for the express purpose of reducing the residential customers' rates. Ms. Talkington testifies,

To *further address* the impact of the proposed rate change on **ENO residential customers** in general, ENO proposes to utilize an *energy-based allocation* for its capacity costs under the Power Purchase Agreements (“PPAs”) that cover the unregulated portion of River Bend Station (River Bend 30%) and the wholesale baseload resources of Entergy Arkansas, Inc. (EAI WBL). **This allocation method will reduce the capacity expenses allocated to the residential class as a whole.** ENO witness Joshua B. Thomas further addresses these two proposals from a policy perspective.<sup>223</sup>

Ms. Talkington admitted under cross-examination that, by selecting the energy-based allocation factor for the capacity costs associated with the EAI WBL and River Bend 30% PPAs,

---

<sup>220</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 18:21-27, at which Mr. Baron explains that, of the total \$135 million base rate increase, ENO proposes to allocate \$72.5 million to each customer class on a uniform percentage basis of 24.75%, but to allocate the remaining \$62.71 million (“which represents the fixed production demand costs associated with the WBL and River Bend PPAs”) on the basis of kWh energy sales.

<sup>221</sup> Exh. ENO-45 (Talkington Revised Direct Testimony) (ENO), at 22:3-5.

<sup>222</sup> *See id.*, at 24:17 – 25:22 and 28:1-11; Exh. ENO-41 (Gillam / Klucher Revised Direct Testimony) (ENO), at 22:20 – 23:7; Exh. ENO-1 (Thomas Revised Direct Testimony) (ENO), at 22:1-23.

<sup>223</sup> Exh. ENO-45 (Talkington Revised Direct Testimony) (ENO), at 3:8-14. (Emphasis and italics added).

ENO seeks to *shift* more of such costs to commercial customers than their appropriate share as established in Cost of Service Study.<sup>224</sup> She follows up by clarifying that, “The re-allocation occurs as a matter of rate design, and does not alter the outcome of the cost of service study. The table below shows how the use of the energy allocator for the River Bend 30% and EAI WBL costs impacts each class’ allocation.”<sup>225</sup>

Rate Class	PPAs Allocated on Revenue	PPAs Allocated on Energy	Difference
Residential Service	\$28,791,686	\$23,876,918	(\$4,914,768)
Small Electric Service	\$10,991,769	\$9,156,356	(\$1,835,413)
Municipal Buildings	\$449,550	\$328,186	(\$121,364)
Large Electric	\$4,444,169	\$5,212,395	\$768,226
Large Electric High Load Factor	\$15,202,541	\$19,970,085	\$4,767,544
Master Metered Non-Residential	\$8,642	\$7,396	(\$1,246)
High Voltage	\$1,084,822	\$1,730,653	\$645,831
Large Interruptible	\$541,645	\$1,802,848	\$1,261,203
Lighting Service	\$1,193,323	\$623,310	(\$570,013)
Total	\$62,708,147	\$62,708,147	\$0

As Ms. Talkington demonstrates, the Residential class will be gifted an additional nearly \$5 million annual rate reduction under ENO’s proposed energy-based allocation of the capacity costs associated with EAI WBL and River Bend 30% PPAs, at the expense – almost exclusively – of the Large Electric and Large Electric High Load Factor classes.<sup>226</sup> The energy-based allocation of the EAI WBL and River Bend 30% PPA capacity costs is highly prejudicial to large customers, such as the Large Electric and Large Electric High Load Factor classes, that use large amounts of energy per kW of demand (*i.e.*, high load factor customers). Recall that these high load factor

<sup>224</sup> TR, June 18, 2019, (Cross Examination of Myra Talkington), at 55:1-25.

<sup>225</sup> Exh. ENO-45 (Talkington Revised Direct Testimony) (ENO), at 28:18-21.

<sup>226</sup> *Id.*, at 29:1, Table.

customers provide a benefit to *all* of ENO’s customers by allowing the utility to spread costs over more units of production, thus lowering the average cost of service to all customers.

The equal percentage base rate increase basis is a traditional allocation factor for assigning fixed, non-fuel costs among rate classes.<sup>227</sup> ENO’s claim that it is engaging in the discriminatory energy-based allocation to “address the impact of the proposed rate change on ENO residential customers in general” is a tall tale. This is a rate decrease case, not a rate increase case. Under ENO’s Revised Application, ***every rate class (except “Lighting”) will see a rate reduction.***<sup>228</sup> More importantly, ENO’s Revised Application – under which every rate class except Lighting will see a rate reduction – is based upon ENO’s egregiously high, requested ROE and inflated revenue requirement that includes forecasted test year investment and expenses. ENO chose to buffer against the unreasonably high ROE and bloated revenue requirement and provide an even greater rate decrease to the residential customers by shifting unwarranted costs to the commercial classes. Under CCPUG’s recommendations, on the other hand, and as shown in Mr. Baron’s Table 7 below, the ROE is a reasonable 9.35%, the mandated historical test years are utilized, *all* rate classes will experience an overall reduction, *and* the subsidies imposed on commercial classes, including the Large Electric and Large Electric High Load Factor classes, will be reduced through the allocation of the EAI WBL and River Bend 30% PPA capacity costs in base rates on an equal percentage basis.<sup>229</sup>

---

<sup>227</sup> Exh. ENO-45 (Talkington Revised Direct Testimony) (ENO), 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>228</sup> *See id.*, at Exh. MLT-3. Note that this is true for the “Including BRAR Scenario”. Under the “Excluding BRAR Scenario (p. 2 of Exh. MLT-3), Lighting and Residential classes experience increases.

<sup>229</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 26:12 – 28:13, and Table 7, showing overall rate reductions for each customer class.



**Table 7**  
**ILLUSTRATION OF CCPUG'S PROPOSED NET REVENUE CHANGE (BASE RATE + RIDERS)**  
**ASSUMING A \$20 MILLION COUNCIL AUTHORIZED REVENUE ADJUSTMENT TO ENO'S REQUEST**

RATE CLASS	CCPUG Proposed Net Revenue Change	BRAR Charges	Adjusted Net Revenue Change	Adjusted Total Revenue	Remaining Revenue Adjustment	Net Revenue Change	Percent Change
RESIDENTIAL	\$ 4,822,238	0	\$ 4,822,238	\$ 254,920,477	\$ (7,415,838)	\$ (2,593,600)	-1.04%
SMALL ELECTRIC	\$ 177,858	\$ -	\$ 177,858	\$ 96,777,359	\$ (2,815,330)	\$ (2,637,472)	-2.73%
MUNI BUILDINGS	\$ 75,474	\$ -	\$ 75,474	\$ 3,849,194	\$ (111,976)	\$ (36,502)	-0.97%
LARGE ELECTRIC	\$ (3,906,873)	\$ 694,624	\$ (4,601,497)	\$ 42,135,332	\$ (1,225,750)	\$ (5,827,247)	-12.47%
LARGE ELECTRIC HLF	\$ (15,949,376)	\$ 2,376,159	\$ (18,325,535)	\$ 148,263,325	\$ (4,313,097)	\$ (22,638,632)	-13.59%
MASTER METERED	\$ (3,422)	\$ -	\$ (3,422)	\$ 76,059	\$ (2,213)	\$ (5,635)	-7.09%
HIGH VOLTAGE	\$ (2,078,605)	\$ 169,558	\$ (2,248,163)	\$ 11,132,934	\$ (323,866)	\$ (2,572,029)	-19.22%
LARGE INTERRUPTIBLE	\$ (3,630,919)	\$ 84,659	\$ (3,715,578)	\$ 7,345,717	\$ (213,693)	\$ (3,929,271)	-35.52%
LIGHTING SERVICE	\$ 170,688	\$ -	\$ 170,688	\$ 8,705,078	\$ (253,238)	\$ (82,550)	-0.97%
13 TOTAL RETAIL	\$ (20,322,938)	\$ 3,325,000	\$ (23,647,938)	\$ 573,205,476	\$ (16,675,000)	\$ (40,322,938)	-6.76%

It should be noted that Mr. Baron's Table 7, above, assumes *only* an additional \$20 million reduction to ENO's electric base rate revenues, whereas CCPUG has recommended a total reduction in the electric base rate revenues of **\$26.230 million**.<sup>230</sup> So, if all of CCPUG's recommendations are adopted, the overall decrease for all customers would be greater than as shown in the table. That said, what the Council is faced with here in this proceeding is how much of a *rate reduction* should each customer class receive. The Council does *not* have to debate in this case how much of a *rate increase* each customer class will receive.

Commercial customers have paid more than their appropriate share of fixed, non-fuel costs associated with the Union Power Station Power Block 1, Ninemile 6 PPA, EAI WBL PPA, and River Bend 30% PPA **for years** because such non-fuel costs have been allocated on an energy basis. As discussed, the non-fuel costs associated with the Ninemile 6 PPA are currently being

<sup>230</sup> See Exh. CCPUG-2 (Kollen Surrebuttal Testimony) (CCPUG), at 6:1, Table entitled, "Entergy New Orleans, LLC, Summary of CCPUG Revenue Requirement Recommendations – Surrebuttal and Cross-Answering Update, Docket No. UD-18-07, Period II test year Ended December 31, 2018, \$ Millions" at "Total CCPUG Recommendations".

recovered from customers via the PPCACR Rider.<sup>231</sup> And those Ninemile 6 PPA capacity costs are currently being recovered through PPCACR Rider **on an energy basis**.<sup>232</sup> The Council approved ENO's recovery of Ninemile 6 PPAs' capacity costs through PPCACR on energy basis in Resolution No. R-12-29.<sup>233</sup>

ENO proposes in this proceeding to realign the non-fuel costs associated with Union Power Station Power Block 1 and the Ninemile 6 PPA capacity costs into base rates and to allocate them on an **equal percentage increase** to base rates of every customer class.<sup>234</sup> The non-fuel costs associated with the Ninemile 6 PPAs that ENO seeks to realign are **not materially different** than – in fact they are **identical in nature** to – the non-fuel capacity costs associated with the EAI WBL and River Bend 30% PPAs.<sup>235</sup> In addition, ENO proposes to recover the capacity costs associated with the Algiers Transaction PPA through base rates on an equal percentage rate increase basis; *not* an energy basis.

It is blatantly inconsistent and arbitrary to allocate fixed, non-fuel costs such as the revenue requirement for Union Power Station Power Block 1 and the capacity costs associated with the Ninemile 6 and Algiers Transaction PPAs on an equal percentage basis, yet allocate the same exact type of fixed, non-fuel costs associated with the EAI WBL and River Bend 30% PPAs on an energy basis. The capacity costs associated with the EAI WBL and River Bend 30% PPAs should be

---

<sup>231</sup> Exh. ENO-33 (Revised Direct Testimony of Orlando Todd, adopted by Laura Beauchamp (“Todd / Beauchamp Direct Testimony”) (ENO)), at 19:8-22.

<sup>232</sup> TR, June 18, 2019, (Cross Examination of Myra Talkington), at 62:7-16.

<sup>233</sup> See Council Resolution R-12-29: AIP stating Ninemile 6 PPAs' capacity costs would (initially) be recovered via Fuel Adjustment Clause – *i.e.*, on an energy basis.

<sup>234</sup> See, e.g., Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 18:21 – 19:1 and Table 2. As Mr. Baron explains, everything **except for** the EAI WBL and River Bend 30% PPA capacity costs have been allocated to the customer classes on an equal percentage basis – here, 24.74%.

