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August 9, 2019

Lora W. Johnson, CMC, LMMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: *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*
Council Docket No. UD-18-07

Dear Ms. Johnson:

On behalf of Entergy New Orleans, LLC ("ENO" or the Company), please find enclosed for your further handling an original and three copies of the Post-Hearing Reply Brief of Entergy New Orleans, LLC, which I would appreciate your filing into the record of this proceeding. Please file an original and two copies into the record in the above referenced matter, and return a date-stamped copy to our courier.

All service copies are being provided by electronic means. No hard copies will be sent. Should you or the any representative of the parties have difficulty accessing the electronic files, or otherwise have any questions regarding this filing, please do not hesitate to contact me.

With kindest regards, I remain

Sincerely,

Alyssa Maurice-Anderson

AMA/amb
Enclosures
cc: Official Service List (*via email only*)

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

POST-HEARING REPLY BRIEF OF ENTERGY NEW ORLEANS, LLC

AUGUST 9, 2019

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POST-HEARING REPLY BRIEF OF ENTERGY NEW ORLEANS, LLC

Entergy New Orleans, LLC ("ENO" or the "Company"), through its undersigned counsel, respectfully submits this Post-Hearing Reply Brief in support of its request that the Council of the City of New Orleans ("Council") grant the relief sought in its 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 and supporting testimony and work papers ("Rate Case Filing") submitted to the Council on September 21, 2018, finding, among other things, ENO's proposed electric and gas rates to be just and reasonable.

I. INTRODUCTION

Throughout this case and in its initial post-hearing brief, the Company has spoken clearly and consistently about the need to have a strong cornerstone and foundation in place in order to achieve goals for transformational change shared by all stakeholders. No party has addressed, much less challenged, this fundamental premise underlying the Company's rate case application. The Company has laid out a bold vision for the future of ENO and the City of New Orleans — one of resilience, renewable and base load resources; a 21st century self-healing grid; accommodations of distributed generation; and support for evolving technology, such as electric vehicles, just to name a few—a vision to which all parties subscribe. The Company's rate plan is designed to provide the cash flow and financial stability required to make this vision a reality — it is a regulatory plan aligned with shared and far-reaching 21st century goals.

In response, the parties advocate outmoded business-as-usual positions in a scattershot approach to lessening cash flow and financial stability, without mentioning that their positions necessarily translate into lowered expectations for the long term and are at odds with the Council's objectives. The Advisors' and Intervenors' attacks on the constructive regulatory environment, which is necessary to support the transformational changes to utility service called for by the Council and ENO's customers, are disappointing at best. The Council should not be persuaded to take a course of action that will harm customers in the long-term for a perceived short-term, short-sighted benefit.

The parties claim that the Company is over-reaching in seeking an authorized Return on Equity ("ROE") of 10.75% and in requesting the approval of riders for the recovery of specific investments. They are wrong on both counts. ENO is not over-reaching; in fact, the Company is matching what is sought to be accomplished with reasonable and necessary means to accomplish it. For example, the Advisors complain that ENO views a constructive regulatory environment as "allowing ENO a notably high ROE relative to those recommended by other witnesses." However, with respect to the ROE recommendation, the parties have failed to give appropriate consideration—and in some cases no consideration at all—to the requirement of *Hope* and *Bluefield* to evaluate utilities of *comparable risk.* Mechanically applying formulae without taking into account comparable risk will lead to an answer that falls short of *Hope* and *Bluefield;* credit rating agencies will recognize the defective reasoning as well as the inadequate result. Perhaps it is for this reason that no party was able to muster any response to the Company's proof that the retail regulator's award of an inadequate ROE in a rate case—one that no doubt was supported by an expert applying a formula—resulted in the effective credit downgrade of Entergy Arkansas, LLC ("EAL"); no party dared to suggest that this result would not happen as a consequence of their recommendation in this case.

ENO's requested ROE is consistent with what both *Hope* and *Bluefield* require in these circumstances. ENO is one of the three riskiest utilities in the United States; that is indisputable. Therefore, ENO should have one of the highest ROEs in the industry. *Hope* states that the "balancing of the investor and the consumer interests" requires that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[1] Similarly, *Bluefield* requires a return equal to that being made on investments and business undertakings "which are attended by corresponding risks and uncertainties."[2] The Advisors overlook these standards from *Hope* and *Bluefield*, and the ROE witnesses, other than Mr. Hevert, do not apply these standards to their analyses. One of the other two riskiest utilities in the U.S. has an authorized ROE of 10.75%. None of the other utilities that the Intervenors point to are as risky as ENO. Therefore, ENO's proposed ROE is reasonable, justified under the circumstances, and should be approved.

Furthermore, the Advisors and Intervenors' positions on riders are factually incorrect; the positions are also erroneous as a matter of sound public policy. Certain parties contend that base rate recovery is being supplanted by exact recovery through riders. As is shown in Table 1 below, this is false. Parties claim that the proposed Riders will lead to out-of-control spending by the Company. This is also false. The Riders proposed by ENO are tailored to specific, large investments—ones that are to be made over an extended period of time according to a detailed plan and that require significant cash flow to develop and support long-lived assets. Each rider provides a meaningful opportunity for review of expenditures by the Council prior to their incurrence, as well as Council review of management and execution after their incurrence.

As to the disingenuous claim that the Riders constitute prohibited single-issue ratemaking, it is obvious that such principle has exceptions,[3] such as when single-issue ratemaking did not prohibit a rate action to provide customers the benefits of the Tax Cut and

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[1] *Federal Power Comm'n v. Hope Nat. Gas Co*., 320 U.S. 591, 603 (1944).

[2] *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679, 692-693 (1923).

[3] Exhibit ADV-1 (Rogers Direct) at 17-18 ("[R]iders may be used to provide for the recovery of significant costs incurred between full rate case proceedings that were not otherwise accounted for in base rates.").

Jobs Act of 2017 ("Tax Cut Act"). In much the same vein, ENO is proposing the Riders to reduce regulatory lag between FRP rate adjustments so that ENO has a reasonable opportunity to earn its authorized return.[4] Furthermore, the potential for any adverse consequences from single-issue ratemaking is substantially mitigated in the Company's rate plan, while the advantages of Rider recovery are substantial. Riders operating in tandem with appropriate Electric and Gas Formula Rate Plans ("FRPs") provide parties and the Council the opportunity to scrutinize all of ENO's costs on an annual basis.

As to the disingenuous claim that the Riders constitute prohibited single-issue ratemaking—a violation of an alleged bedrock principle that did not seem to prohibit the rate treatment based on the Tax Cut Act—it is obvious that there is no such prohibition. The potential for any adverse consequences from single-issue ratemaking is substantially mitigated in the Company's rate plan, while the advantages of Rider recovery are substantial. Riders operating in tandem with appropriate Electric and Gas FRPs provide parties and the Council the opportunity to scrutinize ***all of ENO's costs*** on an annual basis.

Moreover, exact cost recovery mechanisms exist in ENO's current rate structure, and no one has claimed that ENO enjoys a guaranteed recovery today. Likewise, there will be no guarantee going forward under ENO's proposals because ENO is proposing to reduce the costs included in riders in which revenues and costs are reconciled. The Advisors' statements concerning the scope of exact cost recovery and focus on "new costs" are misleading and ignore the details of ENO's proposals. For example, the Purchased Power and Capacity Acquisition Cost Recovery ("PPCACR") Rider exists today, and the rider provides for reconciled exact cost recovery.

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[4] Exhibit ENO-3 (Thomas Rebuttal) at 32.

ENO is proposing to greatly reduce the costs recovered through the PPCACR Rider by realigning them for recovery primarily through base rates. More specifically, today, the Legacy ENO Ninemile 6 Purchase Power Agreement ("PPA") and Union Power Station Power Block 1 ("Union PB1") non-fuel revenue requirement, approximately $64 million on an annual basis, is recovered through the PPCACR Rider. In this proceeding, ENO proposes that those costs be recovered through base rates. Also, today there are two MISO cost recovery riders, one for Legacy ENO Customers and another for Algiers Customers, that provide for reconciled exact cost recovery of a segment of MISO charges and other costs. The new Combined MISO Rider, which is uncontested, will continue the exact cost recovery of certain MISO non-fuel charges only. Thus, the scope of rider recovery is being reduced by ENO's proposals. There is no evidentiary basis for the Council to conclude that ENO is reducing its risk of recovering its electric and gas revenue requirements through its proposed rate structure; instead, ENO is seeking to maintain a constructive regulatory environment by mitigating regulatory lag through tailored riders, if FRPs with forward-looking adjustments are not established.

Furthermore, the Advisors', Crescent City Power Users Group ("CCPUG")'s, and Air Products and Chemicals, Inc.'s ("APC") discussions of incentives for the utility to continue reducing their costs are for measures that would imperil ENO's financial condition. As ENO stated previously, the stated objectives of the Council require ENO to increase its expenditures, not reduce them. The Council-approved Advanced Metering Infrastructure ("AMI") Project, Grid Modernization Project, 100 megawatts ("MW") of renewable resources, and the New Orleans Power Station ("NOPS") will increase ENO's rate base in the near-term. Similarly, the Council has been critical of ENO's electric distribution reliability, and, accordingly, it is necessary to increase Distribution Reliability and Vegetation Management Spending to improve

ENO's reliability performance.[5] If the Council approves ratemaking treatments that reduce ENO's equity return because of planned cost increases, such as a FRP sharing mechanism or a ROE that is unreasonably low or toward the bottom of the zone of reasonableness, when the Council knows full well that cost increases are necessary to meet their objectives, then the Council would not be providing a constructive regulatory environment.

Despite CCPUG's claims that its positions taken in this case will benefit ENO's customers as a whole, CCPUG clearly has only its own interests in mind. CCPUG in its initial brief focuses on the roughly $31.7 million that ENO customers would save if the Council adopts CCPUG's arguments while conveniently omitting the fact that adoption of its positions will primarily benefit its current members at the expense of ENO's other customers, without justification for doing so and irrespective of the fact that its proposal would shift costs to future customers who are likely to receive little to no benefit from the Company's current investments. Although CCPUG purports to advocate for improving household incomes, its arguments are inconsistent with its advocacy and do not promote balance with respect to the interests of the stakeholders involved. Specifically, CCPUG's argues that the service lives of Union PB1 and NOPS should be longer and thus depreciation expense recovered over a more extended period of time than proposed by ENO. This argument is not supported by the record evidence, and it would result in future ENO customers paying for investments that have since been retired and from which they received no benefit.

Further, although CCPUG favors ENO making significant infrastructure upgrades and service improvements that will require the Company to make considerable capital investment, CCPUG opposes the implementation of all but one of the riders proposed by ENO. The riders

[5] The Company will reduce costs in other areas wherever reasonably possible.

are reasonable mechanisms to enable ENO to timely recover the costs of such investment, which is necessary to maintain positive cash flow and in turn ENO's financial condition. The one rider CCPUG does support is a customer-specific charge rider for the AMI Project, which will result in recovery of most of the costs of that program from ENO's residential class. CCPUG's approach to ENO's proposed rates is inconsistent, disingenuous and self-serving, and has no support in sound regulatory policy or principles.

In sum, there is no valid reason to chip away or destroy the cornerstone and foundation for the 21st century utility that the Company seeks to put in place with responsible and innovative regulatory proposals by adopting an unreasonably low ROE with a regulatory paradigm that fails to keep pace with transformative investment and does not serve the public interest. As CCPUG notes, no party disputes that ENO is entitled to the opportunity to earn a reasonable ROE.[6] The disagreement among the parties is over 1) what level of ROE is required and 2) what constitutes a reasonable opportunity for the Company to earn its authorized return.

II. <u>CONTESTED ISSUES</u>

A. As shown by its credit ratings, ENO is one of the riskiest companies in the industry, and, therefore, it should have one of the highest ROEs in the industry; the other parties' recommendations ignore this indisputable fact.

All parties agree on the regulatory principles outlined by the United States Supreme Court in the two seminal cases governing the establishment of a ROE for regulated entities in *Hope*[7] and *Bluefield*.[8] It is both well-established and unchallenged that ENO should be allowed a return that is comparable to other entities with similar risks, sufficient to assure confidence in its

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6 CCPUG Brief at 20-21.

7 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944).

8 *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n* of W. Va., 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923).

financial soundness, adequate to maintain creditworthiness, and will allow it to raise necessary capital.[9]

However, in this proceeding, other parties have misapplied these principles in two fundamental ways. They have argued that the ROE proposed by the Company is in excess of what the Company's peers have received in the last several years. The fallacy in this argument is that the other parties have assumed that, as the Supreme Court put it in *Bluefield*, the entities to which the parties are comparing ENO have "corresponding risks."[10] But this is not the case. As will be discussed in much greater detail below, ENO is one of only three utilities in the entire country with a below investment grade credit rating. This fact puts these companies in a class by themselves and makes simple comparisons to other utilities problematic and inappropriate. Second, even if ENO were a "normal" utility with credit ratings that were comparable to its peers, the other parties' proposed ROEs are still uniformly too low – especially the Advisors' 8.93% recommendation.

ENO is at a critical juncture in its history. The Company is in the process of transforming itself—with its AMI Project, its Grid Modernization Project, its move to increase investment in renewable and community solar resources, its Gas Infrastructure Replacement Program ("GIRP")—into the modern, efficient utility that its customers and the Council desire. But authorization of the 8.93% ROE proposed by the Advisors or the 9.35% ROE recommended by other Intervenors for a below-investment-grade utility like ENO would stifle the Company's modernization efforts. It would also send a clear signal to equity investors about the Council's view on the value of their investment and would not maintain a constructive regulatory

9 *Hope,* 320 U. S. at 605, 64 S. Ct. at 289; *Bluefield, CCPUG*-262 U.S. at 692-93, 43 S. Ct. at 679.

10 *Bluefield,* 262 U.S. at 692-93, 43 S. Ct. at 679.

environment at this critical time when the Council and the Company desire to provide new technologies and enhanced service to customers. Although the Company has a plan that allows it to make the transformational investments to modernize ENO's service to customers, while maintaining the Company's financial condition and affordable rates, successfully executing that plan depends on the Council's taking constructive steps to maintain ENO's financial condition, especially setting a reasonable ROE.[11]

Other parties attack the Company's proposed ROE in exaggerated terms. CCPUG describes the request as "egregious."[12] APC refers to Mr. Hevert's 10.75% recommendation as "grossly overstated."[13] The Advisors refer to Mr. Hevert's recommendation as an "outlier."[14] For example, CCPUG observes that Mr. Hevert's recommendation would be the highest ROE awarded in the last 18 months, exceeds the average ROE authorized in the last five years, and is higher than all but one ROE authorized in the last five years.[15] Similarly, APC argues that Mr. Hevert's recommended ROE is higher than all but one authorized ROE since 2014 and is higher than all awarded ROEs in 2018 and 2019.[16] Other parties also complain that Mr. Hevert's recommendation is not supported by his own analyses, and that he "ignored" certain of his model results.[17]

These comparisons and descriptions might have some applicability if ENO was a typical or average utility. However, the record in this case demonstrates that ENO is not a typical or

[11] Exhibit ENO-1 (Thomas Revised Direct) at 6-7.

[12] CCPUG Brief at 13.

[13] Air Products Brief at 15-16.

[14] Advisors Brief at 31-32.

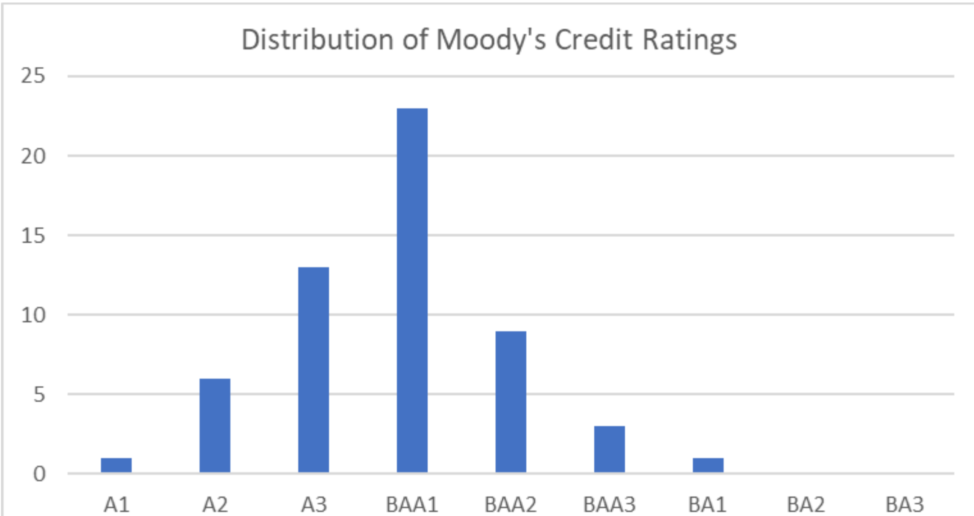
[15] CCPUG Brief at 28.

[16] Air Products Brief at 15.

[17] See, *e.g.*, CCPUG Brief at 30-33; Air Products Brief at 15-20; Advisors Brief at 27-31.

average utility. In fact, it is far from a typical or average utility. As mentioned earlier here, ENO is one of only three utilities in the entire country that has a below investment grade credit rating. The histogram below illustrates how different ENO is from the rest of the industry with respect to its credit rating from Moody's:

Figure 1[18]



Note: PG&E Corp. and SCANA Corp. are not shown. PG&E is rated D by S&P, but is not rated by Moody's. SCANA Corp., was acquired by Dominion Energy, Inc.

The graph shows that the large majority of utility operating companies (77%) are rated Baa1 and higher, only 21% are rated Baa2 or Baa3 (still investment grade), and that ENO is the only electric utility operating company with a below investment grade rating.[19] The only other utility in the country with a split rating like ENO was recently awarded a 10.75% ROE by the public utility commission in South Carolina - the same ROE that Mr. Hevert is proposing in this case.[20]

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18 Source: Exhibit ENO-30 (HSPM Hevert Rebuttal Workpapers), "Revised Hevert ENO Rebuttal Workpapers HSPM 4.22.19", worksheet labeled "Industry Credit Ratings".

19 The other utility companies with below investment grade ratings are parent companies. Exhibit ENO-31 (Hevert Rejoinder) at 2, fn 1, 2.

20 Exhibit ENO-31 (Hevert Rejoinder) at 2-3, <u>citing</u> Public Service Commission of South Carolina, Docket

All of the other parties either ignore this fact or twist the facts to minimize its impact. The best argument Advisors' witness Mr. Watson could come up with is an unsupported opinion that Moody's gave undue weight to ENO's geography and storm risk in rating ENO below investment grade.[21] Nevertheless, Mr. Watson conceded that comparable credit ratings are an appropriate metric in identifying companies with corresponding risks, that Moody's is a qualified and reputable rating agency widely used to rate utility credit, that he himself is not qualified to issue credit ratings, and that he did no analysis to determine whether Moody's rating for ENO is correct.[22] Further, the other parties are disingenuous in their treatment of ENO's risks as compared to those of the industry. What the Advisors and Intervenors fail to acknowledge is that the utilities included in all their various comparisons have above investment grade credit ratings.[23] Mr. Hevert illustrated the point when testifying at hearing:

> The simple fact that the Company is among the few below investment grade ratings sets it apart from all others. So to suggest that the Company should have an authorized return equal to the return available to investment grade utilities, I think, is incorrect.[24]

The chart below graphically illustrates the relationship between the credit ratings of utility operating companies and their authorized ROEs. The chart shows an inverse relationship between credit ratings and authorized ROEs; that is, the lower a company's credit rating, the higher its authorized ROE:

Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2018-804, *Order Addressing South Carolina Electric & Gas Nuclear Dockets* (December 21, 2018) at 90.

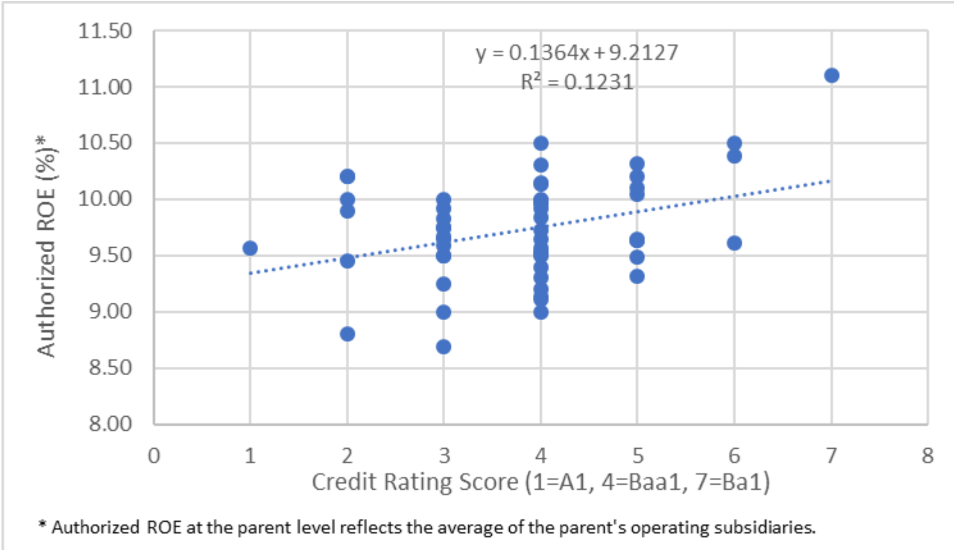
21 Tr. (Watson) 06/21/19 at 44.

22 Tr. (Watson) 06/21/19 at 40, 43-44.

23 Tr. (Hevert) 06/19/19 at 46-47; Exhibit ENO-31 (Hevert Rejoinder) at 32.

24 Tr. (Hevert) 06/19/19 at 62-63.

Figure 2[25]



The disparity depicted in the chart above has real-world consequences. And it should be reflected in how parties determine their ROE recommendations in this case. Moody's attributes the Company's below investment grade rating to the risks of its small size, lack of customer-base diversity, and geographic location and severe weather. These risks are significant but are not accounted for in the other parties' proxy groups or their ultimate ROE recommendations. Analysts note that utilities face risks associated with these factors. Because equity investors will consider these factors in determining the required return for their investment, the Council should consider them as well.[26]

Each of the various models and their inputs used by the respective parties' ROE witnesses will be discussed in greater detail below. But it is important to understand the framework in which these models results are considered. As indicated in ENO's Initial Brief, Mr. Hevert was the *only* ROE witness in the proceeding to consider all four of the ROE

25 Souce: Exhibit ENO-32 (HSPM Hevert Rejoinder workpapers), "Hevert Rejoinder Workpapers", worksheet labeled "Past Rate Cases".

26 Exhibit ENO-31 (Hevert Rejoinder) at 26-27.

methodologies that the Federal Energy Regulatory Commission ("FERC") has determined should be considered in order to satisfy the Supreme Court's *Hope* and *Bluefield* standards under present market conditions.[27]

Not only did the other parties' witnesses fail to perform the four analyses specified by FERC, they relied (either exclusively, in the case of the Advisors, or excessively, in the case of CCPUG and APC) on a single model – the discounted cash flow ("DCF") method – that, as was discussed at length in ENO's Initial Brief, the FERC and other regulatory agencies have recognized provides misleading results given current economic conditions.[28]

Alternative models must be considered, and the results of each should be examined in the context of relevant market information in assessing their appropriateness for consideration in estimating an ROE.[29] Principal use of a single model is not common in financial theory or practice, because no single model provides enough precision to determine a fair ROE.[30] The results of each methodology are evidence to assist in exercising judgment to estimate the ROE.[31] No individual model is more reliable than all the others under all market conditions.[32] Estimating a company's cost of equity involves a complicated and difficult analysis, so more than one model should be used to obtain as much useful and relevant data as possible, and no one model should be used mechanically or exclusively.[33] Employing multiple methodologies can

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27 ENO Brief at 42-43.

28 Exhibit ENO-29 (Hevert Revised Rebuttal) at 9-11.

29 *Id*. at 10.

30 *Id*. at 7, *citing* Roger A. Morin, *New Regulatory Finance*, Public Utility Reports, Inc., 2006, at 428.

31 *Id*.

32 Exhibit ENO-26 (Hevert Revised Direct) at 16.

33 Exhibit ENO-29 (Hevert Revised Rebuttal) at 7.

mitigate the effects of assumptions and inputs associated with any single model.[34] Determining an ROE based strictly on the use and results of a particular financial model, as the Advisors did in this case, can run afoul of the principles espoused in *Hope* and *Bluefield*.

The other parties then compound their error of relying to such a large extent on the faulty DCF methodology by criticizing Mr. Hevert for *ignoring* the results of his DCF (and certain other) analyses.[35] However, Mr. Hevert did not ignore any of his various models' results. As he explained several times at hearing, those results fell at the lower end of the range of ROE results developed from all of the models he considered. He recommended a ROE from the higher end of that range based on ENO's credit rating and risk profile. Further, he determined that the DCF model is subject to several assumptions that are inconsistent with current market conditions, such that results from the model should be given less weight, which is consistent with the recent treatment of such results by other regulatory commissions, including the FERC.[36] Mr. Hevert explained how he factored his DCF results into the development of his recommendation as follows:

> When I look at all the results, even the lowest of the discounted cash flow model results up to the highest of the capital asset pricing model results, I think about the range and then we go back and look at the models and try to understand what the models are saying, how they're developed, what they assume, how its construction aligns with the current capital market. But then . . . we consider the fact that the Company does have a split credit rating . . one of . . . less than a handful of companies in that circumstance. So when I look at all the results and I look at the range of results, we have to think about where the cost of equity generally lies. I do not think a number toward the average properly reflects the Company's risk. I think we have to look toward the upper end of the range. So the discounted cash flow models did inform the range. They were part of it.[37]

34 Exhibit ENO-26 (Hevert Revised Direct) at 16.

35 *See, e.g.,* CCPUG Brief at 30-33; Advisors Brief at 27-31.

