Jay Beatmann
Counsel

jay.beatmann@dentons.com
D +1 504 524 5446

Dentons US LLP
650 Poydras Street
Suite 2850
New Orleans, LA 70130-6132
United States

大成 **Salans FMC SNR Denton McKenna Long**
dentons.com

July 26, 2019

BY HAND DELIVERY

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

In Re: *Application of ENO for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief*, CNO Docket UD-18-07

Dear Ms. Johnson:

Enclosed please find an original and three (3) copies of the *Initial Brief of the Advisors to the City of New Orleans* in the above referenced docket, which the Advisors to the Council for the City of New Orleans are requesting that you file into the record along with this letter in accordance with your normal procedure.

Sincerely,

Jay Beatmann
Counsel

JAB/dpm
Enclosures

cc: Official Service List for UD-18-07

BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: REVISED APPLICATION OF ENERGY 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	))))))	**DOCKET NO. UD-18-07**

INITIAL BRIEF
OF THE ADVISORS TO THE CITY COUNCIL OF NEW ORLEANS

Jerry A. Beatmann, Jr. (Bar No. 26189)
Dentons US LLP
650 Poydras Street, Suite 2850
New Orleans, LA 70130
504-524-5446 (Office)
504-256-6142 (Cell)
jay.beatmann@dentons.com

Clinton A. Vince
Emma F. Hand
Presley R. Reed, Jr.
Dentons US LLP
1900 K Street, N.W.
Washington, D.C. 20006
202-408-6400 (Telephone)
202-408-6399 (Facsimile)
clinton.vince@dentons.com
emma.hand@dentons.com
presley.reedjr@dentons.com

Dated: July 26, 2019

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I. Introduction

A. Statement of Position

While a general rate case is, of course, primarily about how much customers should pay the utility for electric and natural gas service, this Combined Rate Case submitted to the Council by Entergy New Orleans, LLC ("ENO" or the "Company") contains many exciting new options for customers reflective of the Council's leadership in energy sustainability and resilience. ENO is proposing a Green Power Option in compliance with Council Resolution No. R-18-97, under which customers may choose to have up to 100% of their power offset by Renewable Energy Credits from renewable energy sources. ENO is also proposing to expand its existing Demand Response options previously only available in Algiers to all of its customers, which will allow significantly more customers the option of earning a credit from ENO for reducing their energy use at key times as directed by ENO. Pursuant to Council leadership in Docket No. UD-18-01, ENO is also proposing rebates for residential customers for installing electric vehicle ("EV") chargers at their homes and options for commercial customers and the City to partner with ENO on installing EV charging stations in New Orleans. ENO's proposed rates also include a more stable funding mechanism for the very popular and successful Energy Smart energy efficiency program. These are all very positive developments that will help move the City towards becoming a cleaner, more resilient community.

Inherent to moving toward the future of electric and natural gas service in the City is the setting of rates, terms, and conditions for such service that are just and reasonable. Rates should be fair both to customers and to the utility. While the Advisors were pleased to see that ENO's proposal reflected a $20 million decrease in its electric revenue requirement, ENO's overzealous pursuit of exact and nearly instantaneous recovery of all costs is unwarranted, and the Advisors' balanced approach in the instant proceeding results in a recommended $33.1 million electric revenue reduction. A utility is entitled under the law to a reasonable opportunity to recover its revenue requirement -- not a guarantee.[1] A utility may over- or under-earn on its revenue requirement to a reasonable extent in any given year and this is appropriate. Requiring the utility to incur an ordinary level of business risk and reward provides the utility with an appropriate incentive to run its business effectively. Many of the Advisors' recommended changes to ENO's proposal are designed to ensure that ENO is not too richly compensated at ratepayer expense through its rates, but that it has a reasonable opportunity to earn a fair return and that customers are fairly treated.

An overarching theme of ENO's positions in the instant proceeding is ENO's purported need for a "constructive regulatory environment." ENO witness Thomas refers to such an environment no less than twenty-nine times in his direct testimony alone. ENO's testimony in the instant proceeding suggests a constructive regulatory environment that generally consists of allowing ENO a notably high Return on Equity ("ROE") relative to those recommended by other witnesses, proforma adjustments highly favorable to ENO, and rider schedules that provide ENO exact and nearly instantaneous cost recovery. Highlights of ENO's proposals with respect to recovery of its revenue requirement include:

- ENO proposes an allowed-ROE of 10.75% (up-to 11.0% for electric), which is well above those the other four expert witnesses estimated and supported.
- ENO's proforma adjustments for plant additions as of December 31, 2019 constitute the addition of $64.4 million[2] and $25.7 million[3] to ENO's electric and gas rate bases

[1] *South Central Bell Telephone Co. v. Louisiana Public Service Commission*, 594 So. 2d 357, 359-360 (La. 1992).
[2] Ex. No. ENO-33 at 16:8.
[3] Ex. No. ENO-33 at 17:7.

respectively compared to ENO's actual rate base for Period II (*i.e.*, December 31, 2018) as provided for by the Code.[4]

- ENO proposes multiple riders designed to provide ENO nearly 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. In addition to customary exact-cost recovery riders such as the Fuel Adjustment Clause ("FAC") and Purchased Gas Adjustment ("PGA") riders, such proposed riders include,
    - A Gas Infrastructure Replacement Program ("GIRP") Rider which would provide exact recovery of costs related to ENO's investment in gas distribution plant and utility survey costs.[5]
    - A Purchased Power and Capacity Acquisition Cost Recovery ("PPCACR") Rider which would provide exact recovery of costs related to ENO's Purchase Power Agreements ("PPA") and costs related to any new capacity additions by ENO.
    - A Distribution Grid Modernization ("DGM") Rider which would provide exact recovery of costs related to certain ENO investments in its distribution plant.
    - An Advanced Metering Infrastructure ("AMI") customer charge rider for each of the electric and gas customers that would provide exact recovery of costs related to ENO's investments in AMI deployment.
    - A Combined MISO Rider would provide exact cost recovery of costs related to ENO's participation in MISO.

[4] Code of the City of New Orleans, Sec. 158-132 (1).
[5] Ex. No. ENO-41 at 49:5-20.

- A Demand-Side Management Cost Recovery Rider ("DSMCR") would provide ENO exact recovery of costs related to the Council's Energy Smart ("ES") programs, including a return to ENO on deferred DSM expenses.

As a whole, ENO's proposals in the instant proceeding would provide it nearly guaranteed exact cost recovery of most new costs it expects to incur while still allowing it a ROE consistent with a company exposed to significant risks. The "constructive regulatory environment" proposed by ENO appears to mean a high return on investment with a low risk in the recovery of costs. ENO's proposed ratemaking treatments do not fairly balance its interests with those of ratepayers.

Regarding the amount each rate class would pay for ENO's "constructive regulatory environment," ENO proposes that most rate classes experience rate reductions except for residential electric customers in Algiers, who would experience a 3.5% base rate increase.[6]

The Intervenors in general do not support many of ENO's proposals that constitute a "constructive regulatory environment." Specifically, the Intervenors that testified as to ROE rejected ENO's proposed unsupported ROE and several of ENO's proposed riders and proforma adjustments. Notable Intervenor objections to components of ENO's proposed "constructive regulatory environment" include:

- The Intervenors who recommend an ROE, Air Products and Chemicals, Inc. ("Air Products") and Crescent City Power Users Group ("CCPUG"), recommend a ROE substantially lower than that proposed by ENO, *i.e.*, 9.35%.[7] Both Intervenors submitted expert witness testimony in support of the 9.35% ROE figure.

[6] Ex. No. ENO-45 at 32:10-14.
[7] Ex. No. AP-1 at 3:6-8, Ex. No. CCPUG-3 at 3:4-5.

- CCPUG witness Kollen opposes ENO's proposed adjustment to reflect plant additions as of December 31, 2019.[8]

The Advisors' recommendations to the Council provide ENO the full reasonable opportunity to recover its costs contemporaneously with their occurrence along with an ROE that accepted market-based analytical methodologies demonstrate is sufficient to protect ENO's ability to maintain its financial integrity, to attract capital, and to compensate its investors for the risks it assumed by investing in ENO. The Advisors' key recommendations to the Council constituting a fair balancing of ratepayer and ENO interests include:

- Acceptance of ENO's proposed proformas reflecting plant additions through December 31, 2019 and a similar treatment of plant additions as part of a recommended Formula Rate Plan ("FRP") for ENO.
- Acceptance of ENO-proposed riders that provide for contemporaneous cost recovery of those costs that are variable and outside of ENO's control, but not for those costs that are predictable and within ENO's control.
- Recommendation of a ROE that is demonstrated by accepted market-based analytical methodologies to reflect a fair return to ENO, including adjustments that take into account ENO's specific risks of vulnerability to storm-related damages.

In addition to recommending a fair balancing of ratepayer and ENO interests, the Advisors' recommendations also represent a fair balancing of interests among the rate classes. In particular, unlike ENO, which proposes a rate increase for Algiers electric residential customers, the Advisors recommend that no rate class experience a year one rate increase in the instant proceeding. Further, recognizing the interests of residential customers who use limited

[8] Ex. No. CCPUG-1 at 14:10-15.

amounts of energy, the Advisors have recommended a modest customer charge of $10.00/mo.[9] as opposed to ENO's recommendation of $15.53/mo.[10]

The Council's role in a general rate case is to examine the evidence and balance the need of ratepayers to keep rates low against the need to keep the utility financially healthy enough to be able to make the investments needed to provide safe and reliable electric service to the City. The Advisors have reviewed and analyzed the evidence submitted by the parties in the case, and make our recommendations to the Council herein.

B. Background -- the Shifting Landscape

ENO's base rates were last established by the Council approximately ten years ago, in 2009.[11] The landscape has changed significantly since that time, and this Combined Rate Case reflects many of those changes. On May 14, 2015, the Council in Resolution No. R-15-194 approved an Agreement in Principle authorizing ENO to acquire from ELL its electric operations and related assets and liabilities in Algiers and directed ENO to utilize a four-step change in base rates for Algiers Customers. This will be the first base rate case where ENO's service territory is unified into a single territory.

Another significant development has been the retirement of the Michoud units in 2016 and ENO's pursuit of replacement capacity. In 2011, the Council authorized ENO to enter into a PPA for capacity from Ninemile 6,[12] which provides ENO 20% of the output of this 550 MW (nameplate) generating unit. Subsequently, the Council adopted Resolution No. R-15-542 on November 19, 2015 approving ENO's acquisition of Union Power Block I. Finally, ENO filed

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[9] ADV-3 at 60:19-20.
[10] ENO-1 at 8:3-6.
[11] Council Resolution No. R-09-136.
[12] Council Resolution No. R-11-356.

its application to build the New Orleans Power Station ("NOPS") at the Michoud facility, and the Council approved that application.

Customers have also begun to demand alternatives to traditional electric service in increasing numbers. The Energy Smart Program has also grown significantly since the last general rate case, and is now of such significant size as to warrant funding the highly successful program through rates. ENO has also seen continued interest from its customers in rooftop solar and other renewable options. The Council in Resolution No. R-16-103 approved a decoupling mechanism to be incorporated into rates in order to align ENO's incentives with the desires of its customers for increased energy efficiency and customer-generated electricity. ENO has also just received approval for 90 MW of new renewable generation capacity and once that is in operation, will have a total of 96 MW of renewables in its portfolio. Electric vehicles have also just begun to hit the market in significant numbers, and ENO will have to move to meet its customers' needs on that front as well.

ENO is also in the process of rolling out AMI throughout its service territory, which is another significant change that impacts ENO's rates, terms and conditions of service. All of these changes must be reflected in ENO's new rates, terms and conditions of service, and ENO has proposed many changes to its rates, terms and conditions to meet these new demands and challenges.

C. Ratemaking Principles and Applicable Council Resolutions

The Council has the exclusive power to regulate public utilities in the City, including the authority to set retail electric and natural gas rates for its residents. As authorized by the Louisiana Constitution and pursuant to the Home Rule Charter of the City of New Orleans, all legislative powers of the City are vested in the Council.[13][14] Among the legislative powers exclusively granted to the Council are the powers of "supervision, regulation, and control" over those utility companies that furnish services within the City of New Orleans.[15] Rate making is included in the Council's exclusive regulatory powers over utility companies.[16]

Rates set by the Council must be just and reasonable and consistent with regulatory principles and doctrines. The Council's role is to balance the interests of consumers with those of the utility to ensure the lowest reasonable rates consistent with the provision of safe, reliable electric and natural gas service.

There are three major regulatory ratemaking doctrines which are important to keep in mind with respect to utility ratemaking: (1) the *Hope-Bluefield* Doctrine, (2) the prohibition of unreasonable discrimination in rates; and (3) the principle of cost causation.

The *Hope-Bluefield* Doctrine is a U.S. Supreme Court doctrine that provides that a utility must be allowed the opportunity to earn a reasonable rate of return on its investment. The rate of return should be comparable to the returns allowed for similar companies facing comparable

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[13] *Gordon v. Council of City of New Orleans*, 9 So. 3d 63, 71-72 (La. 2009).

[14] **Section 3-101 Legislative Powers**.

(1) All legislative powers of the City shall be vested in the Council and exercised by it in the manner and subject to the limitations hereinafter set forth.

[15] **Section 3-130. Establishment of Rates**.

(1) The Council of the City of New Orleans shall have all powers of supervision, regulation, and control consistent with the maximum permissible exercise of the City's home rule authority and the Constitution of the State of Louisiana and shall be subject to all constitutional restrictions over any street railroad, electric, gas, heat, power, waterworks, and other public utility providing service within the City of New Orleans including, but not limited to the New Orleans Public Service, Inc. and the Louisiana Power and Light Company, their successors or assigns.

See also State ex rel. Guste v. Council of City of New Orleans, 309 So. 2d 290, 293 (La. 1975).

[16] **Section 3-130. Establishment of Rates.**

(2) In the exercise of its powers of supervision, regulation and control of any street railroad, electric, gas, heat, power, waterworks, or other public utility, the Council shall, in cases involving the establishment, change or alteration of rates, charges, tolls, prices, fares or compensation for service or commodities supplied by such utilities, cause notice of the matter to be served upon the person, firm or corporation affected thereby, so that such person, firm or corporation shall have an opportunity, at a time and place to be specified in said notice, to be heard in respect to said matter. The Council shall make all necessary and reasonable rules and regulations to govern applications for the fixing or changing of rates and charges of public utilities and all petitions and complaints relating to any matter pertaining to the regulation of public utilities, and shall prescribe reasonable rules and regulations to govern the trial, hearing and rehearing of all matters referred to herein,....

investment risk and should be sufficient to assure confidence in the financial integrity of the utility so as to maintain its credit and ability to attract capital.[17] As applied in Louisiana, to both the Council and the LPSC, the *Hope-Bluefield* Doctrine means that base rates should allow the utility to recover prudently incurred O&M expenses, taxes, and a fair return on investment that is used and useful in providing utility services.[18]

The Louisiana Supreme Court has held as follows:

> When the Commission reviews a utility's rates it is required to apply a "prudence" standard. Under this so-called "prudence review," the Commission scrutinizes the utility's decision-making processes for reasonableness. This Court has established that in a prudence review of a utility company's rates, the burden of proof is on the utility, which must "demonstrate that it went through a reasonable decision making process to arrive at a course of action and, given the facts as they were or should have been known at the time, responded in a reasonable manner."[19]

The standard for whether an expense or cost was prudent and should be included in utility rates is whether, objectively, the utility acted reasonably,[20] and in a manner consistent with Good Utility Practice. Good Utility Practice is a term of art that is typically defined as:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the

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[17] *Bluefield Water Works & Improvement Co. v. W. Va. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) *and Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 591 (1944).

[18] *Gordon v. Council of the City of New Orleans*, 9 So. 3d 63, 73 (La. 2009), (*citing Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d 1361, 1364-1371 (La. 1987)). *See also, Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n*, 730 So. 2d 890, 894-895 (La. 1999) *(also citing Central Louisiana Elec. Co. v. Louisiana Public Service Comm'n*, 508 So. 2d at 1365).

[19] *Entergy Gulf States, Inc. v. Louisiana PSC,* 726 So. 2d 870, 873 (La. 1999) *quoting Gulf States Util. Co. v. Louisiana Pub. Serv. Comm'n.,* 578 So. 2d 71, 85 (La. 1991*).*

[20] *Gulf States Utils. Co. v. Louisiana Pub. Serv. Comm'n*, 689 So. 2d at 1346. In that case, the LPSC found that certain outages had occurred due to the imprudence of the utility and disallowed the $1.85 million in purchased power costs the utility had incurred during the outages. The LPSC's finding was upheld by the Louisiana Supreme Court. *Id.* at 1347.

exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.[21]

It should be noted that while the Council must set just and reasonable rates for the utility, the Council is not required to set rates that guarantee the utility the opportunity to earn any specific return on its investment. As the Louisiana Supreme Court writes:

> A utility is entitled only to the opportunity to earn a reasonable return on its investment; the law does not insure that it will in fact earn the particular rate of return authorized by the Commission or indeed that it will earn any net revenues. . . By the same token, if the utility's profits turn out to be higher than had been forecast by the Commission in setting the rates, the law does not penalize the Company for its efficiency by requiring a divestiture of unanticipated earnings.[22]

Thus, the Louisiana Supreme Court recognizes that while there is no 100% guarantee under the law that a utility will earn any specific return on its investment, there is a potential upside for utilities that are able to control their costs or increase their efficiencies so that their actual costs end up being lower than the projected costs - in which case the utilities are allowed to keep the savings they have created. This creates an incentive for the utility to continue reducing their costs and increasing their efficiency.

The prohibition of unreasonable discrimination in rates requires the regulator to ensure that the utility does not unreasonably discriminate among its customers through various business practices (such as rebates, preferential charges, and service inequalities).[23] A utility's rate structure must be non-discriminatory.[24] The prohibition on unreasonable discrimination requires that if a utility charges different rates to different customers, there must be a rational basis for the

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[21] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), Att. I, § 1.14 of the *pro forma* Open Access Transmission Tariff, *order on reh'g*, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).
[22] *South Central Bell Telephone Co. v. Louisiana Public Service Commission*, 594 So. 2d 357, 359-360 (La. 1992) (internal citations omitted).
[23] *State ex. Rel. Guste v. Council of the City of New Orleans*, 309 So. 2d 290, 294 (La. 1975).
[24] *Id.*

difference. A rational basis is often demonstrated through the principle of cost causation -- two classes of customers receive different rates either because they are receiving different types of service or because the two classes of customers impose different costs on the utility to provide the same service.

Finally, the principle of cost causation requires that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.[25] Because it is nearly impossible to match an individual customer's costs to their bills with precision, regulation focuses on allocating utility costs to the customer classes that incur the costs as nearly as is reasonably possible. There is often some degree of cross-subsidization that occurs because of the inability to create a perfect match, and there is often some level of cross-subsidization that can be justified for public policy purposes, but generally speaking, this is to be avoided as much as reasonably possible, because it does run a risk of colliding with the prohibition on undue discrimination in rates. This principle also generally prohibits utility rates from being used to recover anything other than the prudently incurred costs of providing service to customers and a reasonable rate of return on the utility's investment.

Council Resolution No. R-17-504 set out certain filing requirements for this proceeding:

- The filing should be made no later than July 31, 2018;
- ENO should have as its objective the presentation of a single set of rates and tariffs for all customers in New Orleans, as well as a single MISO rider unless it would result in rate shock;
- ENO should make a Period II filing reflecting the 12-months ending December 31, 2018;

[25] *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000); *Pac. Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320 (D.C. Cir. 2004).

- ENO should provide a complete set of FRP implementation documents to the extent ENO seeks implementation of an FRP;
- ENO should provide ratepayer funding requirements and a funding mechanism for Council Energy Smart initiatives; and
- ENO should provide other information listed in the resolution and appropriate to comprise a filing sufficient to comply with all Council requirements, fully apprise the Council of the nature of ENO's request, and allow the Council to thoroughly and efficiently review the filing.

A few other Council resolutions are also relevant to this Combined Rate Case. Resolution No. R-15-104, which approved ENO's acquisition of Algiers contained guidance as to the timing of a new base rate case and on the historical test year to be used. In Resolution No. R-16-103, the Council directed ENO to include in this rate proposal a decoupling mechanism and set forth the Council's guidelines for such a mechanism. Finally, in Council Resolution No. R-18-97, the Council directed ENO to include in its rate proposal a green pricing proposal that would allow customers to voluntarily choose to have some or all of their electricity supplied by renewable resources.

II. <u>Argument</u>

A. Revenue Requirement

1. <u>Summary of ENO's Proposal</u>

ENO asserts that its proposed rates should reflect its Period II revenue requirement, including proforma adjustments for known and measurable changes.[26] The Company has requested an overall decrease in ENO's total electric revenue requirement of approximately $20

[26] Ex. No. ENO-55 at 14.

million and a reduction of the overall gas revenue requirement by approximately $142,000.[27] There are several major components of the Company's proposed electric revenue requirement.[28] The largest portion of the electric revenue requirement is based on ENO's cost of service study conducted in connection with this proceeding.[29] However, ENO's cost of service study was limited to costs associated with base rate revenues. Other significant components of the revenue requirement include electric revenues associated with the realignment of certain costs from riders into base rates, costs associated with the implementation of ENO's Advanced Metering Infrastructure, and costs associated with energy efficiency programs.[30]

The Company's cost of service studies were prepared pursuant to Council Resolution R-15-194 dated May 15, 2015 and Resolution R-17-504 dated September 28, 2017.[31] However, ENO's cost of service studies were not fully compliant with the provisions of these Resolutions.[32] Resolution R-15-194 approved an Agreement in Principle authorizing ENO to purchase Algiers' electric operations and the related assets and liabilities, which sale is commonly referred to as the "Algiers Transaction."[33] The Agreement in Principle included ENO's filing a full cost of service study based on combined ENO operation on both the East Bank and West Bank of the Mississippi River. Resolution R-17-504 provides specific, additional filing requirements for inclusion in ENO's rate case application together with a single set of rate tariffs for all ENO customers.[34]

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[27] *Id.* at 16-17.
[28] *Id.* at 17.
[29] *Id.*
[30] *Id.*
[31] Ex. No. ENO-41:5-6.
[32] Ex. No. ADV-6 at 5.
[33] *Id.* at 6.
[34] *Id.* at 8.

2. Cost of Service Studies

The purpose of a class cost of service study is to fully allocate the test year jurisdictional electric plant investment, other rate base items, revenues and expenses to each customer class or rate schedule so that a reasonable measure of cost responsibility can be determined for purposes of developing cost-based rates. Effectively, in a fully allocated cost of service study, all of the components comprising a utility's revenue requirement are allocated or assigned to rate classes reflecting each class' responsibility for "causing" the costs to be incurred by the utility. This principle of cost causality as a basis for establishing cost-based rates is a fundamental principle in ratemaking - a principle that has traditionally been adopted by most regulatory bodies.

a) ENO's Position

Pursuant to Council Resolution R-15-194 and Resolution R-17-504, dated September 28, 2017, ENO's rate filing included two (2) cost of service studies based on combined operations on the east and west bank of the Mississippi River - a Period I cost of service study reflecting the 12-months ending December 31, 2017 and a Period II filing reflecting the 12-months ending December 31, 2018 for both electric and gas operations.[35] The results presented have been proformed for known and measurable costs as of December 31, 2019.[36]

Pursuant to Resolution R-17-504, ENO's cost of service study was to incorporate ENO's costs that are recoverable through base rates and those costs recoverable through various riders, e.g., ENO's FAC, PPCACR, PGA, etc. As discussed more fully below, ENO's class cost of service studies only reflect base rate revenues and costs recoverable through base rates and base rate revenues and do not include revenues and costs recoverable through various proposed riders.

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[35] Ex. No. ENO-55 at 12.
[36] Ex. No. ENO-41 at 2.

A utility's cost of service study should reflect the utility's total cost of providing service, and when compared to the existing total revenue, is the basis for determining whether a revenue increase or decrease is needed. As reflected in Table 1 and Table 2 of the Application, ENO's cost of service study is shown as a component of ENO's proposed total revenue requirement which results in an overall decrease in ENO's present electric Total revenue requirement of approximately $20.3 million.[37] Similarly, ENO's proposed total gas revenue requirement indicates a need for an overall decrease in ENO's present gas total revenue requirement of approximately $0.142 million.[38] Although ENO's cost of service studies were a component of ENO's proposed total revenue requirement, ENO did not base its proposed class revenue requirements on the results of its class cost of service studies. In other words, ENO has not shown how its proposed class revenue requirements impact the customer classes in its cost of service studies.

Although there is an overall decrease in ENO's proposed total revenue, when ENO's proposed class revenue requirements and rate design are applied to some customer classes, i.e., the combined rate for Legacy ENO and Algiers residential customers, some of those customers would see rate increases.[39] The impact of the proposed combined rate on Algiers customers reflects the fact that present Algiers customer rates do not include ENO's recent investments in generation, including the majority of ENO's portion of the Ninemile 6 PPA or any of Union Power Block 1. Also, ENO proposes to change the mechanism for prior cost recovery approved for certain affiliate power purchase agreements and generation from existing riders, and to recover those costs through base rates. In short, ENO proposes to increase base rates by $135 million as a result of the change to, or elimination of, some riders. It should be noted that this is

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[37] Ex. No. ENO-55 at 16.
[38] *Id*. at 17.
[39] Ex. No. ENO-55 at 27.

merely a change in the way certain costs are allocated to, and recovered from, ratepayers and not an increase in total revenues.

b) Intervenor Positions

In general, the Intervenors to this Combined Rate Case, have not criticized the methodology of ENO's cost of service studies but have raised concerns regarding ENO's proposed revenue requirements for the various rate classes. Air Products witness Brubaker found that "the functionalization, classification and allocation of costs employed by ENO in this cost of service study are reasonable."[40] Witness Brubaker stated that the methodologies employed by ENO in the development of its electric class cost of service study are appropriate,[41] but his testimony focused on cost allocation methodologies rather than a total costs of service evaluation. At the heart of Air Products' concerns is that the Large Interruptible Service ("LIS") rate class (of which Air Products is the only subject customer) is a high load factor user, served entirely at the transmission voltage level (without use of ENO's distribution network) that its load mostly interruptible, that ENO's class cost of service study shows that the LIS rate class is providing a high rate of return relative to the total utility rate of return, and that these should be primary considerations in setting the revenue requirement for the LIS rate class.

CCPUG witness Baron found that "ENO's 12 Coincident Peak class cost of service study is a reasonable basis to evaluate the cost of service for each of the Company's rate classes. It should be relied on to assess the reasonableness of the revenue increases to each rate class."[42] Further, he notes that "While it is not necessary to exactly set rates for each customer class at cost of service, rates for each class should move towards cost of service, consistent with the

[40] Ex. No. AP-3 at 5.
[41] *Id*. at 3.
[42] Ex. No. CCPUG-5 at 8.

regulatory principle of gradualism."[43] In contrast, CCPUG witness Baron argues that ENO's proposed allocations of both the overall electric base revenue increase and the overall gas revenue decrease to rate classes are not reasonable.

Specifically, with regard to the electric base rates, CCPUG criticizes ENO's proposed rate class revenue requirements because "it does not specifically address cost of service or the level of subsidies that exist in rates" and because ENO's proposal to separately assign the rolled-in fixed production demand costs of the wholesale baseload resources acquired from Entergy Arkansas, LLC. ("EAL WBL") and the River Bend 30 ("RB30") PPAs on the basis of energy is a significant deviation from cost causation and is only designed to shift costs away from the residential."[44] He notes that in ENO's cost of service study, they are allocated to rate classes on a demand basis, not an energy basis.[45]

With regard to gas rates, ENO is proposing a uniform percentage revenue decrease to each rate class, without basing any customer revenues on its customer class gas cost of service study. Similarly, CCPUG argues that residential gas customers are receiving $3.3 million in subsidies from large customer classes (Mr. Baron notes that the Small and Large Municipal rate classes are also receiving very small subsidies (less than $150,000 combined)).[46] CCPUG takes issue with ENO's failure to propose any revenue requirement by class that is designed to specifically address these subsidies and move gas rates closer to cost of service in this case.

Air Products and CCPUG witnesses did not directly address the issue that ENO's evaluation of its earned ROE and total company revenue requirements was based on a cost of

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[43] *Id*. at 8-9.
[44] *Id.* at 22.
[45] *Id.* at 8.
[46] *Id*. at 29.

service analysis limited to costs and revenues related to base rate recovery. Furthermore, the Air Products and CCPUG witnesses did not critique the Advisors' total cost of service approach.

c) Advisors' Position

Advisor witness Prep criticizes ENO's failure to comply with Council Resolution No. R-17-504 which provided that ENO should evaluate its total cost of service in determining the utility's total revenue requirements. Council Resolution No. R-17-504[47] provides: "include all of ENO's revenues and costs subject to ratemaking treatment, including an allocation of total costs among the rate classes (i.e., matching the allocation of total costs to the total revenues of each ratepayer class) as part of each fully allocated electric and gas cost of service study (i.e., Period I, Period II, and any out of period adjustments)." The Resolution also stated: ". . . in the Council's evaluation of ENO's Filing, the Council will require information required to determine a clear separation of ratepayer class responsibility for the utility's total electric and gas costs of service distinct from, and in advance of, decisions regarding cost recovery mechanisms." ENO witness Klucher stated that ENO prepared a fully-allocated cost of service, "which is limited to what ENO believes are properly considered base rate revenues", and that ENO removed the revenues and corresponding costs for which the revenue requirement will be collected through a mechanism other than base rates.[48]

The Advisors maintain that the Council should evaluate a complete and comprehensive analysis of ENO's costs and return on its total investment in order to establish the utility's total required revenue based on an approved return on equity. Ratemaking limited by setting an ROE based on only a partial set of utility costs rather than on the utility's <u>total</u> costs (those to be recovered through base rates as well as the substantial dollars recovered through riders) does not

[47] Directive 2.f of Resolution No. R-17-504.
[48] ENO-42 at 3:19-4:3.

provide the most complete picture of ENO's financial health and is not the most sound regulatory practice.

