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February 1, 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 three (3) copies of the public, redacted version of the **Direct Testimony of Justin R. Barnes on Behalf of the Alliance for Affordable Energy** in the above-captioned docket. Please file the attached documents and this letter in the record of the proceeding and return one time stamped copy to our courier, in accordance with normal procedures. The HSPM version of the Direct Testimony will be served in hard copy only to the appropriate parties who have executed Non-Disclosure Certificates pursuant to Council Resolution R-07-432.

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

Sincerely,

Logan A. Burke

Logan Atkinson Burke
Executive Director
Alliance for Affordable Energy
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Enclosures
cc: Official Service List

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 COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF	**)))))))**	**DOCKET NO. UD-18-07**

DIRECT TESTIMONY

OF

JUSTIN R. BARNES

ON BEHALF OF THE

ALLIANCE FOR AFFORDABLE ENERGY

PUBLIC VERSION

FEBRUARY 1, 2019

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AAE Exhibit JRB-1: Curriculum Vitae of Justin R. Barnes

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Justin R. Barnes, and my business address is 401 Harrison Oaks Blvd., Suite 100, Cary, North Carolina, 27513. My current position is Director of Research with EQ Research LLC.

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst, where I worked on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and become the Director of Research in 2015.

In my current position, I coordinate EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests. I have testified before utility regulatory commissions in the states of Colorado, New Hampshire, North Carolina, Oklahoma, South Carolina, Texas, and Utah as an expert in clean energy policy, rate design, and cost of service. My *curriculum vitae* is attached as AAE Exhibit JRB-1.

Q3. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE COUNCIL OF THE CITY OF NEW ORLEANS ("COUNCIL")?

A. No.

Q4. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Alliance for Affordable Energy ("AAE").

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the reasonableness of Entergy New Orleans' ("ENO," "Entergy," or "Company") proposals for an increase to the residential customer charge, a revised framework for demand-side management ("DSM") programs, and the rate design associated with the proposed Electric Advanced Metering Infrastructure ("AMI") Rider, the Demand-Side Management Cost Recovery rider ("DSMCR" or "Rider DSMCR") (for DSM programs), and the Distribution Grid Modernization rider ("DGM" or "Rider DGM") (for grid modernization investments). I have developed a series of recommendations for modifying these proposals to better align them with the goals of supporting energy efficiency on the part of customers, avoiding undue adverse impacts on residential customers and low-income customers in particular, and with the sound principles of cost causation.

My testimony discusses the shortcomings of each of these individual proposals as well as how they would operate together in a cyclical or reinforcing fashion that is contrary to these goals.

Q6. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is organized into the following sections.

- Section II describes my objections to ENO's proposed increase in the residential fixed charge, provides a more generalized discussion of the negative impacts that fixed charges would have on ENO's customers and recommends an appropriate residential customer charge.
- Section III describes the reasons why the proposed Electric AMI Charge should use a volumetric rather than fixed monthly rate design.
- Section IV describes why proposed Rider DGM, if approved by the Council, should use a volumetric rather than a percentage of bill-based design.
- Section V discusses the Company's proposed DSM framework and recommends modifications that include the elimination of the Lost Contribution to Fixed Costs ("LCFC") component in favor of full decoupling, modifications to the proposed performance incentive structure, and the reasons why rider DSMCR should use a volumetric rather than a percentage of bill-based design.
- Section VI summarizes the cross-cutting nature of these collective proposals and explains how they fit together in a manner that would be highly damaging to the encouragement of energy efficiency and to the majority of Entergy's

residential customers. I conclude this section with a summary of my recommendations to the Council.

II. RESIDENTIAL FIXED CHARGES

A. Summary of Proposed Residential Fixed Charges and Justification

Q7. PLEASE DESCRIBE ENTERGY'S PROPOSAL FOR SETTING THE RESIDENTIAL FIXED CHARGE.

A. The Company 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. Entergy 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.[1] The true effective increase after incorporating the effects of current percentage-based rider rates and proposed percentage-based rider rates would be $7.94/month. This reflects a rider-adjusted current rate of $8.20/month, and a rider-adjusted proposed rate of $16.14/month.[2]

[1] Revised Direct Testimony of Joshua B. Thomas at 63:14-64:2 (Sept. 2018) ("Thomas Direct").
[2] These values exclude the franchise tax but include all other rate riders.

Q8. DO THE AMOUNTS YOU DESCRIBE ABOVE INCLUDE THE COMPANY'S PROPOSED ELECTRIC AMI CHARGE?

A. No. The proposed 2019 Electric AMI Charge adds an additional $2.95/month in the form of a fixed charge. That brings the total of all fixed charges to $19.09/month and the increase to $10.89/month in 2019 when adjusted for all riders, or $18.48/month and $10.41/month if only the 2019 Electric AMI Charge is included. These amounts would change over time according to rate rider adjustments. For the sake of simplicity, I have used only the $18.48/month and $10.41/month figures as the proposed customer charge and proposed increase in the customer charge throughout the remainder of my testimony. From this basis of comparison, ENO's proposal represents an increase of 129% relative to current fixed charges for both New Orleans and Algiers customers.

Q9. WHY DOES ENO WANT TO INCREASE THE RESIDENTIAL CUSTOMER CHARGE TO BE CLOSER TO ITS CALCULATED EMBEDDED CUSTOMER-RELATED COSTS?

A. Company witness Thomas states several objectives for its proposal, which can be paraphrased as: (1) preserving ENO's revenues; (2) reducing cross-subsidies related to energy efficiency and solar photovoltaic ("PV") adoption; (3) stabilizing residential bills; and (4) stabilizing ENO's cash flow metrics.[3] Company witness

[3] Thomas Direct at 62:16-23.

Talkington also offers the justification that the increase is necessary to align rates with the costs indicated by the Company's embedded cost of service study.[4]

Q10. DO YOU AGREE THAT ENO'S PROPOSED RESIDENTIAL CUSTOMER CHARGE IS REASONABLE?

A. No. I object to the Company's proposal for several reasons, as follows:

1. The proposed charge and the amount of the proposed increase is extreme and fails to reflect the true nature of gradualism in utility ratemaking, as evidenced by national trends in residential fixed charges.
2. The proposal 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."[5]
3. 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 for rate design would cause relatively lower usage customers to subsidize relatively higher usage customers.

[4] Revised Direct Testimony of Myra L. Talkington at 26:10-17 (Sept. 2018) ("Talkington Direct").
[5] Council Resolution No. R-07-600.

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

Furthermore, the Company's proposed Electric AMI Charge would effectively charge customers multiple fixed charges for metering and metering-related costs, once for the cost of existing metering and again for the costs of AMI. I generally address the proposed Electric AMI Charge in a separate section of my testimony, but I mention it immediately below in the context of customer impacts because it constitutes an additional monthly fixed charge. To be clear, I am not objecting to the recovery of the un-depreciated costs of legacy meters, as the Council has already ruled on this issue. I only address the mechanism for that cost recovery from the perspective of rate design.

Q11. ARE THE OBJECTIVES VOICED BY COMPANY WITNESSES THOMAS AND TALKINGTON REASONABLE, AND WOULD ENTERGY'S PROPOSALS ACHIEVE THOSE OBJECTIVES?

A. The Company's proposals would contribute to achieving the revenue stability objectives noted by Company witness Thomas. The more pertinent questions are whether using fixed charges to achieve them is necessary given the Company's other revenue fixing proposals, which include a renewed Formula Rate Plan with a revenue decoupling mechanism, and how to weigh any remaining perceived need against the negative impacts on customer energy efficiency incentives and low-income customers. AAE witness Pamela Morgan discusses how decoupling would support ENO's financial stability in greater detail.

Similarly, relatively higher fixed charges can contribute to customer bill stability, but the Company has presented no evidence that customers would support a large increase in fixed charges as a mechanism for achieving more stable bills. In fact, survey research that the Company conducted in connection with its fixed bill option proposal indicates that only 30% of customers were likely or very likely to participate in the program, which provides bill stability in exchange for a premium.[6] Another way to view this is that 70% of customers are not interested in paying a premium in order to achieve more stable bills.

Finally, the references to rate design replicating cost structure made by ENO witness Talkington, and cross-subsidization created by energy efficiency and PV adoption made by ENO witness Thomas, stem from the false premise that the results of the Company's embedded cost of service study is determinative for the purpose of setting rates that provide economically efficient price signals. There are two prominent inaccuracies with this premise. First, marginal rather than embedded costs are the proper basis for developing economically efficient price signals. Second, an embedded cost of service study does not account for the negative public policy impacts of the result, 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. Embedded cost of service

[6] Revised Direct Testimony of Raiford L. Smith at 26:8-11 (Sept. 2018) ("Smith Direct").

studies are useful for determining the amount of revenue to collect, not how to collect that revenue. As I discuss further in my testimony, contrary to ENO witness Thomas' assertion, the Company's proposed fixed charges would cause low usage customers such as those that invest in energy efficiency and PV, to subsidize high usage customers.

Q12. PLEASE DESCRIBE THE DIFFERENCE BETWEEN EMBEDDED COSTS AND MARGINAL COSTS AND WHY THIS DIFFERENCE IS IMPORTANT FOR RATE DESIGN.

A. 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. Embedded cost studies still serve a purpose in that they aid in determining how responsibility for embedded costs and the associated revenue requirement should be divided between different customers or groups of customers.

As Company Witness Gillam observes, "[t]he objective of preparing a cost of service study for either electric or gas operations is to determine the portion of a utility's costs, as measured by its revenue requirement, for which each of the various rate classes is responsible. This then becomes one of the factors in determining the revenue level appropriately allocated to each rate class, *though the Council has wide discretion in the area of rate design*."[7]

B. ENO's Proposed Fixed Charge Increases Are Extreme

Q13. IN WHAT WAYS ARE THE COMPANY'S PROPOSED RESIDENTIAL FIXED CHARGES EXTREME?

A. The proposed customer charges for the residential class are extreme insofar as they would result in:

1. Fixed monthly charges far in excess of the national average, other Entergy affiliates, and those of corporations deemed comparable to Entergy mentioned in the Direct Testimony of Robert Hevert.[8]
2. An increase far in excess, both in monetary and percentage terms, of increases approved by regulators in other states during rate cases filed during roughly the last four years, including those approved for comparable companies.

Q14. HOW DID YOU ARRIVE AT THE CONCLUSIONS ABOVE AND WHAT EVIDENCE DO YOU PRESENT TO SUPPORT THESE CLAIMS?

A. I conducted a review of current residential customer charges for 168 investor-owned utilities ("IOUs") in 49 states and the District of Columbia.[9] The utilities in

[7] Revised Direct Testimony of Phillip B. Gillam at 13:4-14:2 (Sept. 2018) (emphasis added).
[8] Revised Direct Testimony of Robert B. Hevert at 14, Table 2 (Sept. 2018) ("Hevert Direct").
[9] Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation.

this survey encompass all major IOUs and nearly all smaller IOUs in each state, thus it presents a comprehensive national picture of residential fixed charges. I also conducted a review of adopted increases in residential customer charges for IOU general rate case applications filed since July 2014. A total of 165 general rate cases are represented in this sample, though the total number of utilities is lower because several utilities had multiple rate cases during this time frame. Consequently, the sample of adopted increases reflects these utilities more than once. Both datasets are generally current as of November 16, 2018, but I have also added the results of a recently completed rate case for Entergy Texas, which concluded in December 2018.[10]

As I noted above, the "comparable" utilities are based on the proxy companies that ENO witness Hevert selected for his return on equity analysis. To generate these averages, I selected all of the local distribution utilities affiliated with these companies from my larger dataset of fixed charges and approved increases.

Q15. PLEASE SUMMARIZE THE RESULTS OF THE RESEARCH YOU DESCRIBE ABOVE.

A. Table 1 below presents comparisons between current fixed monthly charge averages and ENO's current ($8.07/month) and proposed nominal rates inclusive of the proposed Electric AMI Charge ($18.48/month). Table 2 presents averages of

[10] Public Utilities Commission of Texas, Docket No. 48371, Order (Dec. 20, 2018).

increases approved in rate cases filed during the last four years relative to the Company's proposed increase of $10.41/month, or 129%.