36 Exhibit ENO-29 (Hevert Revised Rebuttal) at 120-121.

37 Tr. (Hevert) 06/19/19 at 59.

This is not rejection of the DCF model or cherry-picking between the results of Mr. Hevert's analyses; it is using all four models now required by the FERC to develop a range of potential ROEs, and then carefully and thoughtfully applying sound and reasoned judgment based on significant experience in the industry to determine the appropriate ROE from the range of results obtained.

It is this application of sound and reasoned judgment that the other parties failed to employ. It is undisputed that the average ROE award for vertically-integrated electric utilities (excluding limited issue riders) from January 2014 through February 2019 is 9.79%.[38] Mr. Hevert explained in great detail and justified why the greater than average risk associated with an investment in ENO justifies a higher than average ROE. But the other parties never offered a cogent explanation of why investors in a utility lacking an investment grade credit rating should earn a return that is *significantly below* the average ROE; and there is no defensible explanation for this result. It makes no sense and the Council should reject this unreasonable result.

1. Mr. Hevert's Consideration of the Results of Four Separate Models to Determine the Range of Equity Returns was Appropriate.

a. DCF Methodology

In its simplest form, the Constant Growth DCF model expresses a company's ROE as the discount rate setting the current price equal to expected cash flows, and assumes that the current price represents the present value of all expected future cash flows.[39] The model also assumes

[38] CCPUG Brief at 13 fn no. 49; Exhibit ENO-29 (Hevert Revised Rebuttal) at 5, fn no. 6.

[39] Exhibit ENO-26 (Hevert Revised Direct) at 16.

there will never be a change in growth rates, dividend yields, Price/Earnings ("P/E") ratios, Market/Book ratios, or the conditions that support those variables.[40]

Many of the fundamental assumptions underlying the DCF model are inconsistent with the current market environment.[41] None of the parties to this case dispute this fact. Specifically, firms are not paying dividends at a constant yield; constantly changing stock prices and dividend policies result in continuously changing dividend yields, contrary to the DCF model assumption.[42] Also, although the model assumes the P/E ratio will remain constant in perpetuity, utility-sector P/E ratios have expanded such that they recently exceeded their long-term average and the broader market P/E ratio.[43] The DCF model's assumptions do not match practice given the influence on capital market conditions from changing monetary policy. Given these changing monetary policy initiatives and capital market conditions, Mr. Hevert recommends caution in the weight given to the DCF approach to estimating ROE.[44] As explained in ENO's Initial Brief, this is the same reason why the FERC and other regulatory authorities recognize that the DCF model will not produce reliable results given current economic conditions.[45]

For his price and dividend inputs into the DCF model, Mr. Hevert based the dividend yield on the proxy companies' current annualized dividend and used the average closing stock prices for the 30-, 90- and 180-day trading periods ending June 15, 2018.[46] Mr. Hevert used those three different time periods to avoid having the model skewed by abnormal events

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[40] Exhibit ENO-29 (Hevert Revised Rebuttal) at 10.

[41] *Id*. at 10-11.

[42] *Id*.

[43] Exhibit ENO-26 (Hevert Revised Direct) at 23.

[44] *Id*.

[45] Exhibit ENO-29 (Hevert Revised Rebuttal) at 9.

[46] Exhibit ENO-26 (Hevert Revised Direct) at 17, 21.

affecting stock price on a particular day and to reasonably reflect expected long-term capital market conditions.[47] He also applied half of the long-term growth rate to the current dividend yield so that the expected dividend yield, on average, represents and does not overstate the dividends to be paid in the next 12 months.[48] He then calculated the DCF results using long-term growth estimates from three different sources: Zack's, First Call, and Value Line.[49] He calculated the mean, mean high and mean low DCF results for each of his proxy companies. The results of his Constant Growth DCF model are set forth in the table below:[50]

Table 3: Constant Growth DCF Results[51]

	Mean Low	Mean	Mean High
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%

To account for limiting assumptions underlying the Constant Growth DCF, Mr. Hevert also employed a Multi-Stage DCF methodology, which allows input of growth rates over three separate stages.[52] This avoids the model's typical assumption of the same growth rate in perpetuity.[53] The Multi-Stage DCF also calculates the dividend as a product of Earnings Per Share ("EPS") and the payout ratio, which allows for assumptions regarding timing and extent of payout ratio changes to reflect increases or decreases in capital spending or transitions from

47 *Id*. at 18.

48 *Id*.

49 *Id*. at 21.

50 Mr. Hevert updated his analyses in his Rebuttal Testimony but the updated results did not cause him to change his ROE recommendation. *See* Exhibit ENO-29 (Hevert Revised Rebuttal) at 154.

51 Exhibit ENO-26 (Hevert Revised Direct) at 22.

52 Exhibit ENO-26 (Hevert Revised Direct) at 24-25.

53 *Id*. at 26.

current to long-term expected payout levels.[54] Just as with the Constant Growth variant of the model, the Multi-Stage DCF defines the cost of equity as the discount rate setting the current price equal to the discounted value of future cash flows.[55]

The results of Mr. Hevert's Multi-Stage DCF analyses are set forth below:[56]

Table 6: Multi-Stage DCF Model Results[57]

	Mean Low	Mean	Mean High
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%

Other parties criticize Mr. Hevert's Constant Growth and Multi-Stage DCF analyses on a number of grounds and all claim that their respective ROE witnesses' DCF analyses are superior to Mr. Hevert's. For example, as indicated above, CCPUG and the Advisors claim that Mr. Hevert simply ignored his DCF results because they were too low.[58] APC claims that Mr. Hevert's results are based on inflated growth rates and are excessive, and that he used faulty measures for the dividend payout ratio and the terminal stock price.[59] These arguments are incorrect and should be rejected by the Council.

With regard to growth rates, Mr. Walters contends that the average of Mr. Hevert's high growth rate estimates is higher than the expected growth in the overall U.S. economy. However,

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54 *Id*.

55 *Id*. at 25.

56 Mr. Hevert updated his analyses in his Rebuttal Testimony but the updated results did not cause him to change his ROE recommendation. *See* Exhibit ENO-29 (Hevert Revised Rebuttal) at 154.

57 *See* Exhibit ENO-26 (Hevert Revised Direct) at 30.

58 CCPUG Brief at 31-32; Advisors Brief at 28.

59 Air Products Brief at 16.

the 5.67% average growth rate Mr. Hevert used in his Constant Growth DCF analysis, and higher, has historically occurred quite often.[60] In fact, Mr. Hevert's average growth rate represents approximately the 42nd percentile of the actual capital appreciation rates from 1926 to 2017.[61] Mr. Watson takes his 4.42% long-term growth rate from the Energy Information Administration ("EIA"), the Social Security Administration ("SSA"), and IHS Global Insights.[62] Working with those inputs, Mr. Watson produced an estimated ROE range of 5.74% to 10.64%, and chose the median of the range (8.09%) as his recommended unadjusted ROE.[63] Significantly, Mr. Watson's Two-Step DCF approach assumes the first-stage growth rate transitions to his assumed 4.42% growth rate in the 35th year. However, Mr. Watson fails to explain why this assumption is reasonable, or how it corresponds to the forecast horizons from the sources he cites. To the contrary, such an assumption is arbitrary.[64] Mr. Watson also recommends the Council consider the estimates provided by the Congressional Budget Office ("CBO") of real Gross Domestic Product ("GDP") annual growth rates of 1.90% over the next ten years.[65] However, the CBO itself warns that comparisons of its projections to others are not always apt, noting that they may be based on different assumptions and used for different purposes.[66] The CBO has also explained that different forecasters make different assumptions regarding future fiscal policy, and that its estimates assume fiscal policy in the future will be

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60 Exhibit ENO-29 (Hevert Revised Rebuttal) at 103, Chart 18.

61 *Id*. The growth rate equals the capital appreciation rate under Constant Growth DCF model assumptions. *Id*. at n. 239.

62 Exhibit ADV-6 (Watson Direct) at 18-19, Ex. BSW-4 at 3.

63 *Id*. at 43-44, Ex. BSW-4 at 1.

64 Exhibit ENO-29 (Hevert Revised Rebuttal) at 49.

65 Exhibit ADV-6 (Watson Direct) at 20-21.

66 Exhibit ENO-29 (Hevert Revised Rebuttal) at 46, citing *CBO's Economic Forecasting Record: 2017 Update*, October 2017, at 4-5.

based on the current law to aid in the evaluation of proposed changes in law. Given expected changes in law that effect fiscal policy, the CBO's forecasts cannot validate Mr. Watson's projections.[67] Moreover, the error rate for CBO's estimates for "real output growth" and inflation have been 1.30% and .90%, respectively.[68] Applying those error rates to the CBO's real GDP estimate trumpeted by Mr. Watson, which corresponds to a 4.0% nominal GDP, results in a growth rate of 6.20%. Mr. Hevert's 5.45% growth rate estimate for his Mult-Stage DCF analysis is clearly within a reasonable range, especially considering Mr. Watson's proposed GDP growth rate estimate from the CBO.[69]

According to Mr. Walters, Mr. Hevert's Multi-Stage DCF model is based on an unrealistic long-term GDP growth estimate out of accord with analyst forecasts. Such criticism is unfounded. The long-term growth rate used in Mr. Hevert's analysis reflects growth estimates beginning ten years in the future. There are no consensus forecasts that begin ten years in the future, and the terminal growth rate reflects expected growth in perpetuity, so the longest-term GDP forecast used by Mr. Walters in his analysis (2029) does not reflect the expected, perpetual nature of the terminal growth assumed in the model.

Conversely, Mr. Hevert's 5.45% long-term GDP growth rate is the sum of the 3.21% real GDP growth rate from 1929 to 2017 and an inflation rate of 2.16%.[70] Contrary to the criticisms of Mr. Walters and Mr. Baudino, it is reasonable to assume that real GDP growth will revert to its long-term mean over time.[71] Mr. Hevert's long-term GDP growth rate is 66 basis points

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67 *Id*. at 46-47.

68 *Id*. at 47, citing CBO's Economic Forecasting Record: 2017 Update, October 2017, at 9.

69 *Id*. at 47.

70 Exhibit ENO-26 (Hevert Revised Direct) at 28-29.

71 *Id*. at 29.

below the long-term average of 6.11%, within the bounds of the long-term growth estimates Mr. Baudino uses in his Constant Growth DCF analysis, consistent with historical observed nominal GDP, and falls within the range of projected scenarios considered by the SSA.[72]

Likewise, Mr. Walters' and Mr. Baudino's criticisms of Mr. Hevert's dividend payout ratio adjustment are misplaced. There are several reasons why dividend payments could be adjusted in the near term, including increases or decreases in expected capital spending. Therefore, it cannot be assumed such factors will remain constant, and it is reasonable to assume that over time, payout ratios will revert to their long-term average.[73] Moreover, several of the companies in Mr. Walters' proxy group have recently discussed payout ratios consistent with that used by Mr. Hevert, making the ratio in Mr. Hevert's analysis consistent with both historical experience and industry expectations.[74]

Further, the Constant Growth DCF model is based on fundamental assumptions that establish an inverse relationship between expected growth and dividend yield; that is, higher growth results in lower yields and lower growth produces higher yields.[75] Contradicting those assumptions, Mr. Walters in his DCF analysis applies historically high valuations with comparatively low growth rates.[76] The P/E ratios in the utility sector have expanded abnormally over the last several years, and such expansion cannot be expected to continue perpetually.[77] Mr. Walters acknowledged that unsustainable expansions of P/E ratios not explained by higher

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72 *Id*. at 29, citing Bureau of Economic Analysis; Exhibit ENO-29 (Hevert Revised Rebuttal) at 45-46, Charts 19-20.

73 Exhibit ENO-29 (Hevert Revised Rebuttal) at 107.

74 *Id*.

75 *Id*. at 80.

76 *Id*. at 80-81.

77 *Id*. at 82.

growth in earnings or dividends create analytical concerns and require adjustments to the model.[78] Despite this acknowledgment, Mr. Walters did not adjust either his DCF analyses or his interpretation of their results; therefore, his results reflect abnormal market conditions and should be given less weight.[79]

Mr. Walters' Multi-Stage DCF model also includes assumptions that result in unreasonably low ROE estimates. Specifically, it assumes a terminal growth rate beginning in 2029 based on a GDP growth rate projection ending in 2029, and he assumes all dividends are paid out at year end instead of over the course of the year.[80] That long-term growth rate accounts for more than 70% of the model's results, and Mr. Walters' assumed growth rate is inconsistent with the model's structure and with other measures of growth noted in his testimony.[81] Specifically, his assumed 4.19% GDP growth rate is considerably less than the expected growth rate from his CAPM analysis of 9.20%, which he testified should correlate to the GDP growth rate.[82] Using the midpoint between those growth rates as the assumed terminal rate in Mr. Walters' Multi-Stage DCF model, Mr. Hevert found an average ROE estimate of approximately 9.97%, well above Mr. Walters' recommendation.[83]

b. CAPM Analysis.

The CAPM methodology estimates cost of equity for a particular security as a function of a risk-free return plus a risk premium, which compensates investors for the security's systemic,

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78 *Id*. at 81, citing Exhibit AP-1 (Walters Direct) at 47.

79 *Id*. at 82.

80 *Id*.

81 *Id*. at 84, Ex. RBH-28.

82 *Id*. at 84-85.

83 *Id*. at 86.

non-diversifiable risk.[84] Mr. Proctor testified that this model is supported by sound economic principles and is commonly used to estimate utility ROEs.[85] The CAPM is defined by four forward-looking estimates: required market ROE; Beta of an individual security; risk-free rate of return; and required return on the overall market. The market risk premium is the difference between the market portfolio return rate and the risk-free rate.[86] The model relies on the theory that only systemic risk matters to investors because other risks can be diversified away. The systemic risk is measured by the Beta coefficient, which represents the volatility of the company's returns relative to that of the broader market as well as the correlation of returns between the company and the market.[87] Typically, higher Beta coefficients mean a company's returns have moved in tandem with the market, but a Beta coefficient of 1.00 means company and market risk are equal.[88] Beta coefficients represent part but not all of the stock's overall risk, which is one of the limitations on the CAPM.[89] Regardless, the CAPM is widely used by investors in estimating required returns on equity investments. Therefore, the CAPM is proper for use in this proceeding to estimate the ROE for ENO as it would be estimated by investors.[90]

Mr. Hevert's CAPM results are set forth in the table below:[91]

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84 Exhibit ENO-26 (Hevert Revised Direct) at 30.

85 Exhibit ADV-13 (Proctor Surrebuttal) at 2.

86 Exhibit ENO-26 (Hevert Revised Direct) at 31, n. 31.

87 Exhibit ENO-26 (Hevert Revised Direct) at 31.

88 *Id*. at 32.

89 Tr. (Hevert) 06/19/19 at 36.

90 Tr. (Hevert) 06/19/19 at 37.

91 Mr. Hevert updated his analyses in his Rebuttal Testimony but the updated results did not cause him to change his ROE recommendation. See Exhibit ENO-29 (Hevert Revised Rebuttal) at 154.

Table 7: Summary of CAPM Results [92]

	Bloomberg Derived Market Risk Premium	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.11%)	10.13%	10.34%
Near-Term Projected 30-Year Treasury (3.48%)	10.50%	10.71%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.11%)	11.66%	11.91%
Near-Term Projected 30-Year Treasury (3.48%)	12.03%	12.28%

Other parties criticized Mr. Hevert's CAPM analysis, claiming it was based on inflated risk premiums.[93] However, as with the criticisms of Mr. Hevert's DCF analyses, these criticisms should be rejected. In fact, as Mr. Hevert demonstrated, it is the other parties' CAPM analyses that are faulty and should be discounted.

For his CAPM analysis, Mr. Hevert used both the current 30-day average yield on 30-year Treasury bonds and the projected 30-year Treasury yield as risk-free rates, given that utility stocks are longer-term investments.[94] Using a Treasury yield that matches the duration of the subject security as the risk-free rate supports the CAPM's underlying theory.[95] In other words, an analyst should determine the risk-free rate by reference to the subject asset, in this case ENO stock.[96]

92 Exhibit ENO 26 (Hevert Revised Direct) at 34.

93 *See, e.g.*, APC Brief at 16; Advisors Brief at 31.

94 Exhibit ENO-26 (Hevert Revised Direct) at 32.

95 Tr. (Hevert) 06/19/19 at 30.

96 *Id*. at 31.

In contrast, Mr. Proctor and Mr. Baudino based their risk-free rate used for the CAPM on the current short-term Treasury bills. According to Mr. Proctor, the 13-week Treasury bill rate more closely represents a risk-free rate than longer-term Treasury securities, which are more subject to interest rate risk.[97] Mr. Proctor also took the position that using the 30-year Treasury bond yield as the risk-free rate in the CAPM would be inconsistent with the economic principles underlying the CAPM.[98] Mr. Proctor argued that the Treasury bills are nearly risk-free and have very little price fluctuation, while Treasury bond prices vary with interest rates, therefore carrying greater risk and more volatile returns, inappropriate for a proxy based on a risk-free rate.[99] Mr. Proctor further claimed that because utility stock has no maturity dates and can be held for mere minutes, and because a utility's ROE can change over the course of 30 years while fixed bond interest rates are not recomputed, Mr. Hevert was wrong to use a longer-term security as a proxy for a risk-free rate.[100] Mr. Baudino agreed with Mr. Proctor, asserting that Mr. Hevert should have considered short-term Treasury yields in his CAPM analysis because the risk-free rate should have no interest rate risk, and the 5-year Treasury note has much less interest rate risk than the 30-year Treasury bond.[101]

Both Mr. Proctor and Mr. Baudino misunderstand the risk-free rate concept as it applies to the CAPM. The risk-free rate should match the duration of the security as opposed to the timing of any particular investment in the security. The time period of the risk-free security and

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97 Exhibit ADV-9 (Proctor Direct) at 17.

98 *Id*. at 20.

99 *Id*. at 19, 52.

100 *Id*. at 52.

101 Exhibit CCPUG-3 (Baudino Direct) at 43-44.

the risk premium should comport with duration of projected cash flows from the investment.[102] Duration measures the change in a stock's market price resulting from the change in its implied long-term return.[103] The perpetual nature of equity securities requires use of the longest-term Treasury security for the risk-free rate.[104] The risk-free rate used in the CAPM should be consistent with this perpetual nature, and since the Treasury security with the longest duration is the 30-year bond, its yield is the appropriate proxy for the risk-free rate.[105] Mr. Hevert calculated the duration of equity in Mr. Baudino's proxy group and determined the mean and median equity duration is about 32 years. Therefore, just as it is for Mr. Hevert's CAPM, the 30-year Treasury bond is the proper measure of the risk-free rate for Mr. Baudino's CAPM analysis.[106] Mr. Hevert explained this further at the hearing, noting that the idea behind this "duration matching"

> … is that you would effectively immunize . . . the change in value associated with a change in the cost of capital. It's a fairly common principle. It's one that's highly recognized in financial literature and practitioner literature as well. But if you look at it as a practical matter, when you buy a share of stock, the stock is a perpetual asset. It doesn't have a holding period. It doesn't expire after some certain period of time. It is a perpetual investment. . . You can own a share of stock and sell it five years from now, but unless a person buying that stock assumes that the stock has a perpetual life, you would have an unreasonably low value.[107]

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102 Exhibit ENO-26 (Hevert Revised Rebuttal) at 34-35.

103 *Id*. at 35.

104 Tr. (Hevert) 06/19/19 at 60-61. Mr. Watson recognized the perpetual nature of equity as well. Exhibit ADV-6 (Watson Direct) at 14-15.

105 Exhibit ENO-29 (Hevert Revised Rebuttal) at 34-37, *citing* Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008) at 92, and 2011 CFA Curriculum Level 1, Volume 4 at 52.

106 *Id*.

107 Tr. (Hevert) 06/19/19 at 60-61.

As previously discussed, the market risk premium in the CAPM analysis is the additional return equity investors require to assume the risk of owning the market portfolio of equity relative to long-term Treasury bonds.[108] It is meant to be a forward-looking parameter; this is not refuted by Mr. Proctor.[109] Calculating a market risk premium based on historical returns, as Mr. Proctor does, could produce results inconsistent with current capital market conditions and the views of investors.[110] This is important because ensuring that the risk-free rate, the Beta, and the market risk premium inputs to the model reflect market conditions and investor expectations is fundamental to the CAPM analysis.[111] Contrary to Mr. Proctor's proposition that the market risk premium is static over time and across different market conditions, substantial research has shown the opposite—that market risk premium varies over time, relates to market volatility, and increases or decreases inversely to government bond yields.[112] Significantly, the 30-year Treasury yield remains below the 6% yield underlying Mr. Proctor's market risk premium calculation.[113] Regardless, Mr. Hevert's estimates of market risk premium have occurred roughly half the time between 1926 and 2017, so they are also consistent with historical returns. Likewise, his methodology for estimating expected market returns is reasonable, comports with academic research, and is used by finance researchers in understanding factors affecting the market risk premium.[114]

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108 Exhibit ENO-29 (Hevert Revised Rebuttal) at 37.

109 *Id*.; Exhibit ENO-31 (Hevert Rejoinder) at 17.

110 Exhibit ENO-29 (Hevert Revised Rebuttal) at 37.

111 *Id*. at 37-38.

112 *Id.* at 38, citing Kenneth R. French, G. William Schwert, Robert F. Stambaugh, *Expected Stock Returns and Volatility*, Journal of Financial Economics 19 (1987) at 27; Robert S. Harris, Felecia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992 at 69.

113 Exhibit ENO-29 (Hevert Revised Rebuttal) at 39.

114 *Id*. at 40, citing Robert S. Harris and Felecia C. Marston, *The Market Risk Premium: Expectational*

Moreover, the income return on long-term government bonds, not the total return, should be used to calculate the market risk premium. Mr. Proctor incorrectly used the total return, which is actually composed of the income return, capital gains or losses, and reinvestment return.[115] The income return is the interest rate, which does not change, as opposed to the gains and losses that depend on changing interest rates. The income rate should be used because it is the only component of the total return that has no risk.[116]

Using two principally historical market risk premium estimates and a projected 30-year Treasury bond yield of 3.60% as the risk-free rate in his application of the CAPM, Mr. Walters developed expected market returns ranging from 9.70% to 11.30%.[117] The lower bound of this range is unreasonable, as it is 236 basis points below the long-term average market return from 1926 to 2017 and almost as much below the rolling 50-year average annual market return.[118] Likewise, for the same reasons previously discussed with respect to Mr. Proctor's analysis, Mr. Walters' use of the historical average market risk premium is inappropriate and can produce results inconsistent with investor sentiment and current market conditions.[119]

Contrary to Mr. Walters' argument, Mr. Hevert's DCF approach to estimating expected market return does not produce biased results based on extremely high and unsustainable short-term growth rate estimates for individual companies. In fact, Mr. Hevert included 33 extremely low growth rates that were equal to or lower than Mr. Walters' 2.10% inflation estimate, and 19

Estimates Using Analysts Forecasts, Darden Graduate School of Business, University of Virginia, Working Paper No. 99-08 (1999).

115 *Id.*, citing Duff & Phelps, 2018 SBBI Yearbook, at 2-7.

116 *Id*.

117 *Id*. at 86-87.

118 *Id*. at 87.

119 Exhibit ENO-31 (Hevert Rejoinder) at 37-38, 88.

of which were negative, as low as -20.68%.[120] Clearly his analysis was not biased in favor of higher growth rates. According to the FERC, DCF-based growth rates used in calculating the market risk premium in the CAPM need not be proven sustainable, because even though individual companies may not sustain higher short-term rates in perpetuity, the same may not be said for stock indexes such as the S&P 500, which are updated regularly to contain only high market cap companies.[121] The overall market return for purposes of the CAPM is determined by a DCF study of such a market index, and Mr. Walters offers no argument that the S&P 500 growth rate is unsustainable.[122]

c. Bond Yield Plus Risk Premium Approach.

The Bond Yield Plus Risk Premium approach is based on the idea that because equity returns are riskier than debt returns, equity investors require compensation for the additional risk. The model estimates a ROE as the sum of the equity risk premium and the yield on a particular type of bond.[123] The equity risk premium is approximated using both forward-looking and historical estimates, including actual authorized returns for electric utilities.[124] There is support for the model and its underlying theory in published financial literature and research.[125] Significantly, the FERC has now determined that this methodology should be among the four

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120 *Id*. at 56-57.

121 *Id*. at 57.

122 *Id*. at 57-58, citing Docket EL11-66-002, Opinion 531-B Order on Rehearing, 150 FERC ¶ 61,165 (March 3, 2015) at P. 113.

