BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. 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 & Schedules of

Maurice Brubaker

On behalf of

Air Products and Chemicals, Inc.

February 1, 2019

BRUBAKER & ASSOCIATES, INC.

BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. 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**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by Air Products and Chemicals, Inc. in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in the Council of the City of New Orleans Docket No. UD-18-07.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

M S Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 1st day of February, 2019.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2019
Commission # 15024862

Tammy S Klossner
Notary Public

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<u>Direct Testimony of Maurice Brubaker</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and President of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Air Products and Chemicals, Inc. ("Air Products"), a large industrial customer taking service from Entergy New Orleans, Inc. ("ENO"). Air Products has been a customer of ENO, and predecessor company New Orleans Public

Service, Inc. ("NOPSI"), since 1965. Its load is primarily interruptible, and it is the only customer taking service under the Large Interruptible Service ("LIS") rate.

The Air Products facility sustained significant damage as a result of Hurricane Katrina. Air Products spent in excess of $80 million to rebuild the facility and to maintain its presence in New Orleans.

Q HAVE YOU PREVIOUSLY TESTIFIED IN MATTERS BEFORE THE COUNCIL OF THE CITY OF NEW ORLEANS ("CNO" OR COUNCIL")?

A Yes. I have been involved in regulatory proceedings before the Council since about 1980, representing Air Products and sometimes other customers of ENO or NOPSI. I most recently submitted testimony in Docket No. UD-16-02 concerning the New Orleans Power Station ("NOPS") and in Docket No. UD-16-03 concerning approval for ENO to restructure.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A My testimony primarily addresses electric class cost of service, revenue allocation, rate design, certain aspects of ENO's proposed Formula Rate Plan ("FRP"), the Purchased Power and Capacity Acquisition Cost Recovery Rider ("PPCACR"), and the proposed Reliability Incentive Mechanism ("RIM") adjustment to the Evaluation Period Cost of Equity ("EPCOE") which ENO proposes in conjunction with its proposed FRP.

Although I do not address every issue raised by ENO, the fact that I do not comment on a particular issue should not be interpreted as acquiescence in ENO's position or its proposed action.

Q ARE ANY OTHER WITNESSES PROVIDING TESTIMONY ON BEHALF OF AIR PRODUCTS IN THIS CASE?

A Yes. My colleague, Mr. Christopher Walters, also is providing testimony. His testimony addresses the appropriate return on equity ("ROE") for ENO's electric operations. He finds that Mr. Hevert's 10.75% ROE, and ENO's proposed use of a 10.5% ROE are inappropriate and that a more reasonable cost of equity for use in this proceeding is 9.35%.

<u>SUMMARY</u>

Q WHAT ARE YOUR FINDINGS AND RECOMMENDATIONS?

A My findings and recommendations may be summarized as follows:

1. I find that the methodologies employed by ENO in the development of its electric class cost of service study are appropriate. This includes use of the 12 coincident peak ("12 CP") method for the allocation of generation-related fixed costs and purchased power agreements ("PPA").

2. I find that Air Products is served at the transmission voltage level (does not require the distribution system) and its load is mostly interruptible. This makes the cost to serve Air Products substantially less than the cost to serve any other class of customers.

3. I find that the approach taken by ENO to allocate its claimed revenue requirement among customer classes is a step in the right direction of recognizing cost of service, but still leaves Air Products paying about $2.5 million per year more than it should according to ENO's own cost of service study.

4. To the extent that ENO does not receive the full amount of revenues that it seeks, I recommend that the difference between the amount sought by ENO and the amount determined appropriate by the Council be apportioned only to those customer classes that are being charged rates above cost of service as shown on Schedule MEB-3. This would not cause the rates of any class to be higher than what ENO has proposed, and would reduce the burden on those customer classes who would be paying rates above cost of service.

5. I recommend that ENO's proposal to realign certain fixed costs associated with a number of generation facilities and PPAs from the Fuel Adjustment Clause ("FAC") and PPCACR to base rates be approved.

6. I recommend that the cost recovery mechanism in the proposed PPCACR be accepted.

7. I recommend that ENO's proposed RIM be rejected. If it is not rejected, its application should be limited to customers who take service at the distribution level, and the handful of customers (including Air Products) who take service at the transmission level should not be included in any RIM adjustments.

8. I recommend that ENO's proposal to recover costs associated with NOPS, as contained in the proposed FRP, be accepted.

9. I recommend that ENO's proposal to reset rates to the EPCOE be rejected. Instead, I recommend that if the earned return on equity ("EROE") is above the upper bandwidth that the rates be adjusted so as to bring the ROE 60% of the way toward the upper bandwidth. Similarly, if the EROE is below the lower bandwidth I recommend that rates be adjusted so as to move the ROE 60% of the way toward the lower bandwidth.

10. I recommend that ENO's proposed language change to the "Continuity of Service" provision in its Terms and Conditions be rejected and that the current language be retained.

11. I recommend that the $7 million refund recently received by ENO pertaining to a Federal Energy Regulatory Commission ("FERC") ruling in connection with off-system sales by Entergy Arkansas, Inc. ("EAI") be returned to customers through the FAC or the current PPCACR; or if not returned in this manner, allocated using the approach shown on Schedule MEB-3.

ANALYSIS

Q WHAT DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A In this section of my testimony I address the major substantive issues concerning cost of service, rate design and revenue allocation.

Electric Cost of Service

Q HAVE YOU REVIEWED ENO'S PROPOSED ELECTRIC COST OF SERVICE STUDY?

A Yes, I have. I have reviewed the testimony, exhibits and responses to data requests concerning ENO's electric class cost of service study.

Q DO YOU AGREE WITH ENO'S ELECTRIC CLASS COST OF SERVICE STUDY?

A Yes. While I might do some allocations differently if I were preparing a class cost of service study from scratch, I find that the functionalization, classification and allocation of costs employed by ENO in this cost of service study are reasonable, and that the study results are a reasonable determination of the cost of serving ENO's various classes of customers.

Q PLEASE ELABORATE.

A One of the most important factors affecting the allocation of costs among all customer classes is the basis used to allocate the investment in generation and the fixed costs associated with PPAs. For this purpose, ENO has allocated costs among classes using what is referred to as the 12 CP method. This method takes into consideration the contribution of each customer class to each of the 12 monthly peaks on the system.

Q IS THIS THE ONLY REASONABLE METHOD FOR ALLOCATING THESE COSTS?

A No. A review of ENO's load characteristics indicates that the highest demands occur consistently during the summer months, and less frequently during the winter months. Loads in the spring and fall are substantially lower. Although a case could be made to use a combined summer/winter contribution to peak allocation method, the 12 CP method is not unreasonable given ENO's load characteristics. Use of a summer/winter CP method would tend to allocate fewer costs to large high load factor customers, so the 12 CP method is conservative in that regard.

The study also recognizes the difference between firm power and interruptible power. A utility must have investment in generation facilities or PPAs in order to provide reliable service to those customers who need service to be supplied on a firm basis. For customers like Air Products, who take the vast majority of their power on an interruptible basis, the utility need not have firm access to generation resources, so the cost of serving an interruptible load is appreciably less than the cost of serving a firm customer. ENO's class cost of service study explicitly recognizes that difference in terms of the allocation of the fixed costs associated with generation resources.