Table 1: Fixed Charge Comparisons

Basis of Comparison	Fixed Charge ($)	ENO Current Difference ($)	ENO Current Difference %	ENO Proposed Difference ($)	ENO Proposed Difference %
National Average	$10.40	-$2.33	-22.40%	$8.08	77.70%
ENO Affiliate Average	$7.33	$0.74	10.10%	$11.15	152.11%
ENO Comparables	$10.73	-$2.66	-24.79%	$7.75	72.23%
ENO Current	$8.07				
ENO Proposed	$18.48				

Table 2: Fixed Charge Increase Comparisons

Basis of Comparison	Increase ($)	Increase (%)	ENO Above ($)	ENO Above (%)
National Average	$0.96	13.80%	$9.45	115.20%
ENO Affiliate Average	$2.22	31.77%	$8.19	97.23%
ENO Comparables	$1.08	15.74%	$9.33	113.26%
ENO Proposed	$10.41	129.00%		

Tables 1 and 2 clearly show that ENO's current residential customer charge is moderately below the national average, but already slightly above the average for Entergy affiliates. The increase ENO proposes would place the residential customer charge well in excess of the national average and dramatically exceed recent national averages for fixed charge increases and those awarded to Entergy affiliates. The two increases for Entergy affiliates represented in Table 2 refer to a $1.44/month (20.7%) increase granted in 2016 to Entergy Arkansas resulting in a current rate of $8.40/month and a $3.00/month increase granted to Entergy Texas in 2018 that results in a current rate of $10.00/month (a 42.9% increase). Combined, these translate to the $2.22/month and 31.77% averages reflected in Table 2.

Q16. PLEASE EXPLAIN WHY YOU INCLUDED A COMPARISON TO COMPANIES "COMPARABLE" TO ENO IN YOUR ANALYSIS.

A. ENO witness Hevert describes his selection of proxy companies as intended to consist of those with "comparable companies in terms of financial, business, and regulatory risks."[11] To be clear, none of his selection criteria involve an assessment of a company's risk profile based on revenue generated via fixed charges. However, it is inescapable that fixed charges do have the effect of providing a high degree of certainty for a portion of a utility's revenue during a given month or year (*i.e.*, little or no risk of under-recovery), making it less vulnerable to sales fluctuations. In fact, ENO witness Thomas cites revenue preservation and stabilizing cash flow metrics to support finance operations in support of the Company's customer charge proposal.[12]

I make no claims as to how fixed charge revenue may specifically affect a utility's risk profile. Nevertheless, I do believe that Hevert's list of proxy companies is illustrative insofar as it represents an additional basis for comparing different utilities, and shows results similar to the national and ENO affiliate comparisons I have done. Certainly, the comparisons do not suggest that the Company's financial position presents a driving need for such a large increase in order to reduce its risk profile, in particular in light of the other measures the Company proposes with similar objectives, and the detrimental impact that such an increase would have on many of the Company's customers.

[11] Hevert Direct at 80:11-12.
[12] Thomas Direct at 62:16, 20-23.

Q17. ARE THE COMPANY'S PROPOSED INCREASES TO RESIDENTIAL FIXED CHARGES CONSISTENT WITH THE PRINCIPLE OF GRADUALISM?

A. Absolutely not. Company witness Talkington states that ENO's proposals "balances rate design considerations of setting rates at cost and employing gradualism to avoid undue customer impacts."[13] However, as evidenced by both the amount and percentage of the proposed increase embodied within the residential customer charge and the accompanying Electric AMI Charge, the Company's proposal clearly does not represent "gradualism" as practiced by regulators in other states. It is only "gradual" with respect to the Company's calculated customer-related unit costs, which I disagree with and discuss in the next sub-section of my testimony.

Q18. IN REFERENCE TO YOUR OBJECTIONS TO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGE AND CUSTOMER IMPACTS, ARE YOU ALSO OBJECTING TO THE COST ALLOCATION THE COMPANY PROPOSES FOR THE RESIDENTIAL CLASS?

A. No. I am not taking a position on the overall cost allocation methodology or the overall revenue requirement. In other words, I am contesting rate design rather than the revenue requirement for the residential customer class. While I refer to the Company's cost of service study and use some of the associated outputs in my own calculations, I do so only because it is necessary to define a starting point for this

[13] Talkington Direct at 26:14-15.

purpose. This should not be seen as an endorsement of the cost allocation methodology Entergy employs or its overall revenue request.

C. Impacts on Customer Energy Efficiency Incentives

Q19. PLEASE SUMMARIZE HOW FIXED CHARGES AFFECT CONSUMER INCENTIVES TO CONSERVE ELECTRICITY.

A. Fixed charges cannot be avoided by reducing energy consumption or demand for electricity. If one assumes the same total revenue requirement for a class of customers, a rate design weighted towards fixed charges produces less of a customer 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 investments in more efficient equipment.

Q20. PLEASE EXPLAIN THE CONCEPT OF PRICE ELASTICITY OF DEMAND AND HOW IT RELATES TO ENERGY EFFICIENCY.

A. Price elasticity, for electricity or any other product or service, measures how changes in price influence the purchasing behavior of consumers. The Council's energy savings potential study refers to the definition used by the Electric Power Research Institute ("EPRI"), stating, "price elasticity of demand is a measure of how price changes influence electricity use."[14] I believe that this is a reasonable definition for the term.

Price elasticity is typically reflected as a fraction or ratio, most often a negative number (*e.g.*, -0.5). A negative elasticity number indicates that increases in price are associated with declining consumption or use. Conversely, it indicates that decreases in price produce greater consumption or use. Not surprisingly, most products or services, including electricity, exhibit negative price elasticity. A hypothetical elasticity of -0.5 indicates that a 10% increase in price produces a 5% decrease in consumption. Conversely, it indicates that a 10% reduction in electricity prices would produce a 5% increase in consumption.

Price elasticity can also be differentiated by the time horizon being considered. Short-run price elasticity tends to be lower than long-run price elasticity because over longer time horizons, consumers become aware of more alternatives and those alternatives become more attractive. For example, replacing an aging appliance is more attractive than replacing a new one with a more efficient model.

Therefore, when fixed charges cause a reduction in the volumetric rates that a customer would otherwise pay, they cause an increase in electricity consumption relative to what it would be with a lower fixed charge and higher volumetric rate. This effect increases over time because electricity demand is more elastic in the long run than the short run.

[14] Optimal Energy, Inc., *Study of Potential for Energy Savings in New Orleans*, at 59 (Aug. 31, 2018) ("New Orleans Energy Savings Study").

Q21. HOW WOULD ENTERGY'S RATE PROPOSALS SPECIFICALLY AFFECT RESIDENTIAL ELECTRICITY CONSUMPTION?

A. I have calculated that based on short-run (1-5 years) price elasticity the combined fixed charge increases, would undo the equivalent of roughly 2.48 to 3.65 times the Program Year ("PY") 6 efficiency target (*i.e.*, years of efficiency savings), depending on the value used for price elasticity. Using a long-run price elasticity assumption would triple my higher estimate to roughly 11 times the PY 6 target, essentially undoing all of the savings produced by Energy Smart and more. In other words, the proposed customer charge and AMI charge fixed would cause increases in consumption equivalent to years of Energy Smart efficiency savings relative to a scenario where the same amount of total revenue is collected using a volumetric energy charge. From the perspective of supporting customer investments in energy efficiency and achieving greater savings, fixed charge increases are akin to driving with one foot on the gas and one foot on the brake.

Q22. PLEASE EXPLAIN HOW YOU MADE THIS CALCULATION.

A. The Council's New Orleans Energy Savings Study utilized a short-run (1-5 years) price elasticity of -0.13 for the first tier of a hypothetical inclining block rate and a price elasticity of -0.26 for the second tier. EPRI reports a mean short-run value of -0.3 from a survey of relevant literature, with a range of -0.2 to -0.6. Based on the Company's test year billings, translating the proposed nominal fixed charge increase ($7.46/month) to a volumetric rate would increase the energy rate by 0.73 cents/kWh and translating the proposed first year AMI charge ($2.95/month) to a volumetric rate produces a further energy rate increase of 0.29 cents/kWh. Thus the total increase in the energy rate to raise the same amount of revenue as the combined fixed charge increase and AMI charge ($10.41/month) is 1.02 cents/kWh. This equates to an energy rate increase of 10.85% relative to what the energy rate would be if both portions remain fixed.

Applying the elasticity assumptions used in the New Orleans Energy Savings Study, the combined fixed charge increase and AMI charge would result in electricity use 2.21% higher than if both charges were volumetric. Using the EPRI mean value for price elasticity, the increase in use is 3.26%. These increases equate to 49.2 million kWh using the lower price elasticity number and 72.4 million kWh using the higher EPRI figure. The savings target for PY 6 of the Energy Smart program was roughly 19.9 million kWh.[15]

For my long-run estimate, as the New Orleans Energy Savings Study notes, EPRI's literature survey showed that long-run demand elasticity values may range from -0.7 to -1.4, with a mean value of -0.9.[16] I used this mean value in my long-run impact estimate.

Q23. IS THIS CONSISTENT WITH THE COUNCIL'S GOALS FOR ENERGY EFFICIENCY?

A. No. As I previously observed, the Council has expressly stated that it wishes to "align customer pricing and incentives to encourage investment in energy

[15] Revised Direct Testimony of D. Andrew Owens at 10, Table 1 (Sept. 2018) ("Owens Direct"). The savings target amounts were summed to combine the New Orleans and Algiers divisions.
[16] New Orleans Energy Savings Study at 59.

efficiency."[17] The Company's emphasis on fixed charges in rate design has the opposite effect.

Q24. ARE THE NEGATIVE IMPACTS OF FIXED CHARGES ON ENERGY EFFICIENCY RECOGNIZED ELSEWHERE?

A. Yes. The effect is recognized in the Council's own New Orleans Energy Savings Study under hypothetical fixed charge scenarios. It is also recognized by states that have prioritized energy efficiency. The American Council for an Energy-Efficiency Economy ("ACEEE") 2018 Energy Efficiency Scorecard lists the top five states in energy efficiency policy as: Massachusetts, Rhode Island, California, Vermont, and Connecticut.[18] Among IOUs, the average residential fixed charge in these five states is $6.05/month. Furthermore, of the 14 IOUs operating in these states, only two, Green Mountain Power in Vermont and United Illuminating in Connecticut, have residential customer charges higher than $10/month, with United Illuminating only marginally higher at $10.04/month.

These rankings do not consider rate design, so the rankings themselves are not biased towards states with lower residential fixed charges. Rather, the collectively low residential fixed charges are indicative of a desire to avoid diluting the effectiveness of state efficiency goals with counterproductive residential rate design.

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[17] Council Resolution No. R-07-600.
[18] ACEEE, *The 2018 State Efficiency Scorecard* (last accessed January 25, 2019), https://aceee.org/state-policy/scorecard.

D. The Proper Basis for Setting a Reasonable Residential Customer Charge

Q25. WHAT COSTS DOES ENO CLASSIFY AS CUSTOMER-RELATED FOR THE PURPOSE OF DETERMINING ITS CALCULATED CUSTOMER UNIT COST?

A. 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. The Company characterizes the costs embodied within its proposed residential customer charge as "costs that 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."[19] At a different point, ENO also describes these costs as those that are "not correlated to the number of kilowatt hours of electricity used by the customer."[20]

Q26. DO YOU AGREE WITH THIS DELINEATION OF CUSTOMER-RELATED COSTS AND THE APPROPRIATE BASIS FOR ESTABLISHING CUSTOMER CHARGES?