123 Exhibit ENO-26 (Hevert Revised Direct) at 34-35.

124 *Id*. at 35.

125 Exhibit ENO-29 (Hevert Revised Rebuttal) at 50-51; Exhibit ENO-26 (Hevert Revised Direct) at 35-36, citing, e.g., Robert S. Harris and Felecia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992 at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985 at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995 at 89-95.

used to estimate ROEs.[126] Nevertheless, the Advisors' witnesses have not provided any estimation based on this model, nor did any other ROE witness other than Mr. Hevert.[127]

Importantly for this case, the Bond Yield Plus Risk Premium analysis is based on authorized returns for both vertically integrated utilities and distribution only companies. Further, it represents returns for companies generally rated at least BBB+ by the credit rating agencies. Therefore, this model does not appropriately reflect ENO's incremental risk based on the factors previously discussed (geography, size, and credit profile).[128]

Just as he did with his CAPM analysis, Mr. Hevert initially calculated the equity risk premium as the difference between the authorized ROE and the current 30-year Treasury bond yield. He also used authorized ROEs from 1,556 electric rate cases, calculated the average period between filings and final orders in those cases, and calculated the average 30-year Treasury yield over the average time between filings and final orders to reflect interest rate levels during those proceedings.[129] Using a regression analysis, Mr. Hevert realized a statistically significant inverse relationship between the 30-year Treasury yield and the equity risk premium.[130] A summary of Mr. Hevert's bond yield plus risk premium results is shown in this table:[131]

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126 Exhibit ENO-29 (Hevert Revised Rebuttal) at 51, citing Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 18; Docket No. EL11-66-001, et al., *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018) at P. 17.

127 Tr. (Watson) 06/21/19 at 23-24.

128 Tr. (Hevert) 06/19/19 at 38-39.

129 Exhibit ENO-26 (Hevert Revised Direct) at 35.

130 *Id*. at 37. This same statistically significant inverse relationship was found in the empirical study by Maddox, Pippert and Sullivan. See n. 121, supra.

131 Mr. Hevert updated his analyses in his Rebuttal Testimony but the updated results did not cause him to change his ROE recommendation. See Exhibit ENO-29 (Hevert Revised Rebuttal) at 154.

Table 8: Summary of Bond Yield Plus Risk[132]

Premium Results	Return on Equity
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%

The regression analysis shows that this model provides empirically meaningful results, indicating that changes in interest rates explain 74% of authorized ROE changes. Therefore, given that the inverse relationship between the equity risk premium and the 30-year Treasury yield is statistically significant above the 99% confidence level, there is considerable confidence in concluding that the regression coefficient is a proper measure of the changes.

As with the CAPM, other parties criticize Mr. Hevert's market risk premiums used in this model.[133] However, these criticisms should be rejected for the same reasons outlined above. For example, Mr. Proctor cautions against the use of commission-authorized ROEs from other jurisdictions because of the non-economic and financial factors that influence those decisions.[134] However, as previously explained, the other regulatory proceedings used in this analysis involved market-based determinations of ROEs, considering capital market environments and investor concerns. Investors understand that regulatory commissions must balance investor and ratepayer interests in those determinations. Because the authorized ROEs are publicly available, such data has an impact on investors' return expectations.[135]

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132 Exhibit ENO-26 (Hevert Revised Direct) at 37.

133 See, e.g., APC Brief at 16; Advisors Brief at 31.

134 Exhibit ADV-9 (Proctor Direct) at 58-60.

135 Exhibit ENO-29 (Hevert Revised Rebuttal) at 50.

Mr. Walters' risk premium analyses calculate the annual risk premium first by reference to the 30-year Treasury yield, and then considering the average A-rated utility bond yield. However, in both cases he establishes his estimate by referring to five- and ten-year rolling averages over a 33-year period from 1986 to 2018, so the lower and upper bounds of his risk premium range are defined by the lowest and highest rolling averages, regardless of the year.[136] These analyses are flawed because, as Mr. Hevert explains: (a) they ignore the inverse relationship between the risk premium and interest rate level (whether measured by Treasury or utility bond yield) and therefore understate the required risk premium in the current market; (b) the low end is far lower than any authorized ROE since 1986; and (c) they use a Market/Book ratio of 1.00 as a relevant benchmark for assessing authorized ROEs.[137]

d. Expected Earnings Approach.

The FERC has also determined that the Expected Earnings approach should be used to estimate ROEs, and Mr. Hevert was the only ROE witness that performed this analysis.[138] This approach is based on the basic concept that investors will choose the investment with a higher expected return when comparing multiple investments with comparable risks, making it compatible with the economic principle of opportunity costs and the comparable risk standard from *Hope* and *Bluefield*. It calculates projected returns on book value for the electric utility industry and for the individual proxy companies.[139]

For his Expected Earnings analysis, Mr. Hevert gathered projected three- and five-year

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136 *Id*. at 88, citing AP-1 (Walters Direct) at 37-38, Schedules CCW-11 and CCW-12.

137 *Id*. at 91.

138 *Id*. at 53, citing Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 18; Docket No. EL11-66-001, et al., *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018) at P. 17

139 Exhibit ENO-29 (Hevert Revised Rebuttal) at 53.

equity returns for each proxy company from Value Line, and adjusted them because those values reflect outstanding shares at the end of the year rather than average shares outstanding over the course of the year, since earnings are earned over the course of the year.[140] His analysis resulted in a mean ROE of 10.52%.[141]

Mr. Proctor contends that the Council should not give any weight to Mr. Hevert's expected earnings analysis because the projected return on equity is not the same as the opportunity cost of capital or ROE for ratemaking purposes.[142] According to Mr. Proctor, the earned return on equity is a simple accounting measure, while determination of the appropriate ROE for ratemaking must consider economic and financial factors.[143] However, as Mr. Hevert testified, utility rates are set based on the book value of equity, and the expected earnings model directly measures the book-based return that utilities with comparable risks are expected to earn, or the expected opportunity costs of equity capital as acknowledged by Mr. Proctor.[144] More importantly, the expected earnings approach is consistent with the *Hope* and *Bluefield* "comparable return" standard.[145] Dr. Morin, a well-respected published expect on ROE, agrees, arguing that the rate of return on book value as measured by the expected earnings analysis is "highly meaningful;"[146] and the FERC concurs as well, proposing that the expected earnings

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140 *Id*., n. 120.

141 *Id*. at 54.

142 Exhibit ADV-13 (Proctor Surrebuttal) at 25.

143 *Id*.

144 Exhibit ENO-31 (Hevert Rejoinder) at 20-21.

145 *Id*. at 21.

146 *Id*., *citing* Morin, New Regulatory Finance, at 329, 395.

model be given equal weight in determining just and reasonable ROEs because it is used by investors in estimating expected returns and making investment decisions.[147]

2. The Proxy Group Selected by Mr. Hevert is Appropriate.

The primary difference between the proxy companies used by Mr. Hevert for his analyses and those included in the Advisors' proxy group involves the credit rating criteria used. Specifically, Mr. Watson required his proxy companies to have S&P ratings within one notch of ENO's BBB+ rating, while Mr. Hevert required the proxy companies to have investment grade ratings, regardless of whether the ratings were within a notch of ENO's rating.[148] According to Mr. Watson, his credit rating criteria are appropriate because they will provide the Council with useful information regarding the required returns on companies with credit risks comparable to ENO.[149] Mr. Hevert chose his credit rating criteria based on the uncontroverted fact that most utility investors are institutional entities whose investment guidelines typically focus on investment grade companies.[150] Therefore, his criteria are reasonable and appropriate.

3. Mr. Hevert's Consideration of Flotation Costs is Appropriate.

ENO and the Advisors agree that a flotation cost adjustment is reasonable but disagree on the methodology for deriving it. Mr. Hevert uses the weighted average flotation cost of the proxy group to adjust the dividend yield for the DCF approach, while Mr. Proctor contends that the adjustment should only reflect ENO's flotation costs and not those of the proxy companies.[151] Because flotation costs can vary significantly over time depending on numerous

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[147] *Id.*, *citing* Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at P. 34, 36-37.

[148] Exhibit ENO-29 (Hevert Revised Rebuttal) at 22-23.

[149] Exhibit ADV-9 (Proctor Direct) at 27.

[150] Exhibit ENO-29 (Hevert Revised Rebuttal) at 22-23.

[151] Exhibit ENO-31 (Hevert Rejoinder) at 23; Exhibit ADV-13 (Proctor Surrebuttal) at 29.

cyclical factors, *i.e.*, capital market environment, use of proceeds, size of offering, that themselves vary over time, applying the proxy group weighted average appropriately normalizes these variations.[152]

Further, contrary to Mr. Proctor's testimony that flotation costs are operating expenses recovered as part of ENO's revenue requirement,[153] they have not been included in ENO's cost of service study or its operating expenses to be recovered through rates because these costs are not operating expenses.[154] Generally Accepted Accounting Principles ("GAAP") and FERC accounting guidance mandate that flotation costs be recorded as a reduction to equity, and Entergy Corporation has complied with these rules.[155] These costs are associated with equity that has a perpetual life and provides benefits to ratepayers over many years by funding utility assets. Expensing flotation costs would unfairly burden current ratepayers with the full cost of raising capital, the benefits of which will extend indefinitely.[156]

4. Conclusion – What Happened to EAL when it was awarded a Below Average ROE is a Cautionary Tale.

The regulatory regime in which a utility operates is one of the most important factors in determining that utility's credit rating and the assessment by investors of the risk in supplying capital to that utility.[157] Regulatory advantage is the most heavily weighted factor in S&P's analysis of a regulated utility's business risk profile. Transparency, consistency and

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152 Exhibit ENO-31 (Hevert Rejoinder) at 23.

153 Exhibit ADV-13 (Proctor Surrebuttal) at 30.

154 Exhibit ENO-31 (Hevert Rejoinder) at 24; Exhibit ENO-4 (Thomas Rejoinder) at 10.

155 Exhibit ENO-4 (Thomas Rejoinder) at 10-11.

156 Exhibit ENO-31 (Hevert Rejoinder) at 24, citing Morin, New Regulatory Finance at 327-328.

157 Exhibit ENO-29 (Hevert Revised Rebuttal) at 17.

predictability are paramount considerations in this analysis.[158] For Moody's, 50% of the factors it considers in assigning credit ratings to utilities are related to the nature of the regulation those utilities operate under.[159] The situation that EAL found itself in after the Arkansas Public Service Commission authorized a ROE much lower than that requested by EAL is both instructive and cautionary. As a result of that decision by the Arkansas Public Service Commission, Moody's left EAL's credit rating unchanged while upgrading the credit ratings of four other Entergy Operating Companies. The same outcome could befall ENO should the Council set its ROE at the unreasonably low levels recommended by the Advisors and Intervenors. Setting an ROE for an already below investment grade utility considerably lower than industry norms can result in a perceived increase in regulatory and business risks, thereby adversely affecting the utility's credit rating.[160] Adoption of the ROE recommendations of either the Advisors or Intervenors witnesses, especially in light of Moody's current below investment grade rating for ENO, would likely result in investors assessing ENO as having a higher regulatory risk than other utilities. In turn, those investors will demand a higher return for that risk, again to the detriment of ENO customers.[161] ENO is not seeking a return that is excessive or unreasonable; (depending on whether the Reliability Incentive Mechanism ("RIM") is employed) it is a 35-60 basis point reduction to the currently authorized ROE; it is supported by multiple analyses, and it is sufficient to support the transformative change proposed in the Company's application.

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158 *Id*. at 17-18.

159 *Id*. at 18.

160 *Id*.

161 *Id*. at 18-19.

B. The Advisors' argument that ENO views a constructive regulatory environment to mean low risk in cost recovery is a misrepresentation of ENO's request and intent.

In an effort to justify their recommendation that an unreasonably low ROE be approved by the Council, the Advisors contend that "[t]he 'constructive regulatory environment' proposed by ENO appears to mean a high return on investment with a low risk in the recovery of costs."[162] As explained in the previous section, ENO's risk profile indeed requires a high ROE as compared to the industry because it is one of the three riskiest utilities in the industry. The Advisors assertion that ENO is proposing a "low risk in the recovery of costs," however, is a misrepresentation of ENO's proposed rate structure and request in this proceeding.

To begin, the Advisors offer no analysis to support this assertion because the facts and information provided in this proceeding contradict the assertion. In its electric and gas rate structures, ENO proposes to recover approximately $468 million through electric and gas base rates on an annual basis, thus, decreasing the amount of costs recovered through riders by approximately $136 million.

Also, the pejorative tone of the Advisors' description of ENO's proposed riders as "guaranteed exact cost recovery through mechanisms such as monthly or quarterly rate adjustments, over/under collection correction mechanisms, and true ups to reflect actual vs. budgeted costs" – is misleading and suggests ENO is proposing unreasonable cost recovery mechanisms. It is clear, that is not the case, when considered in the context of ENO's contemplated level of investment, and other factors described herein.

First, in a paradigm where activities are being undertaken to reduce sales and usage, especially for a utility with ENO's geographic footprint located near the storm-prone Gulf of

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162 Advisors Brief at 6.

Mexico,[163] no cost recovery is guaranteed. Decreasing usage may mean a utility never recovers a cost or, at the very least, the utility's recovery may take far longer than designed.

Nevertheless, ENO has referred to two types of ratemaking mechanisms as exact cost recovery mechanisms in this proceeding and in the past to distinguish them from typical base rate recovery. Both exist in ENO's current rate structure, and thus, the Council approved them in the past. More importantly, no one has claimed that ENO has a guarantee of cost recovery today as a result of these mechanisms.

The first of these ratemaking mechanisms are riders that reconcile rider revenues to the costs recovered through the rider. These riders enhance the opportunity for cost recovery and virtually eliminate any over-recovery through over/under mechanisms to protect customers.[164] Such riders include the Fuel Adjustment Clause ("FAC") Rider, the Purchased Gas Adjustment ("PGA") Rider, the PPCACR Rider, the two Midcontinent Independent System Operator, Inc. ("MISO") Cost Recovery Riders, and the Ninemile Non-Fuel Cost Recovery ("NNCR") Rider.[165] Second, ENO has referred to the Schedule A process, which is used for Grand Gulf Unit Power Sales Agreement capacity expenses today, as an exact cost recovery mechanism.[166] In the Schedule A process, base rates recover an estimated amount of the cost; to the extent the actual cost differs from the estimated cost, the difference, an over- or under-collection (which is expected to be relatively minor in comparison to the amount recovered in base rates), is

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163 *Id*. at 42.

164 Exhibit ENO-3 (Thomas Rebuttal) at 36. As a result, they symmetrically virtually eliminate any under-recovery.

165 The FAC, PGA do not include a return component. ENO has proposed that the PPCACR Rider be modified and the NNCCR Rider eliminated altogether.

166 Exhibit ENO-33 (Todd Revised Direct) at 18.

recovered through a rider with revenue and costs reconciled.[167] For example, in the Schedule A process, assume ENO estimates a cost to be $90 million on an annual basis, but the actual amount of the cost is $89 million in a given calendar year. ENO's base rates may or may not produce sufficient revenue to recover the $90 million estimate; in contrast, the $1 million over-collection would be returned to customers through a rider.

In fact, when considering the entirety of ENO's proposed electric and gas rate structures, ENO has proposed to reduce the amount of costs recovered through riders which reconcile revenues to costs, thereby increasing the amount of costs recovered through base rates. The table below shows that, under ENO's proposed rate structure, many cost elements would move from current rider recovery to base rate recovery. ENO estimates approximately $136 million of revenue would move from rider recovery to base rate recovery.

Table 1
Comparison of Changes in the Recovery of Cost Elements --
Current Rate Structure versus Proposed Rate Structure

Cost Element	Current Recovery	Proposed Recovery
Union Non-fuel Revenue Requirement	Rider	Base Rates
Legacy ENO Ninemile 6 PPA	Rider	Base Rates (Schedule A)
Resource Plan PPA Capacity Expenses	Rider	Base Rates (Schedule A)
LTSA Expenses	Rider	Base Rates (Schedule A)
Algiers Transaction PPA Capacity Expenses – Ninemile 6 only	Rider	Base Rates (Schedule A)
Algiers Transaction PPA Capacity Expenses - Excluding Ninemile 6	Base Rates	Base Rates (Schedule A)
MISO Transmission Settlements and other MISO Charges	Rider	Rider
GIRP	Insurance Proceeds	GIRP Rider
Energy Efficiency Expenses	Offsets and Rider	DSMCR Rider
Grid Modernization	N/A	DGM Rider
AMI	N/A	AMI Charge as an Increment to Base Rates

Most of the comparisons in the table are straightforward; a few require explanation. The GIRP Rider approximates ENO's historical cost recovery of accelerated replacement gas

167 *Id.*

infrastructure due to storm damage. For ten years, ENO has replaced gas infrastructure with dollar-for-dollar cost recovery with no regulatory lag due to insurance proceeds, which were not depleted until early 2017.[168] After that timeframe, ENO has used and intends to use its capital to fund the GIRP. Relative to base rate recovery, the GIRP Rider would provide an enhanced opportunity to continue timely recovery of the return on and of the incremental capital investment closing to plant in service after December 31, 2019 for as long as that plant is recovered through the GIRP Rider.[169]

ENO does not oppose the periodic realignment of the GIRP costs to base rates through the Gas FRP, if one is established, provided this realignment does not increase regulatory lag. As indicated before, ENO does not oppose the use of a Gas FRP with forward-looking adjustments for the recovery of GIRP costs, but ENO requests the GIRP Rider also be approved in this proceeding, with implementation commencing upon expiration of such FRP so as not to disrupt this important project.[170]

The Demand-Side Management Cost Recovery ("DSMCR") Rider would approximate how ENO historically has recovered energy efficiency expenses through various offsets and the FAC. Although energy efficiency expenses were recovered through base rates from 2009 through 2012, ENO was not obligated to spend more on energy efficiency than what the Council authorized to be recovered through base rates. Since then, energy efficiency expenses have been largely offset through Rough Production Cost Equalization Adjustment receipts and tax benefits,

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168 Exhibit ENO-22 (Bourg Revised Direct) at 9.

169 Exhibit ENO-41 (Gillam Revised Direct) at 48.

170 *See* Exhibit ENO-3 (Thomas Rebuttal) at 9.

including the tax benefits from the Tax Cut Act.[171] Also, ENO recovered a portion of its energy efficiency expenses through the FAC rate applicable to Algiers Customers.[172]

The AMI Charge would operate very similarly to base rates. As explained by Company witness Mr. Thomas, the AMI Charge would change according to the schedule set forth in Exhibit JBT-9 to Exhibit ENO-1 in order to mitigate regulatory lag in cost recovery as well as the realization of operational savings.[173] Then, in the subsequent FRPs, any differences in the revenue resulting from the AMI charges and the actual AMI costs, including any savings from AMI, would be evaluated in the proposed Electric and Gas FRPs.[174] Essentially, the AMI Charge would operate like a forward-looking adjustment to ENO's proposed FRPs, which do not include forward-looking adjustments. That is why ENO believes the AMI Charge would be unnecessary if FRPs with forward-looking adjustments were established.[175]

The only new costs to be recovered through a rider are the costs associated with grid modernization projects, which would be recovered through the DGM Rider. ENO expects the revenue requirement amount recovered through this rider to be small, approximately $5 million, in comparison to ENO's proposed base rate revenue of $428 million. More specifically, the total distribution spending for 2018 (capital and O&M) was forecast to be $117 million,[176] while the $5 million annual revenue requirement associated with grid modernization efforts expected to be constructed or to close over the next four years is but a fraction of that amount, based on the following initial projects:

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171 Exhibit ENO-10 (Owens Revised Direct) at 12.

172 *Id*.

173 Exhibit ENO-1 (Thomas Revised Direct) at 65-66.

174 *Id*. at 66.

175 Exhibit ENO-3 (Thomas Rebuttal) at 9.

176 Exhibit ENO-56, WP Statement AA-2_REV_E (UnitCostStudy).

- Curran Project - $5 million
- Market Project - $21 million
- Lower Coast Project – $11 million
- Almonaster Project - $16 million
- Avenue C Project - $6 million[177]

Furthermore, as stated previously, ENO believes the Electric FRP with forward-looking adjustments would make the DGM Rider unnecessary for the term of such FRP,[178] and ENO does not oppose the periodic realignment of the DGM Rider recovery to base rates through the Electric FRP, if one is established, provided that the realignment does not increase regulatory lag.

In summary, ENO is increasing the amount of costs recovered through base rates (versus riders) by approximately $136 million. Assertions that ENO seeks to guarantee its cost recovery[179] are misrepresentations of ENO's proposed rate structure and an attempt to justify an unreasonable ROE that does not reflect ENO's risk as compared to the industry.

C. The Advisors' and CCPUG's recommendations to employ a hypothetical lower equity ratio in calculating ENO's cost of capital are arbitrary and inconsistent with the *South Central Bell* decision.

Both the Advisors and CCPUG take the positions that as long as their respective witnesses opine that the ENO's actual equity ratio is unreasonable, then the required predicate for employing a hypothetical capital structure has been satisfied. That is insufficient under the

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177 Exhibit ENO-8 (Zimmerer Revised Direct) at 29. Note also that a portion of the initial five projects will be funded through excess deferred taxes as directed by Resolution R-8-277, and grid modernization investments that were forecast to close prior to December 31, 2019 were included in pro forma adjustment AJ14, which incorporates those amounts into base rates. (*Id*. at 30-31.)

178 *Id*.

179 Advisors Brief at 5-6.

South Central Bell decision.[180] That decision requires a finding that a specific investment decision was imprudent or unreasonable.[181] In the Louisiana Public Service Commission ("LPSC") decision that was the subject of the Louisiana Supreme Court's *South Central Bell* decision, the LPSC stated that "the Commission must determine whether that [utility's] capital structure is reasonable for ratemaking" and concluded the utility's actual equity ratio, which was approaching 60%, exceeded its "short term regulatory goal" of a 45% equity ratio and therefore should be reduced to a 50% equity ratio, a reasonable capital structure.[182] In overturning the LPSC's action, the Louisiana Supreme Court characterized the LPSC's action as "[a]pplying hindsight" to hypothesize a theoretical capital investment and structure for the utility.[183] The use of hindsight is improper in a prudence analysis.[184] The need for a proper prudence analysis is why the Louisiana Supreme Court stated the requisite for departing from a utility's actual capital structure to be a "finding by the Commission that the actual capital structure of the utility resulted from unreasonable or imprudent investments."[185] In this instance, both the Advisors and CCPUG are applying hindsight to ENO's actual equity ratio and asserting that ENO's filed equity ratio is unreasonable and should be lower. Neither the Advisors witness nor the CCPUG witness undertook a proper prudence analysis examining the decisions that led to ENO's filed

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180 *South Cent. Bell Tel. Co. v Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357 (La. 1992).

181 *Id*. at 368.

182 LPSC Order No. U-17949-A, dated May 25, 1989, at 17-20.

183 *South Cent. Bell Tel. Co.*, 594 So. 2d at 366.

184 *Id*. at 365-366 ("Further, under the prudent investment rule, a utility is compensated for all prudent investments at their cost when made, irrespective of whether they are deemed necessary or beneficial in hindsight. . . . Although a prudence review is necessarily retrospective in that it involves an examination of past circumstances, past information available, and past decisions, these factors may not be evaluated in light of subsequent knowledge." (citations omitted)).

185 *Id*. at 368.

equity ratio without the benefit of hindsight.[186] Thus, both the Advisors and CCPUG have not satisfied the requisite for departing from ENO's filed equity ratio and, essentially, are misconstruing the *South Central Bell* decision to permit the ratemaking practice that the *South Central Bell* decision prohibited – the arbitrary hindsight substitution of lower cost capital structure for a utility's actual capital structure.

As a counter to the *South Central Bell* decision, the Advisors contend that a later Louisiana Supreme Court case supports the Advisors' argument regarding the regulator's ability to set aside the utility's unreasonable capital structure in favor of a more equitable alternative.[187] The Advisors have misread that case. In *Entergy Gulf States, Inc. v. Louisiana Public Service Commission*, the Louisiana Supreme Court expressly stated that "the Commission has done no more than adopt the Company's actual capital structure using the actual amount of debt outstanding on the Company's books."[188] Thus, the LPSC did not set aside the utility's capital structure. The issue in that case pertained to a technical issue, which of two methods for measuring the utility's long-term debt should be used to calculate the utility's weighted average cost of capital. The court found neither approach to be more compelling than the other.[189] More importantly, the method of measuring ENO's long-term debt is not at issue in the instant proceeding.

Even assuming a hindsight inquiry is permissible, the rationales for the Advisors' and CCPUG's recommendations are flawed. The Advisors contend that ENO's filed equity ratio is

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186 Tr. (Watson) 06/21/19 at 56-57; Tr. (Kollen) 06/20/19 at 14-16.

187 Advisors Brief at 38.

188 730 So. 2d 890, 917 (La. 1999).

