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July 26, 2019

Via Hand-Delivery

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

Re: Revised Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief
City Council of New Orleans Docket No. UD-18-07

Dear Ms. Johnson:

Please find enclosed one original and two copies of the *Public Version* of the **Initial Brief of the Alliance for Affordable Energy and Sierra Club** in the above-captioned docket. Also, in a sealed envelope marked "Confidential – Highly Sensitive Protected Material," please find enclosed on original and two copies of the *Confidential Version* of the **Initial Brief of the Alliance for Affordable Energy and Sierra Club** in the above-captioned docket.

Thank you for your attention to this matter. Please contact me if you have any questions with regards to this filing.

Sincerely,

Susan Stevens Miller

Susan Stevens Miller (*pro hac vice*)
Clean Energy Attorney
Earthjustice
1625 Massachusetts Ave., NW, Ste. 702
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Enclosures
cc: Official Service List

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BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

INITIAL BRIEF OF THE

ALLIANCE FOR AFFORDABLE ENERGY AND SIERRA CLUB

PUBLIC VERSION

JULY 26, 2019

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I. Introduction

The Council of the City of New Orleans ("Council") faces a momentous decision. In Entergy New Orleans, LLC's ("ENO" or "Company") first rate application in ten years, ENO proposes to alter permanently the way customers are billed for electricity service. Having enjoyed excessive profits for years, the Company now asks the Council to abandon basic utility regulatory principles and *guarantee* ENO's profits for the foreseeable future. ENO's rate application guarantees the recovery of costs regardless of customer usage levels, adds to the cost burdens faced by low-income and low-use customers, and weakens the incentives for conservation inherent in rates.

The Company's collective requests are a remarkably aggressive attempt to lock in place fixed utility revenues. Many of the individual proposals conflict with supporting customer investments in energy efficiency and increasing customers' ability to control their energy bills. Moreover, ENO's individual proposals would operate in concert with one another to compound the ill effects of the requests while at the same time enhancing ENO's earnings. While the Company's individual proposals are each problematic in their own right, the total effect is even greater than the sum of the parts.

Imposing unavoidable charges is bad policy for conservation and the growth of markets for distributed energy services, for low users of electricity, and for achieving New Orleans' energy policy goals. The Company's proposals would encourage higher electricity consumption and reduce residential customers' ability to control their electric costs, with the greatest negative impacts falling on customers with lower incomes. In doing so, the proposals would directly increase the costs of meeting energy efficiency targets and indirectly contribute to higher system costs by increasing load growth and the potential need for future capital investments. ENO would benefit financially from such an outcome, but its ratepayers would not. The total effect is a reinforcing cycle of fixed charge escalation, dilution of customer efficiency incentives, and higher costs to achieve the same energy efficiency goals.

Furthermore, fixed charges and riders encourage utilities to increase spending in the cost categories that they are sure to recover through such charges. Because fixed customer charges and riders guarantee revenue recovery of any utility investments included in those mechanisms, they weaken any incentive ENO has to minimize these costs. "Once the leadership of a business finds out that it cannot lose, it can no longer be held accountable for the reasonableness of its decisions."[1]

The Alliance for Affordable Energy ("Alliance" or "AAE") and Sierra Club (collectively, "Public Interest Intervenors") intervened in this case, and have developed the recommendations described below because ENO's overearning must stop and the Company must be prevented from transferring its business risk to New Orleans ratepayers. Apparently, ENO believes that it should rapidly recover, and with certainty, every dollar that it spends providing utility service while it charges rates based on a return on common equity of 10.5% or higher. The Council must protect New Orleans' ratepayers and find that the majority of ENO's proposals are not in the public interest.

The Public Interest Intervenors are not contesting every proposal ENO makes in the Company's rate application. To conserve their limited and, in contrast to ENO, non-ratepayer supported funds, Public Interest Intervenors have to choose which issues to prioritize

[1] *All. for Affordable Energy, Inc. v. Council of City of New Orleans*, 578 So.2d 949, 973 (La. App. 4 Cir. 1991) (quoting Dr. Jeffrey Barach of Tulane University School of Business).

carefully.[2] As discussed below and in the testimony of Alliance witnesses Ms. Pamela Morgan and Mr. Justin Barnes, Public Interest Intervenors recommend that the Council take the following actions regarding ENO's rate application:

- ENO proposes what it calls a "decoupling" mechanism as part of its proposed Formula Rate Plan tariff. After showing that ENO's proposal will not accomplish decoupling, AAE recommends that the Council require ENO to file a tariff that accomplishes full revenue decoupling.

- ENO proposes almost double the residential customer charge, raising the charge from $8.07 to $15.53. The Company has failed to meet its burden of proof to justify any increase. Thus, AAE recommends that the Council reject any increase in the residential customer charge, giving New Orleans ratepayers their best shot at achieving the Council's hoped-for energy savings.

- ENO proposes a lost contribution to fixed costs ("LCFC"), allegedly to return to ENO revenues that it would have received *but for* its energy efficiency programs. As demonstrated by AAE, the LCFC is unnecessary and redundant in conjunction with full decoupling. Therefore, AAE recommends that the Council reject ENO's LCFC proposal.

- The Company proposes to establish a new Electric Advanced Metering Infrastructure ("AMI") Rider under which AMI costs would be recovered under an annually adjusted fixed monthly charge. AAE has demonstrated that the AMI rider is contrary to basic ratemaking principles and would lessen ENO's incentive to control the costs of the program. AAE recommends that the Council reject the Company's AMI rider.

- ENO requests approval of a community solar offering, through which participants can subscribe to shares of a community solar project. In order to obtain approval for a proposal that does not conform to the Community Solar Rules, ENO must demonstrate its non-conforming proposal would bring greater benefits to New Orleans residents than a proposal conforming to the rules. AAE recommends that the Council find not only that ENO's community solar offering does not offer greater benefits, but also that it is anticompetitive and will harm the New Orleans nascent community solar market. Therefore, the Council should reject ENO's community solar proposal.

[2] The decision to not address any specific ENO rate request should not be interpreted as support for that request.

- ENO proposes a Reliability Incentive Mechanism ("RIM"), which is a sliding, allowed return on equity from 10.5% to 11.0% for electric rate base based on ENO's System Average Interruption Duration Index ("SAIFI") performance. AAE recommends that the Council reject ENO's attempt to "do an end run" around its ongoing reliability investigation and refuse to reward ENO for conduct which it is otherwise obligated to undertake.

- ENO is requesting to provide a Green Power Option, under which participating customers would be able to match some or all of their electricity usage with renewable energy certificates ("RECs") generated or purchased by ENO and retired on the customer's behalf. AAE recommends that the Council specifically require ENO to define green power as including only renewable energy and that the tariff should expressly state that ENO cannot recover any of the costs of this program from ratepayers.

II. Procedural History

On September 28, 2017, the Council adopted Resolution No. R-17-504, which directed ENO to make a rate case filing before the Council on or before July 31, 2018. On July 31, 2018, ENO filed with the Council its Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and For Related Relief. The Council expressed concern over certain aspects of ENO's filing. These concerns led the Council to indicate its intent to direct ENO to make a supplemental filing.[3] In a letter dated August 15, 2018, Roderick K. West, Entergy Group President of Utility Operations, explained that ENO had decided to withdraw its July 31, 2018 Application, stating that this decision to withdraw was in response to the feedback that ENO received from members of the Council.

On September 21, 2018, ENO filed with the Council its Revised Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and For Related Relief ("Application").

[3] *See, e.g.*, Fox8, *Entergy New Orleans withdraws plan to hike electric bills* (Aug. 15, 2018), https://www.fox8live.com/story/38891313/entergy-new-orleans-withdraws-plan-to-hike-electric-bills/.

On October 4, 2018, as part of Council Resolution No. R-18-434, the Council docketed ENO's Application as Docket No. UD-18-07. The Council also directed the filing of several rounds of testimony. Pursuant to this directive, the Alliance for Affordable Energy filed the testimony of Ms. Pamela G. Morgan and Mr. Justin K. Barnes. Hearings addressing the Application and all filed testimony were held from June 17 through June 21, 2019.

III. Legal Authority and Basic Regulatory Principles

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.[4] Among the legislative powers exclusively granted to the Council are the powers of "supervision, regulation, and control" over utility companies that furnish services within the City of New Orleans.[5] Ratemaking is included in the Council's exclusive regulatory powers over utility companies.[6] Regulation of public utilities is intended to protect the public interest.[7]

The need for regulation of utilities arises primarily from the monopoly characteristics of the industry. The general objective of regulation is to ensure the provision of safe, adequate, and reliable service at prices that are sufficient, but no more than sufficient, to compensate the regulated firm for the costs (including returns on investment) that it incurs to fulfill its obligation to serve.

[4] La. Const. Art. 6, §§ 4–6 (1974); Home Rule Charter of the City of New Orleans § 3-101(1).
[5] Home Rule Charter of the City of New Orleans § 3-130(1); *see also State ex rel. Guste v. Council of City of New Orleans*, 309 So.2d 290, 293 (La. 1975).
[6] Home Rule Charter of the City of New Orleans § 3-130(2).
[7] *See, e.g., Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 & n.5 (1952) (The purpose of a regulatory agency is "to protect power consumers against excessive prices" by assuring that costs passed through utility rates are just and reasonable).

The primary purpose of the ratemaking process is to set rates at such a level that the utility's revenue will be sufficient to permit the utility both to pay its legitimate operating expenses and to provide a return on investment adequate to compensate existing investors and attract new capital as required.[8] When this level is achieved, the utility's revenues produce a "fair rate of return."

The legal standard for determining a fair rate of return was articulated in two well-known Supreme Court cases: *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). In *Federal Power Commission v. Hope Natural Gas Co.*, the Supreme Court observed: "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, even though they might produce only a meager return on the so-called 'fair value' rate base."[9]

Thus, a utility is entitled only to the *opportunity* to earn a reasonable return on its investment; the law does not ensure that it will, in fact, earn the particular rate of return authorized by a public utility commission or indeed that it will earn any net revenues (*i.e.*, profits).[10] Moreover, utilities have an obligation to manage their facilities efficiently. The utility must make reasonable attempts to minimize costs through prudent decision making since

[8] *See* William K. Jones, *Judicial Determination of Public Utility Rates: A Critique*, 54 B.U.L.Rev. 873, 875 (1974).
[9] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 605 (1944).
[10] *Entergy Gulf States, Inc.v. La. Pub. Serv. Comm'n*, 98-1235, p. 40 (La. 4/16/99); 730 So. 2d 890, 920 (citations omitted).

ratepayers depend on only one monopolistic supplier.[11] The utility must satisfy the regulator's standards for performance at "lowest feasible cost,"[12] to use "all available cost savings opportunities;"[13] and to pursue its customers' legitimate interests free of conflicting business objectives.

Mathematically, the utility's revenue requirement is the sum of the utility's operating expenses and its rate of return times the amount of its rate base. Operating expenses include "maintenance, depreciation, and taxes, incurred to produce revenues;" rate base is "the value of the property, plant, and equipment, (less accumulated depreciation) which provide the service, and on which a return should be earned;" and rate of return is "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."[14]

Under general ratemaking principles, utilities are generally required to "net" all costs and benefits of operation at the time rates are set to avoid "cherry picking" individual cost increases that may be offset by other cost decreases. However, utilities often seek regulatory approval for isolated changes in costs. Consideration of these isolated changes in costs constitutes "single issue ratemaking," which is a deviation from traditional ratemaking. Single issue ratemaking involves "singling out" specific expenditures from a company's base rates and allowing a utility to recover those costs separately from ratepayers. Singling out specific costs can make the

[11] *Gulf States Utils. Co. v. La. Pub. Serv. Comm'n*, 96-2046, p. 12 & n.9 (La. 2/25/97); 689 So.2d 1337, 1346.
[12] *Potomac Elec. Power Co. v. Pub. Serv. Comm'n of D.C.*, 661 A.2d 131, 137 (D.C. 1995).
[13] *Midwestern Gas Transmission Co.*, 36 FPC 61 (1966*), aff'd sub nom. Midwestern Gas Transmission Co. v. Fed. Power Comm'n*, 388 F.2d 444 (7th Cir. 1968), *order rescinded in part sub nom. Knoxville Utils. Bd., et al. v. E. Tenn. Nat. Gas Co.*, 40 FPC 172 (1968) (order rescinded in part due to change in IRS tax policy).
[14] *Cent. La. Elec. Co. v. La. Pub. Serv. Comm'n*, 508 So.2d 1361, 1365 (La. 1987).

traditional ratemaking formula unbalanced. If the regulator evaluates only a subset of cost categories, other cost categories (which may be declining) are ignored. For example, a distribution system upgrade to enhance reliability, although quite possibly a beneficial investment, would be expected to be accompanied by lower maintenance costs and lower line losses, which reduce power supply costs. Similarly, smart grid investments can bring lower costs owing to improved outage identification and prevention, lower line losses, lower billing costs, and lower peak demand. If the costs of either the distribution system upgrade or smart grid investments are recovered through a surcharge or rider, those costs will not be netted against the decreased costs that are anticipated to occur. Thus, any decrease in costs will only benefit the shareholders, at least until the utility's next rate case.

IV. ENO's Application

In its Application, among other things, ENO requests:

1) A variable allowed electric Return on Equity ("ROE") ranging from 10.5% to 11.0% depending on ENO's system reliability performance;

2) A Formula Rate Plan ("FRP") for an "initial" three-year period (2019–2021) and to implement a Decoupling Pilot Program within the electric FRP only, through a four-step process to be applied only if a rate adjustment is necessary. Under the FRP framework, the Council evaluates whether ENO'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. However, the proposal includes a symmetrical change in the bandwidth and increases it from 40 to 50 basis points above and below the midpoint. The bandwidth would apply to any decoupling-related results;

3) To raise the monthly residential customer charge from $8.07 to $15.53;

4) A community solar offering, through which participants can subscribe to shares of a community solar project. ENO proposes to use both an existing 1 MW solar project and an approved 5 MW rooftop solar project as its community solar projects to which customers can subscribe;

5) A Green Power Option, under which participating customers would be able to match some or all of their electricity usage with renewable energy certificates ("RECs") generated or purchased by ENO and retired on the customer's behalf. ENO has already selected Green-e as the REC vendor;

6) A New Orleans Power Station ("NOPS") rider associated with ENO's construction of the $210 million gas-fired generating station to begin recovering the estimated first-year revenue requirement associated with NOPS beginning in the month after the power plant enters commercial operation;

7) A Demand-Side Management Cost Recovery ("DSMCR") rider (effective January 2020), to serve as the funding mechanism for DSM customer offerings, that provides contemporaneous (or even advance) recovery of program costs, lost contributions to fixed costs (*i.e.*, lost revenues), return of (amortization over three years) and return on programs costs at ENO's authorized a rate of return plus the opportunity for an added incentive of 100 basis points for achieving 95% to 120% of the savings goal and 200 basis points for achieving above 120% of the savings goal. Prior to the DSMCR rider taking effect, the interim Energy Efficiency Cost Recovery ("EECR") rider, including lost contributions to fixed costs, would serve as a temporary funding mechanism for the Energy Smart offerings previously approved by the Council;

8) A Distribution Grid Modernization ("DGM") rider, which would serve as the cost recovery mechanism for ENO's planned grid modernization investments made after 2019. The DGM rider consists 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;

9) A Reliability Incentive Mechanism ("RIM") through which ENO would change the rate of return on common equity used in its FRP depending on system SAIFI performance. For initially setting rates, ENO recommends an authorized ROE of 10.50%, which would increase to 10.75% if ENO improves its SAIFI[15] to 1.24, and as high as 11.00% if ENO improves the SAIFI to 1.05 or better;

10) An Advanced Metering Infrastructure ("AMI") rider to recover the cost of AMI installation which would result in a charge starting at $2.95 per month for each

[15] SAIFI, or System Average Interruption Frequency Index, is an index of the average frequency of interruptions, with lower numbers indicating fewer annual power outages on average for electric customers.