<sup>235</sup> See TR, June 18, 2019 (Cross Examination of Myra Talkington), at 64:22 – 65:7; TR, June 20, 2019 (Cross Examination of Joshua Thomas), at 60:25 – 61:13, where each witness agreed there is no material difference in the Ninemile 6 PPA capacity costs and the EAI WBL and River Bend 30% PPA capacity costs.



allocated to customer classes on an equal percentage basis.<sup>236</sup> If the Council approves of ENO's inherently flawed and arbitrary allocation of the capacity costs associated with the EAI WBL and River Bend 30% PPAs on an energy basis, its decision will be subject to reversal. Regulators' decisions are entitled to deference on review, unless they are arbitrary, capricious and/or not reasonably supported by evidence in the record.<sup>237</sup>

To make matters worse, and as previously mentioned, ENO in its *original* Application proposed to allocate capacity costs associated with the EAI WBL and River Bend 30% PPAs to all customer classes **on an equal percentage basis**.<sup>238</sup> ENO altered that proposal in its Revised Application and changed the allocation of such capacity costs to an energy-based allocation. Mr. Thomas testified,

Along those lines, ENO has *revisited* its original application as it relates to the initial proposal to realign capacity expenses associated with two PPAs. **ENO's revised proposal is to allocate those expenses to the various rate classes based on test year (2018) energy sales**, which mimics the current recovery method for these resources (through the Fuel Adjustment Clause ('FAC') as originally approved by the Council). This change in cost allocation also serves to mitigate rate shock to the Algiers residential customers under the Company's prior proposal.<sup>239</sup>

He went on to explain,

As part of its development of its revised Application, ENO undertook **a more in-depth examination of cost allocation issues** in light of the widely disparate bill effects of its previous electric rate proposal using the Council's historical cost allocation. Although ENO sought to combine the Legacy ENO and Algiers rate structure and realign costs to base rates as expected by the Council, **ENO did not give sufficient weight** to the Council's cost allocations outside of base rates.<sup>240</sup>

---

<sup>236</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 24-27.

<sup>237</sup> *Gulf States Utilities Co. v. Louisiana Public Service Com'n*, 578 So.2d 71, 84 (La. 1991), *cert. denied*, 502 U.S. 1004, 112 S.Ct. 637, 116 L.Ed.2d 655 (1991) (relying upon *CTS Enterprises, Inc. v. Louisiana Public Service Comm'n*, 540 So.2d 275 (La. 1989), *Louisiana Power & Light v. Louisiana Public Service Comm'n*, 523 So.2d 850 (La. 1988), and *Central Louisiana Elec. Co., Inc. v. Louisiana Public Service Com'n*, 437 So.2d 278, 279 (La. 1983)).

<sup>238</sup> TR, June 20, 2019 (Cross Examination of Joshua Thomas), at 46:16 – 47:10.

<sup>239</sup> Exh. ENO-1 (Thomas Revised Direct Testimony) (ENO), at 4:7-14. (Emphasis and italics added).

<sup>240</sup> *Id.*, at 21:14-19. (Emphasis and italics added).

Mr. Thomas then made plain ENO's change in position, testifying,

To address these bill effects, **ENO now proposes to allocate** the capacity expenses associated with the PPAs sourced from the unregulated portion of River Bend Station ("River Bend 30%") and the wholesale baseload resources of EAI ("EAI WBL") **using test year energy sales (kWh)**, which more closely replicates the cost recovery determined by the Council when originally approved. **This allocation decreases** the capacity expenses allocated **to the residential rate class** and **increases** the allocation to other rate classes that use larger amounts of energy relative to their demand.<sup>241</sup>

When Mr. Thomas says that ENO failed to "give sufficient weight to the Council's cost allocations outside of base rates", he is referring to the fact that Council originally approved the recovery of the EAI WBL and River Bend 30% PPA capacity costs on an energy basis.<sup>242</sup> So, ENO claims that it reversed course on the proper methodology to use in rate design to allocate the EAI WBL and River Bend 30% PPA capacity costs because it didn't give "sufficient weight" to the initial allocation of these costs set forth in a settlement agreement 15 years ago through which the Council approved the PPAs.<sup>243</sup> Obviously, ENO was well aware of Council's agreement to allow the energy-based recovery of the EAI WBL and River Bend 30% PPA capacity costs through Resolution No. R-03-272 when it filed its original Application in this case in which it proposed an equal percentage increase allocation. The Council's original, 15-year-old allocation methodology bears little relevance in this base rate case in which rates are being re-set, costs currently recovered through riders are being folded into base rates, and other changes are being implemented going forward. ENO's story as to why it singled-out the EAI WBL and River Bend 30% PPA capacity

---

<sup>241</sup> Exh. ENO-1 (Thomas Revised Direct Testimony) (ENO), at 22:1-7. (Emphasis and italics added).

<sup>242</sup> See *id.*, at 22:16-19, stating that the City Council, in Council Resolution R-03-272, dated May 15, 2003, approved an agreement in principle that provided such capacity expenses should be allocated based on energy.

<sup>243</sup> See *id.*, at 22:13-19, pointing to Resolution No. R-03-272, approving the EAI WBL and River Bend 30% PPAs, as a reason for the energy-based allocation ENO now proposes.

costs and decided to lump a disproportionate share of those costs on its commercial customers simply doesn't hold water.

ENO's only other stated purpose for harshly discriminating against the large commercial and industrial customer classes is that such customers purportedly "benefitted" from the EAI WBL and River Bend 30% PPAs due to their low fuel / energy costs (as opposed to capacity costs).<sup>244</sup> This excuse flops as badly as the initial allocation excuse. Mr. Thomas conceded under cross-examination that *all* customer classes – not just the large customer classes – benefit from the low cost EAI WBL and River Bend 30% PPAs.<sup>245</sup> Indeed, as Mr. Thomas admitted, that is why ENO entered those PPAs in the first place.<sup>246</sup> In any event, as Mr. Baron recognizes, the economics of these two PPAs has changed due to significant declines in natural gas prices.<sup>247</sup> The benefits provided by these PPAs have been reduced due to the decline in gas prices and they are not likely to rebound in the foreseeable future.

Moreover, as a class, the Residential class benefitted from the EAI WBL and River Bend 30% PPAs as much as, or more than, the Large Electric and Large Electric High Load Factor classes, because it uses just as much energy, as a class, as these commercial classes. ENO's workpapers show the following energy (kWh) consumption patterns for test year 2017 (Period I):

---

<sup>244</sup> See Exh. ENO-1 (Thomas Revised Direct Testimony) (ENO), at 22:22-23, stating, "...the energy allocator recognizes the significant benefits these low cost resources provide to large energy users."

<sup>245</sup> TR, June 20, 2019 (Cross Examination of Joshua Thomas), at 56:23 – 57:3.

<sup>246</sup> *Id.*, at 57:4-8.

<sup>247</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 23:7-21, and 24:1 Table 5 showing that the EAI WBL PPA is 90% more expensive than the MISO LMPs and the River Bend 30% PPA is 46% more expensive than MISO LMPs.

- Residential Total Adjusted kWh (2017) = 2,311,506,382 kWh
- Large Electric Total Adjusted kWh (2017) = 460,616,226 kWh
- Large Electric High Load Factor Total Adjusted kWh (2017) = 1,771,679,925 kWh<sup>248</sup>

(Total LE and LEHLF Adjusted kWh (2017) = 2,232,296,151 kWh)

A similar pattern occurred in test year 2018 (Period II):

- Residential Total Adjusted kWh (2018) = 2,224,463,493 kWh
- Large Electric Total Adjusted kWh (2018) = 485,605,454 kWh
- Large Electric High Load Factor Total Adjusted kWh (2018) = 1,860,489,764 kWh<sup>249</sup>

(Total LE and LEHLF Adjusted kWh (2018) = 2,346,095,218 kWh)

So, ENO's own data show that the residential customers benefitted equally as much as, if not more than, the large customers from these low cost PPAs due to their relatively large energy consumption level as a class. There is no legitimate reason to single out the large commercial customer classes for punishment by allocating these capacity costs on an energy basis.

Still further, ENO's ham-handed approach to cost allocation in its rate design in this matter flies in the face of the directive this Council provided to the utility in the resolution directing the filing of this rate case. In Resolution No. R-17-504, the Council stated, in part, "WHEREAS, ENO currently recovers certain electric fixed costs through Rider PPCACR for customers on the east bank of the Mississippi River on a volumetric basis (*i.e.*, fixed costs related to Ninemile 6 and

---

<sup>248</sup> See Revised Application, Minimum Filing Requirements Workpapers, Section F: WP Statement\_F\_AF\_E.xlsx (Period I (2017), Allocation Factors), at 6).

<sup>249</sup> See Revised Application, Minimum Filing Requirements Workpapers, Section F: WP Statement\_FF\_AF\_E.xlsx (Period II (2018), Allocation Factors), at 6).

Union Power Block 1);...”<sup>250</sup> The Council went on to advise, “WHEREAS, *sound regulatory principles* generally provide that **the fixed costs currently recovered on a volumetric basis through Rider PPCACR be allocated in a cost of service study according to demand-based allocation factors**; ...”<sup>251</sup> The foregoing statement regarding “sound regulatory principles” is included under the heading “Cost Recovery Mechanisms” in R-17-504. The section on Cost Recovery Mechanisms *follows*, and is separate from, the section on “Cost of Service Studies” in the resolution.<sup>252</sup> The Council, therefore, afforded ENO crystal clear guidance on the proper allocation methodology to be employed for rate design purposes – *i.e.*, demand-based allocation – concerning capacity costs arising from PPAs. ENO flaunted the Council’s guidance.<sup>253</sup> Further, ENO thwarted the Council’s well-known practice of adjusting base rates by applying an equal percentage change to all rate classes.<sup>254</sup>

Finally, ENO admitted it looked at *no other means* of ameliorating rate shock other than to dump excessively high levels of capacity costs on the commercial classes.<sup>255</sup>

It cannot be over-emphasized that the Council is facing a once-in-a-generation opportunity in that this case presents across-the-board rate decreases. Rate shock (but for the Algiers residential customers, who are protected through the ARRT) should not be an issue here. The only issues are determining the extent to which rates will *decrease* for each class. The Council should reject ENO’s ploys as smoke and mirrors designed to hide its blatant and baseless discrimination against

---

<sup>250</sup> Resolution No. R-17-504, at 5.

<sup>251</sup> *Id.*, at 6. (Emphasis and italics added).

<sup>252</sup> *Compare*, Resolution No. R-17-504, at 3-5 and *id.*, at 5-6.

<sup>253</sup> Demand-based allocation, while not exactly the same as an equal percentage increase allocation, produces highly similar results to an equal percentage increase basis.

<sup>254</sup> *See* Exh. ENO-45 (Talkington Revised Direct Testimony) (ENO), at 23:11-12.

<sup>255</sup> TR, June 20, 2019 (Cross Examination of Joshua Thomas), at 49:24 – 50:6.

the large commercial and industrial customers resulting from its energy-based allocation of the EAI WBL and River Bend 30% PPA capacity costs.

The Council should reject ENO's request to allocate the nonfuel costs associated with the EAI WBL and the River Bend 30% PPAs on an energy basis, and, instead, order that such costs be allocated via an equal percentage increase to each class of customers' base rates.<sup>256</sup> Again, when combined with CCPUG's other recommendations correcting ENO's electric revenue requirements and its mitigation adjustment, *each rate class* will see an overall rate reduction.<sup>257</sup>

**5. Estimated Service Lives of UPS and NOPS are too Short, Allowing ENO to Inappropriately Accelerate the Recovery of Depreciation and Unnecessarily Inflate its Revenue Requirement**

ENO proposes service lives for Union Power Station, Power Block 1 ("UPS") and New Orleans Power Station ("NOPS") that are unsupported and unreasonably short. In doing to, ENO seeks to accelerate the recovery of depreciation on these plants and to unnecessarily inflate its revenue requirement, respectively. The Council should reject ENO's unrealistically short service lives and the related depreciation expense and should 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).

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

---

<sup>256</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 24:3 – 25:2.

<sup>257</sup> *Id.*, at 26:12 – 28:13, and Table 7, showing overall rate reductions for each customer class. Again, it should be pointed out that Mr. Baron's Table 7 assumes *only* an additional \$20 million reduction to ENO's electric base rates, whereas CCPUG has recommended a total reduction in the electric base rates of **\$26.230 million**. Therefore, if all of CCPUG's recommendations are adopted, the rate reductions would be larger than those shown on Mr. Baron's Table 7.



before their retirements.<sup>258</sup> ENO's witnesses, Harold J. Clayton and Robert A. Breedlove fell short in rebutting Mr. Kollen's service life recommendation.

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>259</sup> The analyst must use informed judgment when estimating these values.<sup>260</sup> Consequently, as Mr. Clayton admitted, reasonable minds can and do differ on the appropriate service life and salvage value estimates.<sup>261</sup> The retirement date of a plant is an important factor in determining its service life.<sup>262</sup> And the decision whether to retire a plant is driven by multiple factors, such as repair costs, location of the plant, and environmental issues.<sup>263</sup> ENO provided the retirement date for UPS to Mr. Clayton, but did not provide him with any studies, analyses, or empirical data backing up that decision.<sup>264</sup> That means an important (perhaps the *most* important) factor in the determination of the appropriate service life of UPS was force-fed to Mr. Clayton with no supporting analyses.