A. I agree that 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.[21] Another way to view the appropriate role of the

[19] Thomas Direct at 61:20-22.
[20] Thomas Direct at 62:10-11.
[21] 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.

customer charge that produces a similar result is to define customer-related costs as those that vary directly with the number of customers.[22] However, it is a mistake to conflate the costs associated with such a zero-load customer with costs that are not directly correlated with customer demand or energy consumption. Many joint system costs vary more indirectly with one or more cost categories and consequently do not fall neatly within the customer, demand, or energy classification.

Q27. HAVE YOU DEVELOPED AN ESTIMATE FOR ESTABLISHING A REASONABLE RESIDENTIAL CUSTOMER CHARGE?

A. I developed two estimates to provide a reasonable range. My calculations show that a reasonable customer charge would fall within a range from $8.13-$9.53/month. This would correspond to an increase in the current residential customer charge of $0.06-$1.46/month (0.7-18.1%).

Q28. PLEASE DESCRIBE HOW YOU DEVELOPED THE VALUES YOU LIST ABOVE FOR AN APPROPRIATE RESIDENTIAL CUSTOMER CHARGE.

A. I used an excerpt from the Company's cost of service study prepared in response to AAE 2-4 depicting the costs associated with Entergy's calculated residential customer-related unit cost as the starting point. For both estimates, I excluded all costs that are not allocated based on the number of customers in the Company's embedded cost of service study, applied to the items that determine the rate base

[22] *Id.* at 83.

and operating expenses. Thus for my high-end estimate, I excluded a variety of general, administrative, and miscellaneous rate base and expense items. Those remaining rate base and operating expense items include FERC accounts associated with meters, service drops, customer service, and the customer information and billing system.

I applied multipliers to the revised net plant in service amounts derived from the exclusion process above to reflect the Company's return and the incremental taxes and expenses on that return. I then reduced the sum of expenses, return, and incremental taxes by 14.6% so as to be consistent with the Company's proposed residential class cost allocation, as described by Company witness Thomas.[23] I divided the resultant reduced sum by total annual residential bills to derive the customer charge.

For the low-end estimate, I performed the same general set of calculations. However, I also excluded rate base and expenses associated with installations on customer premises in FERC Accounts 371 and 587, operating expenses associated with overhead and underground lines in FERC Accounts 583, 583, 593, and 594, and advertising expenses in FERC Account 909.[24]

[23] Thomas Direct at 63:18-21.

[24] Customer service drops are traditionally considered an exclusively customer-related cost because, apart from customers in multi-family buildings, each customer requires a service drop. However, a portion of the costs of the service drop could also be considered demand-related because customers with larger loads may require a larger service drop. My estimates retain all costs of service drops as customer-related and includable within the customer charge.

Q29. PLEASE EXPLAIN WHY YOU EXCLUDED GENERAL, ADMINISTRATIVE, AND MISCELLANEOUS COST COMPONENTS IN YOUR DERIVATION OF AN APPROPRIATE CUSTOMER CHARGE.

A. The cost components I retained are those directly associated with customer metering, connection, billing, and customer service. By contrast, the costs I excluded can be described as general overhead costs that cannot be assigned to a specific function. It is reasonable to exclude them from the customer charge because they do not vary directly with the number of customers.

Q30. PLEASE EXPLAIN WHY YOU EXCLUDED FERC ACCOUNTS 371 AND 587 FROM YOUR LOW-END CUSTOMER CHARGE ESTIMATE.

A. FERC Account 371 relates to utility-owned plants on customer premises located on the customer's side of the meter. Entergy has indicated that the equipment in this account is composed of lighting fixtures on the premises of residential customers.[25] 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.

[25] ENO response to AAE 3-1(b).

Q31. PLEASE EXPLAIN WHY YOU EXCLUDED FERC ACCOUNTS 583, 584, 593, AND 594 FROM YOUR LOW-END CUSTOMER CHARGE ESTIMATE.

A. 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.

Q32. PLEASE EXPLAIN WHY YOU EXCLUDED FERC ACCOUNT 909 FROM YOUR LOW-END CUSTOMER CHARGE ESTIMATE.

A. 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, and 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.

Q33. YOU PREVIOUSLY STATED THAT MARGINAL COSTS ARE THE PROPER BASIS FOR DESIGNING ECONOMICALLY EFFICIENT RATES. ARE YOUR ESTIMATES OF THE APPROPRIATE CUSTOMER CHARGE BASED ON MARGINAL COSTS?

A. Strictly speaking, they are not based on marginal costs because the Company did not perform a study of marginal customer costs. However, by confining the boundaries of costs included in the charge to those that vary directly with the number of customers, they do represent a reasonable estimate of the incremental costs to connect a customer to the grid. Therefore, they provide a better estimate than the values indicated by the Company's embedded cost of service study.

E. Disproportionate Impacts of Fixed Charges on Low-Income Customers

Q34. PLEASE EXPLAIN HOW THE COMPANY'S PROPOSED FIXED CHARGES WOULD HAVE A DISPROPORTIONATE IMPACT ON LOW-INCOME CUSTOMERS?

A. ENO calculated a customer "indifference" threshold of roughly 1,000 kWh of electric usage per month.[26] 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 in the fixed charge was translated to a volumetric rate that raises an equivalent amount of revenue. A customer with average monthly usage below the indifference threshold prefers a volumetric rate to a fixed rate while customers with average usage above the indifference threshold is made better off by higher fixed charges and lower variable charges.

ENO has provided data showing that, 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. Conversely, higher income customers tend to be better off. Table 3 below shows a breakdown of

[26] Thomas Direct at 64:9-10.

customer usage for twelve income categories broken down into four average monthly usage tranches.[27]

Table 3: Average Monthly Electric Use by Income Category

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3 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. Thus the burdens of relatively higher fixed charges fall disproportionately on those with lower incomes, while higher income customers generally benefit. Furthermore, customers with the lowest incomes are the most likely to experience negative impacts from fixed charge rate designs. These customers would also experience the largest negative impacts

[27] Table 3 is derived from ENO response to AAE 2-5, HPSM Attachment C.

because larger percentages of the lower income customers fall within the lowest average usage category (less than 500 kWh/month).

Q35. CAN YOU PROVIDE ANY OTHER EVIDENCE THAT LOW-INCOME CUSTOMERS WOULD BE PARTICULARLY HARMED BY FIXED CHARGE INCREASES?

A. Yes. Entergy provided energy use statistics for customers that experienced disconnection of service for non-payment during the 2017 calendar year, and it stands to reason that those customers experiencing most difficulty paying their bills are those with lower incomes. Roughly 47% of customers that were disconnected had average usage of less than 1,000 kWh/month during the 12 months prior to disconnection.[28] 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.

[28] Derived from ENO response to AAE 2-6, Attachment.

Q36. IF 47% OF DISCONNECTED CUSTOMERS WOULD HAVE BEEN EVEN WORSE OFF AT HIGHER FIXED CHARGE RATES, DOES THAT NOT ALSO MEAN THAT 53% WOULD HAVE BEEN BETTER OFF?

A. It is true that a greater percentage of 2017 disconnected customers would have in theory been better off with a higher fixed charge and lower volumetric charges. However, high fixed charges coupled with lower usage charges are a poor solution for addressing the needs of those high usage customers. For one, higher fixed charges would be punitive on a group of customers that is nearly as large as the group they help. Second, inordinately high usage can be addressed through targeted energy efficiency, or potentially other measures such as enforcement of building codes. Those strategies can produce outcomes that leave all customers better off, rather than just helping some at the expense of nearly as many others.

Q37. YOU PREVIOUSLY MENTIONED THE SURVEY ENO CONDUCTED ON CUSTOMER INTEREST IN PAYING A PRICE PREMIUM IN EXCHANGE FOR BILL STABILITY. DID THIS SURVEY SHOW ANY DIFFERENCES IN INTEREST BETWEEN RELATIVELY LOWER AND HIGHER INCOME CUSTOMERS?

A. As noted by Company witness Raiford, overall 30% of customers stated that they were likely or very likely to be interested in such an arrangement.[29] The percentages for lower-income customers are similar, at 32% for customers with incomes of $50,000 or less, and 30% for customers with incomes of $35,000 or

[29] Smith Direct at 26:8-11.

less. Thus if one looks at a higher fixed charge as a "premium" for low usage customers (since it causes higher bills), the survey does not suggest that a majority of customers, low-income or otherwise, are interested in paying such a premium in exchange for greater bill stability. To the contrary, a large majority representing 70% of customers, including lower-income customers, are not interested.

III. AMI COST RECOVERY MECHANISM

Q38. PLEASE SUMMARIZE THE COMPANY'S PROPOSED COST RECOVERY MECHANISM FOR AMI DEPLOYMENT.

A. The Company proposes to establish a new Electric AMI Charge under which AMI costs would be recovered under an annually adjusted fixed monthly charge. The same design is proposed for the Gas AMI Charge, but I only address the Electric AMI Charge. The proposed annual charges are depicted in Table 4 below:[30]

[30] Thomas Direct, ENO Exhibit JBT-9.

Table 4: Proposed AMI Charges

	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

Q39. IS THE PROPOSED ELECTRIC AMI CHARGE ADDITIVE TO THE COMPANY'S PROPOSED RESIDENTIAL FIXED CHARGE?

A. Yes. For instance, the proposed 2019 Electric AMI Charge of $2.95/month would apply on top of the Company's proposed customer charge of $15.53/month, bringing the total nominal fixed charge for these components to $18.48/month.

Q40. WHAT JUSTIFICATION DOES THE COMPANY PROVIDE FOR THE PROPOSED FIXED CHARGE DESIGN OF THE AMI CHARGE?

A. Company witness Thomas states, "The 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."[31]

[31] Thomas Direct at 66:6-8.

Q41. DO YOU AGREE THAT THIS IS A REASONABLE BASIS FOR USING A FIXED MONTHLY CHARGE FOR AMI COST RECOVERY? PLEASE EXPLAIN WHY OR WHY NOT.

A. I do not agree. While it is true that metering and associated metering costs are typically recovered through fixed monthly charges, AMI is not "typical" metering. As I previously stated, fixed customer charges should recover the cost of connecting a customer to the grid. Advanced metering and the associated incremental costs above traditional meters are not strictly necessary for the customer to be connected to the grid. A non-advanced meter and associated infrastructure can do so at lower costs. AMI is used for much more than measurement of a customer's consumption for billing purposes. 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. Other quasi-customer related operational savings, such as service connections and reconnections entail specific fees charged to the customer responsible for the service, meaning that they are directly assignable costs to an individual customer rather than customer costs assignable to a customer class as a whole.

Q42. PLEASE EXPLAIN YOUR CONTENTION THAT CUSTOMERS "DO NOT HAVE A MEANINGFUL CHOICE OF WHETHER TO TAKE SERVICE THROUGH AN ADVANCED METER."

A. While Entergy's Proposed Rider Schedule AMO provides a mechanism for customers to opt-out of taking service through an AMI meter, 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.[32] 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, Rider AMO is not a meaningful alternative since such a customer would incur higher charges by virtue of opting out.[33]

[32] Entergy New Orleans, Rider AMO (Advanced Metering Opt-Out), http://www.entergy-neworleans.com/content/price/tariffs/eno/enol_amo.pdf.
[33] Rider AMO is reflected as effective October 30, 2018 on the Company's website, but it is my understanding that the Council has not yet issued its final approval.

Q43. IS THE COMPANY'S EVALUATION OF AMI COSTS AND BENEFITS IN ALIGNMENT WITH THE SUPPOSITION THAT THE INCREMENTAL COSTS OF AMI ARE PRIMARILY RELATED TO PRODUCING ENERGY AND DEMAND COST SAVINGS?

A. Yes. The cost-benefit analysis that ENO used to support its rate 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 on either a nominal or a net present value ("NPV") basis. Added to this are peak capacity reduction benefits and reductions in unaccounted for energy. In total, these three categories produce 63.4% of the NPV benefit and 64.8% of the nominal benefit in the Company's analysis.[34] It is therefore reasonable to consider the incremental cost of AMI deployment as primarily energy and demand related.