Q DOES THE COST OF SERVICE STUDY ALSO RECOGNIZE THE VOLTAGE LEVEL AT WHICH CUSTOMERS ARE SERVED?

A Yes. ENO has a few customers (including Air Products) who takes service directly from the Company's transmission system. This means that ENO does not need to invest in the distribution system in order to provide service to these customers because they take service at a point closer to generation than do distribution level customers. Customers who take service at the transmission level are less costly to serve than customers who take service at the distribution level, and ENO's study recognizes this important factor.

Q IS LOAD FACTOR ANOTHER IMPORTANT DETERMINANT OF THE COST OF SERVING CUSTOMERS?

A Yes. Load factor is a measurement of the intensity of use of electricity. A high load factor customer generally is characterized by relatively even use throughout the day and the year, and may be said to make an efficient use of the maximum capacity required to provide service to it. Load factor is determined by dividing the number of kWh purchased by the customer by the product of the customer's maximum demand and the number of hours in the period (month or year). A customer that used the same amount of demand every hour would have a 100% load factor. A customer that only occasionally reached its peak demand would have a lower load factor. Because kWh are less costly to serve if taken at high load factor, customers who make efficient use of their peak requirements cost less to serve per unit of electricity usage.

As an example, if the total revenue requirement for the residential class is divided by residential kWh purchases, the average cost is 12.7¢/kWh. If the same calculation is performed for the LIS class, the average cost is 3.6¢/kWh. This difference reflects the higher load factor of the LIS class, the fact that it is served entirely at the transmission voltage level (without use of the distribution network), and the fact that it is mostly interruptible.

<u>Revenue Allocation</u>

Q DID ENO USE ITS CLASS COST OF SERVICE STUDY RESULTS TO ALLOCATE ITS PROPOSED REVENUE REQUIREMENT?

A No.

Q HOW DID ENO DISTRIBUTE ITS CHANGE IN REVENUES AMONG RATE SCHEDULES?

A ENO used a multi-step process. First, it realigned revenue recoveries from various riders into base rates. Then, it determined how much base rates would have to be increased to recover the revenue requirement that it was seeking (base rates plus riders). The required amount of base rate revenue change from present rates was determined to be approximately $135 million.

Q WHAT WAS THE NEXT STEP?

A In order to moderate the impact on residential customers, ENO broke this into two components. The first was the PPA revenue requirement associated with ENO's share of the unregulated portion of River Bend Station ("River Bend 30%") and the wholesale baseload resources acquired from Entergy Arkansas, Inc. ("EAI WBL"). These amount to approximately $63 million, and they were allocated to customer classes on the basis of energy sales. The remaining $72 million was allocated as an equal percentage increase to present base rate revenues. The final overall base rate revenue requirement change is the sum of the two components.

The total change in revenues for each class is equal to the change in base rate revenue, determined as described above, minus the change in revenue from riders.

Q WHAT WAS ENO'S EXPRESSED RATIONALE FOR THIS TWO-PART ALLOCATION OF BASE RATE REVENUE?

A This is addressed by ENO witness Thomas at page 22 of his revised direct testimony. Essentially, this approach was used as a means to moderate the impact to residential customers of either a cost-based allocation or an equal percentage increase on current base rate revenues.

Q IS THIS APPROACH COST-BASED?

A No, it is not. The only basis for it is to mitigate the impact on the residential class.

Q AS COMPARED TO ALLOCATING THE BASE RATE INCREASE AS AN EQUAL PERCENTAGE OF BASE RATE REVENUES, HOW MUCH ADDITIONAL COST IS ASSIGNED TO AIR PRODUCTS UNDER ENO'S TWO-PART ALLOCATION?

A As compared to an equal percent increase on base rate revenues, the impact on Air Products is an additional approximately $1.2 million per year share of the overall revenue requirement.

Q HOW DOES THE RESULT OF ENO'S REVENUE ALLOCATION COMPARE TO THE ALLOCATED CLASS COST OF SERVICE?

A I have summarized this on Schedule MEB-1. Column 1 shows the Period II base rate cost of service as calculated by ENO on Schedule RR-1. Column 2 shows the proposed base rate revenue by class as presented on Schedule AA-2 and column 3 shows the dollar difference between cost of service and the revenue proposal. Column 4 expresses the difference as a percent of the proposed base rate revenues.

Q IN GENERAL, WHAT ARE THE RESULTS OF ENO'S REVENUE ALLOCATION PROPOSAL?

A Obviously, some classes (like the residential class) are far below cost of service. The study indicates that the residential class would be below cost of service by more than $32 million, or by 17%. This means that the proposed residential revenues would have to be increased by 17% in order to bring this class to cost of service.

In contrast, the LIS class would be $2.5 million above cost of service at ENO's proposed rates, meaning that its proposed rates would need to be reduced by 50% in order to reach cost of service.

Q DID ENO UPDATE ITS CLASS COST OF SERVICE STUDY?

A Yes. In response to the Advisors' Ninth Set of data requests, ENO provided updated cost of service results. This information is presented on Schedule MEB-2.

Q ARE THERE ANY MATERIAL DIFFERENCES IN THE RELATIONSHIPS BETWEEN RATES AND COSTS IN SCHEDULE MEB-2 AS COMPARED TO SCHEDULE MEB-1?

A No. Some of the numbers are slightly different, but the over/(under) cost patterns are essentially the same.

Q WHAT SHOULD BE THE PRIMARY BASIS FOR ESTABLISHING CLASS REVENUE REQUIREMENTS AND DESIGNING RATES?

A Cost causation should be the primary factor used in both steps.

Just as cost of service is used to establish a utility's total revenue requirement, it should also be the primary basis used to establish the revenues collected from each customer class and to design rate schedules.

Factors such as simplicity, gradualism and ease of administration may also be taken into account, but the basic starting point and guideline throughout the process should be cost of service. To the extent practicable, rate schedules should be structured and designed to reflect the important cost-causative features of the service provided, and to collect the appropriate cost from the customers within each class or rate schedule, based upon the individual load patterns exhibited by those customers.

Electric rates also play a role in economic development, both with respect to job creation and job retention. This is particularly true in the case of industries where electricity is one of the largest components of the cost of production.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT COST CAUSATION BE USED AS THE PRIMARY FACTOR FOR THESE PURPOSES?

A The basic reasons for using cost causation as the primary factor are equity, conservation, and engineering efficiency (cost-minimization).

Q PLEASE EXPLAIN HOW EQUITY IS ACHIEVED BY BASING RATES ON COST CAUSATION.

A When rates are based on cost causation, each customer pays what it costs the utility to provide service to that customer – no more and no less. If rates are based on anything other than cost factors, then some customers will pay the costs attributable to providing service to other customers – which in most cases is inequitable.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful, inefficient use is discouraged or minimized. Only when rates are based on costs do customers receive a balanced price signal upon which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be misled into using electricity inefficiently in response to the distorted rate design signals they receive.