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 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>265</sup> The unsubstantiated differentiation between "pre-2000" combined cycle units and "post-2000" combined cycle units (like UPS) was found not to exist anywhere except in the suppositions of ENO's witnesses. Mr. Clayton testified that the post-2000 UPS combined cycle plant was constructed by an entity other than ENO, was run by an entity other than

---

<sup>258</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 29:7 – 30:10.

<sup>259</sup> TR, June 18, 2019 (Cross Examination of Donald Clayton), at 138:23 – 139:5.

<sup>260</sup> *Id.*, at 139:11-14.

<sup>261</sup> *Id.*, at 139:15-18.

<sup>262</sup> *Id.*, at 140:3-11.

<sup>263</sup> *Id.*, at 140:12 – 141:7.

<sup>264</sup> *Id.*, at 141:20 – 142:7.

<sup>265</sup> *See id.*, at 148:5 – 149:5

ENO, and, since it is more efficient than pre-2000 combined cycle plants, that “would typically tend to shorten the service life.”<sup>266</sup> But Mr. Clayton offers no proof whatsoever that UPS’ service life will, most likely, be shorter than a pre-2000 combined cycle plant; all he supplies is speculation. Mr. Clayton flip-flopped when questioned under cross-examination whether he had even physically inspected the UPS facility in connection with his depreciation study in this proceeding; stating he did not, then stating he did.<sup>267</sup> Eventually, he admitted he had not.<sup>268</sup>

Mr. Breedlove’s attempt at disputing Mr. Kollen’s service life estimate fared no better than Mr. Clayton’s. Mr. Breedlove testified it would be “problematic” to compare UPS to pre-2000 combined cycle plants, but admitted that this view is not fact; it is a matter of judgment.<sup>269</sup> Combined cycle generating plants (pre- and post-2000) are comprised of many components, some of which require repair or replacement over time. A major component replacement can extend the service life of a generating unit.<sup>270</sup> Mr. Breedlove admitted that the combustion turbine rotors are a “major component” of UPS and have an estimated service life of roughly 19 years.<sup>271</sup> The replacement cost for combustion rotors can be \$30 to \$40 million.<sup>272</sup> Yet, Mr. Breedlove didn’t recommend a 19-year service life for UPS; he recommended a 30-year life. To reach a 30-year life, UPS will most likely have to replace its combustion turbine rotors. Although the service life of a plant is not determined by any one component, the combustion turbine rotors are a major component that can greatly extend the life of the plant. Replacing the rotors would add an additional 19 years. Using Mr. Breedlove’s assumptions, replacing the rotors at 19 years gives

---

<sup>266</sup> TR, June 18, 2019 (Cross Examination of Donald Clayton), at 148:18 – 149:15.

<sup>267</sup> *Id.*, at 149:16 – 150:9.

<sup>268</sup> *Id.*, at 150:3-9.

<sup>269</sup> TR, June 19, 2019 (Cross Examination of Robert Breedlove), at 69:16 - 70:4.

<sup>270</sup> Exh. ENO-48 (Rebuttal Testimony of Robert A. Breedlove (“Breedlove Rebuttal Testimony”) (ENO)), at 5:4-12.

<sup>271</sup> *Id.*, at 5:1-18; *see also* TR, June 19, 2019 (Cross Examination of Robert Breedlove), at 71:1 – 72:15.

<sup>272</sup> Exh. ENO-48 (Breedlove Rebuttal Testimony), at 5:14-18.

another 19 years, for a total of 38 years; not 30. Add to this the multiple examples provided by Mr. Kollen of similar combined cycle plants being operated nearly 50 years,<sup>273</sup> and the evidence points to a 40-year service life estimate for UPS, not a 30-year life.

Mr. Breedlove attempted to refute Mr. Kollen's examples of combined cycles with long service lives by pointing to Calpine's Clear Lake cogeneration plant as the purportedly "most similar" to Mr. Kollen's examples.<sup>274</sup> But, the Clear Lake plant Mr. Breedlove said was most similar to UPS was a *pre-2000* unit.<sup>275</sup> Weakening his testimony further, Mr. Breedlove noted that one of the reasons the Clear Lake plant was shut down was its "shrinking profits" but could not say how much of a factor such shrinking profits played in the owner's decision to shut down the plant.<sup>276</sup> The declining profitability of the Clear Lake plant is a major wildcard and renders the reliability of using it as a comparable highly questionable.

Mr. Kollen estimates that the financial effect of using an appropriate 40-year service life for UPS to be a **\$5.029 million reduction** in ENO's electric base revenue requirement.<sup>277</sup>

ENO takes a similar, completely unsupported tack regarding the net salvage value estimate for UPS, assuming it would be *negative 8%* even though ENO has no operating experience with the unit.<sup>278</sup> Use of this negative salvage value increases ENO's depreciation rate by 8%.<sup>279</sup> The fact that ENO has no experience with retirements or net salvage value for UPS means that its actual

---

<sup>273</sup> See Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 29:15 – 30:2. Mr. Kollen's comparable plants included at least 10 similar units, such as Entergy Louisiana, LLC's Sterlington Unit No. 7, some of which are still in operation *more than* 50 years after their commercial operations date.

<sup>274</sup> Exh. ENO-48 (Breedlove Rebuttal Testimony), at 8:7-9.

<sup>275</sup> TR, June 19, 2019 (Cross Examination of Robert Breedlove), at 78:1-11. The Clear Lake unit went into service in 1985.

<sup>276</sup> *Id.*, at 78:12 – 79:1.

<sup>277</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 30:17-18.

<sup>278</sup> *Id.*, at 31:1-23.

<sup>279</sup> *Id.*, at 31:1-6.

experience is 0% net salvage.<sup>280</sup> Mr. Kollen calculated that the effect of employing the supportable 0% net salvage value for UPS for depreciation purposes would lead to a **reduction of \$0.628 million** in the electric base revenue requirement.<sup>281</sup>

With respect to the NOPS facility, ENO seeks recovery of the associated revenue requirement through an interim rate adjustment as specified in its E-FRP, based on the first year NOPS revenue requirement.<sup>282</sup> Importantly, ENO does not propose any subsequent reduction in this interim adjustment as the plant investment is depreciated for book and tax purposes.<sup>283</sup>

ENO's proposal will lead to excessive recovery in the first year and every year thereafter until base rates are reset. This will occur because the rate of return (initially 10.50%) is excessive, the depreciation rate and depreciation expense are excessive because they assume a service life of 30 years for NOPS, and the revenue requirement generally is at the maximum the first year and then declines due to the accumulation of book depreciation and the tax savings from accelerated tax depreciation but ENO does not propose to reduce the revenue requirement.<sup>284</sup>

Mr. Kollen investigated publicly-available information on retirements of combustion turbine plants, like NOPS, and found that similar units have been in operation for nearly 50 years or more.<sup>285</sup> As with the PPA capacity costs, the utility is made whole over time, because it will collect all of its depreciation, including consideration for salvage value.<sup>286</sup> The issue is whether ENO collects these costs over 30 years or 40 years or 50 years. As Mr. Kollen explained, depreciation studies are performed periodically – it is not a once-and-done exercise – and each

---

<sup>280</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 31:7-15.

<sup>281</sup> *Id.*, at 32:22-23.

<sup>282</sup> *Id.*, at 45:18 – 46:4.

<sup>283</sup> *Id.*, at 46:4-6.

<sup>284</sup> *Id.*, at 46:8 – 48:4.

<sup>285</sup> *Id.*, at 47:1-19.

<sup>286</sup> TR, June 21, 2019 (Cross Examination of Lane Kollen), at 9:15-24.

time experience is gained with the asset, and as new components are replaced and old components are removed and retired, the depreciation analysis is continuously updated.<sup>287</sup> Based upon his analysis, he recommends a 50-year service life assumption for NOPS for the revenue requirement be used, instead of ENO's 30-year assumption.

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>288</sup> He calculates the effect of his recommendations and concludes the first-year revenue requirement for NOPS should be **reduced by \$4.073 million.**<sup>289</sup>

#### **6. Electric and Gas Formula Rate Plans are Reasonable *if* Appropriately Modified**

CCPUG supports ENO's proposals to implement Electric and Gas Formula Rate Plans ("FRPs");<sup>290</sup> *but only if* ENO's proposal to include projected costs in the electric and gas FRPs is *rejected*. The Advisors are in favor of including such projected costs in the FRPs. Inclusion of projected costs – which may or may not ever be incurred – undermines a utility's incentive to operate effectively and economically. 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>291</sup> The Council should reject the inclusion of projected costs and use of a forward-looking test year in the electric and gas FRPs.

As mentioned, above, the Council should also order that a 9.35% ROE be used in both the E-FRP and G-FRP. Further, the Council should adopt Mr. Kollen's recommendations concerning

---

<sup>287</sup> TR, June 21, 2019 (Cross Examination of Lane Kollen), at 10:18 – 11:3.

<sup>288</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 48:6-13.

<sup>289</sup> *Id.*, at 48:15-20.

<sup>290</sup> For ease of reference, the electric FRP is sometimes referred to as the "E-FRP", and the gas FRP is sometimes referred to as the "G-FRP".

<sup>291</sup> *See* Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 42-44.

the service life and depreciation rate concerning NOPS, discussed above. CCPUG has the following additional recommendations: The Council should delay implementation of the E-FRP until 2021, except for the NOPS provision, if the Council doesn't accept CCPUG's recommendation to exclude projected 2019 costs, and, similarly, should delay implementation of the G-FRP until 2021, if Council doesn't accept CCPUG recommendation to exclude projected 2019 costs.

**7. A Suite of ENO's Requested Riders Should be Rejected as Unnecessary and Ripe for Abuse<sup>292</sup>**

***a. Reliability Incentive Mechanism Rider***

CCPUG recommends that the Council reject the Reliability Incentive Mechanism ("RIM") Rider which would permit ENO to earn more than its authorized ROE if it met certain reliability criteria. By advancing this proposition, ENO is attempting to externalize one of its core duties to New Orleans customers — to pursue increased reliability. The gratuitous nature of the RIM proposal was confirmed under oath by ENO witness Melonie Stewart, who acknowledged that "ENO does not require an incentive to provide or to strive to provide reliable service."<sup>293</sup> Offering a regulated monopoly a "bonus" for doing what they are paid to do is not only patently absurd, but as a matter of policy, it represents a dangerous concession that removes the principal incentive to operate reliably and efficiently.

The good news here is that ENO has – albeit belatedly – increased its spending on enhancement of its distribution grid's reliability.<sup>294</sup> The bad news is that ENO requests approval of the RIM Rider that would simply give ENO a bonus for doing what it should do – *i.e.*, maintain

---

<sup>292</sup> CCPUG does not address all of the riders ENO proposes, such as the MISO Cost Recovery Rider, the Securitized Storm Cost Offset (SSCO) Rider, or the Purchased Power Cost Recovery (PPCR) Rider. The fact that CCPUG did not address every rider ENO proposes does not signal CCPUG's agreement with or support for any such rider.

<sup>293</sup> TR, June 18, 2019, (Cross Examination of Melonie Stewart), at 122:2-8.

<sup>294</sup> *Id.*, at 119:7 – 120:4.



and improve the reliability of its service to its customers. The proposed RIM Rider is also unnecessary – especially if the E-FRP is adopted. The RIM Rider will serve to remove ENO’s incentive to operate efficiently and invest economically. In fact, Mr. Thomas and Ms. Stewart admitted that ENO will continue to make investments to improve reliability of its service to its customers even *without* the RIM Rider.<sup>295</sup>

ENO, as the monopoly utility service provider in New Orleans has the duty to provide reliable electric and gas service at the lowest reasonable cost.<sup>296</sup> ENO is, therefore, free from competition. No incentive is necessary or advisable for a monopolist to encourage it to fulfill its obligations to its captive customers.

The Council should reject ENO’s proposed RIM Rider for electric operations.<sup>297</sup>

***b. Distribution Grid Modernization Rider***

ENO’s proposed Distribution Grid Modernization (“DGM”) Rider should likewise be rejected. Like the RIM Rider, the DGM Rider is unnecessary and provides accelerated and increased recovery to ENO through use of a forecast test year instead of including the DGM costs in the E-FRP on a historic test year basis.<sup>298</sup> This provides a bonus to ENO for simply doing its job – which should include modernizing its distribution grid.