> customer in 2019 and increasing to $3.67 in 2020. Thereafter, the AMI charge gradually decreases, remaining above $3.00 from 2020 to 2022, decreasing to above $2.00 from 2023 to 2026 and remaining above $1.00 from 2027 to 2031.[16]

V. Discussion

A. The Council Should Adopt the Changes to the Decoupling Mechanism Proposed by the Alliance.

Decoupling is a regulatory mechanism that adjusts rates periodically to ensure that the amount a utility books as revenue for fixed cost recovery is no more and no less than the amount of revenue authorized by the regulator for that cost coverage.[17] Inherently backward-looking revenue decoupling holds a utility to its last authorized revenue, refunding any revenue excess to or collecting any revenue deficiency from the utility's customers. Considerations of cost may trigger a regulatory mechanism to update the authorized revenues for the next period of revenue decoupling, but such mechanisms do not affect the current period calculation whether the utility collected more or less revenue than what its regulator last authorized. Unfortunately, this is not the revenue decoupling that ENO has proposed.

Revenue decoupling is particularly important as ENO works to meet the Council's ambitious goals for energy efficiency in New Orleans. For ENO, revenue decoupling ensures that neither ENO's programs nor conversation and efficiency efforts outside of its programs reduce its revenue. For customers, revenue decoupling ensures that ENO does not collect "lost contributions to fixed costs" that ENO actually receives if increased sales offset deemed savings under its energy efficiency programs. Moreover, with revenue decoupling, ENO can also use its influence to help initiatives that can increase energy efficiency outside of its own programs.

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[16] *See* Ex. ENO-1, Revised Direct Testimony of Joshua B. Thomas at ENO Exhibit JBT-9 (Sept. 21, 2018) ("Thomas Direct") (Chart of AMI charges).
[17] Ex. AAE-1, Direct Testimony and Exhibits of Pamela G. Morgan at 5:15–18 (Feb. 1, 2019) ("Morgan Direct").

Because revenue decoupling does not affect how customers pay for energy utility services, ENO can maintain the volumetric rates that encourage residential and small commercial customers to participate in energy efficiency programs. The Council need not approve higher customer charges or minimum bills to protect ENO from any revenue instability, concerns over which often prompt utilities to request higher customer charges and minimum bills, as ENO has done in their proposal in this docket. Revenue decoupling assures utilities, and their ratings agencies and financial analysts, that changes in energy use or levels of demand will not harm the utility's finances. This means that rate design can focus on supporting policy objectives other than financial stability, such as encouraging conservation, demand management, and investments in energy-efficient and demand-reducing equipment. Similarly, a revenue decoupling mechanism reduces the need to enhance a utility's financial standing through a high authorized return on common equity.[18]

Council Resolution No. R-16-103 ordered ENO to file a decoupling mechanism with these elements:

- Applicable only to electric customers but all of such customers, regardless of rate class or schedule.
- An authorized fixed cost revenue requirement set either through the next rate case (this case) or, if the Council also approved an FRP in the next rate case, the authorized fixed cost revenue requirement emerging from that annual process, allocated to each customer rate class consistent with the allocation methodology used in the rate case.
- Inclusive of all fixed costs, regardless of the revenue recovery mechanism used for them.
- With no adjustment of the actual revenues for weather and no adjustment of the authorized revenue requirement other than the FRP, if approved.

[18] Ex. AAE-1, Morgan Direct at 11:15–12:9.

- An annual true-up to adjust actual revenues to authorized revenues, with under- and over-collections treated symmetrically and no cap on the amounts surcharged or refunded.

- Using the same filing deadlines as an FRP if an FRP is approved.

As explained by Alliance witness Pamela G. Morgan, two of the parameters set forth in Resolution No. R-16-103 should be modified by the Council in order to achieve the objectives of full decoupling. First, the Council should modify the directive that the revenue decoupling mechanism consider all fixed cost revenues. Ms. Morgan agrees with ENO that the decoupling mechanism need not consider any costs recovered through a tariff rider that includes a reconciliation mechanism, such as the Fuel Adjustment Clause. Use of a rider with a reconciliation mechanism means that selling more or less energy provides no financial benefit to ENO, and thus ENO and customers are already afforded the protection that a revenue decoupling mechanism offers for these costs.[19]

Second, a utility should maintain some degree of financial risk with respect to revenues associated with charges that are not usage driven. The most prominent examples of these for ENO are the customer charge billing determinant on the Residential Electric Service rate schedule and the minimum bill associated with the lowest demand tier billing determinant on most of its other electric service rate schedules. Revenues under these billing determinants will vary primarily with customer counts for each rate schedule. In other words, if ENO adds or loses customer accounts under its electricity service tariffs, it will increase or decrease its revenue without that difference being returned to or recovered from all other customers. Maintaining this financial connection to the number of customer accounts is a good step toward helping the utility

[19] *Id.* at 8:19–9:5.

stay customer-centric and in tune with the big picture of the financial and community health of its service territory.[20]

Ms. Morgan's approach reconciles ordering paragraphs 2 and 9 of Council Resolution No. R-16-103. Ordering paragraph 2 describes, on the one hand, a decoupling calculation based on the fixed cost revenue requirements calculated in that year's FRP filing and new rates based on that revenue requirement. On the other hand, ordering paragraph 9 describes an annual true-up to review and adjust the allowed revenues. *Revenue decoupling is always backward-looking: a true-up for what actually happened compared to what was expected to happen*. One can certainly update the "what was expected" authorized revenue component for the subsequent decoupling cycle, but that is a separate matter from the revenue decoupling adjustment itself.[21]

The Council also should adopt the changes to ENO's decoupling proposal recommended by Alliance witness Morgan. First, and foremost, ENO's proposal fails to accomplish revenue decoupling for two reasons. If the FRP result is within the dead-band, no revenue decoupling will occur at all. ENO will not even make the calculations. If the FRP result is outside of the dead-band, all that happens is that ENO makes a rate adjustment that reflects both cost and revenue changes since its last test year. This rate adjustment remains in place until the next FRP adjustment or rate case test year. Customers never receive temporary refunds or pay temporary surcharges, based on the difference between ENO's authorized revenue and actual revenue for one decoupling period, generally a year.

[20] *Id.* at 10:8–21.
[21] Ex. AAE-2, Surrebuttal Testimony and Exhibit of Pamela G. Morgan at 5:3–11 (Apr. 26, 2019) ("Morgan Surrebuttal").

All that has changed with regard to the FRP that ENO claims "includes decoupling" is that the proposed FRP will allocate all fixed *and variable* costs and revenues pursuant to allocation factors that result from the Council's action in this rate case. If the FRP triggers by producing an ROE that is outside of the dead-band, ENO will allocate both the fixed and variable cost/revenue differences according to the allocation method[22] and design a going-forward rate that recovers the new levels of the Evaluation Period revenue requirements. This allocation is also illustrated by ENO witness Phillip B. Gillam in ENO Exhibit PBG-8. Allocating FRP adjustments according to a class cost of service study does not fundamentally change the nature of the FRP and certainly does not accomplish revenue decoupling. As noted by Alliance witness Morgan:

> Thus, if the proposed tariff accomplishes decoupling, then the prior [FRP tariff] did as well. And, in that case, why did the Council find it necessary to investigate the matter over many years and order ENO to file a decoupling mechanism with this case?[23]

Second, ENO's proposed revenue decoupling design subjects any change based on the revenue difference (considered only in conjunction with cost differences) to the proposed FRP dead-band. Ms. Morgan observed that ENO's dead-band differs from traditional dead-bands. A dead-band is most typically a range of variances for what is being measured, such as earned return on common equity for ENO or power costs, within which no rate action occurs to handle the variance. For example, if a power cost adjustment mechanism had a dead-band of $50 million, any variance between the test year amount and the actual would not be subject to collection or return unless it exceeded $50 million either way. ENO's "dead-band" is more of a

[22] Ex. ENO-41, Revised Direct Testimony of Phillip B. Gilliam, ENO Exhibit PBG-7 at 1 of 22 (Sept. 21, 2018) ("Gillam Direct"); *see also id.*, ENO Exhibit PBG-8.
[23] Ex. AAE-1, Morgan Direct at 16:8–11.

trigger. No rate change would happen under its FRP unless the earned return on equity variance from the baseline (as calculated) is greater than 50 basis points. Once that point is reached, *all* of the variance becomes subject to return or collection.[24] Regardless, however, ENO has not provided a reason for subjecting the results of revenue decoupling to a dead-band. To the extent the revenue decoupling mechanism is subject to any dead-band, ENO remains financially interested in encouraging energy use and demands to exceed rate case assumptions, working against its own Energy Smart programs and the policy preferences of the Council.[25]

Third and last, it is clear that ENO does not believe its proposed FRP modifications accomplish revenue decoupling because its proposed DSMCR includes recovery at the start of each calendar year of the revenues—allegedly[26] related to fixed costs—that ENO believes it might lose because of the deemed savings achieved under energy efficiency programs. A standard, backward-looking, revenue decoupling mechanism would naturally pick up any such "lost revenues," and unless sales/revenue gains offset them, allow ENO to collect these amounts from customers. This can be done in compliance with the Generally Accepted Accounting Principles ("GAAP") such that ENO suffers no regulatory lag nor do customers lose the time value of money if the result of revenue decoupling is that ENO owes them a refund.

Accordingly, the Alliance urges the Council to adopt the second and third recommendations Ms. Morgan made to ensure that New Orleans benefits from a policy of revenue decoupling:

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[24] Ex. AAE-2, Morgan Surrebuttal at 2 n.1.
[25] Ex. AAE-1, Morgan Direct at 13:20–14:3.
[26] Allegedly because the formula through which ENO calculates "lost" fixed cost revenues does not separate out revenues it actually recovers regardless of energy efficiency programs because the revenues relate to customer counts, rather than energy usage or demand.

- The tariff for revenue decoupling—whether included in the FRP tariff or not—makes clear that the revenue decoupling will operate only on revenues ENO receives from energy- and demand-driven billing determinants, and not on either (1) Revenues from customer charge billing determinants or minimum bill requirements in tariffs; or (2) Revenues collected under tariff riders that are subject to full reconciliation.[27]

- The tariff for revenue decoupling—whether included in the FRP tariff or not—makes clear that the revenue decoupling comparison is between the most recent approved revenues and the actual revenues for a given period, allocated to rate classes/schedules per approved allocation factors, and not to a calculation of going-forward allocated revenues that combine cost and revenue charges during a given test period.[28]

B. ENO's Excessive Use of Riders Violates Basic Ratemaking Principles.

A rider is a fee imposed on a ratepayer's utility bill in addition to the base rate charge for utility service. In the past, riders were only approved by regulators in rare circumstances to address substantial, volatile, and uncontrollable costs that, if not addressed outside of a base rate case, could threaten to harm a utility's financial health. Thus, a rider is only appropriate if (a) the cost at issue is large enough to pose a threat to the financial integrity of the utility; (b) the cost is highly volatile and cannot be reasonably managed by the utility; and (c) the absence of the rider could result in substantial financial instability to the utility and significant over (or under) charges to ratepayers. Examples of such riders include fuel and purchased power adjustment mechanisms.

As the Council is aware, the ratemaking process is designed to examine all the utility's costs. Those costs that have increased since the utility's last rate case are netted with those costs that have decreased. The result of this netting determines whether the overall rates charged to ratepayers will increase or decrease. Riders circumvent this process and result in the cherry

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[27] Ex. AAE-1, Morgan Direct at 18:16–19:3.
[28] *Id.* at 20:9–13.

picking of certain costs that are then charged to ratepayers without an examination of whether there have been any savings that could and should offset these costs. Thus, riders are a form of single issue ratemaking.

The Council should only authorize the use of riders in limited circumstances. The increasing imposition of riders defeats some of the primary principles of the ratemaking and regulatory review process. In addition to increasing costs to consumers, riders can also result in such additional undesirable consequences as reducing utility incentives to control costs and shifting utility business risks away from investors and onto customers. The Council must not condone a change to one component of costs without considering whether changes to other costs might offset the increase.

The primary purpose of ENO's excessive use of riders appears to be the desire to reduce the potential for "regulatory lag." In this context, regulatory lag is the time between when a cost change affects the utility to the time the value of that change in cost is incorporated into rates.

First, the Council should note that ENO has not filed a rate case in ten years. Apparently, the Company was unconcerned with the "evils" of regulatory lag during this time period. Moreover, as the Council is aware, ENO has been overearning for the last several years. Only now, when the Council is poised to correct the rates and stop ENO from receiving excessive profits, is the Company concerned about the impact of regulatory lag. Finally, since ENO has a history of overearning, it is important to consider that riders allow a utility to increase rates even if the utility is already earning higher than its authorized rate of return. Thus, ENO's excessive use of riders increases the likelihood that the Company will over-earn in the future.

Moreover, ENO's use of riders ignores the benefits of regulatory lag. Riders eliminate the inherent incentive a utility has to manage its costs prudently, by minimizing expenses, between base rate proceedings. Regulatory lag in this context is an important feature of utility ratemaking because the lag forces the utility to bear the risk of higher costs between rate cases. This incentive, over time, works to keep electric rates lower than they otherwise would be. Riders for costs that are within the utility's control reduce the incentive for a utility to control costs, as the costs will be substantially passed through to customers.

Allowing a utility to recover lost revenues or discrete increased costs through a rider can also diminish the utility's incentive to control or reduce expenses because the utility is assured of full cost recovery. Since the utility is passing the cost on to customers, it has less incentive to seek ways to reduce the expense. Guaranteeing recovery of a specific expense reduces the utility's incentives to control costs, and thus shifts the burden of cost increases between rate cases from shareholders onto ratepayers.