Q WILL COST-BASED RATES ASSIST IN THE DEVELOPMENT OF COST-EFFECTIVE DEMAND-SIDE MANAGEMENT (“DSM”) PROGRAMS?

A Yes. The success of DSM (both Energy Efficiency (“EE”) and demand response programs) depends, to a large extent, on customer receptivity. There are many actions that can be taken by consumers to reduce their electricity requirements. A major element in a customer’s decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is based on an under-priced rate, the customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

For example, assume that the relevant cost to produce and deliver energy is 8¢ per kWh. If a customer has an opportunity to install EE or demand response equipment that would allow the customer to reduce energy use or demand, the customer will be much more likely to make that investment if the price of electricity equals the cost of electricity, i.e., 8¢ per kWh, than if the rate is 6¢ per kWh.

The importance of this concept is underscored by the large dollar amount associated with EE programs that will be incorporated into ENO's Integrated Resource Plan. In November 14, 2018 filings in Docket Nos. UD-17-03 and UD-18-02, ENO indicated total expenditures of over $27 million for Program Years 8 and 9. This is a significant commitment of dollars and a large share of the cost is for programs associated with residential customers. Cost-based rates for residential customers will provide higher rewards to customers who implement these programs. Failure to fully price the residential rates, and to reflect the cost of EE programs in the residential rate, will diminish the likelihood that these programs will be successful.

Q HOW DO COST-BASED RATES ACHIEVE THE COST-MINIMIZATION OBJECTIVE?

A When the rates are designed so that the energy costs, demand costs and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

If a utility attempts to extract a disproportionate share of revenues from a class that has alternatives available (such as producing products at other locations where costs are lower), then the utility will be faced with the situation where it must discount the rates or lose the load, either in part or in total. To the extent that the load could have been served more economically by the utility, then either the other customers of the utility or the stockholders (or some combination of both) will be worse off than if the rates were properly designed on the basis of cost.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from large customers and high load factor customers. To the extent that these customers may have lower cost alternatives than do the smaller or the low load factor customers, the same problems noted above are created.

Q TO THE EXTENT THAT ENO DOES NOT RECEIVE THE LEVEL OF REVENUES THAT IT HAS REQUESTED, HOW WOULD YOU ADJUST CLASS REVENUES?

A I would adjust proposed class revenues by spreading the difference between the revenues requested and the revenues awarded by the Council to those customer classes whose revenues would be above cost of service under ENO's rate proposal. I would spread the difference to those classes only, and do so in proportion to the dollar amount by which each class is above cost of service, as compared to the sum of the amounts above cost of service for all classes who would be producing excess revenues under ENO's rate proposal.

Q HAVE YOU PREPARED AN ILLUSTRATION OF HOW THIS COULD WORK?

A Yes. Schedule MEB-3 illustrates this method by assuming that ENO would receive $10 million less revenue than it has proposed. (This is for the purpose of illustrating the mechanics. The same technique would be applied regardless of what the dollar difference turns out to be.)

<u>Realignment of Cost to Base Rates</u>

Q DO YOU AGREE WITH ENO'S PROPOSAL TO REALIGN THE FIXED COSTS ASSOCIATED WITH A NUMBER OF GENERATION FACILITIES AND PPAs FROM THE FAC AND PPCACR TO BASE RATES?

A Yes. These fixed costs belong in base rates and there never was any cost basis for collecting these costs on a kWh basis through the FAC and the PPCACR. For some time now, Air Products has been advocating to remedy this problem and appreciates the fact that ENO has made this change in the context of its current rate case.

Q IN THE ABSENCE OF A COST OF SERVICE STUDY, HOW SHOULD FIXED COSTS ASSOCIATED WITH GENERATION AND PPAs BE ALLOCATED TO AND RECOVERED FROM CUSTOMERS?

A Instead of inappropriately allocating these fixed costs on an energy basis, a much more logical approach would be to allocate them on class base rate revenues. This approach is how ELL and the two predecessor companies have handled the allocation of these types of costs in their Formula Rate Plan ("FRP") filings. While not as precise as using a class cost of service study, it is a much more reasonable proxy than using class kWh.

Q WHAT HAS BEEN THE IMPACT ON AIR PRODUCTS AS A RESULT OF RECOVERING THE FIXED REVENUE REQUIREMENTS ASSOCIATED WITH CERTAIN LEGACY ENO RESOURCES ON A KWH BASIS THROUGH THE PPCACR?

A As I testified in Docket No. UD-16-02, the current PPCACR collects fixed costs associated with Ninemile Unit 6 and Union Power Plant Unit 1 on a per kilowatthour basis instead of a more appropriate basis like percentage of base rate revenue.

From January 2016 through September 2018, the difference between Air Products' share of kWh, and its share of base rate revenues was about 2.3 percentage points. Over that period of time the fixed costs from Ninemile Unit 6 and Union Power Plant Unit 1 (reduced by the rate credits flowed through the PPCACR) that was allocated on a kWh basis was approximately $148 million. Accordingly, the adverse impact on Air Products from this inappropriate allocation during this period is approximately $3.4 million.[1] This adverse impact will continue at about $1.2 million per year until rates are realigned in this case.

Q WILL ENO'S RATE PROPOSALS ELIMINATE THIS MISALIGNMENT?

A No. As noted above, Air Products would still be paying rates in excess of cost, but they are at least a step in the right direction.

[1]This amount does not include over $350,000 of inappropriate Ninemile Unit 6 costs allocated to Air Products in 2015.

Proposed PPCACR Rider

Q HAVE YOU REVIEWED THE PROPOSED PPCACR RIDER?

A Yes.

Q WHAT IS YOUR UNDERSTANDING OF THE PPCACR RIDER?

A As expressed in the proposed tariff, this rider would be used to reconcile the difference between the actual and estimated expenses associated with certain PPAs and long-term service agreements ("LTSA"). It also would include the full revenue requirement associated with any new approved PPAs or LTSAs or newly acquired or constructed capacity additions, except for the NOPS.

Q HOW WOULD COSTS BE APPORTIONED TO CUSTOMER CLASSES?

A In accordance with Attachment B to the PPCACR Rider any costs would be allocated to retail rate classes in the same proportion as the final base rate revenue requirement determined in this proceeding. For example, if a particular class is responsible for 10% of base rate revenue at the end of this case, it would be allocated 10% of any additional revenues under PPCACR.

Q **DO YOU BELIEVE THE PROPOSED PPCACR COST RECOVERY PROVISION IS REASONABLE?**

A Yes. For use between rate cases, and in the absence of the ability to use a more specific cost-based allocation, I believe the PPCACR proposal to allocate cost recovery as an equal percent of base rate revenue is reasonable.

Recovery of NOPS Revenue Requirement

Q **WHERE HAS ENO ADDRESSED THE RECOVERY OF THE NOPS REVENUE REQUIREMENT WHEN IT GOES IN SERVICE?**

A This is addressed in the proposed FRP, specifically in Section III.C which appears on page 5 of ENO Exhibit PPG-7.

Q **WHAT COST RECOVERY PROVISION WOULD APPLY?**

A The tariff refers to Attachment A of rate schedule FRP-5. The structure of Attachment A suggests that the allocation would be on class base rate revenues. However, Attachment A refers to an exhibit attached to an Agreement in Principle ("AIP") in this docket, which does not yet exist.