Q44. ARE THERE OTHER POLICY GOALS THAT ARGUE AGAINST USING A FIXED CHARGE STRUCTURE SFOR RECOVERY OF AMI COSTS?

A. Yes. A fixed monthly charge works at cross-purposes with the single largest source of purported customer benefits: savings due to reduced energy consumption. It takes what would otherwise be a variable cost of consumption that contains a conservation incentive and translates it to a fixed cost that cannot be avoided, thereby diluting customer incentives to conserve energy from what would otherwise be the case.

[34] CNO 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).

Furthermore, it is fundamentally unfair to customers to have to effectively pay two fixed metering charges, one for the un-depreciated cost of legacy meters and one for AMI infrastructure at the same time. Relative to another AMI charge design (*e.g.*, volumetric or percentage-based), this causes lower usage customers, including a larger percentage of lower income customers, to shoulder the greater share of the cost burden while passing the larger share of major benefit streams (*i.e.*, energy and capacity cost savings) to higher usage customers.

Q45. WHAT ARE YOUR RECOMMENDATIONS TO THE COUNCIL ON THE DESIGN OF THE AMI CHARGE?

A. I recommend that the Council adopt a volumetric rate design in order to support energy efficiency, protect the greater portion of lower income customers from disproportionate impacts, and distribute the costs and benefits of AMI more equitably. This is also the simplest way to align fixed monthly charges with the costs necessary to connect a zero-load customer to the system, since customers would continue to pay for the cost of the minimum meter necessary to do so through their payment for the un-depreciated costs of legacy meters.

With respect to cost and benefit sharing, the Council should be cognizant that while a volumetric AMI charge would cause lower usage customers to pay less towards AMI deployment, when those same customers act to reduce their energy consumption or peak period demands, higher usage customers still receive a greater portion of the benefits of the associated cost savings. Therefore, while higher usage customers pay more under a volumetric design, they also receive more in return.

IV. RIDER DGM RATE DESIGN

Q46. PLEASE DESCRIBE THE PURPOSE OF PROPOSED RIDER DGM.

A. Rider DGM is proposed by the Company as a new rate rider for the recovery of capital investments for grid modernization projects. Entergy proposes that the rates reflected in Rider DGM be updated on a quarterly basis as new costs are incurred. The Company has initially proposed five such grid modernization projects in its rate application for inclusion in Rider DGM. The costs for these projects are estimated at $59.3 million.[35] The five projects are composed of three main equipment investments: self-healing network areas, smart devices, and new conductors.[36] Entergy is also requesting the establishment of a streamlined process for Council review and approval of additional future grid modernization projects that would be incorporated into the charges under Rider DGM.[37]

Q47. WHAT RATE STRUCTURE DOES THE COMPANY PROPOSE TO USE FOR RIDER DGM?

A. Rider DGM would operate under a percentage of bill-based structure, like the Company's current formula rate adjustment, increasing the charge for every individual base rate component (*i.e.*, the fixed customer charge, demand charge, and base energy charges) by an incremental amount.

[35] Revised Direct Testimony of Erica H. Zimmerer at 29, Figure 4 (Sept. 21, 2018).
[36] *Id.* at 25-29.
[37] *Id.* at 34-36.

Q48. DOES ENTERGY PROVIDE ANY JUSTIFICATION FOR THIS CHOICE OF RATE STRUCTURE?

A. No.

Q49. DO YOU AGREE THAT THE PERCENTAGE OF BILL-BASED DESIGN IS AN APPROPRIATE RATE STRUCTURE FOR RIDER DGM?

A. No, for two reasons. First, it effectively increases the fixed customer charge, and therefore reduces consumer incentives for energy conservation. Second, the Company's grid modernization investments are investments in the shared distribution system. They do not encompass any customer-related functions or involve costs that otherwise vary directly with the number of customers on the system or connecting a customer to the system. Thus the charge is unreasonable both from a perspective of public policy in support of energy efficiency, and from the perspective of cost causation.

Q50. IF THE COUNCIL WERE TO APPROVE PROPOSED RIDER DGM, HOW SHOULD THE STRUCTURE BE REVISED?

A. The charge in Rider DGM should be aligned with how the Company charges for distribution service more generally in its base rates. For residential customers, this would result in an exclusively volumetric charge. For non-residential customers it may be appropriate for the charge to have a demand component, but only to the extent that an individual investment is caused by additional demand on the system. The current set of five projects target reliability improvements rather than demand growth, thus the charge associated with these investments should also be volumetric for non-residential customers.

Q51. IS SUCH A VOLUMETRIC DESIGN TYPICAL FOR SIMILAR GRID MODERNIZATION RIDERS IN OTHER JURISDICTIONS?

A. Yes. As Company witness Faruqui notes, most grid modernization or distribution infrastructure improvement riders take the form of a volumetric charge.[38]

V. DSM PROGRAM STRUCTURE AND RIDER

A. Summary of ENO's DSM Proposal

Q52. PLEASE BRIEFLY SUMMARIZE ENTERGY'S DSM PROPOSAL.

A. Entergy's proposal has several elements, as follows:

- A mechanism that allows Entergy 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 Entergy 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

[38] Revised Direct Testimony of Dr. Ahmad Faruqui at 55:4-7 (Sept. 21, 2018) ("Faruqui Direct").

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

Q53. WHAT JUSTIFICATION DOES ENTERGY PROVIDE FOR THE COLLECTIVE COMPONENTS OF ITS DSM PROPOSAL?

A. The rationale behind the Company's proposals is discussed in the most detail by Company witness Faruqui. To paraphrase, Dr. Faruqui states that allowing DSM expenses to be effectively rate-based will place energy efficiency at a level equivalent to generation investments from the utility's perspective; a lost revenue adjustment mechanism ("LRAM") is necessary to render the Company indifferent to revenue losses caused by energy efficiency investments; and a performance incentive is an appropriate mechanism for elevating energy efficiency to something of a "preferred resource" status. In other words, the Company proposes removing disincentives to support greater energy efficiency that are ingrained within the utility business model to make the utility indifferent, supplemented with additional revenue opportunities that transform indifference into active support. The Company does not provide any justification for the use of a percentage of bill-based structure in Rider DSMCR, though I understand that this structure is used in the Company's approved energy efficiency charge and other riders.

Q54. WHAT ARE YOUR OBSERVATIONS ABOUT THE OVERALL DESIGN AND POLICY RATIONALE FOR ENTERGY'S DSM PROPOSAL?

A. I agree that creating utility revenue indifference and incentives for good performance are sound policy principles on which to base a DSM program structure. However, I disagree with Dr. Faruqui'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.

I also disagree that the proposals made by the Company and how they fit together are the best way to implement the principles I do agree with. Specifically, full decoupling is a superior mechanism to a lost revenue adjustment for rendering a utility indifferent to declines in sales caused by energy efficiency, and the performance incentive mechanism combined with a rate of return reward on all program costs fails to create an environment where only good performance is rewarded with additional earnings opportunities.

Q55. IS ALLOWING A UTILITY TO EARN A RATE OF RETURN ON DSM EXPENSES A COMMON FEATURE OF ENERGY EFFICIENCY SUPPORT POLICIES IN OTHER JURISDICTIONS?

A. It is relatively uncommon. Dr. Faruqui describes a small number of examples in the states of Illinois, Maryland, New York, and Utah as indicative of "the beginning of a new trend" towards this type of mechanism.[39] At best I think this type of conclusion is preliminary and quite a stretch. Three examples in the last two years do not make a trend. Furthermore, the Utah bill was essentially written by Rocky

[39] Faruqui Direct at 29:17-19.

Mountain Power for its own benefit and received significant criticism from many parties, including consumer advocates, as an "end run" around the regulatory process.[40] Likewise, the Illinois was often referred to as "the ComEd bill", which among other things provided a bailout for ComEd's nuclear power plants, and as initially written, would have effectively eliminated net metering.[41] It is more accurate I think to consider it a trend in something that utilities want, but that has yet to reach a strong position as a best practice.

What should not be lost in this discussion is that a utility's rate of return is simply a number. When applied to program expenditures, it produces an incentive amount, but nothing dictates that such a percentage-based multiplier be tied to the allowable return on capital investments. In fact, using the rate of return in this fashion distorts the playing field in the utility's favor rather than leveling it because energy efficiency expenditures produce both foregone energy expenses in addition to 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 and produce a profit for the utility. AAE witness Pamela Morgan describes further differences in the cost structure and risk profile of DSM investments relative to supply-side resources that should be considered in efforts to "level the playing field."

[40] Brian Maffly, *Critics say Rocky Mountain Power Plan would stick it to Utah ratepayers in the name of clean air*, Salt Lake Tribune (Feb. 9, 2016), http://archive.sltrib.com/article.php?id=3495566&itype=CMSID.
[41] Julie Vahling. *Why the new Exelon/ComEd bill is bad for Illinois consumers*, Illinois Times (May 26, 2016), https://illinoistimes.com/article-17265-why-the-new-exelon_comed-bill-is-bad-for-illinois-consumers html.

Q56. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES THE "DISTORTION" YOU REFER TO ABOVE.

A. Consider a hypothetical example where an energy efficiency measure has a cost-effectiveness ratio of 1.0, meaning that it is cost effective but only just so. The benefits side of this equation is composed of cost savings of 75% avoided energy costs and 25% avoided capacity costs over the measure lifetime. Based on this breakdown one could say that 75% of the cost is energy related and 25% is capacity related, or a ratio of $0.75 and $0.25 for every $1.00. Thus the foregone investment on which the utility would otherwise earn a return is $0.25. At a hypothetical 10% rate of return, the utility lost earnings of $0.025. However, if all expenditures are capitalized at the 10% rate of return, the utility earns $0.10. Thus the utility is being overcompensated for its foregone investment and the playing field is tilted. Ratepayers become responsible for an incremental cost on program expenses that they would not have otherwise paid without the energy efficiency investment.

B. LCFC Component of Rider DSMCR

Q57. PLEASE DESCRIBE THE COMPANY'S LCFC ADJUSTMENT MECHANISM.

A. Under this mechanism, Entergy would project energy efficiency savings on an annual basis and calculate how that savings translates to a reduction in cost recovery for fixed components of its infrastructure, excluding fuel and other riders. The result is the LCFC component of the DSM charge. The LCFC is to be trued-up with actual savings each year. The LCFC is also excluded from the Company's separate decoupling proposal contained within the proposed Formula Rate Plan.

Q58. WHAT ARE THE DISADVANTAGES TO LRAMS SUCH AS THE LCFC PROPOSED BY ENTERGY?

A. To be clear, a LRAM, sometimes referred to as a lost margin recovery mechanism, can be thought of as a limited form of decoupling since the scope of sales variation is *limited* to a specific cause. While such a mechanism does render a utility indifferent to forgone sales due to energy efficiency, it can also create a perverse incentive for a utility to discourage customer efficiency outside of a program since sales attrition outside of the program receives no compensation. In other words, it does not entirely eliminate the throughput incentive. In addition, the mechanism must by necessity rely on estimates of savings, requiring that considerable attention be devoted to methodology and data to ensure accurate counting.

Finally, there an implicit assumption in the mechanism that all projected savings actually translate to an equivalent under-recovery of fixed costs for the utility, which is never actually true at a precise level, and not necessarily true even on a higher, more generalized level. 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. For example, if one assumed that energy efficiency resulted in a 0.5% reduction in sales during a given year, but hot weather contributed to a 0.5% increase in sales relative to expectations, there is not an actual under-recovery of fixed costs. In this scenario, LCFC would therefore charge customers twice for the same fixed costs.

Q59. PLEASE PROVIDE AN EXAMPLE OF THE "PERVERSE INCENTIVE" YOU REFER TO WITH RESPECT TO DISCOURAGING INCREASED ENERGY EFFICIENCY OUTSIDE OF AN INCENTIVE PROGRAM.

A. Entergy's proposal to dramatically increase the residential fixed charge is a perfect example of this type of behavior. This dampens rates-related incentives for customers to be more efficient in their energy use generally, but such savings have a value equivalent to those achieved within an energy efficiency program. Consequently, a utility like Entergy is not supportive of rate designs that produce those savings because they are not counted as lost fixed costs that it is entitled to recover.