CCPUG’s consultants recommend that the Council *reject* ENO’s proposed Distribution Grid Modernization (DGM) Rider, arguing that it will permit ENO to implement quarterly rate increases (*on top of* the rate increases caused by the E-FRP and G-FRP) starting in 2020 and

---

<sup>295</sup> TR, June 18, 2019, (Cross Examination of Melonie Stewart), at 120:22 – 121:19; TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 78:9-19.

<sup>296</sup> TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 70:8 – 71:1.

<sup>297</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 50:7-17, noting that a utility must provide reliable service in return for its monopoly status and absence of competition, along with the opportunity to earn a reasonable rate of return.

<sup>298</sup> *Id.*, 54:3 – 56:21.

continuing into the future until such rider is terminated.<sup>299</sup> CCPUG’s consultants also explain that the DGM Rider (as well as the GIRP Rider) is not necessary if the Council adopts CCPUG’s recommended versions of the E-FRP and G-FRP, because these mechanisms provide near real-time recovery of costs actually incurred.<sup>300</sup> ENO’s witnesses affirmed that the DGM is unnecessary, testifying that, if the rider is rejected and ENO makes investment in a DGM project, it can seek recovery of that investment through its FRP.<sup>301</sup> They also confirmed that the Council has already allowed ENO to use certain funds that would otherwise flow back through to its customers as a result of the Tax Cuts and Jobs Act to invest in DGM projects.<sup>302</sup> Finally, ENO conceded it will continue to make DGM investments even if the DGM Rider is rejected.<sup>303</sup> The evidence firmly establishes that the DGM Rider is unnecessary and ill-advised.

Finally, the “streamlined process” ENO proposes to address recovery of DGM projects in the rider is far too accelerated, endangers due process, and presents the material risk of over-recovery. As Mr. Baudino explains, ENO’s “reasoning would result in the elimination of regulatory lag and any sort of review of the prudence and reasonableness of costs being collected from New Orleans customers,” and, “[t]aken to its logical end, contemporaneous cost recovery would eliminate rate cases as well as Council and intervenor review of a utility’s revenue requirement. Indeed, it would eliminate a utility company’s burden of proving that its costs are just and reasonable.”<sup>304</sup>

---

<sup>299</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 4:15-22; Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 4 and 56:6 – 58:3.

<sup>300</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 56:6 – 58:3.

<sup>301</sup> TR, June 18, 2019 (Cross Examination of Erica Zimmerer), at 103:2 – 104:8.

<sup>302</sup> *Id.*, at 105:7 – 106:14.

<sup>303</sup> *Id.*, at 106:23 – 107:16.

<sup>304</sup> Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 57:22 – 58:2.

ENO's witness, Erica Zimmerer, testified that no discovery would be conducted during the review process under the DGM Rider.<sup>305</sup> Nor are any hearings contemplated under the rider's review process.<sup>306</sup> ENO's recommended approval process short-circuits the review process by the Council and tramples upon the rights of its customers to adequately investigate these multi-million dollar investments prior to their inclusion in rates. The Council should reject the DGM Rider.

***c. Gas Infrastructure Replacement Plan Rider***

CCPUG opposes ENO's requested Gas Infrastructure Replacement Plan ("GIRP") Rider. The proposed GIRP Rider is similar to the proposed DGM Rider and, as such, is unnecessary – especially if the G-FRP is adopted. The GIRP Rider will lead to inevitable, *quarterly rate increases*.<sup>307</sup> The GIRP Rider will serve to remove ENO's incentive to operate efficiently and invest economically.

***d. New Purchased Power Capacity Acquisition Cost Recovery Rider***

ENO proposes a new Purchased Power Capacity Acquisition Cost Recovery ("PPCACR") Rider. CCPUG objects to the proposed new PPCACR, because it would inappropriately allow near *automatic recovery* of new capacity costs and costs of newly-constructed generating assets without a full certification review by the Council.<sup>308</sup> The Council Advisors also oppose the new PPCACR on the basis that it will serve to prevent full certification review prior to plant investments being included in rates.

CCPUG recommends that the Council reject ENO's proposal to recover new / future non-fuel revenue requirements related to constructed and/or acquired capacity (such as a power

---

<sup>305</sup> TR, June 18, 2019 (Cross Examination of Erica Zimmerer), at 108:2-22.

<sup>306</sup> *Id.*, at 108:23 – 109:3.

<sup>307</sup> See Exh. CCPUG-3 (Baudino Direct Testimony) (CCPUG), at 56:6 – 58:3.

<sup>308</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 52:16 – 54:2.

generating station similar to UPS) through PPCACR Rider, especially since such costs would be recovered without sufficient Council review.<sup>309</sup> Similarly, no new generating asset, Long-Term Service Agreement (“LTSA”) costs should be removed from the PPCACR, and ENO should not be permitted to include future capacity costs (nonfuel costs) associated with PPAs or LTSA costs in the PPCACR without Council review.<sup>310</sup> Finally, the Council should establish a process to review the reasonableness of the transactions and agreements, complete with opportunity for stakeholder participation, prior to approving inclusion of such costs in the PPCACR Rider.<sup>311</sup>

#### **8. Capital Storm Restoration Costs Should be Removed from Plant and Reimbursed from Storm Reserves to Save Ratepayers Money**

ENO’s request to recover storm recovery costs by including them in its rate base instead of reimbursing itself for such costs from its two storm reserve accounts is (a) illogical – (the reserve accounts were established for this exact purpose), and (b) will **cost ratepayers more money** than if ENO reimbursed itself for such restoration costs from the reserve accounts. The Council should dismiss ENO’s request to include the storm recovery costs in its rate base and should instead direct ENO to reimburse itself for such costs from its two storm reserve accounts, as it has done with other storm restoration costs in the past.

ENO has two storm reserve accounts: the Securitized Storm Reserve Account and the Existing Escrow Account which are *pre-funded*.<sup>312</sup> This means ENO’s ratepayers have already funded the storm reserve accounts. The balance in these two storm reserve accounts was roughly \$80 million at the end of December 2017.<sup>313</sup> In fact, ENO reimbursed itself for certain storm

---

<sup>309</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 53:8-17.

<sup>310</sup> *Id.*, at 52-54.

<sup>311</sup> *Id.*, at 54:4-11.

<sup>312</sup> *Id.*, at 15:20 – 22. *See also* TR, June 17, 2019 (Cross Examination of Laura Beauchamp), at 169:10-14.

<sup>313</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 15:23 – 16:1; Exh. ENO-33 (Todd / Beauchamp Direct Testimony) (ENO), at 33:3-7. *See also* TR, June 17, 2019 (Cross Examination of Laura Beauchamp), at 169:15-18.

restoration costs during 2018 from these reserve accounts.<sup>314</sup> But, now ENO seeks to include roughly \$17 million of outstanding storm restoration costs in its rate base rather than seek reimbursement from its storm reserve accounts.<sup>315</sup> ENO has further admitted it has a *right* to be reimbursed for these outstanding storm restoration costs from its storm reserve accounts.<sup>316</sup>

ENO's request to include the storm restoration costs in its rate base should be rejected because it is not the least cost method to recover these costs. ENO's witness, Ms. Beauchamp, confirmed that, if ENO is permitted to include the storm restoration costs in its rate base, it will earn – at a minimum – 10.50% return on those costs,<sup>317</sup> whereas, if ENO reimbursed itself from the storm reserve accounts, the cost to ratepayers would be roughly 1%.<sup>318</sup> So, ENO seeks to charge ratepayers over 10 times as much in the way of return on the recovery of the storm restoration costs by including them in its rate base.

Removal of the storm restoration costs from ENO's rate base will save its customers **\$1.614 million** and removing the related expenses will save **\$0.565 million**, for a total of roughly **\$2.18 million per year**.

### **9. ENO's Proposed Algiers Residential Rate Transition Plan Should be Approved, but with a Significant Modification**

The proposed Algiers Residential Rate Transition ("ARRT") Plan will be implemented to phase-in the rate increase to ENO's Algiers residential customers and to create a single, combined

---

<sup>314</sup> Exh. ENO-33 (Todd / Beauchamp Direct Testimony) (ENO), at 32:20 – 33:2; *see also* TR, June 17, 2019 (Cross Examination of Laura Beauchamp), at 170:6-16. ENO reimbursed itself roughly \$2.5 million in storm restoration costs.

<sup>315</sup> Exh. ENO-33 (Todd / Beauchamp Direct Testimony) (ENO), at 33:9 – 34:5; *see also* TR, June 17, 2019 (Cross Examination of Laura Beauchamp), at 170:6-16.

<sup>316</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 15:12-18; *see also* Exh. LK-2, ENO's Response to Data Request CCPUG 2-7.

<sup>317</sup> TR, June 17, 2019 (Cross Examination of Laura Beauchamp), at 172:6-20.

<sup>318</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 17:8-21. Mr. Kollen notes that, after gross-up for income taxes, the return on the storm restoration costs in rate base would be 9.79%, still outrageously higher than 1%.

rate structure for both Algiers and Legacy ENO customers. To accomplish this, the Algiers residential customers and customers in the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes will be subject to the Base Rate Adjustment Rider (“BRAR”). The ARRT is designed to reduce “rate shock” to the Algiers residential customers and is funded *exclusively* by large commercial customers, like CCPUG. That said, the BRAR exacerbates the already significant subsidies large commercial customers are being forced to pay. Mr. Baron highlights the subsidies inherent in the BRAR in his Direct Testimony.<sup>319</sup>

**Table 3**  
**ENO Proposed Base Rate Increases, Including BRAR**

LINE NO.	RATE CLASS	PRESENT	Base Rate		Total	% Increase
		BASE RATE REVENUE	Increase	BRAR	Base Rate Increase	
1	RESIDENTIAL SERVICE	\$134,602,540	\$57,182,346	(\$3,325,000)	\$53,857,346	40.0%
2	SMALL ELECTRIC SERVICE	\$51,387,058	\$21,871,331	\$0	\$21,871,331	42.6%
3	MUNICIPAL BUILDINGS	\$2,101,668	\$848,213	\$0	\$848,213	40.4%
4	LARGE ELECTRIC	\$20,776,705	\$10,353,287	\$694,624	\$11,047,911	53.2%
5	LARGE ELECTRIC HIGH LOAD FAC	\$71,072,624	\$37,555,966	\$2,376,159	\$39,932,125	56.2%
6	MASTER METERED NON-RES	\$40,401	\$17,393	\$0	\$17,393	43.1%
7	HIGH VOLTAGE	\$5,071,596	\$2,985,545	\$169,558	\$3,155,103	62.2%
8	LARGE INTERRUPTIBLE	\$2,532,217	\$2,429,408	\$84,659	\$2,514,067	99.3%
9	LIGHTING SERVICE	\$5,578,843	\$2,003,713	\$0	\$2,003,713	35.9%
10	TOTAL RETAIL	\$293,163,652	\$135,247,202	\$0	\$135,247,202	46.1%

Table 3 establishes that the \$3.325 million subsidy to the Algiers residential customers will be funded nearly exclusively by the Large Electric and Large Electric High Load Factor classes.

CCPUG understands the importance of the ARRT and supports the regulatory principle of gradualism when changing utility rates. Consequently, CCPUG does *not* oppose the ARRT and accompanying BRAR. That said, *however*, the Council should modify both the ARRT Plan and its corresponding BRAR. The goals of the ARRT must be balanced with the adverse effect it will

<sup>319</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 20:7, Table 3: “ENO Proposed Base Rate Increases, Including BRAR”.



have on the commercial classes of customers. The Council should modify the ARRT and BRAR so that the first \$3.325 million of any overall rate reductions ordered in this proceeding *in excess of* the roughly \$20 million proposed by ENO be allocated to large customers to eliminate the subsidy they will pay the Algiers residential customers under the ARRT/BRAR.<sup>320</sup>

#### **10. The AMI Charge Rider, as Proposed by ENO, Should be Approved**

According to Council Resolution R-18-37, the “prudently incurred costs associated with constructing, installing, owning, and operating AMI are eligible for recovery from ENO’s customers through ENO’s Council-approved electric and gas rates resulting from a final order of the Council on 2018 Rate Case.”<sup>321</sup> Further, in Council Resolution R-18-224 (adopted June 21, 2018) the City Council approved an “acceleration” of the deployment of AMI (originally scheduled for 2018 – 2021), as part of the Smart Cities Initiative, which will accelerate deployment by 1 year and add \$4.4 million in capital costs. This would bring the total capital costs for AMI to roughly \$80 million. ENO proposed to recover the AMI costs through the AMI Charge Rider.<sup>322</sup> The AMI Charge Rider would be applied as a “customer-charge”, meaning each customer would pay for his or her cost of the meter, meter reading expense, etc.<sup>323</sup> This was a ray of good news in the Revised Application.