The following Table 1 showing ENO's development of its proposed total electric revenue requirement illustrates this point and is substantially reproduced from ENO's Application.

	Table 1[49] **Summary of Electric Rate Relief Requested**	**Amount ($ millions)**
1	Base Rate Revenue Based on the Cost of Service Study	428.4
2	Fuel and Purchased Energy Revenue After Realignment	117.4
3	Revenue from Existing Riders After Realignment	17.6
4	AMI Charge Electric	7.1
5	Interim Energy Efficiency Cost Recovery Rider	6.0
6	Proposed Total Revenue (Sum of L1 through L5)	576.5
7	Present Base Rate Revenues	293.2
8	Fuel and Purchased Energy	209.8
9	Revenue from Existing Riders	93.9
10	Present Total Revenues (Sum of L7 through L9)	596.9
11	Total Revenue Deficiency/ (Sufficiency) (L6 – L10)	($20.3)
12	Base Rate Revenue Based on Cost of Service Study (L1)	428.4
13	Present Base Rate Revenues (L7)	293.2
14	Total Base Revenue Deficiency/(Sufficiency) (L12 – L13)	135.2

A cost of service study that only includes base rate revenues would only focus on Line 7 and would exclude Lines 8 and 9 - thus, omitting from the revenue requirement analysis costs related to more than 50% of the total electric revenues collected presently. From a related perspective, the allocation of total costs of service to classes determines the class revenue requirements and the composite total revenue requirement. Cost recovery mechanisms and

[49] Ex. No. ENO-55 at 17.

comparisons to present customer class revenues is a subsequent process separate from the development of total revenue requirements.

For completeness, ENO's requested relief for its gas operations is presented as follows.

Table 2[50]
Summary of Gas Rate Relief Requested
Based on the Period II Gas Cost of Service

	Description	**Amount ($ millions)**
1	Base Rate Revenue Based on Cost of Service Study	41.4
2	Purchased Gas Adjustment	34.9
3	AMI Charge Gas	0.8
4	Proposed Total Revenue (L1 + L2 + L3)	77.1
5	Present Base Rate Revenues	42.3
6	Purchased Gas Adjustment	34.9
7	Present Total Revenues (L5 + L6)	77.2
8	Total Revenue Deficiency/ (Sufficiency) (L4 – L7)	(0.1)
9	Base Rate Revenue Based on Cost of Service Study (L1)	41.4
10	Present Base Rate Revenues (L5)	42.3
11	Total Base Revenue Deficiency/(Sufficiency) (L9 – L10)	(0.9)

The gas cost of service study only includes base rate revenues (Line 5) and would exclude Line 6 - thus, omitting 45% of the total gas revenues collected presently. In contrast, the Advisors' cost of service analysis allocated total costs, including purchased gas, and compared the class revenue requirements to the total present revenue from each customer class. In other

[50] Ex. No. ENO-55 at 18.

words, the Advisors' analysis did not assume that cost recovery from a rider was equivalent to the allocated cost responsibility.

As noted above, ENO's filing presented an electric and gas cost of service limited to base rate revenues and the costs ENO identified that correspond to recovery with base rate revenues. ENO failed to address in detail its non-compliance with Resolution R-17-504. ENO stated that the Application contained all the cost and revenue information needed to perform a "total" cost of service. Nevertheless, ENO did not offer any further reconciliation of its filed cost of service analysis with the requirements of R-17-504.

3. Return on Equity

a) Legal Standard

The subject of Rate of Return ("ROR") generally and ROE specifically has been discussed in several U. S. Supreme Court cases and Louisiana Supreme Court cases over the past several decades. In utility ratemaking, the primary objective is to allow the utility company sufficient revenues to meet its operating expenses, provide its shareholders with a reasonable rate of return, and attract new capital.[51] The ratemaking process involves a complicated set of factors under which the regulator approves rate increases or requires rate decreases for each customer class. Retail rates should allow the utility the opportunity to recover prudently incurred operating and maintenance expenses, taxes, and a fair return on investment that is used and useful in providing utility services.[52]

[51] *Gordon v. Council of City of New Orleans*, 9 So. 3d at 73; citing *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d 1361, 1364 (La. 1987); *S. Cent.l Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n,* 352 So. 2d 964, 967 (La. 1977).
[52] *Id.*

At this level, the utility's revenues are said to produce a "fair rate of return."[53] The legal standard for determining what is a fair rate of return was articulated in two seminal cases: *Federal Power Comm'n v. Hope Natural Gas Co.*[54] and *Bluefield Waterworks & Improvements Co. v. Public Service Commission of W. Virginia*.[55] In *Bluefield,* the Court observed:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to **all relevant facts**. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but **it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures**. **The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.** A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[56] (Emphasis added).

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

> **Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid**, ...[57] (Emphasis added).

As a general proposition, these cases hold that the rate-making process rests on a balancing of interests between the investors and the consumers.[58] The method used to balance the interests of the investors and the consumers is well established. The initial determination that

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[53] *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n,* 508 So. 2d at 1365.
[54] *Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944) ("*Hope*").
[55] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923) ("*Bluefield*").
[56] *Id.* at 692-93, 43 S. Ct. at 679.
[57] Hope, 320 U.S. at 605, 64 S. Ct. at 289.
[58] *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n,* 508 So. 2d at 1365.

must be made is the utility's future revenue requirement.[59] As a guide to such a determination, data is generally gathered from some 12-month period taken as a "test year."[60] Customarily, the test year selected is the most recent annual period from which actual operating data is available. The data gathered is then used to calculate the following four variables:

1. The amount of *revenues* generated under the present rate structure.

2. The *operating expenses,* including maintenance, depreciation, and taxes, incurred to produce revenues.

3. The *rate base, i.e*., the value of the property, plant, and equipment, (less accumulated depreciation) and related non-tangible assets, which provide the service, and on which a return should be earned.

4. The *rate of return,* a percentage figure which, when applied to the rate base, will generate revenues sufficient to cover costs and give investors a fair return on their investment.[61]

ENO's allowed return on investment can be regarded as its Weighted Average Cost of Capital ("WACC"), which is constituted as a weighting of the return on long term debt components and an allowed-ROE, which can be regarded as the WACC component allowing ENO a profit (ENO presently does not have any preferred membership interest securities outstanding). Accepted regulatory principles and the U.S. Supreme Court's *Hope* and *Bluefield* decisions provide that ENO be allowed a return on its investment that,

1. is comparable to that being earned by other companies with comparable risks,

2. is sufficient to assure confidence in its financial soundness, and

3. is adequate to maintain its credit worthiness and enable it to raise necessary capital.[62]

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[59] *Id.*
[60] *Id*. citing James C. Bonbright, *et al.*, Principles of Public Utility Rates 150, n.7 (1961).
[61] *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n,* 508 So. 2d at 1365.
[62] *Bluefield*, 262 U.S. at 692; and *Hope*, 320 U.S. 591.

The Council is not obligated to employ any specific methodology when setting ENO's rates, however, both ENO in its Application and the Advisors in their direct testimony calculate their respective proposed rates based on allowing the opportunity for recovery of prudently incurred operating costs, plus a fair return on investment to include a reasonable allowed-ROE, which is an accepted methodology. Further, for many years, the Council has repeatedly acknowledged these ratemaking principles set forth in *Hope* and *Bluefield* in a variety of rate proceedings.[63]

These variables are then used to determine the "return" that is available to be distributed to the utility's investors and the "actual rate of return" presently being earned by the utility.[64] The "return" or earnings is equal to the utility's revenues less its operating expenses, exclusive of interest.[65] The ratio of the utility's return to its rate base is equal to its actual rate of return.[66]

As part of the Council's ratemaking authority when setting ENO's retail rates in this proceeding, the concept of ROR specifically means an appropriate WACC whose components are long-term debt total cost and ROE.

b) ENO's Proposed ROE

In its Application, ENO asserts that the Company's ROE lies in the range of 10.25% to 11.25%.[67] Within that range, the Company considers 10.75% to be the best estimate of ENO's Cost of Equity and recommends that the Council adopt a 10.75% ROE.[68] ENO also proposed a Reliability Incentive Mechanism ("RIM") Plan, which would affect the base rates to be set in this

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[63] Resolution Nos. R-03-272, at 11-12 (resolving rate case Docket No. UD-01-04), R-09-136, at 10 (resolving rate case Docket No. UD-08-03), and R-14-278, at 17-18 (resolving rate case Docket No. UD-13-01), all reference and accept these regulatory ratemaking principles regarding the appropriate allowed return on ENO's investments.
[64] *Bluefield*, 262 U.S. 692 and *Hope*, 320 U.S. 591.
[65] *Id.*
[66] *Id.*
[67] Ex. No. ENO-26 at 5:11.
[68] *Id.*

proceeding and afterwards through the proposed Electric FRP.[69] Under the RIM Plan, ENO proposed that the earnings component of its electric base rates be correlated to reliability performance through an adjusted ROE formula, included in the FRP that features a Reliability Adjustment.[70] Under the Company's RIM Plan,[71] ENO is requesting that for the purpose of initially setting rates resulting from this proceeding that a ROE of 10.50% be implemented on its electric Cost of Service based on a negative adjustment of 25 basis points applied to the proposed ROE of 10.75% recommended by Company witness Robert B. Hevert.[72] Through the Company's proposed electric FRP as described by Company witness Phillip B. Gillam, ENO seeks an opportunity to achieve enhanced returns commensurate with the 10.75% recommended by Mr. Hevert as ENO realizes increases in electric service reliability.[73] According to ENO, the Company should be allowed to earn more than its baseline ROE under the RIM Plan as a matter of fairness and maintaining a constructive regulatory environment.[74]

ENO's proposed ROE is poorly supported by ENO's own testimony. Mr. Hevert's updated DCF analyses in his rebuttal testimony produced results ranging from 8.34%-10.38% which clearly does not support his recommended 10.75% ROE.[75] Similarly, Mr. Hevert's revised CAPM ROE analyses presented in his rebuttal testimony produced a substantially lower range of results, from 8.25%-11.34%, placing his recommended 10.75% near the top of his revised range of results.[76] ENO's updated analyses provide further support for the Advisors' and Intervenors arguments that the Company's requested 10.75% ROE is unreasonable and not supported by the preponderance of evidence in the instant docket.

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[69] Ex. No. ENO-55 at 2.
[70] *Id.*
[71] Ex. No. ENO-2 at 23:1-30:5 (HSPM).
[72] Ex. No. ENO-55 at 21.
[73] *Id.* at 21-22.
[74] Ex. No. ENO-2 at 27:14-16 (HSPM).
[75] Ex. No. ENO-29 at 144:1.
[76] *Id*.

c) Intervenor Arguments

Intervenors, CCPUG, and Air Products also submitted testimony in this proceeding that included ROE recommendations to the Council. CCPUG provided two methods of analysis for estimating a fair rate of return for ENO, the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses.[77] The results of CCPUG's CAPM analysis support the reasonableness of its DCF results as well as CCPUG's overall ROE recommendation for ENO.[78] Based on these independent analyses, CCPUG concluded that a reasonable investor required ROE in the range of 8.7% - 9.35% would be appropriate for ENO.[79] Employing these widely accepted financial methods for developing an ROE recommendation, CCPUG recommends that the Council adopt an ROE of 9.35%, which is on the high end of CCPUG's range.[80]

Air Products also provided extensive ROE testimony in this case utilizing several financial models to estimate ENO's cost of common equity, including various forms of a DCF analysis, a Risk Premium analysis and a CAPM analysis similar to the financial models used by other ROE witnesses in the case.[81] Based on the comprehensive studies utilizing multiple industry accepted financial models, Air Products concluded that an ROE in the range of 9.0%-9.7% would be appropriate for ENO.[82] An estimate of 9.35% was supported as a reasonable midpoint.[83]

The Advisors, CCPUG, and Air Products all heavily criticized the 10.75% ROE recommendation made by ENO witness Mr. Hevert. Specifically, CCPUG claims, and the Advisors agree, that Mr. Hevert's range of 10.25% to 11.00% fails to reflect the full range of

[77] Ex. No. CCPUG-3 at 15:15-24.
[78] *Id.*
[79] *Id.* at 30:3-5.
[80] *Id.*
[81] Ex. No. AP-1 at 17:5-10.
[82] *Id.* at 49:5-8.
[83] *Id.*

results from his analyses.[84] According to CCPUG, Mr. Hevert's mean DCF results, which were fairly consistent with CCPUG witness Mr. Baudino's results, were completely excluded from his range of recommendations.[85] In fact, Mr. Hevert rejected the results from two of his four ROE methodologies and chose to mainly rely on the results from his CAPM analysis.[86] CCPUG noted that Mr. Hevert's own historical data shows that more recent allowed returns are far below the calculated returns used by Mr. Hevert in making his 10.75% ROE recommendation.[87] ENO, according to CCPUG witness Baudino, also omits critically important information from his DCF model and, as a result, greatly overstates the investor required ROE for investment grade regulated utilities.[88] According to CCPUG, employing ENO's requested ROE of 10.75% as opposed to the 9.35% ROE recommended by CCPUG, would be excessive and would expose New Orleans ratepayers to $6.2 million per year in unnecessary costs.[89]

With respect to ENO's proposed RIM plan, CCPUG urges the Council to reject the plan considering that reliable electric service is "part and parcel" of every utility company's duty, including ENO, under the Regulatory Compact.[90] In return for its ability to operate as a monopoly and the opportunity to earn an almost guaranteed rate of return, the utility must provide reliable service to its customers.[91]

Air Products effectively responds to the Company's ROE recommendation by criticizing ENO witness Mr. Hevert's heavy reliance on the highest growth rate estimates for each company provided by each of his sources to support an unreasonably high ROE.[92] Air Products also cited

[84] Ex. No. CCPUG-3 at 33:6-7.
[85] *Id.*
[86] *Id.*
[87] *Id*. at 39:11-12.
[88] *Id.*
[89] *Id.* at 39:17-21.
[90] *Id*. at 50:7-17.
[91] *Id.*
[92] AP-1 at 53:11-18.

several instances of Mr. Hevert's use of flawed and inflated assumptions in his DCF analyses that create a "manipulative" effect by the unreasonably high results of his studies.[93] Air Products' witness Walters identified similar issues related to Mr. Hevert's CAPM study.[94] Mr. Walters took issue with the overstated market risk premiums used in Mr. Hevert's CAPM analyses because they do not reflect a reasonable estimate of the expected return on the market.[95] Mr. Walters also expresses concern about Mr. Hevert's failure to measure the market risk premium in relationship to the projected risk-free rate projections in his CAPM return estimates.[96] Mr. Walters identifies several other erroneous aspects of ENO's ROE analyses that seriously weaken the Company's request for a 10.75% ROE.[97] Mr. Hevert uses highly uncertain projected bond yields in his Risk Premium analysis and the Company considers "additional" risks that should be accounted for in establishing an ROE, which Mr. Walters believes are already accounted for in the credit ratings issued by various credit agencies.[98]

d) Advisors' Recommendation

The Advisors recommend that the Council adopt an allowed-ROE of 8.93% for both electric and gas based on the comprehensive and persuasive testimony and analyses of two expert witnesses in this proceeding. The Advisors' recommendation is based on the evaluation of market-based and accepted analytical methodologies that demonstrate that an 8.93% ROE represents a fair return to ENO.

While an 8.93% ROE is in-line with the recommendations of the Intervenor witnesses (*i.e.*, 9.35%), the Advisors have pointed out that ENO's ROE proposal of 10.75% is an outlier

[93] *Id*. at 55:1-13.
[94] *Id.* at 62:1-63:7.
[95] *Id*. at 63:14-64:10.
[96] *Id.*
[97] *Id.* at 72:1-13.
[98] *Id.*

among the other recommended ROEs in this proceeding.[99] The Advisors based their ROE recommendation on many factors, including accepted market-based analytical methodologies. Advisors' witness Watson conducted a two-step DCF analysis which sought to estimate the implied ROE of utilities comparable to ENO as a proxy for ENO's own appropriate allowed-ROE, which itself cannot be directly measured.[100] His DCF analysis is also based on objective market data such as dividend yields and professional analysts' opinions as to growth factors.[101] The results of witness Watson's two-step DCF ROE analysis establish, among proxy companies and unadjusted for risk and flotation costs, a range of implied ROEs of 5.74% to 10.64% with a median implied ROE of 8.09%.[102]

Advisors' witness Proctor performed a CAPM analysis that identifies an allowed-ROE of 7.57% (unadjusted for risk and flotation costs).[103] Mr. Proctor's CAPM allowed-ROE is 52 basis points less than that of Advisor witness Watson's two-step DCF ROE analysis result. However, as a DCF ROE analysis and a CAPM ROE analysis are based on different financial concepts (*i.e.*, DCF is based on dividend yields and growth factors, while CAPM is based on market returns and correlations therewith), this relative concurrence in results between these analyses has probative value for the Council in the instant proceeding.[104]

CAPM is a conceptually sound and market-driven (*i.e.*, based on market statistical measures) ROE estimation methodology that is commonly employed and accepted throughout the utility industry.[105] Advisor witness Watson has reviewed Mr. Proctor's CAPM study and he

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[99] Ex. No. ADV-8 at 18:14-19:4.
[100] Ex. No. ADV-7 at 13:1-7 (HSPM).
[101] *Id.* (HSPM).
[102] *Id.* at 44:1-4 (HSPM).
[103] *Id.* (HSPM),
[104] *Id*. at 44:14-45:2 (HSPM).
[105] *Id*. at 45:3-7 (HSPM).

agrees with Mr. Proctor's analysis and results.[106] Mr. Proctor's analysis is based on accepted methodologies and data.[107]

Mr. Proctor discusses the ROE-related risk factors discussed by ENO witness, Mr. Hevert, and recommends the Council allow a risk-related ROE upward adjustment in this instant proceeding of 84 basis points.[108] In evaluating a reasonable ROE recommendation, the Advisors adjusted their ROE findings for additional business risk ENO incurs largely as a result of its geographic location, its small size and its propensity to incur significant storm damage.[109] However, the additional business risk, if any, is mitigated by the supportive ratemaking treatment ENO enjoys through regulation.[110] For example, it is mitigated in part by the Advisors' recommendation in support of an FRP with proforma adjustments for the rate effective periods that offset effects to business risk.[111] In consideration of these factors, the Advisors recommend the Council allow ENO an 81-basis point adjustment, for ENO's business risk, to the Advisors' unadjusted ROE estimates.[112] Mr. Proctor's one standard-deviation adjustment methodology is objective and reflective of the variability of systemic risks among the Proxy Companies.[113] The Advisors specifically evaluated and addressed ENO's business risk[114] and Mr. Proctor's proposed 81 basis point adjustment was based on objective analysis and is reasonable, while ENO's arguments are general, subjective, and speculative. The Advisors' business risk adjustment is supported by the preponderance of the evidence and should be adopted by the Council as part of the Advisors' recommended allowed ROE of 8.93%.

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106 *Id*. (HSPM).
107 *Id*. (HSPM).
108 Ex. No. ADV-10 at 61:3-63:6 (HSPM).
109 *Id.* at 61:3-10 (HSPM).
110 *Id.*(HSPM).
111 *Id*. (HSPM).
112 *Id*. (HSPM).
113 *Id*. at 61:17-62:4 (HSPM).
114 *Id*. at 61:3-10 (HSPM).

The Advisors made an additional adjustment to their recommended ROE for flotation costs. Flotation costs relate to incremental costs incurred from the issuance of common stock.[115] These costs include incremental direct expenses such as costs for accounting, marketing, consulting, administrative and legal services incurred for the issuance.[116] The costs are legitimately recoverable through utility rates either as a cost of equity or an operating expense.[117]

Mr. Watson presents the flotation cost-adjusted implied ROEs for the proxy companies, the median of such values is 8.12%, or approximately 3 basis point greater than the median of the non-flotation-adjusted proxy company implied ROEs.[118] Mr. Watson's two-step DCF proxy company mean ROE analysis result of 8.09% plus these appropriate upward adjustments for business risks and flotation costs yields an Advisor recommended allowed-ROE of 8.93%. The Council should note that Mr. Proctor's CAPM ROE analysis's results are broadly consistent with those of Mr. Watson's two-step DCF ROE analysis and that Mr. Proctor's analysis confirms that an allowed-ROE higher than the Advisors' recommended 8.93% allowed-ROE (including a risk and flotation-cost adjustment as discussed above) is not necessary.[119] As such, Advisor witness Watson recommends the Council take the results of Mr. Proctor's CAPM ROE analysis into account in the instant proceeding and adopt the Advisors' recommended 8.93% ROE for ENO.[120]

Four expert witnesses, Messrs. Watson, Proctor, Baudino and Walters, have provided ROE testimony in this proceeding based on market-based analyses and industry accepted methodologies. The recommendations of all four of these experts are supported by sound and

[115] *Id.* at 62:2-4 (HSPM).
[116] *Id.* (HSPM).
[117] *Id*. (HSPM).
[118] Ex. No. ADV-7, Ex. BSW-4 (HSPM).
[119] Ex. No. ADV-7 at 45:15-46:2.
[120] *Id*. (HSPM).

objective financial and market data. ENO's 10.75% ROE proposal is based largely on Mr. Hevert's subjective opinion. In fact, most of Mr. Hevert's analyses support an ROE much lower than ENO has recommended. Specifically, Mr. Hevert's modeling results contained in his Revised Rebuttal Testimony in this proceeding no longer support the ROE recommendation made in his Direct Testimony.[121] This decline in Mr. Hevert's results is particularly noticeable in his CAPM analyses.[122] The preponderance of the sworn testimony in this case addressing the appropriate ROE for ENO (4 out of 5 witness recommendations) supports a ROE no greater than 9.35%.[123] As such, ENO's request for an unreasonably high and unsupported ROE of 10.75% should be rejected and the Council should take into consideration the testimony of the other four expert ROE witnesses recommending an ROE of either 8.93% or 9.35%.

4. Equity Ratio

ENO proposes that its actual equity ratio be employed for ratemaking purposes in this proceeding. ENO witness Orlando Todd states that ENO projects its capital structure as of December 31, 2018 will consist of 52.2% common equity, with the rest consisting of long-term debt.[124] The Company used this estimated 52.2% equity ratio to calculate its WACC and revenue requirement in its cost of service studies in this proceeding.[125]

The Advisors submitted testimony that clearly shows that ENO's proposed capital structure, if adopted, would constitute inappropriate double leveraging.[126] A useful meaning of "double leverage" for the purposes of the instant proceeding is the practice of maintaining a significantly higher common equity ratio at the utility operating company level (*i.e.*, ENO) than

[121] Ex. No. ADV-8 at 18:14-21:5.
[122] *Id*.
[123] *Id*. at 18:9-16.
[124] Ex. No. ENO-33 at 14:13-14.
[125] *Id.*
[126] Ex. No. ADV-7 at 51:1-4 (HSPM).

is maintained at the highest corporate level ultimately owning the utility (*i.e.*, Entergy Corp.).[127] Because the return on a utility's investment component of its revenue requirement is customarily based on its WACC and the rate of the ROE component of WACC is typically at a higher rate than those of the debt components (especially on a pre-tax basis), a high common equity ratio tends to increase a utility's WACC, and revenue requirement.[128] The effect of a utility that engages in double leverage is as if it borrows money at the top corporate level and places that money into its utility subsidiaries as common equity providing a potential return which is likely greater than its original borrowed cost.[129]

Further, based on the Advisors' analysis, ENO's equity ratio is greater than those of Entergy Corp. as well as the average of the other Entergy Operating Companies ("EOCs").[130] ENO's proposed equity ratio of 52.2% is 18.1% higher than that of Entergy Corp. as of December 31, 2018, while the average equity ratio of the other EOCs projected as of December 31, 2018 is only 15.5% higher than that of Entergy Corp.[131] As such, the revenue requirement effect of ENO's double leverage on New Orleans ratepayers is more pronounced than that for the average ratepayer of the other EOCs.[132] Despite ENO's claims to the contrary, comparing ENO's capital structure to that of the other EOCs is important for the Council's consideration because such a comparison serves as a guide for assessing the reasonableness of ENO's capital structure. Also, analyzing these comparisons provides the revenue requirement effect of ENO's proposed capital structure as compared to that of the other EOCs.[133] In fact, employing ENO's Period II External Models and changing ENO's equity ratio to be consistent with the non-ENO

[127] *Id.* (HSPM).
[128] *Id*. at 51:4-8 (HSPM).
[129] *Id*. at 51:8-11 (HSPM).
[130] *Id.* at 50:5-6 (HSPM).
[131] *Id*. at 53:1-3 (HSPM).
[132] *Id*. at 53:3-5 (HSPM).
[133] *Id*. at 52:20-53:5 (HSPM).

EOCs' average equity ratio of 49.6% as opposed to ENO's proposed 52.2% yields a $1.5 million reduction in electric revenue and a $0.3 million reduction in gas revenue.[134]

Considering the arguments set forth by the Advisors regarding double leverage, the significance of ENO's equity ratio being higher than that of the average of the other EOCs and the impact of ENO's proposed equity ratio on ratepayers, the Advisors recommend that the Council adopt an equity ratio of 50% in the instant proceeding for setting ENO's electric and gas rates.[135] For setting rates as part of any FRP evaluations the Council may approve in this case, the Council should employ an equity ratio equal to the lesser of (a) ENO's then actual equity ratio properly excluding the effects of securitization bonds and cash, and (b) 50%.[136]

ENO relies heavily on a Louisiana Supreme Court decision to support its unreasonably high capital structure proposal.[137] ENO claims that the Court in *South Central Bell* held very narrowly that the utility "'is entitled to have its rates fixed on the basis of its actual cost of capital under its existing capital structure'" absent a finding "'that the actual capital structure of the utility resulted from unreasonable or imprudent investments.'"[138] The Company then claims that the Advisors have "not pointed to a single instance that the Company made an unreasonable investment or financing decision."[139] However, ENO's strict interpretation of the Court's ruling on this issue is erroneous. *South Central Bell* plainly states that if the regulator finds that the utility's proposed capital structure is unreasonable, it may adopt a reasonable alternative.[140] Specifically, the Court stated, "we conclude … that the Commission must find a utility's capital

[134] *Id*. at 53:8-11 (HSPM).
[135] *Id.* at 55:16-18.
[136] *Id*. at 55:16-56-1.
[137] Ex. No. ENO-3 at 24:5-6; Ex. No. ENO-4 at 15:17-19; citing *S. Cent. Bell Tel Co. v. Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357.
[138] Ex. No. ENO-4 at 15:19-16-1.
[139] *Id*. at 16:1-2.
[140] *S. Cent. Bell Tel. Co*., 594 So. 2d at 363.

structure imprudent or unreasonable before disregarding it in ratemaking.[141] The unreasonableness is, thus, not limited to investments made by the utility. The unreasonableness that the Advisors clearly establish in their testimony results primarily from, among other reasons, the effect of double leverage that exists as a result of Entergy Corporation having a significantly lower equity ratio than that of its subsidiary, ENO.

In addition, 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.[142] In the *Entergy Gulf States* case, the company used the net proceeds of debt to determine the ratio of debt to equity capital in its capital structure.[143] "The Commission, however, adjusted the Company's filing by reducing its average weighted cost of capital to reflect the gross proceeds of debt in the company's capital structure."[144] The sole capital structure problem presented to this Court in this case is whether the Commission acted arbitrarily or capriciously by including the gross proceeds of debt, rather than the net proceeds of debt, in the Company's capital structure.[145] In affirming the regulator's authority to adopt a different capital structure than the one proposed by the utility, the Court stated;

> The right of commissions to consider [capital structure] in setting rates cannot be questioned, since a commission has an obligation to protect the consumer from excessive wages, excessive pension provisions, excessive prices for purchased materials and supplies, and other such things, including excessive costs of capital.[146]

The Court also clearly found, in affirming the regulator's adjustment to the utility's proposed capital structure, that the utility had not demonstrated that the Commission had set

[141] *Id.*
[142] *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n*, 730 So. 2d 890 (La. 1999).
[143] *Id.* at 915-16.
[144] *Id.*
[145] *Id.*
[146] *Id.* at 917.

unjust or unreasonable rates.[147] Orders of utility regulators in the State of Louisiana are "entitled to great weight" and "they should not be overturned absent a showing of arbitrariness, capriciousness, or abuse of authority by the Commission."[148] Courts should also "be reluctant to substitute their own views for those of the expert body charged with the legislative function of rate-making."[149] Finally, the Council should note that ENO routinely recommends utilizing a hypothetical capital structure in requesting rate recovery of costs incurred by the Company. For example, the Company acknowledged in this proceeding that in Council Docket UD-15-01, ENO's own witness recommended a hypothetical capital structure of 50% be used for ratemaking purposes for the recovery of costs associated with the acquisition of Union Power Block 1.[150] ENO also employed an "Assumed 50% Common Equity" even though ENO's actual equity ratio was not 50% in Council Docket No. UD-17-02 related to the Company's Gas Infrastructure Rebuild Program.[151] Interestingly, in these instances, when recommended by the Company, a 50% equity ratio was not only reasonable but specifically proposed by ENO is its requests for cost recovery.

As shown by the Advisors in sworn testimony and supporting analyses provided in this proceeding, ENO's proposed capital structure is unreasonable and it should be rejected in favor of a more reasonable equity ratio of the lesser of 50% or ENO's actual equity ratio.