Q **WHAT SHOULD BE THE BASIS FOR THE ALLOCATION OF THE NON-FUEL REVENUE REQUIREMENT FOR NOPS AND FOR INCREASES IN OTHER FIXED COSTS?**

A As was the case with respect to PPCACR, the allocation among classes should be an equal percentage of base rate revenues. Other than using a class cost of service study, this is the most reasonable way to distribute such increases that take place between rate cases.

Reliability Incentive Mechanism

Q HAVE YOU REVIEWED ENO'S PROPOSED RIM?

A Yes.

Q WHAT IS YOUR UNDERSTANDING OF HOW THIS MECHANISM WOULD OPERATE?

A It is my understanding that ENO proposes to establish a baseline ROE and that certain measurements of distribution system reliability would provide for a ±25 basis points adjustment, which means that the ROE used in the FRP calculations could range between 10.5% and 11.0%.

Q DO YOU AGREE WITH THE COMPANY'S PROPOSED RIM?

A No. First of all, the 10.75% starting point rate of return is excessive, as testified to by my colleague Mr. Walters. Beyond that, the mechanism is conceptually flawed because it would reward ENO for doing what it is supposed to be doing in the first place – namely, providing reliable service. Even worse is the fact that ENO proposes to institute a Distribution Grid Modernization Rider ("Rider DGM") that would charge customers for the cost of upgrading the grid, which would in turn be expected to improve reliability.

Essentially, ENO proposes to charge customers for the cost of achieving higher reliability and then to charge them again with the higher ROE because the monies they contributed caused the system to be more reliable.

Q WHAT IS YOUR RECOMMENDATION?

A I recommend that the Council reject the proposed RIM.

Q IF, INSTEAD, THE COUNCIL APPROVES A FORM OF RIM SHOULD IT APPLY TO AIR PRODUCTS?

A No. Air Products and a few other customers take service at the transmission level, and do not utilize the distribution system. Improvements in reliability on the distribution system do not benefit Air Products and the handful of other customers who take service directly from the transmission system. It is perfectly clear from the revised direct testimony of ENO witness Melonie Stewart that the entire focus of reliability improvement is at the distribution level. All of the programs discussed and all of the dollar expenditures contemplated are designed to improve the reliability of the distribution system. No plans or programs are planned for the transmission system. While ENO will include in its System Average Interruption Frequency Index ("SAIFI") calculation events on the transmission system that contribute to outages on the distribution system, it is equally clear that ENO's reliability improvement plan does not include any work on the transmission system, and that the safety measure will not even consider outages that affect customers taking service at the transmission level. (See ENO responses to APC Data Request Nos. 5-2, 5-4, 5-5 and 5-6, attached hereto as Schedule MEB-4.)

So, should the Council find it appropriate to approve some form of RIM, adjustments should not apply to transmission level customers.

<u>Revenue Adjustments Under the FRP if ROE is Outside (Above or Below) the Bandwidth</u>

Q DOES ENO'S PROPOSED FRP HAVE A BANDWIDTH ON ROE?

A Yes. The proposed ENO bandwidth is ±50 basis points around the EPCOE.

Q WHAT HAPPENS TO RATES IF THE EROE FALLS WITHIN THE BANDWIDTH?

A If it falls within the bandwidth, then no adjustments are made to rates.

Q WHAT ADJUSTMENT DOES ENO PROPOSE IF THE EROE IS OUTSIDE OF (ABOVE OR BELOW) THE BANDWIDTH RANGE?

A If the EROE is either above or below the bandwidth range, ENO proposes a complete reset in rates such that rates would be recalculated to bring earnings to the EPCOE.

Q DO YOU AGREE WITH THIS PROPOSAL?

A No, I do not. In responding, let me first note that the existence of a bandwidth recognizes that there is a range of reasonableness around any given point estimate or finding of ROE. By leaving rates unchanged over a reasonable range (in this case, the proposed ±50 basis points), the FRP also avoids having rates change every year for minor changes in results of operations, which could cause small increases in one year followed by small decreases in another year, and so forth.

As to the structure of ENO's bandwidth adjustment mechanism, I believe it reduces the incentive for the utility to improve its efficiency of operations.

Q PLEASE EXPLAIN WHY IT WOULD REDUCE THE INCENTIVE FOR ENO TO IMPROVE ITS EFFICIENCY OF OPERATIONS.

A First, let's examine the circumstance where the EROE is above the upper bandwidth. Under ENO's proposal, the reset would be all the way back to the EPCOE. This reduces the incentive for the utility to continue to be efficient, and certainly discourages it from increasing its level of efficiency because the result would be lower rates.

Q IN YOUR VIEW, WHAT WOULD BE A BETTER APPROACH?

A I would recommend that if the EROE is above the upper bandwidth the revenue adjustment be only partially moved toward the upper bandwidth. This would allow the utility to retain some of the benefits of the efficiencies that it has gained. In a static sense, it could be argued that customers would not benefit as much; but, in a dynamic sense, given the right incentive for the utility, there should be more money to share with the customers. This is similar to the mechanism that ELL has in place, under which the movement toward the upper bandwidth is 60% of the way toward the upper bandwidth. This allows ELL to retain 40% of the amount above the upper bandwidth.

Q WHAT WOULD HAPPEN IF THE EROE IS BELOW THE LOWER BANDWIDTH?

A Under those circumstances, the utility loses all incentive to maintain or improve efficiency, because doing so could push its EROE up into the zone of no change in which case it would be worse off than if it lowers its ROE in order to have the right to increase its rates to the EPCOE. I believe this is an undesirable incentive.

Q WHAT DO YOU RECOMMEND?

A I recommend that when earnings are below the lower edge of the bandwidth the adjustment also be 60% of the way toward the lower bandwidth, as is done in the ELL FRP. By not compensating for the entire difference, ENO has an incentive to improve operations to reduce costs.

<u>Service Regulations Applicable to Electric Service</u>

Q HAVE YOU REVIEWED ENO EXHIBIT MPS-8 WHICH IS A RED-LINED VERSION OF ENO'S SERVICE REGULATIONS APPLICABLE TO BOTH ELECTRIC AND GAS SERVICE?

A Yes. I have reviewed this material with respect to the provision of electric service.

Q DO YOU HAVE ANY COMMENTS ON THOSE REGULATIONS?

A Yes. I disagree with the change that ENO proposes to make in the "Continuity of Service" provision. This is set forth on page 18 of ENO Exhibit MPS-8 in red-lined form. For convenience, I am repeating that provision here:

> "~~10~~11. **Continuity of Service**. The Company shall use Prudent Utility Practice to provide safe, adequate and continuous Service but shall not be responsible for loss or damage caused by the failure or other defects of Service when such failure is not reasonably avoidable or due to unforeseen difficulties ~~or causes beyond its control~~, however caused."

Q WHAT IS THE ISSUE THAT YOU HAVE WITH THE PROPOSED PROVISION?

A Currently, ENO would be excused from responsibility for loss or damages caused by the failure or other defects of Service when the failure is not reasonably avoidable or is due to unforeseen difficulties or causes beyond its control. ENO proposes to delete the language "or causes beyond its control", and substitute the words "however caused".