Q60. YOU PREVIOUSLY STATED THAT A FULL DECOUPLING MECHANISM WOULD BE SUPERIOR TO THE COMPANY'S LCFC. PLEASE ELABORATE ON WHY THIS IS TRUE.

A. Full decoupling completely removes the throughput incentive. In doing so, it avoids creating an incentive to discourage non-programmatic energy savings. It also ties cost recovery directly to the actual under-recovery of fixed costs, avoiding the inherent danger that a mechanism such as the LCFC will go beyond making a utility "whole" and instead become a profit center.

Q61. DOES ENTERGY'S SEPARATE DECOUPLING PROPOSAL WITHIN THE PROPOSED FORMULA RATE PLAN ACCOMPLISH THESE SAME GOALS?

A. No. By creating a separation and exclusion between two limited forms of decoupling, it not only makes the ratemaking system more complicated than it needs to be, it also retains all of the disadvantages of the LCFC that I have described. AAE witness Pamela Morgan elaborates on the national prevalence of LRAMs such as the proposed LCFC, shortcomings in the LCFC model, and how a revised decoupling mechanism would remove the need for the proposed LCFC.

Q62. WOULD FULL DECOUPLING PROVIDE A BETTER FOUNDATION FOR ACHIEVING THE CITY'S ENERGY EFFICIENCY GOALS THAN THE COMPANY'S PROPOSED LCFC?

A. Yes. There is strong evidence that decoupling is generally associated with better energy efficiency outcomes than LRAMs like the LCFC. Figures 1 and 2, developed by ACEEE, illustrate this general theme, first by comparing 2013 energy savings data in states with decoupling to those with a LRAM (Figure 1) and then separately depicting the same comparison except for limiting the scope to include only states with an energy efficiency resource standard ("EERS") (Figure 2).[42]

[42] Annie Gilleo *et al.*, *Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms*, ACEEE, at 16, Figure 12 & 17, Figure 14 (June 2015), https://aceee.org/sites/default/files/publications/researchreports/u1503.pdf.

Figure 1: Comparison of Energy Savings With Decoupling vs. LRAM

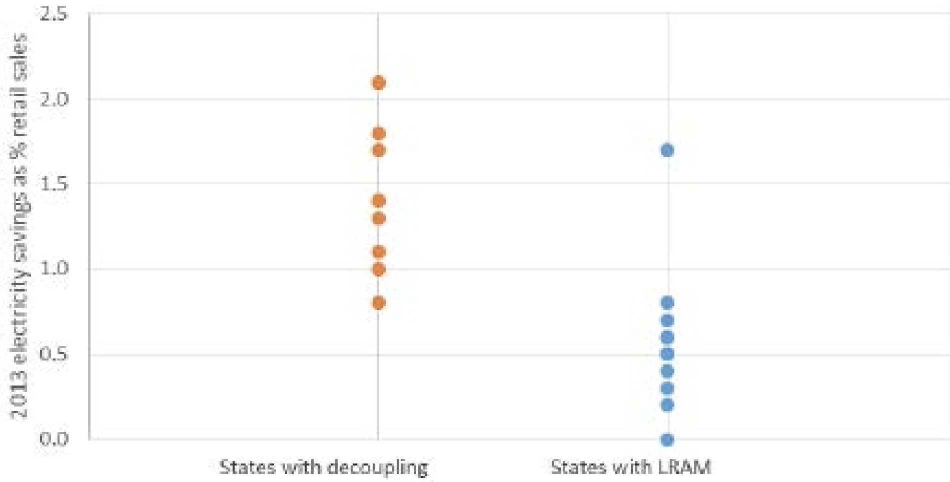
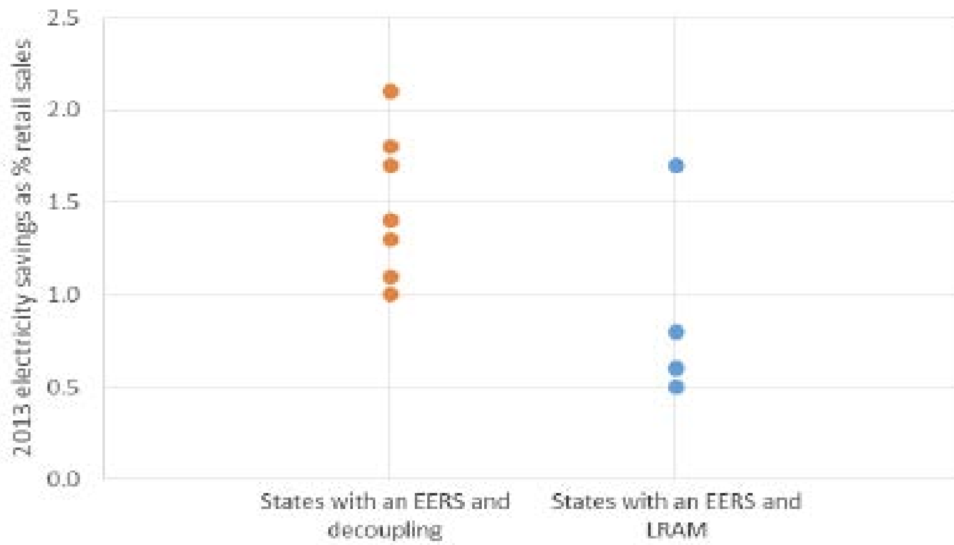


Figure 2: Energy Savings in EERS States With Decoupling vs. LRAM



It is clear in both of these figures that decoupling is associated with better energy efficiency outcomes than LRAMs. For the reasons I have described, ACEEE only considers LRAMs appropriate as a temporary solution for addressing concerns about revenue losses due to efficiency gains. Consequently, ACEEE has observed:

> 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.[43]

Q63. ARE YOU PROVIDING ANY RECOMMENDATIONS TO THE COUNCIL REGARDING THE DETAILS OF DECOUPLING DESIGN ITSELF?

A. No. Decoupling design details are discussed in the Direct Testimony of AAE witness Pamela Morgan.

C. Performance Incentive Structure

Q64. PLEASE DESCRIBE ENTERGY'S PROPOSED ENERGY EFFICIENCY PERFORMANCE INCENTIVE FRAMEWORK.

A. Entergy 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[44]

This type of structure is sometimes referred to as "step-based" because when placed in graphic form it resembles a series of steps.

[43] *Id.* at 21.
[44] Owens Direct at 26, Figure 3.

Q65. DO YOU AGREE THAT THE PERFORMANCE INCENTIVE MECHANISMS CAN BE A REASONABLE WAY OF ALIGNING UTILITY INCENTIVES TO PURSUE ENERGY EFFICIENCY?

A. Yes, generally speaking. Some research on the cause and effect relationship between the provision of performance incentives and achieved energy savings has been inconclusive due to the fact that multiple policy factors can be associated with producing lower or higher levels of savings. For instance, in a 2015 report, ACEEE found that states with performance incentive policies spent significantly more on energy efficiency as percentage of utility revenue than states without performance incentives (2.0% vs. 1.4%) and produced higher savings as a percentage of retail sales (0.9% vs. 0.5%).[45] However, the same report also found that if states were grouped by whether they had an EERS or not, little difference could be seen within the EERS and no EERS subgroups between states with and without performance incentives. That said, the report concludes that in aggregate some correlation exists between spending and results as well as the existence of performance incentives, speculating that performance incentives may be important for securing support from utility management even though the absolute effect is difficult to quantify.[46]

Therefore, I agree that performance incentives should be considered as a method for encouraging support for energy efficiency, but I think the Council should be cautious in how it approaches the matter. The point is to reward truly

[45] Seth Nowak *et al.*, *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, ACEEE, at 24 (May 2015), https://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.
[46] *Id.* at 25.

good performance with an incentive, such that the incremental cost is a reasonable tradeoff for the contribution it makes to the success of the program. It should not be a mechanism that provides rewards for all potential program outcomes because at that point the incentive is simply a cost that serves no beneficial purpose. As shown by the statistics I have presented above on the relative effectiveness of an EERS compared to performance incentives, the stick is sometimes more effective than the carrot.

Q66. WHAT WEAKNESSES DO YOU SEE IN ENTERGY'S PROPOSED PERFORMANCE INCENTIVE DESIGN?

A. First, Entergy's proposal to earn a return on all program expenditures provides incentives that are too rich, effectively providing a shareholder return regardless of the amount of savings achieved relative to the target. Second, the step-based design creates only a loose tie between performance and incentive rewards.

Q67. PLEASE ELABORATE ON HOW THE PERFORMANCE INCENTIVE STRUCTURE IS "TOO RICH."

A. If a performance incentive is to truly reward good performance, there should be a reasonable minimum threshold at which no incentive is allowed. Entergy'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.

Q68. PLEASE DESCRIBE THE SHORTCOMINGS OF THE COMPANY'S PROPOSED STEP-BASED PERFORMANCE INCENTIVE DESIGN.

A. The chief problem with this type of design is 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. 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 Entergy'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. Entergy 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.

Q69. WHAT ALTERNATIVE STRUCTURE DO YOU RECOMMEND FOR AN ENERGY EFFICIENCY PERFORMANCE INCENTIVE?

A. The incentive should contain several elements, as follows:

- 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.

These characteristics could be established under a rate of return model or a different design where incentive awards do not bear any relationship to the Company's allowed rate of return. In other words, 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.

A formulaic model without steps would utilize an equation to draw a curve or a line where the percentage of the savings goal sits on one axis and the incentive award percentage sits on the other axis. For example, if the line is linear with no incentive at a minimum savings threshold of 80% and an 8% return on expenses at savings of 120% of the target as a maximum, the incentive at 100% of the target is 4% of expenses. In the form of a linear equation with the incentive on the Y-axis and performance on the X-axis, this would be reflected as follows:

Formula: $Y = (X/5) – 16$

Example (92% of target): $Y = (92/5) – 16 = 18.4 – 16 = 2.4\%$

Such a formula can be easily applied at whatever degree of precision the Council wishes.

Q70. ARE YOU MAKING ANY RECOMMENDATIONS FOR SPECIFIC ENERGY EFFICIENCY TARGETS THAT WOULD UNDERPIN THIS PERFORMANCE INCENTIVE DESIGN?

A. No. However, I will observe that incremental performance incentives represent a cost that serves little useful purpose if the targets themselves are unambitious. Company 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 division.[47] The establishment of more ambitious targets that are difficult to consistently achieve would provide a justification for the associated incremental costs.

For that reason, while I have provided numeric examples to illustrate how the model would function, in practice the scale (*e.g.*, minimum and maximum incentives) should be responsive to the level of ambition embodied in the targets. Past program results, as well as the issue I have raised with respect to the Company's proposal overshooting true financial indifference, suggest that an incentive equivalent to the Company's weighted cost of capital should only be awarded for target achievement well in excess of 100%.

[47] Owens Direct at 10, Table 1.

Q71. PLEASE ELABORATE ON YOUR SUGGESTION THAT A PERFORMANCE INCENTIVE INCLUDE PENALTIES FOR POOR PERFORMANCE.

A. As I previously observed, sometimes sticks are more effective than carrots. A symmetrical incentive combines both of these aspects, as the Company has proposed. An incentive design that includes adverse consequences for unreasonably poor performance sets a floor of minimum expectations without compromising reward upside for good performance. Such a floor is not dissimilar 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, I suggest that the Council consider a variable penalty based on foregone cost savings for each kWh between the amount of savings achieved and the minimum threshold. 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.

Q72. COULD SUCH A DESIGN BE EXTENDED TO PROGRAMS TARGETING REDUCTIONS IN PEAK DEMAND RATHER THAN JUST ENERGY SAVINGS?