189 *Id*. ("After reviewing the arguments propounded by the Commission and Company, we conclude that there is no compelling support for the positions of either party, as far as we can discern").

unreasonable because it is higher than its parent's equity ratio,[190] but the Advisors point to no authority that holds a utility's equity ratio is unreasonable merely because it is higher than its parent's equity ratio. The Advisors suggest that ENO's filed equity ratio is unreasonable because it is higher than the average of its sister operating companies' equity ratios,[191] but the Advisors point to no authority that holds a utility's equity ratio is unreasonable merely because it is higher than such average. Furthermore, for the reasons stated previously, the Council would be arbitrary and capricious if it were to rely on a non-precedential agreement in principle or a data request response regarding financial planning to cap ENO's equity ratio at 50%.[192]

In its previous brief, ENO explained that CCPUG's capital structure recommendation was arbitrary and would understate ENO's cost of capital.[193] Now, CCPUG insists that Mr. Kollen testified that ENO's actual capital structure is unreasonable, but his hearing testimony is equivocal on this point.[194] When asked about his deposition testimony, Mr. Kollen affirmed that at his deposition, he said the following in response to the question "Are you saying that ENO did something imprudent with short-term debt, question mark?":

> No. I'm saying that this is how I recommend that you determine the capital structure and the cost or the rate of return that will be applied to rate base. And I'm not saying you [ENO] did anything wrong, you know, historically, or that you're [ENO is] doing anything wrong prospectively, but I'm saying that the Commission should, I think, make a presumption that you're [ENO is] going to use 2 percent short-term debt at least for purposes of setting the base rates.[195]

190 Advisors Brief at 38.

191 *Id*. at 37.

192 ENO Brief at 57-58.

193 *Id*. at 60-61.

194 CCPUG Brief at 96-97.

195 Tr. (Kollen) 06/20/19 at 15.

Mr. Kollen affirmed that he was not asserting that ENO did anything unreasonable with its short-term debt in the past or prospectively. Therefore, CCPUG's recommendation should be rejected.

Additionally, CCPUG's recommendation is internally inconsistent. CCPUG argues for presumption be applied for purposes of setting rates in this case but recommends that short-term debt be determined in the FRPs based on the average balance over the previous thirteen months ending with the last month of the evaluation period. At hearing, Mr. Kollen conceded that that method could result in a zero weighting.[196] This demonstrates the arbitrariness of Mr. Kollen's presumption. Accordingly, CCPUG's capital structure recommendation should be rejected.

D. The transformational investment desired by the Council requires new measures to maintain the stability of ENO's financial condition, whether they are forward-looking FRPs or a combination of traditional FRPs and riders; concerns about single-issue ratemaking, regulatory lag, or a utility's incentive to reduce costs are not compelling and do not take into account transformative goals that are necessary for ENO to progress to a twenty-first century utility.

As was stated previously, the Council's policy objectives for the benefit of customers require ENO to increase investment.[197] The Council approved the AMI Project, which will increase ENO's rate base in the near-term while bringing long-term cost savings,[198] and then later directed ENO to accelerate the project, which increased the project's costs.[199] In other words, the Company gave the Council a cost estimate, and the Council directed ENO to spend more to complete the project quicker than originally planned by ENO. The Council approved construction of the NOPS to meet capacity and reliability needs.[200] This construction grew out of a Council directive to pursue the development of local, new-build generation capacity after

196 Tr. (Kollen) 06/20/19 at 19.

197 ENO Brief at 67-68.

198 Resolution R-18-37, dated February 4, 2018.

199 Resolution R-18-99, dated April 5, 2018 and Resolution R-18-224, dated June 21, 2018.

200 Resolution R-18-65, dated Mar 8, 2018 and Resolution R-19-78, dated Feb. 21, 2019.

termination of the Entergy System Agreement.[201] The Council has been critical of ENO's electric distribution reliability,[202] and, accordingly, it has been necessary to increase Distribution Reliability and Vegetation Management Spending to improve ENO's reliability performance.[203] Also, the Council has directed ENO to prioritize a comprehensive grid modernization initiative.[204] In July 2019, the Council approved a Stipulated Settlement Term Sheet approving the construction of a self-build renewable resource, the purchase of a renewable resource, and a PPA sourced from a renewable resource.[205] These resources resulted from a Council directive regarding renewable resources.[206] Furthermore, ENO has advised that the utility industry and ENO are facing increasing costs and the need for large new investments in infrastructure and technology[207] and that ENO expects its capital expenditures over the period 2018-2022 to dwarf its capital expenditures over the previous five years.[208] Although the Company will use prudent utility practices to manage all of the necessary investments, this body of Council directives and the evidence in the record demonstrate unequivocally that ENO's costs, including capital costs, that one would ordinarily expect to be recovered through base rates are expected to increase in the near term.

The cost of the transformational change outlined above requires new ratemaking measures to maintain ENO's financial stability. ENO proposed traditional Electric and Gas

[201] Resolution R-15-542, dated November 5, 2015, at 12.

[202] Exhibit ENO-1 (Thomas Revised Direct) at 4, 23.

[203] Exhibit ENO-6 (Stewart Revised Direct) at 30-36; Exhibit ENO-33 (Todd Revised Direct) at 29 ("Very recently, ENO's management approved an increase of $5.0 million to address distribution system reliability.").

[204] Resolution R-18-36, dated February 4, 2018; Exhibit ENO-8 (Zimmerer Revised Direct) at 7-9.

[205] Resolution R-19-293, dated July 25, 2019.

[206] Resolution R-18-97, dated April 5, 2018.

[207] Exhibit ENO-1 (Thomas Revised Direct) at 53.

[208] *Id*. at 48.

FRPs and three new riders and the continuation of an existing rider (collectively the "Specific Project Riders") to mitigate harmful regulatory lag from undermining its ability to earn its authorized return and the cash flow necessary to support investing to create this transformational change. The Advisors have proposed Electric and Gas FRPs with forward-looking adjustments to mitigate harmful regulatory lag. ENO supports this proposal, assuming a reasonable ROE is set in this proceeding, and believes such proposal could mitigate the need for two of the new riders. As one can see, the Company and the Advisors agree that regulatory lag is a concern for ENO given its planned capital program and the Council's objectives. Accordingly, the Council should approve a set of new ratemaking measures to address regulatory lag and maintain ENO's financial stability, and all of the arguments in opposition to the Advisors' proposed forward-looking FRPs or the Company's combination of traditional FRPs and riders regarding single-issue ratemaking, regulatory lag, or incentives for a utility to control costs are misplaced.[209]

CCPUG argues that new measures are unnecessary because traditional FRPs "provide near real-time recovery of costs actually incurred."[210] This statement has no evidentiary support. CCPUG's testimony contains the vague, conclusory statement that traditional FRPs "eliminate much of the regulatory lag" without any analysis to clarify what this statement means.[211] In contrast, Company witness Mr. Thomas provided an analysis showing the cash flow effects of recovering a large, long term capital project with multiple plant closings throughout the year, like

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209 Advisors Brief at 12 ("This creates an incentive for the utility to continue reducing their costs and increasing their efficiency."); AAE Brief at 17 ("riders can also result in such additional undesirable consequences as reducing utility incentives to control costs"); Air Products Brief at 37 ("However, the proposed structure of ENO's bandwidth adjustment mechanism, which resets rates to the EPCOE if ENO earns outside of the bandwidth, reduces the incentive for the utility to improve its efficiency of operations.").

210 CCPUG Brief at 72.

211 Exhibit CCPUG-3 (Baudino Direct) at 56.

the GIRP and grid modernization, in a traditional FRP versus a rider, like the GIRP Rider or the Rider DGM, in his Exhibit JBT-8. The analysis showed that, for these types of projects, rider recovery provided substantially more cash flow – more than ten times the cash flow – than traditional FRP recovery over a two-year period.[212] Thus, the evidence in the record shows that a traditional FRP would compromise cash flow associated with capital projects like the GIRP and grid modernization and that new measures, such as the Specific Project Riders, are the superior mechanism for achieving "near real-time recovery of costs actually incurred" and support ENO having a reasonable opportunity to earn its authorized return as required by the *Hope* and *Bluefield* standards.

Thus, the evidence in the record shows that a traditional FRP would result in a significant deterioration of ENO's financial condition with capital projects like the GIRP and grid modernization.[213]

Although the Alliance for Affordable Energy ("AAE") does not oppose the Advisors' proposed FRPs with forward-looking adjustments, AAE suggests that forcing ENO to bear regulatory lag is justified because ENO has not filed a base rate case in ten years and has been overearning in recent years.[214] AAE misunderstands the purpose of the proposed riders. ENO has the unilateral right to file a rate case when it deems necessary.[215] Filing pancaked rate cases to timely recover the costs of the GIRP, grid modernization, and AMI could address ENO's regulatory concerns but would cause customers to bear significant costs associated with the preparation and conduct of those rate cases. Instead, ENO is proposing the Specific Project

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212 Exhibit ENO-1 (Thomas Revised Direct) at 54.

213 *Id*.

214 AAE Brief at 17.

215 See *Louisiana Power & Light Co. v. Louisiana Pub. Serv. Comm'n*, 523 So. 2d 850, 856 n. 3 (La. 1988).

Riders as a way to timely recover the costs associated with those capital projects without incurring significant rate case costs, which would be the responsibility of customers. Also, from a factual standpoint, AAE's suggestion is inequitable because AAE overlooks that the Council has approved the rate path leading to this rate case.[216] The Council, pursuant to an agreement in principle regarding Ninemile 6, ordered ENO to file a base rate case in 2014,[217] but the Council later decided to forego that rate case. In 2014, pursuant to an agreement in principle, the Council approved a four-step phased-in base rate increase for Algiers Customers and a FRP and directed ELL and ENO to seek approval for ENO to purchase ELL's electric operations in Algiers ("Algiers Transaction").[218] In 2015, pursuant to an agreement in principle, the Council approved the Algiers Transaction, affirmed the four-step phased-in base rate increase for Algiers Customers, eliminated the Algiers FRP, and established a base rate freeze lasting until the filing of this rate case.[219] Thus, the Council approved the timing of this rate case.

Also, AAE argues that ENO is concerned about regulatory lag only because the decision in this proceeding will reduce its earnings. AAE ignores the effect of regulatory lag on the ability of the Company to achieve ambitious goals. Additionally, AAE overlooks important facts. The Council and ENO together repeatedly have developed ratemaking solutions to address regulatory lag for the benefit of customers and the Company while maintaining rates below the national average. As mentioned previously, last year, when the Tax Cuts Act's reduction to the federal corporate income tax rate became effective January 1, 2018, the Council embraced

[216] Since its last rate case concluded in 2009, ENO filed three sets of evaluation reports in the previous Electric and Gas FRPs; these proceedings resulted in three successive electric and gas rate decreases for customers with the last decrease occurring in 2013. The last rate decrease was accompanied by a refund so as to make the rate decrease effective as of October 2012.

[217] Resolution R-12-29, dated February 2, 2012.

[218] Resolution R-14-278, dated July 10, 2014.

[219] Resolution R-15-194, dated May 14, 2015, at 4.

single-issue ratemaking in order to avoid regulatory lag that would have prevented customers from receiving the benefits of that tax rate reduction until the rates set in this proceeding became effective,[220] and, as result of an agreement in principle, ENO's customers began receiving the benefits of the reduction in tax expense in 2018.[221] Other ratemaking solutions to address regulatory lag that were developed through consensus include the PPCACR Rider and the two MISO Cost Recovery Riders currently in effect. In additional to near-contemporaneous cost recovery, these riders also have facilitated contemporaneous realization of significant savings for customers (*e.g.*, joining MISO, fuel savings) and other benefits for ENO's customers.

1. CCPUG's and APC's proposals to modify the Electric and Gas FRPs are contrary to Council practice and would prevent ENO from having an opportunity to recover its costs.

CCPUG argues that the Council should delay implementation of the FRPs to 2021 with an initial evaluation period of 2020, if the Council includes expected capital additions through December 31, 2019 in the revenue requirements determined in this proceeding.[222] Such delay would be inconsistent with past Council practice. The Council previously has used the calendar year when new base rates go into effect as the first evaluation period for multi-year FRPs. This occurred with respect to the 2003 evaluation period under ENO's first FRPs pursuant to Resolution R-03-272 and the 2009 evaluation period under ENO's second FRPs pursuant to Resolution R-09-136.[223] This same approach was used by the Louisiana Public Service Commission following Entergy Louisiana, LLC's ("ELL") last base rate case, which ELL, like

[220] Resolution R-18-38, dated February 8, 2018, Ordering Paragraph 1.

[221] Resolution R-18-227, dated June 21, 2018.

[222] CCPUG Brief at 70.

[223] Exhibit ENO-3 (Thomas Rebuttal) at 12.

ENO here, also sought a three-year FRP.[224] Thus, the proposed Electric and Gas FRPs' structures are consistent with Council's past practice. Moreover, the timing of the first FRPs ensures that the level of rates set as a result of the base rate case that established the FRPs is appropriate.

APC argues that should ENO's earned ROE in the FRPs fall above or below the proposed fifty-basis point bandwidth, the revenue adjustment should be only partially moved 60% of the way towards the upper or lower end of the bandwidth, respectively.[225] ENO disagrees because such a sharing mechanism would result in ENO not having an opportunity to recover its costs. The evidence in the record demonstrates unequivocally that ENO's costs, including capital costs, that one would ordinarily expect to be recovered through base rates are expected to increase in the near term. In such circumstances, APC's proposed sharing mechanism would always result in rate adjustments that set rates at a level below ENO's revenue requirement and would provide no opportunity to recover its costs. Accordingly, the Council should reject APC's proposal.

E. The Company's proposed rate design reasonably balances cost causation, rate effects and preserves past Council decisions in a manner that is just and reasonable.

1. The Council should approve the Company's proposed rates and rate design, including the Algiers Residential Rate Transition Plan.

a. ARRT Plan-- ENO's proposed Algiers residential rate transition (ARRT) plan is reasonable and should be adopted.

The briefs of the parties confirm that no party opposes in concept ENO's Algiers Residential Rate Transition Plan ("ARRT"), though Advisors and CCPUG propose minor adjustments to its implementation. Importantly, Advisors' Initial Brief eliminates an area of

224 *Id*.

225 Air Products Brief at 37.

uncertainty when it states that the ARRT "could be implemented in the context of a Rider applicable to the combined residential base rate tariff and would extend to future rate actions as necessary."[226] Using a rider to implement the ARRT aligns with ENO's proposal, and eliminates unnecessary complexities associated with attempting to implement the ARRT through the FRP or the base rate tariffs, as explained in ENO's Initial Brief.[227]

Although ENO recognizes that there is more than one plausible method for mitigating Algiers residential rate impacts, ENO continues to disagree with Advisors' proposal to implement the ARRT by shifting the residential class allocation from Algiers customers to Legacy ENO residential customers. ENO, continues to believe it is more reasonable to accomplish the temporary mitigation between Algiers customers and the customer classes otherwise receiving the largest overall rate decreases in this case. The classes ENO proposes to include in the ARRT Plan (Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible) receive overall rate decreases under ENO's proposed allocation ranging from 7.01% to 22.59%.[228] The residential class, by comparison, receives an overall rate reduction of 0.04%, and a typical residential customer (1000 kwh per month) receives an increase of 1.65%.[229] Although the Advisors highlight that their version of the ARRT Plan results in no initial change in rates for Algiers customers,[230] under the Advisors' approach to the ARRT Plan, considering just the impact of the Base Rate Adjustment Rider, independent of FRP changes, residential Algiers customers will receive higher rate increase adjustments in the future

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226 Advisor Brief at 58.

227 ENO Brief at 89-92.

228 Exhibit ENO-56, Statement AA-2_E: Summary of Impact of Proposed Rates.

229 Exhibit ENO-56, Statement AA-5_E Errata: Summary Bill Comparisons.

230 Advisors Brief at 57.

(4% annually) compared to ENO's proposal (3.5% annually) irrespective of any applicable FRP adjustment. On balance, ENO's approach reflects a balancing of interests that mitigates potential hardships caused by shifts in cost responsibility; as such, adoption of ENO's ARRT proposal is a sound exercise of Council rate setting discretion.

Air Products, which is in one of the classes affected by the ARRT Plan, expresses no opposition to its implementation. CCPUG similarly recognizes the need for the ARRT Plan. However, CCPUG continues to argue that any reduction to the ENO proposed revenue requirement should be applied first to undo the impact of the ARRT on the classes participating in it, rather than being applied as an overall reduction to the benefit customers overall.[231] Air Products similarly proposes dedicating reductions to ENO's overall revenue requirement to reducing the revenues allocated to certain customer classes.[232] ENO has already addressed in its Initial Brief why it is improper to mix revenue requirement determinations with cost allocations. Proper rate-setting methodology requires that the revenue requirement be determined as a whole, prior to determining how to allocate that revenue requirement.[233] Beyond this, ENO notes that Advisors' Initial Brief zeros in on the flaw in CCPUG's proposal: "CCPUG proposal would, in effect, transfer the funding of Algiers mitigation to all other customers except those four large industrial customer classes."[234] In the same manner, APC's proposal to devote revenue requirement reductions (which ENO opposes) to only select classes would prevent other classes from fully participating in any such reduction the Council might see fit to adopt.

231 CCPUG Brief at 18-19, 76-77.

232 Air Products Brief at 30-31.

233 ENO Brief at 92-93.

234 Advisors Brief at 56.

b. ***Revenue Allocation-- The Company's proposed revenue allocation reasonably balances cost of service principles, Council policy, and customer rate impacts.***

Revenue allocation is as much art as science, depending as it does on balancing considerations of cost causation, customer impacts, rate stability and other important policies. ENO continues to urge the Council to carefully consider the positions of the parties, in the light of the credible evidence, so as to arrive at a class revenue allocation that reasonably balances the competing allocation policies.

ENO's main concern with the revenue allocation recommendations of the Advisors continues to be their idea that final adjustments to the results from the class cost of service should be based on varying the class rate of returns until a satisfactory result is reached.[235] ENO continues to believe this approach is overly subjective and, frankly, arbitrary, as explained in Section II, N. of this brief.

CCPUG expends many pages complaining in a hyperbolic tone about the "massive subsidies" it is exposed to under ENO's proposed electric revenue allocation. The Council, however, should take pains to separate the facts of the case from CCPUG's inflammatory, unhelpful rhetoric.

First, CCPUG focuses almost exclusively on the allocation of ENO base revenues, ignoring almost completely the overall impact of the rate change. Yet, CCPUG does recognize that the large base revenue increase for all classes does not represent an actual increase in rates, because much of that increase simply represents a shift, from recovery of the same costs in riders to recovery through base rates.[236] From the standpoint of the overall change in rates (including

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[235] *E.g.*, Advisor Brief at 54.

[236] CCPUG Brief at 4-5. *See e.g.*, Exhibit CCPUG-5 (Baron Direct) at 7.

base revenues and riders) the classes of concern to CCPUG (Large Electric ("LE"), Large Electrict - High Load Factor ("HLF") and High Voltage ("HV")) are among the best off of all the classes. While these classes' proposed base revenue allocation increases from ENO present revenues, *their overall proposed revenues decrease substantially* from present rates:

Customer Class	Present Revenue	Proposed Revenue	% Reduction
Large Electric	**$46.7 M**	**$43.5 M**	**(7.01%)**
Large Electric HLF	**$166.6 M**	**$154.8 M**	**(7.05%)**
High Voltage	**$13.4 M**	**$11.9 M**	**(11.26%)**[237]

ENO's proposed revenue allocation was designed to consider the stated goals of the Council regarding gradualism in rate changes, whereas CCPUG's proposed revenue allocation will serve to increase the already substantial reduction in rates these customers will experience, to the detriment of other customer classes, especially residential customers.

Another oft-repeated CCPUG complaint is that ENO is arbitrarily and without justification departing from the Class Cost of Service Study.[238] Almost in the same breath, however, CCPUG goes on to admit that it too has departed from the Class Cost of Service Study ("CCOS") by allocating the base revenue requirement on an equal percentage basis. In fact, this same allocation method is the starting point for ENO's revenue allocation as well.[239] In addition to employing the same revenue allocation methodologies, CCPUG and its witness agree that ENO's allocation reduces the inter-class "subsidies" that CCPUG claims exist. Mr. Baron explains that "the roll-in of fixed PPA production demand costs into base rates, as proposed by ENO, provides subsidy reduction itself.[240] Mr. Baron's testimony further shows that the ENO

237 Exhibit ENO-56 Statement AA-2_E: Summary of Impact of Proposed Rates.

238 *E.g.,* CCPUG Brief at 52-53.

239 Exhibit ENO-45 (Talkington Revised Direct) at 29.

240 Exhibit CCPUG-5 (Baron Direct) at 27.

proposed revenue allocation reduces the offending "subsidies" to residential customers by almost $10 million.[241]

CCPUG's biggest complaint with ENO's proposed revenue allocation is the Company's proposal to allocate the costs of the wholesale baseload ("WBL") and the unregulated thirty percent portion of River Bend ("RB30") PPAs ("Resource Plan PPAs")[242] on the basis of energy. CCPUG bewails the fact that this allocation proposal is a departure from the allocation of capacity costs in the COSS.[243] Of course, CCPUG is once again quick to forget that its own proposed allocation of these costs—using an equal percentage revenue increase for all classes—is also a departure from the COSS. In fact, though these costs are not allocated in the same manner as in the COSS, no party to this case recommends strictly following the cost of service study, because such an approach would lead to substantial adverse customer rate impacts.

Contrary to CCPUG's arguments, there is nothing arbitrary or politically motivated about ENO's proposal to continue the existing allocation of the Resource Plan PPAs based on class energy consumption. As ENO thoroughly explained at hearing and in its initial brief, this approach continues the allocation that the Council has already ordered for these costs in 2003; it addresses concerns of the Council that the revenue allocation ENO proposed in its initial rate case filing weighed too heavily on residential customers; and it is properly based on cost causation concepts, since a key benefit of these contracts has been the realization of significant energy

241 Compare *Id.* at 17 (residential subsidy at present ENO rates =$45.3 M) to *Id.* at 21 (residential subsidy at proposed ENO rates = $35.5 M).

242 Legacy ENO Customers' FAC rate includes capacity expenses associated with a PPA with ELL sourced from the unregulated 30% portion of River Bend owned by ELL and EAL sourced from its WBL resources, which PPAs are referred to as the "Resource Plan PPAs."

243 *E.g.,* CCPUG Brief at 14-16.

savings for all customer classes.[244] As ENO witness Thomas explained:

> … those units provide a low-cost source of energy in that, you know,they have a low variable cost of operation and, therefore, the energy cost of those resources is low, which is picked up through fuel on a per kilowatt hour charge. And ultimately the per kilowatt hour charge for those particular resources is low, which benefits flow primarily to the larger users of electricity.[245]

Regarding the energy benefits of these contracts, CCPUG erroneously contends that an energy-based allocation is wrong because "as a class, the Residential class benefitted from the EAL WBL and River Bend 30% PPAs [Resource Plan PPAs] as much as, or more than, the Large Electric and Large Electric High Load Factor classes."[246] This claim provides no basis whatsoever for rejecting ENO's proposed energy-based allocation. Under ENO's proposal, *all customers*, not just CCPUG's favored classes, are allocated their cost-based share of the Resource Plan PPAs based on their energy use. As CCPUG's witness testimony shows, residential customers, for example are still allocated the greatest share of these costs—$23.9 million—because they have the greatest share of energy usage.[247] This energy-based approach allocates costs fairly to all customer classes consistent with fundamental cost causation principles.

In sum, the testimony of ENO witnesses Joshua Thomas and Myra Talkington, summarized and further discussed in ENO's Initial and Reply Briefs, fully supports ENO's revenue allocation as reasonable and consistent with well accepted cost allocation and rate design principles. That said, ENO realizes that in the case of revenue allocation, there can be more than one way to arrive at a reasonable result, and requests that the Council render a fair and judicious decision on these matters, consistent with the weight of the credible evidence.

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[244] ENO Brief at 84-85; Tr. (Thomas) 06/20/19 at 46-55.

[245] *Id.* at 58.

[246] CCPUG Brief at 61.

[247] Exhibit CCPUG-5 (Baron Direct) at 19 (Table 2).

F. The Company's proposed customer charge reduces subsidies among high and low usage residential customers, and reasonably balances consideration of cost of service principles and customer rate impacts.

Advisors, AAE, and Building Science Innovators, LLC ("BSI") all address the Company's proposed customer charge. BSI briefly argues, for the first time its brief, that the customer charge should be lowered to $5.00. BSI has provided no evidence to substantiate this untimely assertion and its proposal is inconsistent with well-established principles of rate design, as discussed by Dr. Faruqui and Ms. Talkington.[248] BSI's proposal should be rejected.

Advisors' main concern regarding ENO's proposed customer charge is that the increase is purportedly not gradual enough: "ENO's proposed $15.21 electric customer charge is almost a 100% increase above the existing customer charge, and that large change would have a substantial adverse impact on low-use customers."[249] Advisors' professed concern, however, is unsupported by any data or analysis cited in their brief. In fact, though the increase from $8.07 to $15.21 appears large in percentage terms, it is part of an overall monthly bill that for low use residential customers (250 kwh) is in the range of only $46.00.[250] As Ms. Talkington explained,

> ENO's proposed increase in the customer charge is well below the $21.07 charge that would reflect the unit cost of service. While there are variations among usage levels in monthly bill effects, for ENO Legacy residential customers on average, the overall rate change proposed by ENO is 1.29%, including the effect of the higher customer charge. The customers at lower usage levels experience a higher relative percentage increase, but they also have the lowest overall bills. Moreover, it is these customers who are currently receiving the largest subsidies from higher usage residential customers. On balance, I continue to believe ENO's proposed customer charge is reasonable.[251]

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[248] *See, e.g.,* Exhibit ENO-16 (Faruqui Rebuttal) at 17-25; Exhibit ENO-46 (Talkington Rebuttal) at 11-19; Exhibit ENO-47 (Talkington Rejoinder) at 11-15.