The plain reading of this proposed new language would be that as long as ENO could sustain the claim that what happened was unforeseen it would be "off the hook" even if the loss or damage was attributable to negligence on the part of ENO employees or ENO contractors. Effectively, ENO seeks to exempt itself from any responsibility even if the loss or damage was occasioned by something within its control. This is totally inappropriate, and I urge the Council to reject this proposed change, and instead retain the existing language of this provision.

Refunds from Entergy Arkansas, Inc. to
<u>ENO and the Other Entergy Operating Companies</u>

Q HAVE ENO AND THE OTHER ENTERGY OPERATING COMPANIES RECENTLY RECEIVED REFUNDS FROM EAI AS A RESULT OF A DECISION OF THE FERC IN DOCKET NO. EL09-61-004?

A Yes. For reference, I am including as Schedule MEB-5 the cover letter used by Entergy's counsel to make its compliance filing with FERC on December 17, 2018. Page 8 of the letter states that on December 14, 2018, ENO received a refund of $7,016,952, including interest.

Q WHAT IS THE REASON FOR THIS REFUND?

A This refund arises from the FERC decision on a complaint initiated by the Louisiana Public Service Commission involving inappropriate treatment by EAI of certain off-system sales transactions.

Q WHAT NEGATIVE IMPACTS ON ENO ARE BEING REMEDIED BY THIS REFUND?

A As a result of the treatment of off-system sales by EAI, the energy costs charged to ENO and other Operating Companies under the Entergy System Agreement were higher than they should have been. The amounts in question are predominantly variable costs of the nature that flow through the FAC.

Q WHAT IS YOUR RECOMMENDATION FOR HOW THIS REFUND AMOUNT SHOULD BE RETURNED TO ENO'S CUSTOMERS?

A Because the refund relates predominantly to overcharges in components that flow through the FAC, it would be appropriate for this amount to be returned to customers as a credit through the FAC.

Q ARE YOU AWARE OF HOW ENTERGY LOUISIANA, LLC ("ELL") IS RETURNING ITS REFUND TO ITS RETAIL CUSTOMERS?

A Yes. ELL is returning its refund amount to its retail customers through the FAC in equal amounts over the months of January, February and March, 2019.

Q HAS ENO STATED HOW IT INTENDS TO RETURN THESE AMOUNTS TO ITS CUSTOMERS?

A No. This question was recently asked of a representative of ENO and the response was that ENO was awaiting instructions from the Council.

Q TO THE EXTENT THAT THE REFUND AMOUNTS ARE NOT CREDITED BACK TO CUSTOMERS THROUGH THE FAC, WHAT IS YOUR RECOMMENDATION?

A If the amount is not refunded to customers through the FAC, or the current PPCACR, it should be considered as an offset to revenue requirements in this rate case, and allocated using the approach shown on Schedule MEB-3.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission ("FERC"), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed.

It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

ENTERGY NEW ORLEANS, LLC

Comparison of Cost of Service with Proposed Revenue, Electric Period II
($000)

Line	Rate Classes	Cost of Service [1] (1)	Proposed Revenue [2] (2)	Class Above or (Below) Cost of Service: Amount (3)	Class Above or (Below) Cost of Service: Percent (4)
1	Residential	$224,442	$191,784	($32,658)	(17.0%)
2	Sm. Electric Service	$65,090	$73,258	$8,169	11.2%
3	Municipal Buildings	$2,192	$2,950	$758	25.7%
4	Large Electric	$28,025	$31,130	$3,105	10.0%
5	Lg. Electric High Ld. Factor	$96,324	$108,630	$12,306	11.3%
6	Master Metered Non-Residential	$42	$58	$16	27.4%
7	High Voltage	$5,810	$8,057	$2,247	27.9%
8	Large Interruptible	$2,480	$4,962	$2,482	50.0%
9	Lighting Service	$3,852	$7,583	$3,731	49.2%
10	Total Retail	$428,256	$428,412	$156	0.0%

(1) Schedule RR-1
(2) Schedule AA-2

ENTERGY NEW ORLEANS, LLC

Comparison of Cost of Service with Proposed Revenue, Updated Electric Period II
($000)

Line	Rate Classes	Cost of Service [1]	Proposed Revenue [2]	Class Above or (Below) Cost of Service	
				Amount	Percent
		(1)	(2)	(3)	(4)
1	Residential	$223,943	$191,784	($32,159)	(16.8%)
2	Sm. Electric Service	$64,942	$73,258	$8,316	11.4%
3	Municipal Buildings	$2,186	$2,950	$764	25.9%
4	Large Electric	$27,948	$31,130	$3,182	10.2%
5	Lg. Electric High Ld. Factor	$96,057	$108,630	$12,574	11.6%
6	Master Metered Non-Residential	$42	$58	$16	27.6%
7	High Voltage	$5,803	$8,057	$2,254	28.0%
8	Large Interruptible	$2,475	$4,962	$2,487	50.1%
9	Lighting Service	$3,843	$7,583	$3,739	49.3%
10	Total Retail	$427,239	$428,412	$1,173	0.3%

[1] Updated Cost of Service in Response to the Advisors' 9th Set of Data Requests.
[2] Schedule AA-2

ENTERGY NEW ORLEANS, LLC

Illustration of How to Allocate Any Reduction in Requested Revenue Requirement Among Classes That are Above Cost of Service at Proposed Rates
($000)

Line	Rate Classes	Amount Above Cost of Service [1] (1)	Class Share of Excess Revenue (2)	Allocation of $10 Million Difference (3)
1	Sm. Electric Service	$8,169	24.9%	$2,489
2	Municipal Buildings	$758	2.3%	$231
3	Large Electric	$3,105	9.5%	$946
4	Lg. Electric High Ld. Factor	$12,306	37.5%	$3,750
5	Master Metered Non-Residential	$16	0.0%	$5
6	High Voltage	$2,247	6.8%	$685
7	Large Interruptible	$2,482	7.6%	$756
8	Lighting Service	$3,731	11.4%	$1,137
9	Total Retail	$32,814	100.0%	$10,000

(1) From Schedule MEB-1

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

Response of: Entergy New Orleans, LLC
to the Fifth Set of Data Requests
of Requesting Party: Air Products and
Chemicals, Inc.

Question No.: APC 5-2 Part No.: Addendum:

Question:

Ms. Stewart's testimony at the bottom of page 26 states that the SAIDI and SAIFI metrics reported in Figure 4 on page 27 are referred to as "Distribution Line" which is described as excluding transmission- or substation-related outages. Please explain what this means. For example:

a. Do the outages reported here include or exclude outages on the distribution system that resulted from interruptions or other problems on the transmission lines/substations or in the substations that step down from the transmission system to the distribution system?

b. Do they include or exclude outage minutes experienced by customers of ENO who are served at the transmission level?

c. Please provide the detailed descriptions and formulas used to calculate "Distribution Line" view statistics including all criteria that an outage must meet to be included in the calculations and identify the categories of customers whose outages are included.