A. Yes. Based on my understanding, the Council has not historically established peak demand reduction goals. Many other jurisdictions have found value in establishing peak demand reduction targets in addition to energy savings targets, and it would be reasonable for the Council to consider doing so. The performance incentive model I have described could be adapted to supporting peak reduction targets as well. Care would have to be taken to ensure that demand savings are not double-counted, and it may be reasonable to use a different performance incentive scale for demand reduction measures because the cost savings benefits peak demand reduction are likely to be weighted towards avoided capital costs. This influences the amount of performance incentive that would make the utility financially indifferent.

D. Rider DSMCR Rate Design

Q73. IS THE PERCENTAGE OF BILL RATE STRUCTURE CONTAINED IN RIDER DSMCR AN APPROPRIATE WAY TO RECOVER ENERGY EFFICIENCY PROGRAM COSTS?

A. No. The percentage of bill-based design effectively increases the fixed charge that a customer pays each month. This is not appropriate for two reasons. First, it dampens the energy conservation price signal that a customer sees relative to a fully volumetric charge, operating at cross-purposes to the goals of the program and penalizing the precise type of customer behavior the program targets. Second, energy efficiency investments avoid future energy supply costs, and potentially distribution infrastructure costs, on the shared system. This objective does not have a customer-specific component or any other relationship to costs associated with connecting a customer to the electric grid.

Q74. YOU PREVIOUSLY STATED THAT CUSTOMER SERVICE EXPENSES ARE GENERALLY CONSIDERED CUSTOMER-RELATED. WOULD THE SAME NOT BE TRUE FOR CUSTOMER SERVICE EXPENSES RELATED TO EFFICIENCY PROGRAMS?

A. No. For normal utility operations, customer service is an integral part of making the ability to purchase energy available to a customer. By contrast, customer service aspects associated with energy efficiency programs are effectively energy or demand related because their function is to enable investments that avoid the need for additional energy or capacity resources. As such they are akin to the costs that would be associated with energy or fuel purchases, or the conduct of a solicitation for capacity resources.

Q75. WHAT ARE YOUR RECOMMENDATIONS FOR THE RATE DESIGN TO BE USED FOR RIDER DSMCR?

A. The conservation signal and cost causation would be more accurately reflected in a volumetric charge. This is how energy efficiency program costs are commonly recovered, with the occasional variation that uses a demand-based charge for program elements targeting demand reductions. As in utility rates more generally, demand-based energy efficiency program charges are limited to larger non-residential customer classes.

VI. DISCUSSION OF CROSS-CUTTING ISSUES & CONCLUSION

Q76. PLEASE SUMMARIZE YOUR GENERAL ASSESSMENT OF ENTERGY'S RATE APPLICATION.

A. The Company's collective requests are one of the most aggressive attempts to fix utility revenues that I have ever seen in a single rate application, if not the most aggressive. As I have discussed throughout my testimony, many of the individual elements would do so in a manner that conflicts with supporting customer investments in energy efficiency and increasing customers' ability to control their energy bills. What is even more concerning is that the individual proposals would operate in concert with one another to exacerbate these issues while at the same time enhancing Entergy's earnings. The individual proposals I have critiqued are each problematic in their own right, but the total effect is even greater than the sum of the parts. 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.

Q77. PLEASE ELABORATE ON HOW ENTERGY'S PROPOSALS WOULD CREATE THE "REINFORCING CYCLE" YOU REFER TO ABOVE.

A. This cycle starts with the direct increases in fixed charges that Entergy has proposed, specifically the increase in the residential customer charge and the fully fixed AMI charge. In the first year, that produces a total nominal fixed charge increase of $10.41/month. As I have already described, that would alone sacrifice years worth of energy savings achieved through the Energy Smart program. Layered on top of this are further indirect increases in fixed charges via the use of percentage of bill-based riders, including those proposed under Rider DGM and Rider DSMCR. With a higher residential customer charge, these riders produce a higher indirect increase in the residential customer charge than would be the case if the customer charge was lower. For instance, if the total combined percentage increase for both riders was 10%, the incremental indirect increase in the residential customer charge is $0.807/month at the current customer charge of $8.07/month, but would be $1.553/month at the proposed customer charge.

When rate design related incentives for customer energy efficiency are diluted, achieving the same energy efficiency results will require greater DSM spending. This effect is unavoidable, as lower customer cost savings through rates will have to be supported by greater incentives in order to overcome cost barriers. At the same time, Entergy has proposed revising the manner in which it earns performance incentives to be based on DSM spending. This translates to incrementally higher program costs that would be further increased by the LCFC component of Rider DSMCR and further still by the Company's proposal to amortize the balance over three years. As I have described above, those higher costs are then passed to customers through a percentage of bill-based charge that effectively increases the residential customer charge by an amount that varies directly in relation to the amount of the customer charge, which the Company proposes to roughly double.

Thus, the cycle is one where an increase on one fixed charge component produces increases in others, the combination of which dilute rate-related customer incentives for energy efficiency—producing higher DSM program costs which in turn result in further effective increases in fixed charges. Entergy benefits financially from this cycle through a proposed DSM performance incentive that rewards greater spending in a manner that is connected only very loosely to results.

Q78. IS SUCH A RESULT IN THE INTEREST OF NEW ORLEANS RATEPAYERS?

A. No. 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, it 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. Entergy would benefit financially from such an outcome but its ratepayers would not.

Q79. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COUNCIL.

A. I recommend that the Council:

- Adopt a residential customer charge consistent with the costs of connecting a customer to the electric grid and my 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.

- Adopt a volumetric rate design for the recovery of AMI costs on the basis that the incremental costs of AMI above traditional meters are associated primarily with producing energy and demand-related cost savings.
- Adopt a rate design consistent with how customers are charged for the use of the shared distribution system for the recovery of costs associated with the Company's proposed grid modernization investments, should the Council approve any such investments.
- Reject the Company's proposal to re-establish the LCFC within Rider DSMCR and instead adopt a full decoupling mechanism consistent with the recommendations of AAE witness Pamela Morgan.
- Adopt a volumetric rate design for recovery of the costs of any approved DSM program.
- Reject the Company's proposed DSM performance incentive structure and instead adopt a structure that contains symmetrical incentives and penalties and a more granular performance reward calculation, as discussed in more detail in the body of my testimony. This design could include a variation to incentivize peak demand reduction if the Council were to adopt peak demand reduction targets, which should be considered for future programs.

Q80. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

I, Justin Barnes, do hereby swear under the penalty of perjury the following:

That I am the person identified in the attached prepared testimony and that such testimony was prepared by me under my direct supervision; that the answers and information set forth therein are true and accurate to the best of my personal knowledge and belief; and that if asked the questions set forth herein, my answers thereto would, under oath, remain the same.

Justin Barnes

SWORN TO AND SUBSCRIBED BEFORE ME THIS 28th **DAY OF** January

BLAKE W. ELDER NOTARY PUBLIC DURHAM COUNTY, NC

Blake W. Elder

NOTARY PUBLIC

My commission expires: May 16, 2021

Exhibit JRB-1

Curriculum Vitae of Justin R. Barnes

JUSTIN R. BARNES

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EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager*,* March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource DER value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst*,* September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing **Direct Testimony of Justin R. Barnes on Behalf of the Alliance for Affordable Energy** 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 1st day of February, 2019.

Al Luna
Litigation Assistant
Earthjustice

April 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, redacted version of the **Surrebuttal Testimony of Justin R. Barnes on Behalf of the Alliance for Affordable Energy** in the above-captioned docket. The HSPM version of the Surrebuttal Testimony will be served in hard copy only to the appropriate parties who have executed Non-Disclosure Certificates pursuant to Council Resolution R-07-432.

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

Sincerely,

Logan A. Burke

Logan Atkinson Burke
Executive Director
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, LA 70125
(504) 208-9761
logan@all4energy.org

Enclosures
cc: Official Service List

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	**)**	

SURREBUTTAL TESTIMONY

OF

JUSTIN R. BARNES

ON BEHALF OF THE

ALLIANCE FOR AFFORDABLE ENERGY

PUBLIC VERSION

APRIL 26, 2019

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LIST OF TABLES

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Alliance for Affordable Energy ("AAE").

Q3. ARE YOU THE SAME JUSTIN R. BARNES WHO FILED DIRECT TESTIMONY IN THIS DOCKET ON FEBRUARY 1, 2019, ON BEHALF OF AAE?

A. Yes.

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimonies filed by Entergy New Orleans ("ENO" or "Company") witnesses Andrew Owens, Myra L. Talkington, Dr. Ahmad Faruqui, and Joshua B. Thomas related to the Company's residential customer charge proposal, the proposed Electric Advanced Metering Infrastructure ("AMI") Charge, and the proposed Demand-Side Management ("DSM") program structure and associated cost recovery rider ("Rider DSMCR").

III. RESIDENTIAL CUSTOMER CHARGE

Q5. PLEASE SUMMARIZE THE COMPANY'S OBJECTIONS TO YOUR RECOMMENDED RESIDENTIAL FIXED CHARGE.

A. Company witnesses Talkington and Faruqui both address this aspect of my Direct Testimony. Ms. Talkington voices several objections. To paraphrase, Ms. Talkington contends that the comparisons I made to the fixed monthly charges of other utilities are not relevant and that the calculations I conducted in developing my recommended charge of $8.13/month are incorrect because I excluded certain costs that are "fixed" in nature.[1] Dr. Faruqui disputes my contentions that increasing fixed charges will discourage energy efficiency and that such increases would adversely and disproportionately impact low-income customers.[2]

Q6. ARE MS. TALKINGTON'S ASSERTIONS REGARDING THE RELEVANCE OF AVERAGE RESIDENTIAL CUSTOMER CHARGES CONSISTENT?

A. I find them confusing. On the one hand, Ms. Talkington says that the customer charge should be based on the specific facts affecting ENO.[3] On the other hand, she states that a "totality of relevant factors" should be considered in setting the charge[4], relates statistics from the national survey I conducted showing that some utilities have higher charges than my recommendation,[5] and describes the outcome of ratemaking practices for Entergy's Arkansas and Texas affiliates which result in fixed customer charges covering a higher

[1] Rebuttal Testimony of Myra L. Talkington at 15-18 (Mar. 2019) ("Talkington Rebuttal").
[2] Rebuttal Testimony of Dr. Ahmad Faruqui at 22-24 (Mar. 2019) ("Faruqui Rebuttal").
[3] Talkington Rebuttal at 15:8-9.
[4] *Id.* at 14:18-19.
[5] *Id.* at 15:9-16.

percentage of calculated customer unit costs.[6] Ms. Talkington cannot credibly argue that the residential customer charge should be based exclusively on ENO-specific factors, while at the same time selectively citing factors and statistics that are not specific to ENO to support her position.

Q7. HOW DO YOU RESPOND TO MS. TALKINGTON'S ASSERTIONS ON THE SUBJECT OF A NATIONAL PERSPECTIVE ON RESIDENTIAL CUSTOMER CHARGES?

A. I agree that setting the residential customer charge should consider a totality of factors, including cost causation, customer impacts, gradualism, consistency with overall energy and ratemaking policies, and the stability of rates and rate structure. My survey speaks to several of these factors but most specifically reflects the practice of gradualism in ratemaking as practiced on a national level. I note that the customer charge I recommended, $8.13/month, is similar to the $8.40/month current charge levied by Entergy Arkansas and the $10/month charge levied by Entergy Texas, both of which Ms. Talkington cites. The distinction Ms. Talkington makes between ENO and these affiliates is that ENO's calculated customer unit costs are significantly higher. This raises an interesting question as to why that would be the case. It could be that both of these other jurisdictions use a more restrictive definition of customer-related costs, as is represented in my own calculations, or that ENO's costs are simply much higher than those of these two affiliates.

Leaving the issue of cost magnitude, Ms. Talkington is correct that some utilities levy higher customer charges and the national average is in fact higher than the amount I

[6] *Id.* at 16:3-9.

recommended. I never suggested otherwise. However, my recommended charge is far more consistent with the broad benchmarks established by national statistics than ENO's proposal. The national average charge is $10.40/month while the median is approximately $9.40/month, the national average increase (per rate case) is $0.96/month while the median increase in my data set is approximately $0.34/month. These averages reflect the "totality" of factors that Ms. Talkington refers to, where the differences in specific facts and circumstances for each case even out by virtue of averaging.