[249] Advisors Brief at 62.

[250] Exhibit ENO-56, Statement AA-5_E Errata: Summary Bill Comparisons.

[251] Exhibit ENO-47 (Talkington Rejoinder) at 14-15.

AAE makes several erroneous claims in the course of its attempt to argue there should be no movement at all towards cost of service in the residential customer charge:[252]

- Focus on incremental costs, not embedded costs, is the key to proper rate design;
- ENO allegedly "refuses to recognize"[253] that an excessive customer charge will have negative effect on energy efficiency programs.
- ENO's unit cost study does not reliably represent the costs associated with the customer charge.
- ENO's proposed customer charge adversely affects low income customers.
- ENO's proposed customer charge is higher than an average of other utility customer charges, calculated based on a nationwide survey of customer charges.

ENO will address these erroneous claims in turn.

Regarding AAE's insistence that rate design in this case should be based on review of incremental, rather than embedded costs, AAE rather than ENO is off base. Advisors' Brief succinctly identifies AAE's error: "AAE witness Barnes' argument that the customer charge should reflect the cost to add one additional customer inappropriately juxtaposes incremental cost concepts with rate design based on the allocation of embedded costs."[254] Under Council direction and rate setting policies in this case, rates are to be set to recover fully allocated embedded costs. Nowhere does the Council hint that rate design is to depart from this principle. In fact, as Dr. Faruqui explains, AAE's viewpoint is not "to be found in the rates that are offered by most utilities in the U.S., which use embedded costs to design rates."[255]

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[252] AAE Brief at 19-31.

[253] *Id.* at 22.

[254] Advisors Brief at 62.

[255] Exhibit ENO-16 (Faruqui Rebuttal) at 20.

ENO's design of the customer charge to collect the allocated minimum fixed cost of customer service is completely consistent with these principles. Ms. Talkington further detailed the evident flaw in AAE's focus on incremental (*i.e.*, marginal) customer-related costs:

> Mr. Barnes contends that his approach is more consistent with marginal pricing principles, which he believes are more appropriate for determining the customer charge, and he seems to fault ENO for not preparing a marginal cost study. ENO did not perform such a study, however, because it is not required by the Council. The Council instead requires "rates based on an evaluation of fully allocated electric and gas cost of service studies, and alternatives, that include total revenues and allocate total utility costs to the various rate classes." Mr. Barnes' approach would not be consistent with these principles, because he excludes from his evaluation of customer-related costs a significant portion of the fixed cost of serving customers.[256]

Equally unavailing is AAE's claim that ENO "refuses to recognize" the negative impact of the proposed customer charge level on energy efficiency. There is no such negative impact to recognize, again as explained by Dr. Faruqui. Dr. Faruqui pointed to studies indicating that in determining whether to pursue energy efficiency, customers respond to their total bill, rather than to particular components. The fact is, customers:

> are rarely influenced by how large is the fixed portion of their bill. As a result, increasingly weighting a rate design towards fixed charges will… have little impact on average price or customer incentives to conserve electricity.[257]

Additionally, Company witness Thomas explained that putting too many customer costs in the energy charge results in an unfair subsidy to customers who can avoid their fair share of those fixed costs by installing solar and reducing their consumption from ENO's system.[258] AAE's only response to this problem is to fault ENO for not producing a study to support Mr.

256 Exhibit ENO-46 (Talkington Rebuttal) at 17-18.

257 Exhibit ENO-16 (Faruqui Rebuttal) at 22.

258 Exhibit ENO-1 (Thomas Revised Direct) at 62.

Thomas' contention.[259] In fact, as Mr. Thomas explained during the hearing, he did not need an empirical study to support this straightforward conclusion:

> I guess I don't know that ENO would need to do a study to determine that. I think it's fairly evident that … [i]n the way that Entergy New Orleans' rates are currently structured, … [o]ur costs are highly fixed and our rates are highly volumetric. So when a customer adopts, you know, solar, then the amount of kilowatt hours that they displace in their usage is -- the total cost that is recovered from that customer is no longer consistent with the amount [of fixed costs] that ought to be recovered from that customer.[260]

AAE makes several claims in support of its position that ENO's unit cost study does not reliably represent the costs associated with the customer charge. AAE argues, taking various fragments of the record out of context, that ENO has inconsistently varied its representations regarding the nature of the costs. This is simply untrue. ENO has consistently stated that customer costs are the fixed costs necessary to serve a customer regardless of whether the customer imposes a demand on the system, and that these costs are driven by the number of customers, not the volume of energy consumed.[261] Indeed, this very definition is captured by AAE's description of customer costs: "the customer charge should reflect the cost of a customer that does not impose a demand or consume energy."[262]

In fact, it is AAE's theories regarding the customer charge that are inconsistent. For example, AAE says the proper way to identify customer-related costs is to focus on those costs that vary with the number of customers. Mr. Barnes, however, without explanation eliminated

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259 AAE Brief at 23.

260 Tr. (Thomas) 06/20/19 at 91.

261 *E.g.*, Exhibit ENO-1 (Thomas Revised Direct) at 61; Exhibit ENO-45 (Talkington Revised Direct) at 23; Exhibit ENO-46 (Talkington Rebuttal) at 16.

262 AAE Brief at 26.

from the customer charge compilation various items in the COSS that are allocated based on number of customers.[263]

AAE also attempts to cobble together a claim that ENO has improperly included executive salaries in the costs subject to the customer charge. Mr. Barnes' testimony does not address this matter specifically, and AAE has instead attempted to use a discovery response as the basis for an after-the-fact analysis, included for the first time in its brief.[264]

First of all, contrary to AAE's representation, the discovery response (ENO Response to AAE 2-4) does not establish the ENO has included "$3.5 million of officer and executive compensation…." AAE cites only to a single line in an ENO spreadsheet supporting its customer charge calculation (Tab RR4 Customer, Line 295), which reveals only that $3.5 million is allocated to the residential class for account "920: Salaries." FERC Account 920 includes not only salaries of officers and executives, but also "other employees of the utility properly chargeable to utility operations and not chargeable directly to a particular operating function."[265]

Regardless of the error in AAE's characterization of the nature of Account 920 costs, the inclusion of a portion of Account 920 and other A&G costs in the customer charge is consistent with the fact that the persons carrying out the direct customer services necessary to extend and maintain initial service to the customer need an organization to support them in that particular work. This is the case with customer service, just as it is in any other aspect of utility service.

As Ms. Talkington explained:

> Mr. Barnes' formulation, for example, in effect assumes that zero general and administrative costs are expended to support basic customer service functions. Similarly, it effectively assumes that zero costs of customer premises utility

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263 AAE highlights the inconsistency in its own approach in its Brief at 27.

264 AAE Brief at 28 and n. 64.

265 FERC Uniform System of Accounts, Account 920 definition.

> installation activities relate to the fixed cost of serving customers. These are not reasonable assumptions. Indeed, his proposal appears to assume that a customer may only want to connect to the grid with no desire to receive a service.[266]

AAE also continues to argue that the proposed customer charge disadvantages low use, low income customers. AAE's statements in brief, however, reveal its overly narrow view of the interests of low income customers. For example, at p. 29 of its brief, AAE states that "[c]ustomers with *lower* than average monthly usage are *nearly* equally likely to experience difficulty paying their bills as higher usage customers." (Emphasis added). What this statement implicitly recognizes is that higher usage low income customers are *even more likely* to experience difficulty paying their bills than lower usage low income customers. ENO's proposed customer charge helps these higher usage low income customers by making sure that the fixed customer costs of providing service are not shifted to them from lower usage customers. AAE's proposal, on the other hand, ensures that lower usage customers do not pay their fair share of costs, while at the same time making it even harder for low income customers with higher usage to pay their electric bill.[267]

Finally, AAE argues that ENO's proposed customer charge is unreasonable because it is higher than an average of utility customer charges Mr. Barnes has compiled based on a survey of utilities nationwide, and because it is higher than the customer charges of several ENO affiliates.[268] Mr. Barnes' survey information and related conclusions should be given no weight, since they have no reliable tendency to cast doubt on the reasonableness of ENO's proposal. Mr. Barnes' ENO "comparable" group, for example, included 12 companies with a customer charge

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266 Exhibit ENO-46 (Talkington Rebuttal) at 17.

267 See also Exhibit ENO-16 (Faruqui Rebuttal) at 23 (high usage low income customers would experience a decrease due to ENO customer charge proposal since the volumetric charge would be lower).

268 AAE Brief at 31.

at or higher than the level proposed by ENO.[269] His "national" group of companies included 28 with a customer charge $15 of higher.[270] Moreover, though he described some of these utilities as "comparable" to ENO, Mr. Barnes made no investigation of how they compared to ENO in terms of residential customer base, number of customers, governing regulatory rate design policies, or distribution system characteristics.[271] Ultimately, Mr. Barnes agreed he was not "actually recommending the ENO customer charge in this case should be established by the benchmarking results."[272]

AAE's reference to the customer charges of ENO affiliates EAL and Entergy Texas, Inc. ("ETI") are equally unsupportive of its position. Although these companies' approved customer charges are lower than ENO's proposal, they are much larger utilities with different operational and customer characteristics. What is more informative, however, as pointed out by Ms. Talkington, is that these approved customer charges cover 74% of EAL's customer-related costs, and 73% of ETI's customer costs, respectively. Approval of an electric customer charge of $10 for ENO (as proposed by Advisors) covers only 48% of its customer-related costs. ENO's proposed $15.53 customer charge, however, would allow it to recover 74% of customer-related costs, which is squarely in line with the level of fixed customer cost support produced by the EAL and ETI customer charges.[273]

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[269] Tr. (Barnes) 06/21/19 at 10.

[270] *Id.* at 11.

[271] *Id.* at 12-13.

[272] *Id.* at 11.

[273] Exhibit ENO-46 (Talkington Rebuttal) at 16.

1. A customer-based charge for recovery of AMI costs is consistent with cost causation principles.

ENO has demonstrated that AMI costs are fixed and driven by customer count, and that ENO's proposed AMI charge directly incorporates the customer service-related savings of advanced meter deployment.[274] As such, allocation of those costs based on customer count and collection of those costs through a customer chargedis, as opposed to Advisors' and AAE's attempt to make a much more complex allocation of costs based on subjective judgments about the ultimate benefits of AMI metering. Stated simply, just as is the case with traditional meter costs, collecting AMI costs through a customer charge reflects the manner in which ENO incurs costs for the benefit of customers. The Company will not repeat the details of that discussion (which is equally applicable to the claims made in the briefs of Advisors and AAE) but notes here several instances in which AAE's brief opposing the AMI customer charge actually highlights the correctness of recovering AMI costs through a customer charge.

AAE, for example, argues that allocation of AMI costs should be based on the view that an AMI meter can be a tool to produce energy and demand savings.[275] The problem with this view, from the standpoint of AMI deployment costs, is the AMI meter and related customer costs do not change with or depend on energy and demand savings. Those meter costs remain the same per customer, regardless of how successfully a customer is at using AMI to control their energy costs. The savings AAE is talking about come in ENO's energy charges, which are allocated to and collected from customers completely separate from the customer charge. Mr.

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274 ENO Brief at 22, 75-77; Exhibit ENO-1 (Thomas Revised Direct) at 55, 66 ("Through the proposed AMI Charge, which I discuss later in my testimony, customers will receive routine meter reading, meter service, and reduced write-off benefits, which represent approximately 36% of AMI project benefits."). Exhibit ENO-3 (Thomas Rebuttal) at 43-47.

275 AAE Brief at 42.

Thomas' explanation of this point is undisputed: separate and apart from the customer charge, "[c]ustomers will automatically and immediately receive consumption reduction and unaccounted for energy reduction benefits as advanced meters are deployed. These two items represent approximately 50% of AMI project benefits."[276]

AAE's reference to the savings from "drive by" meter reads using AMI technology further bolsters ENO's position.[277] The realization of such savings has nothing whatever to do with reduction in demand or consumption by the customer. The savings result simply because the customer has an AMI meter, regardless of their consumption level. The costs incurred to produce those savings are therefore appropriately captured through a per customer charge. ENO's proposed customer charge for recovery of AMI fixed customer costs should be adopted.

G. The Advisors' assessment of financial risk to customers from the ENO's proposed ratemaking treatment of FIN 48 Accumulated Deferred Income Taxes ("ADIT") is incorrect because the related deferred income tax expense does not increase the income tax expense included in the Company's revenue requirement; CCPUG makes a similar argument, which should be rejected.

ENO has excluded from its rate base the portion of various ADIT liabilities that is unlikely to produce cost-free capital due to the uncertain (*i.e.*, aggressive) tax position subject to FASB Interpretation No. 48 ("FIN 48") taken by ENO in its filings with the tax authorities. The Advisors argue that because ENO proposes to remove the FIN 48 ADIT for rate base but not reduce the related deferred income tax expense, the risk of ENO not achieving aggressive tax positions "is largely placed on the ratepayers."[278] The Advisors are incorrect and ignore the hearing testimony of their expert, Mr. Proctor.

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276 Exhibit ENO-1 (Thomas Revised Direct) at 55.

277 AAE Brief at 42.

278 Advisors Brief at 42.

At hearing, Mr. Proctor admitted whether ENO took an aggressive tax position resulting in ADIT has no effect on the amount income tax expense included in the Company's revenue requirements. The Advisors ignore what occurred at hearing on this issue. The pertinent colloquy is discussed in detail in ENO's Brief at 142 through 147. To summarize, the colloquy focused on two examples in Exhibit RLR-6 to Exhibit ENO-52: Example One, in which there was no timing difference as Regulatory Pre-Tax Income was the same as Tax Return Taxable Income,[279] and Example 3, in which there was a timing difference similar to that which occurs when a utility takes an aggressive tax position[280] or uses accelerated tax depreciation on its income tax return.[281] When confronted with these examples, Mr. Proctor admitted that whether or not ENO uses an aggressive tax position or accelerated tax depreciation on its income tax return does not affect the level of income tax expense included in ENO's revenue requirement and customers' rates.[282] Thus, whether ENO takes the aggressive tax position or not does not affect the amount of income tax expense included in ENO's revenue requirement and rates and, therefore, does not shift financial risk to the customers.

The Council should also reject the Advisors' alternative argument, which demonstrates the Advisors' misunderstanding of income tax normalization, as discussed in ENO's previous brief.[283] When ENO takes a deduction pursuant to an aggressive tax position, current income tax expense is reduced (*i.e.*, credited) and deferred income tax expense is debited (*i.e.*, debited).[284]

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279 Tr. (Proctor) 06/21/19 at 103.

280 *Id*. at 105.

281 *Id*. at 104.

282 *Id*. at 114-115.

283 ENO Brief at 148.

284 Exhibit ENO-50 (Roberts Rebuttal) at 3 ("Customers' rates reflect the same amount of income tax expense because the deferred income tax expense for normalized items is offset dollar for dollar by an increase or reduction in the current income tax expense.").

That is why Example One and Example Three in Exhibit RLR-6 show the same amount of income tax expense in ENO's revenue requirement. If the deferred income tax expense debit is excluded, then the related current income tax expense credit should be excluded as well, resulting in no change to ENO's revenue requirement.

CCPUG argues that the income tax expense in ENO's revenue requirement should be lower because of the aggressive tax position.[285] The Council should reject that argument for reasons similar to those discussed above. As discussed above, taking an aggressive tax position or any other deduction causing a timing difference does not change the amount of income tax expense included in ENO's revenue requirement and ENO's rates. Moreover, ENO does not pocket "carrying charges"; ENO accrues interest expense on its aggressive tax positions, which interest expense is not borne by customers.[286]

H. The Advisors' arguments opposing the inclusion of net operating loss ("NOL") ADIT in rate base are erroneous and not based on current tax law; if followed by the Council, the Advisors' advice would harm customers.

ENO fully addressed the Advisors' arguments in detail in its previous brief.[287] Therein, ENO explained that the Council should approve the inclusion in rate base of the portion of NOL ADIT attributable to accelerated tax depreciation consistent with Internal Revenue Service ("IRS") Private Letter Rulings ("PLRs"), included in the evidentiary record as Exhibit RLR-2 to Exhibit ENO-50, reviewing regulated ratemaking treatment of NOL ADIT in other jurisdictions. ENO is only seeking to include the amount of NOL ADIT in rate base that the IRS requires to

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285 CCPUG Brief at 81 ("This occurs because customers paid income tax expense as if there were no tax deduction . . .").

286 Exhibit ENO-50 (Roberts Rebuttal) at 19.

287 ENO Brief at 136-145.

avoid the loss of using accelerated tax depreciation. If ENO loss the ability to claim accelerated tax depreciation, customers rates would increase due to the loss of cost-free capital.

In their brief, the Advisors argue that the PLRs have "very little value to the Council in this proceeding" because the PLRs have no precedence as to ENO[288] and do not discuss deferred income tax expense[289] and the NOL cannot be tied to accelerated tax depreciation.[290] This is poor advice. The PLRs interpret and apply federal laws, 26 U.S.C. §168(i)(9) and 26 C.F.R. §1.167(l)-1, which would affect customers if the Council acts inconsistent with these laws. The PLRs do not discuss deferred income tax expense because deferred income tax expense from accelerated tax depreciation deductions does not increase a utility's revenue requirement, despite Mr. Proctor's erroneous opinion, which he contradicted at hearing. 26 C.F.R. §1.167(l)-1 requires ENO to determine what portion of its NOL is attributable to accelerated tax depreciation.

1. ENO has not claimed the PLRs in Exhibit RLR-2 are precedent; rather, the PLRs interpret and apply the pertinent federal income tax laws.

ENO has not argued that the PLRs in Exhibit RLR-2 are precedential. Rather, ENO has stated that Internal Revenue Code §168(i)(9) and Treasury Regulation §1.167(l)-1 set forth the IRS normalization rules applicable to all utilities regarding the ratemaking treatment for NOL ADIT; that the rules make clear that the amount of a utility's NOL ADIT asset that is attributable to accelerated tax depreciation must be included in rate base; and that the PLRs in Exhibit RLR-2 interpret and apply the normalization rules.

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288 Advisors Brief at 47-48.

289 *Id*. at 46-47.

290 *Id*. at 48.

Advisors witness Mr. Proctor on cross-examination, agreed that ENO's requested ratemaking treatment for NOL ADIT attributable to accelerated tax depreciation is "very similar" to the ratemaking treatment that the IRS required in the PLRs.[291] Mr. Proctor also agreed that his alternative recommendation is similar to a ratemaking proposal that the IRS concludes is inconsistent 26 U.S.C. §168(i)(9) and 26 C.F.R. §1.167(l)-1.[292] Ultimately, Mr. Proctor conceded that the Council should compare the facts of those cases to this case and determine whether the facts were discussed adequately in the PLRs.[293] Thus, Mr. Proctor did not suggest that the PLRs have "very little value" and should be ignored; he suggested that they should be carefully analyzed to see what weight they should be accorded.

2. The PLRs do not discuss deferred income tax expense because deferred income tax expense resulting from accelerated tax depreciation does not increase ENO's revenue requirement or rates and does not increase revenues received from customers.

At hearing, Mr. Proctor testified that his misinformation claim concerned the fact that the taxpayers in the PLRs did not state that deferred income tax expense was reflected in their rates in prior periods and the IRS did not discuss deferred income tax expense.[294] This was critical to him because he argued in filed testimony that "ENO's recovery of the depreciation related deferred income taxes increased ENO's cash revenues by an amount equal to the deferred taxes" and "provided cost-free capital from the customers."[295] At hearing, when confronted with Exhibit RLR-6, Mr. Proctor admitted that whether or not ENO uses accelerated tax depreciation on its tax return does not affect the level of income tax expense included in ENO's revenue

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291 Tr. (Proctor) 06/21/19 at 84.

292 *Id*. at 88-89.

293 *Id*. at 90-91.

294 *Id*. at 91-92.

295 Exhibit ADV-13 (Proctor Surrebuttal and Cross-Answering) at 50.

requirement and customers' rates.[296] When pressed on whether he stated in his deposition that deferred income tax expense from accelerated tax depreciation increased ENO's revenue requirement, he responded that he "may have misspoke."[297] Indeed, Mr. Proctor misspoke not only in his deposition but also in his filed testimony quoted above. Thus, Mr. Proctor's claim of misinformation is a misunderstanding on his part, not an infirmity in the PLRs.

3. A federal regulation requires ENO to determine what portion of its NOL is attributable to accelerated tax depreciation.

In 1999, the Louisiana Supreme Court affirmed an LPSC decision excluding the utility's NOL ADIT from rate base on the grounds that the NOL ADIT was attributable to the deregulated portion of the utility's operations and not regulated accelerated tax depreciation and observed that "no Internal Revenue Service rules or regulations" precluded the NOL ADIT analysis presented by the LPSC Staff's consultant.[298] Since then, however, the IRS has issued 26 C.F.R. §1.167(l)-1, which provides if the accelerated tax depreciation claimed by a utility causes a NOL or increases a NOL, then the amount of ADIT included in rate base shall be determined in a manner "satisfactory to the district director."[299] And, the IRS has issued private letter rulings explaining what method is satisfactory for determining the portion of NOL ADIT attributable to accelerated tax depreciation, as shown in Exhibit RLR-2. Thus, the Advisors' argument that "the

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296 Tr. (Proctor) 06/21/19 at 114-115. A sentence on page 145 of ENO's Brief expressing the same idea has a typographical error; the word not was omitted. The corrected sentence should read as follows: "As shown by Exhibit RLR-6, the use of accelerated tax depreciation, although it increases deferred income tax expense, does not change the level of income tax expense reflected in a utility's revenue requirement."

297 *Id*. at 112-113.

298 *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n*, 730 So.2d 890, 911 (La. 1999) ("[W]e find that the Commission did not act arbitrarily or capriciously by not reconsidering its previous ruling to exclude from rate base the NOL and AMT carryforwards discussed hereinabove based upon its determination that the carryforwards were caused by the deregulated portion of River Bend.").

299 Exhibit ENO-50 (Roberts Rebuttal) at 11-12; Exhibit ENO-52 (Roberts Rejoinder) at 5-6.

NOL cannot be tied to the excess depreciation over straight-line depreciation"[300] is inconsistent with federal law. Accordingly, the Council should reject the Advisors' recommendation and permit the NOL ADIT attributable to accelerated tax depreciation to be included in rate base.

I. The Advisors are misrepresenting the evidentiary record by claiming ENO did not specify how including ADIT related to the stranded meters in rate base violated the Internal Revenue Code; ENO's testimony explained why such treatment violated Internal Revenue Code Section 168(i)(9).

The Advisors argue that ENO claimed "unspecified 'potential violations' of IRS normalization rules" if the ADIT related to the stranded meters was included in rate base, as proposed by the Advisors.[301] The Advisors are misrepresenting the evidentiary record regarding this issue. Company witness Mr. Roberts explained why including the ADIT related to the stranded meters was included in rate base would be a potential violation of Internal Revenue Code Section 168(i)(9), which requires consistency between the inclusion of assets in rate base and the inclusion of the related ADIT liability in rate base.[302] The Advisors' proposal is inconsistent because it proposes the full weighted average cost of capital ("WACC") be applied to the ADIT related to the stranded meters but that the full WACC not be applied to the stranded meters.[303] At hearing, Advisors witness Mr. Watson agreed that the Advisors' proposed treatment violated the IRS normalization rules.[304]

Company witness Mr. Roberts further explained that Internal Revenue Code Section 168(i)(9) cannot be circumvented by the accounting subterfuge suggested by Mr. Watson, who is neither a certified public accountant nor an income tax expert. Internal Revenue Code Section

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300 Advisors Brief at 48.

301 Advisors Brief at 148.

302 Exhibit ENO-50 (Roberts Rebuttal) at 15.

303 *Id*.

304 Tr. (Watson) 06/21/19 at 72.

168(i)(9) requires ENO to establish a reserve for the deferral of taxes for the difference between book and tax depreciation and that reserve has to be treated consistently with respect to rate base. The code section does not reference a particular account. Changing the name of the reserve or the book account of the reserve does not negate the requirement for the reserve (*i.e.*, the accelerated tax depreciation ADIT) to be treated consistent with the related assets for rate base purposes.[305] Thus, the Council should reject the Advisors' proposal that would result in a normalization violation and harm customers.

J. The Company's proposed Rider DSMCR is the best DSM cost recovery model for achieving the Council's Energy Smart goals.

1. The Advisors' newly-contrived criticisms of Rider DSMCR do not support rejection of Rider DSMCR in favor of maintaining the status quo.