5. Depreciation Rates

ENO's witness Donald J. Clayton sponsored new depreciation rates based on a study conducted by Tangibl, LLC, which was carefully reviewed by the Council's Advisors.[152] The

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[147] *Id.*
[148] *Id.* at 897.
[149] *Id.*
[150] City Council Hearing Transcript, 120:5-9 (June 20, 2019).
[151] Ex. No. ADV-7 at 54:18-55:3 (HSPM).
[152] Ex. No. ADV-7 at 60:3-4 (HSPM).

study employs accepted depreciation study methodologies to create what is commonly referred to as *Iowa Curve* factors taking into account survivor curves, expected retirement dates, and salvage factors.[153] Mr. Clayton reports that ENO's proposed depreciation rates would increase ENO's depreciation expense by $2.5 million and $0.1 million for electric and gas respectively as compared to retaining ENO's currently approved depreciation rates.[154]

The Advisors' review of Mr. Clayton's testimony indicates that ENO's proposed depreciation rates are based on accepted analytical methodologies and represent an incremental change to depreciation rates that ENO reports as having been in effect since 1980 and 2009 for electric and gas respectively.[155] Further, as depreciation represents recovery of ENO's investments in plant, ENO's requested overall increase in depreciation rates serves to slightly hasten the decline in ENO's appropriate dollar return on rate base.[156] ENO's proposed depreciation rates also appropriately provide for removing stranded costs from rate base over a 10-year period.[157] Accordingly, the Advisors recommend the Council adopt ENO's proposed new depreciation rates.[158]

6. <u>FASB Interpretation No. 48</u>

The FASB's FIN 48 provides an interpretation of FAS No. 109 regarding the accounting for uncertainty in income taxes recognized in financial statements.[159] In applying FIN 48, a determination is made by the taxpayer for specific transactions as to whether it is more likely than not that a tax position will be sustained upon examination, including resolution of appeals or

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[153] *Id*. at 4-6 (HSPM).
[154] Ex. No. ENO-35 at 16, Comparison table.
[155] Ex. No. ADV-7 at 61:7-17 (HSPM).
[156] *Id.* (HSPM).
[157] *Id.* (HSPM).
[158] *Id.* (HSPM).
[159] Ex. No. ADV-10 at 82:1-2 (HSPM).

litigation processes, based on the technical merits of the position.[160] Then the tax position is measured at the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement. This amount is recognized as an Accumulated Deferred Income Tax ("ADIT") liability for financial reporting purposes.[161]

Differences between tax positions taken in a tax return and the tax amounts recognized in financial statements result in either: (1) an increase in a liability for income taxes payable or a reduction of an income tax refund receivable, or (2) a reduction in a deferred tax asset or an increase in a deferred tax liability, or both.[162] As a result of applying FIN 48, the amount of taxes recognized in financial statements may differ from the amount reflected in a tax return.[163] To reflect the differences on the books pursuant to FIN 48, a liability is created which represents a taxpayer's potential future obligation to the taxing authority for a tax position that ultimately is not sustained. In this case, the liability created is an ADIT liability.[164]

ENO has removed, from its rate base, the portion of various ADIT liabilities that is unlikely to produce cost-free capital due to the aggressive tax positions taken by the Company in its filings with federal and state taxing authorities.[165] The Company determined that those tax deductions are so unlikely to be realized that they must be disclosed for financial reporting.[166] The Advisors disagree with this approach from the perspective of setting rates.

The Advisors evaluated the FIN 48 issues in this proceeding in a two pronged approach: (1) how is the financial risk shared between ratepayers and shareholders with respect to the uncertainty of the income tax position taken by ENO; and (2) making the correct adjustment

[160] *Id.* at 82:2-5 (HSPM).
[161] *Id.* at 82:5-7 (HSPM).
[162] *Id.*
[163] *Id.*
[164] Financial Accounting Series No. 281-B, June 2006, FASB Interpretation No. 48 of the FASB of the Financial Accounting Foundation.
[165] Ex. No. ENO-51 at 16:20-17:6 (HSPM).
[166] *Id.*

required for ratemaking purposes.[167] With respect to issue of financial risk, the Advisors disagree with ENO's adjustment to eliminate FIN 48 ADIT liability balances, from rate base for its electric and gas operations.[168] ENO, through complying with normalization rules, records DIT expense that is part of ENO's cost of service and, therefore, is recoverable in utility rates.[169] ENO's recording of DIT expense and including it in the cost of service provides them a cost-free loan from the customers which requires that the related FIN 48 ADIT liability also be included in rate base.[170] When Deferred Income Tax ("DIT") expense and the related ADIT liability are recorded to comply with FIN 48, and the Company eliminates the FIN 48 ADIT liability (thereby increasing rate base) for ratemaking purposes, the risk of ENO not achieving the uncertain tax filing position is largely placed on the ratepayers.[171]

For ratemaking purposes in this proceeding, as FIN 48 ADIT Liabilities are not included in ENO's proposed rate base, ENO also should have credited DIT expense in equal amounts to its reversal of the FIN 48 ADIT Liabilities to synchronize ratemaking treatment.[172] If the Council approves ENO's proposal to reverse and exclude the FIN 48 ADIT liabilities from rate base then a corresponding ratemaking adjustment should be made to credit, or decrease, DIT expense.[173] Thus, this aspect of ENO's FIN 48 proposal, as stated in its Application, is unbalanced, unnecessarily risky to ratepayers, and therefore should be rejected by the Council.

7. New Orleans Power Station Treatment in Rates

ENO proposes to begin recovering the estimated first year revenue requirement associated with the NOPS in the first billing cycle of the month after the NOPS enters

[167] Ex. No. ADV-10 at 82:17-83:2 (HSPM).
[168] *Id.* at 83:5-10 (HSPM).
[169] *Id.* at 83:12-13 (HSPM).
[170] *Id.* at 83:13-15 (HSPM).
[171] *Id.* at 83:7-10 (HSPM).
[172] *Id.* at 84:12-16 (HSPM).
[173] *Id.* at 84:16-18 (HSPM).

commercial operation.[174] Currently, the Company expects the NOPS to enter commercial operation in January 2020.[175]

ENO proposes to recover the estimate through an interim rate adjustment under ENO's proposed Electric FRP.[176] Assuming that the Council approves an electric FRP, the Company requests that the Council confirm in this proceeding that an interim rate adjustment under ENO's proposed Electric FRP is the contemporaneous cost recovery mechanism to be used to recover the NOPS first year revenue requirement.[177]

CCPUG argues that it is reasonable to include an interim rate adjustment in the EFRP to recover the costs of NOPS, but that the costs included in the calculation of the interim rate adjustment are not reasonable for three reasons.[178] First, ENO's ROE is excessive – (ENO's proposed 10.5% ROE should be replaced by CCPUG proposed 9.35% ROE or whatever other return on equity the Council authorizes.[179] Second, the NOPS depreciation rate and depreciation expense are excessive, and should be based on a CCPUG proposed service life of 50 years, instead of the Company's assumed service life of 30 years.[180] The third reason the costs included in the calculation of the interim adjustment are unreasonable is that CCPUG believes that ENO intends to maintain the NOPS first year revenue requirement until the next general rate case, with no revenue requirement reduction due to greater accumulated depreciation and ADIT.[181]

In Council Docket No. UD-16-02, in which the Council approved NOPS, the Advisors proposed that the cost recovery of the NOPS investment be accomplished contemporaneously as

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[174] Ex. No. ENO-2 at 67:11-13 (HSPM).
[175] *Id.* at 67:13-14 (HSPM).
[176] *Id.* at 67:18-19 (HSPM).
[177] *Id.* at 67:20-23 (HSPM).
[178] Ex. No. CCPUG-1 at 46:8-11.
[179] *Id.* at 46:13-20.
[180] *Id.* at 47:1-19.
[181] *Id.* at 47:20-48:4.

a second step rate adjustment subsequent to the 2019 effective date of the revised rates from the instant docket.[182] Specifically, the Advisors believe that the NOPS interim rate adjustment could be a provision in the proposed FRP, providing contemporaneous recovery from the date of NOPS commercial operation ("COD"). The Advisors have proposed that proforma adjustments be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP.[183] NOPS is expected to enter commercial operation in early 2020.[184] If the NOPS updated revenue requirement filing is not included as a prospective proforma adjustment in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS costs are included in the ROE bandwidth evaluation of the following FRP.[185] If the NOPS updated revenue requirement filing is included as a 2020 proforma adjustment in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment would be effective with the COD until the FRP rate adjustment is implemented in September 2020, at which time NOPS cost recovery would be included in the FRP rate adjustment.[186]

ENO objects to Advisors' witness Mr. Prep's approach. The Company asserts that the potential exists that the bandwidth calculation may prevent ENO from recovering 100% of the NOPS costs.[187] ENO argues that "it would be illogical to permit 100% recovery of the NOPS costs in the interim rate adjustment but later reduce that recovery because of the FRP bandwidth mechanics."[188] Therefore, the Company believes that the first-year revenue requirement should

[182] Resolution No. R-18-65, at 176.
[183] Ex. No. ADV-5 at 24:18-25:2.
[184] Ex. No. ENO-2 at 67:13-14.
[185] Ex. No. ADV-5 at 25:3-6.
[186] *Id.* at 25:4-10.
[187] Ex. No. ENO-3 at 48:5-6.
[188] *Id.* at 48:6-8.

be reflected in its entirety in the FRP Rate Adjustment and any subsequent cost changes be subject to the bandwidth calculation.[189]

The Advisors urge the Council to adopt witness Prep's recommendation regarding NOPS cost recovery and the inclusion of NOPS in the proposed FRP revenue adjustment. The first-year revenue requirement associated with NOPS should be included in rates as an in-service rate adjustment, beginning with the month after NOPS enters commercial operation. This rate adjustment shall remain in place until NOPS costs are included in the costs of an FRP evaluation period and in the ROE bandwidth calculation. The Advisors disagree with ENO's argument that it should be permitted to recover the initial year of NOPS costs without being included in an ROE evaluation. As with all other costs included in an FRP evaluation of earnings, ENO has the opportunity to earn its approved ROE rather than a guarantee that it will recover 100% of NOPS costs.

8. <u>Net Operating Loss Carry Forward</u>

In any given year, when a company has more income tax deductions than taxable income, the excess of the income tax deductions over taxable income is called a net operating loss ("NOL").[190] This NOL represents a future income tax benefit that ENO may use, and is referred to as a net operating loss carry forward ("NOLCF"), and is accounted for as an ADIT debit whereby carry forward losses from prior years can be used to offset future profits and therefore lower future income taxes.[191] For this reason, ENO records these amounts in an ADIT asset account.[192] The Company has not, however, incurred a cash distribution to pay income tax

[189] *Id.* at 48:8-10.
[190] ENO-51 at 9:17-18; ADV-14 at 52:2-5.
[191] Ex. No. ADV-10 at 77:13-14.
[192] *Id.* at 77:14-15.

expense to federal or state governments with respect to the recording of these ADIT assets.[193] Thus, the recording of these assets is for non-cash events and the related ADIT asset balances should not be included in ENO's rate base to collect a return on them from ratepayers.[194] However, if the Council allows inclusion of the NOLCF ADIT asset balance in electric and gas rate base, the Council should also order ENO to include a credit to deferred income tax expense of the same amount for ratemaking purposes to synchronize treatment.[195] ENO opposes this approach. The Company cites two private letter rulings ("PLR") that purportedly explain the income tax normalization rules that require the inclusion in rate base of the NOLCF ADIT asset balance attributable to accelerated tax depreciation.[196] ENO asserts that the two PLRs explain that the NOLCF ADIT asset balance must be included in rate base to offset the credit ADIT by the amount for which no cost-free capital was received.[197] To do otherwise, according to the Company, would be a normalization violation of the IRS's income tax rules which could cause the IRS to prohibit ENO from using accelerated tax depreciation on its income tax return.[198]

In response, the Advisors have established that the PLRs that ENO relies upon have very little value to the Council in this proceeding. The Council should not rely on the conclusions drawn in these PLRs because it is impossible to compare the facts, as presented by the taxpayers in those cases, to this case as presented by ENO.[199] Advisor witness Mr. Proctor further testified that the PLRs relied upon by ENO likely contained misinformation.[200] Specifically, Mr. Proctor notes that there is no indication that the taxpayers that requested the PLRs stated that deferred

[193] *Id.* at 77:15-17.
[194] *Id.* at 77:19-78:1-2.
[195] Ex. No. ADV-10 at 78:9-12.
[196] Ex. No. ENO-51 at 11:19-22.
[197] *Id.* at 11:22-23 and 12:1.
[198] *Id.* at 12:1-3.
[199] Hearing Transcript 6/21/19 at 90:16-21.
[200] *Id.* at 91:10-14.

income tax expense was reflected in their rates in prior periods.[201] Without the benefit of this critical information, the Council is unable to rely on these PLRs as a basis for approving ENO's proposed ratemaking treatment of NOLCF ADIT asset balances.

Furthermore, the IRS private letter rulings, PLR Nos. 201438003 and PLR 201548017, relied upon by ENO and attached as Exhibit RLR-2 to Mr. Roberts Rebuttal Testimony, include the following language.

> PLR No. 201438003:
>
> This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit. Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above. This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. (Emphasis Added).
>
> PLR No. 201548017:
>
> Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above. This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. (Emphasis Added).

Therefore, not only do the circumstances relied on by the IRS in issuing these PLRs not explain the circumstances regarding ENO's NOLCF ADIT assets and the ratemaking treatment

[201] *Id*. at 91:10-25.

sought by ENO for them from the Council, the rulings have no precedence with respect to an IRS PLR which could be sought by ENO.[202]

Even if ENO's arguments on this issue were accepted, the NOLCF ADIT asset is not attributable to accelerated depreciation because the NOL cannot be tied to the excess depreciation over straight-line depreciation.[203] That is, when ENO records an NOL, ENO's NOL is caused by the collective effect from all components of its Income Statement.[204] The NOL falls out from ENO's calculation of net income after accounting for its utility service revenues, other operating revenues, all operation & maintenance expenses, regulatory debits and credits, straight-line depreciation expense and excess depreciation expense, taxes other than income taxes and other miscellaneous tax deductions.[205] ENO cannot simply calculate an NOLCF ADIT asset attributable to solely excess depreciation over straight-line depreciation expense when the NOLCF ADIT asset results from the collective effect from all components of the Income Statement.[206] As Advisor witness Mr. Proctor points out, an Entergy witness has previously acknowledged and testified in a separate proceeding that no one item of expense can be pinpointed as the cause of net operating losses.[207] Further, ENO's total income tax expense, for financial accounting purposes, includes a current provision payable to the government based on income tax law and deferred provision based on financial accounting standards,[208] and as such ENO was allowed recovery of all tax expenses, current and deferred, which constitutes taxable revenue. Thus, the NOL carried forward during the previous periods was less than it otherwise would have been by an amount equal to the deferred income taxes which were not paid to the

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[202] Ex. No. ADV-14 at 49-50:1-4.
[203] *Id*. at 52:13-14.
[204] *Id*. at 52:14-16.
[205] *Id*. at 52:16-20.
[206] *Id*. at 52:20-53:1-3.
[207] *Id*. at 53:7-10.
[208] Ex. No. ADV-13 at 33:7-10.

government but were collected from ratepayers.[209] None of ENO's NOLCF ADIT assets are directly "attributable" to income tax timing differences,[210] or the attributable balance of such is zero. As stated above, ENO's NOLCF ADIT asset balance should not be included in rate base. If the Council allows ENO to include the ADIT asset balance in rate base, then the Council should also order ENO to include a credit to deferred income tax expense of the same amount for ratemaking purposes so that ratepayers do not incur inappropriately high rates related to this issue.

9. Restricted Stock Incentive Plan

The Advisors audited ENO's affiliate transactions, and for the most part, found that ENO had properly treated its Billing Adjustments related thereto, with one exception.[211] Based on the Advisors' review of ENO's affiliated transactions during the test-year period, the Advisors recommend that the cost of Project F5PPZZ4091, Restricted Stock Incentive Plan, should not be recovered in rates.[212] This recommendation would reduce ENO's revenue requirement related to its electric operations by $648,314 and the revenue requirement related to its gas operations by $145,211.[213]

ENO argues that this adjustment is unwarranted because the Advisors have not demonstrated that ENO's compensation plans are unreasonable.[214] However, incentive compensation plans and stock options may only be recovered in rates to the extent that the company demonstrates that such plans benefit ratepayers.[215] Whether or not the compensation plan is reasonable, the purpose of the subject incentive plan is a plan tied to the long-term

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[209] *Id.* at 50:20-22-51:1-4.
[210] *Id.* at 51:11-12.
[211] Ex. No. ADV-17 at 3:9-7:14.
[212] Ex. No. ADV-17 at 3:4-6.
[213] Ex. No. ADV-17 at 3:6-8
[214] Ex. No. ENO-3 at 50:14-17.
[215] Ex. No. ADV-18 at 4:5-7.

performance of Entergy Corporation common stock, therefore the benefit of the plan accrues solely to Entergy shareholders, and not to ratepayers, and therefore the costs thereof should not be recovered through rates.[216]

10. Summary of Impact of Advisors' Proposed Changes on Revenue Requirement

The Advisors developed their recommended total electric and gas revenue requirements based on an analysis of the total electric and gas utility cost of service, including total rate base, total operating expenses, and return on rate base, and comparing the total cost of service to present total retail revenues for both electric and gas operations.[217] Regulatory principles support a "fully-allocated" cost of service study which refers to an analysis of the total utility costs incurred in providing service and the total retail revenues of all customer classes, as well as other operating revenues derived from the use of utility investment.[218] In the instant proceeding, ENO provided certain updated accounting information and capital expenditures through the end of calendar year 2019 as proforma adjustments to the 2018 evaluation period (Period II) that are known and measurable.[219] Based on the analyses of the Advisors' witnesses of ENO's proposed proforma adjustments, the Advisors developed ENO's total electric and gas utility cost of service consistent with the application of sound regulatory ratemaking principles. The Advisor-recommended adjustments to ENO's per-book electric and gas cost of service include a variety of issues that affect the Company's proposed rates.[220]

As a result, the Advisors' total cost of service analyses support a decrease in ENO's total electric utility revenue requirement of $33.1 million and a decrease in the Company's total gas

[216] Ex. No. ADV-18 at 4:12-16.
[217] Ex. No. ADV-4 at 11:4-7.
[218] *Id*. at 11:12-16.
[219] *Id*. at 13:19-21.
[220] *Id*. at 19, Table 3 and 33, Table 6.

utility revenue requirement of $3.8 million from their respective present revenue levels in Period II. The Council should adopt the Advisors' recommendations and order ENO to set rates accordingly based on these total utility revenue reductions.

B. Cost Allocation and Customer Class Rate Impacts

In this Combined Rate Case, ENO proposes several changes to the way that its total cost of service/revenue requirement is allocated among its customers. These changes impact the extent to which various customer classes see a rate increase or decrease as a result of the overall revenue decrease proposed by ENO.

1. <u>Summary of ENO's Cost Allocation Methodologies</u>

a) ENO Proposal

ENO's witness Talkington states that ENO's cost allocation methodologies have been historically used by the Company and are consistent with those traditionally approved by the Council. Table 1 in witness Talkington's Direct Testimony summarizes ENO's allocations of electric operating costs, while the table on page 40 of witness Talkington's Direct Testimony summarizes ENO's allocations of gas operating costs. These cost allocation methodologies are essentially the same methodologies that ENO employed in its previous rate case, with a few exceptions. Since ENO limits its cost of service allocations to costs recovered in base rates, ENO's allocations of all other costs in the total revenue requirement are effectively determined by ENO's proposed rider tariff design for revenue recovery. For example, ENO proposed an allocation of AMI costs (through its proposed AMI Rider) on the basis of numbers of customers (which heavily weights the AMI cost recovery on residential).

b. *Intervenor Positions*

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

c *Advisors' Position*

The Advisors accepted ENO's cost allocation methodologies with few exceptions. The Advisors' position differed with ENO with respect to the allocations of AMI costs. Specifically, the Advisors recommend that the cost responsibility for AMI implementation should be based on the costs and benefits of AMI established in Docket No. UD-16-04. The Advisors also used a different basis for developing the cost allocation to interruptible load, which was incorporated in the Advisors' recommendations regarding customer class revenue requirements.

2. <u>Class Cost of Service Study and Customer Class Revenue Requirements</u>

a) *ENO Proposal*

ENO's class cost of service study in the Application shows the various customer class rates of return (limited to base rates rather than total costs of service) that result from present base rate revenues and the allocation of costs that ENO has identified as related to recovery with base rate revenues. ENO's class cost of service study also shows how each customer class present base rate revenue differs from the customer class revenue that would provide a rate of return equal to that proposed by ENO. However, ENO's proposal for revenue changes by customer class (corresponding to its proposed revenue change for the total utility) was not based on the class cost of service allocation study filed in the Application. Neither did ENO use its class cost of service study to show how its proposed revenue requirements by customer class changed the various customer class rates of return (base rate-related) that correspond to present base rate revenues. Rather, ENO proposed class revenue requirements based on an energy-based class allocation for the RB30 and EAI WBL capacity, the impact of implementing the first step of its proposed Algiers Residential Rate Transition ("ARRT") plan, and a final class revenue adjustment pro-rated on present customer class base rate revenues.

b. Intervenor Positions

Air Products witness Brubaker would adjust proposed class revenues by first calculating the difference between the total revenues ENO requested and the total revenues awarded by the Council, and then spreading that difference to only those customer classes whose revenues would be above cost of service under ENO's rate proposal. CCPUG's witness Baron regarded the important issue in this case to be the extent to which the Council follows the cost of service results in its revenue allocation decision; but he also recommended that base rate revenues be increased by a uniform percentage amount, with a cap on the total revenue change at a 2% increase level. CCPUG also proposed that the first $3.325 million of Council approved revenue adjustments should be applied to eliminate the increases proposed for the four Large Industrial classes proposed by ENO to fund ENO's Algiers residential mitigation plan. CCPUG illustrated the results of their proposal in witness Baron's testimony, and their proposed percentage changes to customer class revenue were relatively similar to those proposed by the Advisors.

c. Advisors' Position

The Advisors' position is to develop proposed customer class revenue requirements using the class cost of service analysis to evaluate how each change to customer class revenue relates to changes in the customer class rates of return. The Advisors believe that the Council should be provided specific information to consider the impacts on relative rates of return among the customer classes in determining the changes to the present revenue of each customer class. The cost of service is the established total revenue for each customer class. When class allocations are finalized for all other components of the cost of service except return, the class cost of service model provides the specific information related to discrete changes in present class revenues and rates of return. The Advisors recommendations to the Council regarding individual customer class revenue requirements recognized the disparity among the customer class rates of return and the impacts of changes to each customer class total present revenue. When the Council sets the revenue requirement (cost of service) level for each customer class in this Docket, the corresponding rate of return of each customer class would be used in the subsequent FRP to calculate the return component of the FRP customer class revenue requirement and the decoupling revenue adjustment.

3. Algiers ARRT Plan

a) ENO Proposal

One goal of the Council to be implemented in this rate proceeding is to address the disparity between Algiers residential customers and Legacy ENO residential customers. Currently, the typical Algiers residential monthly bill (1,000 kWh/mo.) is $104.28 as opposed to $122.11 for customers on the East Bank.[221] The Council, in Resolution No. R-17-504, directed ENO to present one combined cost of service study and one combined set of rate schedules for the Legacy ENO and Algiers customers, "*unless significant rate shock could occur to single or multiple classes of customer[s]*."[222]

[221] Ex. No. ENO-55, Statement A-5.
[222] Ex. No. ENO-55 at 27, quoting Resolution No. R-17-504.

Under the Company's proposed combined residential rate without any rate mitigation, a typical residential Algiers monthly bill would see a $16.16 increase or 15.50%,[223] a wholly unacceptable impact. In order to reduce the rate shock for Algiers residential customers that would otherwise result from a strict adherence to ENO's proposed residential revenue requirement and a combined residential rate, ENO proposed to phase-in the revenue increase to Algiers residential customers so that an Algiers residential customer's typical bill increases no more than 3.5% per year.

As proposed, the first step of the phase-in will be implemented as a part of the rates ultimately approved by the Council in this case. As proposed by ENO, Algiers typical residential bills will increase by $3.65. The second step of the phase-in would be in September 2021, at the same time as the annual revenue adjustments that would be authorized under its proposed FRP. ENO notes that the second step in 2021 foregoes an additional ARRT-related increase for Algiers customers in 2020, when the New Orleans Power Station ("NOPS") is tentatively scheduled to be included in ENO rates.[224] As proposed, Algiers typical residential monthly bills will increase in 2021 by $3.76, moving them closer to parity with other Legacy ENO residential customers.

In order to implement the ARRT plan as proposed, the costs that Algiers residential customers would otherwise pay are paid for by four other participating rate classes - Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes. In addition, ENO proposes to "phase-in" their proposed rate decrease to the four industrial customer rate classes that would otherwise receive a proposed overall decrease greater than twice the

[223] Ex. No. ENO-2 at 14:14-18.
[224] Ex. ENO-55 at 28.

overall ENO decrease. These industrial rate classes would see an offsetting rate reduction in September 2021 when the second step increase is implemented for Algiers residential customers.

By 2021, ENO contends that the Algiers residential typical bill would move approximately halfway to the full transition to a combined residential rate structure/parity with ENO's Legacy residential customers. It should be noted that ENO recognizes that its ARRT plan is but one approach that would result in just and reasonable rates. ENO states that it is open to other options that would result in a better path to achieving rate parity among residential customers.[225]

It should also be noted that Algiers customer rates currently do not include ENO's recent investments in generation, including the majority of ENO's portion of Ninemile 6 PPA or any of Union Power Block 1. ENO's proposed rates, including its ARRT plan reflect the inclusion of such costs equally between Legacy ENO and Algiers.

b) Intervenor Positions

Air Products, Building Science Innovators and the Alliance for Affordable Energy do not address ENO's proposed ARRT plan.

CCPUG criticized ENO's ARRT Plan but would not oppose the Plan if the first $3.325 million of any reduction in ENO's proposed base rate revenue requirement increase are designated for the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes that would bear funding for ENO's ARRT proposal. This CCPUG proposal would, in effect, transfer the funding of Algiers mitigation to all other customers except those four large industrial customer classes.

[225] *Id.*

c) Advisors' Position

The Advisors propose a residential combined rate adjustment for Algiers, which would be a revenue adjustment between Legacy ENO residential customers and Algiers residential customers and would be applied with each prospective annual rate action until parity was reached. Contrary to ENO's proposed 3.5% increase to Algiers residential customers, the Advisors propose that Algiers' residential customers would have no initial revenue change in the instant docket. Subsequent to the instant proceeding and under a combined residential rate, the adjustment could increase Algiers residential revenue up to 4%, with a corresponding adjustment to Legacy ENO customers such that the combined adjustment would reflect the revenue change for the total residential class. If the total residential revenue increase was less than 4%, Algiers residential revenue would be increased 4% in subsequent rate actions and the increase to Legacy ENO residential would be moderated accordingly to reflect the total residential class increase. If a prospective ENO-wide residential revenue increase was greater than 4%, all residential customers, including Algiers, would receive the revenue change exceeding 4%. The following table illustrates the initial application of the Advisors' recommended combined rate adjustment for Algiers.

Description	**Algiers**	**Legacy**	**Combined**
Unadjusted Revenue from combined rate for Legacy and Algiers	$31,144,620	$215,551,810	$246,696,430
Less: Present Revenue	$28,158,662	$221,939,577	$250,098,239
Unadjusted Revenue Increase (Decrease)	$2,985,958	($6,387,767)	($3,401,809)
Algiers Adjustment	($2,985,960)	$2,985,960	

Final Proposed Revenue- Legacy & Algiers	$28,158,662	$218,537,770	$246,696,432
Recommended Adjusted Revenue Increase (Decrease)		($3,401,807)	
% Increase (Decrease)		-1.53%	-1.36%

The Advisors' Algiers proposal could be implemented in the context of a Rider applicable to the combined residential base rate tariff and would extend to future rate actions as necessary.

3. Realignment of Rate Structure

a) ENO Proposal

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

None of the Intervenors contested ENO's realignment of rate classes and rate structures.

The Advisors do not oppose ENO's proposal to eliminate and consolidate customer classes, including the existing Algiers electric tariffs, to be combined into nine electric customer rate classes.

4. Non Jurisdictional Gas Customers

Non-Jurisdictional ("NJ") customers are a subset of industrial customers for whom ENO provides interruptible gas service pursuant to negotiated special contracts.[226] Advisor witness Prep notes that these customers were not included in ENO gas cost of service study and as such there is no basis under that approach to determine their allocated cost responsibility.[227]

a) ENO Proposal

ENO did not address this class of gas customers in its Application or Direct Testimony. In response to the Advisors' testimony, witness Bourg does not disagree with Mr. Prep's recommendation that NJ customer rates should be reviewed; however, ENO's opinion that placing the existing NJ customers on the current or proposed published Large General Service rate would not be in the customer's best interest because it would likely result in a material increase in the cost for gas service for this class of customers. "By offering interruptible service under special contracts to these customers, gas service should be able to remain competitive with the prices available to other similar industrial customers with whom the ENO industrial customers are in competition."[228] ENO also notes that by continuing to serve NJ customers under special contracts also means that theses interruptible gas customers will be served in a manner similar to the way gas service is provided to all other industrial customers throughout the

[226] Ex. No. ENO-25 at 27.
[227] Ex. No. ADV-3 at 50.
[228] Ex. No. ENO-25 at 30.

state because the natural gas prices paid by customers classified as industrial are a confidential matter between the customers and the seller.[229]

b) Intervenor Positions

Similarly, none of the Intervenors addressed NJ gas customers.

c) Advisors' Position

Advisor witness Prep testifies that ENO's use of "NJ" to refer to these customers is a misnomer. The rates or charges applied to any person or entity receiving gas or electric service in New Orleans are subject to Council retail rate regulation. Since NJ customers receive gas service through the same gas distribution system mains as do all other ENO gas customers and all NJ customers are located in New Orleans, he assumes that they are subject to Council retail rate regulation. He also notes that the NJ customers take their retail gas service through non-published contracts.[230]

Although there is no NJ customer cost analysis, witness Prep states that NJ customers' rates and established business operations in New Orleans should not be modified without careful Council evaluation. Instead, he recommends: (1) that ENO should be required to provide a complete cost of service analysis in support of the NJ customers' rates as part of future Council rate actions; (2) that the Council affirm that the terms under which ENO offers gas service to the NJ customers are subject to Council retail rate regulation; (3) that the Council direct ENO not to execute any new NJ contracts without express Council approval.[231]

[229] *Id*.
[230] *Id*. at 52.
[231] *Id*. at 55-56.