CCPUG’s consultants recommended the adoption of the AMI Charge Rider since it was designed to recover the AMI costs on a per metered customer basis and these charges are customer-specific, rather than socializing the collection of these costs in the E-FRP or base rates.<sup>324</sup> The

---

<sup>320</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 27:9 – 28:8.

<sup>321</sup> Resolution No. R-18-37, at ¶ 5, p. 4.

<sup>322</sup> Exh. ENO-1 (Thomas Revised Direct Testimony) (ENO), at 8:8-11 and 61:6 – 62:3.

<sup>323</sup> *Id.*, at 65:18 – 66:8, noting, in part, that, “these costs should be recovered through a customer charge so that a customer bears only the cost that customer causes.”

<sup>324</sup> See Exh. CCPUG-2 (Kollen Surrebuttal Testimony) (CCPUG), at 31:2-14.

rider, therefore, follows cost-causation principles. The Advisors, however, have recommended that the AMI costs be socialized by including them in base revenue requirement and that subsequent forecast costs be incorporated annually in each evaluation period under the E-FRP and G-FRP.<sup>325</sup>

CCPUG's is opposed the inclusion in rates of any such forward-looking adjustments or projected costs that extend beyond the Period I and Period II test years expressly defined in Resolutions R-15-194 and R-17-504 directing ENO to file this base rate case and/or outside of the test year used for the FRPs.<sup>326</sup> Such forecasts of future costs are not known and measurable and are subject to overstatement bias.<sup>327</sup> The Council should approve the customer-specific AMI Charge Rider as proposed by ENO.

Alternatively, should the Council choose to adopt the Advisors' recommendation and approve the inclusion of the AMI expenses in the E-FRP, such expenses should not include any projected costs or be based on a forward-looking test year / evaluation period. Further, if the Council decides to include the AMI costs in the E-FRP, they should be recovered only *within* the earnings bandwidth. If the AMI expenses are included in the E-FRP but outside of the earnings bandwidth, then ENO will recover 100% of such expenses regardless whether its earnings fall below the earnings bandwidth. There is no material difference between the AMI expenses and other base rate operating expenses that are subject to the earnings bandwidth. There is also no reasonable justification for carving the AMI expenses out of the bandwidth and affording them 100% recovery status.

---

<sup>325</sup> See Exh. CCPUG-2 (Kollen Surrebuttal Testimony) (CCPUG), at 31:16-20.

<sup>326</sup> See *id.*, at 31:22 – 32:7.

<sup>327</sup> *Id.*

## **B. Tax-Related Issues**

### **1. Remove (for Electric) and Reduce (for Gas) Asset Net Operating Loss Accumulated Deferred Income Taxes**

In the Revised Application, ENO included Asset Net Operating Loss (“NOL”) Accumulated Deferred Income Taxes (“ADIT”) of \$5.831 million in electric rate base and \$21.245 million in gas rate base for Period I.<sup>328</sup> Similarly, ENO included NOL ADIT of \$6.184 million in electric rate base and \$22.589 million in gas rate base for Period II.<sup>329</sup> ENO corrected these NOL ADIT amounts in response to discovery from the Advisors and CCPUG,<sup>330</sup> which saved ratepayers money. CCPUG’s participation in this matter directly saved ratepayers money. That is the good news. The bad news is that the possibility exists there will be additional reductions in NOL ADIT in connection with ENO’s year-end 2018 accounting and in future years, including 2019, therefore, if the Council does not reject ENO’s inclusion of 2019 costs in rate base and operating expenses (which it should), it should update and reduce the NOL ADIT based on forecast taxable income in 2019.<sup>331</sup>

### **2. Remove Asset Accumulated Deferred Income Taxes – Deferred Storm Costs**

ENO included two adjustments to add asset ADIT to deferred storm costs to rate base, but did not subtract the storm damage reserve liability amounts from the rate base pursuant to traditional ratemaking principles.<sup>332</sup> Recall CCPUG strongly recommends that the Council order ENO to reimburse itself for storm restoration costs out of the two storm reserve accounts rather

---

<sup>328</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 18:16-22.

<sup>329</sup> *Id.*, at 18:22 – 19:2.

<sup>330</sup> *See id.*, at 19:3-7.

<sup>331</sup> *Id.*, at 19:14 – 20:16.

<sup>332</sup> *Id.*, at 21:1-9.

than placing such restoration costs in rate base. ENO acknowledged that these two accounts should not have been added to rate base given that storm damage reserve amounts are not subtracted from rate base.<sup>333</sup> Here, again, CCPUG's involvement in this proceeding saved all of ENO's customers money.

### **3. Remove 2019 Amortization of Protected Excess ADIT**

The Tax Cuts and Jobs Act ("TCJA") reduced the federal income tax rate for utility companies from 35% to 21%.<sup>334</sup> This reduction in the federal income tax rate reduced the valuation of existing Accumulated Deferred Income Taxes (ADIT) on ENO's books as of December 31, 2017, which created "excess ADIT" that needs to be returned to ENO's customers that paid the ADIT. There are two types of excess ADIT: Protected Excess ADIT and Unprotected Excess ADIT. Under the federal tax code, Protected Excess ADIT may only be returned over the remaining regulatory lives of the property generating the excess ADIT.<sup>335</sup> Unprotected Excess ADIT, on the other hand, can be flowed back to customers much more quickly, essentially at the regulator's discretion.<sup>336</sup> In Resolution No. R-18-227, the Council adopted the Tax Law Agreement In Principle which provided, among other things, that the ratemaking treatment of flow back of the Unprotected Excess ADIT through the FAC.

ENO's Revised Application and supporting testimony called for the use of projected amounts of Protected Excess ADIT, rather than the per book amounts of such ADIT as of December 31, 2018 Period II test year. ENO used projected 2019 amounts which increased its rate base (upon which it earns a return) by \$1.155 million (electric) and \$0.290 million (gas).<sup>337</sup> For all

---

<sup>333</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 21:11-14.

<sup>334</sup> *Id.*, at 22:1-6.

<sup>335</sup> *Id.*, at 22:7-20.

<sup>336</sup> *Id.*, at 22:7-10.

<sup>337</sup> *Id.*, at 22-23.

of the reasons set forth above regarding ENO’s manipulation of the test years and violations of Resolution Nos. R-15-194. and R-17-504, CCPUG recommends that the Council remove the 2019 amortization of the Protected Excess ADIT, which would lower ENO’s electric base revenue requirements by **\$0.113 million** and would lower its gas base revenue requirement by **\$0.029 million**.<sup>338</sup>

#### **4. Subtract FIN 48 Accumulated Deferred Income Taxes**

ENO has taken certain deductions for “uncertain tax positions” (“UTPs”) on its tax returns.<sup>339</sup> If ENO is unsuccessful on audit and appeal of these UTPs, it must repay the tax savings to the federal government along with interest.<sup>340</sup> ENO has not subtracted related FIN 48 ADIT from rate base increases and base revenue requirement, which deprives its customers of *ever receiving* the carrying charge value of the FIN 48 ADIT.<sup>341</sup> This occurs because customers paid the income tax expense as if there were no tax deduction, but ENO claimed the UTP-related deductions, which reduced its current income tax expense and cash payments to the taxing authorities.<sup>342</sup> In this way, ENO pockets the carrying charge value on the savings that were funded by ratepayers. The Council should subtract the FIN 48 ADIT amounts from rate base.<sup>343</sup>

#### **C. ENO’s Gas Operations**

As with its electric rate design, ENO’s gas rate design is structured to provide subsidies to the Residential class at the expense of the large commercial customers.<sup>344</sup> Mr. Baron illustrates the subsidies under present rates in his Direct Testimony:<sup>345</sup>

---

<sup>338</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 23:11-14.

<sup>339</sup> *Id.*, at 23:16-21.

<sup>340</sup> *Id.*, at 24:1-2.

<sup>341</sup> *Id.*, at 24:14-18.

<sup>342</sup> *Id.*, at 24:17 – 25:2.

<sup>343</sup> *Id.*, at 25:23 – 26:6.

<sup>344</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 29:9-16.

<sup>345</sup> *Id.*, at 29:17, Table 8: “ENO Gas Cost of Service Study Results – Present Rates”.

<u>LINE NO.</u>	<u>RATE CLASS</u>	<u>Rate of Return</u>	<u>Relative Rate of Return</u>	<u>Present Rate Subsidies*</u>
1	RESIDENTIAL	6.27%	0.66	3,291,317
2	SMALL GENERAL	19.18%	2.03	(1,525,452)
3	LARGE GENERAL	22.05%	2.33	(1,900,464)
4	SMALL MUNICIPAL	0.15%	0.02	28,404
5	LARGE MUNICIPAL	8.45%	0.89	106,195
6	TOTAL RETAIL	9.46%	1.00	0

\* A positive value indicates that a subsidy is being received.

Table 8, above, shows that residential customers are receiving approximately \$3.3 million per year in gas rate subsidies. ENO proposes no remedy to reduce these subsidies. Mr. Baron recommends an allocation of the overall \$2,230,281 base revenue decrease that will reduce current dollar subsidies paid and received by each rate class by 25% of the subsidies at present rates, with a small mitigation adjustment so that no class will receive a gas rate increase.<sup>346</sup> This is a modest and imminently reasonable recommendation to lessen the burden of these continuing subsidies on the large commercial customers. Mr. Baron demonstrates how his 25% reduction in the subsidies would work in Table 9 of his Direct Testimony, set forth below:<sup>347</sup>

<sup>346</sup> *Id.*, at 30:7-13.

<sup>347</sup> *Id.*, at 31:1, Table 9: "CCPUG Proposed Gas Base Revenue Increases".



LINE NO.	RATE CLASS	Proposed Revenue Increases	
		\$	%
1	RESIDENTIAL	(756,501)	-2.8704%
2	SMALL GENERAL	(627,531)	-10.2176%
3	LARGE GENERAL	(710,728)	-10.8931%
4	SMALL MUNICIPAL	-	0.0000%
5	LARGE MUNICIPAL	<u>(135,521)</u>	<u>-4.2304%</u>
6	TOTAL RETAIL	(2,230,281)	-5.2737%

The Council should adopt CCPUG’s recommendation to reduce the subsidies in ENO’s proposed natural gas rates by 25% as proposed by Mr. Baron.

**II. REDUCTION OF CROSS-SUBSIDIES**

CCPUG’s consultant, Mr. Baron, discussed the vexing problem of persistent and sizeable subsidies ENO’s commercial customers have been forced to pay, as well as the proposal to continue penalizing these customers in the future by the continued application of subsidies. He illustrates the significant penalties in the form of cross-subsidization that commercial customers are currently suffering in his Direct Testimony, a selection from which is provided below for the Council’s convenience.<sup>348</sup>

---

<sup>348</sup> Exh. CCPUG- 5 (Baron Direct Testimony) (CCPUG), at 17:1: Table 1, entitled, “Class Rates of Return and Subsidies at Present Rates”.

LINE NO.	RATE CLASS	Present Rates ROR%	Relative ROR Index	Present Rates Subsidy*
1	RESIDENTIAL SERVICE	3.22%	0.286	\$ 45,361,859
2	SMALL ELECTRIC SERVICE	15.35%	1.363	\$ (6,235,998)
3	MUNICIPAL BUILDINGS	20.03%	1.778	\$ (5,556,745)
4	LARGE ELECTRIC	118.78%	10.546	\$ (4,911,277)
5	LARGE ELECTRIC HIGH LOAD FAC	21.25%	1.887	\$ (21,350,744)
6	MASTER METERED NON-RES	60.33%	5.356	\$ (3,811,576)
7	HIGH VOLTAGE	24.39%	2.166	\$ (673,490)
8	LARGE INTERRUPTIBLE	29.60%	2.628	\$ (18,010)
9	LIGHTING SERVICE	<u>33.48%</u>	<u>2.972</u>	<u>\$ (2,804,019)</u>
10	TOTAL RETAIL	11.26%	1.000	\$ 0

\* A positive value indicates that a subsidy is being received by the rate class.