While acknowledging that the Council has "long recognized energy efficiency and demand response offerings … as high-priority resources for serving ENO's customers,"[306] it appears that the Advisors believe that the only objective in this proceeding is implementing a "stable and predictable funding source" for Energy Smart.[307] It is disappointing that the Advisors have taken such a narrow view of what can and should be accomplished in this rate case. The Advisors' narrow scope ignores their own recognition of the Councils' goal of making DSM a "high-priority resource" and the Council's policy objectives of, in addition to providing stable and predictable funding, (1) developing a process to align incentives equally for energy efficiency and supply side resources, and (2) providing an opportunity to earn a comparable profit for saving energy as is generally available for generating or delivering energy.[308]

305 Exhibit ENO-52 (Roberts Rejoinder) at 13.

306 Advisors Brief at 67.

307 Advisor Brief at 67.

308 Resolution R-07-600, dated December 6, 2007, at 3-4.

The Interim Energy Efficiency Cost Recovery ("EECR") Rider supported by the Advisors arguably meets the goal of providing stable and predictable funding in that it is designed to recover the costs of the Energy Smart program, but it falls well short of accomplishing the Council's other important goals. As explained in the Company's Initial Brief, Rider DSMCR is the best cost recovery method proposed in this case because it not only provides a stable and predictable source of funding but also aligns incentives equally for DSM and supply-side resources and provides an opportunity to earn a comparable return. In fact, it does not appear that any party seriously disputes the potential for maximizing DSM savings that the Company's proposed Rider DSMCR could achieve.

Nonetheless, the Advisors claim for the first time in their Initial Brief that "[i]f ENO truly desired to create a level playing field, it would amortize the cost of each DSM program year over the life of the DSM measure (typically 10-20 years) rather than only for a three-year period."[309] ENO witness D. Andrew Owens explained that the Company proposed a three-year amortization period because it aligns well with the Council three-year IRP cycle, where DSM opportunities are analyzed and included in resource planning:

> ENO's proposed three-year amortization period ties directly to the Council's practice of approving portfolios of and budgets for DSM offerings in three-year cycles as part of the IRP process. In addition to marrying well with the Council's current approval process, amortization over three years will help mitigate near-term bill impacts that would occur if DSM investments were recovered in a single year. Rather than recovering the costs of a [Program Year] all in one calendar year, which is how the May 2018 EECR and the Interim EECR would operate, the proposed amortization period allows the investment to be recouped over a longer time period, thus lessening the immediate effect on customer bills.[310]

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[309] Advisor Brief at 81.

[310] Exhibit ENO-10 (Owens Revised Direct) at 22.

That said, the Company is not opposed to a longer amortization period. The weighted average measure lives for residential and commercial Energy Smart products for 2017, as reported by the Company and available on the U.S. Energy Information Administration's website, was approximately 15 years.[311] The preliminary numbers for 2018 decreased to approximately 8 years for residential measures and 9.5 years for commercial measures.[312] Accordingly, the Company believes it would be reasonable to extend the amortization period up to ten years. Capping the amortization period at ten years is reasonable because it recognizes that some measure lives are considerably shorter than the average, so limiting the recovery period to ten years in turn limits the time period when some measurers have exceeded their useful life yet costs are still to be recovered. Extending the amortization period also increases the nominal costs of the regulatory asset because the regulatory asset would accrue carrying costs over a longer period of time. Limiting the amortization period to ten years or less therefore reduces the amount of nominal costs compared to longer periods.

On a net present value ("NVP") basis, the analysis conducted by Mr. Owens comparing the recovery of Energy Smart costs over a three-year period via Rider DSMCR versus one year under the Interim EECR would continue to show that Rider DSMCR will have a lesser rate impact, on a NPV basis, if the recovery period is extended to ten years.[313] In other words, in the analysis conducted by Mr. Owens, which was admitted into the record as Exhibit ENO-12, Workpaper DAO-2, the amortization period can be adjusted, which would show that a longer amortization period still results in Rider DSMCR having a lower rate impact on a NPV basis than the Advisors' proposed EECR rider.

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311 https://www.eia.gov/electricity/data/eia861/ (accessing the file "Energy_Efficiency-2017" for 2017).

312 https://www.eia.gov/electricity/data/eia861/ (accessing the file "Energy_Efficiency-2018" for 2018).

313 Exhibit ENO-12 (Owens Rebuttal) at 17-22 and associated workpapers.

Of course the Advisors' second new criticism of Rider DSMCR is that Mr. Owens's NPV analysis has a flawed assumption regarding the time value of money.[314] This criticism should be rejected on its face because the Advisors did not provide any testimony or analysis supporting this new theory now raised for the first time in their Brief. The Advisors' argument is merely unsupported speculation, and they offer no evidence regarding what different discount rate they believe should be used in the NPV calculation. Nonetheless, Mr. Owens made it clear at hearing that the Company used the same discount rate it has historically used when comparing resource alternatives, and one of the Council's Energy Smart objectives is to place supply-side and demand-side resources on equal footing,[315] which logically requires that they be evaluated on equal footing:

> At the same time, I'm going to say again and again this is exactly the same way we compare options. Whether it's a power plant investment or its DSM investment, we do it the same way. It's the same methodology, the same assumption.[316]

Mr. Owens also explained at hearing that using the NPV approach to evaluate Rider DSMCR versus the Advisors' proposed EECR rider takes tax effects into account, which is one of the key benefits of Rider DSMCR.[317] Accordingly, the Company has put into evidence an

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314 Advisors Brief at 81.

315 Resolution R-07-600, dated December 6, 2007.

316 Tr. (Owens) 06/19/19 at 138. *See also* Tr. (Owens) 06/19/19 at 127 (this "is our normal practice [] any time we're comparing alternatives, whether it's supply side investment with an alternative"); 128 ("We follow the standard methodology we use, which is when you're comparing alternatives for a discount rate, we use the weighted average cost of capital. I've been with the Company a long time and to my knowledge, that's the standard practice that we use to compare alternatives."); 131 ("I don't think the analysis we that we did on an NPV basis is any different that we would do comparing other alternatives."); 135 ("This is the normal way we compare two options of what customers would pay. These are revenue requirement numbers."); 136 ("And the practice we follow is a practice, to my knowledge, we always follow, which is to use the weighted average cost of capital as a discount rate."); and 136 ("It's the accumulation of cash flows, and it's, again, the standard practice we follow. If it's a power plant investment, we would do the math the same way. We didn't do the math differently because there's anything different in terms of comparing two options.").

317 Tr. (Owens) 06/19/19 at 127. See also Tr. (Owens) 06/19/19 at 131 ("there's a significant tax effect with

analysis, based on its long-standing standard procedures used for comparing alternative investments, that shows that Rider DSMCR is superior to the Interim EECR rider on an NPV basis in terms of rate impacts. Neither the Advisors nor any other party offered any testimony or other analyses contesting Mr. Owens's analysis. The Advisors' late, unsupported criticisms should be rejected. Rider DSMCR is the better cost recovery mechanism for pursuing the Council's aggressive DSM goals and implementing its long-term vision, and it has a lower rate impact on customers. The Advisors' approach would be inferior.

2. The Alliance for Affordable Energy's and Sierra Club's recommendations do not align with the Council's goals, and their proposed changes to Rider DSMCR are unwarranted.

The AAE first argues that the Council should reject any DSM cost recovery mechanism that allows the Company to "rate base" DSM expenses, essentially arguing that the Company has an obligation to pursue DSM regardless of whether it has the opportunity to earn a return on its DSM investments.[318] This narrow view ignores the Council's goals of aligning the incentives equally for DSM and supply-side resources and providing a comparable earnings opportunity.[319] Mr. Owens explained that, if supply-side resources and DSM are to be treated equally, the utility's investment in each should be afforded similar treatment.[320] Even the AAE's own witnesses agreed that DSM should provide an ***earnings opportunity*** as good as ***or better*** than it has for new generation.[321] Providing a return of and on DSM expense via regulatory asset treatment accomplishes that goal, and under the Company's proposal, it would only have an

the timing difference between your income tax expense. That timing difference and spreading that out significantly changes what customers would be paying.").

318 AAE Brief at 32.

319 Resolution R-07-600, dated December 6, 2007.

320 Exhibit ENO-10 (Owens Revised Direct) at 23.

321 Tr. (Barnes) 06/21/19 at 17-18; Tr. (Morgan) 06/18/19 at 186.

opportunity to earn a return ***better*** than it has for new generation if its DSM efforts produce significant savings.[322] Simply put, the Company's proposed Rider DSMCR is designed to advance the Council's Energy Smart vision and put DSM and supply-side resources on a level playing field. The AAE's proposed recommendations do not.

To that point, the AAE makes a pass at claiming that ENO's proposal actually tilts the playing field in the utility's favor because DSM produces both foregone energy expenses and forgone capital investments.[323] First, the Company does not view this issue as an "us versus them" proposition, and leveling the playing field means making DSM and supply-side investments equal in terms of cost recovery and earnings potential.

Second, when viewed in the context of trying to level the playing field between supply-side and DSM investment, the AAE's argument makes no sense. Dr. Faruqui explains that utilities typically earn a return on the capital they prudently invest in supply-side resources.[324] In order for the "playing field" to be leveled, utilities should also be allowed to earn on prudently-incurred demand-side resources. The AAE argument is that because DSM investment can avoid energy and capacity costs resulting in savings to customers (which is part of what can make DSM investments cost-effective), allowing ENO to earn a return on the investment required to produce those savings is somehow a double-counting in the utility's favor. In other words, because a utility would not earn a return on energy costs that DSM investments can help to avoid, the utility should not earn a return on the investment required to avoid those costs.

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[322] Exhibit ENO-10 (Owens Revised Direct) at 25-26.

[323] AAE Brief at 32.

[324] Exhibit ENO-14 (Faruqui Revised Direct) at 11.

As ENO's discovery response to request AAE 3-7 explained,[325] investments in supply-side assets can often produce reduced fuel costs; that benefit is part of what makes them net-beneficial, cost-effective, and prudent. The return earned on such investments is on the equity portion of capital investment (in total), not the investment net of the avoided or reduced fuel costs that would have been incurred had the investment not been made.[326] So, to level the playing field between supply- and demand-side investments, incentive mechanisms should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset. Rider DSMCR does this by providing a mechanism for ENO to earn a return on investments in cost-effective DSM resources (which the Council has indicated should be prioritized) and **not** a return on the avoided costs that contribute to those resources being cost-effective in the first place.

The AAE next attacks the lost contribution to fixed costs ("LCFC") component of Rider DSMCR, asserting that LCFC and revenue decoupling are designed to achieve the same objective and that the Company does not need both.[327] Implicit in that position is the recognition that, if LCFC is not addressed through decoupling, it does need to be addressed somewhere else. In fact, it is undisputed that LCFC needs to be addressed, it is just a matter of where – the AAE wants to address it through Ms. Morgan's redesigned decoupling mechanism; the Advisors want to address it through an adjustment to the FRP, and APC wants to address it via Rider DSMCR.

Despite clearly agreeing that LCFC needs to be addressed,[328] the AAE makes a curious argument that LCFC recovery is not necessary to level the playing field between supply-side and

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325 Exhibit ENO-12 (Owens Rebuttal) at Exhibit DAO-7.

326 Exhibit ENO-12 (Owens Rebuttal) at 29.

327 AAE Brief at 33.

328 Tr. (Morgan) 06/18/19 at 182; Exhibit AAE-3 (Morgan Surrebuttal) at 8-9 (("I agree with Mr. Owens that

DSM investments because they have different risk profiles.[329] Similarly, AAE posits, citing to evidence outside the record, that other factors, like unusual weather and customer growth, can produce additional energy sales in any given year, mitigating the negative effect that lost sales from DSM has on the Company's opportunity to recover its revenue requirement (of course AAE ignores the converse situation where mild weather and customer loss reduce energy sales and exacerbate the negative effect that lost sales from DSM has on the Company's ability to recover its revenue requirement).[330] These arguments simply cannot be reconciled with the AAE witness's recognition that LCFC needs to be addressed "[i]f the regulators and the service territories' goals are to have the utility pursue energy efficiency with all due attention."[331] What the AAE is really arguing is that "standard decoupling" advocated by Ms. Morgan is the better approach for dealing with LCFC – not that LCFC should be disregarded or ignored.[332] As discussed in ENO's Initial Brief, Ms. Morgan's proposal to implement "standard decoupling" is inconsistent with Resolution No. R-16-103, so the Company's proposed LCFC component of Rider DSMCR remains crucial to providing the Company an opportunity to recover its revenue requirement and earn a fair return.[333]

Mr. Owens further explained that, should the Council revise the R-16-103 decoupling framework in accordance with the AAE's recommendations, the lag associated LCFC recovery

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the decoupling/FRP mechanism as proposed does not adequately address the LCFC issue and that the recommendation I made in my Direct Testimony may not fully resolve the issue.").

329 AAE Brief at 34.

330 AAE Brief at 36 (citing to AAE Brief Attachment C, which is not in evidence in this proceeding).

331 Tr. (Morgan) 6/18/19 at 182.

332 AAE Brief at 34-36; Tr. (Morgan) 6/18/19 at 164.

333 ENO Brief at 108-110.

via the AAE's decoupling approach would still need to be addressed.[334] AAE witness Morgan agreed that her original decoupling framework did not adequately address LCFC recovery lag,[335] and she proposed certain accounting adjustments in an attempt to address the issue.[336] Mr. Owens responded that the accounting approach does not adequately solve the lag issue because rate adjustments resulting from decoupling would not go into effect until a year after the LCFC occurred, which would unfairly undermine the Company's opportunity to recover its authorized revenue requirements and corresponding return on equity.[337] Thus, even if the AAE "standard decoupling" were implemented (which ENO opposes absent an acceptable FRP), additional work on the LCFC issue would be required.

Assuming that the Company's proposed Rider DSMCR is approved, the AAE next criticizes certain aspects of the LCFC reconciliation procedure.[338] First, the AAE claims that ENO failed to define the adjusted gross margin ("AGM").[339] This is somewhat confusing because the AAE explained several pages earlier in its Initial Brief that "LCFC is the weighted average of the most recently approved rated in effect on the filing date … multiplied by the deemed, projected lost sales (kWh and/or kW) attributable to the Energy Smart Programs for the applicable program year."[340] The first portion of that equation is the AGM, so it is unclear why the AAE takes the position that the term requires additional definition.

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334 Exhibit ENO-12 (Owens Rebuttal) at 12.

335 Exhibit AAE-2 (Morgan Surrebuttal) at 8-9 ("I agree with Mr. Owens that the decoupling/FRP mechanism as proposed does not adequately address the LCFC issue and that the recommendation I made in my Direct Testimony may not fully resolve the issue.")

336 Exhibit AAE-2 (Morgan Surrebuttal) at 9-10.

337 Exhibit ENO-13 (Owens Rejoinder) at 7-8.

338 AAE Brief at 36-37.

339 AAE Brief at 36-37.

340 AAE Brief at 33.

The AAE next argues that, if the Council adopts Rider DSMCR, the proposed LCFC reconciliation is flawed because deemed savings are not reconciled with actual savings determined through evaluation, measurement and verification ("EM&V"), and the AAE makes two recommended adjustments to remedy the purported defects.[341] The AAE's proposed adjustments are not necessary because the AAE does not understand the Company's proposed LCFC reconciliation process.

The DSMCR rate schedule as proposed and filed by the Company specifically references EM&V in Section VI:

> All aspects of utility-sponsored energy efficiency efforts, including, but not limited to, measures, offerings, and reports are potentially subject to Evaluation, Measurement and Verification ("EM&V"). All EM&V activities undertaken as part of the utility-sponsored offerings, ***including, but not limited to, estimation of energy efficiency savings and process evaluations***, shall be conducted consistent with the New Orleans TRM or other similar accepted EM&V standards.[342]

Further, the Rider DSMCR language includes in Section V that the Rider DSMCR true-up adjustment is meant to reflect the "cumulative true-up adjustments, inclusive of carrying charges, reflecting the (over)/under recovery balance from the actual offerings implemented in the prior program year(s) including; the revenue requirements resulting from the costs of the actual offerings, ***the actual achieved LCFC*** and the actual approved performance incentives."[343] Moreover, Rider DSMCR includes a separate true-up schedule that labels the LCFC True-up "for Actual kWh Savings" with a footnote describing that this true-up "[r]eflects the difference between the Rider DSMCR ***LCFC generated by the actual kwh savings*** for the reconciliation period, outlined in Note 2, compared to the previously implemented estimated

341 AAE Brief at 37.

342 Exhibit ENO-10 (Owens Revised Direct) at Exhibit DAO-3 (emphasis added).

343 Exhibit ENO-10 (Owens Revised Direct) at Exhibit DAO-3 (emphasis added).

amounts."[344] Nowhere in the tariff does the language limit the LCFC true-up to "the difference between estimated numbers of participants/measures and actual numbers of participants/measures" as stated by the AAE.[345] Accordingly, the AAE's proposed changes are unwarranted.

Finally, the AAE argues that the incentive framework of Rider DSMCR is "too rich." ENO addressed this issue in its Initial Brief, including its openness to including more "steps" in the incentive framework and why no additional penalties are needed.[346] ENO also explained why a baseline return component is reasonable given that the Company is serving as the vehicle for implementing the Council's Energy Smart Program using the Company's capital. However, the AAE makes the additional argument that the targets are not ambitious enough.[347] As the AAE recognizes, it is the Council that sets that targets, not ENO,[348] so it is unfair to criticize the Company's proposed DSMCR framework for elements that are out of its control.

K. ENO Agrees with the Advisors' Recommendation that the Council Reject Customer-Lowered Energy Price ("CLEP").

BSI's brief makes several new, and unsubstantiated, assertions concerning alleged benefits of its proposed CLEP rate schedules, which the Council has previously rejected on two occasions. The alleged benefits BSI identifies for the first time in its brief have not been supported with testimony or any other evidence in the record of this proceeding. As the Advisors point out in their brief, there is a significant risk associated with CLEP as BSI readily admits that CLEP would cause increased bills for customers that are unsuccessful in navigating the complex

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344 Exhibit ENO-10 (Owens Revised Direct) at Exhibit DAO-3.

345 AAE Brief at 37.

346 ENO Brief at 119-123.

347 AAE Brief at 40.

348 AAE Brief at 40.

system of transactions required to achieve the bill savings or other benefits that BSI alleges CLEP can facilitate.[349] Unsubstantiated claims of benefits and free admissions of detriments do not establish adequate support for BSI's request that the Council implement: CLEP (or direct ENO to do so), or, investigate CLEP with a rulemaking docket.

The Advisors also point out another challenge with CLEP, one which almost certainly renders it impossible to implement without enormous cost. Under BSI's proposal, CLEP participants would be engaging in energy transactions every 5 minutes. As the Council is aware, the data from AMI meters is recorded and transmitted at 15-minute intervals. Thus, it does not appear that it is possible to implement CLEP without significantly altering the configuration of AMI deployment, which is presently underway. Even if it were possible to facilitate the transactions at the intervals BSI proposes, that scenario would create an enormous administrative burden. Assuming 20,000 customers (roughly 10% of ENO's customer base) participated in CLEP, that would mean that ENO would be responsible for recording, administering, settling, and otherwise facilitating approximately 5.76 million CLEP transactions on a ***daily*** basis. To give an idea of the administrative burden and cost the CLEP rate structures would create, consider the Council's Community Solar Program, which requires one transaction per month with each participating customer. ENO is presently incurring significant cost and time commitments to attempt to establish an administrative framework for accommodating the Council's program and complying with its rules, and the underlying Council rulemaking is still underway, over a year after it was initiated. The costs associated with the Council's Utility Regulatory Office's ("CURO") oversight of the consumer protection aspects of the Council's program are still unknown. CLEP presents a framework that is several orders of magnitude more

[349] See Advisors Brief at 122-23.

complex than the Council's Community Solar Program. As such, CLEP would clearly require a vastly larger investment of time and cost from both ENO and the CURO (assuming consumer protection enforcement was assigned to the CURO) than the Council's Community Solar Program. Given the unsubstantiated nature of the alleged benefits of CLEP, the acknowledged potential for significant downside, and the potentially enormous administrative burden associated with it, ENO believes the Council should reject CLEP again and decline the invitation to divert resources from important issues the Council and the Company are handling to create a docketed rulemaking devoted to CLEP. The Council should deny each component of BSI's request for relief

L. CCPUG's recommendations to reject the DGM rider are at odds with the Council's goal of quickly modernizing the electric grid in New Orleans.

CCPUG argues that, because the Company has indicated that it would invest in grid modernization even if the DGM rider were rejected, the Company has failed to justify the need for the rider.[350] CCPUG fails to recognize that the Council itself has expressed a sense of urgency with respect to modernizing the electric distribution grid in New Orleans.[351] The very purpose of the DGM rider is to support an accelerated pace of grid modernization through providing a streamlined review process and providing the cash flows necessary to accomplish this important project.[352] Mr. Thomas and Ms. Zimmerer also explained that the DGM rider will allow ENO to deliver grid modernization at the lowest reasonable cost for customers because it

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350 CCPUG Brief at 71.

351 Exhibit ENO-8 (Zimmerer Revised Direct) at 7-8 (citing Resolutions R-18-36 and R-18-227). For example, the Council said in R-18-36 that "the cornerstone of a Smart Cities initiative is the modernization of the electric grid and its integration with other technologies" and then the Council directed ENO to file a report within 60 days detailing available grid modernization technologies along with a description of how to implement them. (R-18-36 at 2-4.) ENO is proposing a comprehensive path for quickly and efficiently implementing a modernized grid in this rate case.

352 Exhibit ENO-1 (Thomas Revised Direct) at 57; Exhibit ENO-8 (Zimmerer Revised Direct) at 32.

will enable ENO to make the long-term commitment to contractors and for other resources.[353] In other words, without the DGM rider, the current expedited pace of grid modernization would not likely be achievable, which is contrary to the Council's goals.

CCPUG's cries of alarm with respect to the streamlined review process for DGM investments are simply unsupported rhetoric.[354] First, Ms. Zimmerer explained that the proposed review process is similar to the successful and fair process already being used by the Council and the LPSC for gas infrastructure rebuild and replacement programs.[355] Second, ENO's proposed process envisions a **six-month** review process with the following elements:

- As ENO's Grid Modernization team develops additional projects for ENO's service area, ENO will periodically submit to the Council for review Project Design Packages, similar to the HSPM Exhibit EHZ-2 (attached to Exhibit ENO-8), which will include a description of each proposed project, details on project design, engineering, expected benefits, estimated budgets, anticipated timelines, and other aspects of the project;

- The Council and/or its Advisors, along with other stakeholders, will have **two months** from ENO's submission of a Project Design Package within which to provide written feedback to ENO on the projects described within each Package;

- Within one month of receipt of written feedback, ENO will convene a Technical Conference to discuss issues raised therein;

- As necessitated, within one month of the Technical Conference, ENO will resubmit the Project Design Package to the Council with any modifications resulting from the written feedback and subsequent Technical Conference; and

- Within two months of ENO's submission of the Revised Project Design Package (if applicable), or within three months of the Technical Conference if no modifications to the Project Design Package are necessitated, **the Council shall issue a decision regarding the proposed project(s) and determining the eligibility of project costs for recovery through Rider DGM**.[356]

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353 Exhibit ENO-4 (Thomas Rejoinder) at 13; Exhibit ENO-8 (Zimmerer Revised Direct) at 35-36.

354 CCPUG Brief at 72-73.

355 Exhibit ENO-8 (Zimmerer Revised Direct) at 34.

356 Exhibit ENO-8 (Zimmerer Revised Direct) at 34-35.

Accordingly, ENO's proposed process would not deprive parties of the opportunity to participate in or the Council of any ability to review the prudence of ENO's construction activities, and the proposed administration of Rider DGM includes an annual filing through which the Council and its Advisors can track ENO's spending on grid modernization projects, monitor ENO's adherence to the project budgets, and consider the prudence of its project execution.[357] CCPUG's concerns with the expedited review process are wholly unwarranted.

M. The Company's proposed GIRP rider is the best way to ensure the continued safety of the Company's gas distribution system and to mitigate customer costs.

Several parties in their Initial Briefs took issue with the Company's proposal to institute a GIRP Rider. Specifically, CCPUG argued that it was similar to the Company's DGM proposal and was unnecessary. They argued that these costs could simply be included in the Company's FRP, which would remove the need for the rider.[358] The Advisors' position regarding the Company's request for a GIRP rider is more nuanced. Advisors do not dispute that the scope of GIRP program is appropriate. They agree that it is "consistent with industry trends to identify risks and replace aging infrastructure prior to failure."[359] However, they are concerned with the "rate at which GIRP investment should proceed" and what measures ENO or the Council can take … to mitigate the … impact on ratepayers."[360] Because of these concerns, the Advisors recommend:

(1) the Council approve recovery of the GIRP infrastructure costs incurred as proformed through the end of 2019 as generally approved by Resolution R-17-38;

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357 *See* Exhibit ENO-41 (Gillam Revised Direct) at Exhibit PBG-13.