5. Customer charge

a) ENO Proposal

ENO's proposes to increase the electric residential customer charge from the current $8.07 to a proposed $15.53 customer charge.[232] According to ENO, its cost of service study showed customer-related costs of service per residential customer to be $21.07 a month.[233] ENO witness Talkington stated that customer-related costs that do not vary with monthly changes in a customer's demand or energy usage should be recovered through a fixed monthly customer charge.[234] Witness Thomas added that higher fixed charges relative to volumetric rate structures provide more stability to ENO's revenues.[235]

b) Intervenor Positions

AAE witness Barnes criticized ENO's customer charge proposal as extreme and failing to reflect gradualism in utility ratemaking, as evidenced by national trends in residential fixed charges.[236] Barnes charged that ENO's calculated customer unit cost is inflated by including numerous costs that bear little or no relationship with costs (i) associated with connecting a customer to the grid, or (ii) which vary directly with the number of customers being served. Barnes also charged that a higher customer charge would lower the volumetric kWh rate, thus diluting customer incentives to use less energy.[237] AAE also proposed eliminating the customer charge from any Rider cost recovery mechanism using base rate revenue to recover costs per customer class.

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[232] Ex. No. ENO-45 at 26.
[233] *Id.*
[234] *Id.* at 23.
[235] Ex. No. ENO-2 at 62.
[236] Ex. No. AAE-3 at 10-14.
[237] *Id.* 15-19.

c) *Advisors' Position*

The Advisors' recommendation of a $10 per month electric customer charge is a relatively small increase which recognizes that costs have increased since the 2008 rate case but also minimizes the impact on low-use customers.[238] 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. 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.[239] The Advisors' recommendation is reasonable and balanced, considering both the bill impact of the relatively small customer charge increase (from $8.07 to $10.00) on low usage levels and the increased costs since the 2008 rate case.

6. New Riders for Cost Recovery

a) *Overview of Cost Recovery Rider Proposals*

ENO is proposing several riders, each of which would allow ENO contemporaneous and nearly exact recovery of its related costs, including:

- Fuel Adjustment Clause rider ("FAC Rider"): recovery of fuel and energy costs, including the recovery of certain power purchase agreement ("PPA") related capacity costs;
- Purchase Gas Adjustment Clause Rider ("PGA Rider"): recovery of costs related to the provision of gas sold to ENO's retail customers;

[238] Ex. No. ADV-4 at 60.
[239] *Id*. at 20-25.

- Midcontinent Independent System Operator, Inc. Rider ("MISO Rider"): recovery of costs charged to ENO pursuant to the MISO Open Access Transmission Energy and Operating Markets Tariffs that are not recovered via the Fuel Adjustment Clause;
- Purchase Power and Capacity Acquisition Cost Recovery Rider ("PPCACR"): recovery of certain PPA-related capacity costs, Long-Term Service Agreement ("LTSA") costs, and the non-fuel revenue requirement related to future constructed and/or acquired capacity additions;
- Distribution Grid Modernization Rider ("DGM Rider"): recovery of costs related to certain distribution investments and O&M expenses characterized by ENO as relating to grid modernization;
- Interim Energy Efficiency Cost Recovery Rider ("EECR Rider"): recovery of costs related to the Council's Energy Smart program over an interim period;
- Demand-Side Management Cost Recovery Rider ("DSMCR Rider"): recovery of costs related to the Council's Energy Smart program upon the expiration of Interim EECR Rider;
- Gas Infrastructure Replacement Program Rider ("GIRP Rider"): recovery of costs related to gas distribution investment beyond 2019 and recovery of utility conflict survey costs; and
- Advanced Metering Infrastructure ("AMI") Charge for Electric Service ("AMICE Rider")/Advanced Metering Infrastructure

Charge for Gas Service ("AMICG Rider"): recovery of net costs related to AMI deployment beyond 2019 for electric and gas respectively.

In support of these riders, ENO witness Thomas states "[u]tilities are currently undergoing a paradigm shift caused by the need for large new capital additions at a time of increasing costs and decreasing average usage per residential customer. A regulatory environment that provides for contemporaneous cost recovery of large investments outside of the traditional rate case provides the utility the necessary opportunity to earn its allowed return while continuing to invest in the system and mitigate operational risks."

In contrast, the Advisors urge caution in using riders as cost recovery mechanisms. The Advisors assert that ENO's request for Council approval of certain riders that would provide exact cost recovery for their respective costs (i.e., a near-guarantee that ENO will recover all of its costs contemporaneous with their incurrence or through a true-up mechanism involving carrying costs for any under collection balance). Historically, such riders were only approved by regulators in rare instances to address volatile and uncontrollable costs, e.g., the recovery of fuel and purchased power costs or natural gas commodity costs through a fuel adjustment rider or purchased gas adjustment rider. Advisor witness Rogers testifies that typically, riders are used for costs that can be significantly variable in nature and outside the control of utility. This is the case with respect to ENO's FAC, PGA, and MISO riders. At other times, riders may be used to provide for the recovery of significant costs incurred between full rate case proceedings that were not otherwise accounted for in base rates.

The Advisors raise significant concerns regarding ENO's request for Council approval of riders that would provide exact cost recovery for their respective costs (i.e., a near-guarantee that

ENO will recover all of its costs contemporaneous with their incurrence or through a true-up mechanism involving carrying costs for any under collection balance). Specifically, the Advisors recommend that such riders should be rejected when they constitute inappropriate single-issue ratemaking.

Witness Watson testifies that "[s]ingle-issue ratemaking is a deviation from the accepted regulatory ratemaking principle that rates should generally be based on a utility's overall costs and risks. The Supreme Court of Louisiana has found that: "[s]ingle issue ratemaking occurs when a utility's rates are altered on the basis of only one of the numerous factors that are considered when determining the revenue requirements of a regulated utility." Said differently, single-issue ratemaking occurs when particular portions of a utility's revenue requirement are considered for recovery in isolation from the utility's total costs and revenues.

In addition, Advisor witness Watson testifies that "[s]ingle-issue ratemaking is generally not appropriate because its application is contrary to the generally accepted regulatory ratemaking principle that a utility's rates that produce its revenues should be based on a utility's overall costs. Single-issue ratemaking may not capture the overall impact of the portion of a utility's revenue requirement under special consideration by potentially not reflecting offsetting changes in other areas of the utility's operations. Further, single-issue ratemaking may reduce a utility's incentive to control its costs to the extent such ratemaking guarantees cost recovery through a true-up mechanism. As such, single-issue ratemaking is particularly inappropriate when other ratemaking mechanisms that are not subject to single-issue ratemaking deleterious effects are available."

Further, it should be noted that the Advisors approach does not preclude the appropriate use of Riders. Witness Prep acknowledges that there may be valid and supportable reasons to use revenue from a rider to recover certain costs of service. Thus, an appropriately selected Rider should generate revenue from each customer class based on the costs determined to be recovered from each customer class as reflected in the allocation of the total cost of service. Witness Prep notes that "[s]ingle-issue ratemaking is avoided when the costs and revenues related to proposed electric and gas Riders are included in each evaluation of the utility's total cost of service, when all utility costs and revenues are evaluated in terms of ENO's return on rate base and allowed ROE." Advisor witness Watson also testifies that a Rider may be acceptable "if the specific costs are substantial, vary significantly and/or are unpredictable, or require periodic review by the Council."

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

Witness Rogers also explains that in order to mitigate concerns related to regulatory lag, witness Prep recommends that the Council approve an annual electric utility FRP and annual gas utility FRP for a period of three years. As proposed, the FRP would provide for an annual adjustment to ENO electric and gas rates to reduce the time between regulatory base rate actions and mitigate regulatory lag. Additionally, and to further mitigate regulatory lag, Witness Prep recommends that ENO be allowed to include prospective proforma adjustments for known and measurable capital additions budgeted for the 12-month period immediately following the FRP test year.

b) Cost Recovery for the Energy Smart Program EECR/DSMCR

The Council has long recognized energy efficiency and demand response offerings (collectively "demand-side management" or "DSM") as high-priority resources for serving ENO's customers, and in 2009, established the Energy Smart program to encourage the development of such resources in New Orleans by offering various programs and incentives for customers wishing to implement DSM measures to reduce their energy use.[240] The Energy Smart Program is now mid-way through Program Year 9, and has been funded through a variety of mechanisms over the first nine years of its existence. The program has been highly successful, having received the U.S. Environmental Protection Agency's Partner of the Year Award in both 2014 and 2016, a Pro 3 award from the Southeast Energy Efficiency Alliance and a first-in-the-nation ranking in an American Council for an Energy-Efficient Economy study with respect to the kWh savings per participant for low-income customers.[241] The program, however, has lacked a stable and predictable funding source.[242]

(1) ENO Proposal Overview

In this case ENO proposes a new model for cost recovery related to DSM initiatives offered through Energy Smart.[243] ENO's model would use a rider for Energy Smart funding, incorporating a regulatory asset that would earn a return and be amortized over three years, to recover the costs of each Program Year ("PY") of Energy Smart.[244] Under ENO's proposal the

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[240] *See* Resolution No. R-09-136. *See also*, Resolution Nos. R-07-600 and R-09-483.
[241] *Id.* at 9:18-24, *citing* http://aceee.org/sites/default/files/low-income-baseline-0717.pdf.
[242] *Id.* at 11:1-3.
[243] *Id.* at 3:10-12.
[244] *Id.* at 3:12-17.

return and rate of return that ENO would earn on the regulatory asset would function as an incentive mechanism for achieving the savings goals established during the Integrated Resource Plan ("IRP") process.[245] The rider would also recover the Lost Contributions to Fixed Costs ("LCFC"), but would not include those dollars as part of the regulatory asset.[246] ENO argues that its proposed model would fulfill the Council's directive that demand-side resources should be on an equal financial footing with traditional supply-side resources.[247]

ENO argues that cost recovery for DSM offerings must fairly address (1) direct and indirect costs of DSM offerings;[248] (2) LCFC and (3) some form of incentive, and that these three elements will "level the playing field" between DSM and supply-side alternatives and will increase the likelihood that a utility will maximize the utilization of cost-effective DSM to meet customer needs.[249] ENO is proposing implementation of two separate riders as funding mechanisms -- one to continue funding for Energy Smart through the end of PY 9, the Interim Energy Efficiency Cost Recovery Rider ("Interim EECR"), and another mechanism intended to be applied for PY10 and beyond, the Demand-Side Management Cost Recovery Rider ("Rider DSMCR").[250]

(2) Interim Energy Efficiency Cost Recovery Rider

ENO designed the Interim EECR to contemporaneously recover the Council-approved funding for Energy Smart from customers for the period of August 2019 until December 2019[251] (the period between when the new rates go into effect and the end of PY9). It would serve as an

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[245] *Id.* at 3:17-21.
[246] *Id.* at 3:20-4:1.
[247] *Id.* at 5:8-11.
[248] Such costs would include direct incentives paid to customers and other direct costs, ENO labor costs and indirect costs necessary to develop and administer the DSM offerings and provide reporting, and amount paid to ENO's vendors for development and administration of DSM offerings as well as separate EM&V services. *Id.* at 21:9-15.
[249] Ex. No. ENO-10 at 18:11-18, *see also* Ex. No. ENO-55 at 33.
[250] Ex. No. ENO-10 at 14:3-5.
[251] *Id.* at 14:17-19.

interim universal funding mechanism for both the Legacy ENO and Algiers Energy Smart offerings approved in Resolution No. R-17-623.[252] The Council approved a similar Interim EECR in Resolution No. R-17-623 that was never implemented due to the availability of funding from another source.[253] ENO's proposed Interim EECR Rider in this proceeding utilizes the allocation factors that the Council approved in Resolution No. R-17-623.[254] ENO does not propose to implement the Interim EECR Rider as a line item on customers' bills.[255]

(3) Demand-Side Management Cost Recovery Rider

The second mechanism ENO proposes for recovery of its costs associated with DSM, its Rider DSMCR, is for PY 10 and beyond.[256] ENO proposes Rider DSMCR in response to the Council Resolutions aimed at identifying a permanent funding mechanism for DSM customer offerings (Resolution Nos. R-17-504, R-17-623, and R-17 176).[257] ENO argues that running DSM costs through a rider allows the Council, its Advisors, and other stakeholders to specifically identify and track the level of ENO's investments in DSM and the recovery of those investments, through the annual filings to the Council that will be associated with updating the rider.[258] ENO also argues that the use of a rider provides greater stability and facilitates planning by providing a long-term mechanism for helping to ensure that funding will be available, and a rider was clearly identified in Resolution No. R-17-623 as the preferable long-term approach.[259] ENO also argues that use of a rider that is updated annually provides a clearer path for the Council to incorporate changes to Energy Smart, or add other DSM offerings to ENO's demand-

[252] Ex. No. ENO-10 at 14:10-12.
[253] Resolution Nos. R-17-623 and R-18-227.
[254] Ex. No. ENO-10 at 15:1-2.
[255] *Id.* at 15:5-7.
[256] *Id.* at 15:11-14.
[257] Ex. No. ENO-55 at 33.
[258] Ex. No. ENO-10 at 16:21-17:.1.
[259] *Id.* at 17:8-11, *see also* Ex. No. ENO-55 at 33.

side portfolio, which would allow for greater flexibility in responding to customer needs.[260] ENO is not proposing that the rider appear on the customer's bill, rather that it be included within another line item such as the Energy Charge.[261] Rider DSMCR would be composed of four components.[262]

The first component would be the total balance associated with the DSM investment.[263] ENO's Rider DSMCR would utilize regulatory asset-based cost recovery model to allow DSM investment to be treated more equivalently to traditional supply-side and other investments in capital assets.[264] ENO argues it would also initially help mitigate higher bill impacts that would otherwise occur with full contemporaneous cost recovery.[265] Under the Rider DSMCR, ENO would estimate the total investment required to provide DSM offerings for the next calendar year (or PY).[266] These estimates would be based on savings goals and associated budgets approved by the Council as part of the IRP process and evaluation of the DSM Potential Study.[267] ENO proposes to amortize its total DSM investments over a three-year amortization period, which, ENO argues, 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 as well as mitigate the near-term bill impacts that would occur if DSM investments are recovered in a single year.[268] ENO would earn a return on its investments over the three-year period and explains that although DSM offerings are not typically capital investments, such a regulatory asset-based cost recovery

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[260] Ex. No. ENO-10 at 17:11-15.
[261] *Id.* at17:19-21.
[262] *Id.* at 19:16-18.
[263] *Id.* at 19:11-12.
[264] Ex. No. ENO-10 at 19:4-6; Ex. No. ENO-14 at 24:17-23.
[265] Ex. No. ENO-10 at 19:6-8; Ex. No. ENO-14 at 25:1-4.
[266] Ex. No. ENO-10 at 19:11-12.
[267] *Id.* at 19:12-14.
[268] *Id.* at 22:6-18.

model, with the associated performance adjustments will help put DSM investment on equal investment footing with other types of traditional utility assets.[269]

AAE opposes the Rider DSMCR rate design, arguing that the percentage of bill-based design effectively increases the fixed charge that a customer pays each month, which dampens the energy conservation price signal.[270] Additionally, AAE argues it is inappropriate because the objective of avoiding future energy supply costs and potentially distribution infrastructure costs does not have a customer-specific component or any other relationship to costs associated with connecting a customer to the grid.[271] AAE argues that a volumetric charge should be used for Rider DSMCR.[272] AAE recommends the following modifications to the Rider DSMCR: (1) a meaningful minimum savings threshold below which ENO recovers expenses but receives no return on those expenses and is subject to a penalty equivalent to the value of foregone cost savings for failing to achieve the minimum threshold; (2) a more granular formulaic incentive calculation system in place of the large "steps" in ENO's proposal; and (3) a cap on total incentive awards.[273]

The Advisors believe it would be reasonable to use the proposed EECR Rider as the permanent mechanism to recover the costs (which have all been expenses and not capital investment) of the Energy Smart program for both Legacy ENO customers and Algiers customers, and that the Rider DSMCR should not be implemented.[274] The Advisors also recommend that prospective Energy Smart costs beyond 2019 be included in each FRP evaluation.[275] While ENO argues that Rider DSMCR would initially have a lower impact on

[269] *Id.* at 23:13-15.
[270] Ex No. AAE-3 at 53:19-54:1.
[271] *Id.* at 53:1-5.
[272] *Id.* at 54:19-20.
[273] Ex. No. AAE-5 at 14:18-15:5.
[274] Ex. No. ADV-3 at 68:7-13.
[275] *Id.* at 68:10-11.

customers, customers will pay less in total costs by recovering Energy Smart costs contemporaneously as expenses, rather than by deferring expenses and treating them as a regulatory asset.[276] Moreover, ENO is not proposing a true regulatory asset treatment, because ENO makes no attempt to match the term of the deferral of the payment of costs to the life of the DSM measures being funded, which is typically more in the 10-20 year range than in the three-year range. Thus, Rider DSMCR does not propose a true leveling of the playing field between DSM and traditional supply-side assets. In addition, regulatory asset treatment is appropriate if a large, non-recurring cost is recovered over several future years, whereas Energy Smart costs recur every year, and are only likely to increase as the program pursues the Council's goal of increasing savings until it reaches 2% of annual sales.[277] ENO witness Dr. Faruqui argues that while it is true DSM costs would not typically be recovered as a regulatory asset, the traditional regulatory paradigm can act as a road block to encouraging aggressive and effective DSM, and ENO has proposed a progressive solution to encourage innovation.[278] The Advisors, however, are not persuaded that a "progressive solution" that requires ratepayers to pay more in nominal dollars than they otherwise would for DSM in order to allow the utility to earn a return on DSM investment (as deferred expenses) is a solution that benefits ratepayers in the long term.

While ENO performed and presented an analysis comparing net present values of funding options to demonstrate that ratepayers will ultimately save money with the proposed DSMCR Rider,[279] ENO's Net Present Value calculations hinge on ENO's assumptions regarding the time value of money -- essentially how much benefit a customer receives by being able to make use of their money over the time period for which payment is deferred. For that calculation ENO uses

[276] *Id.* at 69:4-7.
[277] *Id.* at 68:1-3 and 69:4-10.
[278] Ex. No. ENO-14 at 10:18-11:10.
[279] Ex. No. ENO-12 at 18:9-22:4.

its own after-tax weighted average cost of capital of 7.78%.[280] As ENO's witness Owens conceded at hearing, this means that ENO's calculations of the value customers receive by being able to spread the costs over three years rather than by paying the costs up front are essentially based on the assumption that on average, customers could earn a return on their money of 7.78% over the time that the customer is able to keep the money.[281] This is an overly optimistic expectation of what customers, on average, would be able to achieve in the market or other investment vehicles if they could invest the amounts they defer paying to ENO, and therefore, the Advisors dispute ENO's claim that the analyses demonstrate that Rider DSMCR will actually have less of an effect on customers than Rider EECR.

The second component to be recovered through proposed Rider DSMCR would be a utility performance incentive that would involve taking the resulting balance corresponding to the total amount of the investment (as deferred expense) in DSM offerings for a given PY and the Company being allowed to earn a return at ENO's pre-tax weighted-average cost of capital ("WACC") based on its allowed ROE, subject to a performance adjustment.[282] ENO proposes a performance adjustment that would tie cost recovery to ENO's overall performance relative to annual savings goals and/or other Council-approved DSM metrics.[283] ENO is proposing a sliding-scale performance incentive be used to increase (or reduce as may be necessary) the allowed ROE that is earned on the unamortized balance for each PY's portfolio of DSM offerings.[284] ENO proposes that achieving 60-95% of the Council's savings goal would not result in any reward or bonus for ENO, while achieving less than 60% would result in a penalty

[280] *Id.* at 19:21-23.
[281] City Council Hearing Transcript, 137:20-138:16 (June 19, 2019).
[282] Ex. No. ENO-10 at 19:19-23; Ex. No. ENO-14 at 26:12-14.
[283] *Id.* at 19:20-23.
[284] Ex. No. ENO-14 at 26:14-17.

that reduces the allowed ROE by 100 basis points and achieving between 95-120% would yield a reward of 100 basis points and above 120% would yield a 200 basis point increase in ROE.[285]

AAE argues that it is relatively uncommon for a utility to earn a rate of return on DSM expenses, and that rather than being a trend for regulators to grant such treatment, it is merely a trend in what utilities want to get.[286] ENO takes offense at and disputes the suggestion that the regulatory asset model is some kind of scheme devised by utilities for their own exclusive benefit.[287] ENO witness Dr. Faruqui argues that DSM rate-basing is gaining acceptance for its attributes.[288]

AAE does support the use of utility performance incentives as a method for encouraging energy efficiency, but states that the Council should be cautious and only reward truly good performance.[289] AAE also prefers an energy efficiency resource standard ("EERS") as a better option than a performance incentive.[290] AAE argues that ENO's proposed performance incentives are too rich and will provide shareholders a return regardless of the amount of savings achieved relative to target.[291] AAE argues that when a return is earned on all program expenditures, the foregone energy costs that would not have otherwise earned a return because they are pass-through costs that are capitalized and produce a profit for the utility that overcompensates the utility for its foregone revenues.[292] AAE suggests a meaningful minimum savings threshold below which no additional earnings are received, such as 80% of the annual

[285] Ex. No. ENO-10 at 25:15-26:6; Ex. No. ENO-14 at 14-17.
[286] Ex. No. AAE-3 at 39:14-40:7.
[287] Ex. No. ENO-12 at 25:1-28:9.
[288] Ex. No. ENO-16 at 7:16-18.
[289] Ex. No. AAE-3 at 47:18-48:4.
[290] *Id.* at 48:4-7.
[291] Ex. No. AAE-3 at 48:8-19.
[292] *Id.* at 40:14-41:14.

target with penalties for poor performance; a more graduated incentive with more granular steps; and a cap on total incentive awards.[293]

ENO argues that 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.[294] ENO explains that the return earned on such investments is on the 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.[295] ENO argues that to level the playing field, the incentive mechanism should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset.[296] ENO also argues that AAE's proposal to penalize ENO by limiting recovery solely to Energy Smart investments below a predetermined savings threshold, and additionally to impose a second-step penalty equivalent to the value of foregone cost savings for failing to achieve the minimum threshold is unreasonable, absent a finding of imprudence in light of the fact that it is ultimately the Council's decision as to what ENO implements.[297] ENO is, however, amenable to a more granular framework with smaller "steps."[298] In its rejoinder testimony, ENO proposes changing the framework such that achieving between 90% and 110% of targeted Energy Smart savings in a given year would not result in any ROE adjustment while ROE is reduced by 5 basis points for every 1% below 90% that is achieved, and increased by 5 basis points for every 1% above 110% that is achieved, with

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[293] *Id.* at 49:15-50:5.
[294] Ex. No. ENO-12 at 29:6-8.
[295] *Id.* at 29:8-11.
[296] *Id.* at 29:11-13.
[297] Ex. No. ENO-13 at 10:2-11.
[298] *Id.* at 10:21-22.

a maximum of up to 100 basis points.[299] ENO also states that there will be a cap on the performance incentive that is used.[300]

ENO urges the Council to determine the appropriate incentive procedure in this docket and not to delay consideration until the Council considers the specific goals and budgets for future years of Energy Smart in the IRP docket as recommended by Advisor witness Prep.[301]

The third component to be recovered through Rider DSMCR would be LCFC, adjusted each year based on the incremental (or decremental) change to ENO's DSM investment and resulting projected energy savings.[302] ENO proposes to calculate projected annualized LCFC amounts the same way that LCFC has been calculated historically, albeit with updated values reflecting the outcome of the rate case.[303] ENO proposes to calculate the total projected annualized LCFC amount for the upcoming year, which would be recovered concurrently through the Rider DSMCR (but not through the regulatory asset) and would be subject to a true-up relative to actual results that would occur in the following year.[304] ENO argues that it is important to provide recovery of LCFC in order to put DSM offerings and more traditional, supply-side resources on more equal footing.[305]

AAE opposes ENO's proposal to collect LCFC, and argues that a utility that has a decoupling mechanism will automatically recover the net effect of any energy or demand reduction resulting from its program, along with changes in energy and demand resulting from matters outside its influence or control, and therefore ENO does not need LCFC.[306] AAE also argues that an LCFC is not necessary to level the playing field between demand-side and supply-

[299] *Id.* at 10:22-11:4.
[300] *Id.* at 33:4:7.
[301] Ex. No. 12 at 23:6-9.
[302] Ex. No. ENO-10 at 20:1-6.
[303] *Id.* at 28:3-5.
[304] *Id.* at 28:8-12; Ex. No. ENO-14 at 25:11-18.
[305] Ex. No. ENO-10 at 28:18-20.
[306] Ex. No. AAE-1 at 30:21-31:4.

side resources because demand-side resources are more appealing than supply side resources due to the lack of any need for the utility to have any ongoing role in maintenance or operation of those resources.[307] AAE recommends that the Council reject the LCFC in favor of a simple decoupling mechanism that AAE proposes.[308]

AAE argues that a full decoupling mechanism is a superior mechanism to a lost revenue adjustment, and the performance incentive mechanism combined with a rate of return reward on all program costs fails to create an environment where only good performance is rewarded with additional earnings opportunities.[309] AAE explains that full decoupling is preferable because it avoids creating an incentive for the utility to discourage non-programmatic energy savings and ties cost recovery directly to the actual under-recovery of fixed costs, avoiding the inherent danger that LCFC will go beyond making a utility "whole" and instead become a profit center.[310] AAE also points out that lost revenues are not themselves equivalent to under-recovery of fixed costs for the utility because other factors, such as weather, customer growth, economic growth, or off-system sales may provide a balancing effect.[311] AAE also argues that there is strong evidence that decoupling is generally associated with better energy efficiency outcomes than LCFC.[312]

The Advisors oppose the inclusion of LCFC in any cost recovery mechanism.[313] As ENO's own witness, Dr. Faruqui notes:

> To address the issue of LCFC, regulators in many states allow utilities to recover the LCFC that is specifically associated with reduced energy sales due to the utility's DSM investments. Recovery of DSM-specific LCFC is most commonly achieved concurrently through a dedicated DSM rider based on a forward-looking period. In some states,

[307] *Id.* at 33:6-34:21.
[308] Ex. No. AAE-1 at 38:16-17.
[309] Ex. No. AAE-3 at 39:8-13.
[310] *Id.* at 43:14-18.
[311] *Id.* at 42:15-18.
[312] *Id.* at 44:8-46:7.
[313] Ex. No. ADV-3 at 76:5-6.

> regulators have **instead** chosen to fully decouple the utility's revenues from its energy sales (known as "full revenue decoupling").[314]

In Resolution No. R-16-103, the Council directed ENO to file a proposal for full decoupling in this Combined Rate Case.[315] Therefore, the inclusion of LCFC in a DSM-specific rider is not appropriate, rather, any erosions in fixed costs should be considered in the annual FRP review and Decoupling mechanism.[316] Air Products, however, argues that to the extent the Council allows ENO to recover any LCFC costs, those costs should be recovered as part of the EECR or DSMCR mechanism and not as part of the FRP and decoupling mechanisms in order to keep those costs associated with the programs and customers that cause them.[317] Air Products takes the position that LCFC result directly from utility sponsored and funded energy efficiency programs, and the benefits inure to the particular customer classes who are using less energy and imposing less demand as a result of the programs.[318] Air Products argues that it is not appropriate to recover LCFC from all customers because the direct beneficiaries of the programs are those who receive assistance from the programs and the larger class of customers to which the participating customers belong.[319] Air Products also argues that energy efficiency programs increase the utility's average cost of supplying service, resulting in an increase in rates, and that such programs can only be regarded as beneficial to nonparticipants of the end result were to be rates lower than they otherwise would have been, as evidenced by a Ratepayer Impact Measure test of 1.0 or greater.[320] Air Products argues that such an outcome is rare, and there is no

[314] Ex No. ENO-14 at 12:17-13:2 (emphasis added).
[315] Resolution No. R-16-103, at 21.
[316] Ex. No. ADV-3 at 76:6-7.
[317] Ex. No. AP-4 at 12:13-23.
[318] *Id.* at 12:17-13:2.
[319] *Id.* at 13:3-14.
[320] *Id.* at 13:15-21.

evidence to support the RIM test results for the energy efficiency program being in excess of 1.0, therefore nonparticipants do not benefit from the energy efficiency programs.[321]

ENO disputes this point and argues that the Council has established rules and a process for assessing the cost effectiveness of each PY's portfolio of DSM offerings and their associated budgets, and that the Council's rules primarily call for evaluation of cost effectiveness of DSM based on the Total Resource Cost ("TRC") test, though the Council also does consider the Ratepayer Impact Measure test in establishing the budgets and DSM portfolios for each year.[322] Therefore, ENO argues, Air Products' comments regarding the cost-effectiveness of energy efficiency are misplaced.[323]

Although ENO argues that the decoupling mechanism adopted by the Council in Resolution No. R-16-103 differs from typical "full" decoupling,[324] ENO agrees with the Advisors that if the final design of the FRP incorporates features that ENO believes adequately address LCFC, then the Company would not need to recover LCFC amounts in Rider DSMCR or through some other cost recovery mechanism other than the FRP.[325] ENO witness Owens stated in his rebuttal testimony that the Advisors' proposal to make proforma adjustments to address timely recovery of demand-side management costs could present a workable solution to the LCFC issue, contingent on agreeing on the specific FRP language.[326] ENO does not, however, believe that the AAE's decoupling proposal could adequately address LCFC because it would delay recovery of the lost revenues by at least a year.[327] ENO opposes methods of cost recovery

[321] *Id.* at 14:1-4.
[322] Ex. No. ENO-13 at 11:18-12:7.
[323] *Id.* at 12:7-9.
[324] Ex No. ENO-18 at 4:3-6.
[325] Ex. No. ENO-12 at 10:13-18.
[326] Ex. No. ENO-13 at 7:10-11.
[327] *Id.* at 7:17-8:5.

that would cause ENO to be always a year or more behind in the recovery of fixed costs attributable to Energy Smart-related DSM investments.[328]

Finally, the fourth component included in ENO's proposed Rider DSMCR would be an adjustment resulting from a true-up that will occur once a year based on prior year actual results.[329] ENO proposes that Rider DSMCR rates be set only once a year and take effect at the beginning of each PY with the first billing cycle.[330] ENO also argues that the EECR may over or under-recover Energy Smart costs if it does not include some form of annual true-up mechanism within the EECR Rider, because of EECR revenues in any given year were less than the amount of Energy Smart program costs, but the FRP evaluation results were within the bandwidth, no rate adjustment would occur, and ENO would not recover all of the Energy Smart costs for that year.[331]

The Advisors recommend that the EECR Rider be utilized as the long-term funding mechanism for the Energy Smart program. ENO has failed to demonstrate that its proposed Rider DSMCR would be more beneficial to ratepayers than the EECR Rider. Compared to ENO's arguments for its proposed DSMCR, the EECR (i) does represent a permanent funding mechanism, (ii) can track DSM investments and cost recovery through annual filings, (iii) provides stability by ensuring funding will be available, (iv) provides a clear path and flexibility to incorporate changes to DSM, (v) does not have to appear as a separate line item on customers' bills and (vi) represents less of a financial burden to ratepayers than DSMCR, since the nominal cost to ratepayers with DSMCR would be higher including ENO's return on the regulatory asset. While the Advisors appreciate ENO's stated intent to create a level playing field between supply-

[328] Ex. No. ENO-12 at 11:4-11 and 12:11-19.
[329] Ex. No. ENO-10 at 20:16-18.
[330] *Id.* at 20:18-19.
[331] Ex. No. ENO-12 at 23:10-17.

side and demand-side resources, ENO's proposal falls short of achieving that goal. If ENO truly desired to create a level playing field, it would amortize the costs of each DSM program year over the life of the DSM resource (typically 10-20 years) rather than only for a three-year period. The EECR Rider will provide ENO with a reasonable opportunity to recover its DSM investments. Lost revenues due to the Energy Smart program should be addressed through the decoupling and FRP mechanisms, rather than the proposed DSMCR rider. Although ENO argues that this does not guarantee that all lost revenues due to Energy Smart will be recovered, the purpose of allowing lost revenue recovery is not to guarantee that the utility earns exactly as much money as it would if DSM was not implemented, rather it is to ensure that the utility has a fair and reasonable opportunity to earn its authorized revenue requirement. To the extent that increased sales due to weather or other factors offsets revenues lost due to the implementation of energy efficiency measures, there is simply no need to further compensate ENO.