Response:

a. The outages reported here exclude transmission line/substation outages.

b. The current outage management system captures only distribution level customer outages. Therefore, outages for those customers fed directly from the transmission system are excluded from the outage management system.

c. The following descriptions were taken directly from IEEE 1366 Standard:

CI	Customers interrupted
CMI	Customer minutes of interruption

Question No.: APC 5-2.

sustained interruption: Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes.

3.2 Sustained interruption indices

3.2.1 SAIFI: System Average Interruption Frequency Index

The System Average Interruption Frequency Index (SAIFI) indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this is given in Eq. (1).

$$\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} \quad (1)$$

To calculate the index, use Eq. (2).

$$\text{SAIFI} = \frac{\sum N_i}{N_T} = \frac{CI}{N_T} \quad (2)$$

3.2.2 SAIDI: System Average Interruption Duration Index

The System Average Interruption Duration Index (SAIDI) indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in minutes or hours of interruption. Mathematically, this is given in Eq. (3).

$$\text{SAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}} \quad (3)$$

To calculate the index, use Eq. (4).

$$\text{SAIDI} = \frac{\sum r_i N_i}{N_T} = \frac{CMI}{N_T} \quad (4)$$

Entergy's criteria for DLIN outages:

- Must be a sustained outage (>5 min, per IEEE 1366)
- Cause must be determined to have been on the Distribution system existing outside the fence line of any substation
- Major Events are excluded (per IEEE 1366)
- Outages in the following categories are excluded:
- Shed Event due to load or voltage
- Mandated by local authority
- Customer Equipment
- Scheduled/planned outages will be excluded beginning January 1, 2019
- Outages' official start time must be within the requested timeframe
- Residential, Commercial, Industrial, and Governmental Customers served at distribution voltages are included in our calculations.

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

Response of: Entergy New Orleans, LLC
to the Fifth Set of Data Requests
of Requesting Party: Air Products and
Chemicals, Inc.

Question No.: APC 5-4 Part No.: Addendum:

Question:

For each of the years 2013 through 2017, please provide separately for customers served at the distribution level and customers served at the transmission level, the SAIDI and SAIFI metrics, and provide all supporting workpapers.

Response:

The Company does not track SAIDI or SAIFI specifically for customers served at the transmission-voltage level. The calculation of SAIDI and SAIFI is determined per industry standard IEEE-1366 (Guide for Electric Power Distribution Reliability Indices). These distribution reliability metrics were designed to track reliability performance at the distribution system level and as such are not appropriate for reliability reporting at the transmission level.

The Company does track SAIDI and SAIFI for distribution customers as impacted by the transmission system (i.e., events originating from a transmission line or substation). The transmission system's contribution to these metrics for 2013-2017 are provided below.

	2013	**2014**	**2015**	**2016**	**2017**
TransmissionView SAIFI	0.145	0.390	0.186	0.169	0.208
TransmissionView SAIDI	11.108	22.496	8.854	16.754	12.722

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

Response of: Entergy New Orleans, LLC
to the Fifth Set of Data Requests
of Requesting Party: Air Products and
Chemicals, Inc.

Question No.: APC 5-5 Part No.: Addendum:

Question:

The testimony of ENO witness Stewart at page 44, lines 8-13, references reliability statistics computed in different ways, including those described as "IEEE," "customer" view, "all," "WOF," and "Distribution Line." None of these terms are defined in the IEEE Benchmark Year 2017 Study referenced in the testimony and included in the workpapers, or in the "IEEE Guide for Electric Power Distribution Reliability Indices," IEEE Standard 1366- 2012. Please state the source for these concepts and definitions and provide copies of the relevant documents where these terms are defined and discussed.

Response:

"Customer View" and "Distribution View" are internal definitions built around the IEEE 1366 standard; both views exclude shed events, mandated events, and customer equipment events, as described in the Company's response to ADV 5-2. "Customer View" includes all applicable outages; "Distribution View" restricts "Customer View" to only applicable outages that occur on the Distribution System as defined above.

"IEEE" is shorthand for the IEEE 1366 Guide for Electric Power Distribution Reliability Indices. Without Feed ("WoF") is an IEEE data type defined in their Submission Instructions. It is noted as meaning "the data that remains after transmission or source interruptions are excluded from the daily dataset." This is equivalent to the internal labeled "Distribution Line" dataset including outages for shed, mandated, and customer equipment events. The "IEEE all" category includes all data, i.e. no exclusions for ME Days.

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

Response of: Entergy New Orleans, LLC
to the Fifth Set of Data Requests
of Requesting Party: Air Products and
Chemicals, Inc.

Question No.: APC 5-6 | Part No.: | Addendum: 1

Question:

With regard to the IEEE "Distribution Reliability Working Group" Study referenced at page 43 of ENO witness Stewart's testimony, and included in the workpapers, please provide the following:

a. ENO's identification code as used on pages 12-18 of the presentation.

b. The instructions that were given to the utilities as to how to perform calculations and report metrics for purposes of this report.

c. For each of pages 12-19, please define the units for the vertical axis.

d. A comprehensive narrative description of what is being presented on pages 12, 13 and 14, and how the data presented differs among the three pages.

e. A comprehensive description of the five color-coded indicators on page 12

f A comprehensive description of what the graphical material in other colors represents.

g. The workpapers supporting the calculation of the ENO statistic reported on each of pages 12-18, separately identifying interruption minutes and events for customers served at the transmission level and for customers served at the distribution level.

Response:

a. ENO’s identification code is 218.

b. The instructions given can be found at the following link: http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Submission-for-2016.pdf

Question No.: APC 5-6 Addendum 1

c. Pages 12-14 – Customer Minutes Interrupted; Pages 15-16 – Customer Interruptions; Pages 17-18 is Customer Minutes Interrupted divided by Customer Interruptions (aka CMI/CI). For definitions, please see the Company's response to ADV 5-2.

d. Page 12 ("2018 SAIDI for 2017 Data") – The SAIDI of participating utilities including and sorted by Major Event days, Transmission outages, and Planned outages.

Page 13 ("2018 SAIFI for 2017 Data") – The SAIDI of participating utilities including Major Event Days, Transmission, and Planned outages without IEEE sorting.

Page 14 ("Total (STD) SAIDI 2018 for 2017 Data") – The SAIDI of participating utilities excluding Major Events as defined by IEEE 1366.

e. SAIDI_Distribution is the Distribution system SAIDI for the utility in question; SAIDI_Plan is Planned Outage SAIDI of the utility in question; SAIDI_FEED is the SAIDI value of the non-distribution system of the utility in question; SAIDI_ME_FEED is the SAIDI of the non-distribution system for Major Event Days of the utility in question; and SAIDI_ME_Distribution is the SAIDI of the distribution system for Major Event days.

f. The other colors not listed on the legend originate from slide 5 and indicate the NERC Region of the utility data being represented graphically.

g. The workpapers supporting the calculation of the ENO statistic reported on each of pages 12-18, separately identifying interruption minutes and events for customers served at the transmission level and for customers served at the distribution level.

Addendum 1:

g. The workpapers supporting the calculation of the ENO statistic reported on each of pages 12-18 can be viewed at the following link:

http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Submission-for-2016.xls

All data presented is that of customers at the Distribution level. No transmission-level customer data breakout is possible from this data.