ENO's witness, Myra Talkington, addressed several issues, including cost allocation factors, adjustments to historic and projected test year period revenues, and development of ENO's proposed rate design.<sup>349</sup> She confirmed that she **did not take issue** with Mr. Baron's Table 1 or his estimates of current subsidies being paid to residential rate class regarding electric rates in her pre-filed testimony.<sup>350</sup> Ms. Talkington also agreed that she did not point out any errors in Mr. Baron's Table 1 or analysis of current subsidies being paid to residential rate class regarding electric rates in her pre-filed testimony and provided **no regulatory principle** that contradicts Mr. Baron's testimony stating that subsidies being paid by Large Electric and Large Electric High Load Factor customers should be reduced or eliminated.<sup>351</sup> Finally, Ms. Talkington confirmed that, according to Mr. Baron's Table 1, ENO's Residential class – under current rates – is **receiving over \$45 million annually** in subsidies from the other rate classes.<sup>352</sup>

<sup>349</sup> See Exh. ENO-45 (Talkington Revised Direct Testimony) (ENO), at 1:18 – 2:12.

<sup>350</sup> TR, June 18, 2019, (Cross Examination of Myra Talkington), at 57:2 – 58:9.

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

<sup>352</sup> *Id.*, at 57:2-23.

And, Mr. Baron's Table 1 also shows that the Large Electric class is supplying almost \$5 million of the \$45 million subsidy, under current rates, while the Large Electric High Load Factor class is supplying over \$21 million of that subsidy. That means the roughly 1,000 customers in these two electric rate classes – Large Electric and Large Electric High Load Factor – are currently providing close to **58% of the total annual subsidy** to the approximate 181,500 customers in the Residential class.<sup>353</sup> As Mr. Baron acknowledges, ENO's proposal in its Revised Application to roll in certain PPA fixed production costs (*e.g.*, capacity costs) to base rates will serve to partly reduce these subsidies, *but* its proposal to allocate the EAI WBL and River Bend 30% PPA fixed costs on energy basis will **continue** a large portion of these subsidies. Mr. Baron testified,

The Company's proposal to roll-in these PPA fixed production demand costs to base rates will act to reduce subsidies and better align rates for all customer classes with cost of service. *However*, as I will discuss next, the Company's proposal to specifically allocate the fixed production demand costs of the WBL and River Bend PPAs to customer classes **on the basis of energy continues the subsidies** associated with these PPAs.<sup>354</sup>

Under cross-examination, ENO's witness, Mr. Thomas, walked back ENO's claim that its decision to reject the class allocation derived by the fully allocated class Cost of Service Study when designing rates and, instead, to follow an energy-based rate design for costs such as the capacity costs associated with the EAI WBL and River Bend 30% PPAs, was as a result of "comments" by the Council.<sup>355</sup> After stating that the change in allocation methodology was the result of the comments from the Council, Mr. Thomas couldn't recall who made the comments or

---

<sup>353</sup> See Exh. CCPUG- 5 (Baron Direct Testimony) (CCPUG), at 17:1: Table 1, Line 4, showing that the Large Electric class is providing \$4,911,277 in annual subsidies and Line 5 revealing that the Large Electric High Load Factor class is supplying \$21,350,744 in subsidies each year, for a total of \$26,262,021. ( $\$26,262,021 \div \$45,361,859$  total annual subsidy = 0.5789).

<sup>354</sup> *Id.*, at 17:8-13. (Emphasis and italics added).

<sup>355</sup> TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 46:16 – 47:10, where Mr. Thomas admits ENO changed the allocation of the capacity costs associated with the EAI WBL and River Bend 30% PPAs from an equal percentage basis to an energy basis in the Revised Application after receiving "comments from the City Council".

even if there was a specific comment about allocation; ultimately, saying it was ENO’s decision to change the allocation in the Revised Application.<sup>356</sup>

Mr. Baron’s Table 2 illustrates the disparate impact of ENO’s proposed rate design which serves to baselessly increase the base rate percentage increase for a targeted group of customers – the large commercial and industrial customers.<sup>357</sup> Mr. Baron’s Table 2 is provided below for ease of reference.<sup>358</sup>

LINE NO.	RATE CLASS	PRESENT	Part 1		Part 2 Increase PPA's		Total	BASE RATE
		BASE RATE REVENUE	Increase	% Increase	Allocated on Sales	% Increase	Increase (Part 1 + Part 2)	PERCENT CHANGE
1	RESIDENTIAL SERVICE	\$134,602,540	\$33,305,428	24.74%	\$23,876,918	17.74%	\$57,182,346	42.5%
2	SMALL ELECTRIC SERVICE	\$51,387,058	\$12,714,975	24.74%	\$9,156,356	17.82%	\$21,871,331	42.6%
3	MUNICIPAL BUILDINGS	\$2,101,668	\$520,027	24.74%	\$328,186	15.62%	\$848,213	40.4%
4	LARGE ELECTRIC	\$20,776,705	\$5,140,892	24.74%	\$5,212,395	25.09%	\$10,353,287	49.8%
5	LARGE ELECTRIC HIGH LOAD FAC	\$71,072,624	\$17,585,881	24.74%	\$19,970,085	28.10%	\$37,555,966	52.8%
6	MASTER METERED NON-RES	\$40,401	\$9,997	24.74%	\$7,396	18.31%	\$17,393	43.1%
7	HIGH VOLTAGE	\$5,071,596	\$1,254,892	24.74%	\$1,730,653	34.12%	\$2,985,545	58.9%
8	LARGE INTERRUPTIBLE	\$2,532,217	\$626,560	24.74%	\$1,802,848	71.20%	\$2,429,408	95.9%
9	LIGHTING SERVICE	\$5,578,843	\$1,380,403	24.74%	\$623,310	11.17%	\$2,003,713	35.9%
10	TOTAL RETAIL	\$293,163,652	\$72,539,055	24.74%	\$62,708,147	21.39%	\$135,247,202	46.1%

The above table demonstrates that the Large Electric, Large Electric High Load Factor, High Voltage and Large Interruptible classes are scheduled to pay far more than the total retail average base rate increase of 46.1%. Worse, with respect to the Part 2 increase, the Large Electric and Large Electric High Load Factor classes will bear a 25.09% and 28.10% increase, respectively, as compared to the 17.74% increase the Residential class will experience. Recall that, because

<sup>356</sup> TR, June 20, 2019, (Cross Examination of Joshua Thomas), at 47:11 – 48:3.

<sup>357</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 19:1, Table 2.

<sup>358</sup> *Id.* (Highlighting in original).



ENO is rolling the recovery of various costs currently recovered via riders into its rate base, it will create a base rate increase of over \$135 million; however, due to the savings provided through the elimination of these riders, an overall rate decrease will occur.

When the effects of ENO's ARRT Plan and its accompanying BRAR are considered, the resulting disparity in percentage base rate increases for the large commercial and industrial customers compared to the retail average of 46.1% *worsens* – the Large Electric class will experience a 53.2% increase; the Large Electric High Load Factor class will absorb a 56.2% increase; the High Voltage class will suffer a 62.2% increase; and, finally, the Large Interruptible class will see a 99.3% increase.<sup>359</sup> Meanwhile, the Residential class' percentage base rate increase *drops even further* – to 40% – as compared to the retail average of 46.1%.

A vital ratemaking goal the Council should pursue would be to move ENO's base rates towards cost of service,<sup>360</sup> following cost of service principles, which would drive every customer class' base rates towards a uniform percentage increase.<sup>361</sup> In other words, the Council should reduce the material disparities seen in the base rate percentage increases shown in Mr. Baron's Table 2. CCPUG's consultants have developed methods of reducing the unjustified subsidies on the commercial classes while *reducing rates for all classes*, thus moving ENO's rates far closer to cost of service than under ENO's proposal.

Mr. Baron's Table 2 also highlights in stark detail a second, but equally important fact about ENO's Revised Application. It shows that ENO's proposed rates embody inconsistent treatment of certain fixed, base rate costs. In Part 1, ENO applies an equal percentage increase to all customer classes' base rates. Part 1 includes the realignment of the Ninemile 6 PPA capacity

---

<sup>359</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 20:8, Table 3, "ENO Proposed Base Rate Increases, Including BRAR".

<sup>360</sup> TR, June 20, 2019 (Cross Examination of Joshua Thomas), at 43:23 – 44:4.

<sup>361</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 7:8 – 8:2, 8:17 – 9:2, and 21:7-10.

costs from the PPCACR Rider into base rates as well as the base rate recovery of the Algiers PPA capacity costs. Then, however, ENO changes the allocation of the capacity costs associated with the EAI WBL and River Bend 30% PPAs in Part 2 and assigns those costs in base rates on an energy basis. The energy-based allocation drives the disparate base rate increases seen in Part 2. This flip-flopping in the application of allocation methodologies to the exact same type of cost – capacity costs associated with long-term PPAs – among rate classes is blatantly arbitrary, capricious, and unduly harms the large commercial and industrial customer classes.

Under ENO’s proposed rates, the overall cross-subsidization of the Residential class by the large commercial and industrial classes will continue at an unacceptably exorbitant level. Mr. Baron’s Table 4 shows that the subsidies under ENO’s proposed rate design for the Residential class will continue at the pace exceeding *\$35 million per year*.<sup>362</sup> Mr. Baron’s Table 4 is reproduced below for reference.

---

<sup>362</sup> Exh. CCPUG-5 (Baron Direct Testimony) (CCPUG), at 21:1 Table 4, “ENO Proposed Rate Class Subsidies, Include BRAR Impact”.



NO.	LINE RATE CLASS	Proposed Rate Subsidies*
1	RESIDENTIAL SERVICE	\$ 35,568,733
2	SMALL ELECTRIC SERVICE	\$ (8,293,207)
3	MUNICIPAL BUILDINGS	\$ (3,867,479)
4	LARGE ELECTRIC	\$ (2,570,208)
5	LARGE ELECTRIC HIGH LOAD FAC	\$ (14,915,773)
6	MASTER METERED NON-RES	\$ (2,422,896)
7	HIGH VOLTAGE	\$ (762,856)
8	LARGE INTERRUPTIBLE	\$ (15,917)
9	LIGHTING SERVICE	\$ (3,737,695)
10	TOTAL RETAIL	\$ -

\* A positive value indicates that a subsidy is being received by the rate class.

Again, Ms. Talkington admitted under cross-examination that she did not dispute Mr. Baron's estimate in his Table 4 regarding the on-going subsidies under ENO's proposed rates.<sup>363</sup>

The Council should adopt CCPUG's recommended changes to ENO's rate base, revenue requirements and rate of return and seize this once-in-a-generation opportunity in a climate of declining rates to ameliorate the substantial and unjustified subsidies imposed on the commercial classes of customers, which – as CCPUG has illustrated – can be accomplished without raising residential customers' rates.

<sup>363</sup> TR, June 18, 2019 (Cross Examination of Myra Talkington), at 61:21 – 62:6.

### III. OTHER ISSUES ADDRESSED BY CCPUG

#### A. Rate Base Issues - Correction of Cash Working Capital

CCPUG recommends that the Council correct the Company's cash working capital ("CWC") calculation to include the dividend component of the return on equity. It is a cash expense and should be included in the CWC calculation.

The Company used the lead/lag approach in the calculation of cash working capital included in rate base. However, the Company failed to include the dividend component of the return on equity as a cash expense in the cash working capital calculation.<sup>364</sup> The return on equity consists of a dividend return plus a growth factor under the discounted cash flow ("DCF") methodology or a dividend return and a premium under the risk premium methodology or a dividend return and a risk adjusted premium under the capital asset pricing methodology.<sup>365</sup>

The dividend component of the return on equity is a cash disbursement (expense). Consequently, it should be reflected in the cash working capital calculation, along with all other cash expenses recovered in the revenue requirement. ENO's witness, Kenneth F. Gallagher, performed a lead/lag study to determine the need for CWC. Mr. Gallagher did not include the payment of common stock dividends in his lead/lag study.<sup>366</sup> Mr. Kollen, CCPUG's consultant, states that common stock dividends should be included in CWC, because the payment of common stock dividends is a cash disbursement and, therefore, should be reflected in the cash working capital calculation, along with all other cash expenses recovered in the revenue requirement.<sup>367</sup>

---

<sup>364</sup> The cash working capital revenue lag days and expense lag days are shown on ENO Exhibit KFG2 (Attachment A for electric and Attachment B for gas) attached to the Direct Testimony of Kenneth Gallagher.