As is discussed above, regulatory asset treatment is typically approved for non-recurring costs, like the construction of a power plant, while recurring and increasing annual costs, like those associated with the Energy Smart program, are typically treated as expenses and paid as they are incurred. ENO concedes that ratepayers would pay substantially more in nominal dollars under the Rider DSMCR than under the EECR Rider, and ENO's net present value analysis attempting to demonstrate that customers are better off in the long term was based on an unreasonable assumption regarding the time value of money.

The Advisors recommend that the EECR rate design not be based on a percentage of bill, as proposed in DSMCR, but rather that it not include a customer charge or customer specific component.

It is appropriate for a utility performance incentive to be included in ENO's compensation for the energy Smart program, however, it is more appropriate for such mechanisms to be determined along with the Energy Smart program designs, budgets and savings goals than in a rate case, and the Advisors continue to recommend that the performance incentive be addressed in that proceeding rather than in this case. ENO's argument that the Council should determine the appropriate utility incentive procedure in this Docket and not delay consideration is without merit, since the Council will be considering the implementation plan for the next Energy Smart program years in the third quarter of this year.

c) Grid Modernization

(1) ENO Proposal

ENO contends that its grid modernization investments differ from grid maintenance investments in that the latter costs are typically incurred as part of a utility's ordinary course of business and are required for a utility to continue to provide reliable service in the short term.[332] According to ENO, grid maintenance investments are typically reactive in nature and are incurred due to problems presented by existing equipment (*e.g.*, replacing damaged or aging assets, addressing compliance issues, etc.). In contrast, grid modernization investments are proactive investments designed to enhance the functionalities and services that grid infrastructure can provide to customers, while also changing the paradigm for evaluating and maintaining the reliability of the distribution system.[333] ENO's proposed DGM Rider is intended to ensure timely recovery of ENO's grid modernization investment.

ENO notes that the five current grid modernization projects discussed by ENO's witness Zimmerer are expected to improve reliability by reducing the number of customer interruptions

[332] Ex. No. ENO-6 at 34:13-35:5.
[333] *Id.*

by more than 53,000 per year and lowering the number of customer minutes of experienced interruptions by approximately 7.2 million per year.[334] The costs for these projects are estimated at $59.3 million[335] through January 31, 2022, of this amount $12.8 million is funded through ratepayer savings due to the effects of the TCJA.[336] Prudently-incurred costs related to the remaining $46.5 million, would be appropriately recoverable through rates. Additionally, ENO proposes that the investment associated with the portions of the grid modernization projects expected to close to plant in service by December 31, 2019, be reflected in base rates adopted in this proceeding.[337]

With regard to portions of the above projects closing after December 31, 2019, and any future grid modernization projects, ENO is proposing that the Council, in this proceeding, approve Rider DGM as the cost recovery mechanism. As proposed, Rider DGM would consist of a charge based on a percentage of base rates that is incremental to base rates and would recover depreciation and return on grid modernization investments made in the applicable year. The rider would be updated on a quarterly basis to include any new investments made in the preceding three months for the grid modernization projects described above, or for future grid modernization projects.[338]

In addition, ENO proposes that an expedited process be approved for future grid modernization projects. As proposed, the Advisors, and stakeholders would review and provide input on the design of such future projects through written comments and a technical conference subject to Council approval. ENO's proposed process would have the Council render a

[334] Ex. No. ENO-8 at 24:5-7.
[335] Ex. No. AAE-3 at 35:7-8.
[336] Tax Cuts and Jobs Act of 2017, Pub, L. 115-97, 131 Stat. 2054, December 22, 2017.
[337] Ex. No. ENO-41 at 54:1-2.
[338] Ex. No AAE-3 at 35.

determination on the eligibility of such projects for recovery through the proposed DGM rider within six months of ENO's initial submission of the projects to the Council.[339]

(2) Intervenor Positions

AAE witness Barnes criticizes the proposed DGM rider.[340] According to witness Barnes, ENO did not provide any justification for this choice of rate structure.[341] Further, he asserts that that the DGM rider "effectively increases the fixed customer charge, and therefore reduces consumer incentives for energy conservation."[342] Further, witness Barnes claims that the ENO's grid modernization investments are investments in the shared distribution system and do not encompass any customer-related functions or involve costs that otherwise vary directly with the number of customers on the system or connecting a customer to the system.[343] Thus, Mr. Barnes states that the charge "is unreasonable both from a perspective of public policy in support of energy efficiency, and from the perspective of cost causation."[344]

As an alternative, AAE's witness Barnes says the "[t]he charge in Rider DGM should be aligned with how the Company charges for distribution service more generally in its base rates. For residential customers, he argues that it should be an exclusively volumetric charge. For non-residential customers, he allows that it may be appropriate for the charge to have a demand component, but only to the extent that an individual investment is caused by additional demand on the system. Noting that the current five projects target reliability improvements rather than

[339] Ex. No. ENO-55 at 35-36.
[340] Ex. No. AAE-3 at 36:4-13.
[341] *Id.*
[342] *Id.*
[343] *Id.*
[344] *Id.*

demand growth, the charge associated with these investments should also be volumetric for non-residential customers.[345]

CCPUG's witness Kollen argues that "[i]f the EFRP and GFRP are adopted, they likely will result in annual rate increases starting in 2020. If the DGM Rider and/or GIRP Rider are adopted, they will result in quarterly rate increases starting in 2020. These rider increases will be above and beyond any rate increases resulting from the EFRP and GFRP or any future base rate proceeding unless and until these riders are terminated."[346]

(3) Advisors' Position

As Advisors' witness Watson stated, the proposed DGM rider would allow ENO quarterly rate adjustments to recover expected costs related to grid modernization investments and provides for an annual true-up of rider collections versus actual revenue requirements. As such, the DGM rider constitutes contemporaneous exact cost recovery of certain distribution investments that ENO intends and classifies as grid modernization.[347]

Mr. Watson correctly argues that the DGM rider constitutes inappropriate single-issue ratemaking because "it would set a separate rate for incremental distribution investments and ensure ENO exact cost recovery."[348] Specifically, Mr. Watson notes that these costs are predictable and within ENO's control.[349] Further, the DGM rider is not necessary to allow ENO the opportunity to recover its prudently-incurred costs, as other ratemaking mechanisms are available to allow ENO recovery of its grid modernization-related costs.[350]

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[345] *Id.* at 36-37.
[346] Ex. No. CCPUG-1 at 4:15-19.
[347] Ex. No. ADV-7 at 88:9-11 (HSPM).
[348] *Id.* at 86:20-21 (HSPM).
[349] *Id*. at 89:6-7 (HSPM).
[350] *Id.* at 89:15-17 (HSPM).

d) GIRP

Resolution R-17-38 authorized ENO to proceed with the replacement of gas infrastructure until the resolution of the 2018 Combined Rate Case.[351]

(1) ENO Proposal

Through its Gas Infrastructure Replacement Program ("GIRP"), ENO proposes to follow the gas industry trend of accelerated infrastructure replacement of aging infrastructure to ensure the safety and reliability of its gas distribution system. On January 26, 2017, in Docket No. UD-07-02, the Council adopted Resolution R-17-38 which authorized ENO "to proceed with the replacement of gas infrastructure . . . at a rate of approximately 25 miles per year and approximately $12.5 million in capital investment per year until the resolution of the 2018 Combined Rate Case.[352] ENO proposes to include GIRP investment made through the end of this proceeding in the costs collected through the proposed GIRP Rider.[353] The Company specifically proposes to replace or abandon a total of 238 miles of low pressure cast iron and steel and vintage plastic pipes at an estimated cost of $119 million because, according to the ENO, cast iron and vintage plastic are two of the material types that the natural gas industry recognizes are prone to failure and recommends should be replaced.[354] ENO also argues that a gas distribution system that is entirely high-pressure also offers the benefit of providing a form of "storm hardening," as high-pressure operation prevents the infiltration of water into the system.[355]

ENO witness Gilliam testifies that ENO proposes to recover the investment and expenses that have not been reflected in the Company's rates and are placed into service and/or expended

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[351] Ex. No. ENO-55 at 14.
[352] *Id.* at 36.
[353] Ex. No. ENO-22 at 17.
[354] *Id.* at 15.
[355] *Id.*

during the Initial Service Period (*i.e.*, from January 1, 2020 through March 31, 2020) through the GIRP Rider.[356] The "Initial Service Period" assumes the rates implemented as a result of this rate case include plant in service through December 31, 2019.[357]

ENO's proposal contemplates that it will make a rate filing within 60 days of the end of the Initial Service Period with new rate to become effective for bills rendered on and after the first billing cycle of July 2020.[358] The percent rate adjustment would be applied to each gas rate class (*i.e.*, Residential. Small General, Large General, Small Municipal, and Large Municipal) with the exception of the customers ENO describes as "Non-Jurisdictional".[359]

Further, ENO is proposing quarterly rate redeterminations, with each quarterly filing submitted within sixty days after each three month period, e.g., assuming an Initial Service Period ends March 31, 2020, the next Service Period 9 would end June 30, 2020 and the filing would be made by August 31, 2020.

As proposed, the GIRP Rider rate will reflect: (1) the pre-tax return on the cumulative Eligible Plant, net of the associated provision for depreciation and the associated accumulated deferred income taxes, (2) depreciation expense associated with the Eligible Plant, (3) the expenses associated with the identification and resolution of underground utility conflicts, and (4) an annual reconciliation of the difference between the revenue requirement and actual revenue collected for the reconciliation period. The reconciliation period will be the twelve month period ending December 31 of each year after the initial filing year, and the reconciliation

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[356] Ex. No. ENO-41 at 49.
[357] *Id*.
[358] *Id.* at 49-50.
[359] Ex. No. ADV-6 at 80:4-7.

difference would be included in a filing each year starting in 2021 and applied to bills commencing on the first billing cycle of July of each year.[360]

The Company proposes that the term of GIRP Rider will be in effect through 2027, regardless of whether an FRP remains in place for ENO.[361] If this GIRP Rider is terminated before 2027, then the Company proposes that the GIRP Rider Rate then in effect would remain in effect until the Council approves an alternative recovery mechanism.[362]

None of the Intervenors addressed the proposed GIRP Rider, however, with regard to ENO's proposed GIRP, the Advisors recommend:

(1) that 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;[363]

(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;[364.]

(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;[365] and

(4) that ENO be required to identify potential measures to mitigate the identified impact on ratepayers.[366]

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360 *Id*. at 50.
361 *Id*. at 52.
362 *Id*. at 52-53.
363 Ex. No. ADV-1 at 41:28-42:1.
364 Ex. No. ADV-6 at 81:5-7.
365 Ex. No. ADV-1at 42:2-4.
366 *Id*. at 42:4-6.

Advisor witness Rogers testifies that although he agrees that the proposed scope of GIRP is consistent with industry trends to identify risks and replace aging infrastructure prior to failure, "I remain concerned with the impact on ratepayers. The recovery of costs related to GIRP investment through 2019 will have been addressed through the Council's setting gas rates beginning the first billing cycle in August 2019 and are estimated to have a bill impact on a typical 100 ccf/month residential customer of approximately $6.12/month in 2019." Including the estimated costs related to GIRP investment <u>after</u> 2019 and the estimated costs related to address historical underground utility conflicts, the estimated bill impact on a typical 100 ccf/month residential customer peaks at approximately $20.45/month in 2026.[367] Advisor witness Watson notes that ENO's Period II gas cost of service studies include costs related to GIRP investments totaling approximately $39.5 million through December 31, 2019. Based on their proposed ROE and equity ratio, the Advisors estimate ENO's 2019 revenue requirement related to these investments to be approximately $4.2 million and the average typical residential bill (100 ccf/mo.) impact to be $6.12.[368]

Witness Rogers further states that he "agree[s] with the Council and ENO that ENO's proposed GIRP will provide customers with a safer, more reliable gas distribution system. What still remains to be determined, is: (1) the rate at which GIRP investment should proceed to maintain the safe operation of ENO's gas system while minimizing the adverse impact to ratepayers, and (2) what measures ENO or the Council can take, if necessary, to mitigate the identified impact on ratepayers once the rate at which GIRP investment should proceed is

[367] *Id.* at 39:18-40:4.
[368] Ex. No. ADV-6 at 80:11-15.

determined."[369] However, ENO has not shown that the proposed scope and pace of the GIRP plan adequately mitigates its rate impact.

Notwithstanding the Advisors' efforts, through discovery, to identify the approximate number of miles of pipe that should be replaced annually to ensure the safety of the gas distribution system, ENO refrained from providing a specific estimate. At best, based on ENO's response to Advisor data request CNO 3-10 d, it appears that a slower rate of replacement could be achieved while maintaining the safe operation of ENO's gas distribution system.[370] Despite ENO's discovery response that appears to indicate that a slower rate of replacement could be achieved while maintaining the safe operation of ENO's gas distribution system, ENO maintains its position for the original GIRP schedule presented in the Application.[371] Given ENO's unwillingness to depart from its proposed pace of GIRP-related investments, Advisor witness Rogers recommends that a working group composed of the Advisors, ENO, and Intervenors be established immediately to explore cost mitigation measures.[372]

Advisor witness Watson testifies that ENO's proposed GIRP Rider is not necessary to allow ENO the opportunity to recover its related costs.[373] He states that "[t]hese GIRP-related costs are predictable and manageable by ENO." As such, other ratemaking mechanisms exist to allow ENO the opportunity to recover such costs such as ENO's proposed FRP that Advisor witness Prep recommends the Council approve subject to certain modifications.[374] In fact witness Watson testifies that "ENO witness Bourg testified, 'ENO agrees that a properly structured FRP would provide an appropriate means to adjust ENO's gas rates to allow it to

[369] Ex. No.ADV-1 at 40:5-10.
[370] *Id*. at 41:2-23.
[371] Ex. No. ENO-24 at 5:14-16.
[372] Ex. No. ADV-2 at 10:19-21.
[373] Ex. No. ADV-6 at 81:9-10.
[374] *Id*. at 81:11-14.

recover its gas revenue requirements, including its GIRP-related costs and a reasonable return on its investment.'"[375]

e) Rate Base Adjustment Rider (ARRT)

(1) ENO Proposal

ENO proposes a Rate Base Adjustment Rider to implement the ARRT plan. The rider contemplates two step changes in the rates of the Algiers residential customer and other participating classes (Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible). The first step takes place when rates approved in this proceeding are implemented and the second step in September 2021. As noted above, the Advisors recommend that the Council reject ENO's proposal (that would place the burden of the Algiers mitigation on industrial customer classes) and adopt the Advisors' proposal which has the mitigation costs limited to Legacy ENO's residential class. The Advisors' Algiers proposal could be implemented in the context of a Rider applicable to the combined residential base rate tariff, and would extend to future rate actions as necessary.

f) AMI Customer Charge

(1) ENO Proposal

ENO describes its AMI Charge for electric and gas service as follows — "On February 8, 2018, in Resolution R-18-37, the Council approved a Stipulated Settlement and Term Sheet regarding the AMI Implementation. The Term Sheet provided that the prudently incurred costs associated with AMI were eligible for recovery from ENO's customers through electric and gas rates resulting from a final order of the Council in this rate case. The Term Sheet recognized that ENO and the Advisors were unable to reach agreement on the specific method for cost recovery

[375] *Id.* at 82:6-9, citing Council Docket No. UD-07-02, the Rebuttal Testimony of Michelle P. Bourg at 8.

at that time and reserved the parties' rights to argue their cost recovery positions in future proceedings. ENO proposes that the Council authorize ENO to include in electric and gas bills beginning in the first billing cycle of August 2019, the expected effective date of base rates from this case, an Electric AMI Charge and a Gas AMI Charge [Rider AMICE and Rider AMICG, respectively]. Both would change annually, beginning on January 1, 2020. After 2022, the Electric AMI Charge would decline over time based on the schedule. After 2020, the Gas AMI Charge would decline over time based on the schedule."[376] The proposed monthly customer charges are depicted in the following table.[377]

	Electric	Gas
2019	2.95	0.60
2020	3.67	0.96
2021	3.28	0.87
2022	3.01	0.77
2023	2.79	0.65
2024	2.57	0.53
2025	2.35	0.41
2026	2.13	0.29
2027	1.91	0.17
2028	1.69	0.05
2029	1.47	0
2030	1.25	0
2031	1.03	0
2032	0.81	0
2033	0.60	0
2034	0.40	0
2035	0	0

Further, ENO contends that "[t]he number of customers ENO serves, in large part, drives the level of the costs associated with AMI." Therefore, these costs should be recovered through a customer charge so that a customer bears only the cost that the customer causes. The charges are intended to recover the net present value of the Electric and Gas AMI revenue requirements. Any differences in the revenue resulting from the customer charges and the actual costs of AMI would be reconciled through the proposed Electric and Gas FRPs. For customers that are billed

[376] Application at 37-38.
[377] Ex. No. AAE-3 at 30, citing Ex. No. ENO-4, Exhibit JBT-9.

on a rate schedule with a customer charge, the Electric and Gas AMI Charges would be added to the rate schedule customer charge approved in this case. For customers that are not billed on rate schedule with a customer charge, the Electric AMI Charge would be added to the charge for the first block of demand approved in this case.[378]

(1) Intervenor Positions

AAE witness Barnes argues that ENO's proposed fixed monthly charge is unreasonable[379] because AMI is not "typical" metering.[380] He states that "fixed customer charges should recover the cost of connecting a customer to the grid. Advanced metering and the associated incremental costs above traditional meters are not strictly necessary for the customer to be connected to the grid. A non-advanced meter and associated infrastructure can do so at lower costs. AMI is used for much more than measurement of a customer's consumption for billing purposes."[381]

Instead AAE witness Barnes recommends the Council adopt a volumetric rate design in order to support energy efficiency, protect the greater portion of lower income customers from disproportionate impacts, and distribute the costs and benefits of AMI more equitably. This is also the simplest way to align fixed monthly charges with the costs necessary to connect a zero-load customer to the system, since customers would continue to pay for the cost of the minimum meter necessary to do so through their payment for the un-depreciated costs of legacy meters."[382] Further AAE notes that a volumetric AMI charge would cause lower usage customers to pay less towards AMI deployment, when those same customers act to reduce their energy consumption or peak period demands, higher usage customers still receive a greater portion of the benefits of the

[378] *Id.* at 38.
[379] Ex. No. AAE-3 at 31-34.
[380] *Id.* at 31.
[381] *Id.*
[382] *Id.* at 34.

associated cost savings. Therefore, while higher usage customers pay more under a volumetric design, they also receive more in return.[383]

(2) Advisors' Position

Advisor witness Watson testifies that ENO's proposed per-customer charges in Rider AMICE and Rider AMICG are intended to allow ENO recovery of its AMI-related costs, including capital-related costs and O&M costs.[384] Specifically, ENO removes certain Period II per-books AMI-related costs from its base rate cost of service studies. Thus, the Company intends to recover substantially all of its AMI-related costs through these riders rather than base rates.[385]

Advisor witness Watson also testifies that ENO's proposed allocation of cost responsibility for AMI-related costs on a per-customer basis is inappropriate single-issue ratemaking.[386] Specifically, he notes that the pace of AMI deployment is known, measurable, and reasonably within ENO's control and related costs are similarly known and measurable.[387] As such, singling-out AMI costs for recovery through riders constitutes inappropriate single-issue ratemaking. Accordingly, the Advisors recommend the Council deny ENO's request for Rider AMICE and Rider AMICG.

7. <u>Adjustments to Existing Riders/Schedules</u>

a) FAC

ENO proposes several changes to its FAC Rider. The first is to combine the separate FAC riders for Legacy ENO customers and Algiers customers into a single FAC Rider for all

[383] *Id.*
[384] Ex. No. ADV-6 at 83-84.
[385] *Id.* at 84.
[386] *Id.*
[387] *Id.* at 84-85.

customers.[388] ENO also proposes: (1) to modify the recovery of the Resource Plan PPA capacity expenses to include the return of the difference between estimated monthly capacity expenses and that amount recovered through base rates and, and the actual monthly capacity expenses; (2) elimination of the recovery of LTSA expenses, which ENO proposes to recover through base rates and the PPCACR Rider; (3) elimination of the Grand Gulf repricing mechanism for Algiers Customers, (4) elimination of the allocation to Legacy ENO Customers of Union Power Block 1 fuel costs and wholesale revenues so that all customers are allocated these expenses and benefit from these revenues; (5) combination of the two over/under balances into a single over/under balance; and (6) use of per book rider revenue instead of calculated FAC collections.[389]

The proposed combined FAC Rider is significantly simpler than the rider it is intended to replace and produces a single FAC Rider rate for both Legacy ENO Customers and Algiers Customers by eliminating the Geographic-Specific adjustments.[390] This represents a significant improvement with respect to ease of calculation and understanding.[391] The Advisors did, however, note some errors in the formulas and references and also an inconsistency in the formulas in ENO's Exhibit SMC-2 for the treatment of certain costs as compared to historical treatment and the treatment proposed in ENO's proposed PPCACR Rider for similar costs.[392]

ENO submitted no testimony in response to the errors noted by the Advisors, rather, ENO stated that there are no substantive disputes regarding the FAC Rider Schedule.[393] ENO stated that the only outstanding issue concerns which over and under collections, if any, should be included in the rider, which is dependent on the final resolution of allocation issues.[394] ENO

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[388] Ex. No. ENO-55 at 30.
[389] *Id.* at 31; see also Ex. No. ENO-44 at 5:1-6:12..
[390] Ex. No. ADV-1 at 23:7-9.
[391] *Id.* at 23:9-10.
[392] *Id.* at 23:11-27:8.
[393] Ex. No. ENO-3 at 6:5-7.
[394] *Id.* at 6:7-9.

proposes that this component of the rider be addressed in the compliance filing process.[395] The Advisors support this suggestion, and therefore recommend that the Council approve the proposed FAC Rider Schedule, as corrected by the Advisors.

b) PGA

(1) ENO Proposal

ENO proposes to use per book PGA Rider revenue instead of calculated PGA Rider collections in order to ensure a more accurate calculation by reflecting customer billing corrections recorded in the operations month.[396]

The proposed combined PGA Rider is similar to the rider it is intended to replace.[397] ENO has proposed modifications from the previous rider to revise the formulas for calculating the over/under balance to utilize per book PGA Rider revenue.[398] A similar treatment is included in ENO's proposed FAC Rider, and the change in the source data for the calculation will not make a material difference in the rate charged under the FAC rider or PGA Rider.[399] The Advisors did note some errors in the formulas of the proposed PGA Rider and recommend the Council approve the Rider as corrected for these errors.[400]

c) PPCACR

ENO explains that, effective with new base rates from this proceeding, it will no longer recover the Union PB1 and Ninemile 6 PPA costs exclusively through the Rider PPCACR.[401] ENO proposes to transfer current Rider PPCACR costs relating to the Union Power Station acquisition and the Ninemile 6 PPA into base rates in this proceeding, and then reset the

[395] Ex. No. ENO-3 at 6:9-10.
[396] Ex. No. ENO-55 at 31.
[397] Ex. No. ADV-1 at 28:1.
[398] *Id.* at 28:1-3.
[399] *Id.* at 5-7.
[400] *Id.* at 28:8-29:6..
[401] Ex. No. ENO-41 at 44:19-23.

PPCACR Rider at zero.[402] On a going-forward basis, ENO then proposes to include three types of recoverable costs in revised Rider PPCACR: (1) the incremental difference between the estimated, approved PPA and LTSA costs in the new base rates and the actual PPA and LTSA costs incurred on a monthly basis; (2) costs related to newly constructed and/or acquired capacity; and (3) costs related to new PPAs the Company may enter into as approved by the Council.[403] ENO proposes to allocate the Rider PPCACR revenue requirement to the rate classes using the base rate revenue requirement allocation methodology approved by the Council in this proceeding.[404] Similar to the current PPCACR Rider, ENO proposes a cumulative over/under calculation that compares the cumulative over/under balance and the applicable monthly costs to the PPCACR Rider Revenue for that operations month.[405] Any prior period adjustments will be added or subtracted and an interest component will be applied based on the average of the beginning of the month and end of the month cumulative over/under balance for the operations month using that month's prime interest rate.[406]

Air Products supports the PPCACR Rider to allocate cost recovery as an equal percent of base rate revenue as reasonable in the absence of the utility to use a more specific cost-based allocation.[407]

CCPUG argues that it is inappropriate to allow ENO to include any and all revenue requirements for newly constructed or acquired capacity or the expenses related to new PPAs and new LTSAs ENO may enter into through a PPCACR Rider.[408] CCPUG argues that doing so would inappropriately allow ENO to include these costs without review or further action by the

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[402] Ex. No. ENO-55 at 32; Ex. No. ENO-41 at 44:19-23.
[403] Ex. No. ENO-55 at 32; Ex. No. ENO-41 at 45:8-46:6.
[404] Ex. No. ENO-41 at 46:10-14.
[405] *Id.* at 46:17-19.
[406] *Id.* at 46:19-23.
[407] Ex. No. AP-3 at 19:3-5.
[408] Ex. No. CCPUG-1 at 53:8-11.

Council other than the initial estimated revenue requirement for newly constructed or acquired capacity.[409] CCPUG recommends that the proposed tariff be modified so that no revenue requirement for newly constructed to acquired capacity or no expenses for new PPAs or LTSAs may be included without action by the Council and without an opportunity for the Council to review the reasonableness of the transactions and agreements as well as setting forth a process to allow intervenors to review the transactions and agreements as well as the revenue requirements and expenses that will be included in the rider.[410]

While a rider to permit contemporaneous recovery of PPA and LTSA costs may be appropriate, the scope of the rider should not be so broad as to encompass any as-yet unknown non-fuel revenue requirements related to construction and/or acquisition of new capacity, new PPA, or new LTSA.[411] Rider PPCACR is not necessary to allow ENO a reasonable opportunity to recover its prudently incurred costs related to future ENO-owned capacity additions, because mechanisms exist to allow ENO the opportunity to recover such costs.[412] Such non-fuel costs for new acquisitions, once known and measurable, are more appropriately addressed in a general rate proceeding where all of ENO's cost categories and magnitude of costs are considered in total.[413] Rider PPCACR would set a separate rate for incremental ENO-owned capacity additions and ensure ENO exact cost recovery, which constitutes inappropriate single-issue ratemaking.[414]

Because the timing of any new construction and/or acquisition of new capacity, new PPA, or new LTSA is currently unknown as are the magnitude of any costs associated with the

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[409] Ex. No. CCPUG-1 at 53:11-14.
[410] *Id.* at 54:5-11.
[411] Ex. No. ADV-1 at 32:3-6.
[412] Ex. No. ADV-6 at 86:9-11.
[413] Ex. No. ADV-1 at 32:6-10.
[414] Ex. No. ADV-6 at 17-7:2.

unknown future capacity additions, consideration in this instant base rate proceeding is not appropriate.[415] Additionally, the proposed PPCACR rider allocates costs to rate classes using a Base Rate Revenue Requirement allocation factor, but since the costs proposed for recovery in this rider are non-fuel costs associated with production plant, a Production Demand Allocation Factor would be more appropriate and consistent with how the costs would be anticipated to be allocated in a base rate proceeding.[416]

The Code of the City of New Orleans, Sec. 158-732(c) requires ENO to seek Council approval for taking an interest in a transmission or generation facility or for entering into a PPA whose costs generally exceed two percent of the rate making value of ENO's property.[417] ENO can reasonably request that the Council approve cost recovery relief as part of any such application; therefore, there is no need at this time for the Council to approve such currently unknown costs to be recovered through the proposed PPCACR Rider.[418] To that end, the Advisors recommend that (1) costs for non-fuel revenue requirements related to construction and acquisition of new capacity, costs associated with new PPAs, and costs associated with new LTSAs not be provided automatic recovery in the proposed PPCACR rider, and that the name of the rider be changed to the Purchase Power Cost Recovery Rider ("PPCR"); (2) that the new PPCR Rider collect the difference (positive or negative) between the estimated PPA capacity and LTSA expenses in the new base rates from this proceeding (Schedule A costs) and the actual PPA capacity and LTSA expenses incurred by ENO on a monthly basis; (3) costs recoverable in the PPCR Rider be limited to costs associated with ENO's existing power purchase agreements and long term service agreements including: Grand Gulf UPSA, EAL Resource PPA, Riverbend

[415] Ex. No. ADV-1 at 32:10-13.
[416] *Id.* at 32:13-18.
[417] Ex. No. ADV-8 at 3-6.
[418] Ex. No. ADV-2 at 6-9.