Q8. DO YOU WISH TO AMEND YOUR DESCRIPTION OF ENO'S RESIDENTIAL CUSTOMER CHARGE PROPOSAL AS "EXTREME" GIVEN MS. TALKINGTON'S OBJECTION TO "SUCH A PEJORATIVE LABEL"?

A. Absolutely not. The Company proposes an increase of $10.41/month or 129% considering the additive effect of the customer charge increase and the proposed Electric AMI Charge, relative to national average increases of $0.96/month and 13.80%. The proposed increase would exceed the single *largest* monetary increase adopted in recent years by $2.72/month and is more than nine times the average percentage increase. The only larger percentage increase was one granted to Duke Energy Kentucky (144%), which resulted in a charge of $11.00/month. The outsized percentage increase is attributable to the fact that the prior fixed charge was only $4.50/month. "Extreme" is the best description I can think of under the circumstances.

Q9. IS YOUR DERIVATION OF A REASONABLE CUSTOMER CHARGE CONSISTENT WITH COST CAUSATION?

A. Yes. Ms. Talkington disputes the exclusions I made in my calculation, focusing specifically on the exclusion of administrative and general costs and contending that several other costs I excluded do not vary with customer demand or consumption.[7] I do not disagree that these costs must be recovered, nor do I disagree that they do not necessarily vary with customer demand or energy consumption. Furthermore, I do not disagree that cost allocation may reflect the assignment of a portion of these costs on the basis of the number of customers in a class. What Ms. Talkington fails to address is that the costs I excluded do not vary with the *number of customers* either, and I did not exclude costs directly related to customer-specific functions such as billing, metering, and customer service.

Administrative and general plant costs always pose a quandary for cost causation evaluation because they cannot be said to vary according to any of the three traditional classifications (energy, demand, and customer). However, regardless of how those costs are allocated, 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.[8] This is what I have done in my calculations, which produce a result broadly similar to average residential customer charges established in other jurisdictions. My method is not unusually or unduly restrictive.

[7] *Id.* at 17:6-13.
[8] Frederick Weston *et al.*, *Charging for Distribution Utility Services: Issues in Rate Design*, at 19, REGULATORY ASSISTANCE PROJECT (Dec. 2000), http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

One reason for establishing limitations of this type is to avoid rendering the customer charge a "dumping ground" for costs that cannot be said to fall clearly within another classification. The case is particularly compelling when a jurisdiction has established energy efficiency as a high priority, as the Council has done by establishing energy efficiency as a "high-priority energy resource" and seeking to "align customer pricing and incentives to encourage investment in energy efficiency."[9] Costs that are recovered via a fixed charge are costs that do not contribute to customer incentives for energy efficiency through increases the volumetric rate (*i.e.*, the "savings" rate for a customer that pursues energy efficiency).

Q10. DOES ECONOMIC EFFICIENCY OF RATES ARGUE FOR RECOVERY OF SO-CALLED FIXED COSTS VIA FIXED CHARGES?

A. No. As I observed in my Direct Testimony, embedded cost of service studies are better suited to determining how much revenue should be collected from different groups of customers, not the rate design associated with collecting that revenue. Rate design should reflect an effort to produce consumer behavior that maximizes long-term economic efficiency and supports public policy goals. Many different rate designs are capable of producing a similar amount of revenue while not compromising public policy goals.

Q11. HOW DO YOU RESPOND TO DR. FARUQUI'S CLAIM THAT FIXED CHARGES DO NOT DEPLETE CONSUMER INCENTIVES TO BE MORE ENERGY EFFICIENT?

A. Dr. Faruqui states that customers consider their total bill, rather than individual portions of their bill like the fixed charge, when considering whether to make investments in energy

[9] Council Resolution No. R-07-600.

efficiency. Dr. Faruqui then notes that the consequence of weighting a rate towards fixed charges results in low demand elasticity.[10] I agree with both assertions, but they actually serve to reinforce rather than diminish my argument that high fixed charges deplete consumer efficiency incentives.

Low demand elasticity refers to circumstances where consumers are not sensitive to their energy consumption because changes in that consumption produce little change in their bill (*i.e.*, they save little money by making investments or changing their behavior). Stated another way, if customers are sensitive to changes in their total bill, relatively higher volumetric rates produce a higher bill at higher levels of use, therefore a customer that is sensitive to their total bill will be inclined to use less energy. The amount of a fixed charge that a customer sees on their electric bill is not the relevant factor here. The relevant factor is that under a given revenue requirement, increasing the fixed charge produces lower volumetric charges, reducing demand elasticity by diminishing the bill savings that energy conservation will produce.

Q12. DOES DR. FARUQUI PRESENT A COMPELLING CASE REFUTING YOUR ARGUMENT THAT STATES THAT RANK HIGH IN THE AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY ("ACEEE") RANKINGS SUPPORT THESE GOALS IN PART THROUGH LOW FIXED CHARGES?

A. No. Dr. Faruqui first notes that the three major investor-owned utilities ("IOUs") in California presently have zero or very low fixed charges that drag down my calculated average charge of $6.05/month for the top five states. He notes that each has made

[10] Faruqui Rebuttal at 22:5-11.

proposals to increase the charge to up to $10.00/month, and that the New York utilities (sixth in the ACEEE rankings) have relatively higher fixed charges.[11] Even if one assumed that the fixed charges for the three California IOUs will increase to $10/month, the overall average would increase only to $8.13/month. Coincidentally, that amount is identical to my recommended charge. Adding New York, which ranks sixth as Dr. Faruqui appears to suggest is appropriate, increases the average further to $11.13/month, still assuming that the California utilities have fixed charges of $10.00/month.

I think either addition is debatable, given that the California proposals have not been adopted and adding New York by itself resembles cherry-picking. For the sake of argument though, expanding the scope to the ACEEE top ten states by adding Oregon, Minnesota, Washington, and Maryland produces an average of $10.36/month if the California increases are assumed, and $9.55/month at the present fixed charges for the major California IOUs. The conclusion that states that prize energy efficiency tend to adopt low residential fixed charges remains the same, and one can also conclude that the states with the highest rankings employ, on average, lower fixed charges than those further down (though still relatively highly ranked).

Q13. HOW DO YOU RESPOND TO THE COMPANY'S CONTENTION THAT INCREASING FIXED MONTHLY CHARGES WOULD NOT HAVE DISPROPORTIONATE ADVERSE IMPACTS ON LOW-INCOME CUSTOMERS?

A. I strongly disagree with the Company's conclusions. Dr. Faruqui contends that there is no disproportionate impact because a minority of low-income customers, roughly 40%, are

[11] Faruqui Rebuttal at 23:1-4.

made better off by higher fixed charges (*i.e.*, because they have above average electricity use). He also states that the distribution of usage for low-income customers is similar to the residential class overall, though he provides no data to support this assertion.[12] Company witness Thomas makes similar statements with respect to the proposed fixed monthly Electric AMI Charge, and additionally asserts that my conclusion that low-income customer impacts would be disproportionate "is predicated on the assumption that all low-income customers are low usage customers."[13]

In response to both, I point to Table 3 of my Direct Testimony (redacted as HSPM material). Table 3 makes it quite clear that low usage customers are much more likely to fall at the lower end of the income spectrum than high usage customers, including within the lowest monthly usage tranche (500 kWh or less). Contrary to Mr. Thomas's assertion, my analysis is not predicated on an assumption that all low-income customers are low-usage customers. I never made such a statement or even implied as much in my Direct Testimony. Rather, I maintain that the adverse effects of fixed charges on low-income customers are disproportionate because: (a) a significantly greater percentage of lower income customers are low-usage customers than the percentage for the class as a whole, and (b) a significantly greater percentage of lower income customers are in the lowest usage tranche (*i.e.*, those most adversely affected) than the percentage for the class as a whole. Table 1 presents this data in a different format, showing the percentage of customers with monthly usage of 500 kWh and 1,000 kWh or less sectioned with household income breakpoints of $15,000, $25,000, and $35,000.

[12] Faruqui Rebuttal at 23:11-16.
[13] Rebuttal Testimony of Joshua B. Thomas at 46:6-8 (Mar. 2019) ("Thomas Rebuttal").

Table 1: Income Tranche vs. Monthly Usage Tranche

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]

The data provided in Table 1 represents the very definition of disproportionate, showing that lower income is associated with lower usage, and that the largest adverse effects are most pronounced for the lowest income segment.

IV. ELECTRIC AMI CHARGE

Q14. PLEASE SUMMARIZE THE RECOMMENDATIONS YOU MADE IN YOUR DIRECT TESTIMONY ON THE COMPANY'S PROPOSED AMI RIDER.

A. I recommended that the Electric AMI Charge utilize a volumetric rate design rather than a fixed monthly charge design.

Q15. HOW DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Mr. Thomas maintains that the Company's original proposal is appropriate, including the use of a fixed monthly charge to recover AMI costs.[14] Mr. Thomas contends that a fixed monthly charge is consistent with cost causation while a volumetric charge as I have recommended is not.[15] He also contends that because over 50% of the benefits of AMI flow through to customers via usage-based charges, "each customer individually should

[14] Thomas Rebuttal at 44:3.
[15] *Id.* at 45:19–46:5.

bear the costs associated with the infrastructure producing those benefits, which costs are fixed."[16]

Q16. IS MR. THOMAS'S ASSERTION THAT A VOLUMETRIC ELECTRIC AMI CHARGE CONFLICTS WITH COST CAUSATION CORRECT?

A. No. Cost causation is an exercise in evaluating *why* costs are incurred and *how they vary* according to different factors. In the case of AMI, the *why* is primarily related to the production of energy and demand savings, while *how they vary* is based on the number of customers. Mr. Thomas asserts that my analysis of cost causation for AMI rests on a "labored argument" against "traditional cost causation logic" with respect to metering rate design.[17] My argument is in fact quite simple and is entirely consistent with "traditional" cost causation evaluation, which considers both factors. When costs are incurred to produce energy or serve demand, those costs are considered energy- or demand-related. 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.

Differentiating between how costs and benefits are experienced by customers distorts price signals and conflicts with the primary purpose of AMI. Furthermore, as I observed more generally in my Direct Testimony and earlier in my Surrebuttal Testimony, fixed charges have disproportionate adverse impacts on low-income customers, which should also be a consideration in rate design.

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[16] *Id.* at 44:12-16.
[17] *Id.* at 45:16-17.

Q17. DO YOU WISH TO RESPOND TO ANY OTHER ASSERTIONS MADE BY MR. THOMAS?

A. Yes. Mr. Thomas erroneously disputes a position that I did not take in my Direct Testimony, to wit, that ENO should not be permitted to recover the un-depreciated costs of retired legacy meters.[18] In fact, in my Direct Testimony, I expressly stated: "To be clear, I am not objecting to the recovery of the un-depreciated costs of legacy meters, as the Council has already ruled on this issue. I only address the mechanism for that cost recovery from the perspective of rate design."[19]

Mr. Thomas's assertion appears to stem from my statement that requiring customers to effectively pay two *fixed monthly metering charges* is fundamentally unfair. I maintain this position, but it has nothing to do with cost recovery. It relates to rate design. Since the Company is recovering the un-depreciated costs of traditional metering via the customer charge, the incremental costs of AMI at present are the full costs.

V. DSM PROGRAM DESIGN AND RIDER DSMCR

Q18. PLEASE SUMMARIZE THE COMPANY'S OBJECTIONS TO YOUR TESTIMONY ON ITS DSM PROPOSAL.