<sup>365</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 26:12 – 27:2.

<sup>366</sup> TR, June 18, 2019 (Cross Examination of Kenneth Gallagher), at 32:2-15.

<sup>367</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 27:4-8.

Mr. Gallagher testified that there is no conceptual difference with respect to including the payment of common stock dividends and preferred stock dividends in the CWC analysis.<sup>368</sup> He would not include the payment of preferred stock dividends in CWC, because they are not expense items, either.<sup>369</sup> Yet, Mr. Gallagher admitted that is *exactly what he did* in the last base rate case for ENO's affiliate, Entergy Louisiana, LLC, before the Louisiana Public Service Commission.<sup>370</sup>

Given that there is no material difference between including preferred stock dividend payments in the CWC analysis and common stock dividend payments, and considering the LPSC has authorized the inclusion of preferred stock dividends, there is no valid reason to exclude the payment of common stock dividends from the CWC analysis in this proceeding. Adopting this recommendation would result in a **\$0.238 million** reduction in the total base revenue requirement.<sup>371</sup>

## **B. Operating Expense Issues**

### **1. Correction of Error in Patterson Solar Depreciation Rate and Expense.**

The Company acknowledged an error in the depreciation study performed by Mr. Clayton for the Patterson Solar facility in response to CCPUG discovery.<sup>372</sup> The correct depreciation rate for the Patterson Solar facility should be 4.01%, not the 4.35% reflected in the depreciation study and used to calculate the depreciation expense included in the electric base revenue requirement. The effect of this correction is a **\$0.070 million** reduction in the electric base revenue requirement.

---

<sup>368</sup> TR, June 18, 2019 (Cross Examination of Kenneth Gallagher), at 34:16-23.

<sup>369</sup> *Id.*, at 33:6-14.

<sup>370</sup> *Id.*, at 34:25 – 35:8. Mr. Gallagher claims he did so because it was the practice of the LPSC to include preferred dividends.

<sup>371</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 26:12 – 27:20.

<sup>372</sup> *Id.*, at 33:4-9; *see also* ENO's Response to Data Request CCPUG 2-18 (Exh. LK-6).

## 2. Extension of Amortization of Algiers Transaction Costs to 10 Years

ENO proposes a 3-year amortization of the deferred Algiers transaction costs. ENO tied the 3-year amortization period for the deferred Algiers transaction costs to the term of the proposed E-FRP, but did not cite any reason for the 5-year amortization period for the deferred Algiers migration costs.<sup>373</sup> The proposed 3-year amortization period is too short and increases the electric base revenue requirement.<sup>374</sup> It is not tied to any specific period for any specific reason.<sup>375</sup> The proposed 3-year amortization for the deferred Algiers transaction costs, although tied to the E-FRP, has nothing to do with the proposed E-FRP and the recovery of the amortization expense will continue after the three-year term of the E-FRP until base rates are reset or the E-FRP is extended beyond the initial three-year term.<sup>376</sup> The effect of the 3-year amortization period on the Algiers transaction costs is, therefore, arbitrary and inappropriately increases the revenue requirement.

CCPUG recommends a 10-year amortization period to minimize the effect on the base revenue requirement and to minimize the potential over-recovery if the E-FRP is not renewed after its initial three-year term. The effect would be a reduction of **\$0.260 million** in the electric base revenue requirement.

## 3. Remove Algiers Migration Costs

The Algiers migration costs will be incurred in 2018 and 2019 to facilitate the billing of former Algiers customers as ENO customers and to eliminate current back-office processes and

---

<sup>373</sup> Exh. CCPUG-1 (Kollen Direct Testimony), at 33:16-21.

<sup>374</sup> *Id.*, at 34:1-3.

<sup>375</sup> *Id.*

<sup>376</sup> *Id.*, at 34:3-7.

associated expenses.<sup>377</sup> ENO forecasts that it will incur \$4.277 million in expenses for this purpose and proposes that the deferred costs be amortized over a period of five years.<sup>378</sup>

Another effect of the migration is that there will be savings to ENO. ENO's witnesses acknowledge that the migration will reduce ENO's expenses.<sup>379</sup> CCPUG recommends that the Council authorize the deferral of the Algiers migration costs for actual costs incurred, but require that the Company offset these deferrals with the savings that result, and in this manner, amortize the deferral as the savings are achieved. CCPUG further recommends that the Council remove the forecast costs from rate base and the related amortization from operating expenses.<sup>380</sup> In the event that the Company does not recover the entirety of the deferred costs in this manner, then it should seek recovery of the remaining deferred costs in its next base rate proceeding.<sup>381</sup>

The effect of CCPUG's recommendation is a reduction of **\$1.171 million** in the electric base revenue requirement.<sup>382</sup> This includes the effect of removing the costs from rate base and removing the related amortization expense.

#### **4. Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years**

ENO proposes that the amortization period for the general plant reserve deficiency be set at 10 years. CCPUG's consultants have advised that this rate is unnecessarily short given the magnitude of this general plant reserve deficiency.<sup>383</sup> This reserve deficiency was "separated" from

---

<sup>377</sup> Exh. ENO-33 (Todd / Beauchamp Direct Testimony) (ENO), at 26:19 – 27:5.

<sup>378</sup> Exh. CCPUG-1 (Kollen Direct Testimony), at 35:2-3.

<sup>379</sup> Exh. ENO-33 (Todd / Beauchamp Direct Testimony) (ENO), at 26:19 – 27:5. (Migration will "eliminate current back-office processes and associated expenses..."). *Also see* Exh. ENO-6 (Revised Direct Testimony of Melonie P. Stewart ("Stewart Revised Direct Testimony") (ENO)), at 48:8-11 ("It will also enhance ENO's operations in that, currently, there is an administratively intensive back-office process required to move payments received on former ELL-Algiers customer accounts to ENO. It will also enhance operations in that there will be fewer bills generated each month, resulting in lower mailing costs.").

<sup>380</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 35:17 – 36:2.

<sup>381</sup> *Id.*, at 36:3-5.

<sup>382</sup> *Id.*, at 36:8-10.

<sup>383</sup> *Id.*, at 37:2-11.

the general plant asset accounts and is based on a comparison of the actual depreciation reserve compared to a theoretical depreciation reserve. As ENO's depreciation expert, Mr. Clayton, has stated:

The Company has been using a scheduled retirements approach for its general plant other than structures and improvements for many years. However, the existing rates for electric general plant have been too low, and the book reserve as of the study date was approximately \$10.2 million lower than it should have been. This portion of the book reserve was separated so that it could be recovered over a 10-year period.<sup>384</sup>

Mr. Clayton testified at the hearing on the merits that there is no single asset related to this reserve deficiency; rather the reserve is tied to "vintages of assets" and "it could be more than one".<sup>385</sup> Consequently, the reserve deficiency is simply an amount to balance ENO's accounts and ensure that its plant assets are fully depreciated and recovered over time. As CCPUG's witness Mr. Kollen noted in his direct testimony, "[I]t is unusual to separate any theoretical reserve surplus or deficiency in this manner, especially for only one category of plant."<sup>386</sup>

CCPUG recommends that the Council use a more reasonable 20-year amortization period to reduce the effect on the revenue requirement. ENO still will fully recover its costs, but over a longer period of time. It also will recover a return on this cost, so it should be indifferent on a net present value basis. Adopting this recommendation would result in a reduction of **\$0.514 million** in the electric base revenue requirement.<sup>387</sup>

---

<sup>384</sup> Exh. ENO-35 (Revised Direct Testimony of Donald J. Clayton ("Clayton Revised Direct Testimony") (ENO)), at 14:15-19.

<sup>385</sup> TR, June 18, 2019 (Cross Examination of Donald Clayton), at 144:3-21.

<sup>386</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 37:9-11.

<sup>387</sup> *Id.*, at 37:19-20.



### **C. Rate of Return Issues – Inclusion of Short-Term Debt in Capitalization**

ENO proposes a capital structure of 47.80% in long-term debt and 52.20% in common equity. The exclusion of short-term debt from ENO's proposed capital structure is unreasonable when considering the fact even a modest amount of short-term debt can result in significant reductions in the base revenue requirement.<sup>388</sup> CCPUG is recommending that the Council include approximately \$16.8 million of short-term debt in the capital structure, or 2.0% of total capitalization.

ENO has available two sources of short-term debt. 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.

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. 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.

ENO has been both a borrower from and investor in the Entergy Money Pool, although it has been a borrower on balance over the last three years. In 2016, 2017 and 2018, ENO generally was a borrower from the Entergy Money Pool, except for temporary periods when it was an investor after it issued new long-term debt.<sup>389</sup> In 2018, ENO was a borrower from the Entergy Money Pool at the end of April, May, June, July, and August, although it also borrowed from the Entergy Money Pool during other months. The 13-month average short-term debt using month-

---

<sup>388</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 40:1-4.

<sup>389</sup> See *id.*, at 38:19-22 and fn. 30, referencing ENO's Response to Data Request CCPUG 2-31. (Note: The Company has designated the attachment to this response as HSPM).

end balances outstanding was \$7.870 million, although it borrowed as much as \$43.7 million on any one day.<sup>390</sup>

ENO uses short-term debt because it is the lowest cost form of financing. In 2018, the cost of its Entergy Money Pool borrowings was only \$0.153 million, or slightly less than 2.0% based on the 13-month average outstanding.<sup>391</sup> This cost compares very favorably with the Company's cost of a new long-term debt issue in September 2018 at 4.0%.<sup>392</sup> It also compares very favorably with ENO's requested cost of common equity at 10.75%, which actually is 14.65% when grossed-up for the income taxes, bad debt, and regulatory fees included in the revenue requirement.<sup>393</sup>

In his Direct Testimony, Mr. Kollen testified it is not reasonable – in other words, **it is unreasonable** – to exclude short-term debt from the capital structure and cost of capital. In particular, he testified,

**Q. *Is it reasonable to exclude short-term debt from the capital structure and cost of capital?***

A. *No.* ENO uses short-term debt to reduce its actual financing costs. However, even if it did not, it nevertheless 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>394</sup>

When asked at the hearing about the short-term debt issue, Mr. Kollen expounded on his pre-filed testimony:

Q. So to be very clear, your recommendation in this case for the purpose of setting base rates is that the Council should make a presumption that ENO is going to use short-term debt with a capital structure weighting of 2 percent; right?

A. Yes, that's correct. Because it is lower cost than long-term debt or common equity, the Company has the capacity to use it. Declaration that it will not use or

---

<sup>390</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 39:1-5.

<sup>391</sup> *Id.*, at 39:8-10.

<sup>392</sup> *Id.*, at 39:10-12.

<sup>393</sup> *Id.*, at 39:12-14.

<sup>394</sup> *Id.*, at 39:22 – 40:4. (Italics added).

doesn't plan to use it, **I don't think is a rational basis for the Council to act on this capital structure.** I think the fact is short-term debt is available. It's available at 2 percent, a fraction of the cost of long-term debt and common equity and the Company's offered no reason why it cannot or should not -- and in any event, if the Council adopts that recommendation, then Entergy is free to do whatever it wants to do. If it doesn't choose to use short-term debt, then it doesn't have to.<sup>395</sup>

If the Council agrees with Mr. Kollen that ENO's capital structure is unreasonable because it excludes all short-term debt, it may deploy a hypothetical capital structure that is reasonable.<sup>396</sup> It is reasonable to include short-term debt in the cost of capital because it is the lowest cost form of financing.<sup>397</sup> CCPUG recommends that the Council include approximately \$16.8 million of short-term debt in the capital structure so that it comprises 2.0% of total capitalization. The recommended \$16.8 million amount is very modest, and well below the \$150 million authorized by FERC. Further, the recommended 2.0% cost for the short-term debt is consistent with ENO's recent actual cost of borrowings from the Entergy Money Pool and is consistent with other short-term debt interest rates.