Singling out specific costs can make the traditional ratemaking formula unbalanced. If the regulator evaluates only a subset of cost categories, then other cost categories (which may be declining) are ignored. For example, a distribution system upgrade to enhance reliability, although quite possibly a beneficial investment, would be expected to be accompanied by lower maintenance costs and lower line losses, which reduce power supply costs. Similarly, smart grid investments can bring lower costs owing to improved outage identification and prevention, lower line losses, lower billing costs, and lower peak demand. If the costs of either the distribution system upgrade or smart grid investments are recovered through a surcharge or rider, those costs will not be netted against the decreased costs that are anticipated to occur. Thus, any decrease in costs will only benefit the shareholders, at least until the utility's next rate case.

C. The Council Should Reject ENO's Request to Almost Double the Residential Fixed Charge.

A fixed charge is a flat fee on a customer's monthly bill that is typically designed to recover the portion of costs that do not vary with usage. These costs may include, for example, costs of meters, service lines, meter reading, and customer billing.[29]

It is important to note that the level of the fixed charge is a rate design decision. Rate design is not about how much total revenue a utility can collect. Rather, rate design decisions determine how the utility can collect a set amount of revenue from customers. That is, once the utility regulator determines the amount of revenues that a utility can collect, rate design determines the method for collecting that amount.

ENO proposes to set the residential customer charge at $15.53/month. This value is arrived at by starting with the customer unit cost value of $21.07/month from the Company's Period II cost of service study. ENO reduces this amount by 14.6% to reflect its proposed rate class cost allocation, arriving at a value of $18.01/month, which is $9.94/month higher than the current nominal customer charge of $8.07/month. The Company then reduced the amount of the theoretical increase by 25% in the interest of "gradualism," arriving at a proposed increase of $7.46/month. When added to the current charge, this results in a proposed residential customer charge of $15.53/month.[30]

ENO attempts to justify this inordinate increase by claiming that the increase is necessary to achieve several objectives: (1) preserving ENO's revenues; (2) reducing cross-subsidies

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[29] Jim Lazar & Wilson Gonzalez, *Smart Rate Design for a Smart Future*, at 36, Regulatory Assistance Project (July 2015), http://www.raponline.org/document/download/id/7680.
[30] Ex. ENO-1, Revised Direct Testimony of Joshua B. Thomas at 63:14–64:2 (Sept. 21, 2018) ("Thomas Direct"); Ex. AAE-3, Direct Testimony of Justin R. Barnes at 4:7–15 (Feb. 1, 2019) ("Barnes Direct").

related to energy efficiency and solar photovoltaic ("PV") adoption; (3) stabilizing residential bills; and (4) stabilizing ENO's cash flow metrics.[31] ENO also claims that the increase is necessary to align rates with the costs indicated by the Company's embedded cost of service study.[32]

The Council should reject ENO's inflated customer charge for the following reasons:[33]

1. The fixed charge increase would result in a considerable dilution of customer incentives to use less energy, in conflict with the Council's policy of supporting energy efficiency, including but not limited to recognizing energy efficiency as a "high-priority energy resource" and resolving to "align customer pricing and incentives to encourage investment in energy efficiency."[34] ENO's proposal achieves the exact opposite of the Council's stated goal; the drastic increase is a clear disincentive to investing in energy efficiency.

2. The Company's calculated customer unit cost, which forms the starting point for its derivation of the proposed charge, is inflated by the inclusion of numerous costs that bear little or no relationship with the costs associated with connecting a customer to the grid, or which vary directly with the number of customers being served. Utilizing this inflated customer unit cost is directly contrary to the defined purpose of fixed charges and would cause relatively lower usage customers to subsidize relatively higher usage customers.

3. The negative impacts of increases to fixed charges would fall disproportionately on low-income customers while generally benefitting higher-income customers.

4. The proposed charge and the amount of the proposed increase are extreme and fail to reflect the true nature of gradualism in utility ratemaking, as evidenced by national trends in residential fixed charges.

While ENO's inflated fixed charge will help the Company achieve "revenue stability," ENO has failed to provide evidence that the inordinate level of the residential fixed charge is necessary, particularly given the Company's other revenue fixing proposals, which include a

[31] Ex. ENO-1, Thomas Direct at 62:16–23; Ex. AAE-3, Barnes Direct at 5:16–19.
[32] Ex. ENO-45, Revised Direct Testimony of Myra L. Talkington at 26:10–17 (Sept. 21, 2018) ("Talkington Direct").
[33] Ex. AAE-3, Barnes Direct at 6:5–3.
[34] Council Resolution No. R-07-600.

renewed FRP with a revenue decoupling mechanism. The incremental revenue stability impact of a large residential fixed charge increase would be greatly overshadowed by the effects of the FRP and revenue decoupling, while the detrimental impact on residential customers and the Council's efficiency goals would be severe. Moreover, in light of the fact that ENO has been overearning for the last several years,[35] the Company cannot establish that its revenues are at risk or that ENO needs this protection to ensure its financial viability.

Similarly, while higher fixed charges can contribute to customer "bill stability," ENO failed to present any evidence that customers would support such a large increase in fixed charges as the mechanism for achieving more stable bills. In fact, survey research that the Company conducted in connection with its fixed bill option proposal indicates that 70% of customers are not interested in paying a premium in order to achieve more stable bills.[36] Apparently, ENO customers are more interested in maintaining control over their ability to lower their bills by consuming less energy than they are in assuring ENO receives a guaranteed revenue stream.

The Council should also be aware that the references to rate design replicating cost structure made by ENO witness Talkington stem from the false premise that the results of the Company's embedded cost of service study are determinative for the purpose of setting rates that provide economically efficient price signals. Embedded cost of service studies are useful for determining the amount of revenue to collect, not how to collect that revenue.[37] As established

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[35] *See* Docket No. UD-16-04, Direct Testimony of Byron S. Watson, at 12 (May 26, 2017) (excerpt attached hereto as Attachment A).
[36] Ex. ENO-19, Revised Direct Testimony of Raiford L. Smith at 26:8–11 (Sept. 21, 2018).
[37] Ex. AAE-3, Barnes Direct at 8:21–9:2.

by Alliance witness Justin K. Barnes, marginal costs rather than embedded costs[38] are the proper basis for developing economically efficient price signals.[39] ENO's only response to Alliance witness Barnes' contention regarding marginal costs is to assert that the Council does not require ENO to use marginal costs.[40]

Moreover, an embedded cost of service study does not account for the negative public policy impacts that result from using embedded unit costs as the basis for rate design, most notably the departure from economic efficiency in rates and the dilution of customer incentives to use less energy and thereby contribute to producing long-term system cost savings.[41]

ENO also refuses to recognize that its excessive residential fixed charge will have an adverse effect on the Council's approved energy efficiency programs. Fixed charges cannot be avoided by reducing energy consumption or demand for electricity. A rate design weighted towards fixed charges reduces a customer's incentive to pursue energy efficiency because collecting a larger amount of revenue via fixed charges lowers the amount to be collected from other charges. That produces lower rates for those other charges, reducing the amount of cost savings that a customer can achieve by modifying their energy usage patterns or making

[38] Embedded costs are costs that have already been incurred (*i.e.*, on a utility's books) while marginal costs are forward-looking, evaluating the incremental costs associated with adding one more customer, one more unit of demand, or one more unit of energy. The rationale for using marginal costs as the basis for rate design is that marginal cost pricing supports the economically efficient use of a good or service. In other words, when looking to achieve outcomes based on pricing incentives in rates, it makes more sense to look to future costs rather than costs that can no longer be avoided. *Id.* at 9:9–16.
[39] *Id.* at 8:16–17.
[40] ENO Response to AAE 3-5. (Responses to Discovery Requests attached hereto as Attachment B).
[41] Ex. AAE-3, Barnes Direct at 8:18–21.

investments in equipment that is more efficient.[42] A high fixed charge, when accompanied by lower energy charge, can increase energy usage by five to ten percent.[43]

ENO also has failed to establish that "cross-subsidization created by energy efficiency and PV adoption" even exists.[44] When asked about whether ENO had conducted any studies to establish that this cross-subsidization is occurring and the level of that alleged subsidy, ENO witness Joshua B. Thomas stated ENO would not need a study to determine this.[45] This witness further asserted that the benefits to the system are not a factor.[46]

ENO's position that the benefits brought to the system by energy efficiency programs and distributed energy resources can be ignored in calculating rates is contrary to basic ratemaking principles. As noted above, basic ratemaking requires a netting of increased and decreased costs. To ignore the benefits that both energy efficiency and distributed generation bring to ENO's system in the form of lower costs for *all* ratepayers results in the over-collecting of costs and produces an unwarranted financial penalty on those ratepayers who are in actuality reducing overall costs to the benefit of every ratepayer using the system.

For example, the basic premise of energy efficiency programs is that these programs are a less expensive alternative to other costs that a utility would incur in the absence of such programs. Utilities invest heavily in generation as well as the poles and wires infrastructure that is necessary for them to provide reliable power when and where customers need it. Investments

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[42] Ex. AAE-3, Barnes Direct at 15:6–13.
[43] Jim Lazar, *Electric Regulation in the US: A Guide*, Regulatory Assistance Project, at 69 (2d Ed. June 2016), https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.
[44] Ex. AAE-3, Barnes Direct at 8:12–13.
[45] Hr'g Tr. 6/20/19, 91:5–6.
[46] *Id.* at 92:18–19.

in energy efficiency can allow a utility to reduce such investments, defer spending on physical upgrades to constrained delivery networks, and purchase less energy and capacity. These savings are then passed on to customers. Thus, even if there are costs that energy efficiency participants do not pay, or do not pay fully (a proposition that ENO failed to study and therefore cannot prove),[47] when the appropriate cost netting occurs, those unrecovered costs are more than made up for by the savings all ratepayers receive through the reduced need for other investments. ENO cannot justify its increased charges by intentionally only looking at one side of the rate equation.

Similarly, several recent studies have shown that distributed generation resources are very cost-effective because they can significantly reduce revenue requirements by avoiding generation, transmission, and distribution costs.[48] All of these studies find that distributed generation resources are very cost-effective in terms of reducing utility revenue requirement. In fact, they are generally more cost-effective than almost all other electricity resource options.[49] These benefit-cost ratios are far higher than other electricity resource options because the host customers (*i.e.*, the distributed generation owner) typically pay for the cost of installing and operating the distributed generation resource.

Clearly, ENO's argument that energy efficiency programs and distributed energy resource users are "subsidized" by other ratepayers is a classic example of single issue

[47] Hr'g Tr. 6/20/19, 90:14-91:6.
[48] Melissa Whited *et al.*, *Caught in a Fix: The Problem with Fixed Charges for Electricity*, Synapse Energy Economics, at 27 (Feb. 9, 2016), https://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf.
[49] The results from these studies demonstrate that distributed generation resources have benefit-cost ratios that range from 9:1 (New Jersey and Pennsylvania) to roughly 40:1 (Colorado, Maine, North Carolina) to as high as 113:1 (Arizona). *Id.* at 28.

ratemaking. Under accepted ratemaking principles, it is improper for the Council to consider changes in isolation. Often an increase in one item of the rate base is offset by a corresponding decrease in another item. For instance, certain increased expenses for one aspect of a utility's business may be offset by savings in another area, thereby removing the need for increased revenue.

Thus, ENO's arguments regarding energy efficiency program participants and distributed energy resource users' failure to pay their "share of costs" must be rejected. Accepted general principles of ratemaking require that the financial benefits to all ratepayers offered by these programs be assessed in conjunction with any imposition of charges by the utility.

ENO also inappropriately inflated the residential customer charge by including costs that do not vary directly with the number of customers. According to the Regulatory Assistance Project, the most common method of determining the customer charge is to limit it to the costs associated with metering, billing, customer service, and service drops.[50] In contrast, ENO's derivation of customer-related costs includes the embedded costs of meters, service drops, meter reading, billing, customer service, and customer records and collection, as well as allocations of certain distribution expenses and a variety of general and administrative overhead costs.[51] The Company's varying rationale for the inclusion of all these costs include that the costs "are incurred by a utility even if a customer does not impose a demand on the Company's capacity or consume energy. These costs vary with [sic] number of customers served."[52] At a different

[50] *See* Lazar & Gonzalez, *supra* note 29, at 36.
[51] Ex. AAE-3, Barnes Direct at 20:4–7.
[52] Ex. ENO-1, Thomas Direct at 61:20–22.

point, ENO also describes these costs as those that are "not correlated to the number of kilowatt hours of electricity used by the customer."[53]

However, the customer charge should reflect the cost of a customer that does not impose a demand or consume energy. This cost is represented by the incremental cost of connecting a customer (*i.e.*, the marginal cost), which is generally limited to the costs for a meter and service drop along with expenses for meter reading, billing, and customer service.[54] Another way to view the appropriate role of the customer charge that produces a similar result is to define customer-related costs as those that vary directly with the number of customers.[55]

Alliance witness Barnes performed an examination of the individual components of ENO's proposed residential customer charge based on the Company's cost of service study. He derived an alternative amount by first eliminating all costs that are not allocated on the basis of the number of customers. He then reviewed the remaining components for cost items that were allocated in whole or in part based on customer numbers and eliminated additional cost items. With respect to these additional subtractions from ENO's calculated residential customer charge, as Mr. Barnes explains, rate base and expenses associated with installations on customer premises in Federal Energy Regulatory Commission ("FERC") Accounts 371[56] and 587,[57]

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[53] *Id.* at 62:10–11.
[54] *See* Lazar & Gonzalez, *supra* note 29, at 36.
[55] *Id.* at 83.
[56] FERC Account 371 relates to utility-owned plants on customer premises located on the customer's side of the meter. ENO has indicated that the equipment in this account is composed of lighting fixtures on the premises of residential customers. *See* ENO Response to AAE 3-1(b) (Attachment B).
[57] FERC Account 587 relates to expenses associated with customer installations, including property leased to customers and contained in FERC Account 372. Neither relates to costs that are directly associated with connecting a customer to the grid, thus even if they are allocated to the residential class as a whole, it is improper to include them as a component of the residential customer charge. Ex. AAE-3, Barnes Direct at 23:14–18.

operating expenses associated with overhead and underground conductors in FERC Accounts 583, 584, 593, and 594,[58] and advertising expenses in FERC Account 909[59] should be excluded from the calculation of the residential fixed charge because they do not vary directly with the number of customers.[60]

Remarkably, neither ENO witness Talkington nor ENO witness Thomas seem to even know all the costs they are now arguing should be included in the residential fixed charge. While objecting to Alliance witness Barnes' exclusion of administrative and general costs from the fixed charge,[61] ENO witness Talkington was clearly unaware of what costs comprise the administrative and general category. When asked on cross-examination whether the administrative and general category included executive and officer compensation or outside consultant services, Ms. Talkington had absolutely no idea[62] and neither did Mr. Thomas.[63] These costs are included in FERC Account 920. According to information provided by ENO, approximately $3.5 million of officer and executive compensation is included in the residential fixed charge. Dividing this amount by 2,178,000 annual customer bills translate to a

[58] These accounts collectively relate to operation and maintenance costs for overhead and underground distribution lines. Both elements are part of the shared distribution system that serves all customers. Since these costs are not attributable to the incremental cost of connecting an additional customer to the grid, they should not be reflected in the customer charge. *Id.* at 24:1–7.
[59] Advertising and the provision of information to customers may fall generally within the customer service function. However, such information is not, strictly speaking, related to connecting a customer to the grid. Moreover, another FERC Account, FERC Account 908, includes expenses directly associated with customer assistance (*e.g.*, processing customer inquiries). Furthermore, advertising costs do not necessarily bear any direct relationship to the number of customers that a utility serves. *Id.* at 24:10–15.
[60] *Id.* at 23:5–8.
[61] Ex. ENO-46, Rebuttal Testimony of Myra L. Talkington at 17:6–13 (Mar. 22, 2019).
[62] Hr'g Tr. 6/18/19, 80:14–81:14.
[63] Hr'g Tr. 6/20/19, 96:20–22.

contribution of $1.61 per month. Similarly, $2.68 million for outside consultant services is also included in the proposed residential customer charge. This amount translates into approximately $1.23 per month.[64]

ENO's proposed excessive increase also is inconsistent with the principle of gradualism. Ms. Talkington contends that ENO's proposal "balances the rate design considerations of setting rates at cost and employing gradualism to avoid undue customer impacts."[65] However, as evidenced by both the amount and percentage of the proposed increase embodied within the residential customer charge, the Company's proposal clearly does not represent "gradualism" as practiced by regulators in other states. Moreover, the residential fixed charge is only "gradual" with respect to the Company's flawed calculated customer-related unit costs.