A. The Company collectively, via Dr. Faruqui and Mr. Owens, finds fault with virtually all aspects of my testimony on the topic, disputing my arguments that the Lost Contribution to Fixed Costs ("LCFC") element should be eliminated in favor of full decoupling as well as disagreeing with my proposal for a DSM performance incentive structure with stricter requirements for the provision of additional earnings. In parts, Mr. Owens seems to take

[18] *Id.* at 44:18–45:4.
[19] Direct Testimony of Justin R. Barnes at 7:9-12 (Feb. 1, 2019).

personal affront to my critiques. Among other things, he accuses me of "[d]ismissing ENO's proposed model out of hand simply because ENO proposed it."[20] He further states that I did not focus "on its merits or technical aspects" and characterizes my assertion that sometimes requirements are more effective than incentives as an "attack" that "undermines a view of utility regulation where collaboration is a foundation to identifying a model that will provide a 'win' for all stakeholders."[21]

Q19. DO THE PASSAGES FROM MR. OWENS' REBUTTAL TESTIMONY THAT YOU DESCRIBE ACCURATELY REFLECT THE INTENT AND CONTENT OF YOUR TESTIMONY?

A. No. Mr. Owens' rhetoric is a distraction from substantive issues I have identified with the Company's proposal. Contrary to his assertions, my critiques are not an exercise in "verbal gymnastics" to "find imaginary flaws."[22] I find this characterization surprising because it seems that we actually agree on several core principles with respect to developing a solid DSM structure.

Mr. Owens perhaps objects to the frame I used in discussing energy efficiency performance incentives (*i.e.*, the use of "sticks" where appropriate). I fail to see why it is unreasonable to make this observation. Utility regulation has always been a balance of sticks and carrots, and the ACEEE data I relayed in my Direct Testimony suggests that minimum standards have historically performed well, while the results of performance

[20] Rebuttal Testimony of D. Andrew Owens at 27:8-9 (Mar. 2019) ("Owens Rebuttal").
[21] *Id.* at 27:12-16.
[22] *Id.* at 29:19–30:2.

incentives has been less clear. Nevertheless, I recommended that performance incentives be considered, as ACEEE also recommends, though with caution given the mixed results.[23]

Q20. PLEASE SUMMARIZE YOUR POINTS OF AGREEMENT AND DISAGREEMENT WITH ENO'S DSM PROPOSAL.

A. With the exception of disagreements on merits and drawbacks of the LCFC, which I will allow AAE witness Pamela G. Morgan to respond to, my recommended DSM program design is quite similar what ENO originally proposed. I agree with ENO that an indifference mechanism to address potential revenue attrition from energy efficiency should be adopted, and that the DSM program design should allow the Company to receive a performance incentive for successfully supporting increased customer energy efficiency. Where we appear to differ is on the amount of that incentive and how closely it ties to achieving energy efficiency savings goals.

In terms of differences, more specifically, the Company proposed a rate of return model where it would receive a return equivalent to its pre-tax weighted average cost of capital ("WACC") on DSM expenses, modified to lower the return for the return on equity ("ROE") component by 100 basis points if it achieves less than 60% of the savings target, while increasing the ROE component by 100 basis points for achieving 95-120% of the target or 200 basis points for savings in excess of 120% of the target. My recommended structure featured additional elements and modifications as follows:

1. A meaningful minimum savings threshold below which the Company recovers expenses but receives no return on those expenses, and is subject to a penalty

[23] Barnes Direct at 47:18-20.

equivalent to the value of foregone cost savings for failing to achieve the minimum threshold.

2. A more granular formulaic incentive calculation system in place of the large "steps" in ENO's proposal.

3. A cap on total incentive awards.

Modification (2) above does not appear to be in a point of significant contention, as Mr. Owens agrees that the performance incentive calculation could be made more granular, suggesting splitting the percentage targets into increments of 5% with a 20 basis point adder for each increment.[24] On modification (3), a cap on the incentive, Mr. Owens disagrees with establishing a cap, contending that the allowed maximum allowed ROE would create an effective cap and that an additional cap would add unnecessary complexity.[25] Modification (1) is the primary source of disagreement between myself and the Company, relating to the amount of the performance incentive in relation to program spending (*i.e.*, the percentage return allowed), minimum standards for receiving an incentive, and potential penalties for underperformance. All of these elements are in fact associated with the "technical merits" that Mr. Owens believes I have ignored. The Company disputes my assertion that the overall program design produces an incentive for ENO that I described as "too rich."[26]

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[24] Owens Rebuttal at 32:16-22.
[25] *Id.* at 33:3-10.
[26] *See id.* at 29:19; Faruqui Rebuttal at 15:11.

Q21. PLEASE EXPLAIN YOUR USE OF THE PHRASE "TOO RICH" IN DESCRIBING THE PERFORMANCE INCENTIVE STRUCTURE.

A. I used this phrase as a general descriptor. The relative "richness" of the incentive can be evaluated from multiple perspectives, as follows:

1. The minimum level of performance at which an incentive is earned.
2. The relationship of a percentage award on expenditures in relation to savings achieved.
3. The total maximum incentive that ENO is permitted to earn.

My concerns center on the first two aspects. I recommended a total incentive cap be established, but as I discuss later, this can be effectuated as an offshoot of the percentage award that is permitted.

Q22. DOES A MINIMUM PERFORMANCE THRESHOLD DILUTE THE "WIN-WIN" OUTCOME THAT MR. OWENS SEEKS?

A. No. Ratepayers do not "win" if the costs they pay towards a program fail to produce good results. That is the purpose of setting a reasonable minimum threshold. The Company receives a "win" by being permitted to earn additional revenue for achieving a minimum goal where it would otherwise be permitted to recover program expenses and no more. As captured in ACEEE's review of energy efficiency performance incentives, minimum threshold requirements are, for good reason, quite common. ACEEE's summary depicts minimum thresholds ranging from 55% to 100% of savings or net benefits targets.[27] As I

[27] Seth Nowak *et al.*, *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, ACEEE, at 11-13 (May 2015), https://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.

observed in my Direct Testimony, a minimum threshold should consider the ambitiousness of the targets in order to reward only good performance, and not be punitive to a utility in the context of highly ambitious targets.

ENO's proposal simply does not tie the performance incentive closely enough to results. Under the Company's proposal, if ENO met 50% of the target, it would earn a performance incentive nearly equivalent to its WACC, reduced only by 100 basis points for the ROE component of the calculation. I stand by my assertion that this result, equivalent to a reward for a failing grade, is not reasonable. It is "too rich" in relation to the results achieved and as such fails to constitute a "win" for ratepayers.

Q23. IS ROE AN ACCURATE MEASURE TO USE FOR A PERFORMANCE INCENTIVE IN ORDER THE "LEVEL THE PLAYING FIELD" BETWEEN SUPPLY-SIDE AND DSM INVESTMENTS?

A. No. Mr. Owens justifies an ROE-based system by arguing that "incentive mechanisms should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset."[28] On a conceptual level, I agree that this is one flavor of what leveling the playing field can mean.[29] However, it is incorrect to assume, as Mr. Owens does, that fully 100% of DSM expenditures are associated with displaced capital investment.

[28] Owens Rebuttal at 29:12-13.

[29] This represents financial indifference on the part of the utility. The other aspect is *planning indifference*, referring to resource evaluations that consider the full life-cycle cost-effectiveness of supply-side and demand-side investments on an equal basis.

As I observed in my Direct Testimony, a portion of DSM expenditures displaces variable pass-through costs because DSM investments are justified through consideration of both capacity and energy costs. Only foregone capacity costs represent foregone investments, so capitalizing *all* DSM expenditures under a regulatory asset-based model goes beyond rendering a utility financially indifferent. The Council could perhaps justify this result as reasonable in order to make DSM the highest priority investment, but such a decision should be made with awareness of what that decision means in practice.

Q24. HOW DOES THIS IMPLICATION AFFECT YOUR RECOMMENDATIONS FOR SETTING PERFORMANCE-BASED INCENTIVE LEVELS?

A. Since the displacement of capital investment by DSM spending does not take place on a 1:1 basis, the performance incentive should only award the equivalent of full ROE on DSM expenses for performance at, or above, savings targets. Regardless of one's interpretation of the meaning of creating a collaborative DSM framework, failing to meet savings targets should not produce an incentive award that is effectively already above the true financial indifference benchmark.

Q25. WOULD THE APPROVED ROE FOR A PERFORMANCE INCENTIVE, AS MR. OWENS SUGGESTS, ESTABLISH A TRUE INCENTIVE CAP?

A. This would hold true if total expenditures are also capped, since even if the percentage return on DSM investments is capped, the total incentive would still be sensitive to overall spending. To the extent that the budget is not subject to overages, I agree that the maximum percentage return establishes a firm cap.

Q26. DO YOU HAVE ANY FURTHER THOUGHTS ON THE ESTABLISHMENT OF A TOTAL INCENTIVE CAP AND THE LEVEL OF PERFORMANCE INCENTIVES?

A. Yes. Dr. Faruqui presents the results of his calculations of performance incentive caps for states ranked in the top 15 of ACEEE's energy efficiency scorecard rankings. The total number of states for which he shows a calculation is nine because some states do not award performance incentives and the cap in Illinois is stated in relation to ROE. Of these nine, five are below the maximum indicated by ENO's proposal, while four are higher.[30]

I observe several things from this graphic. First, the four states that cap incentives below what ENO proposes (California, Connecticut, Massachusetts, and Rhode Island) constitute four of the top five states in the ACEEE rankings. All of these states rely on both Energy Efficiency Resource Standards and performance incentives as part of their DSM policies (*i.e.*, both carrots and sticks). Furthermore, as I have previously discussed, all four support their efficiency goals with low fixed charges so as not to diminish consumer efficiency incentives. Second, performance incentives are not universal even among highly ranked states.

Collectively, I see these characteristics as pointing to a common theme of alignment between rate design and energy efficiency policy goals, and the use of all available policy tools to achieve those goals. A truly collaborative and effective approach encompasses all of these aspects on the part of a utility, other stakeholders, and regulators.

[30] Faruqui Rebuttal at 16, Figure 1.

VI. CONCLUSION

Q27. HAS THE COMPANY'S REBUTTAL TESTIMONY CAUSED YOU TO MODIFY ANY OF THE RECOMMENDATIONS YOU MADE IN YOUR DIRECT TESTIMONY?

A. No. My recommendations are unchanged. With respect to the contested issues, my recommendations are as follows:

- The residential customer charge should be set consistent with the costs of connecting a customer to the electric grid, which I have calculated to be $8.13/month, in order to: (a) align the charge with costs that are definitively customer-related, (b) support the Council's policy on promoting energy efficiency, and (c) avoid significant adverse impacts on low-income customers.
- The Electric AMI Charge should use a volumetric design because the incremental costs of AMI are primarily energy- and demand-related and customers will still continue to pay a fixed monthly charge for the un-depreciated costs of retired meters.
- The Company's proposed DSM performance incentive structure should be rejected and the Council should instead adopt a structure that: (a) features a symmetrical system of rewards and penalties as dictated by a minimum savings threshold, (b) uses a more granular performance incentive calculation, and (c) scales the amount of the incentive in relation to efficiency targets in a manner that incentivizes truly good performance, with consideration of the relative ambitiousness of savings targets and the true level of financial indifference on the part of ENO.

Q28. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF VIRGINIA)
) ss.
COUNTY OF WISE)

I, Justin Barnes, do hereby swear under the penalty of perjury the following:

That I am the person identified in the attached prepared testimony and that such testimony was prepared by me under my direct supervision; that the answers and information set forth therein are true and accurate to the best of my personal knowledge and belief; and that if asked the questions set forth herein, my answers thereto would, under oath, remain the same.

Justin Barnes

SWORN TO AND SUBSCRIBED BEFORE ME THIS 23 **DAY OF** April**,** 2019

KEDRIC WALTER MEADE
NOTARY PUBLIC 7530864
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES JANUARY 31, 2020

NOTARY PUBLIC

My commission expires: 1/31/2020

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing **Surrebuttal Testimony of Justin R. Barnes on Behalf of the Alliance for Affordable Energy** has been served on the persons listed below by electronic mail and/or U.S. First-Class mail, postage prepaid:

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Washington, DC, this 26th day of April, 2019.

Nicolas Thorpe
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