Adopting this recommendation would result in a reduction of **\$1.073 million** in the electric base revenue requirement and a reduction of **\$0.155 million** in the gas base revenue requirement. These quantifications are based on the electric rate base and gas rate base after the CCPUG recommended adjustments.<sup>398</sup>

## CONCLUSION

Based on the evidence and facts developed in the administrative record of this proceeding, CCPUG urges the Council to adopt its recommendations, discussed in detail, above. In particular, although not exclusively, CCPUG requests the Council, on the strength of the facts in the record

---

<sup>395</sup> TR, June 20, 2019 (Cross Examination of Lane Kollen), at 16:7 – 17:3.

<sup>396</sup> *South Central Bell Telephone Co. v. Louisiana Public Serv. Comm'n*, 594 So.2d 357, 366 (La. 1992).

<sup>397</sup> Exh. CCPUG-1 (Kollen Direct Testimony) (CCPUG), at 40:7-11.

<sup>398</sup> *Id.*, at 40:16-21.

and the applicable legal standards, to (a) order an overall rate decrease of \$51.736 million (electric and gas rates), (b) set ENO's ROE at 9.35% for electric and gas operations, (c) order ENO to remove all projected 2019 costs and related expenses from its test years for Period I and Period II, (d) likewise order ENO to utilize only historic test years (earnings review periods) in its E-FRP and G-FRP, and (e) reduce the unjustified, arbitrary, and capricious subsidies on commercial customers inherent in ENO's proposed rates by ordering the allocation among customer classes in rate design of the capacity costs associated with the EAI WBL and River Bend 30% PPAs on an equal percentage increase basis, rather than an energy basis, and (f) direct ENO to employ a 40-year service life and a 0% net salvage value for UPS for depreciation purposes, as well as a 50-year service life for NOPS revenue requirement purposes.

CCPUG requests all other relief available under the facts and the applicable law.

Respectfully submitted:

**ROEDEL, PARSONS, KOCH, BLACHE,  
BALHOFF & McCOLLISTER**

8440 Jefferson Highway, Suite 301  
Baton Rouge, LA 70809  
Telephone: (225) 929-7033  
Facsimile: (225) 928-4925

- and -

1515 Poydras Street, Suite 2330  
New Orleans, Louisiana 70112  
Telephone: (504) 525-7086  
Facsimile: (504) 525-4991

By: \_\_\_\_\_



Luke F. Piontek (Bar Roll #19979)  
J. Kenton Parsons (Bar Roll # 10377)  
Charles M. Pisano (Bar Roll # 19107)  
Christian J. Rhodes (Bar Roll # 31935)  
George W. Hardy, IV (Bar Roll # 38012)

***Counsel for Crescent City Power Users' Group***



## CERTIFICATE

I hereby certify that on this day a copy of the foregoing Crescent City Power Users' Group's Initial Post-Hearing Brief has been sent to the official service list by email, and/or served by United States mail, postage prepaid, through their representatives, at the following addresses:

**Lora W. Johnson**  
[lwjohnson@nola.gov](mailto:lwjohnson@nola.gov)

Clerk of Council  
City Hall- Room 1E09  
1300 Perdido Street  
New Orleans, LA 70112

**Erin Spears**, [espears@nola.gov](mailto:espears@nola.gov)

Chief of Staff

**Bobbie Mason**, [bfmason1@nola.gov](mailto:bfmason1@nola.gov)

**Connolly A. F. Reed**, [careed@nola.gov](mailto:careed@nola.gov)

City Hall - Room 6E07  
1300 Perdido Street  
New Orleans, LA 70112

Andrew Tuozzolo

CM Moreno Chief of Staff

City Hall- Room 2W40

1300 Perdido Street

New Orleans, LA 70112

[avtuozzolo@nola.gov](mailto:avtuozzolo@nola.gov)

**David Gavlinski**, [dsgavlinski@nola.gov](mailto:dsgavlinski@nola.gov)

Council Chief of Staff

City Hall - Room 1E06

1300 Perdido Street

New Orleans, LA 70112

**Sunni LeBeouf**, [Sunni.LeBeouf@nola.gov](mailto:Sunni.LeBeouf@nola.gov)

**Michael J. Laughlin**, [mjlaughlin@nola.gov](mailto:mjlaughlin@nola.gov)

**Mary Katherine Kauffman**,

[mkkaugman@nola.gov](mailto:mkkaugman@nola.gov)

Law Department

City Hall - 5th Floor

New Orleans, LA 70112

**Norman White**, [Norman.White@nola.gov](mailto:Norman.White@nola.gov)

Department of Finance

City Hall - Room 3E06

1300 Perdido Street

New Orleans, LA 70112

**Hon. Jeffrey S. Gulin**,

[judgegulin@gmail.com](mailto:judgegulin@gmail.com)

3203 Bridle Ridge Lane

Lutherville, MD 2109

**Basile J. Uddo**

**J.A. "Jay" Beatmann, Jr.**

c/o DENTONS US, LLP

650 Poydras Street

Suite 2850

New Orleans, LA 70130

[buddo@earthlink.net](mailto:buddo@earthlink.net)

[jay.beatmann@dentons.com](mailto:jay.beatmann@dentons.com)

**Clinton A. Vince**,

[clinton.vince@dentons.com](mailto:clinton.vince@dentons.com)

**Presley Reed**, [presley.reedjr@dentons.com](mailto:presley.reedjr@dentons.com)

**Emma F. Hand**,

[emma.hand@dentons.com](mailto:emma.hand@dentons.com)

1900 K Street NW

Washington, DC 20006

**Joseph W. Rogers**,

[jrogers@ergconsulting.com](mailto:jrogers@ergconsulting.com)

**Victor M. Prep**, [vprep@ergconsulting.com](mailto:vprep@ergconsulting.com)

**Byron S. Watson**,

[bwatson@erconsulting.com](mailto:bwatson@erconsulting.com)

Legend Consulting Group

6041 South Syracuse Way, Suite 105

Greenwood Village, CO 80111

**Errol Smith**, [ersmith@btcpas.com](mailto:ersmith@btcpas.com)  
Bruno and Tervalon  
4298 Elysian Fields Avenue  
New Orleans, LA 70122

**Gary H. Huntley**  
Entergy New Orleans, Inc.  
Manager, Regulatory Affairs  
1600 Perdido Street, L-MAG 505B  
New Orleans, LA 70112  
[guntle@entergy.com](mailto:guntle@entergy.com)

**Tim Cragin**  
**Brian L. Guillot**  
**Alyssa Maurice-Anderson**  
Entergy Services, Inc.  
Mail Unit L-ENT-26E  
639 Loyola Avenue  
New Orleans, LA 70113  
[tcraigin@entergy.com](mailto:tcraigin@entergy.com)  
[bguill@entergy.com](mailto:bguill@entergy.com)  
[amauric@entergy.com](mailto:amauric@entergy.com)

**Joe Romano, III**  
**Suzanne Fontan**  
**Therese Perrault**  
Entergy Services, Inc.  
Mail Unit L-ENT-4C  
639 Loyola Avenue  
New Orleans, LA 70113  
[jromani@entergy.com](mailto:jromani@entergy.com)  
[sfontan@entergy.com](mailto:sfontan@entergy.com)  
[tperrau@entergy.com](mailto:tperrau@entergy.com)

**Logan Atkinson Burke**,  
[logan@all4energy.org](mailto:logan@all4energy.org)  
**Sophie Zaken**,  
[regulatory@all4energy.org](mailto:regulatory@all4energy.org)  
4505 S. Claiborne Ave.  
New Orleans, LA. 70125

**Katherine W. King**,  
[Katherine.king@keanmiller.com](mailto:Katherine.king@keanmiller.com)  
**Randy Young**,  
[randy.young@keanmiller.com](mailto:randy.young@keanmiller.com)  
400 Convention St. Suite 700

Baton Rouge, LA. 70802

**Carrie R. Turnillon**,  
[carrie.tournillon@keanmiller.com](mailto:carrie.tournillon@keanmiller.com)  
900 Poydras St., Suite 3600  
New Orleans, LA 70112

**Mark Zimmerman**,  
[zimmermr@airporducts.com](mailto:zimmermr@airporducts.com)  
720 I Hamilton Blvd.  
Allentown, PA. 18195-1501

**Maurice Brubaker**,  
[mbrubaker@consultbai.com](mailto:mbrubaker@consultbai.com)  
16690 Swigly Ridge Rd., Suite 140  
Chesterfield, MO 63017

**Brian L. Guillot**, [bguill1@entergy.com](mailto:bguill1@entergy.com)  
**Polly S. Rosemond**, [prosemo@entergy.com](mailto:prosemo@entergy.com)  
**Derek Mills**, [dmills3@entergy.com](mailto:dmills3@entergy.com)  
**Keith Woods**, [kwood@entergy.com](mailto:kwood@entergy.com)  
**Seth Cureington**, [scurein@entergy.com](mailto:scurein@entergy.com)  
**Kevin T. Boleware**, [kbolewa@entergy.com](mailto:kbolewa@entergy.com)  
1600 Perdido Street, L-MAG 505B  
New Orleans, LA 70112

**Renate Heurich**,  
[350louisiana@gmail.com](mailto:350louisiana@gmail.com)  
1407 Napoleon Ave,#C  
New Orleans, LA, 70115

**Andy Kowalczyk**,  
[a.kowalczyk350no@gmail.com](mailto:a.kowalczyk350no@gmail.com)  
1115 Congress St.  
New Orleans, LA 70117

**Susan Steven Miller**,  
[smiller@earthjustice.org](mailto:smiller@earthjustice.org)  
[aluna@earthjustice.org](mailto:aluna@earthjustice.org)  
[nthorpe@earthjustice.org](mailto:nthorpe@earthjustice.org)  
25 Massachusetts Ave., NW, Ste. 702  
Washington, DC 20036



**Myron Katz, PhD.,**  
[Myron.bernard.katz@gmail.com](mailto:Myron.bernard.katz@gmail.com)  
302 Walnut St  
New Orleans, La 70118

**Julie DesOrmeaux Rosenzweig,**  
[Julie.Rosenzweig@sierraclub.org](mailto:Julie.Rosenzweig@sierraclub.org)  
PO Box 8619  
New Orleans, LA 70182

**John H. Chavanne,** [jchav@bellsouth.net](mailto:jchav@bellsouth.net)  
111 West Main St., Suite 2B  
PO Box 807  
New Roads, LA 70760-8922

**Brian A. Ferrara,** [bferrara@swbno.org](mailto:bferrara@swbno.org)  
**Yolanda Y. Grinstead,**  
[ygrinstead@swbno.org](mailto:ygrinstead@swbno.org)  
Legal Department  
625 St. Joseph St., Rm 201  
New Orleans, LA 70165

**Lane Kollen** ([lkollen@jkenn.com](mailto:lkollen@jkenn.com))  
**Stephen Baron** ([sbaron@jkenn.com](mailto:sbaron@jkenn.com))  
**Randy Futral** ([rfutral@jkenn.com](mailto:rfutral@jkenn.com))  
**Richard Baudino** ([rbaudino@jkenn.com](mailto:rbaudino@jkenn.com))  
**Brian Barber** ([brbarber@jkenn.com](mailto:brbarber@jkenn.com))  
J. Kennedy & Associates  
570 Colonial Park Dr., Suite 305  
Rosewell, Ga. 30075

**Rev. Gregory Manning,**  
[gmanning1973@yahoo.com](mailto:gmanning1973@yahoo.com)  
**Pat Bryant,** [pat46bryant@yahoo.com](mailto:pat46bryant@yahoo.com)  
**Happy Johnson,** [hjohnson1081@gmail.com](mailto:hjohnson1081@gmail.com)  
**Sylvia McKenzie,** [sylkysmooth.sm@cox.net](mailto:sylkysmooth.sm@cox.net)  
c/o A Community Voice  
2221 St. Claude Ave.  
New Orleans, LA 7011

**Grace Morris,**  
[Grace.Morris@sierraclub.org](mailto:Grace.Morris@sierraclub.org)  
4422 Bienville Ave  
New Orleans, LA 70119

**Dave Stets,** [Dave.Stets@BySolar.net](mailto:Dave.Stets@BySolar.net)  
2101 Selma St.  
New Orleans, LA 70122

New Orleans, Louisiana, this 26<sup>th</sup> day of July, 2019.



---

**LUKE F. PIONTEK**