Importantly, ENO ignores the fact that its excessive residential fixed charge increase will have a disproportionate adverse impact on low-income customers. ENO calculated a customer "indifference" threshold of roughly 1,000 kWh of electric usage per month.[66] The indifference threshold defines the amount of monthly electricity consumption at which a customer experiences the same total annual bill increase under the Company's proposed fixed charge as they would if the amount of the proposed increase was included in the volumetric rate instead. A customer with average monthly usage below the indifference threshold prefers a volumetric rate

[64] *See* ENO Response to AAE 2-4, Attachment, tab "RR 4 Customer," line 296 "920 Salaries" & line 299 "923 Outside Services." These figures were calculated by taking each line item of the residential customer charge composition based on the class cost of service study in the above-mentioned Excel document and dividing it by the number of customers. FERC Account 920 is related to salaries for executives and officers not attributable to a specific function (*e.g.*, transmission, distribution, etc.), while FERC Account 923 is related to outside services. For further information on FERC's Uniform System of Accounts, *see* 18 C.F.R. Part 101.
[65] Ex. ENO-45, Talkington Direct at 26:14–15.
[66] Ex. ENO-1, Thomas Direct at 64:9– 10.

to a fixed rate while customers with average usage above the indifference threshold are made better off by higher fixed charges and lower volumetric charges.[67] According to ENO's own data, on average, lower-income customers tend to have average monthly usage below the indifference threshold. Thus, in general, they would experience larger adverse impacts in terms of increases to their annual electricity costs as a result of the proposed fixed charge.[68] ENO's data shows that roughly [[[redacted]]] of residential customers in total experience [[[redacted]]] when revenue is collected via a fixed charge. Furthermore, [[[redacted]]] of customers with incomes [[[redacted]]] are made worse off, and [[[redacted]]] of customers in the [[[redacted]]] are worse off.[69]

ENO provided energy use statistics for customers that experienced disconnection of service for non-payment during the 2017 calendar year. Roughly 47% of customers that were disconnected had average usage of less than 1,000 kWh/month during the 12 months prior to disconnection.[70] In other words, 47% of residential customers that had difficulty paying their electric bill in 2017 would have been even worse off by higher fixed charges. Furthermore, this data shows that disconnection risk is not correlated with above-average or irresponsible electric usage resulting in a high bill. Customers with lower than average monthly usage are nearly equally likely to experience difficulty paying their bills as higher usage customers.[71]

Finally, the Council should find that ENO's proposed residential fixed charge is extreme when compared to the national average, other ENO affiliates, increases approved by other utility

[67] Ex. AAE-3, Barnes Direct at 25:8–16.
[68] *Id.* at 25:17–20.
[69] Ex. AAE-4, Barnes Direct (HSPM) at 26:4–8.
[70] Ex. AAE-3, Barnes Direct at 27:9–11. Derived from ENO Response to AAE 2-6.
[71] Ex. AAE-3, Barnes Direct at 27:6–16.

regulators, and those of corporations ENO itself deems comparable to the Company.[72] Alliance witness Barnes reviewed the current residential customer charges for 168 investor-owned utilities ("IOUs") in 49 states and the District of Columbia, as well as adopted increases in residential customer charges for IOU general rate case applications filed since July 2014. As Mr. Barnes demonstrates, the increase in the residential fixed charge ENO proposes would place the Company's residential customer charge well in excess of the national average and dramatically exceed recent national averages for fixed charge increases and those awarded to ENO affiliates.[73]

Mr. Barnes further demonstrated that ENO's proposed residential customer charge is even further out of step with those established for utilities in states that place a high priority on energy efficiency, showing that the average residential customer charge in the five top-scoring states on ACEEE's 2018 Energy Efficiency Scorecard is only $6.05/month.[74] This is only 39% of the amount that ENO has proposed. Stated another way, ENO's proposed charge is nearly 2.5 times the average charge in states that make energy efficiency a top policy priority. The simple fact is that high customer charges are the antithesis of support for energy efficiency, which is well recognized by regulators throughout the country, a fact that ENO chooses to ignore wholly.

In contrast to ENO's apparently haphazard determination of which costs should be included in a residential customer charge, Alliance witness Barnes developed two estimates based on the Company's cost of service study, a study prepared in response to AAE 2-4 which depicts the costs associated with ENO's calculated residential customer-related unit cost as the starting point. For both estimates, Mr. Barnes excluded all costs not allocated based on the

[72] Ex. ENO-26, Revised Direct Testimony of Robert B. Hevert at 14, Table 2 (Sept. 21, 2018) ("Hevert Direct").
[73] Ex. AAE-3, Barnes Direct at 10:18–12:14.
[74] *Id.* at 19:7–11.

number of customers in the Company's embedded cost of service study, applied to the items that determine the rate base and operating expenses.[75]

Based on these extensive calculations, Mr. Barnes concluded that the Council should adopt a residential customer charge consistent with the costs of connecting a customer to the electric grid and Mr. Barnes' low-end customer charge calculation of $8.13/month, in order to properly reflect cost causation, avoid significant adverse impacts on customers with lower incomes, and support the Council's policies on energy efficiency.

The Council should reject ENO's extreme, unsupported increase in the residential customer charge and should adopt the charge proposed by the Alliance.

D. In the Absence of Significant Changes, the Council Should Reject ENO's Proposed Rider DSMCR.

ENO's Demand-Side Management Cost Recovery ("DSMCR") rider proposal has several elements:[76]

- A mechanism that allows ENO to earn a return on energy efficiency program expenses at its pre-tax weighted average cost of capital ("WACC").
- A lost fixed cost recovery mechanism that compensates ENO for foregone sales as a result of energy efficiency program investments referred to as the Lost Contribution to Fixed Costs ("LCFC") component.
- A performance incentive that provides for increases or decreases to the Company's return on program expenditures depending on the amount of energy savings achieved relative to annual targets.

The Company proposes that the collective costs associated with all of these elements be recovered via a new rate rider, Rider DSMCR. Rider DSMCR rates would be set on a

[75] Ex. AAE-3, Barnes Direct at 21:16-22:1 (Mr. Barnes' calculations are set forth in Ex. AAE-3, Barnes Direct at 22-24).
[76] *Id.* at 37:10–18.

percentage of bill basis, such that all base charges are effectively increased by a defined percentage.

ENO's rationale for these aspects of the rider is that (1) allowing DSM expenses to be effectively rate-based will place energy efficiency at a level equivalent to generation investments from the utility's perspective; (2) a lost revenue adjustment mechanism ("LRAM") is necessary to render the Company indifferent to revenue losses caused by energy efficiency investments; and (3) a performance incentive is an appropriate mechanism for elevating energy efficiency to something of a "preferred resource" status.[77] ENO failed to provide any justification for the use of a percentage of bill-based structure in Rider DSMCR.

1) The Council Should Reject ENO's Request to "Effectively Rate-Base" DSM Expenses.

First, the Council should reject ENO's assertion that allowing energy efficiency program expenses to be rate-based is necessary to place energy efficiency on par with other resources. The Company already has both an obligation to pursue least-cost resources and an obligation to abide by the requirements placed on it by the Council, including but not limited to goals that the Council sets for energy efficiency.[78]

Second, as discussed by Alliance witness Barnes, using the rate of return in the fashion proposed by ENO distorts the playing field in the utility's favor rather than leveling it because energy efficiency expenditures produce both foregone energy expenses and foregone capital investments. 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 are capitalized

[77] *Id.* at 38:6–12.
[78] *Id.* at 39:3–6.

and produce a profit for the utility.[79] This distortion requires ratepayers to become responsible for an incremental cost on program expenses that they would not have otherwise paid without the energy efficiency investment.[80]

2) The Council Should Reject the LCFC Component of Rider DSMCR.

LCFC and revenue decoupling are alternatives designed to achieve the same objective. ENO does not need both. The LCFC is the weighted average of the most recently approved base rates in effect on the filing date (July 31, 2019, for the Interim Energy Efficiency Cost Recover rider, and October 2019 and subsequent years for Rider DSMCR) multiplied by the deemed, projected lost sales (kWh and/or kW) attributable to the Energy Smart Programs for the applicable program year.[81] In other words, the LCFC purports to return to ENO revenues that it would have received *but for* its energy efficiency programs. However, this "but for" world is a fiction that never actually occurs. There is always much more that has happened than the sum of the elements being extracted (and potentially cherry picked) to create this imaginary world. In contrast, decoupling does not rely on creating an imaginary world. Thus, from a principled ratemaking perspective, revenue decoupling is a more suitable mechanism for ensuring that energy efficiency programs do not cause ENO to "lose" revenues.

Both ENO witness D. Andrew Owens and ENO witness Dr. Ahmad Faruqui assert that the LCFC is necessary to "level the playing field" between DSM and supply-side investments.[82]

[79] Ex. AAE-3, Barnes Direct at 40:11–17.
[80] *Id.* at 41:13–14.
[81] *See* Ex. AAE-1, Morgan Direct at 23:21–24:2; Application, Statement A-3 – Electric (Proposed Electric Rate Tariffs), Rider Schedule EECR-1 (Interim Energy Efficiency Cost Recovery Rider) at 37.1 (pdf page 1377 of the Application); Ex. ENO-10, Revised Direct Testimony of D. Andrew Owens, ENO Exhibit DAO-3 at DSMCR Rider Attachment B, page 2 of 4 (Sept. 21, 2018) ("Owens Direct").
[82] Ex. AAE-1, Morgan Direct at 31:7–32:6, 33:10–11.

This assertion is fundamentally flawed. The similarities between DSM and generating resources—primarily that they both help meet the electricity needs of a utility's customers—have long blinded utilities and others to the very significant ways in which the two are different and in which DSM resources are far more appealing to utilities than supply-side resources. Most importantly, utilities have no responsibility for the operation of the DSM assets. Once the program has paid a customer the incentive or otherwise sold the customer on making a DSM investment, how the resource operates and whether it produces the result for which the customer hoped is solely the customer's responsibility. This is vastly different than a supply-side resource, where the utility remains responsible for the entire operating life of the resource, including premature obsolescence.[83]

Aside from the difficulty of basing recovery on a fiction, ENO's LCFC also has several other problems. ACEEE has examined the flaws of LRAM proposals[84] and found:

> LRAM as a permanent policy fix is fraught with flaws. The regulatory burden is great, and the potential to shortchange customers and overcompensate utilities is ever present. As states gain more experience with LRAMs, problems continue to arise. Several states are striving for a simpler and fairer way to implement an LRAM that all parties will sign on to. In practice, an ideal LRAM possessing all of those qualities has yet to present itself. Finally, as noted above, having an LRAM policy in place does not currently appear to be associated with states' achieving higher levels of energy efficiency program spending or energy savings.[85]

[83] *Id.* at 33:10–34:5.
[84] The LCFC is a type of Lost Revenue Adjustment Mechanism ("LRAM").
[85] Annie Gilleo *et al.*, *Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms*, ACEEE, at 21 (June 2015), https://aceee.org/sites/default/files/publications/researchreports/u1503.pdf.

The NRDC also recently discussed the problems associated with a utility's use of an LRAM, stating:

> Giving a utility *lost revenues* from its energy-efficiency programs removes the utility's disincentive to support those programs, but still allows the utility to benefit from increased sales. Because a utility does not have to give up *found revenues*—when sales are higher than assumed in the rate-setting process—lost revenues are asymmetric and cause customers to pay a windfall to the utility when sales are above the volume used to set rates. An LRAM makes it unlikely that a utility will implement valuable market transformation programs, because savings from these programs are difficult to evaluate. LRAMs add controversy to the process of measuring energy savings from efficiency programs because significant dollars are now attached to savings. Finally, an LRAM presents an opportunity for gaming: if a utility runs an energy-efficiency program that looks good on paper but saves little or nothing in practice, the utility keeps the revenue associated with the unsaved energy while also collecting lost revenues.[86]

Finally, the Council should note that ACEEE "strongly recommends" full decoupling over the use of LRAMS, stating:

> ACEEE strongly recommends full revenue decoupling as the preferable approach to address *both* lost margin recovery and the throughput incentive. While LRAM does address recovery of fixed costs, it does not remove the throughput incentive. Furthermore, while under-collection of authorized revenues is addressed by both LRAM and decoupling, only symmetrical decoupling requires over-collection of revenues to be refunded to customers.[87]

Experience with the implementation of LRAMs has resulted in the adverse consequences of these mechanisms becoming clear. These adverse consequences include:

[86] NRDC, *Removing Disincentives to Utility Energy Efficiency Efforts*, at 2 (May 2012), https://www.nrdc.org/sites/default/files/decoupling-utility-energy.pdf (attached to Ex. AAE-1, Morgan Direct as AAE Exhibit PGM-3).
[87] ACEEE, *Aligning Utility Business Models with Energy Efficiency*, https://aceee.org/sector/state-policy/toolkit/aligning-utility (attached to Ex. AAE-1, Morgan Direct as AAE Exhibit PGM-4).