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December 17, 2018

Via E-Filing
Hon. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: *La. Pub. Serv. Comm'n v. Entergy Corporation, et al.*, Docket No. EL09-61-004

Dear Secretary Bose,

Pursuant to the Order on Initial Decision issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket EL09-61-004, *La. Pub. Serv. Comm'n v. Entergy Corp., et al.*, 165 FERC ¶ 61,022 (2018) ("Opinion No. 565"), Entergy Services, LLC ("ESL"),[1] hereby submits this compliance filing in the above-referenced proceeding. Consistent with the Commission's orders in this matter, this filing provides the final calculation of refunds due from EAI to the other Entergy Operating Companies. ESL also provides the total sum of interest due and the timing of payments, as required by the Commission.[2] This filing includes workpapers supporting the calculation of payments due plus interest. The refunds were effectuated amongst the current Operating Companies on December 14, 2018.[3]

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[1] ESL is acting as agent for the Entergy Operating Companies responding. The Entergy Operating Companies are currently Entergy Arkansas, LLC. ("EAL"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, LLC ("EML"), Entergy New Orleans, LLC ("ENOL"), and Entergy Texas, Inc. ("ETI").

[2] *La. Pub. Serv. Comm'n v. Entergy Corp., et al.*, 165 FERC ¶ 61,022 at P 141 (2018).

[3] On October 1, 2015, Entergy Gulf States Louisiana, L.L.C. ("EGSL") and the former Entergy Louisiana, LLC ("Entergy Louisiana") completed a transaction in which EGSL and Entergy Louisiana combined substantially all of their respective assets and liabilities into a single successor public utility now known as ELL ("ELL Business Combination"). On October 30, 2015, ELL succeeded to the tariffs and rate schedules of EGSL and Entergy Louisiana pursuant to the Louisiana Business Combination. *See Entergy La., LLC*, Docket No. ER16-218, Letter Order (Dec. 18, 2015) (accepting notice of succession filing). On November 30, 2017, ENOL and the former Entergy Operating Company, Entergy New Orleans, Inc. ("ENOI"), completed a transaction following which ENOL succeeded to the tariffs and rate schedules of ENOI. On November 30, 2018, EML and the former Entergy Operating Company Entergy Mississippi, Inc. ("EMI") completed a transaction following which EML succeeded to the tariffs and rate schedules of EMI. On December 1, 2018, EAL and the former Entergy Operating Company Entergy Arkansas, Inc. ("EAI") completed a transaction following which EAL succeeded to the tariffs and rate schedules of EAI.

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I. Background

The underlying case came before the Commission as a complaint under section 206 of the Federal Power Act, filed on June 29, 2009, by the Louisiana Public Service Commission. The complaint alleged that Entergy Corporation and its subsidiary Operating Companies violated the Entergy System Agreement when EAI sold excess electric energy to certain parties outside of the System Agreement over the period 2000 through 2009 (the Opportunity Sales). Consideration of the merits of this complaint proceeded in three distinct phases resulting in the following Commission decisions.

A. Phase I – Opinion 521[4]

The Commission determined in Phase I that, while EAI was permitted to make the Opportunity Sales under Section 4.05 of the System Agreement, ESL had accounted for the Opportunity Sales in a manner that violated the System Agreement.[5] ESL had included the Opportunity Sales in EAI's net area load for purposes of the energy and related cost allocations required by the System Agreement. The Commission concluded that ESL should have excluded the Opportunity Sales from EAI's net area load and instead accounted for the transactions as off-system wholesale sales, or "sales to others," pursuant to Section 30.04 of the System Agreement.[6] The Commission found that an assessment of refunds was necessary to remedy the effect of the improper accounting for these Opportunity Sales and remanded for further proceedings to quantify such refunds.[7] Specifically, the Commission ordered that the Intra-System Billing ("ISB") be re-run wherein,

> Entergy should calculate the difference between the incremental energy costs allocated to Entergy Arkansas due to inclusion of the Opportunity Sales in its load under section 30.03(a) and the incremental costs of energy sales to the system it should have been allocated for the Opportunity Sales under section 30.04.[8]

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[4] Opinion No. 521, *La. Pub. Serv. Comm'n v. Entergy Corp.*, 139 FERC ¶ 61,240 (2012) (Order Affirming in Part and Reversing in Part Initial Decision and Establishing Further Hearing Procedures).

[5] *Id.* at PP 106, 110, 124-29.

[6] *Id.* at PP 128-29.

[7] *Id.* at PP 136-38.

[8] *Id.* at P 136.

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B. Phase II – Opinion 548[9]

Phase II of this docket concerned, in part, how to properly prioritize the allocation of energy and associated costs to Opportunity Sales under Section 30.04 of the System Agreement in order to calculate refunds owed by EAI. Parties used several sample years of data from the period at issue to advocate different approaches.[10] The Commission decided the method proposed by the Louisiana Commission should be utilized for quantifying the refunds.[11] The Commission further determined that the effect of the change in energy accounting for the Opportunity Sales be reflected in the remainder of the cost allocations required by the Service Schedules to the Entergy System Agreement, including the Bandwidth Formula, except that margins on the Opportunity Sales be assigned 100% to EAI.[12] Finally, the Commission directed further proceedings to re-run the ISB as ordered for each of the months during the period at issue and to determine whether to "cap" the amount by which any prior over-payment of Bandwidth monies by EAI could offset refunds due as a result of this proceeding.[13]

C. Phase III – Opinion 565[14]

The Commission concluded in Phase III that there should be no "cap" on the Bandwidth offset applied to the amount of refunds.[15] The Commission also confirmed that the refunds should only address those sales originally accounted for as part of EAI's net area load and exclude certain other transactions identified by the Louisiana Commission that were never included in EAI's net area load as part of the System Agreement accounting

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9 Opinion No. 548, *La. Pub. Serv. Comm'n v. Entergy Corp.*, 155 FERC ¶ 61,065 (2016) (Order on Initial Decision).

10 *Id.* at P 86.

11 *Id.* at P 87.

12 Opinion No. 548, 155 FERC ¶ 61,065, at P 2 ("[W]e find that a full re-run of the ISB that reflects a reordering of energy priorities on the Entergy System is necessary to provide a full and fair accounting of damages. However, we also find that damages should be adjusted to reflect adjustments to Service Schedules and other provisions of the System Agreement, including for bandwidth payments made under Service Schedule MSS-3 of the System Agreement (Exchange of Electric Energy Among the Operating Companies), to reflect the energy priority reordering. . . ."); *see id.* at P 36 (noting assignment of margins to EAI in Phase II Initial Decision).

13 *Id.* at PP 200, 212.

14 Opinion No. 565, *La. Pub. Serv. Comm'n v. Entergy Corp.*, 165 FERC ¶ 61,022 (2018) (Order on Initial Decision).

15 *Id.* at P 75.