PPA, Ninemile 6 PPA, Algiers Slice of System PPA, and LTSA Costs associated with the following facilities: Union PB1, Ninemile 6, Perryville 1 (Algiers SOS PPA), and Acadia (Algiers SOS PPA); (4) the Schedule A costs identified in the new PPCR be those costs identified in the HSPM Exhibit OT-2, broken down by month; (5) the new PPCR Rider allocate costs to rate classes using the Production Demand Allocation Factor determined in this proceeding; and (6) the Council implement a new PPCR Rider that is based on the redline of ENO's proposed PPCACR Rider provided as Exhibit No. JWR-6 attached to Exhibit No. ADV-1.[419]

d) MISO Cost Recovery Rider

(1) ENO Proposal

Consistent with the combination of Legacy ENO and Algiers customers, ENO proposes a combined MISO Cost Recovery Rider that for the most part mimics the current separate MISO Riders, though certain now inapplicable costs have been eliminated from the formula.[420] The combined MISO Cost Recovery Rider would be re-determined annually and subject to annual true-ups beginning in 2020.[421] ENO also proposes to use this combined rider in the upcoming 2019 MISO Rider filing in order to facilitate the transition from the two current riders and two sets of rates to the combined rates expected to become effective in August 2019.[422] The general purpose of the MISO Cost Recovery Rider is to define the procedure by which ENO shall implement and adjust rates contained in the designated rate classes for recovery of the costs, including, but not limited to, costs charged to ENO pursuant to the FERC-approved MISO Open Access Transmission Energy and Operating Markets Tariffs that are not recovered via the Fuel

[419] Ex. No. ADV-1 at 33:14-34:16.
[420] Ex. No. ENO-55 at 31; Ex. No. ENO-41 at 40:12-15.
[421] *Id.* at 31; Ex. No. ENO-41 at 40:15-18.
[422] *Id.* at 31-32.

Adjustment Clause.[423] The Combined MISO Rider revenue requirement would reflect the following costs and revenues: (1) estimated Net MISO Charges or Credits (*i.e.*, MISO charges and credits for which recovery has not been requested separately through the Fuel Adjustment Clause), and (2) a true up of actual revenues to actual costs, including carrying charges.[424]

The Advisors have reviewed the proposed rider and supporting testimony and did not find any reference errors or calculation errors.[425] The Advisors' analysis indicates that the proposed rider is consistent with the directions given to ENO by the Council in Resolution No. R-17-504 to develop a single set of proposed tariffs applicable to all customers, that its cost allocation is appropriate and that the cost categories and adjustment calculations that ENO removed are no longer necessary.[426] Therefore, the Advisors recommend that the Council approve the MISO Rider as proposed by ENO.

C. Annual Revenue Adjustments

ENO proposes adoption of an FRP for both electric and gas service as well as a decoupling plan embedded within the Electric FRP.[427] ENO argues that a well-designed FRP provides regulatory clarity through a rate-setting mechanism that is easy to use and easy to monitor; reduces the cost associated with base rate adjustments through a regulatory mechanism that is more streamlined and efficient; promotes price stability through gradual annual rate changes; allows routine review and input from the Council, Advisors and other interested parties; and supports a utility's ability to access capital on reasonable terms.[428]

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[423] Ex. No. ADV-1 at 29:10-15.
[424] Ex. No. ENO-41 at 40:23-41:3.
[425] Ex. No. ADV-1 at 29:18-19 and 30:13-14.
[426] *Id.* at 3-13.
[427] Ex. No. ENO-55 at 20-21.
[428] *Id.* at 20.

1. FRP

ENO proposes an electric FRP with an initial term of three years that incorporates many features of the predecessor FRP approved by the Council in Resolution R-09-136, including the basic structure that evaluates whether the Company's rates fall within a bandwidth around the authorized ROE (midpoint) established by the Council, with annual evaluations that prospectively adjust rates to the midpoint.[429] However, ENO proposes seven categories of changes to the previous Electric FRP: (1) changes to the EPCOE to incorporate the proposed RIM Plan's adjusted ROE formula; (2) changes to accommodate the Energy Smart Program; (3) changes to implement the Decoupling Pilot Program; (4) a new provision for an interim Rate Adjustment for NOPS non-fuel revenue requirement; (5) a new provision for changes in income tax rates; (6) a change to the "Extraordinary Cost Changes" provision related to the revenue trigger; and (7) a new provision for Rider PPCACR Transitional Items.[430]

ENO also proposes an FRP for gas service based on the Gas FRP Rider previously approved by Council Resolution No. R-19-136.[431] ENO proposes three changes to the prior Gas FRP, consistent with changes to the electric FRP: (1) changing the filing date to April 30, with the initial rate adjustment to be effective for the first billing cycle in September; (2) the treatment of changes in the tax rate; and (3) increasing the revenue requirement impact trigger to the Extraordinary Cost Changes section from $750,000 in the previous FRP to $1 million.[432]

Both of ENO's FRPs, which are based largely on the FRP's previously approved by the Council, include, among others, the following features:

- Use of the previous calendar year as the Evaluation Period (*i.e.*, historic test year);

[429] Ex. No. ENO-55 at 20.
[430] Ex. No. ENO-41 at 29:11-21.
[431] Ex. No. ENO-55 at 21.
[432] Ex. No. ENO-55 at 21; Ex. No. ENO-41 at 48:15-22.

- Use of the authorized return on equity set in this proceeding as the target Evaluation Period Cost of Equity ("EPCOE");
- A dead band of plus or minus 50 basis points centered on the EPCOE, in which there would be no change in rates;
- A formula that adjusts the FRP revenue level for the Evaluation Period to prospectively earn the EPCOE, commonly referred to as "resetting to the midpoint," if the Earned Rate of Return on Equity ("EROE") is above or below the deadband;
- A seventy-five day review period;
- A specified dispute resolution procedure; and
- A three-year term.[433]

CCPUG witness Kollen argues that if the Council approves an EFRP and/or GFRP implementation date of 2020 based on a calendar year 2019 Evaluation Period, it should require ENO to exclude all proforma adjustments for 2019.[434] If such proforma adjustments are not excluded for 2019, then CCPUG objects to an ERFP implementation date of 2020 and recommends that it be delayed until 2021.[435] CCPUG also argues that the costs ENO proposes to include in its interim rate adjustment related to NOPS are not reasonable.[436] CCPUG argues that ENO's proposed return is excessive, the depreciation rate and depreciation expense are excessive, and the interim rate adjustment is proposed to be based on the first year NOPS revenue requirement without declining over time to reflect depreciation and the tax savings from

[433] Ex. No. ENO-41 at 28:14-29L7; Ex No. ENO-3 at 7:3-20.
[434] Ex. No. CCPUG-1 at 45:12-14; 51:12-26; Ex. No. CCPUG-2 at 25:1-7.
[435] *Id.* at 45:14-15.
[436] *Id.* at 46:8-11.

accelerated tax depreciation that occurs over time.[437] CCPUG recommends that the Council (1) reduce the return on equity to 9.35% or whatever other return on equity it authorizes for the base revenue requirements; (2) reduce the first-year revenue requirement to reflect a 50-year service life; and (3) require ENO to reduce the revenue requirement each year to reflect an additional year of depreciation and deferred income tax expense (reflected in greater accumulated depreciation and ADIT).[438] CCPUG calculates that this would result in a first-year revenue requirement reduction of $4.073 million.[439]

Air Products opposes ENO's proposal to completely reset rates if the EROR is above or below the bandwidth range, such that rates would be recalculated to bring earnings to the EPCOE.[440] Air Products proposes that if the EROE is above the upper bandwidth, the revenue adjustment be only partially moved toward the upper bandwidth (60% of the way toward the upper bandwidth), such that ENO is able to retain some of the benefits of the efficiencies it gained.[441] When earnings are below the lower edge of the bandwidth, Air Products recommends that the adjustment be 60% of the way toward the lower bandwidth.[442]

Similar in its approach in the Application to use a cost of service limited to base rates, ENO opposes the inclusion of all revenues and expenses, including riders, in the Electric and Gas FRPs. Air Products also opposes the Advisors' proposal to include total revenues and expenses in FRP evaluations. Air Products argues that costs related to items that have mechanisms designed to track, reconcile and true-up costs and revenues and operate independently of base rates, such as the FAC Rider, MISO Rider, etc. should not be included

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[437] *Id.* at 46:4-48:4.
[438] *Id.* at 48:7-13.
[439] *Id.* at 48:17-18.
[440] Ex. No. AP-3 at 22:13-14.
[441] *Id.* at 23:13-21.
[442] *Id.* at 24:8-11.

because they have absolutely nothing to do with whether ENO is under-earning or over-earning. The Advisors disagree; the Council should evaluate whether ENO is under-earning or over-earning by evaluating the total utility cost of service. The Advisors recommend that the FRP use total ENO revenues and expenses, rather than limiting the FRP evaluation to base rate costs and revenues. That approach to evaluating total utility revenue requirements is consistent with the Advisors' approach establishing a fully allocated cost of service.

The Advisors concur with ENO's proposal to exclude Energy Smart costs, LCFC, and the utility incentive from the FRP mechanism.[443] The Advisors also concur with ENO's proposal to use the EFRP Provision for Other Rate Changes as a transition to recover the revenue requirements related to NOPS, which is scheduled to go into service in 2020 during the evaluation of the first FRP filing.[444] The Advisors concur with ENO's proposed provisions regarding the effect of any tax rate changes, increasing the revenue requirement trigger in the Extraordinary Cost Changes Section from $2 million to $6 million, and realigning future purchase power capacity recovered in the Advisors' proposed PPCR to the FRP.[445]

The Advisors recommend that the Council approve a three-year FRP with an appropriate ROE and a bandwidth of +/- 50 basis points.[446] Based on an estimated August 2019 implementation of the new rates at issue in this case, the Advisors agree that the FRP should begin with a May 2020 filing covering a calendar year 2019 test year.[447] The Advisors recommend that the FRP provision for NOPS cost recovery provided for in FRP Section III.C, Provision for Other Rate Changes, by a separate rate adjustment, include an allocation based on the rate case production demand allocation factor, rather than total base rate costs (which

[443] Ex. No. ADV-3 at 76:3-4.
[444] *Id.* at 76:8-11.
[445] *Id.* at 76:14-17.
[446] *Id.* at 77:8-9.
[447] *Id.* at 77:9-11.

includes customer and distribution costs).[448] The Advisors recommend clarifying the intent of the language that a proceeding may be initiated to consider a pass-through of the extraordinary cost change, and to include the extraordinary cost change as a proforma adjustment prospective to the FRP Evaluation Period pursuant to the Advisors' proposed revision to Attachment C, Adjustments para. 8, if such occurs during the period.[449] Otherwise, the extraordinary costs may be considered for interim recovery, and included in the ROE bandwidth evaluation of the next FRP.[450]

The electric FRP revenue adjustment for each customer class would be determined by comparing the evaluation period fixed & variable revenue by class with the FRP evaluation period allocation of total ENO fixed and variable revenue requirement.[451] The Advisors also recommend an additional provision under FRP Attachment C, Evaluation Period Adjustments, paragraph 8. Other that would state: "ENO may propose other known and measureable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP Evaluation Period."[452] This provision would include those prospective costs proposed by ENO to be recovered within the FRP revenue adjustment.[453]

ENO witness Thomas agreed that incorporating forward-looking proforma adjustments to account for known and measurable costs (and attendant revenue changes)in the calendar year following the FRP evaluation period in a properly structured FRP would address ENO's concerns regarding regulatory lag to a great degree.[454] Witness Thomas also agreed that the Advisors' proposed prospective treatment of known and measurable costs and attendant revenue

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[448] *Id.* at 77:13-16.
[449] *Id.* at 77:16-20.
[450] *Id.* at 77:20-21.
[451] *Id.* at 78:6-8.
[452] *Id.* at 78:9-13.
[453] *Id.* at 78:13-14.
[454] Ex. No. ENO-3 at 8:9-12, Ex. No. ENO-4 at 13:21-23.

change would mitigate the need for the Electric and Gas AMI Charge Rider and the DGM Rider, though he argues for a provision to implement those riders in the event the FRP terminates after the initial three-year term.[455]

CCPUG opposes the Advisors' proposal to include adjustments for forecast increases in costs beyond the historic evaluation period.[456] CCPUG argues that this would fundamentally and negatively change the ratemaking process by allowing ENO to annually and continuously increase rates based on forecast costs that it develops with the near certainty these costs will be recovered in real time as they are incurred.[457] CCPUG argues that ENO's proposed ERFP and GRFP already provide a significant reduction of any potential harm to ENO from regulatory lag without the delay and cost of a traditional base rate proceeding.[458]

Air Products also opposes the Advisors' proposal that whenever an FRP evaluation is conducted, the external allocation factors be updated, arguing that this would make the process unnecessarily complex, expensive, contentious and inefficient.[459]

However, in an FRP filing, a comprehensive evaluation of the earned ROE compared to the Council-approved ROE requires that all costs and revenues be included.[460] Contrary to the assertion of ENO that there would be double-counting of cost and revenues, as long as all costs and revenues are supported by the financial reports of the system accounts, and each program adjustment is supported with explanation and workpapers, double-counting of costs and revenues should be avoided.[461] In addition, Directive 6 of Resolution No. R-16-03 requires that all utility fixed costs should be included in the decoupling revenue adjustment, regardless of the revenue

[455] Ex. No. ENO-3 at 9:3-7.
[456] Ex. No. CCPUG-2 at 25:12-19.
[457] *Id.* at 26:5-8
[458] *Id.* at 26:12-17.
[459] Ex. No. AP-4 at 12:3-11.
[460] Ex. No. ADV-5 at 23:11-13.
[461] *Id.* at 24:1-6.

recovery mechanism used to recover any specific fixed (non-fuel) costs.[462] After determining the allocated cost responsibility from the total cost of service, the FRP adjustment by customer class can be determined by the difference between the customer class total cost of service and the customer class total revenue and there would be no issue of double recovery.[463]

ENO disagrees with the suggestion of CCPUG witness Kollen that the proposed FRPs should not use calendar year 2019 as the first evaluation period. ENO argues that to use 2019 as the first evaluation period would be consistent both with prior Council practice and LPSC practice.[464]

ENO changed its proposal as to NOPS costs recovery, suggesting that the Council not determine the parameters for recovery of the NOPS revenue requirement in this proceeding, but wait until ENO makes its proposed rate filing prior to the in-service date of NOPS based on the estimated first NOPS revenue requirement.[465] CCPUG opposes this suggestion and argues that the Council should decide the issue in this case.[466]

With the commercial operation date of NOPS being anticipated in early 2020, if the NOPS updated revenue requirement filing is not included in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment would be effective until NOPS costs are included in the bandwidth of the following FRP.[467] If the NOPS updated revenue requirement filing is included as a 2020 proforma adjustment in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment would be effective with the COD until the FRP rate adjustment effective September 2020, at which time NOPS recovery would be included in the FRP rate adjustment.[468]

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[462] Ex. No. ADV-5 at 24:6-9.
[463] *Id.* at 24:9-12.
[464] Ex. No. ENO-3 at 12:12-20, citing Resolution Nos. R-03-272 and R-09-136.
[465] *Id.* at 48.
[466] Ex. No. CCPUG-2 at 29:9-30:13.
[467] Ex. No. ADV-5 at 25:2-6
[468] *Id.* at 25:6-10.

2. Reliability Incentive Mechanism Plan

ENO proposes a RIM within its electric FRP. ENO states that it is proposing its RIM Plan because it recognizes that its reliability performance has not met the expectations of ENO, its customers, and the Council.[469] ENO's intention is to align the earnings component of its base rates to its distribution reliability performance.[470] ENO proposes that its electric ROE (which ENO proposes to be 10.75%) would be reduced by 25 basis points (to 10.5%) then, if ENO's performance improves, as measured through ENO's Distribution System Average Interruption Frequency Index ("SAIFI"), it would return to the baseline ROE (10.5%) and thereafter ENO's SAIFI based on the Evaluation Period data would then translate into a number of positive or negative basis points (maximum of 25) to be added to the baseline ROE.[471] ENO states that its expected year-end 2018 SAIFI score is expected to be 1.65.[472] ENO proposes that if its SAIFI improves to 1.24 the adjustment would be zero, a score of 1.40 or worse would warrant a 25 basis point decrease from 10.75%, and an improvement to 1.05 would warrant a 25 basis point increase from 10.75%.[473] ENO argues that this proposal directly addresses the reliability issue, balances the interests of stakeholders, is transparent, and is administratively straightforward to implement.[474]

CCPUG argues that the proposed RIM should be rejected by the Council.[475] CCPUG argues that given ENO's unacceptably poor electric system reliability over the last few years, the Council should not under any circumstances approve a regulatory incentive mechanism that

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[469] Ex. No. ENO-1 at 23:3-6.
[470] *Id.* at 23:11-12.
[471] *Id.* at 24:1-26:2.
[472] *Id.* at 28:5-6.
[473] *Id.* at 28:3-16; Ex. No. 41 at 31:2-23..
[474] *Id.* at 26:5-19.
[475] Ex. No. CCPUG-3 at 50:7-8.

provides the possibility of ENO earning a higher ROE for improved system reliability.[476] CCPUG argues that reliable service is part and parcel of every utility company's duty, including ENO, under the Regulatory Compact.[477] In other words, in return for its monopoly status and the absence of competition, its power of eminent domain, and the opportunity to earn and almost guaranteed rate of return, the utility's service must be reliable.[478] CCPUG argues that the Council should set base level performance attainment levels in this proceeding of 1.16 for SAIFI and 113.8 for SAIDI.[479] CCPUG suggests a 25 basis point reduction penalty for underperformance and no incentive for improved performance.[480]

Air Products also opposes the RIM, arguing that the mechanism is conceptually flawed because it would reward ENO for doing what it is supposed to be doing in the first place -- namely, providing reliable service.[481] Air Products urges the Council to reject the proposed RIM.[482]

As a public service company, ENO should prudently manage its electric utility, including making prudent expenditures and investments, and SAIFI is one metric for ENO's performance.[483] ENO should not require an incentive to act prudently and achieve reasonable results for stakeholders.[484] Even if the Council were to decide to incentivize ENO to improve its reliability, the Advisors would not recommend the Council utilize an ROE adjustment to do so. There is not a direct relationship between ROE and distribution performance and the ROE customarily affects ENO's return on all its investments, not just the investments in the

[476] Ex. No. CCPUG-1 at 50:10-13.
[477] *Id.* at 50:13-14.
[478] *Id.* at 50:14-17.
[479] *Id.* at 52:20-23.
[480] *Id.* at 52:14-18 and 53:2-5.
[481] Ex. No. AP-3 at 20:14-16.
[482] *Id.* at 21:5.
[483] Ex. No. ADV-1 at 15:2-4.
[484] *Id.* at 15:4-5.

distribution plant that is generally regarded as most closely related to many of ENO's reported service outages, which constitutes only 57.9% of ENO's net plant in service.[485] Moreover, the Council is currently investigating ENO's reliability performance in Council Docket No. UD-17-04, including consideration of what appropriate SAIFI and SAIDI standards should be as well as any appropriate incentives and penalty mechanisms related to those standards.[486] Setting a target SAIFI level and incentive mechanism in this proceeding would be premature prior to the conclusion of the investigations being conducted in Docket No. UD-17-04.[487] Additionally, the impacts on ratepayers of the proposed RIM are not insignificant. Under ENO's proposed RIM, if ENO were to succeed in improving its SAIFI performance sufficiently to allow its ROE to increase from 10.5% to 11.0%, the result would be that ENO is able to collect an additional approximately $2.7 million from its ratepayers.[488] The Advisors recommend that the Council not approve ENO's proposed RIM.

In response to the Advisors' argument that any minimum reliability standard should be addressed in Council Docket No. UD-17-04, ENO responds that it would be amenable to the Council setting ENO's electric ROE at 10.50% in this proceeding and directing the details of a balanced financial incentive and penalty mechanism that would permit ENO's ROE to adjust above 10.50% be determined in Docket No. UD-17-04, which ENO anticipates would be resolved prior to the resetting of rates through the FRP.[489]

There is, however, no need to consider ENO's proposed RIM further in Docket No. UD-17-04.[490] ENO's appropriate allowed-ROE will be established in this rate case, and the Council

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[485] *Id.* at 15:9-14.
[486] Resolution No. R-17-427.
[487] Ex. No. ADV-1 at 16:10-17:2.
[488] *Id.* at 14:18-20. Ex. No. ADV-6 at 12:3-11.
[489] Ex. No. ENO-3 at 19:20-20:3.
[490] Ex. No. ADV-2 at 4:11-15.

is considering whether or not to adopt minimum reliability performance standards in Docket No. UD-17-04.[491] There is no need to consider ROE and minimum reliability performance standards in conjunction with each other.[492] There simply is no direct relationship between the utility's ROE and distribution performance -- any adjustment to ROE would typically affect ENO's return on all of its plant, not just the distribution plant that is generally regarded as most closely related to many of ENO's reported service outages.[493]

3. Decoupling

a) ENO Proposal

ENO proposes a Decoupling Pilot Program within the electric FRP, through a four-step process to be applied only if a rate adjustment is necessary under the terms of the rider.[494] Under the decoupling proposal, the fixed and variable cost revenue requirements would be recovered from each rate class consistent with the allocation methodology used in the baseline rate case.[495] In the first step, the Baseline Fixed Cost Revenue Requirement and the Variable Cost Revenue Requirement are determined.[496] The second step is to allocate each Rate Class's Evaluation Period Base Revenue (and FRP Revenue, if any) between Fixed Revenue and Variable Revenue using the Baseline Revenue Requirement.[497] The third step is to compute each rate class's Evaluation Period Fixed and Variable Revenue Deficiency or Excess.[498] The fourth and final step is to calculate the Rate Adjustment for each rate class.[499]

[491] Ex. No. ADV-2 at 4:6-8.
[492] *Id.* at 4:8-9.
[493] *Id.* at 4:9-5:4.
[494] Ex. No. ENO-55 at 20-21; Ex. No. ENO-41 at 32:23-33:2.
[495] Ex. No. ENO-55 at 21.
[496] Ex. No. ENO-41 at 34:12-17.
[497] *Id.* at 36:6-8.
[498] *Id.* at 36:16-18.
[499] *Id.* at 37:3-7.

AAE witness Morgan recommends four changes to ENO's decoupling proposal: (1) remove it from the effects of the FRP deadband; (2) clarify that it will only operate on either (a) revenues from customer billing charge billing determinants or minimum bill requirements in tariffs; or (a) revenues collected under tariff riders that are subject to full reconciliation; (3) clarify that the comparison is between the most recent approved revenues and the actual revenues, allocated to rate class/schedules per approved allocation factors, and not to a calculation of required allocated revenues that includes changes in costs during the decoupling period and (4) authorize ENO to calculate the difference between actual and authorized through-based revenues for fixed recovery on a monthly basis during any year, applying a Council-set carrying charge rate evenly to balances owed customers and owed ENO.[500] AAE witness Morgan admits that she did not participate in any of the Council's decoupling proceedings leading to the adoption of the Council's decoupling resolution, Resolution No. R-16-103.[501] She maintains, however, that decoupling should focus only on revenues, not expense, and that revenue decoupling is always backward looking - a true-up for what actually happened compared to what was expected to happen.[502] AAE argues that any decoupling mechanism should operate separately from any FRP, be backward-looking in reconciliation, remove the need for any LCFC and ensure that there are no gaps that could penalize ENO for achieving the most energy efficiency it can.[503]

ENO argues that its decoupling mechanism does comply with the Council's resolution on decoupling. ENO notes that AAE witness Morgan neither participated in nor reviewed the Council's decoupling proceeding in Docket No. UD-08-02, and that her recommendations would

[500] Ex. No. AAE-1 at 3:11-23; AAE-2 at 2:6-3:7, 9:16-21, 16:16-22.
[501] Ex. No. AAE-2 at 3:15-4:1.
[502] *Id.* at 4:14-15 and 5:8-9.
[503] *Id.* at 8:10-18.

alter the decoupling structure embodied in the Decoupling Resolution. ENO argues that AAE's recommendation would be an entirely different alternative mechanism that would replace the portion of the FRP proposal addressing decoupling in its entirety.

The Advisors concur with ENO's recommendation that a Decoupling adjustment be applied only if the FRP revenue adjustment is outside the bandwidth.[504] All electric customer classes should be included in the decoupling adjustment, which should be determined relative to the customer class total revenue requirements which will be determined in this proceeding.[505] Rather than limiting the revenue requirements to costs related to base rate recovery, the Advisors propose that the total costs of service for each customer class be included in the adjustment.[506]

Compared to ENO's proposed 4 steps in applying the decoupling adjustment, the Advisors propose the following steps: (1) the "baseline" revenue requirement in the instant Docket is updated with a new baseline of fixed and variable revenue requirements in the FRP; (2) 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; (3) the revenue deficiencies/excesses are determined for each customer class by comparing the FRP customer class revenue requirements with the customer class evaluation period revenues; (4) the customer class decoupling adjustments are applied within each customer class with updated billing determinants. The Advisors propose that the allocation methodology of FRP evaluation period costs should be applied consistent with the allocation of costs applied in this proceeding to determine the decoupling revenue adjustments by customer class.[507] That methodology should include an

[504] Ex. No. ADV-3 at 79:3-4.
[505] *Id.* at 79:4-7.
[506] *Id.* at 79:7-8.
[507] *Id.* at 79:9-11.

updated consideration of the before-tax rates of return for each customer class based on the final rate class revenues and corresponding rate of return approved in this proceeding.[508] Consistent with the Council's guidance in Resolution No. R-16-103, the allocation factors for each customer rate class should be updated in each FRP 12-month evaluation with the then-current customer data using existing software that provided the allocation factors in this proceeding.[509] The Decoupling rate adjustment would be applied within each rate class by dividing the customer FRP revenue adjustment by the then-current evaluation period billing determinants.[510] Customer charge would not be included in the residential class billing determinants used to apply the decoupling rate adjustment.

ENO agrees with Air Products that there could be unintended consequences if a decoupling mechanism were to include all customer classes, particularly classes with few customers.[511] The concern of unintended consequences related to a customer class with few customers is without merit because updating allocation factors and billing determinants with each FRP will accommodate any shifts in customers within these classes. ENO also argues that it has significant concerns with the Advisors' proposal that the decoupling adjustment be performed by applying the same allocation methodology approved in this proceeding, and that ENO provide a new COS Study each year by updating the allocation factors for each customer class with then-current customer data.[512] ENO argues that it would substantially undermine the purposes and efficiencies of an FRP and there would be minimal benefit to be gained from developing updated allocation factors and presenting a fully developed COS Study each year.[513]

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[508] *Id.* at 79:11-13.
[509] *Id.* at 79:17-80:2.
[510] *Id.* at 80:2-4.
[511] Ex. No. ENO-13 at 2:8-15 and 4:11-13.
[512] Ex. No. ENO-42 at 14:16-15:3.
[513] *Id.* at 15:3-6.

ENO also argues that the Advisors' proposal would substantially undermine the purposes and efficiencies of an FRP by creating an inefficient use of resources and significant additional work.[514] ENO argues that FRP's streamline the rate setting process by eliminating the usual contentious debate around the allocation of the revenue requirement to the various rate classes and the rate design for 3 to 5 years, which is allowed because, typically, there are no substantial changes in operations from year to year that would materially affect cost allocations among customer classes.[515] ENO argues that it will be very labor intensive and require numerous resources for ENO to develop the allocation factors for the FRP that would be required under the Advisors' proposal.[516]

Air Products also argues that the Advisors' proposal would make the process unnecessarily complex, expensive, contentious, and inefficient.[517] Air Products also argues that there is the potential for decoupling to create very disruptive rate increases to individual customer classes.[518] Air Products' witness Brubaker explains that the decoupling proposals hold each customer class responsible for its share of the demand-related and energy-related costs based on revenue requirements approved by the Council in this case and that in future evaluation periods, individual class rates would be adjusted to maintain the same proportion of class revenues to total as in the baseline.[519] He explains that the problem this creates is that for classes with very few (*i.e.* 1 or 2) customers, if one of the customers changes their business operations and significantly reduces their energy usage the rates for that class could go up significantly to ensure that the class continues to contribute the same level of revenue.[520] Air Products

[514] *Id.* at 15:3-20.
[515] *Id.* at 15:12-19.
[516] *Id.* at 16:9-21.
[517] Ex. No. AP-4 at 12:1-11.
[518] *Id.* at 14:10-11.
[519] *Id.* at 14:13-17.
[520] *Id.* at 16:1-18.

recommends that (1) any decoupling mechanism only result in an adjustment if ENO's overall earned ROE is outside the bandwidth of the FRP, and (2) that either customer classes with only a few members should be excluded from the decoupling mechanism, or alternatively, putting a cap on the percentage change in rates resulting from the application of the decoupling mechanism to individual customers in rate classes Master Metered Non-Residential, High Voltage and Large Interruptible Service.[521]

The Advisors disagree with the ENO and APC arguments: the Advisors' proposal is not a new COS each year equivalent to the effort required to develop the COS study for this Application and finalize the COS results in the instant Docket. The update of the COS study using the same methodologies and models, including updating the allocation factors with current customer billing data will provide the full decoupling adjustment and not undermine the efficiencies of the FRP. With the implementation of AMI, increasing energy efficiency and demand response, and growth in renewables, storage and distributed generation, allocation factors will need updating and should not be relied upon until the next general rate case several years hence.