1. LRAMs guaranteed utilities' revenue for fixed cost recovery even if sales gains elsewhere (*e.g.*, weather-driven sales or new customers) offset the losses assumed to be occurring because of the utility's energy efficiency programs;

2. LRAM proceedings were highly contentious because the usage "lost" to the energy efficiency programs could be determined only by arduous evaluation, measurement and verification ("EM&V") studies, that often required a long time to prepare making it impossible for utilities, stakeholders or regulators to know how much the utility should recover until the studies were done;

3. LRAMs addressed only sales "lost" to energy efficiency programs suitable for subsequent EM&V studies.[88]

Moreover, under ENO's LCFC[89] proposal, there is an implicit assumption that all projected savings actually translate to an equivalent under-recovery of fixed costs for the Company, which is never actually true. That is, lost revenues are not themselves equivalent to under-recovery of fixed costs because other factors, such as weather, customer growth, economic growth, or off-system sales, may provide a balancing effect.[90]

ENO also has failed to define or explain several aspects of the LCFC. For example, ENO has failed to define the adjusted gross margin ("AGM"). It appears that the AGM includes all billing determinants in calculating LCFC, regardless of whether energy efficiency programs can actually affect those billing determinants. In other words, even though the ratepayers must pay customer charges and minimum bills regardless of how much they reduce their electricity use

[88] Ex. AAE-2, Morgan Surrebuttal at 12:12–13:6.
[89] The Council should be aware that ENO would have received an additional $2,505,290 in "lost" revenues despite overearning for several years. *See* Lost Contribution to fixed Costs and Utility Performance Incentive Filing for Program Year 8 for Entergy New Orleans, LLC (Resolution No. R-15-140; Docket No. UD-08-02, UD-17-03), ENO calculation of the Lost Contribution to fixed Costs and Utility Performance Incentive related to Program Year 8 of Energy Smart (June 27, 2019) (attached hereto as Attachment C). Thus, one of the many flaws in the LCFC methodology is that ENO will be found to have "lost revenue" despite earning more than the Council determined the Company was entitled to in the last rate proceeding.
[90] Ex. AAE-3, Barnes Direct at 42:12–18.

through Energy Smart programs, the LCFC calculations assume that a portion of these revenues is "lost."[91]

Similarly, ENO fails to explain how reconciliation will occur under the LCFC. The proposed reconciliation covers the difference between estimated numbers of participants/measures and actual numbers of participants/measures.[92] This means that deemed savings are not reconciled with actual savings, determined through evaluation, measurement and verification. Making this assumption certainly simplifies reconciliation, but it provides little comfort to ratepayers, who may not achieve the deemed savings but must pay the LCFC regardless. Revenue decoupling, of course, eliminates this problem because any revenue effects of the Energy Smart programs will manifest in the actual revenues that are compared to the authorized revenues.

While the Alliance strongly recommends that the Council reject ENO's LCFC, if the Council approves the LCFC proposal, then the reconciliation *should* cover the differences between:

- Projected LCFC *revenues* and LCFC *revenues* actually received.

- The timing of savings, *i.e.*, the billing periods when the projected LCFC assumed the savings would occur and reduce kWh or kW and the billing periods such savings actually occurred. Energy efficiency program savings do not all occur on the first day of a given program year or even smoothly across that year—often they are back-end loaded. Again, ENO does not state what assumption about timing it will use in calculating the LCFC it proposes to collect up-front during the year it is working to obtain the savings through its programs. In any event, whatever the assumed timing, the actual timing is likely to differ and reconciliation should take this into account.[93]

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[91] Ex. AAE-1, Morgan Direct at 24:17–25:3.
[92] *See* Ex. ENO-10, Owens Direct, ENO Exhibit DAO-3 at DSMCR Rider Attachment B, page 4 of 4; Application, Statement A-4 – Electric (Present Electric Rate Tariffs), Rider Schedule EFRP-4, Attachment G (pdf page 1518 of the Application).
[93] Ex. AAE-1, Morgan Direct at 27:8–28:2.

3) The Council should reject ENO's proposed Energy Efficiency Performance Incentive Framework.

ENO proposes a performance structure whereby the rate of return it would earn on rate-based efficiency program expenditures is tied to achieving specified percentages of annual energy savings targets, as follows:

- Savings less than 60% of target: 100 basis point reduction
- Savings from 60 – 95% of target: no change in return
- Savings from 95 – 120% of target: 100 basis point increase
- Savings in excess of 120% of target: 200 basis point increase[94]

The Council should reject ENO's incentive proposal, which provides that ENO will earn a return on all program expenditures, because the incentive proposal provides incentives that are too rich, effectively providing a shareholder return regardless of the amount of savings achieved relative to the target. The proposal also should be rejected because the step-based design creates only a loose tie between performance and incentive rewards.

As explained by Alliance witness Barnes, if a performance incentive is to truly reward good performance, there should be a reasonable minimum threshold at which no incentive is allowed.[95] ENO's proposed design does not allow for that since it permits a return for shareholders even if expenditures produce little savings. While the allowed return on expenditures is reduced for missing a 60% target threshold, the reduction is modest and retains most of the benefit that would otherwise accrue to shareholders.[96]

With regard to the loose tie between ENO's performance and the incentive rewards ENO hopes to receive, Alliance witness Barnes notes that the main problem with this type of design is

[94] Ex. ENO-10, Owens Direct at 26, Figure 1.
[95] Ex. AAE-3, Barnes Direct at 48:16–21.
[96] *Id.*

that it can create large differences in incentive amounts that are tied to small differences in performance, particularly when the granularity of the individual steps is low.[97] This can contribute to goal-seeking behavior based on relatively arbitrary step divisions, and can lead to contentious disagreements when achieved results approach the step divisions. For instance, under ENO's proposal, achieving 94.9% of the savings target produces no incremental performance incentive, while reaching 95% would result in an increased return of 100 basis points. ENO would also have no incentive to target additional savings within the 95% to 119.9% range because the incentive reward remains the same apart from the ingrained spending incentive created by the rate of return structure. However, that spending is, to a large degree, disconnected from an equivalent incentive to produce results.[98]

Moreover, nothing necessitates using the Company's rate of return as a benchmark. For instance, the structure could allow an incentive of 1% of program expenditures at 80% of the target, 2% at 85%, and so forth. That represents a more granular step-wise approach similar to that currently reflected in the Company's Formula Rate Plan Rider, which utilizes 5% increments for determining return on equity reward percentages.[99]

Finally, the Council should recognize that incremental performance incentives represent a cost that serves little useful purpose if the targets themselves are unambitious. ENO witness Owens presented the Company's historic performance at meeting annual energy efficiency targets in his testimony, showing that over the last seven program years, the Company has achieved 113% of the aggregate targets for the ENO Legacy division and 94% for the Algiers

[97] *Id.* at 49:3–14.
[98] *Id.*
[99] *Id.* at 49:17–50:5.

division.[100] The Council needs to establish more ambitious targets that are difficult to consistently achieve in order to justify the incremental cost increases associated with the incentive mechanism.

If the Council is going to adopt an incentive mechanism, the incentive should contain the following:

- A meaningful minimum savings threshold below which no additional earnings are received, such as meeting 80% of an annual target, supplemented with the potential for penalties for unreasonably poor performance (*i.e.*, a symmetrical incentive system).

- A more graduated incentive, with more granular steps (*e.g.*, 5% increments) or a formula where each incremental kWh of energy savings produces an incremental incentive.

- A cap on total incentive awards, which could be set as a percentage of total program costs, a fixed dollar amount, net ratepayer benefits, or another metric.

If the Council adopts an incentive mechanism, it should also penalize ENO for failing to meet the energy efficiency targets. A symmetrical incentive combines both of these aspects. An incentive design that includes adverse consequences for unreasonably poor performance sets a floor of minimum expectations without compromising the reward upside for good performance. Such a floor is similar to how many state renewable energy targets are structured, where a failure to achieve goals is met with compliance payments or civil penalties that cannot be recovered from ratepayers. The Council would, of course, retain discretion to waive or mitigate penalties for extraordinary circumstances or otherwise reasonable justification.

With respect to a penalty model, the Council should adopt Alliance witness Barnes suggestion that the Council consider a variable penalty based on foregone cost savings for each

[100] Ex. ENO-10, Owens Direct at 10, Table 1.

kWh between the amount of savings achieved and the minimum threshold.[101] A variable penalty set at average marginal energy and capacity costs would align with the goal of using energy efficiency to produce system cost savings. The Council would also retain the discretion to impose additional fines as it sees fit for instances where compliance shortfalls can be attributed to specific acts of negligence, such as willful failure to abide by Council directives.

E. The Council Should Reject ENO's Proposed AMI Rider.

ENO proposes to establish a new Electric AMI Rider through which AMI costs would be recovered under an annually adjusted fixed monthly charge. ENO's rationale for this rider is that "[t]he number of customers ENO serves, in large part, drives the level of costs associated with AMI. Therefore . . . these costs should be recovered through a customer charge so that a customer bears only the cost that customer causes."[102]

The proposed annual charges are depicted in ENO witness Thomas's direct testimony:[103]

Proposed Electric and Gas Monthly AMI ($)

	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

[101] Ex. AAE-3, Barnes Direct at 52:12–14.
[102] Ex. ENO-1, Thomas Direct at 66:6–8.
[103] *Id.*, ENO Exhibit JBT-9.

The Council should reject this justification. As Alliance witness Barnes' direct testimony demonstrates, 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 necessary for the customer to be connected to the grid. A non-advanced or standard meter and associated infrastructure can do so at lower costs. AMI is used for much more than the measurement of a customer's consumption for billing purposes. Furthermore, since customers do not have a meaningful choice of whether to take service through an advanced meter from a cost perspective, those customers are not truly "causing" the incremental advanced metering costs. Treating AMI costs exclusively as customer-related just because they relate to "metering," and consequently recovering them through a customer charge is an oversimplification of the cost causation factors at play.

The incremental costs of AMI above traditional metering are more accurately viewed as primarily energy and/or demand related because AMI deployment is generally undertaken with a goal of producing system cost savings associated at least in part with energy or demand related functions, or system operation and reliability. While it is true that some cost savings categories, such as meter reading expenses, fall within the customer domain, meters capable of automated reading (*e.g.*, "drive-by" reading) can provide this type of cost savings at a lower incremental cost to customers.

ENO's argument also ignores that AMI can help achieve line loss reductions, peak load reductions, improved reliability, and reduced operating costs for meter reading and outage repairs. Thus, ENO choice to use a rider to collect these costs violates a basic principle of utility ratemaking. The AMI rider will impose the costs of AMI on ratepayers without addressing or netting out the very cost benefits that are the rationale for installing AMI in the first place.

Moreover, the cost-benefit analysis that ENO used to support its application to invest in AMI shows consumption reduction as the largest benefit of AMI, without which AMI deployment would not produce a net customer benefit. Added to this are peak capacity reduction benefits and reductions in unaccounted for energy. In total, these three categories produce 63.4% of the net present value benefit and 64.8% of the nominal benefit in the Company's analysis.[104] The incremental costs of AMI above traditional metering are primarily energy and demand related because they effectively serve the same purpose as generating an additional unit of energy or investing in infrastructure to serve additional demand.[105] It is, therefore, reasonable to consider the incremental cost of AMI deployment as primarily energy and demand related.[106]

Furthermore, while the Council authorized ENO to implement an opt-out policy for residential customers who do not wish to receive an AMI meter,[107] under the Company's Proposed Rider Schedule opt-out customers must pay a one-time fee of either $131.94 (pre-AMI install) or $146.96 (post-AMI install), plus a monthly fee of $12.42/month.[108] For a customer seeking to opt-out in order to avoid AMI charges for AMI capabilities that they do not intend to take advantage of, the opt-out tariff schedule is not a meaningful alternative since such a customer would incur significantly higher charges by virtue of opting out.

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[104] Docket No. UD-16-04, Application of Entergy New Orleans Inc. for Approval to Deploy Advanced Metering Infrastructure, Request for Cost Recovery and Related Relief, at 10, Table 1 (Oct. 2016).
[105] Ex. AAE-5, Surrebuttal Testimony of Justin R. Barnes at 11:13–15 (Apr. 26, 2019) ("Barnes Surrebuttal").
[106] Ex. AAE-3, Barnes Direct at 33:5–12.
[107] *See* Resolution No. R-18-37 at 4–5 (Feb. 8, 2018).
[108] Entergy New Orleans, September 24, 2018 Filing re Advanced Metering Infrastructure Opt-Out, at 3 (attached hereto as Attachment D).

As noted above, riders are an inappropriate cost recovery mechanism where the expenditures are not volatile or outside the control of a utility. With regard to AMI installation, the utility is able to influence the timing and extent of these costs by, for example, issuing bids for the projects to evaluate the most cost-effective options. Utilities have less of an incentive to seek out cost-effective measures when the Company is guaranteed dollar for dollar recovery through a rider.

The Council should be aware that other utility regulators have rejected utility requests to recover AMI costs through a rider. For example, the Maryland Public Service Commission ("Maryland Commission") rejected a request from Baltimore Gas and Electric to recover AMI implementation costs through a surcharge. In rejecting this request, the Maryland Commission found that the programs for which the Commission had approved surcharges were fundamentally different in purpose and function from the AMI proposal.[109] The Commission noted that neither energy efficiency nor demand response programs build utility infrastructure.[110] Specifically, the Maryland Commission stated that:

> [S]urcharges guarantee dollar-for-dollar recovery of specific costs, diminish the Company's incentive to control those costs, and exclude classic, ongoing utility expenses from the standard, contextual ratemaking analysis. We therefore limited this recovery mechanism to very large, non-recurring expense items that have the potential to seriously impair a utility's financial well-being and that do not contribute to the Company's rate base as opposed to classic, ongoing costs of running a utility company.[111]

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[109] *In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost*, Case No. 9208, Order No. 83410 at 28 (MD PSC June 21, 2010).
[110] *Id.*
[111] *Id.* at 29 (internal quotations omitted).

The Maryland Commission then found that the investment in AMI "would represent a large, but classic, investment in BGE's distribution infrastructure."[112] In reconsidering the application, the Maryland Commission again rejected this surcharge request, finding that AMI deployment is analogous to an investment in a power plant, an investment that historically would be recovered through traditional ratemaking.[113] The Delaware Public Service Commission reached the same conclusion, stating that it "should encourage Delaware's energy companies to continue moving forward with its investment in advanced metering technology" but deferred any analysis of costs and benefits and cost recovery except in the context of a base rate case proceeding.[114]

Similarly, the Illinois appellate court found that ComEd's AMI rider (referred to as Rider SMP) did not meet its criteria to warrant single-issue ratemaking because: (1) the expenses related to upgrading to smart grid technology were not "unexpected, volatile, or fluctuating," as ComEd alone dictated the program's scope and, therefore, its costs; (2) the capital costs associated with the upgrades were not the result of a legislative mandate but rather were the result of ComEd's decision to renovate to reduce other costs; (3) ComEd can cover the expenses by a fiscal and operational plan that is completely within the utility's control; and (4) the Commission heard no evidence that the system modernization costs might produce unacceptable

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[112] *Id.*

[113] *In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost*, Case No. 9208, Order No. 83531 at 35 (MD PSC Aug. 13, 2010).