358 CCPUG Brief at 73.

359 Advisors Brief at 89.

360 *Id.*

(2) that the Council reject ENO's proposed GIRP Rider as it constitutes inappropriate single-issue ratemaking and any Council-authorized GIRP-related costs are more appropriately recovered in base rates;

(3) that ENO be required to identify, for Council consideration, a rate of gas distribution pipe installation and dollar investment that is required to maintain the safe operation of ENO's gas system; and

(4) that ENO be required to identify potential measures to mitigate the identified impact on ratepayers.[361]

The Company appreciates and agrees with the Advisors' recommendation to approve the recovery of the 2019 GIRP costs as generally approved by Council Resolution R-17-38. However, the Company explained at length in its Initial Brief and earlier here why the concern over single-issue ratemaking should not prohibit adoption of the GIRP Rider.[362] Further, Company witness Ms. Michelle Bourg explained why it is inappropriate to characterize the Company's gas distribution system in a binary fashion as "safe" or "unsafe."[363] The Company cannot predict with certainty the exact pace of gas infrastructure pipe replacement necessary to maintain the safe operation of the Company's gas system.

But what it is important for the Council to understand is that the rider the Company is proposing to implement in order to replace this aging pipe is the single best mechanism the Company (or the Council) has at its disposal to address both of the Advisors' remaining concerns: to ensure both the safety of the system and that the cost impact of this effort on the Company's customers will be mitigated to greatest extent possible. If the Advisors are truly interested in both the safety of the Company's gas system and in mitigating the cost impact of

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361 *Id.*, at 88.

362 *See, e.g.*, ENO Brief at 70-75.

363 Exhibit ENO-24 (Bourg Rebuttal) at 3-6.

this replacement program, as they say they are, they should embrace both the concept of the rider and the proposed 10-year length.

In the first instance, the Advisors' position on the continued safe operation of the Company's gas distribution system is inconsistent. On the one hand, Advisor witness Mr. Joseph Rogers admitted that ENO is in the best position to determine what is required for the safe operation of its gas distribution system.[364] However, when the Company proposes a 10-year infrastructure replacement program that Ms. Bourg explains is the Company's best effort to balance both (i) the absolute need to replace this pipe and operate a safe system and (ii) the concern over ratepayer costs, the Advisors instead request that the Company identify a minimum investment that is necessary to keep the system safe.

The Advisors' position on cost mitigation is also inconsistent. Although the Advisors beseech the Company to engage them in determining various cost mitigation strategies,[365] their ideas seem not fully formed. At hearing, Mr. Rogers could not identify either what an acceptable level of mitigation would be or what an acceptable level of annual bill growth would be:

> Q. But your testimony doesn't indicate what an acceptable level of mitigation would be; correct?
>
> A. No, it does not indicate that.
>
> Q. And you didn't identify what would be an acceptable level of annual bill growth or rate trajectory; isn't that true?
>
> A. That's true.[366]

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364 Tr. (Rogers) 06/21/19 at 145.

365 Tr. (Rogers) 06/21/19 at 144 and 152-153.

366 *Id.*, at 144.

Similarly, Mr. Rogers admitted at hearing that his testimony regarding financing these costs through some sort of existing securitization option may not even be possible:

> Q. Have you determined that the cost of GIRP is eligible to be financed at the state level through any of the existing securitization acts?
>
> A. I have not made a determination on the—with respect to the existing securitization acts. I have relied on ENO's statements that they are not available to them…[367]

Mr. Rogers also admitted that the Advisors had not drafted any proposed securitization legislation to address these costs.[368]

Yet, despite this failure to identify any concrete mitigation measures or suggestions, the Advisors dismiss the Company's mitigation efforts - that were built into its proposal from the beginning - out of hand and without any justification. Ms. Bourg explained, both in prefiled testimony and at hearing, that the length and scope of the program, and the rider, was specifically designed to minimize program costs. She stated that the steady, predictable pace of work resulting from the rider would help ensure the availability of required contractors and lead to reduced costs and increased investment by the contractors in the city.[369] She also testified that a rider would allow the Company to continue the practice of issuing requests for contractor proposals every three years, which has been an effective cost mitigation strategy.[370] At hearing,

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367 *Id.*, at 149-150.

368 *Id.*

369 Exhibit ENO-24 (Bourg Rebuttal) at 25; Tr. (Bourg) 06/17/19 at 147 and 148.

370 Exhibit ENO-24 (Bourg Rebuttal) at 25.

Advisors witness Mr. Rogers could not dispute that this approach had been an effective cost savings device for the Company.[371]

The Advisors' concerns over the safety of the Company's gas distribution system and cost impact of the GIRP program on customers do not justify their rejection of the Company's proposed GIRP rider. In fact, both concerns are reasons to wholeheartedly support the Company's proposal. A GIRP rider similar to the one proposed by the Company is the best way to help ensure the continued safety of the system and mitigate customer costs.

N. The Council should approve the Company's proposed decoupling approach because it is the only approach consistent with Resolution R-16-103 and supported by filed testimony, an example, and a proposed rate schedule; other parties' proposed decoupling approaches should be rejected, including the Advisors' Total Cost of Service Approach.

1. ENO complied with Resolution R-17-504; nevertheless, the Advisors' Total Cost of Service Approach should not be incorporated into the FRPs.

In their brief, the Advisors state that Advisors witness Mr. Prep criticized ENO's cost of service studies for their failure to comply with Resolution R-17-504, which allegedly requires the Total Cost of Service Approach.[372] Company witness Mr. Klucher explained that ENO complied with Resolution R-17-504 and Mr. Prep's criticism was, at most, a dispute regarding the presentation not the substance of ENO's cost of service studies.[373] Even if ENO's compliance was not complete, the issue is now moot.

As explained previously, the Advisors' Total Cost of Service Approach is an untested and an unnecessary departure from the typical ratemaking approach used in the FRPs and would

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371 Tr. (Rogers) 06/21/19 at 148.

372 Advisors Brief at 20.

373 Exhibit ENO-43 (Klucher Rejoinder) at 2-5.

harm customers in certain instances.[374] The Advisors' Total Cost of Service Approach would require ENO to include, for example, FAC revenue and fuel expenses in the calculation of the Earned Return on Equity, although Mr. Prep testified his intent was that fuel expenses should not be recovered through base rates or the FRPs.[375] Mr. Prep admits no other retail regulator uses this approach.[376] The Council should not require ENO to depart from the tested method of calculating the Earned Return on Equity in the FRP for a method that introduces unnecessary information and could potentially harm customers. Additionally, Mr. Prep admitted at hearing that the reason for his Total Cost of Service approach is so that the allocation of cost responsibility for all costs, both those recovered in base rates and riders, such as fuel expenses, can be adjusted amongst the rate classes in the Electric FRP.[377] Adjusting the allocation of costs recovered in riders in the Electric FRP would be an egregious departure from the purpose of such a proceeding.

Furthermore, like APC,[378] ENO is troubled by the conclusiveness and effect attributed to Resolution R-17-504 by Mr. Prep and the lack of process before its adoption. The Council did not provide for any hearing on the proposed resolution or even an opportunity to provide formal comments before the date of its consideration. Such alleged effect is troubling when Resolution R-17-504 purports to modify Resolution R-15-194, which resulted from an agreement in principle in a litigated proceeding involving filed testimony. Such alleged effect is troubling when Mr. Prep contends that Resolution R-17-504 directs ENO to change the way ENO has

374 ENO Brief at 102-103.

375 Tr. (Prep) 06/20/19 at 184-185.

376 *Id*. at 186.

377 *Id*. at 185.

378 Air Products Brief at 27.

prepared cost of service studies and FRPs after decades of using an approach satisfactory to the Council and consistent with City Code.

2. The Company's proposed decoupling approach is consistent with Resolution R-16-103 and supported by the evidence in the record; the Advisors' proposed approach is incomprehensible, and AAE's approach seeks to rewrite Resolution R-16-103 in its entirety.

The Company's proposed decoupling approach is the only decoupling approach consistent with Resolution R-16-103 and accompanied by detailed explanatory testimony,[379] a complete rate schedule setting forth the decoupling approach with exhibits,[380] and a detailed example.[381] No other party has provided a proposal as comprehensive as ENO's.

The Advisors' approach is incomprehensible because they have not explained how ENO is to determine the revenue requirements for each rate class in its Electric FRP filing with their proposed varying rates of return on rate base. Previously in its initial brief, ENO showed how Mr. Prep changed his positions on how ENO was to determine the varying rates of return by rate class; he testified in deposition that the Company should use its judgment and then, at hearing, testified that the Company should maintain relative cost responsibility among the rate classes established in this proceeding.[382]

Mr. Prep's hearing testimony agrees with ENO's decoupling approach, which uses the revenue by rate class established in this proceeding to allocate the revenue requirement by rate class. Other statements by the Advisors suggest that the Advisors agree with ENO's decoupling approach. In his Direct Testimony, Mr. Prep mentions "updated consideration of the before-tax rates of return for each customer class ***based on the final rate class revenues approved in this***

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379 Exhibit ENO-41 (Gillam Revised Direct) at 32-37.

380 *Id*., Exhibit PBG-7.

381 *Id*., Exhibit PBG-8.

382 ENO Brief at 105-106.

proceeding."[383] In their brief, the Advisors wrote "the FRP fixed and variable total revenue requirements are determined for each customer class by an allocation of costs and a return component based on the rates of return ***corresponding to the customer class revenues set in the instant Docket.***"[384] On the other hand, the Advisors also wrote that "duplication of the results [from the rate case] in the FRPs is not an objective."[385] This statement contradicts the Advisors' two above-quoted statements. These contradictions on this most important aspect of decoupling render the Advisors' proposed decoupling approach incomprehensible.

Furthermore, if the FRP revenue requirement is to be allocated in a manner "based on the final rate class revenues approved in this proceeding" or "corresponding to the customer class revenues set in the instant Docket," then updating allocation factors (or class rates of return) is not necessary in the FRP and would be a waste of resources. The allocation can be done in one step and correspond to the customer class revenues set in this proceeding. As explained previously, using updated allocation factors in the FRP to allocate the revenue requirement would lead to a disruptive shift in cost responsibility to the Residential Rate Class.[386]

The AAE is clear in its intent with respect to the three-year pilot decoupling mechanism ordered by the Council in Resolution R-16-103, leading off its argument with the following heading: "The Council Should Adopt the Changes to the Decoupling Mechanism Proposed by the Alliance."[387] ENO explained in its Initial Brief that the "changes" recommended by the AAE

383 Exhibit ADV-3 (Prep Direct) at 79 (emphasis supplied).

384 Advisors Brief at 114 (emphasis supplied).

385 Advisors Brief at 119.

386 ENO Brief at 107-108.

387 AAE Brief at 10.

are fundamental changes to the decoupling mechanism prescribed in Resolution R-16-103.[388] Resolution R-16-103 itself was the result of various reports and recommendations of the Advisors, which were in turn based on the numerous technical conferences and filed comments (including the AAE), that occurred over a multi-year period.[389] Simply put, it is too late to challenge the findings and conclusions reached by the Council with respect to the three-year decoupling pilot to be implemented with this rate case.

O. Depreciation rates proposed by the Company and supported by the Advisors should be adopted by the Council.

As explained in ENO's Initial Brief, depreciation expense in this case was based, in large part, on the depreciation study performed for the Company by ENO witness Mr. Donald Clayton.[390] This study was properly conducted and the resulting depreciation rates (along with the depreciation rates for the advanced metering equipment proposed by ENO witness Zimmerer, which were uncontested) were supported by the Advisors[391] and should be approved by the Council.

1. CCPUG's arguments regarding the useful lives of Union PB1 and NOPS are incorrect and should be rejected by the Council.

CCPUG takes issue with several issues affecting the depreciation rates proposed by the Company in this proceeding. First, they challenge the Company's proposal to use a 30-year depreciable life for Union PB1, incorrectly claiming that a 40-year life is more appropriate.[392] CCPUG also claims that the NOPS' first year revenue requirement will, when it enters service,

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388 ENO Brief at 108-110.

389 *Id*.

390 ENO Brief at 123.

391 Advisors Brief at 39-40.

392 CCPUG Brief at 64.

be too high because it should be depreciated over a 50-year life instead of the useful life that the Company plans to utilize to determine the revenue requirement when it is constructed and actually enters service.[393] CCPUG further takes issue with the reasonable 10-year amortization period for the general plant reserve deficiency proposed by the Company. Instead, CCPUG witness Lane Kollen proposes that the amortization be extended to 20 years.[394] CCPUG's arguments are wrong on all of these issues, and the Council should reject their proposals. The Company's Initial Brief explained in detail why the proper life for the Union PB1 should be 30 years and not the 40 years that CCPUG witness Kollen recommends and why the amortization period for the general plant reserve deficiency should be five years.[395] CCPUG's additional arguments will be addressed below.

2. CCPUG witness Kollen is not an engineer or a certified depreciation specialist and not qualified to render an opinion on engineering issues such as the depreciable lives of generation plants, and his opinion regarding the depreciable lives of generation assets should be given no weight.

In its Initial Brief, CCPUG argued that Mr. Kollen surveyed available "public data" and determined that plants like Union PB1 had a 40-year life. CCPUG also claims that ENO's witnesses that addressed the issue, Mr. Donald Clayton or Mr. Robert Breedlove, "fell short" in rebutting this claim. [396] This is blatantly wrong. Both Mr. Clayton and Mr. Breedlove went to great lengths to explain why Union PB1 was not comparable to the plants that Mr. Kollen "surveyed." The evidence on this issue was explained by ENO in its Initial Brief.[397] But there is

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393 *Id.*

394 *Id.* at 93-94.

395 ENO Brief at 125-132 and 134-136, respectively.

396 CCPUG Brief at 65.

397 ENO Brief at 125-132.

another important reason why CCPUG is wrong on this account. Its witness on this issue, Mr. Kollen, is not an engineer or a certified depreciation expert, and he is simply unqualified to render a credible opinion regarding whether the generation technology used at Union PB1 (or NOPS) is or is not similar to the generation technology used at another plant.

This was starkly illustrated in a recent case at the FERC in which Mr. Kollen recommended extending the depreciable life of another generation plant – a combined cycle gas turbine ("CCGT") unit owned by EAL. In that case, the FERC judge observed that the Uniform System of Accounts not only requires that an asset's cost be spread over the depreciable life of that asset in a systematic and rational way, but that the depreciable life of an asset should be based on engineering considerations or a depreciation study.[398] The judge went on to rule, rather bluntly, that although Mr. Kollen (and another intervenor witness) were accountants, they had no "engineering training, experience, or expertise,"[399] and that, therefore, their client "has no ability in this case to make engineering assessments."[400]

Mr. Kollen is attempting to make a similarly deficient argument in this case: that the more modern generation technology used in Union PB1 is similar to the technology in an older vintage of generators, and his testimony should be rejected by the Council for the same reasons that the FERC rejected his recommendations in that proceeding.

3. CCPUG's arguments for a longer depreciable life for Union PB1 are incorrect and should be rejected by the Council.

In its Initial Brief, CCPUG offers the novel suggestion that the hearing testimony of ENO witness Mr. Breedlove regarding the replacement of Union PB1's rotors after 19 years supports

398 *Entergy Services, Inc.*, 136 FERC P 63015 (F.E.R.C.), 2011 WL 4432882.

399 *Id.*, at ¶115.

400 *Id.*, at ¶116.

Mr. Kollen's proposed 40-year life. CCPUG argues that, since the plant needs the rotors to operate, replacing the rotors after 19 years would extend the plant's useful life for another 19 years, and that the resulting total of 38 years is beyond the 30-year service life advocated by the Company and very close to the 40-year life proposed by Mr. Kollen.[401] What CCPUG fails to mention is that, at hearing, Mr. Breedlove clearly explained that the rotors that CCPUG references are not the only major plant component that will need to be replaced in order to extend the plant life beyond 30 years. It is sheer speculation for CCPUG to assume today that all of these various major equipment replacements can be made sometime in the future in order to allow the plant to run economically beyond 30 years. As Mr. Breedlove testified at hearing:

> Q. And you say that the design life of these rotors is about 19 years; right? (As read.)
>
> A. That's correct.
>
> Q. And Union Power Station has similar combustion turbine rotors in it?
>
> A. Yes, it does.
>
> Q. But you don't use a 19-year service life for Union Power Station, do you?
>
> A. No, we do not. Again, that is only one component of a number of components that have different operating lives and I think you have to look at the plant in its entirety, not just focus on one component.[402]

CCPUG also argues that Mr. Breedlove's testimony that Union PB1 is similar to the Clear Lake generation plant undercuts his argument supporting a 30-year life for Union PB1

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401 CCPUG Brief at 66-67.

402 Tr. (Breedlove) 06/19/19 at 72.

because, unlike Union PB1, the Clear Lake plant is a pre-2000 plant that was shuttered for economic reasons.[403] But again, CCPUG distorts the record in this case. Mr. Breedlove testified on redirect examination at hearing that its technology was "outdated,"[404] and there is no reason to believe that the Clear Lake plant would have operated beyond 30 years. Neither Mr. Kollen nor CCPUG have any evidence or basis for an expert opinion that it would have:

> Q. So your reference to similarity was with respect to size and not with respect to the design margins and other characteristics that you mentioned with respect to pre-2000 combustion turbine machines; correct?
>
> A. Correct.
>
> Q. Again with respect to the Clear Lake unit, do you have any reason to believe that the design life of that unit was greater than 30 years?
>
> A. No, I do not.[405]

4. The depreciable life of NOPS is not at issue in this case, and Mr. Kollen's recommended 50-year depreciable life for NOPS is unreasonable and should be rejected by the Council.

Although the depreciable life of NOPS is not at issue in this case and there is no need for the Council to decide the issue in this proceeding, CCPUG argues that a 50-year service life should be incorporated in the first year revenue requirement that is eventually included in the Company's FRP.[406] However, besides the fact the issue is not ripe for decision in this case, Mr. Kollen's attempt to impermissibly extend the service life of the NOPS plant suffers from the same deficiencies previously outlined in connection with his attempt to extend the depreciable

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[403] CCPUG Brief at 67.

[404] Tr. (Breedlove) 06/19/19 at 78.

[405] Tr. (Breedlove) 06/19/19 at 82.

[406] CCPUG Brief at 68-69.

life of Union PB1. CCPUG's position is based on the claim that Mr. Kollen "investigated publically-available information on retirements of combustion turbine plants, like NOPS."[407] NOPS is not a combustion turbine ("CT") and should not be compared to one. Because Mr. Kollen is not an engineer, he may not appreciate the fact that NOPS will be powered by a reciprocating internal combustion engine—a completely different generation technology than that used for a CT unit.[408] Therefore, the depreciable lives of CT units should not be considered as a guide to the depreciable life of NOPS, and the CCPUG's argument should be rejected by the Council.

P. The Advisors' and AAE's concerns about the potential market effect of the Company's Community Solar Offering are exaggerated.

ENO explained in its Initial Brief why its proposed Community Solar Offering should be approved in this rate case.[409] While not filing any testimony or otherwise previously taking a position on Community Solar, the AAE now argues that the Company's proposal should be rejected.[410] While the Company addressed most of the AAE's arguments in its Initial Brief, the AAE emphasizes its concern that the Company's Community Solar Offering could somehow disadvantage other developers under the Council's new Community Solar rule.[411] That concern is exaggerated when put in context.

Mr. Owens explained that the Company's Community Solar offering is limited to 6 MW of solar capacity and that any future community solar offerings made by the Company would be in accordance with the Council's new rules that were implemented after the Company made this

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407 *Id.* at 68.

408 Resolution R-18-65, dated March 8, 2018, at 11.

409 ENO Brief at 166-168.

410 AAE Brief at 49.

411 AAE Brief at 51. *See also* Advisor Brief at 133.

rate case filing.[412] Council Resolution R-19-111, which establishes the Council's Community Solar rules, limits solar capacity development to 5% of ENO's annual peak.[413] Given that ENO's forecast peak for 2019 is 1,150 MW,[414] the cap for community solar capacity would be approximately 58 MW. ENO's Community Solar proposal (6 MW) would only be about 10% of the size of the market allowed under the Council's new rules. Thus, ENO's small Community Solar Offering, which will not be expanded, could not have any appreciable effect on any market that may develop out of the Council's new rules.

Q. CCPUG's argument against pro forma adjustments for 2019 plant additions is without merit and should be rejected.

CCPUG continues to make the erroneous assertion that ENO's proposed pro forma adjustments to its rate base reflecting plant additions through December 2019 violates prior Council resolutions. The resolutions at issue, Resolution R-15-194 and Resolution R-17-504, set forth the historical test year periods to be used for ENO's 2018 combined base rate case filing. Specifically, Resolution R-15-194 set Period I as a historical test year ending December 31, 2017, and Resolution R-17-504 set Period II as the 12-month period ending December 31, 2018. ENO's inclusion of capital investments to be closed to plant in service by December 31, 2019, through Adjustment AJ14 is not an extension of Periods I or II, nor does it convert them into a forecast year based on assumptions about the future; it is merely an adjustment based on known and measurable changes to plant in service.

Contrary to CCPUG's implication that a resolution or order from the Council is required to include costs incurred beyond Periods I and II defined by these resolutions, the Code of the

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412 Exhibit ENO-10 (Owens Revised Direct) at 41.

413 Resolution R-19-111 at Appendix A., Section V.

414 Exhibit ENO-55 (Revised Application) at Statement G-5, Section G (158-138), Page 1 of 3.

City of New Orleans contemplates that pro forma adjustments may be made to Period I and Period II actual figures for known and measurable changes.[415] The City Code governs ENO's combined rate case filing, and Periods I and II established by Resolution R-15-194 or Resolution R-17-504 are consistent with the Code; CCPUG's witness Mr. Kollen concedes as much.[416] Neither resolution prohibits pro forma adjustments to ENO's cost of service study for plant additions that will benefit customers during the effective period of the rates set in this proceeding.

Pro forma adjustments for known and measurable changes have support in Louisiana jurisprudence as well. The Louisiana Supreme Court has noted that the test year concept in ratemaking depends on the data from the historical test year being representative of the operating conditions to be in effect when the proposed rates will be effective.[417] When it is clear that the test year data is not sufficiently representative of future conditions, adjustment should be made, and arbitrary reliance on the test year is improper.[418] The Court found that the test year should be "adjusted for known changes which will occur within a reasonable time after the end of said period so as to fairly represent the future period for which the rates are being fixed."[419] By this decision, the Louisiana Supreme Court has rejected Mr. Kollen's argument that any costs to be incurred after the test year cannot be known and measurable because they have not yet been incurred.

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415 City Code Sec. 158-41.

416 Exhibit CCPUG-2 (Kollen Surrebuttal) at 8.

417 *Central Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So.2d 1361, 1369 (La. 1987).

418 *Id*. at 1370.

419 *Id*. at 1369 (emphasis added).

ENO included plant additions expected to close by December 31, 2019, to align recovery of such investment with the period during which customers benefit from the investment and to avoid the significant regulatory lag in recovering those costs through the Company's proposed electric FRP.[420] Advisors concurred with ENO's pro forma adjustments to Period II for rate base costs as of December 31, 2019, as a way in which regulatory lag can be reduced.[421] As Advisor's witness Mr. Prep testified at hearing, ENO may include in its test year known and measurable cost changes that will occur during the rate-effective period, and can include Council-approved projects, expenditures or programs and costs included in the Company's business plan and budget, if confirmed.[422]

CCPUG neither produced nor cited to any evidence in support of its sensational claim that allowing the type of pro forma adjustments to test years contemplated by the City Code transforms this process into ENO's ATM machine. As Mr. Prep testified, the probability of these known and measurable costs not actually being incurred is very low.[423] This would especially be true with respect to the capital projects projected to close to plant in service by the end of 2019 that were included in ENO Adjustment AJ14. Mr. Kollen's testimony that the rates in this case will go into effect before any of these plant addition costs are incurred is misleading and ultimately incorrect. As Ms. Beauchamp testified, the Company was halfway through its capital investment portfolio for 2019 at the time of hearing, had already completed several projects, and was well on its way in outlaying the capital necessary to complete each project.[424]

[420] Tr. (Beauchamp) 06/17/19 at 166.

[421] Exhibit ADV-5 (Prep Surrebuttal) at 22-23; Exhibit ADV-8 (Watson Surrebuttal) at 4.

[422] Tr. (Prep) 06/20/19 at 207-208.

[423] Tr. (Prep) 06/20/19 at 208.

[424] Tr. (Beauchamp) 06/17/19 at 160-162.

The idea that the remainder of these plant addition costs will not be actually incurred, such that ratepayers will fund projects from which they will not benefit, is baseless and without merit.

Should the Council accept Mr. Kollen's recommendation over that of ENO and the Advisors and determine that plant additions from calendar year 2019 should not be included in rate base, corrections must be made to Mr. Kollen's calculation of the rate base effect of his recommendation. Specifically, although he considered the effects of Adjustment AJ15 for the AMI charge, he added the total adjustment amount of $33.718 million for the AJ15 amounts instead of the appropriate 2019 related amount of $21.260 million. Further, he did not consider the pro forma adjustments' effect on accumulated depreciation and associated ADIT and did not reduce his calculation by the ADIT associated with ENO's 2019 plant additions even though the Company reduced plant in service, accumulated depreciation and ADIT balances and associated depreciation expense in Adjustments AJ15 and AJ18. Therefore his rate base reduction was overstated; the revenue requirement reduction pertaining to rate base is $1.615 million, not $3.482 million.[425] Regarding his depreciation expense calculation, Mr. Kollen incorrectly calculated the amortization expense on the intangibles and failed to add back amounts taken out through Adjustments AJ15 and AJ18. These errors overstated his depreciation expense reduction; the revenue requirement reduction pertaining to 2019 depreciation expense should be $1.373 million, not $3.684 million. The total revenue requirement reduction resulting from Mr. Kollen's recommendation is $2.989 million.[426]

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425 Exhibit ENO-4 (Thomas Rejoinder) at 29-30.