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in the first instance.[16] Finally, the Commission ordered a compliance filing setting forth final refund calculations with interest, information regarding how refunds will be issued, and the timeline for such issuance.[17]

II. Compliance Submission

A. ISB Re-Runs

The manner for computing the refunds due from EAI first required that ESL re-run the ISB to account for the Opportunity Sales as directed in Opinion Nos. 521 and 548 for each month of October 2000 through December 2009. Consistent with Opinion No. 565, the ISB re-runs do not include certain transactions identified by the Louisiana Commission that were never accounted for as part of EAI's net area load in the first instance.[18]

The results of the ISB re-runs were summarized in the Phase III Answering Testimony of Patrick J. Cicio,[19] which results are replicated below:

Operating Company	Charge	(Receipt)
EAI	$81,659,842	
ELL		($11,574,226)
EMI		($24,391,046)
ENOI		($3,588,177)
EGSL		($23,765,328)
ETI		($18,341,065)

The detailed results of the ISB re-runs were provided as Exhibit ESI-017 in Phase III, which exhibit is also included as Attachment 1 to this refund report. The annual data is also summarized in the top portion of Attachment 4 under the heading "Refunds where the Net Balance is allocated to EAI."

B. Effect of ISB Re-Runs on the Bandwidth Formula

In Opinion No. 548, the Commission recognized that the ISB re-runs would cause changes in production costs that would, in turn, affect certain inputs for the Bandwidth

16 *Id.* at PP 102-03, 128-29.

17 *Id.* at P 141.

18 Opinion No. 565 at PP 102-03, 128-29.

19 Exhibit ESI-015 at 5.

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Formula.[20] In Phase III, ESL re-computed the annual Bandwidth calculation for the seven months ended December 2005 and the calendar year 2006, 2007, 2008 and 2009 test periods based on the then-latest applicable Bandwidth Formula to determine the extent to which the original incorrect accounting for the Opportunity Sales caused EAI to previously overpay Bandwidth payments to the other Operating Companies.

In particular, two Bandwidth Formula variables required adjustment as a result of the ISB re-runs applying different energy accounting treatment to the Opportunity Sales for the 2005-2009 test periods:[21]

1. The ISB allocates production costs between the Operating Companies and those costs are a portion of the Variable Production Costs in the Bandwidth Formula. The net change in production-related costs as a result of the change in energy accounting in the ISB re-runs was reflected as an adjustment to Variable Production Costs (specifically, Variable PURP).

2. Variable DR – Removal of the Opportunity Sales from EAI's load reduced its demand ratio and allocated System Average Fixed Production Costs while causing increases for those same variables for the other Operating Companies.

The net results of the re-computation of the relevant Bandwidth calculations were presented in the Phase III Supplemental Answering Testimony of David Hunt at Revised Table 2[22] and in Exhibits ESI-020R and ESI-021R. For this filing, ESL has replicated that same approach using the latest applicable Bandwidth Formula for each test period. The Bandwidth formulas utilized are as follows:

<u>2005 Bandwidth</u> for the 7 months ended December 31, 2005 - Comprehensive Recalculation Compliance Filing made in Docket Nos. EL01-88-015 & EL01-88-016 pursuant to Opinion No. 561 on July 16, 2018,

<u>2007 Bandwidth</u> for the 2006 test period and **2008 Bandwidth** for the 2007 test period – Compliance Filing Revisions made in Docket Nos. EL01-88-015 & EL01-88-016 pursuant to Opinion No. 561 on July 16, 2018,

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20 Opinion No. 548 at PP 196-201.

21 *See* Phase III Hunt Answering Testimony, Exhibit ESI-019 at 7-8.

22 Exhibit ESI-030 at 13.

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2009 Bandwidth for the 2008 test period – Compliance Filing made in Docket No. ER10-1350 pursuant to Opinion No. 545 on February 15, 2016,

2010 Bandwidth for the 2009 test period – Compliance Filing made in Docket No. ER10-1350 pursuant to Opinion No. 545-A on November 18, 2016.

The net change in Bandwidth (Payments)/Receipts after accounting for the ISB re-runs is as follows:

Operating Company	Bandwidth (Payments)/Receipts
EAI	**$13,709,000**
EGSL	($1,080,000)
ELL	($4,983,000)
Total ELL	**($6,063,000)**
EMI	**($6,467,000)**
ENOI	**($247,000)**
ETI	**($932,000)**

The underlying Bandwidth Recalculations for each relevant test period are provided as Attachments 2 and 3 to this refund report in the same format as Phase III Exhibits ESI-20R and ESI-21R.

C. Bandwidth Offset

The net change in Bandwidth payments/receipts is an offset to the calculation of refunds resulting from the ISB re-runs consistent with Opinion No. 565.[23] The net results without any "cap" on the Bandwidth offset were provided in the Phase III Cross-Answering Testimony of Bruce Louiselle at Table 4 Revised[24] and in Exhibit ESI-013R. Replicating that calculation here with the updated Bandwidth calculations results in the following net refunds.

[23] Opinion No. 565 at P 75.

[24] Exhibit ESI-026 at 25.

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Net Refunds Based on ISB Re-Runs and Updated Bandwidth Recalculation Payment / (Receipt)			
Operating Companies	ISB Re-run (2000-2009)	Bandwidth Recalculation Offset (2005-2009)	Net Effect of ISB Re-run and Bandwidth Recalculation
EAI	**$81,659,842**	**$13,709,000**	**$67,950,842**
EGSL	($23,765,328)	($1,080,000)	($22,685,328)
ELL	($11,574,226)	($4,983,000)	($6,591,226)
Total ELL	**($35,339,554)**	**($6,063,000)**	**($29,276,554)**
EMI	**($24,391,046)**	**($6,467,000)**	**($17,924,046)**
ENOI	**($3,588,177)**	**($247,000)**	**($3,341,177)**
ETI	**($18,341,065)**	**($932,000)**	**($17,409,065)**

Attachment 4 supporting the net effect of the ISB re-runs and the Bandwidth offset is provided with this refund report in the same format as Exhibit ESI-013R.

D. Interest

ESL has calculated interest through the date of payment of the refunds as directed in Opinion No. 565.[25] Attachment 5 supports the interest calculation.

[25] The interest applied is based on the Commission's published rates. *See* 18 C.F.R. § 35.19(a)(2)(iii)(A) and (B).

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E. Total Refunds Due

Total refunds inclusive of interest in the following amounts were paid by EAL to the other Operating Companies on December 14, 2018.

Operating Companies	Total Refunds Including Interest		
	Payment / (Receipt)		
	Principal	Interest	Total
EAL	**$67,950,842**	**$67,087,072**	**$135,037,914**
EGSL	($22,685,328)	($21,013,622)	($43,698,950)
ELL	($6,591,226)	($8,356,395)	($14,947,621)
Total ELL	**($29,276,554)**	**($29,370,017)**	**($58,646,571)**
EML	**($17,924,046)**	**($18,228,980)**	**($36,153,026)**
ENOL	**($3,341,177)**	**($3,675,775)**	**($7,016,952)**
ETI	**($17,409,065)**	**($15,812,300)**	**($33,221,365)**

F. Communications

ESL requests all correspondence and communications with respect to this compliance filing should be sent to, and that the Secretary include on the official service list, the following:

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Attachments
cc: Official Service List in Docket No. EL09-61