[114] *In the Matter of the Filing by Delmarva Power & Light Company for a Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy*, PSC Docket No. 07-28, PSC Regulation Docket No. 59, Order No. 7420 at ¶ 40, 2008 WL 10627024 (DE PSC Sept. 16, 2008).

financial outcomes if not afforded special treatment.[115] Precisely because the improvements covered by Rider SMP were expected to reduce other expenses and increase income in the long-term, which would affect the utility's revenue requirement, the court held that to allow Rider SMP would be to improperly consider in isolation changes in a particular portion of a utility's revenue requirement.[116]

Because a rider is a method of single issue ratemaking, the Council should not approve the implementation of a rider in the absence of exceptional circumstances. In this instance, ENO has failed to present any circumstances that would justify using a rider to collect AMI costs. The Council should find that the AMI Rider is a classic example of single issue ratemaking because AMI is the type of cost that should be addressed through normal ratemaking procedures.

F. The Council Should Reject ENO's Proposed Reliability Incentive Mechanism.

When asked whether ENO had a duty to provide safe and reliable electric service, ENO witness Stewart stated "I don't think I would describe it as a duty."[117] This response epitomizes ENO's attitude as well as the Company's failure to recognize its obligations as the monopoly service provider in New Orleans. ENO is granted a monopoly in New Orleans in exchange for the Company's public service obligation to provide safe and reliable service. ENO's request for approval of a Reliability Incentive Mechanism ("RIM") must be viewed in this light.

Given ENO's failure to even recognize the Company's responsibility to provide reliable service to New Orleans ratepayers, it is not surprising that the Council was forced to open an investigation into ENO's repeated service disruptions. On August 10, 2017, the Council adopted

[115] *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 405 Ill. App. 3d 389, 414–15, 937 N.E.2d 685 (2010).
[116] Id. at 415 (citations omitted).
[117] Hr'g Tr. 6/18/2019, 114:17–18.

Resolution No. R-17-427, establishing Docket No. UD-17-04, for the Council's investigation into outages, and reliability issues in Orleans Parish in general and to consider the establishment of minimum reliability performance standards, including the establishment of financial penalty mechanisms for failure to meet such minimum reliability performance standards.[118]

In Resolution No. R-17-427, the Advisors analysis determined that during a one-year period there were 2,599 outages on ENO's distribution system, including 1,462 outages that occurred during fair weather conditions.[119] The Advisors also found that approximately 41% of the outages that occurred during the day lasted longer than two hours, while approximately 31% of outages during this time period lasted longer than three hours. For outages that occurred in the evening, 54% of these outages were greater than two hours in duration and 38% of outages were greater than three hours in duration.[120]

In response to this investigation, ENO requests that the Company be rewarded for operating its distribution system in the manner ratepayers are entitled to but have not been receiving for years. ENO proposes a RIM, which is a sliding, allowed ROE from 10.5% to 11.0% for electric rate base based on ENO's System Average Interruption Duration Index ("SAIFI") performance. Depending on ENO's SAIFI performance, ENO's RIM plan would adjust the FRP rider rate to reflect the RIM plan's calculated electric allowed ROE. A SAIFI value of 1.05 or better would allow ENO an electric allowed-ROE of 11.0% in any subsequent FRP evaluation.[121]

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[118] Resolution No. R-17-427 (Aug. 10, 2017).
[119] *Id.* at 3.
[120] *Id.*
[121] As Mr. Watson discusses in his testimony, the revenue effect of increasing ENO's proposed initial 10.50% allowed-ROE to 11.0% is approximately $2.7 million. Ex. ADV-6, Direct Testimony of Byron S. Watson at 12 (Feb. 1, 2019) ("Watson Direct").

The Council should reject ENO's attempt to "do an end run" around its ongoing investigation. The investigation in Docket No. UD-17-04 will provide additional information outside of this rate proceeding, and this information will inform the Council regarding the level of penalty that is warranted and whether an incentive mechanism is even appropriate. The Council's conclusions in that docket may not bear any relation to ENO's RIM proposal and may actually be inconsistent with it.

Moreover, ENO's ROE affects the Company's return on all its investments, not just the distribution plant that is most closely related to many of ENO's reported service outages. The estimates for ENO's ROE provided by witnesses Hevert, Proctor, and Watson, are based on the market performance of proxy companies to ENO and not on any SAIFI values. As such, adjusting ENO's allowed-ROE may not be the best mechanism to incentivize ENO's distribution-related performance given its broad impact on ENO's overall rates.[122]

Furthermore, ENO has been overearning for a number of years.[123] During that time period, ENO maintained the Company's dismal record regarding distribution system outages. Thus, there is no reason to believe that continuing to allow ENO to over-earn is the best way to incentivize the Company.

More importantly, New Orleans ratepayers have been paying for reliable service for years, service that they were entitled to but did not receive. A utility should not be rewarded for conduct that it is otherwise obligated to undertake.[124] For example, FERC has denied an

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[122] Ex. AAE-3, Barnes Direct at 13:3–21.
[123] *See* Docket No. UD-16-04, Direct Testimony of Byron S. Watson, at 12. Advisor witness Watson concluded that ENO had excess revenues of $10.6 million in 2014, $19.5 million in 2015, and $16.2 million in 2016 (though ENO credited ratepayers $5 million of the 2016 excess revenues).
[124] *See, e.g.*, *Cal. Pub. Utils. Comm'n v. FERC*, 879 F.3d 966, 977 (9th Cir. 2018).

incentive for a maintenance construction pilot project where it found that the incentive would "unjustly reward" the utilities "for doing what it is supposed to do, *i.e.*, to adequately maintain its facilities in a prudent cost-effective manner."[125] ENO's RIM is nothing more than a bonus for good behavior. Similarly, the Council should not require New Orleans ratepayers to pay extra for a service they are entitled to by virtue of ENO's status as the monopoly provider of electric service.

G. The Council Should Reject ENO's Specific Community Solar Tariff Because the Company Failed to Establish that the Proposal Would Bring Greater Benefits.

The Council expressly considered ENO's request that the Council apply separate requirements to ENO's community solar offerings and those from Subscriber Organizations. In Docket No. UD-18-03, ENO specifically requested that the Council remove the restriction in the Proposed Rules that prohibited ENO from giving itself preferential treatment or using ratepayer funding for community solar projects.[126] The Council determined that in order to obtain approval for a proposal which did not conform to the recently adopted rules, the applicant would have to demonstrate why the alternative proposal brings greater benefits than a proposal conforming to the Community Solar Rules.[127]

At the evidentiary hearing, ENO witness Owens stated that there were two benefits associated with ENO's community solar offering. The first benefit is timing. According to ENO witness Owens, while the Council's Community Solar Rules are final, there are numerous other things that have to be addressed such as the role of the Council Utilities Regulatory Office, the

[125] *New England Power Pool*, 97 FERC ¶ 61,093 at 61,477 (Oct. 25, 2001), *order on reh'g*, 98 FERC ¶ 61,249 (Mar. 4, 2002).
[126] Resolution No. R-19-111 at 28–29 (Mar. 28, 2019).
[127] *Id.* at 30.

interconnection process, and application procedures.[128] Owens also asserted that the permitting and construction of the subscriber organizations projects would take two years or more.[129] Owens claimed that ENO had "deliberately designed it differently so that it could be ready to go in six months."[130]

The second benefit discussed by ENO witness Owens is that ENO's offering is "pay as you go" and the offering does not have any long-term contractual binding terms. Owens asserts that other developers are going to need commitments, whether it is up-front payments that are substantial or long-term contractual commitments.[131] ENO's "benefits" must be viewed in light of the Council's policy goals. One of the principles established by the Council with regards to community solar programs was the principle of a level playing field. In Council 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.[132]

ENO has essentially conceded that the potential "benefits" of its community solar offering stem from its status as a regulated utility.[133] ENO's ability to offer potential subscribers service without upfront payments or long-term contracts stems from the fact that the Company

[128] Hr'g Tr. 6/19/2019, 119:22–25.
[129] *Id.* at 119:25–120:2.
[130] *Id.* at 120:5–6.
[131] *Id.* at 120:7–15.
[132] Resolution No. 18-223 at 3 (June 21, 2018).
[133] *See* Ex. ENO-12, Rebuttal Testimony of D. Andrew Owens at 41:10–12 ("Many of these unique benefits result from the fact that ENO is a regulated, vertically-integrated utility that can offer 'Utility-Scale' community solar projects.") (Mar. 22, 2019).

bears no financial risk in making this offer. ENO's community solar offering is provided from solar projects that are fully supported by all ratepayers in ENO's rates. Regardless of the number of participants in ENO's community solar offering and whether the fees and credits proposed by ENO for participants fully offset the costs of the projects in ENO's community solar offering, ENO's prudently incurred costs related to the solar projects will be recovered. This guaranteed recovery places solar developers at a clear and substantial disadvantage and, as a result, these developers may choose not to participate in the New Orleans market.

Moreover, ENO witness Owens relies on unsubstantiated assertions in describing the benefits of the Company's offering. ENO claims that other solar developers will need substantial upfront payments or long-term commitments. The Company offers no evidence regarding how other developers might structure their projects. For example, ENO's community solar offering does require an initial 12-month contract[134] and imposes a termination fee of $50.00 should a subscriber chose to end his contract early.[135] No evidence in this proceeding supports the assertion that other solar developers cannot design their offers in the same manner.

ENO's community solar offering does not meet the standard established by the Council in Resolution No. R-19-111. The Company's offering does not offer greater benefits than a proposal conforming to the recently adopted Community Solar Rules. To the contrary, ENO's offering creates the real risk of harm to the nascent community solar market without presenting any benefits for New Orleans residents. The Council should reject ENO's community solar offering.

[134] Application, Schedule CSO (Community Solar Option), Section III (pdf page 462 of the Application).
[135] *Id.* at Section VI (E) (pdf page 464 of the Application).

H. ENO's Green Power Tariff Must Be Amended to Ensure that Only Truly Green Power is Purchased for Participants and that Only Participants are Held Responsible for the Costs of the Program.

ENO is requesting to provide a Green Power Option, under which participating customers would be able to match some or all of their electricity usage with renewable energy certificates ("RECs") generated or purchased by ENO and retired on the customer's behalf. ENO has already selected Green-e as the Company's REC vendor.

ENO witness Owens admitted that the Green Power Option tariff does not define "green energy" and that the Company's third-party vendor would certify renewable energy technologies eligible to receive RECs.[136] However, the Council does not regulate Green-e and, therefore, cannot control the type of power Green-e would provide to the program. Some states actually include energy generated from black liquor or waste to energy facilities in their renewable portfolio standard. Thus, these unclean resources actually receive RECs and could be included as resources in ENO's green power offering. The Council should direct ENO to define explicitly green energy as actual clean resources, *i.e.*, solar, wind, and battery storage.

According to ENO, all costs of the Green Power Option tariff offering will be borne by the participants. However, when asked who bears the costs of this program, such as marketing, contracting with Green-e, if no one participates in the program or too few people opt to participate, ENO witness Owens failed to answer the question, simply stating that the costs in that instance would be "de minimus."[137] The Council should hold ENO to its assertion that none of the costs of this offering will be assessed to ratepayers. The Council should direct ENO to

[136] Application, Rider Schedule GPO (Green Power Option) (pdf page 623–24 of the Application); Hr'g Tr. 6/19/2019, 115:11–14.
[137] Hr'g Tr. 6/19/2019, 118:22–23.

include language in the Green Power Option tariff that expressly states that any costs or expenses not recovered from participants may not be recovered from ratepayers.

I. ENO Has Failed to Justify the Proposed Gas Plant Rider.

ENO has proposed a New Orleans Power Station ("NOPS") rider associated with ENO's construction of the $210 million gas-fired generating station. If approved, this rider would enable ENO to begin recovering the estimated first-year revenue requirement associated with NOPS beginning in the month after it enters commercial operation. The tariff provision states, in pertinent part:

> ENO shall include through an interim rate adjustment effective as of the first billing cycle of the month following the Commercial Operation Date ("COD") the final estimated first-year revenue requirement associated with the completion of the construction of the New Orleans Power Station ("NOPS"), *the construction of which was approved by the Council of the City of New Orleans in Resolution R-18-65*.[138] (emphasis added).

As the Council is aware, on June 14, 2019, the District Court issued a bench ruling voiding Resolution No. R-18-65. Judge Griffin memorialized this oral ruling in a written judgment issued on July 2, 2019.[139] Thus, contrary to the rationale set forth in the tariff language, the construction of NOPS does not have the approval of the Council. While the Court recently granted the Council's request for a suspensive appeal, this decision does not change the fact that the Council's approval has been voided. Thus, ENO's authority to construct NOPS at ratepayer expense is questionable at best. ENO is not entitled to collect the costs of NOPS construction from the ratepayers in the absence of a finding by the Council that construction of

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138 Application, Rider Schedule EFRP-5 (Electric Formula Rate Plan Rider Schedule), Section III (C) (pdf page 1077 of the Application).
139 Civil District Court for the Parish of Orleans, Notice of Judgment and Judgment, Case No. 18-3843 (July 2, 2019) (attached hereto as Attachment E).

the project is in the public interest. Moreover, ENO is only entitled to recover prudently incurred costs. ENO should not automatically recover these construction costs without establishing that all the costs associated with the construction of this plant were prudently incurred. Therefore, the Council must reject the NOPS rider.

VI. Conclusion

In this docket, ENO requests that the Council approve the Company's first rate application in ten years. ENO has established that it will not act in the interests of New Orleans ratepayers. Moreover, ENO has determined that the Company should not be bound by the basic ratemaking principles that govern other utilities operating in this country. ENO's application is a breathtakingly aggressive attempt to lock in revenues for the foreseeable future, revenues that are not justified even based on ENO's own testimony. In other words, ENO seeks a guaranteed revenue stream and expects the Council to approve its extreme charges despite the heavy and unfair burden these costs will place on the ratepayers of New Orleans.

The Council is the only protection the New Orleans ratepayers have against a monopoly provider's excessive charges for a vital service. ENO has failed to establish that the Company's excessive use of riders is necessary or a prudent manner in which to recover its costs. To the contrary, these riders will lessen ENO's incentive to operate in an efficient and cost-effective manner because, regardless of the Company's actions, ENO will recover *all* the costs associated with the services and programs covered by the riders. Similarly, ENO has failed to justify the Company's almost doubling of the residential customer charge. This drastic increase in an unavoidable charge will simply ensure that ENO continues overearning, thereby increasing the already heavy energy cost burden New Orleans residents have experienced for years. The

Council must reject the proposed riders and the dramatic increase in the residential customer charge as contrary to the public interest.