426 *Id*. at 30.

R. No regulator has concluded that common dividends should be included in a Cash Working Capital ("CWC") allowance, as CCPUG recommends, and CCPUG is taking Mr. Gallagher's testimony out of context; the Council should reject CCPUG's recommendation.

The Company has addressed this issue in detail in its Initial Brief at 158-161. To reiterate, at hearing, CCPUG witness Mr. Kollen admitted that he was not aware of any retail regulators that have agreed with his opinion that a common dividend component should be included in a lead-lag analysis.[427] Also, a common dividend component in a lead-lag analysis is conceptually unsound because common dividends are not expenses, and the lead-lag analysis should only consider revenues and expenses consistent with Council practice and rule.[428] Finally, Mr. Kollen's proposed adjustment to ENO's lead-lag analysis does not measure the cash effects of ENO's common dividends paid but rather is based incorrectly on a purely hypothetical extrapolation of Entergy Corporation data.[429]

In brief, CCPUG suggests that Company witness Mr. Gallagher's testimony should be given little weight because he included *preferred dividend payments* in his lead-lag analysis performed for ELL in an LPSC proceeding.[430] CCPUG's suggestion is self-serving and omits the import of Mr. Gallgher's hearing testimony. Mr. Gallagher explained that he included <u>preferred dividends</u> in ELL's lead-lag analysis because that was the LPSC's rule, but he did not agree with it:

> . . .once [the regulator] establish[es] a rule, despite my opposition to it, [the regulator] can do what [the regulator] want[s] on it, but as a practical matter, no

427 Tr. (Kollen) 06/20/19 at 27.

428 Exhibit ENO-39 (Gallagher Rebuttal) at 4-5.

429 Tr. (Kollen) 06/20/19 at 26-27.

430 CCPUG Brief at 91. (Emphasis added)

> dividends, common or preferred, should be included in a lead/lag analysis because they are not operating expenses.[431]

The Council's rule is not to include common dividends in a lead-lag analysis, and Mr. Gallagher testified that changing such rule based on CCPUG's reasons is conceptually unsound. Accordingly, CCPUG's recommendation should be rejected.

S. ENO's proposed RIM Plan will only reward exceptional service reliability.

The Company's proposed RIM Plan addresses a core concern of the Council, that being ENO's recent reliability performance, in the context of the ROE authorized by the Council in this proceeding. However, there is no question that irrespective of the RIM Plan proposal, ENO accepts its responsibility to provide reliable service to its customers at the lowest reasonable cost; any suggestion to the contrary is an empty semantic argument.[432] The Company has already significantly increased its spending on distribution system reliability programs, which has already improved the reliability of its service.[433]

Many of the parties disparage the RIM Plan for allegedly rewarding the Company for merely providing reliable service. For example, CCPUG argues that the RIM Plan inappropriately seeks to charge customers a "bonus" for ENO's obligation "to pursue increased reliability."[434] This characterization blatantly misstates how the RIM Plan would operate. The RIM Plan will not reward ENO in the form of an increased ROE merely for providing reliable service. It could only compensate the Company if the reliability it achieves over a very short time period greatly exceeds the average reliability provided by similarly sized and situated utilities. Specifically, Mr. Thomas explained that achieving a SAIFI score of 1.24, the average

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[431] Tr. (Gallagher) 06/18/19 at 35.

[432] Tr. (Thomas) 06/20/19 at 70-71.

[433] Tr. (Stewart) 06/18/19 at 119-120.

[434] CCPUG Brief at 70.

of the median SAIFI scores for small and medium utilities, would simply permit the Company to use its authorized ROE for purposes of setting the EPCOE in the proposed FRP.[435] Indeed, a SAIFI score of 1.24 indicates better reliability than the median SAIFI score (1.34) for small utilities.[436]

To have the opportunity to earn a higher ROE, the Company must provide better than average reliability, or better than a 1.24 SAIFI score. Ms. Stewart explained that achieving a SAIFI score of 1.24 or better during the three-year term of the FRP, to which the RIM Plan is limited, would be a 25% improvement over current levels.[437] CCPUG is correct that ENO will continue investing in improving its recent reliability performance with or without the RIM Plan, as no incentive is required to provide reliable service. The RIM Plan will provide the Company with an opportunity for an enhanced return *only* in the event it provides its customers with the benefit of exceptional reliability performance.

With respect to the argument advanced by AAE and APC that transmission customers should not be subject to the RIM Plan given ENO's focus on distribution-related reliability performance, the Company recognizes that all outages, regardless of whether they occur on the transmission system, at a substation or on the distribution, affect customers.[438] Therefore, the SAIFI scores mentioned above that determine whether an incentive is warranted under the RIM Plan are "customer view" SAIFI.[439] The customer view SAIFI includes all outages greater than

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435 *Id*. at 176. SAIFI is an industry standard measure of reliability performance, indicating the number of outages experienced by the average customer over the reporting period. Exhibit ENO-6 (Stewart Revised Direct) at 41.

436 Exhibit ENO-6 (Steward Revised Direct) at 44-45.

437 *Id*. at 45.

438 Exhibit ENO-6 (Stewart Revised Direct) at 26.

439 *Id*. at 40-41.

five minutes occurring on transmission, substation and distribution assets, excluding outages for major events, those mandated by government authorities, and outages due to load shed events.[440]

Moreover, as demonstrated by APC witness Brubaker's Exhibit MEB-4, transmission-related outages do occur,[441] and while Ms. Stewart's testimony focused on the distribution-related reliability efforts of the Company, as she oversees the distribution system,[442] it is not accurate to claim, as APC does, that "ENO's reliability improvement plan does not include any work on the transmission system."[443] It is only true that ENO's *distribution* reliability improvement plan discussed by Ms. Stewart does not include transmission work. In fact, ENO forecast transmission spending of over $29 million in 2018.[444] Accordingly, because the RIM Plan adjustments would be a function of outages from **all** parts of ENO's system, including transmission, all customers will benefit from reliability performance improvements encompassed in both transmission and distribution spending and should participate in the plan. Of course, should the Council adopt the RIM Plan, ENO is open to and will support further discussion and collaboration amongst the interested parties with regard to the appropriate allocation of any future ROE adjustment warranted by its reliability performance.

T. ENO's Restricted Stock Incentive Plan expenses are reasonable and necessary and the Advisors offered no evidence to the contrary

The Advisors rely on their witness Thomas J. Ferris' inaccurate statement of the legal burden of proof necessary for ENO to recover the costs of its restricted stock incentive plan in arguing that such costs should be excluded from the Company's revenue requirement. Mr. Ferris

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440 *Id*. at 41, n. 15.

441 Exhibit APC-3 (Brubaker Direct) at Exhibit MEB-4, page 3 of 6.

442 Exhibit ENO-6 (Stewart Revised Direct) at 2.

443 Air Products Brief at 36.

444 ENO Exhibit 56, WP Statement AA-2_REV_E (UnitCostStudy).

is a certified public accountant, yet he purports to offer opinion testimony on the legal basis for recovery of these costs without citing any precedent or other authority. Contrary to his unsupported and unqualified opinion, the prudent investment rule applies to this ratemaking proceeding and has been long established in Louisiana.[445] Under that rule, ENO is entitled to compensation for all prudent investments, and "is entitled to the presumption that the investments were prudent, *unless the contrary is shown*."[446] As pointed out in the Company's initial brief, the Advisors offered no evidence to make such a showing. In contrast, ENO witness Mr. Thomas explained that the costs of the restricted stock incentive program are reasonable and necessary to help ENO attract and retain the required personnel to provide reliable service to its customers at reasonable cost.[447] Beyond the reasonableness and necessity of the plan, it offers benefits to ENO customers by encouraging the Company's personnel to act prudently with financial resources and to resolve operational issues using cost-effective methods.[448] Mr. Ferris acknowledged that the plan promotes such efficiency and responsibility. Therefore, the Council should allow ENO to recover the costs of the restricted stock plan through the rates established in this proceeding.

U. The Company's proposed PPCACR Rider promotes certainty of timely cost recovery of Council-approved renewable resource additions and should be approved in the absence of a FRP with forward-looking features.

Although the Advisors agree that regulatory lag is a valid concern and propose forward-looking adjustments for the FRPs, they oppose inclusion in the Company's proposed PPCACR

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445 *South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n*, 594 So.2d 357, 365 (La. 1992), citing *Morehouse National Gas Co. v Louisiana Pub. Serv. Comm'n*, 162 So.2d 334 (1964)

446 *South Cent. Bell*, 594 So.2d at 366 (emphasis added), citing *Duquesne Light Co. v. Barasch*, 109 S.Ct. 609, 616 (1989) and *Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Comm'n*, 43 S.Ct. 544, 547, n. 1.

447 Exhibit ENO-4 (Thomas Rejoinder) at 31.

448 *Id*.

Rider of any as-yet unknown non-fuel revenue requirement related to construction and/or acquisition of new capacity, new PPA or new Long-Term Service Agreements ("LTSA"). The Advisors approve a modified version of the rider to allow recovery of costs related to existing PPA and LTSA. CCPUG objects to the proposed PPCACR Rider the claim because it will allow automatic recovery of the capacity costs and costs of new generation assets without full certification review by the Council. APC witness Mr. Brubaker agrees with ENO that the cost-recovery mechanism in the proposed PPCACR Rider is reasonable and should be accepted.[449]

Under the Advisors' proposed modifications, in the absence of a forward-looking FRP, timely recovery of prudent costs associated with Council-approved resource additions becomes uncertain.[450] Such additions include the Company's investment in the 90 MW solar investment already proposed to the Council and other renewable resource needs identified by the Council in the future.[451] The Council has previously indicated its appreciation for the importance of contemporaneous cost recovery related to new generation resources by allowing the Company to recover the costs of prior generation resource additions.[452] Without certainty of timely recovery of prudent costs, ENO's cost of capital will remain higher, to the detriment of all stakeholders, including ENO customers.[453] Although the Advisors argue that it is more appropriate to address the non-fuel costs of new acquisitions in a base rate case once they are known and measurable, they do not explain how such an approach addresses regulatory lag, which they recognize as a legitimate issue.

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449 Exhibit AP-3 (Brubaker Direct) at 4, 19.

450 Exhibit ENO-4 (Thomas Rejoinder) at 12.

451 Exhibit ENO-3 (Thomas Rebuttal) at 9-10.

452 Exhibit ENO-4 (Thomas Rejoinder) at 13.

453 *Id*. at 12.

Contrary to the protest of CCPUG, ENO will not automatically recover the costs of any future capacity acquisition or PPA through the PPCACR Rider. Per the explicit terms of the rider, ENO can only recover those non-fuel costs associated with new resources determined by the Council to be prudent and in the public interest to secure. Thus, the Council will decide the prudence of the investment in any future resource addition before ENO recovers any costs, and therefore no customer harm will occur.[454] Because it will promote timely cost recovery pertaining to acquisition and construction of future capacity that will also require Council approval, the proposed PPCACR Rider should be approved by the Council.

1. ENO's treatments of the Algiers Transaction Expense Regulatory Asset and the Algiers Migration Expenses are reasonable; CCPUG's recommended treatment would interfere with the timely recovery of these costs.

ENO addressed CCPUG's unreasonable recommendations, which seek to prolong recovery of these costs unnecessarily, at pages 156-158 of its Initial Brief. CCPUG's recommendations do not attempt to balance the need for timely cost recovery with customer interests. Thus, the Council should reject CCPUG's recommendations.

III. UPDATE ON UNCONTESTED ISSUES

A. AAE is incorrect regarding the status of the NOPS approval; the Council should approve the proposed recovery method for the NOPS non-fuel revenue requirement.

In this proceeding, ENO has proposed to begin recovering the first-year revenue requirement associated with NOPS in the first billing cycle of the month after NOPS enters commercial operation in 2020.[455] More specifically, the Electric Formula Rate Plan Rider

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454 Exhibit ENO-3 (Thomas Rebuttal) at 10; Exhibit ENO-4 (Thomas Rejoinder) at 13.

455 Exhibit ENO-1 (Thomas Revised Direct) at 67-69.

("EFRP") proposed by ENO includes a provision that specifically addresses NOPS cost recovery in Section III., entitled "Provisions for Other Rate Changes." The NOPS provision in that section provides, in part, that "ENO shall include through an interim rate adjustment effective as of the first billing cycle of the month following the Commercial Operation Date ('COD') the final estimated first-year revenue requirement associated with the completion of the construction of the New Orleans Power Station ('NOPS'), the construction of which was approved by the Council of the City of New Orleans in Resolution R-18-65." The provision goes on to state that that first-year revenue requirement shall form the basis for an in-service adjustment to the Company's base rates. In its previous brief, ENO treated its proposed in-service adjustment for the NOPS first-year revenue requirement as an uncontested issue because no party opposed the proposal in filed testimony.

In its Initial Brief, AAE goes beyond its filed testimony and outside of the administrative and evidentiary record in this proceeding to argue that the Council should not approve the contemporaneous recovery of NOPS costs provided for in the proposed FRP. Specifically, AAE cites and attaches a copy of a state court judge's July 2, 2019 Judgment in the Open Meetings lawsuit that that arose out of the NOPS proceeding before the Council and was filed by certain intervenors in that proceeding and other.[456] In that state court proceeding, the judge ruled that the Council's approval for ENO to construct NOPS via Resolution R-18-65 in March 2018 was void due to an alleged violation of Louisiana's Open Meetings Law. The Council moved for a suspensive appeal of that ruling, and that motion was granted. The plaintiffs in the Open Meetings lawsuit then filed with the Louisiana 4th Circuit Court of Appeal an Application for Supervisory Writ and Request for Expedited Consideration, seeking to overturn the district

[456] AAE Brief at 53.

court's grant of the Council's Motion for Suspensive Appeal. The 4th Circuit recently denied that Writ Application, refusing to exercise its supervisory jurisdiction.

AAE latches onto the language in the EFRP's provision referring to NOPS and stating "the construction of which was approved by the Council of the City of New Orleans in Resolution R-18-65" and then cites the July 2nd Open Meetings ruling to argue that "contrary to the rationale set forth in the tariff language, the construction of NOPS does not have the approval of the Council."[457] There are at least two main fallacies in the AAE's argument.

First, as noted, the Council has moved for and been granted the right to a suspensive appeal, and that right to suspensively appeal has now been upheld by the Louisiana 4th Circuit Court of Appeal. The effect of the judgment purporting to void the Council's approval of NOPS would be suspended pending the appeal and, therefore, the Council's March 2018 approval to construct NOPS would be in effect until the appeal runs its course.

Second, and even more damning to AAE's position, is the fact that the Council *this year* reaffirmed its approval of NOPS. In Council Resolution R-19-78, adopted on February 21, 2019, the Council approved a settlement with ENO of a "show cause" proceeding relating to the NOPS proceeding and therein effectively re-approved the construction of NOPS, noting in its acceptance of the settlement offer that "ENO's settlement offer is . . . conditioned upon the Council's approval of NOPS remaining in effect as adopted in Resolution R-18-65." That Resolution went on to impose various conditions on ENO's construction and operation of NOPS, including, *inter alia*, bi-monthly reporting on the progress of the NOPS construction. The Council's acceptance of ENO's settlement offer via Resolution R-19-78 clearly authorized – effectively required – ENO to continue with the construction of NOPS. That Resolution is now

[457] *Id.*

final and unappealable. In conclusion, it is worth pointing out that the same state court judge who entered the Judgment in the Open Meetings lawsuit, also heard a separate lawsuit filed by AAE and others challenging the Council's NOPS approval on the merits. However, in that case, the judge affirmed the Council's action and held that the Council's approval of the construction of NOPS was based on an extensive evidentiary record and was not arbitrary and capricious.

NOPS is a $210 million project to construct an essential generation resource for New Orleans that will assist in stabilizing the transmission grid, preventing cascading outages, restoring power after major storms, and that will provide substantial economic benefits for ENO customers and for the City of New Orleans. ENO's proposal to provide for contemporaneous cost recovery for this important resource is necessary to maintain ENO's financial stability and for this and all the reasons set forth in the evidentiary record by ENO's witnesses the mechanism should be approved by the Council as proposed.

B. There is no longer any contested issues regarding the Securitized Storm Cost Offset Rider - SSCO Rider ("SSCO Rider"); the Council should allow the SSCO Rider to remain in place with one modification proposed by the Advisors.

In its Initial Brief, the Company anticipated a dispute as to the continuation of the SSCO Rider. The Advisors are no longer seeking to terminate the SSCO Rider. The Company does not oppose the use of ENO's then-current WACC when redetermining the SSCO Rider rate.

C. The AAE recommends unsupported and unwarranted changes to the Company's Green Power Option.

Again, failing to provide any testimony on this issue, the AAE for the first time in its Brief claims that the proposed Green Power Option should be revised to define the types of renewable resources that qualify as "green" energy and that it specify that "none" of the costs of the offering will be borne by nonparticipants.[458] First, the Company's filing complies with Council Resolution R-18-97, which simply requires that ENO make a "proposal under which customers may voluntarily choose to have some or all of the electricity supplied by ***renewable resources***."[459] Resolution R-18-97 does not otherwise define "renewable resources," so AAE's recommendation is not supported by the operative guidance in this proceeding. Further, AAE offered no evidence supporting its new argument that the scope should be narrower.

Second, the Company committed that the renewable energy credits ("RECs") sourced for the Green Power Offering would be "Green-e" certified.[460] Contrary to the AAE's assertion that ENO will obtain RECs *from* Green-e, Green-e is an independent consumer protection organization that verifies that the RECs procured by the Company are (a) sourced from facilities that meet quality criteria that has been endorsed by a diverse stakeholder group; (b) marketed transparently and honestly; and (c) delivered exclusively to the purchaser of the REC, *i.e.*, that the renewable attribute of the generation is not used toward a state renewable energy mandate or otherwise double-counted.[461] Green-e has specific minimum criteria related to: facility online date, REC vintage, and eligible resource types, yet it also allows flexibility in design.[462] Thus, while ENO has not narrowed the types of renewable resources offered under its proposed Green Power Offering, it has put in place assurances that the energy is from renewable sources and that there is no double-counting.

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458 AAE Brief at 52.

459 Resolution R-18-97, dated April 5, 2018 (emphasis added).

460 Exhibit ENO-19 (Smith Revised Direct) at 44.

461 Exhibit ENO-19 (Smith Revised Direct) at 44.

462 Exhibit ENO-19 (Smith Revised Direct) at 44.

Third, Resolution R-18-97 requires that "[t]he green pricing proposal should reflect *to a reasonable extent* ENO's incremental net cost to provide this option to customers."[463] Importantly, R-18-97 does not require that ENO ensure "none" of the costs could ever be borne by nonparticipants. Mr. Owens (adopting Mr. Smith's testimony) explained that the Green Power Option pricing has been designed such that it is "reasonably assured" that the price of the RECs and incremental costs of offering the product will be recovered from participants,[464] and Advisors witness Watson agreed that "Rider GPO would impose substantially no costs or risks to non-participants."[465] Mr. Owens added that actual participation levels and costs will be monitored, and ENO will seek adjustments, subject to Council approval, if warranted.[466] Accordingly, the AAE's recommendations should be rejected because they exceed the scope of R-18-97 and are unwarranted.

D. In their Initial Brief, the Advisors did not address their proposal to lower the amount of the Prepaid Pension Asset to be included in rate base; accordingly, the Council should reject this proposal.

In their brief, the Advisors did not address their proposal to lower the amount of the Prepaid Pension Asset included in ENO's Period II electric and gas rate bases. If the Advisors intended to withdraw this proposal, the the Council should recognize such withdrawal and treat the issue as uncontested. If the Advisors do not intend to withdraw this proposal, ENO has addressed the proposal in its previous brief at pp. 150-154.

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463 Resolution R-18-97, dated April 5, 2018 (emphasis added).

464 Exhibit ENO-19 (Smith Revised Direct) at 48.

465 Exhibit ADV-6 (Watson Direct) at 72.

466 Exhibit ENO-19 (Smith Revised Direct) at 49.

E. BSI's claims that CLEP is superior to GPO are unsupported.

BSI claims that CLEP is superior GPO in terms of offsetting usage with renewables,[467] but it offered no testimony or any other evidence to support its claims, which are also made for the first time in its Brief. The Council should reject BSI's competing proposal.

F. The Company continues to object to including the e-Tech rebates in Energy Smart.

The Advisors support the EV charger rebate program (e-Tech), but they continue to advocate that future e-Tech efforts should be considered as part of Energy Smart.[468] For the reasons discussed in ENO's Initial Brief, ENO opposes including measures designed to increase sales while promoting sustainability as part of Energy Smart, which is intended to reduce energy sales.[469]

G. The Company is not opposed to Air Product's Recommendation on Service Policy Changes.

Air Products recommends that ENO's proposed change to the Continuity of Service provision in ENO's Service Regulations not be adopted.[470] ENO does not object to APC's recommendation; however, ENO does object to the Advisor's characterization of the legal effect of the current provision.[471]

H. The Company supports the Advisors' corrections to the proposed FAC Rider

As noted by the Advisors, the Company's request to combine the FAC riders for Legacy ENO and Algiers customers into a single FAC rider is simpler in terms of calculation and understanding. The Advisors agree with ENO's suggestion to address over and under collection

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467 BSI Brief at 25.

468 Advisor Brief at 140.

469 ENO Brief at 181-182.

470 Air Products Brief at 44.

471 Advisor Brief at 144.

in the compliance filing process, and recommend approval of the proposed FAC Rider Schedule with certain corrections.[472] No other party opposes the approval of the proposed FAC Rider. ENO accepts the Advisors' corrections and seeks Council approval of its proposed combined FAC rider in accordance with the Advisors' recommendation.

I. The Company supports the Advisors' corrections to the proposed PGA Rider

The Advisors also recommend Council approval of ENO's proposed combined PGA Rider, with certain errors corrected.[473] No other party objected to or opposed the proposed PGA Rider. ENO accepts the Advisors' corrections and seeks Council approval of the proposed PGA Rider in accordance with the Advisors' recommendation.

1. MISO Rider

The Advisors reviewed the Company's proposed MISO Rider and found no reference or calculation errors. They also determined the rider is consistent with the Council's directive in Resolution No. R-17-504 to develop a single set of tariffs applicable to all customers, that its cost allocation is appropriate. The Advisors recommend approval of the MISO Rider as proposed by ENO, and no other party objected to its adoption.[474] Therefore, the Company's proposed MISO Rider should be approved.

IV. CORRECTIONS

472 Advisors Brief at 95-96.

473 *Id*. at 96.

474 Advisors Brief at 101.

A. ENO did not correct any ADIT amounts in response to discovery from CCPUG; all ADIT corrections resulted from the Company's preparing responses to Advisors' data requests.

In its brief, CCPUG claims that "ENO corrected these NOL ADIT amounts in response to discovery from the Advisors and CCPUG, which saved ratepayers money" and "[t]hat is the good news."[475] CCPUG's "good news" is not true.

CCPUG erroneously bases its claim on the Company's response to CCPUG 6-2, which is Exhibit LK-3 to Exhibit CCPUG-1. The Company received CCPUG 6-2 on January 2, 2019 and responded to it on January 14, 2019. CCPUG 6-2 has nothing to do with NOL ADIT. Additionally, although the Company's response to CCPUG 6-2 refers to a correction, ENO made the correction in response to Advisors 5-19, which ENO served on December 14, 2018 – nineteen days before receiving CCPUG 6-2. Furthermore, ENO corrected its proposed NOL ADIT amounts in Addendum 1 to Advisors 5-9; ENO served the Addendum on December 11, 2018, weeks before the Company received the CCPUG's Sixth Set of Data Requests. Thus, CCPUG 6-2 did not cause ENO to correct any ADIT amounts in its cost of service studies.

V. CONCLUSION

ENO is requesting that the Council put in place a new combined rate structure that will enable the Company to provide its customers throughout the City reliable, twenty-first century service that incorporates the industry's technological advances and that will continue to meet customers' evolving expectations and the Council's policy objectives. The Company has a plan that allows it to meet the objectives it shares with the Council and expectations of its customers, which plan requires it to undertake a large, aggressive capital program to transform the delivery of electric service to customers and maintain the Company's financial condition. But successful

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475 CCPUG Brief at 79.

execution of that plan is highly dependent on the continuation of the constructive regulatory environment, the elements of which have been identified and discussed throughout ENO's Revised Application and supporting evidence providing by its witnesses through testimony, exhibits and work papers. For these reasons and the reasons set forth throughout ENO's initial Post-Hearing Briefs, ENO respectfully requests that the Council adopt ENO's proposed electric and gas base rates, the requested elements of its proposed rate structure as set forth in its Revised Application and all related relief.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this 9th , day of August, 2019, served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual, by: ☒ electronic mail, ☐ facsimile, ☒ hand delivery, and/or by depositing same with ☐ overnight mail carrier, or ☐ the United States Postal Service, postage prepaid.

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