In addition, implementing the Advisors' decoupling recommendations will not require a level of effort from the parties to an FRP comparable to a rate case. If an electric FRP is approved, then return on equity, allocation methodology issues, and other cost issues limited by the structure of the formula rate plan would not require the effort expended in a general rate case proceeding.[522] Regardless of whether a decoupling adjustment is included, total company cost of service is required in the FRP to determine the earned return, and revenue and kWh information

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[521] *Id.* at 17:16-18:17.
[522] Ex. No. ADV-5 at 25:25:16-19.

is updated for the evaluation period.[523] In addition, the allocation of costs should be more streamlined with the allocation factors update, and fewer adjustments.[524] For example, there would be no requirement for two test periods, weather normalization would not be used, weighting factors would not require much updating, and the use of the external and internal allocation factors in the cost of service model would not be changed.[525] Further, updating of allocation factors is certainly not a waste of resources -- updated allocation factors are necessary to reflect the change in usage patterns related to increased energy efficiency, distributed energy resources, renewables including solar, new products and equipment, and other current impacts affecting usage that were not as much of a concern in years previous.[526] The Advisors' decoupling proposal would not substantially undermine the purposes and efficiencies of an FRP.[527] Rather, it would lead to greater assurance that ENO is being compensated appropriately in accordance with the Council's directives.

ENO also argues that the Advisors' assignment of the different required before-tax rates of return on rate base to each rate class, which is a principal driver of the Total Cost of Service by customer class was done under no objective standard that can be replicated, and would thus create an issue that would have to be addressed each year.[528] ENO argues it would not be consistent with Resolution No. R-16-03 for the Council to adopt different before-tax rates of return on rate base for each rate class because they are not allocation factors and their determination did not and would not follow a methodology, whereas R-16-103 contemplated an allocation methodology that could be updated and applied consistently on an annual basis.[529]

[523] *Id.* at 25:19-26:1.
[524] *Id.* at 26:2-3.
[525] *Id.* at 26:18-27:1.
[526] *Id.* at 27:6-10.
[527] *Id.* at 26:7-8.
[528] Ex. No. ENO-42 at 20:6-21:9.
[529] *Id.* at 21:11-19; Ex. No. ENO-43 at 7:13-8:4.

ENO proposes instead that the proposed revenue by rate class approved in this proceeding be used to allocate ENO's revenue requirement in future FRP evaluation reports.[530]

However, duplication of the results in the FRPs is not an objective.[531] Rather the Advisors' approach would apply cost allocation methodologies consistently based on the instant proceeding, and any changes to the customer class rates of return would be entirely at the discretion of the Council.[532] The Advisors' proposal is consistent with Resolution No. R-16-103, in that it does include allocation methodologies consistent with the instant proceeding, and it does consist of an annual determination of the allocated fixed cost revenue requirements using the approach the Advisors proposed in this proceeding.[533] Finally, the Advisors propose an additional adjustment to evaluate and adjust the customer class billing determinants if supported by appropriate documentation.[534]

ENO's argument related to customer class before-tax rates of return on rate base is without merit. The customer class rates of return will be determined by the Council-accepted cost allocation methodologies and customer class revenues set by the Council in the instant Docket. Those customer class rates of return applied to the class allocation of rate base represents the basis for the customer class return component of the FRP class revenue requirements. It is a concern unwarranted and misleading to emphasize that the Council will adopt new class rates of return with FRP decoupling, other than adjustments to the composite revenue requirement which should not have any appreciable impact among customer classes. The Advisors' FRP full decoupling proposal is therefore in compliance with Resolution R-16-103 and should be accepted by the Council.

[530] Ex. No. ENO-42 at 22:3-4.
[531] Ex. No. ADV-5 at 27:17.
[532] *Id.* at 27:17-28:2.
[533] *Id.* at 28:6-17.
[534] *Id.* at 29:16-30:4.

D. New Voluntary Service Offerings and Billing Options

1. Summary of Proposals

ENO is proposing two new voluntary billing options in order to facilitate expanded choice and convenience for customers.[535] The two new proposed options are Pre-Pay Electric Service and the Fixed Bill Option.[536] ENO is also proposing several new products and services for Council approval, in order to give customers greater opportunities for the utilization of renewable energy and new energy-related technologies.[537] These include the Community Solar Offering, the Electric Vehicle Charging Infrastructure Offering, an d the Green Power Option.[538]

2. Demand Response Riders

Both ENO and BSI propose rates that would allow customers to be paid for actively reducing their load during key times.

a) ENO Proposal **-** *Extend MVLMR and MCDRR to All Customers*

ENO proposes to extend two of the riders previously in effect in the Algiers territory to all of its customers, the Market Valued Load Modifying Rider ("MVLMR") and the Market Valued Demand Response Rider ("MVDRR").[539] These riders provide the opportunity for qualified retail customers, or qualified aggregators of retail customers, to act as a load modifying resource (MVLMR) or a demand response resource (MVDRR), consistent with MISO-prescribed standards and requirements.[540] Demand response and load modifying resources are important facets of the Council's policy to expand demand side management in New Orleans,[541] and because these riders have already been implemented in Algiers, ENO has experience

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535 Ex. No. ENO-55 at 42.
536 *Id.* at 41.
537 *Id.* at 38.
538 *Id.* at 38.
539 *Id.* at 30.
540 Ex. No. ADV-3 at 64:13-18.
541 *Id.* at 64:18-20.

administering the Riders; therefore, the Advisors support ENO's proposal to expand the MVLMR and MVDRR to ENO's full service territory. The Advisors recommend, however, that because many customers will be unable to perform a cost benefit analysis of the investment they make by volunteering in the riders, ENO should provide support, such as providing a cost estimate from the MISO tariff and other related information regarding cost, to customers to help them make more informed decisions as to whether to voluntarily participate.[542]

b) BSI CLEP proposal

BSI proposes the adoption of three Customer Lowered Energy Pricing ("CLEP") rates, a CLEP residential rate, a CLEP non-residential rate, and CLEP community solar.[543] CLEP community solar is discussed below in Section II.D.6(b). Under the CLEP rates, a customer either earns a payment or incurs a charge every five minutes (called "CLEP5"). The customer earns a CLEP5 payment for each five minute period in which either (a) the customer purchases electricity from ENO when the current MISO price of energy is lower than ENO's cost to produce energy; or (b) the customer sells electricity to ENO when the current MISO price of energy is higher than ENO's cost to produce energy.[544] Conversely, the customer would incur a CLEP5 charge win each five-minute period that the customer either (a) purchases electricity from ENO when the MISO price for electricity is higher than ENO's cost to produce energy or (b) sells electricity to ENO when the current MISO price for energy is lower than the ENO's cost to produce electricity.[545] Customers would also earn monthly payments or incur monthly charges (called CLEPm) for providing or demanding power at nearly the same times the utility

[542] *Id.* at 65:4-9.
[543] Ex. No. BSI-1 at 6:13-16.
[544] *Id.* at 12:1-9.
[545] *Id.* at 12:9-13.

experiences its annual peak demand.[546] The CLEP5 payments and charges are summed monthly and added to the CLEPm payment or charge to produce a credit or charge on the customer's monthly bill.[547] It does not replace and otherwise has no effect on the customer's regular monthly bill under the customer's regular rate.[548] If CLEP results in a payment to the customer that exceeds the charges the customer owes on its monthly bill, the customer receives a monetary credit.[549] BSI states that the impact on other customers of the CLEP rate is mitigated by the inclusion of a 5% service charge on every CLEP transaction and by the fact that proper use of the CLEP rate by a customer will lower the average cost of electricity ENO incurs, while a CLEP customer that fails to modify their behavior and makes purchases or sales at the wrong time will only cause an increase in their own electricity bill.[550]

BSI argues that its CLEP rate would lower ENO's true cost of service to supply power, enhance reliability, appropriately assign demand charges to customers with higher than usual demand, correctly reflects residential customers' impact on demand and energy use, account for entities with a peak that differs from ENO's peak, provide economic benefit to customers who have heavily invested in storage, provide credits to EV owners who charge off peak, provide a financial incentive to install batteries, and generally cause customers to make choices that will lower demand.[551]

Whether the CLEP proposal will actually produce these benefits is uncertain. In addition, the design of CLEP is extremely complicated and not one that customers will easily be able to navigate. Customers are unlikely to be able to determine the relative positions of ENO and

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[546] *Id.* at 12:17-19.
[547] *Id.* at 16:11 and 17:1.
[548] *Id.* at 14:17-22.
[549] *Id.* at 15:15-17.
[550] *Id.* at 23:1-4.
[551] *Id.* at 23:16-26:4.

MISO's costs of producing electricity in five-minute increments. BSI is clear that CLEP customers who fail to successfully adapt their behavior to change as the relative positions of ENO and MISO's costs change would see an increase in their electricity bills. ENO opposes the CLEP proposal and argues that it appears to be substantially the same as to the proposal already rejected by the Council in Resolution Nos. R-16-106 and R-17-100.[552] The Advisors believe that the most likely outcome of implementing CLEP would be that most CLEP customers experience difficulty in managing their energy use and production in five minute increments, resulting in increased electricity bills and frustration. Therefore, the Advisors do not recommend that CLEP be adopted by the Council, particularly in light of the demand response opportunities available under Riders MVLMR and MVDRR.

3. Pre-Pay Billing

ENO proposed a Pre-pay Electric Service ("PES") Option and Pre-pay Gas Service ("PGS") Option (Schedules PES and PGS) which are prepaid billing options for residential customers.[553] ENO's proposal would be a voluntary billing option enabled by AMI and supporting technology.[554] Under the Pre-pay proposal, customers would make deposits into their electric or gas accounts via payment centers, online, by phone, or any other accepted method of payment.[555] Customers would be able to monitor their account balance online via mobile device or computer and by telephone, and customers would be able to set up account balance notices.[556] Pre-pay would require no deposit, and while service would be disconnected if the account balance reaches zero (subject to certain moratoriums) service could be restored quickly with no

[552] Ex. No. ENO-12 at 50:7-11.
[553] Ex. No. ENO-55 at 42.
[554] *Id.* at 42-43; Ex. No. ENO-19 at 4:20-5:2.
[555] *Id.* at 43; Ex. No. ENO-19 at 5:11-14.
[556] Ex. No. ENO at 43; Ex. No. ENO-19 at 5:14-15.

late fees or reconnect fees.[557] ENO argued that there are several benefits to pre-pay service for customers, including a greater sense of control, reduced potential for surprises, a more clear link between cause and effect for customers and elimination of the security deposit requirement.[558] The Advisors support the development of a pre-pay option for ENO customers. However, in its rejoinder testimony, ENO suspended its request for approval of the pre-pay option due to delays and increased complexity in the integration of the AMI customer web portal with the Company's legacy IT and billing systems.[559] ENO states that the expected additional integration and IT development efforts to fully deploy pre-pay service are more complex than were originally envisioned.[560] Because ENO has suspended this request, the Council need not consider ENO's pre-pay proposal at this time.

4. Fixed Billing

In its Application, ENO proposed a voluntary fixed billing option for residential customers under which, in exchange for paying a premium over what the standard residential service rate would be, customers receive a monthly fixed bill that will not change over the contract period.[561] The fixed rate would be reset at the end of each 12 month contract period based on actual usage, rate changes and other factors.[562] However, in response to the Advisors' testimony, ENO withdrew this proposal in its Rebuttal Testimony.[563] Therefore, the Fixed Billing proposal need not be addressed by the Council at this time.

[557] Ex. No. ENO-55 at 43; Ex. No. ENO-19 at 5:18-6:5.
[558] Ex. No. ENO-19 at 6:7-8:12.
[559] Ex. No. ENO-13 at 14:4-8.
Id. at 14:10-12.
[561] Ex. No. ENO-55 at 44.
[562] *Id.* at 44-45.
[563] Ex. No. ENO-21 at 2:10-11.

5. Green Power Option

a) ENO Proposal

ENO is proposing a "green pricing proposal" in this case consistent with Council direction in Resolution No. R-18-97.[564] Under ENO's proposed Green Power Option ("Rider GPO"), a voluntarily enrolled customer would be able to match some or all (*i.e.* 100%) of their electricity usage with renewable energy certificates ("RECs") sourced from renewable energy sources like wind and solar.[565] A REC represents the environmental benefits of 1 megawatt hour of renewable energy.[566] By purchasing and pairing RECs with their electricity service, retail customers can use and receive the benefits of that renewable electricity.[567] ENO argues that RECs are used across the country as a low-risk option to support renewable energy and meet renewable energy usage goals.[568] ENO's proposed Green Power Option would be open to all customers and allow them the option of matching 100%, 50%, or 25% of their electricity usage each month with RECs.[569] ENO explains that nationally, demand for green pricing options provided by utilities has increased substantially in recent years, and that, according to surveys conducted by ENO, approximately 36% of ENO's customers have expressed interest in participating in a green power option.[570]

The offering will be certified by "Green-e", an independent consumer protection organization that offers certification and verifies the integrity of RECs through the entire chain of custody, so customers can be confident in their purchase.[571] It will be available to all customer

[564] Ex. No. ENO-55 at 41, Ex. No. ENO-19 at 41:4-16.
[565] Ex. No. ENO-55 at 41, Ex. No. ENO-19 at 40:9-11.
[566] Ex. No. ENO-55 at 41, Ex. No. ENO-19 at 40:13-15.
[567] Ex. No. ENO-55 at 41.
[568] Ex. No. ENO-55 at 41, Ex. No. ENO-19 at 40:18-41:2.
[569] Ex. No. ENO-55 at 41, Ex. No. ENO-19 at 43:15-17.
[570] Ex. No. ENO-19 at 41:17-42:12.
[571] *Id.* at 44:1-4.

classes and there will be no limit on the number of customers that can participate.[572] Under ENO's proposal, there will be no minimum contract term for participation, though customers who withdraw will not be eligible to return until after the seventh month following their withdrawal.[573] Customers would be allowed to change their election no more than one time in any six month period.[574] ESI's System Planning and Operations Organization ("SPO") would acquire and retire the RECs associated with the Green Power Option.[575]

The price for the Green Power Option would incorporate REC prices (as driven by the national market), a small contingency to account for fluctuations in REC prices and vendor support costs related to customer enrollment, customer education/marketing, and Green-e certification.[576] ENO proposes the following charges for each of the three options:[577]

Option	**GPO Election**	**Rate (per kWh)**
Tier One Option	25%	$0.015 per kWh
Tier Two Option	50%	$0.0125 per kWh
Tier Three Option	100%	$0.01 per kWh

The options would be priced at different amounts in order to encourage customer to choose to offset more of their usage with renewable energy.[578] ENO's proposed pricing is based on assumptions regarding participation levels over the first three years, and to the extent that actual participation levels and costs are significantly different than ENO's assumptions and/or

[572] Ex. No. ENO-19 at 44:18-21 and 45:18.
[573] *Id.* at 46:6-10.
[574] *Id.* at 46:13-14.
[575] *Id.* at 47:3-9.
[576] *Id.* at 47:12-21.
[577] *Id.* at 48:6-10.
[578] *Id.* at 48:12-14.

change over time, ENO would seek pricing adjustments, though ENO does not anticipate that adjustments would be needed frequently.[579]

Under ENO's proposed rate, a 1,000 kWh per month customers (which is approximately the average residential customer) who chose the 100% Green Power Option would experience a surcharge on their bill of approximately $10/month.[580] ENO would profit from Rider GPO, but not materially or over the long term, and the estimated O&M costs related to the GPO Rider do not constitute a substantial risk to ratepayers should ENO's actual costs be less.[581] Any collections in excess of actual expenses would be corrected for prospectively as part of any FRP evaluation.[582] The Advisors recommend that the Council approve Rider GPO because it presents a valuable option for ratepayers who wish to offset the environmental impact of their electricity consumption while imposing substantially no costs or risks to non-participants.[583] The Advisors also recommend that the Council evaluate the programs' actual costs of operation as part of future rate actions, such as FRP evaluations, and take any further appropriate action at that time, including adjustments to Rider GPO's rates.[584]

6. Community Solar

ENO and BSI both propose some form of community solar program or pricing in this case. ENO proposes its Community Solar Offering ("Schedule CSO") while BSI proposes its CLEP community solar rate.

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[579] *Id.* at 49:6-11.
[580] Ex. No. ADV-6 at 71:13-14.
[581] *Id.* at 71:16.
[582] *Id.* at 71:18-72:1.
[583] *Id.* at 72:6-9.
[584] *Id.* at 72:12-15.

a) *ENO Proposal*

ENO proposes a new community solar offering whereby participants voluntarily pay for a specific allocation of offsite solar PV projects, and in return for an upfront or ongoing payment, the participant receives a credit on his or her monthly electric bill, tied to the actual output of the solar PV project.[585] ENO proposes to use both its existing ~1 MW_{AC} solar project located at the Paterson site along with the recently approved 5 MW_{AC} rooftop solar project.[586] ENO argues that using existing projects allows interested customers to sign up for a program based on real-life systems as opposed to having to wait until enough interest has been expressed before ENO can move forward with constructing a resource to support community solar.[587] ENO's proposed program would be open to both residential and non-residential customers on non-lighting rate schedules, subject to a few limitations.[588] ENO has designed its proposal as a "pay-as-you-go" model to maximize participation.[589] The monthly charge is fixed for the duration of the offering and is set at $15.00 per kW_{AC} based on the customer's allocated share in kW.[590] This rate is designed to cover the incremental costs associated with using an outside vendor to get ENO's community solar offering up and running, as well as the monthly bill credits that customers receive for participating; it is not meant to cover the upfront and ongoing costs of the solar assets that underpin the offering - those costs will be reflected in overall rates that all customers pay.[591] The credit rate that is applied to the customer's allocated share of the actual output of the solar systems that underpin the community solar offering is based on two components: the historic embedded value of generation, which is adjusted from time to time, and the current FAC

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585 Ex. No. ENO-55 at 39.
586 Ex. No. ENO-10 at 41:16-18.
587 *Id.* at 41:20-42:3.
588 *Id.* at 42:15-17.
589 Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 43:19-20.
590 Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 44:1-3.
591 Ex. No. ENO-10 at 44:10-22.

value.[592] Any verified RECs produced by the solar systems that underpin the offering belong to ENO, will be retired each year, and will not be transferred in any manner to subscribing customers.[593]

One of the principles established by the Council with regards to community solar programs was the principle of a level playing field. In Resolution No. R-18-223, the Council specifically indicated that:

> In order to ensure a level playing field, to the extent that ENO chooses to become a community solar developer, it must offer the same privileges it allows itself to all other developers. ENO may not give itself preferential treatment as a developer of a community solar project, and may not use ratepayer funding for its community solar projects in any manner not available to other developers.[594]

ENO's proposed Community Solar Offering may result in preferential treatment for ENO that may discourage other Community Solar developers from developing projects in New Orleans under the Council's Community Solar Rules.[595] Under ENO's proposal, it is ensured to recover its prudently incurred costs of any solar projects, regardless of the number of subscribers its Community Solar Offering has, or whether the fees and credits for its participants fully offset the costs of the projects.[596] This is an advantage that other community solar developers will not have - they will have no guarantee that they will fully recover their costs if they are not able to attract a sufficient number of subscribers or charge a high enough price. While it may (or may not) be true that approving ENO's Community Solar Offering could bring community solar to New Orleans faster than allowing the market to form naturally under the Council's Community Solar Rules, it may permanently impair the market by preventing competing developers from being able to compete with ENO. Essentially, ENO's proposed Community Solar Offering

[592] Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 45:3-8.
[593] Ex. No. ENO-10 at 49:11-13.
[594] Resolution No. R-18-233 at 3.
[595] Ex. No. ADV-1 at 44:12-15.
[596] *Id.* at 44:16-20.

monthly charge is designed to recover incremental administrative and marketing costs and the cost of providing solar credits to all potential participants at the retail rate.[597] The Community Solar Rules clearly state that the capital and operating costs of a community solar garden facility will not be recovered from ratepayers, but rather those costs are the responsibility of the developer/owner of the community solar garden to be recovered from the participants in it.[598] ENO's proposal violates this, by requiring ENO ratepayers to pay for a portion of the facilities' fixed costs.[599]

In addition, ENO's proposed credit for community solar is valued differently than the credit in the Council's Community Solar Rules.[600] It would be preferable to have only one methodology for determining the appropriate credit for community solar offerings.[601]

b) BSI Proposal

BSI proposes a CLEP solar rate where the customer would receive the sum of the monthly kWh produced by the customer's share of the community solar project multiplied by ENO's cost of energy plus the customer's CLEPm payment or charge plus the monthly sum of the customer's CLEP5 payments and charges.[602] This would be instead of the community solar payments set by the Council's Community Solar Rules.[603] However, while BSI admits that its proposal would not be consistent with the Council's Community Solar rules, BSI makes no attempt to demonstrate to the Council why its Community Solar proposal would provide greater benefits than a proposal that complies with the Council's rules. In addition, the CLEP

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[597] Ex. No. ADV-3 at 72:4-6.
[598] *Id.* at 72:17-73:1.
[599] *Id.* at 73:1-9.
[600] Ex. No. ADV-1 at 45:2-9.
[601] *Id.* at 45:9-10.
[602] Ex. No. BSI-1 at 17:16.
[603] *Id.* at 18:3-6.

community solar proposal is too complex to be easily understood or implemented by customers. Therefore, the Advisors do not recommend that the Council implement CLEP community solar.

In adopting its Community Solar Rules, the Council explicitly left open the opportunity for parties to propose community solar projects that do not directly conform to the Council's rules and set forth a requirement that parties proposing such a program demonstrate why the alternative proposal brings greater benefits than a proposal conforming to the Community Solar Rules would bring.[604] However, neither ENO, nor BSI have demonstrated to the Advisors' satisfaction that their community solar proposals provide greater benefit to ratepayers than a community solar project structured under the Council's would. Therefore, the Advisors recommend that the Council not approve either community solar proposal as part of this rate case.

ENO acknowledges that its proposed Community Solar Offering Rider is not in conformance with the draft rules and states that it was not intended to be, since its efforts to develop a community solar offering began before the Council opened its rulemaking docket.[605] ENO argues that it is not fair to apply such rules retroactively and that its offering will give customers earlier access to community solar.[606] However, although ENO may have been working internally to develop its own community solar proposal, it did not communicate its intent in either the proceeding seeking approval of the 1 MW Paterson solar facility or the 5 MW commercial rooftop solar project, nor did it file a community solar counter-proposal to the community solar proposal made by the Advisors in the docket regarding the 5 MW commercial rooftop solar project.[607] Moreover, in light of the Advisors' proposal in that proceeding, which

[604] *See* Resolution No. R-18-538, at 30-31.
[605] Ex. No. ENO-12 at 38:10-13.
[606] *Id.* at 38:21-39:4.
[607] Ex. No. ADV-5 at 34:10-35:14.

did not require ratepayer funding, ENO should have been aware that the Advisors would likely oppose proposals where ENO used ratepayer funding to subsidize a community solar project, as they propose to do in the instant proceeding. Moreover, the Council is not obligated to approve ENO's community solar project simply because ENO proposed it before the Council adopted its own community solar rules. The Council must still review ENO's community solar proposal to ensure that it is just and reasonable and not unduly burdensome or preferential. While the Advisors are concerned that the proposal does not conform to the Council's community solar rules, regardless of whether the rules are applied to ENO or not, allowing ENO to use ratepayer funding to subsidize the costs of community solar violates the principle of cost causation and gives ENO a distinct competitive advantage over other developers that may want to develop community solar projects in the City in a way that could ultimately adversely affect the long term growth of community solar in New Orleans.[608] The Advisors do not believe that the potential near-term benefits of having some form of community solar available to ratepayers more quickly and allowing ENO to gain some experience administering a community solar program will be significant enough to offset the potential damage to the long-term market.[609]

ENO also argues that it has attempted to justify its Community Solar Offering in this proceeding and that ENO is entitled to an adjudication on the merits of its proposal in this proceeding based on any regulatory requirements that existed at the time the proposal was filed.[610] ENO argues that customers who enroll in its program would be able to switch to other developers later without any penalties if the Council's community solar initiative ultimately attracts any, and would allow ENO to gain experience with the administration of a community

[608] *Id.* at 36:13-17.
[609] *Id.* at 37:11-19.
[610] Ex. No. ENO-12 at 39:6-9, Ex. No. ENO-13 at 12:12-13:18.

solar offering before the Council's initiative gets under way.[611] ENO also argues that it may reduce the incremental costs of administering the Council's program, thus benefitting those customers as well.[612] ENO argues that its proposal will bring greater benefits than the Council's Community Solar Rules because (1) it will not require the Council or CURO to create additional regulatory mechanisms for the oversight of ENO's proposed rider; (2) it provides the opportunity for customers to participate in "Utility-Scale" offerings that could help to offset the revenue requirements associated with ENO's commitment to add up to 100 MW of renewable energy to its generation portfolio; (3) it would mean that customers have a community solar option in a more timely manner.[613] ENO argues that it would be counterproductive and wasteful for the Council to reject ENO's proposal.[614]

The Advisors do not believe that ENO has presented sufficient evidence to demonstrate that the benefits brought by its proposed community solar project would be so much greater than the benefits from projects conforming to the Council's Community Solar Rules as to offset the potential damage to the long-term growth of community solar, and therefore do not recommend that the Council approve the project as part of the instant proceeding. However, the project has sufficient potential that the Advisors do recommend that ENO be given another opportunity, in a separate proceeding, to demonstrate that its project would produce greater benefits than projects conforming to the Community Solar Rules.[615]

[611] Ex. No. ENO-12 at 39:16-22.
[612] *Id.* at 39:22-40:3.
[613] *Id.* at 41:9-42:8.
[614] *Id.* at 44:12-13.
[615] Ex. No. ADV-5 at38:7-15.

7. EV Charging Infrastructure

a) ENO Proposals

ENO proposes two different concepts designed to expand access to EV charging infrastructure in New Orleans and which would complement an offering currently available to residential customers.[616] ENO also proposes a separate initiative involving rebates for customer-owned EV charging infrastructure.[617]

(1) Rider Schedule Electric Vehicle Charging Infrastructure ("EVCI")

The first concept, available to non-residential customers, would involve ENO constructing, owning, and operating EV charging infrastructure on customer-owned property.[618] In return, the customer would pay a fixed amount each month tied to a percentage specified under the proposed Rider Schedule EVCI and the installed cost of the equipment, less (1) the value of a 30% tax credit available from the State of Louisiana and (2) an estimated level of near-term, non-fuel revenue.[619] ENO argues that there are several benefits to non-participating customers: (1) new revenues from charging usage helps recover fixed costs on ENO's system and other costs, and thus helps control rates for all of ENO's customers; (2) only the participating customer is paying for the dedicated EV charging facilities; (3) to the extent the customer uses the program to provide public EV charger access (such as at a shopping mall or parking lot), non-participants who live in New Orleans and own or lease an EV would benefit from increased access; and (4) expanding access to EV charging infrastructure would provide important environmental and other public policy benefits.[620] ENO's Rider Schedule EVCI was

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[616] Ex. No. ENO-55 at 40.
[617] Ex. No. ENO-10 at 58:5-7.
[618] Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 58:8-14.
[619] Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 59:9-12.
[620] Ex. No. ENO-10 at 60:18-61:4.

based on ENO's existing Rider AFC with adjustments made for the expected useful life of EV infrastructure, EV-specific inputs, and the concept that ENO will estimate incremental revenues from EV charging and will correspondingly adjust the overall installed cost applied to the rider.[621] O&M expenses associated with each installed facility will be negotiated with the customer based upon the characteristics of their installation and the specific level of ongoing services they desire, and will be included in the agreement with the customer and added to the amount billed during the first 10 years.[622] Customers who take advantage of this program will be able to provide access to the chargers to their employees, customers, and/or tenants without issue, including being able to charge a fee for use of the charger.[623]

The Advisors' review of ENO's Rider EVCI proposal indicates that it is properly constructed.[624] The rider would be entirely voluntary to ratepayers and would not impose any material costs on non-participant ratepayers.[625] The proposed Rider EVCI is consistent with the theory underlying Rider AFC, which the Council has already approved.[626] There appears to be no reason to expect that Rider EVCI would prevent ratepayers from funding their own EV charging stations; a commitment under Rider EVCI is entirely voluntary; however, the Council may wish to make clear to ENO that similar new meter installations are appropriate for ratepayer-funded EV charging stations, subject to all of ENO's service standards.[627] The Advisors recommend that the Council approve Rider ECVI-1 as proposed by ENO, and specifically note that it is not to be applied prejudicially to ratepayers who choose to construct

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[621] *Id.* at 61:8-20.
[622] *Id.* at 62:6-18.
[623] *Id.* at 64:19-21.
[624] Ex. No. ADV-6 at 94:10-11.
[625] *Id.* at 94:11-12.
[626] *Id.* at 94:12-14.
[627] *Id.* at 94:19-95:1.