Dated: July 26, 2019

Respectfully submitted,

Susan Stevens Miller

Susan Stevens Miller (*pro hac vice*)
Clean Energy Attorney
Earthjustice
1625 Massachusetts Ave., NW, Ste. 702
Washington, DC 20036
(202) 667-4500
smiller@earthjustice.org

Counsel for the Alliance for Affordable Energy and Sierra Club

Attachment A: Excerpt of Direct Testimony of Byron S. Watson on Behalf of the Advisors, Docket No. UD-16-04 (May 26, 2017)

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-04**

PUBLIC REDACTED VERSION

DIRECT TESTIMONY

OF

BYRON S. WATSON, CFA, CRRA

ON BEHALF OF

THE ADVISORS TO THE

COUNCIL OF THE CITY OF NEW ORLEANS

May 26, 2017

Q. WHAT HAVE BEEN ENO'S RECENT EARNING LEVELS?

A. The below table presents approximate estimates of ENO's regulatory Earned ROE and resulting revenues in excess of those required for it to earn the Council's last allowed ROEs (i.e., excess revenues) for the years 2016, 2015, and 2014 based on an analysis of ENO's FERC Form 1 data for these years.[15] Workpapers supporting the 2016 values presented in the below are provided as Exhibit No. ___ (BSW-4).

Table 1: ENO' Estimated Financial Performance (Gas and Electric)

	2016	2015 [1]	2014 [2]
Excess Revenues	$11.2 million	$19.5 million	$10.6 million
Earned ROE	12.8%	15.8%	14.3%

[1] Source: ENO-provided estimate dated April 20, 2016
[2] Source: Council Docket No. UD-15-01, Exhibit BSW-4

I note that in 2016, following discussions among ENO representatives and the Advisors to the Council ("Advisors") related to ENO's 2015 excess revenues, ENO voluntarily credited ratepayers $5 million outside of its Council-authorized rates pursuant to Council Resolution No. R-16-333. Had ENO not done so, its 2016 excess revenues as estimated based on an analysis of ENO's FERC Form 1 data would have been $16.2 million and its Earned ROE 13.6%. Also, the Advisors requested that ENO provide its estimate of its regulatory earnings so they could be placed into the instant docket's record, but ENO objected to this request and refused to provide such an estimate.[16] As the above table

[15] ENO has correctly noted that estimating its earned ROE based on an analysis of FERC Form 1 data is not "regulatory grade" suitable for ratemaking purposes. Such estimates provide reasonable guidance as to ENO's financial condition.

[16] See the Advisors' RFIs CNO 2-18 and 2-19

Attachment B: Compilation of Selected ENO Responses to AAE Discovery Requests

Entergy NEW ORLEANS, LLC.
CITY OF NEW ORLEANS
Docket No. UD-18-07

Response of: Entergy New Orleans, LLC
to the Third Set of Data Requests
of Requesting Party: Alliance for Affordable Energy

Question No.: AAE 3-1 Part No.: Addendum:

Question:

Please refer to the Public Attachment ENO provided in response to AAE 2-4 depicting the costs underlying ENO's calculated residential customer unit cost, in the tab labeled "RR 4 Customer".

a. Please provide a complete description of the equipment associated with FERC Account 371 referring to installations on customers' premises, including the number of each individual piece of equipment contained in the account. (Line 3 in tab RR 4 Customer). For example: 100 cable vaults, 25 motors.

b. Please identify the total number of residential customers who have equipment included in FERC Account 371 located on their premises, and the number of customers for each type of equipment identified in your response to (a) above.

c. For each piece of equipment identified in your response to (a) above, please describe the typical circumstances under which such equipment is needed and explain why the equipment is properly assigned to the residential class rather than directly assigned to the individual customer who requires that equipment.

Response:

a. The Company does not have forecasted asset balances at the retirement unit level that correspond to the amounts reflected in FERC account 371, which are reflected on line 3 on the RR4 Customer tab.

b. As of December 31, 2018, the Company had a total of 3,660 lighting fixtures on the premises of its residential customers. Identifying the total number of customers having these fixtures on their premises is not readily ascertainable from the Company's records and would be unduly burdensome because a given customer may have more than one fixture on premises.

Question No.: AAE 3-1

c. The Company provides these fixtures pursuant to Lighting rate schedules, which are included in the Lighting rate class. Accordingly, the Company would not allocate these costs to individual customers but to the Lighting rate class.

If all costs allocated to Distribution General were allocated to Distribution Lighting and, therefore, the Lighting rate class as opposed to all customers, which change would not be appropriate, such change would reduce the calculated residential customer charge in the Unit Cost Study to $20.07. This level of residential customer charge still supports the Company's proposed level of $15.53 as a reasonable step in moving toward a residential customer charge that is commensurate with the Unit Cost Study.

ENTERGY NEW ORLEANS, LLC.
CITY OF NEW ORLEANS
Docket No. UD-18-07

Response of: Entergy New Orleans, LLC
to the Third Set of Data Requests
of Requesting Party: Alliance for Affordable Energy

Question No.: AAE 3-5 Part No.: Addendum:

Question:

Please state whether ENO has performed a marginal cost study for customer-related costs, and if so, please provide a copy of that study in executable format with all formulas intact.

Response:

ENO objects to this Request to the extent that it calls for the production of information that is subject to the attorney-client privilege and/or the work product doctrine. ENO further objects on the grounds that the request is overly broad. Subject to and without waiving the foregoing objections, the Company responds as follows:

ENO did not perform a marginal cost study in connection with the test years that are the subject of this proceeding. ENO has utilized an embedded cost of service approach, rather than a marginal cost of service approach, as is consistent with historical practice for ratemaking at the City Council. In addition, a marginal cost study is not required by the Minimum Filing Requirements of the City Council.

Attachment C: Entergy New Orleans, Lost Contribution to Fixed Costs and Utility Performance Incentive Filing for Program Year 8, Docket Nos. UD-08-02, UD-17-03 (June 27, 2019)

Entergy

Entergy New Orleans, LLC
1600 Perdido Street, Bldg #505
New Orleans, LA 70112
Tel 504 670 3680
Fax 504 670 3615

Brian L. Guillot
Vice President,
Regulatory Affairs
bguill1@entergy.com

June 27, 2019

VIA HAND DELIVERY
Ms. Lora W. Johnson, CMC, LMMC
Clerk of Council
City Hall, Room 1E09
1300 Perdido Street
New Orleans, Louisiana 70112

RE: Lost Contribution to Fixed Costs and Utility Performance Incentive Filing for Program Year 8 for Entergy New Orleans, LLC (Resolution R-15-140; Docket No. UD-08-02, UD-17-03)

Dear Ms. Johnson:

Pursuant to Council Resolution R-15-140, enclosed please find an original and three copies of Entergy New Orleans, LLC's ("ENO") calculation of the Lost Contribution to Fixed Costs and Utility Performance Incentive related to Program Year 8 of Energy Smart. Please file an original and two copies into the record in the above-referenced matter and return a date-stamped copy to our courier.

Thank you for your assistance with this matter.

Sincerely,

Brian L. Guillot

Enclosure

cc: Official Service List UD-08-02 and UD-17-03 *(via electronic mail)*

RECEIVED
JUN 27 2019
BY:

SUMMARY

ENO-LEGACY		
Performance Incentive	$	852,019
LCFC	$	2,308,736
Total	**$**	**3,160,755**

ENO-Algiers		
Performance Incentive	$	-
LCFC	$	196,554
Total	**$**	**196,554**

WORKSHEET A

ENO-LEGACY PERFORMANCE INCENTIVE

Gross kWh Achieved (worksheet E)	47,374,464
Gross kWh Goal	42,988,810
Percent	110.2%
ENO Incentive	$ 852,019

Savings Goal	Incentive Formula
60%<N<94%	0
95%<N<99%	
100%	$750,000
100%<N<120%	$750,000+$10,000*(X)

WORKSHEET B

ENO-ALGIERS PERFORMANCE INCENTIVE

Gross kWh Achieved (worksheet E)	2,942,064
Gross kWh Goal	3,110,496
Percent	94.6%
ENO Incentive	$ -

Savings Goal	Incentive Formula
60%<N<94%	0

Worksheet E

Program	Energy Savings (kWh) Plan	Verified Gross	%
HPwES	149,257	376,159	252.0%
Low Income	98,072	121,880	124.3%
Multifamily	37,633	37,760	100.3%
Green Light Direct Install	97,542	9,061	9.3%
Res Lighting and Appliances	264,768	307,473	116.1%
AC Tune-Up	133,532	160,029	119.8%
Energy Smart School Kits and Education	136,695	48,272	35.3%
Scorecard Behavioral	722,424	745,249	103.2%
Direct Load Control	-	-	-
Small Commercial Solutions	484,792	418,266	86.3%
Large C&I	766,112	488,175	63.7%
Publicly Funded Institutions	219,669	229,740	104.6%
Algiers Total	**3,110,496**	**2,942,064**	**94.6%**
HPwES	2,008,202	3,074,470	153.1%
Low Income	1,316,362	1,907,136	144.9%
Multifamily	493,311	829,465	168.1%
Green Light Direct Install	167,958	67,967	40.5%
Res Lighting and Appliances	3,503,824	5,525,610	157.7%
AC Tune-Up	1,711,475	2,295,461	134.1%
Energy Smart School Kits and Education	546,782	800,576	146.4%
Scorecard Behavioral	4,277,576	4,933,408	115.3%
Direct Load Control	-	-	-
Small Commercial Solutions	5,309,288	6,870,151	129.4%
Large C&I	21,047,929	18,402,858	87.4%
Publicly Funded Institutions	2,606,103	2,667,362	102.4%
Total Legacy	**42,988,810**	**47,374,464**	**110.2%**

Worksheet F

Entergy New Orleans, LLC
Energy Efficiency Program Support
2018 Per Book Usage, Base Revenue and AGM

Rate Class	Base Revenue	kWh	AGM
Excluding Algiers			
Residential	122,879,208	2,103,643,962	
Small Electric	45,863,233	794,255,050	
Municipal Buildings	1,730,467	23,348,837	
Large Electric	19,625,772	455,144,822	
Large Electric High Load Factor	63,814,733	1,688,979,457	
Master Metered Non Residential	70,966	1,365,080	
High Voltage	4,932,563	157,904,140	
Large Interruptible Service	2,811,934	189,042,000	
Lighting	4,464,606	48,514,709	
Total Excluding Algiers	266,193,482	5,462,198,057	$0.04873
Algiers			
Algiers Residential	19,937,643	294,435,756	
Algiers Small General Service	3,936,157	41,386,415	
Algiers Large General Service	5,576,176	109,756,543	
Algiers Lighting	718,286	5,987,608	
Total Algiers	30,168,262	451,566,322	$0.06681
Total Entergy New Orleans	$296,361,744	5,913,764,379	$0.05011

Attachment D: Entergy New Orleans, Filing Re: Advanced Metering Infrastructure Opt-Out, Docket No. UD-16-04 (Sept. 24, 2018)

Entergy

Entergy New Orleans, LLC
1600 Perdido Street, Bldg. #505
New Orleans, LA 70112
Tel 504 670 3680
Fax 504 670 3615

Gary E. Huntley
Vice President,
Regulatory Affairs
ghuntle@entergy.com

September 24, 2018

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

Re: ***Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief; Resolution and Order Directing Entergy New Orleans, LLC to Accelerate Implementation of its Advanced Metering Initiative; CNO Docket No. UD-16-04***

Dear Ms. Johnson:

Pursuant to Resolution R-18-37, Entergy New Orleans, LLC ("ENO" or the "Company"), respectfully submits this Compliance Filing. In February 2018, the Council approved ENO's Application to Deploy Advanced Meter Infrastructure ("AMI"), filed October 18, 2016, finding that that ENO's proposed AMI deployment is prudent and in the public interest.[1] In connection with its approval of ENO's Application, the Council authorized the Company to implement an opt-out policy for residential customers who do not wish to receive an AMI meter.[2] The Council directed the Company to make a compliance filing in 2018 prior to meter deployment for approval of the opt-out fees consistent with the methodology described in the Direct Testimony of Company witness Jay A. Lewis.

The Parties in this case were also directed to convene a technical conference for the purpose of reaching consensus on a methodology and calculation of the opt-out charge designed to avoid cost shifting between AMI customers and opt-out customers. On June 15, 2018, the Parties convened the required technical conference, and no Party expressed any specific

1 *See* Resolution R-18-37, February 8, 2018.
2 *See* Resolution R-18-37, at 5.

SEP 24 4 36

objections to the proposed opt-out tariff methodology described in the Direct Testimony of Jay A. Lewis, pages 30-36, which was approved by Resolution R-18-37.

Accordingly, pursuant to Resolution R-18-37, the Company hereby files its Compliance Filing attaching its proposed AMI Opt-Out Tariff for approval by the Council before AMI deployment, which updates its October 2016 filing for current cost assumptions and inputs.[3] The Company also requests expedited consideration and approval of this Compliance Filing in order to support the timely notification of the Opt-Out option for ENO's customers before meter deployment begins in February 2019 (*i.e.*, ENO has contemplated a 90-day notice period for customers, which would begin in November 2018). Please file an original and two copies into the record in the above referenced matter, and return a date stamped copy to our courier.

In connection with the Company's filing, a Confidential Version of the above-described documents bearing the designation "Highly Sensitive Protected Materials" are being provided to the appropriate reviewing parties pursuant to the terms and conditions of the Official Protective Order adopted in Council Resolution R-07-432. Portions of the information included in the filing consist of Highly Sensitive Protected Materials pursuant to Council Resolution R-07-432, the disclosure of which could subject not only the Company, but also its customers, to a substantial risk of harm. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

If you have any questions regarding this information, please contact me at (504) 670-3680.

Sincerely,

Gary E. Huntley

Gary E. Huntley

Enclosure

cc: Official Service List, Council Docket No. UD-16-04

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[3] The Company herein attaches (1) the proposed tariff, (2) an Opt-Out Tariff Fee Summary, (2) Customer Opt-Out Forms, and (3) HSPM Workpapers.

ENTERGY NEW ORLEANS, LLC
ELECTRIC SERVICE

RIDER SCHEDULE AMO

Effective: October 30, 2018
Filed: September 24, 2018
Supersedes: New Schedule
Schedule Consists of: One Page

ADVANCED METERING OPT-OUT

I. AVAILABILITY

This rider is available to customers served on an Entergy New Orleans, LLC ("ENOL" or "the Company") rate schedule for residential service, where facilities of adequate capacity and suitable phase and voltage are adjacent to the premises to be served, and service is taken under the regular terms and conditions of the Company.

This rider is available to residential customers who elect non-standard meter service in lieu of the standard communicating advanced meter service (Opt-Out) and who are currently taking service at no more than 200 Amps under a rate schedule for which a communicating advanced meter is the standard meter service. Customers electing this service must submit the applicable required up-front fee along with the required signed form requesting such service.

II. APPLICABILITY

Pursuant to the Council of the City of New Orleans (the "Council") Resolution No. R-18-37, ENOL is authorized to implement an Opt-Out policy for residential customers. The Council's Order No. XXXXX defines the approved opt-out fees in Section III.