EV charging stations outside of Rider EVCI in terms of vendor selection, provision of related electric service, and financing services.[628]

(2) Public EV Charging Infrastructure Offering

ENO's second proposal would be available to public institutions and would involve ENO constructing, owning, and operating EV charging infrastructure solely for public use at a handful of key locations in New Orleans.[629] ENO would collaborate with City officials to determine optimal locations for the EV chargers, which could include downtown City-owned right-of-way, public libraries and schools, parks, and other recreational areas.[630] ENO is proposing to invest up to $500,000 over the next 24-30 months to build out EV charging infrastructure on public property that would be made accessible to electric vehicle drivers.[631] ENO is proposing to recover the capital investment and related expenses in retail rates through the normal ratemaking process.[632] ENO is proposing that no additional fee or charge be levied on any EV driver for using the charging equipment regardless of where the EV charger is located relative to a customer's meter.[633] The City or other public entity that owns the property may charge for parking, but ENO would not impose an additional fee or charge related to using the EV charger or the electricity dispensed by the equipment used to charge the EV's battery.[634] ENO anticipates that the cost of the electricity provided in this manner would be small, and for locations where the charging equipment is not behind the customer's meter, ENO proposes that the value of electricity not being billed to the EV drivers would be reflected in ENO's FAC in

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[628] *Id.* at 95:19-96:2; Ex. No. ADV-2 at 50:6-8.
[629] Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 58:15-15-17.
[630] Ex. No. ENO-55 at 40-41; Ex. No. ENO-10 at 58:17-20.
[631] Ex. No. ENO-55 at 41; Ex. No. ENO-10 at 58:22-23.
[632] Ex. No. ENO-55 at 41; Ex. No. ENO-10 at 67:16-19.
[633] Ex. No. ENO-10 at 68:3-5.
[634] *Id.* at 68:5-8.

the same way that unaccounted-for energy from line losses and other forms of non-technical losses are treated today.[635]

Advisors recommend that ENO's proposal to invest $500,000 building EV charging stations be taken up in the Council's EV docket, UD-18-01.[636] The Advisors support EV charging stations installed behind the ratepayer meter, where the ratepayer pays ENO for the electricity consumed and then makes a decision as to whether and how much to charge users of the EV charging stations to charge their cars.[637] The Advisors support the ability of such ratepayers to offer amenities, such as free EV charging, that the ratepayer deems valuable to their business or purpose, and do not view free EV charging offered in this context as anti-competitive.[638]

By way of contrast, however, the Advisors do believe that ENO's proposal to build some charging stations in front of the customer meter (where use is not measured or paid for) and to offer charging for free to EV drivers with the costs rolled into ENO's rates and borne by all ratepayers is problematic. First, the generally accepted regulatory ratemaking principle of cost causation does not support socializing one ratepayer group's (*i.e.*, EV charging station users) costs among other groups (*i.e.*¸ all other ratepayers), even if the subsidy is small, it is not appropriate to require other ratepayers to pay for an EV charger customer's electricity.[639] Second, free EV charging offers an incentive for EV owners to avoid charging where energy is not free, such as at home.[640] Further, since EV owners reasonably could be expected to prefer free EV charging stations over those that charge a fee, non-ENO EV charging station providers

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[635] *Id.* at 68:8-15.
[636] Ex. No. ADV-6 at 101:17-102:3.
[637] *Id.* at 100:12-15.
[638] *Id.* at 100:12-15.
[639] *Id.* at 99:4-7. Advisors' witness Watson calculates the amount to be socialized in this manner as possibly being as high as $64,432, ENO witness Owens argues that it would be only a fraction of that amount. Ex. No. ENO-12 at 46:3-21.
[640] Ex. No. ADV-6 at 99:7-9.

could be deterred from installing EV charging stations near an ENO free EV charging station.[641] Adding EV charging stations is consistent with the Council's goals and policies regarding Smart Cities and environmental benefits for New Orleans; however, rather than having the Council decide an issue that could have such a significant impact upon the market for EVs in New Orleans as part of this rate case, the Advisors initially recommend that the issue of whether ENO should install EV chargers and/or offer free charging to the public should be taken up in the EV Docket, UD-18-01, where stakeholders with an interest in encouraging EVs in New Orleans will have better opportunity to participate in the discussion.[642]

ENO argues that any costs borne by all ratepayers for EV drivers receiving free charging would be very small, particularly at the beginning while so few EVs are currently on the road.[643] ENO also states that if the Council were to approve the proposal, but order ENO to develop a method of charging EV drivers for using the public chargers that are not located behind an electric meter, the Company would develop a methodology for charging EV drivers (*e.g.*, by time spent charging).[644] While the Advisors and ENO may disagree on the exact potential amount of costs that might be borne by non-participating ratepayers, the Advisors do agree with ENO that the harm of the proposed program would be minimal.[645]

With respect to the Advisors' proposal that the issue be considered not in this proceeding, but in UD-18-01, ENO proposes that the issue of ENO's investment be separated from the issue of where to locate the EV chargers, and that Docket UD-18-01 might be the forum in which ENO, the City and the stakeholders could collaborate as to where to locate the estimated 30 to 50

[641] *Id.* at 100:8-10.
[642] *Id.* at 100:16-102:3.
[643] Ex. No. ENO-12 at 46:3-21.
[644] *Id.* at 46:21-47:2.
[645] Ex. No. ADV-8 at 51:2-4.

Level 2 chargers that ENO would construct and operate.[646] The Advisors agree with ENO's proposal and recommend that ENO be allowed to proceed with its proposed $500,000 investment with siting of the charging stations to be considered as part of Council Docket No. UD-18-01.[647]

ENO's proposal that the Council authorize ENO to invest up to $500,000 in public EV charging infrastructure in the instant proceeding and then use Council Docket NO. UD-18-01 to engage stakeholders where best to cite ENO's proposed EV chargers is reasonable and mitigates the Advisors' concerns, particularly in light of Council's stated interest in promoting environmental benefits, the limited scope of ENO's specific investment proposal, and the minimal amount of socialized costs.[648] The Advisors, therefore, recommend that the Council authorize ENO's proposed investment of up to $500,000 in public EV charging infrastructure that would provide free EV charging services at roughly 30-50 locations and consider any stakeholder input as to the siting of such locations in Council Docket No. UD-18-01.[649]

(3) Rebate for EV Charger Installation

ENO also proposes to continue with its Electric Technology initiative ("eTech") under which it provides a $250 rebate to qualifying customers to partially offset the costs they incur to install Level 2 EV chargers at their home or business.[650] In return for the rebate, ENO requires certain basic information such as paperwork proving the installation was made including the total installed cost of the Level 2 charger, the make and model of the equipment, etc.[651] In addition, the customer agrees to provide ENO with access to verify the EV charger installation.[652] ENO argues that the program is beneficial, because it allows ENO to know which of its customers

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646 Ex. No. ENO-12 at 48:1-11.
647 Ex. No. ADV-8 at 51.
648 *Id.* at 51:9-14.
649 *Id.* at 51:18-52:3.
650 Ex. No. ENO-10 at 69:9-12.
651 *Id.* at 69:12-15.
652 *Id.* at 69:15-16.

have installed a Level 2 charger, and to periodically get data about impacts on electric load including hours of the day, possible frequency of charging, and so forth.[653] Knowing where EV chargers are located on its system and being able to perform analysis could help with grid planning and maintain reliability and also help inform how grid modernization can help to accommodate increased penetration of EVs.[654] ENO could also periodically survey participating customers to better understand their real-world experience as EV drivers in New Orleans, what actions they would like to see taken by ENO and/or the City to expand access, etc.[655]

The Advisors also support ENO's proposed EV charger rebate program. A Level 2 charger may be considered a load-modifying resource when used off-peak, which can generate benefits for all ratepayers reflected in MISO charges and credits.[656] Because Level 2 chargers can be viewed as DSM and, when used off-peak, are likely to utilize less carbon-intensive production resources, the Advisors believe that encouraging Level 2 EV chargers through a rebate program is consistent with the Council's policies on energy efficiency and environmental benefits.[657] The Advisors also believe that because EV chargers may be considered energy efficiency or DSM measures, it would be most appropriate to fund them through the Energy Smart Program, going forward, but recognizing that the earliest such a mechanism would be in place would be for Energy Smart Program Year 2020, the Advisors recommend that in the interim, the Council authorize ENO to continue its $250 per Level 2 charger rebate program, and that any related cost recovery proposal be considered through the FRP mechanism.[658] ENO argues that the eTech efforts are efforts at electrification (conversion of equipment that uses

[653] *Id.* at 69:16-19.
[654] *Id.* at 69:19-70:2.
[655] *Id.* at 70:3-70:6.
[656] Ex. No. ADV-6 at 96:16-97:1.
[657] *Id.* at 97:1-4.
[658] *Id.* at 97:6-98:5.

fossil fuel to electric), which ultimately increases electricity usage, and therefore should not be considered energy efficiency measures and funded through the Energy Smart program.[659] ENO argues that the costs should be recovered through normal ratemaking.[660]

E. Other Miscellaneous Issues

ENO is proposing that the Council approve of certain modifications to the Service Regulations Applicable to Electric and Gas Service by ENO.[661] The proposed modifications vary in purpose: addressing minor modifications necessary to reflect the changing nature of service due to innovations such as the impending deployment of AMI and new customer offerings and billing options the Company proposes to make available to customers[662] as well as the combination of the Algiers and Legacy ENO service territories into a single territory.

1. <u>Datalink and Other Related Riders Changing due to AMI</u>

ENO proposes to modify Datalink and related riders to take into account deployment of AMI.[663] Datalink is an optional service that provides a customer with web-based viewing access to the customer's interval load data.[664] Because the deployment of AMI also includes this service, ENO proposes to amend the Datalink Rider to eliminate the two-year minimum term once a customer receives an AMI meter so that a customer may cancel the Datalink Rider upon receipt of an AMI meter, regardless of whether or not the 2-year minimum has been met.[665] ENO notes that once AMI has been fully deployed, it may be necessary to further modify this rider.[666]

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[659] Ex. No. ENO-12 at 49:3-16.
[660] *Id.* at 49:16-18.
[661] Ex. No. ENO-55 at 45.
[662] *Id.* at 45-46.
[663] *Id.* at 32.
[664] Ex. No. ENO-6 at 56:18-19.
[665] *Id.* at 56:19-57:5.
[666] *Id.* at 56:5-7.

Rider Schedule RCL provides for a communications link between ENO's meter and a customer's premises to provide access to the meter data.[667] With the deployment of AMI, this rider will no longer be necessary, and since there are currently no customers participating in RCL, the Company proposes to close and discontinue Schedule RCL.[668]

The Advisors have reviewed ENO's proposal and have no objection to it.

2. Service Regulation Amendments

a) ENO Proposal

ENO proposes certain minor modifications to its Service Regulations to reflect current practices, add new definitions, requirements and modifications necessary to reflect the changing nature of service (such as AMI, and the new offerings)[669]. Such minor modifications include changes such as updating listings for ENO's website, updating hours of Customer Service centers, and job titles for certain employees, updating certain definitions to reflect AMI deployment, and language that separately references East Bank and West Bank customers, and eliminating outdated or duplicative language.[670]

ENO also proposes to make some more significant changes to its Service regulations to reflect changes to the nature of service due to AMI deployment and/or the transition to multiple, digitally-based options for customers to communicate with ENO, which in many cases eliminates the need for paper-based communications.[671] With regard to AMI, ENO proposes changes to the language that discusses techniques for providing estimated bills, meter relocations, and meter tests to customers, which would be different following AMI.[672] It also

[667] *Id.* at 57:12-13.
[668] *Id.* at 57:13-16.
[669] *Id.* at 59:4-9.
[670] *Id.* at 59:18-60:8.
[671] *Id.* at 60:14-17.
[672] *Id.* at 60:17-20.

proposes the elimination of the "Self-Read" program, which is used by fewer than 25 customers and would no longer be needed following full deployment of AMI.[673]

ENO also proposes to modify the Service Regulations to broaden the definition of "Written Communications" to reflect the new array of digital communications that will be available to customers to allow customers more choice in how they receive communications from ENO and to allow their choice to apply to all ENO communications.[674]

ENO is also proposing to modify its Service Regulations to provide ENO with options to remedy issues related to ENO's ability to access customers' premises to all situations in which ENO access to the premises is necessary, rather than limiting the remedy solely to meter-reading issues (i.e. to also grant ENO a remedy where ENO needs access to a customer's property for other legitimate purposes, such as to install, maintain or remove its equipment, to connect or disconnect service, etc.).[675]

Finally, ENO proposes changes to its Service Regulation to reflect the addition of new customer offerings and payment offerings being proposed in this rate case.[676]

b) Intervenor Positions

Air Products opposes ENO's proposed change to Section 11 Continuity of Service, which would excuse ENO from responsibility for loss or damages caused by the failure or other defects of Service when the failure is not reasonably avoidable or is due to unforeseen difficulties or causes beyond its control.[677] Air Products asks the Council to reject this change as inappropriate.[678]

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[673] *Id.* at 60:20-61:2.
[674] *Id.* at 61:3-10.
[675] *Id.* at 61:11-25.
[676] *Id.* at 62:1-6.
[677] Ex. No. AP-3 at 25:8-18.
[678] *Id.* at 25:18-19.

c) Advisors' Position

The Advisors agree with Air Products' stated concern. ENO should continue to be held responsible for failure of Service that is reasonably avoidable, due to foreseeable difficulties or causes within its control. The Advisors recommend that the Council reject this change.

3. Update of Fees for Certain Service Schedules

ENO is proposing to update fees for Rate Schedules MES (Miscellaneous Electric Services) and MGS (Miscellaneous Gas Services), which capture fees associated with service provided beyond the normal requirements of providing electric and gas service; changes to Schedule EOES (Extension Of Electric Service policy) and changes to EOGS (Extension of Gas Service policy) to more closely align with Schedule EOES.[679]

In addition to having a single, consolidated schedule for all ENO customers (as opposed to separate schedules for Algiers), ENO is proposing changes to Rate Schedule MES for the Suspended Service Reconnection Charge, Temporary Service Connection Charge and Meter Test Charge.[680] In addition, the connection charge that was applicable to Algiers customers would be removed.[681] For Rate Schedule MGS, ENO is proposing changes to the Suspended Service Reconnection Charge and Meter Test Charge.[682] ENO is also proposing to adjust the Deposit charges referenced in both Rate Schedules MES and MGS.[683] ENO states that its proposed changes will more closely align the fess with the costs of providing these services, and thus will allow customers who use a particular service to pay the associated costs for such services.[684]

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[679] Ex. No. ENO-55 at 46.
[680] Ex. No. ENO-6 at 52: 14-17. The Suspended Service Reconnection Charge applies to reconnecting an existing account that has been disconnected, the Meter Test Charge is a charge for a meter test performed upon the request of a customer, and the Temporary Service Charge is a charge for a temporary service connection requested by a customer (such as for construction). Ex. No. ENO-6 at 53:3-16.
[681] Ex. No. ENO-6 at 52:17-18.
[682] *Id.* at 52:18-19.
[683] *Id.* at 52:19-21.
[684] *Id.* at 54:2-4.

ENO also provided analysis identifying the cost components for each activity and calculating the weighted average total cost for each activity in order to support its proposed fee changes.[685] The Suspended Service Reconnection Charge for electric service will be reduced to $14.45 and for gas service it will be reduced to $14.39, with the fee for reconnecting both to be $24.98.[686] The Temporary Service Connection Change will be changed to $75.00 where distribution lines are readily accessible and no new poles or lines will need to be installed.[687] In other circumstances, it will be derived based on actual cost.[688] The meter Test charge for both electric and gas service will be reduced to $33.35.[689] The Deposit Charge for residential electric service will be adjusted to $215 based on the average electric bill multiplied by two to cover two months' service, and the similarly calculated gas Deposit Charge will be $70.[690]

With respect to the changes to Schedule EOES (the Extension of Electric Service Policy), the proposed changes amount to minor wording changes for the purposes of clarification.[691] The changes to Schedule EOGS (Extension of Gas Service Policy), ENO proposes minor word changes for clarification purposes, and to add language defining when customers would be required to make a contribution in aid of construction for installing a gas service line to match the electric service extension policy.[692] ENO proposes to require a contribution in aid of construction for installing a gas service line when (1) the gas service line exceeds 200 feet extending from the existing gas main piping; or (2) the gas service line will cost more than two times the customer's estimated projected annual revenue, excluding purchased gas costs.[693]

[685] *Id.* at 54:8-18, and HSPM Exhibit MPS-5.
[686] *Id.* at 55:3-6.
[687] *Id.* at 55:10-12.
[688] *Id.* at 55:12-15.
[689] *Id.* at 55:19-20.
[690] *Id.* at 56:2-8.
[691] *Id.* at 58:5-7.
[692] *Id.* at 58:11-14.
[693] *Id.* at 58:14-18.

When required, the amount of the contribution will be the amount by which the cost of the line extension exceeds two times the customer's estimated projected minimum annual revenue, excluding purchased gas cost, and grossed up for applicable income taxes.[694]

The Advisors have reviewed the proposed changes and have no objection to them.

4. Discontinuation of Certain Schedules

a) ENO Proposal

ENO proposes to withdraw all of its Algiers schedules and riders (except for the aforementioned Market Valued Load Modifying Rider and Market Valued Demand Response Rider) and to withdraw several obsolete base rate schedules (Master Metered Residential and Experimental Interruptible, Remote Communications Link Rider).[695]

ENO proposes to close several private lighting area lighting offerings to new customers including the Outdoor Directional Security Lighting rate schedule and the High Pressure Sodium Vapor 100 watt Outdoor Night Watchman rate schedule.[696] This would reflect the growing popularity of ENO's programs utilizing Light Emitting Diode ("LED") lighting as compared to the older High Intensity Discharger ("HID") programs.[697]

The withdrawal of riders no longer necessary because Algiers will no longer be served separately from the Legacy ENO territory is reasonable, therefore the Advisors support ENO's proposal to withdraw those riders. Similarly, the withdrawal of obsolete base rate schedules that are no longer being utilized is reasonable and the Advisors also support the withdrawal of those schedules.

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[694] *Id.* at 58:18-21.
[695] Ex. No. ENO-55 at 30.
[696] *Id.* at 45.
[697] *Id.* at 45.

The Advisors believe that the phasing out of HID programs as LED programs gain in popularity is consistent both with customer interests and with the Council's desire to continue to advance energy efficiency measures. Therefore, the Advisors support ENO's proposal to close those programs to new customers.

5. City of New Orleans Billing Issues

CCPUG witness Baron recommends that the Council require ENO to establish a working group, following completion of the rate case to address billing issues.[698] ENO opposes this recommendation, noting that CCPUG did not identify the aspects of billing that the City claims to be at issue, and recommends that instead the City work with its account representative to address any billing issues.[699] The Advisors agree that a working group likely is not necessary to resolve the City's concerns, and are willing to work with the City and ENO to assist in resolving these concerns to the City's satisfaction.

1. Tax Benefits Related to AMI

a) ENO Proposal

As part of the AMI deployment ENO must retire certain related existing plant, such as meters, prior to its full recovery through depreciation ("Stranded Plant").[700] The retirement of this Stranded Plant is associated with ENO's per-book recording of ADIT liabilities. In its Application, ENO incorrectly removed ADIT related to Stranded Plant from rate base in the amounts of $6,227,006 and $823,146 for electric and gas respectively.[701] Intervenors did not comment on ENO's exclusion of this ADIT from its rate base.

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[698] Ex. No. CCPUG-5 at 31:13-32:9.
[699] Ex. No. ENO-42 at 23:12-25:9.
[700] Ex. No. ADV-6 at 57:1-3.
[701] Ex. No. ADV-6 at 58, 11-13.

b) *Advisor Recommendation*

ENO's rates should reflect the economic benefit it enjoys due to cost-free capital. Out of an abundance of caution for ENO's unspecified "potential violations" of IRS normalization rules, an appropriate mechanism to recognize ENO's cost-free capital is a regulatory liability.[702] As the economic benefit to ENO of Stranded Plant ADIT is undisputed, the Advisors recommend the Council recognize the benefit to ENO of cost-free capital and direct ENO to create regulatory liabilities in the amount of $6,227,006 and $823,146 for electric and gas respectively and include those liabilities in ENO's regulatory rate base.[703]

III. <u>Conclusion</u>

In conclusion, the Advisors ask the Council to adopt each of the Advisors' recommendations as set forth herein, the highlights of which are presented below. The Advisors calculate that the combined application of these recommendations will result in annual revenue reductions compared to present revenues of $33.1 million and $3.8 million for electric and gas respectively. The Advisors additionally recommend that the Council:

- Allow ENO a ROE of 8.93% for both electric and gas.
- In the calculation of ENO's WACC for ratemaking purposes, employ an equity ratio equal to the lesser of ENO's actual equity ratio or 50%.
- Approve a 3-year Gas and electric FRP with electric revenue full decoupling, based on the Advisors' proposal, that evaluates all of ENO's costs and revenues when evaluating its earned-ROE.

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[702] Ex. No. ADV-8 at 37:2-3.
[703] *Id.* at 37:10-13.

- In each FRP evaluation, allow ENO to proform known and measurable cost adjustments through the twelve-months following the evaluation's test year, and billing determinants adjusted based on approve Energy Smart reduction targets.
- Upon NOPS's COD, an interim rate adjustment is approved as part of the electric FRP.

- Direct ENO to employ its then current WACC when setting Rider SSCO's rates, as was agreed to by ENO.[704]
- Approve a $10.00 electric residential customer charge.
- Maintain the current $12.50 gas residential customer charge.
- Approve the Advisors recommendations regarding NJ gas customers that provide for normalization of their regulatory treatment.
- Do not approve ENO's proposed RIM ROE enhancement mechanism.
- Do not approve ENO's proposal to exclude Stranded Plant ADIT (AMI deployment) from rate base, but rather reflect this cost-free capital as a regulatory liability in ENO's rate base.
- Do not approve ENO's proposal to exclude FIN 48 ADIT from its rate base.
- Do not approve ENO's proposal to increase its rate base through the inclusion of NOLCF ADIT assets.
- Do not approve ENO's proposed ARRT, but rather approve the Advisors' Algiers mitigation plan that avoids any Algiers revenue increase in the instant proceeding.
- Do not approve ENO's proposed AMI customer charges.
- Do not approve ENO's proposed GIRP rider.

[704] ENO-4 at 28:6-9.

- Do not approve ENO’s proposed DGM rider.
- Do not approve ENO’s proposed DSMCR rider, but rather approve a permanent EECR rider as recommended by the Advisors.
- Do not approve ENO’s proposed PPCACR rider, but rather approve Rider PPCR as recommended by the Advisors.
- Do not approve ENO’s proposed Community Solar Option in the instant proceeding.
- Approve ENO’s proposed realignment of rate structures, including the reduction in the number of rate classes and the harmonization of rates between Legacy ENO and Algiers.
- Allocate revenues among the rate classes according to the Advisors’ recommendations.
- Approve ENO’ proposed depreciation rates, as corrected by ENO.
- Approve riders FAC and PGA with corrections as noted by the Advisors
- Approve a combined MISO rider.
- Approve ENO’s proposed Green Power Option.
- Approve ENO’s proposed EVCR rider.

Respectfully submitted,

Jerry A. Beatmann, Jr. (Bar No. 26189)
Dentons US LLP
650 Poydras Street, Suite 2850
New Orleans, LA 70130
504-524-5446 (Office)
504-256-6142 (Cell)
jay.beatmann@dentons.com

Clinton A. Vince
Emma F. Hand
Presley R. Reed, Jr.
Dentons US LLP
1900 K Street, N.W.
Washington, D.C. 20006
202-408-6400 (Telephone)
202-408-6399 (Facsimile)
clinton.vince@dentons.com
emma.hand@dentons.com
presley.reedjr@dentons.com

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SERVICE LIST

Lora W. Johnson, lwjohnson@nola.gov
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112
(504) 658-1085 - office
(504) 658-1140 - fax
Service of Discovery not required

Erin Spears, espears@nola.gov
Chief of Staff, Council Utilities Regulatory Office
Bobbie Mason, bfmason1@nola.gov
City Hall - Room 6E07
1300 Perdido Street
New Orleans, LA 70112
(504) 658-1110 - office
(504) 658-1117 – fax

Andrew Tuozzolo, CM Moreno Chief of Staff, avtuozzolo@nola.gov
1300 Perdido St. Rm. 2W40
New Orleans, LA. 70112

David Gavlinski, 504-658-1101, dsgavlinski@nola.gov
Council Chief of Staff
City Hall - Room 1E06
1300 Perdido Street
New Orleans, LA 70112

Sunni LeBeouf, Sunni.LeBeouf@nola.gov
Michael J. Laughlin, mjlaughlin@nola.gov
Law Department
City Hall - 5th Floor
New Orleans, LA 70112
(504) 658-9800 - office
(504) 658-9869 - fax

Norman White, Norman.White@nola.gov
Department of Finance
City Hall - Room 3E06
1300 Perdido Street
New Orleans, LA 70112
(504) 658-1502- office
(504) 658-1705 – fax

ADMINISTRATIVE HEARING OFFICER

Hon. Jeffrey S. Gulin, judgegulin@gmail.com
3203 Bridle Ridge Lane
Lutherville, MD 2109
(410) 627-5357

NEW ORLEANS CITY COUNCIL CONSULTANTS

Clinton A. Vince, clinton.vince@dentons.com
Presley Reed, presley.reedjr@dentons.com
Emma F. Hand, emma.hand@dentons.com
1900 K Street NW
Washington, DC 20006
(202) 408-6400 - office
(202) 408-6399 – fax

Basile J. Uddo (504) 583-8604 cell, buddo@earthlink.net
J. A. "Jay Beatmann, Jr. (504) 256-6142 cell, (504) 524-5446 office direct,
jay.beatmann@dentons.com
c/o DENTONS US LLP
650 Poydras Street
Suite 2850

New Orleans, LA 70130

Joseph W. Rogers, jrogers@legendcgl.com
Victor M. Prep, vprep@ legendcgl.com
Byron S. Watson, bwatson@ legendcgl.com
Legend Consulting Group
6041 South Syracuse Way, Suite 105
Greenwood Village, CO 80111
(303) 843-0351 - office
(303) 843-0529 – fax

Errol Smith, (504) 284-8733, ersmith@btcpas.com
Bruno and Tervalon
4298 Elysian Fields Avenue
New Orleans, LA 70122
(504) 284-8296 – fax

ENTERGY NEW ORLEANS, LLC

Brian L. Guillot, 504-670-3680, bguill1@entergy.com
Entergy New Orleans, LLC
Vice-President, Regulatory Affairs
Polly S. Rosemond, 504-670-3567, prosemo@entergy.com
Derek Mills, 504-670-3527, dmills3@entergy.com
Keith Wood, kwood@entergy.com
Seth Cureington, 504-670-3602, scurein@entergy.com
Kevin T. Boleware, 504-670-3673, kbolewa@entergy.com
1600 Perdido Street, L-MAG 505B
New Orleans, LA 70112
504-670-3615 fax

Tim Cragin (504) 576-6571 office, tcragin@entergy.com
Alyssa Maurice-Anderson (504) 576-6523 office, amauric@entergy.com
Harry Barton (504) 576-2984 office, hbarton@entergy.com
Entergy Services, Inc.
Mail Unit L-ENT-26E
639 Loyola Avenue
New Orleans, LA 70113
(504) 576-5579 - fax

Joe Romano, III (504) 576-4764, jroman1@entergy.com
Suzanne Fontan (504) 576-7497, sfontan@entergy.com
Therese Perrault (504-576-6950), tperrau@entergy.com
Entergy Services, Inc.
Mail Unit L-ENT-4C
639 Loyola Avenue
New Orleans, LA 70113
(504)576-6029 – fax

350 NEW ORLEANS

Renate Heurich, 504-473-2740, renate@350neworleans.org
1407 Napoleon Ave,#C
New Orleans, LA, 70115

Andy Kowalczyk, a.kowalczyk350no@gmail.com
1115 Congress St.
New Orleans, LA 70117

ALLIANCE FOR AFFORDABLE ENERGY

Logan Atkinson Burke, logan@all4energy.org
Sophie Zaken, regulatory@all4energy.org
4505 S. Claiborne Ave.
New Orleans, LA. 70125

Susan Steven Miller, smiller@earthjustice.org
aluna@earthjustice.org
nthorpe@earthjustice.org
1625 Massachusetts Ave., NW, Ste. 702
Washington, DC 20036
202-667-4500

AIR PRODUCTS AND CHEMICALS, INC.

Katherine W. King, Katherine.king@keanmiller.com
Randy Young, randy.young@kean miller.com
400 Convention St. Suite 700
Baton Rouge, LA. 70802

Or
P.O. Box 3513
Baton Rouge, LA 70821-3513

Carrie R. Tournillon, carrie.tournillon@keanmiller.com
900 Poydras St., Suite 3600
New Orleans, LA 70112

John Wolfrom, 610-513-1388, wolfrojj@airproducts.com
7201 Hamilton Boulevard
Allentown, PA 18195

Maurice Brubaker, mbrubaker@consultbai.com
16690 Swigly Ridge Rd., Suite 140
Chesterfield, MO 63017
Or
P.O. Box 412000
Chesterfield, MO. 63141-2000

BUILDING SCIENCE INNOVATORS, LLC

Myron Katz, PhD., Myron.bernard.katz@gmail.com
302 Walnut St
New Orleans, La 70118
504-343-1243

Michael W. Tifft, mwtifft@mwtifft.com
710 Carondelet Street
New Orleans, La. 70130
(504) 581-4334

SEWERAGE AND WATER BOARD OF NEW ORLEANS

John H. Chavanne, 225-638-8922, jchav@bellsouth.net
111 West Main St., Suite 2B
PO Box 807
New Roads, LA 70760-8922
Fax 225-638-8933

Brian A. Ferrara, bferrara@swbno.org
Yolanda Y. Grinstead, ygrinstead@swbno.org
Legal Department
625 St. Joseph St., Rm 201
New Orleans, LA 70165
504-585-2154

CRESCENT CITY POWER USERS' GROUP

Luke F. Piontek, Lpiontek@,roedelparsons.com, Jsulzer@roedelparsons.com
Christian J. Rhodes
Shelley Ann McGlathery
Roedel, Parsons, Koch, Blache,
Balhoff & McCollister
1515 Poydras Street, Suite 2330
New Orleans, LA 70112

Lane Kollen (lkollen@jkenn.com)
Stephen Baron (sbaron@jkenn.com)
Randy Futral (rfutral@jkenn.com)
Richard Baudino (rbaudino@jkenn.com)
Brian Barber (brbarber@jkenn.com)
J. Kennedy & Associates
570 Colonial Park Dr., Suite 305
Rosewell, Ga. 30075

JUSTICE AND BEYOND

Rev. Gregory Manning, 913-940-5713, gmanning1973@yahoo.com
Pat Bryant, 504-905-4137, pat46bryant@yahoo.com
Happy Johnson, 504-315-5083, hjohnson1081@gmail.com
Sylvia McKenzie, sylkysmooth.sm@cox.net
c/o A Community Voice
2221 St. Claude Ave.
New Orleans, LA 7011

SIERRA CLUB

Grace Morris, 973-997-7121 Grace.Morris@sierraclub.org
4422 Bienville Ave
New Orleans, LA 70119

Dave Stets, 804-222-4420, Davidmstets@gmail.com
2101 Selma St.
New Orleans, LA 70122