III. ADVANCED METER OPT-OUT FEES

A customer receiving non-standard metering service and opting out from receiving an advanced meter shall be charged a one-time fee depending upon when the request to opt-out is received relative the customer's meter being replaced and a recurring monthly manual meter reading fee:

One-time Up-Front Fee for Opt-Out before the initial Advanced Meter Install*	$131.94
One-time Up-Front Fee for Opt-Out after the initial Advanced Meter Install	$146.96
Monthly Manual Meter Reading Fee for Opt-Out Customers	$12.42 per Month

**Existing meters must pass an inspection to ensure the meter meets safety and accuracy standards. If the existing meter fails the safety inspection or accuracy test, the existing meter will be replaced with a refurbished digital non-communicating meter.*

Customers taking service under Rider Schedule AMO relocating to a new premise who wish to continue service under Rider Schedule AMO are required to request new service according to the Company's Opt-Out request requirements including payment of the one-time service and administration fee at the new premise. A Customer who cancels service under Rider Schedule AMO and later re-enrolls for this service at any location served by the Company would be required to pay another one-time service and administration fee.

If a customer's account includes both an electric contract and a gas contract, the fees in Section III will be applicable to only the electric contract; however, the customer's electric and gas meters will be read manually.

Entergy New Orleans, LLC.
Docket UD-16-04
Calculation of Opt-Out Fees

Ln #	Up-front Fee Components	Estimated Cost	Estimated # Opt-Out Customers	Estimated Fee
1	Billing programming changes to build the one-time and monthly fees in CCS	$ 38,500	510	$ 75.49
2	Barrel lock and seal for non-advanced meters	$22.86/ea		$ 22.86
3	Opt out paperwork mailing costs for one-time mailing to customers, to enroll and confirm opt-out election	$4.86ea		$ 4.86
4	Trip charge: employee labor and vehicle costs to perform field test and inspect meter (assuming opt-out occurs prior to installation of advanced meter) OR to remove AMI meter and replace with non-AMI meter (assuming opt-out occurs after installation of advanced meter)	$28.73/ea		$ 28.73
5	**Total Up-Front Fee for Opt-Out Pre-Advanced Meter Install**			**$ 131.94**
7	Meter fee for replacing AMI meter with tested salvaged digital meter (Assuming opt-out occurs after installation of advanced meter)	$15.02/ea		$ 15.02
8	**Total Up-Front Fee for Opt-Out Post Advanced Meter Install**			**$ 146.96**
	Monthly Fee components	**Estimated Cost**	**Estimated # Opt Out Customers**	**Estimated Monthly Fee**
9	Trip charge: employee labor and vehicle costs for meter reads	$10.91/ea		$ 10.91
10	ENO Share of Salary for two ESI customer service specialists (Estimate = $131K annual labor / ~7,300 system opt outs * ENO Opt-Outs)	$ 9,204	510	$ 1.50
11	**Total Monthly Fee for Opt-Out Customers**			**$ 12.42**

[DATE]
[CUSTOMER ACCOUNT NUMBER]
[CUSTOMER NAME]
[MAILING ADDRESS]
[MAILING CITY STATE ZIP]

Dear Entergy New Orleans Customer,

Thank you for contacting us about the meter that you currently have at your location. Your request to keep a non-communicating meter rather than receiving a new advanced meter has been received. Your choice to opt out of receiving an advanced meter and to receive service using a non-communicating meter will require that you pay additional fees. These fees are required to cover the additional costs that the Company will incur for equipment, monthly meter readings, ongoing maintenance, and visits to your premises to manually perform meter services. If you have gas and electric services with us at this location, you will be automatically opted out for both your gas and electric meters.

In order to retain a non-communicating meter, please sign and complete this form and return it to Entergy New Orleans by **MM/DD/YYYY** along with your payment for the non-refundable one-time service and administration fee listed below. Once your signed and completed form has been received, we will bill you the monthly manual meter reading fee shown below. It will be automatically added to your monthly bills.

Non-refundable opt-out fees approved by the City Council of New Orleans:

• **One-Time Service and Administration Fee***	$ 131.94
• **Monthly Manual Meter Reading Fee****	$ 12.42

*Any applicable state and local taxes/fees will be added to your next bill after submitting this signed and completed form with your payment.
**The recurring monthly fee is in addition to all other applicable charges that appear on your bill.

Because you are choosing to have non-standard metering service and to forego the benefits of having an advanced meter:

- You are responsible for providing and maintaining access to Entergy New Orleans for meter installation, maintenance, readings, etc. Failure to do so may result in termination of your opt-out participation, along with the installation of an advanced meter.
- You are only eligible for Entergy New Orleans' residential rate schedule tariff and will not be able to receive any other enhanced benefits that the advanced metering system may provide.
- You may opt-in to receive an advanced meter at any time by calling 1-800-Entergy (1-800-368-3749).

In order to complete your request to retain a non-standard meter, please:

- Return this completed and signed document to Entergy New Orleans by **MM/DD/YYYY**.
- Pay the applicable non-refundable one-time service and administration fee, listed above.

Both the completed document and payment (by Check, Cashier's Check, or Money Order ONLY made payable to Entergy New Orleans, LLC. ATTN: __________) should be sent to_____________________________.

Failure to complete these steps by the above date will result in the replacement of your existing non-standard meter with an advanced meter. If you have any questions, please call the Entergy Customer Service Center at 1-800-Entergy (1-800-368-3749).

Acknowledgement: I represent and warrant that I am the named, authorized person on the customer account number above. I understand that if my existing meter does not meet applicable standards, it will be replaced with a non-communicating meter. Further, I understand and accept the above fees, requirements, and limitations associated with non-standard metering service and hereby request that you initiate non-standard metering service at the address above.

______________________________ ______________________
Account Holder Signature Date

______________________________ ______________________
Print Name Phone number

[DATE]
[CUSTOMER ACCOUNT NUMBER]
[CUSTOMER NAME]
[MAILING ADDRESS]
[MAILING CITY STATE ZIP]

Dear Entergy New Orleans Customer,

Thank you for contacting us about the meter that you currently have at your location. Your request to have a non-communicating meter rather than an advanced meter has been received. This letter is being sent to inform you that your option to have your advanced meter removed and to receive service using a non-communicating meter requires you to pay additional fees. These fees are required to cover the additional costs that the Company will incur for equipment, monthly meter readings, ongoing maintenance, and visits to your premises to manually perform meter related services. If you have gas and electric services with us at this location, you will be automatically opted out for both your gas and electric meter.

In order to receive a non-communicating meter, please sign and complete this form and return it to Entergy New Orleans along with your payment for the non-refundable one-time service and administration fee listed below. Once your signed and completed form and payment have been received, we will bill you the monthly manual meter reading fee shown below. It will automatically be added to your monthly bill(s).

Non-refundable opt-out fees approved by the New Orleans City Council:

- **One-Time Service and Administration Fee*** $ 146.96
- **Monthly Manual Meter Reading Fee**** $ 12.42

*Any applicable state and local taxes/fees will be added to your next bill after submitting this signed and completed form with your payment.
**The recurring monthly fee is in addition to all other applicable charges that appear on your bill.

Because you are choosing to have non-standard metering service and to forego the benefits of having an advanced meter:

- You are responsible for providing and maintaining access to Entergy New Orleans for meter installation, maintenance, readings, etc. Failure to do so may result in termination of your opt-out participation and may require the installation of an advanced meter.
- You are only eligible for Entergy New Orleans' residential rate schedule tariff and will not be able to receive any other enhanced benefits that the advanced metering system may provide.
- You may opt-in to receive an advanced meter at any time by calling 1-800-Entergy (1-800-368-3749), or by visiting one of our walk-in centers.

In order to complete your request to receive a non-standard meter, please:

- Return this completed and signed document to Entergy New Orleans.
- Pay the applicable non-refundable one-time service and administration fee, listed above.

Both the completed document and payment (by Check, Cashier's Check, or Money Order ONLY made payable to Entergy New Orleans, LLC. ATTN: ___________) should be sent to___________________________.

If you have any questions, please call the Entergy Customer Service Center at 1-800-Entergy (1-800-368-3749).

Acknowledgement: I represent and warrant that I am the named, authorized person on the customer account number above. I understand that my existing advanced meter will be replaced with a non-communicating meter. Further, I understand and accept the above fees, requirements, and limitations associated with non-standard metering service and hereby request that you initiate non-standard metering service at the address above.

______________________________	______________________
Account Holder Signature	Date
______________________________	______________________
Print Name of Account Holder	Phone number

HIGHLY SENSITIVE PROTECTED MATERIALS
HAVE BEEN REDACTED PURSUANT TO
COUNCIL RESOLUTION R-07-432

ATTACHMENT 5 : Opt Out Fee Workpaper (HSPM) HAS BEEN REDACTED PURSUANT TO COUNCIL RESOLUTION R-07-432

Attachment E: Civil District Court for the Parish of Orleans, Notice of Judgment and Judgment, Case No. 18-3843 (July 2, 2019)

Civil District Court for the Parish of Orleans
STATE OF LOUISIANA

No: 2018 - 03843

Division/Section: I-14

DEEP SOUTH CENTER FOR ENVIRONMENTAL JUSTICE ETAL ET AL
versus
THE COUNCIL OF THE CITY OF NEW ORLEANS ETAL ET AL

Date Case Filed: 4/19/2018

NOTICE OF SIGNING OF JUDGMENT

TO:

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In accordance with Article 1913 C.C.P., you are hereby notified that Judgment in the above entitled and numbered cause was signed on July 2, 2019

New Orleans, Louisiana
July 2, 2019

MINUTE CLERK

CIVIL DISTRICT COURT FOR THE PARISH OF ORLEANS
STATE OF LOUISIANA

CASE NO. 18-3843 DIVISION "I" Section 14

THE SOUTHERN CENTER FOR ENVIRONMENTAL JUSTICE, INC. d/b/a DEEP SOUTH CENTER FOR ENVIRONMENTAL JUSTICE, VAYLA NEW ORLEANS, JUSTICE AND BEYOND, 350 NEW ORLEANS, SIERRA CLUB, MR. THEODORE QUANT, AND MS. RENATE HEURICH

VERSUS

THE COUNCIL OF THE CITY OF NEW ORLEANS, THE UTILITY, CABLE, TELECOMMUNICATIONS AND TECHNOLOGY COMMITTEE OF THE NEW ORLEANS CITY COUNCIL, JASON R. WILLIAMS, HELENA MORENO, JOSEPH I. GIARRUSSO, JAY H. BANKS, KRISTIN GISLESON PALMER, JARED C. BROSSETT, AND CYNDI NGUYEN

FILED: ____________________ ____________________
Deputy Clerk

JUDGMENT

Petitioners' Amended Petition to Enforce the Louisiana Open Meetings Law, for Declaratory Judgment, Injunction, and Attorneys' Fees and Costs came before this Court for hearing on July 19, 2018.

Present at the hearing in court were:

William Quigley, Monique Harden, Alexander Bollag, Susan Stevens Miller, and Jill Tauber, for petitioners; and

Corwin St. Raymond, William Goforth, and Cherrell S. Taplin, for defendants.

After considering the pleadings and memoranda filed with this Court, the evidentiary record, and the arguments of counsel, this Court announced its ruling in open court on June 14, 2019. The Court explained this judgment is to make sure that "citizens voices are heard" at City Council meetings. Regarding the February 21, 2018 meeting of the Utilities, Cable, Telecommunications and Technology Committee of the New Orleans City Council ("UCTTC") and the March 8, 2018 meeting of the New Orleans City Council (the "Council"), the Court found that the Council "did nothing wrong." The Court acknowledged the Council's own investigatory findings that, as a result of Entergy New Orleans' actions, "paid citizens were present" at public meetings held on October 16, 2017 and February 21, 2018. The Court further found that "Entergy's actions undermined" the Open Meetings Laws, La. R.S. 42:11, *et seq*. Finally, the Court found that "the Open Meetings Laws were not adhered to as relates to the meaning and policy behind the Open Meetings Laws."

Regarding the February 21, 2018 meeting of the Utilities, Cable, Telecommunications and Technology Committee of the New Orleans City Council, the Court finds that the Open Meetings Law was violated.

Regarding the March 8, 2018 meeting of the New Orleans City Council, the Court ***does not*** find that the Open Meetings Law was violated. However, the February 21, 2018 action was a necessary component of the full council's decision to adopt Resolution No. 18-65. As such, the full council's vote to adopt the resolution was void *ab initio*.

IT IS ORDERED, ADJUDGED AND DECREED that, for the reasons stated in open court on June 14, 2019, there be judgment in FAVOR of petitioners, The Southern Center for Environmental Justice, Inc. d/b/a Deep South Center for Environmental Justice, VAYLA New Orleans, Justice and Beyond, 350 New Orleans, Sierra Club, Mr. Theodore Quant and Ms. Renate Heurich, and AGAINST defendants, The Council of the City of New Orleans, the Utility, Cable, Telecommunications, and Technology Committee of the New Orleans City Council, Jason R. Williams, Helena Moreno, Joseph I. Giarrusso, Jay H. Banks, Kristin Gisleson Palmer, Jared C. Brossett, and Cyndi Nguyen; and

IT IS FURTHER ORDERED, ADJUDGED and DECREED that, for the reasons stated in open court on June 14, 2019, the action of the then-sitting members of the UCTTC at its February 21, 2018 meeting is VOID; and

IT IS FURTHER ORDERED, ADJUDGED and DECREED that, for the reasons stated in open court on June 14, 2019, the action of the then-sitting members of the New Orleans City Council adopting Council Resolution No. R-18-65 at a March 8, 2018 meeting is VOID.

New Orleans, Louisiana, this 2nd day of July 2019.

THE HONORABLE PIPER D. GRIFFIN
DISTRICT COURT JUDGE, DIVISION "I"

A TRUE COPY
DEPUTY CLERK, CIVIL DISTRICT COURT
PARISH OF ORLEANS
STATE OF LA.

CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of July 2019, a copy of the *Public Version* of the **Initial Brief of the Alliance for Affordable Energy and Sierra Club** has been served on the persons listed below by electronic mail and/or U.S. First-Class mail, postage prepaid:

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I hereby certify that on this 26th day of July 2019, a copy of the *Confidential Version* of the **Initial Brief of the Alliance for Affordable Energy and Sierra Club** has been served on the persons listed below by electronic mail and/or U.S. First-Class mail, postage prepaid:

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Additionally, pursuant to the New Orleans, Louisiana Code of Ordinances, Ch. 158, Art. III, Div. 1, § 158-236, the following persons have been served with copies of the aforementioned document, in triplicate, via U.S. first-class mail, postage prepaid:

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Washington, D.C., this 26th day of July, 2019.

Susan Stevens Miller
Clean Energy Attorney, Earthjustice