BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: 2018 TRIENNIAL INTEGRATED	**)**	
RESOURCE PALN OF ENTERGY	**)**	**DOCKET NO. UD-17-03**
NEW ORLEANS, INC.	**)**	

<u>ADVISORS TO THE COUNCIL OF THE CITY OF NEW ORLEANS' RESPONSES TO ENTERGY NEW ORLEANS, LLC'S FIRST SET OF REQUESTS FOR INFORMATION</u>

The Advisors to the Council of the City of New Orleans ("Advisors") hereby provide their responses to Entergy New Orleans, LLC's ("ENO") First Set of Data Requests in this docket to the Advisors and Optimal Energy. These responses by the Advisors should not be construed as a waiver of any claim that the Advisors may have regarding the admissibility of the response in this proceeding or any other proceedings.

<u>RESPONSES</u>

<u>ENO 1-1:</u>

Please refer to Table 2 on page 3 of the Optimal Potential Study. Please explain the calibration process that resulted in a 0.5% kWh savings being identified as the "Program Potential" for 2018 given that the Council-approved savings target for Energy Smart PY8 is 0.8%.

<u>Response</u>:

The year 1 savings of 0.5% is based on the savings achieved from current Energy Smart programs (about 0.3% per year) combined with the year 1 adoption rates as defined by the Delphi Panel.

ENO 1-2:

Please refer to page 4 of the Optimal Potential Study. Given that Council Resolution No. R-18-65 approved construction of seven reciprocating internal combustion engine generator sets, with a total capacity of 128 MW, what is the statement "the recently approved 150MW gas turbine plant" intended to reference?

Response:

This statement referred to the referenced power plant approved in Resolution No. R-18-65 of 128 MW, but misstated the total capacity at 150 MW. This was merely an example to illustrate the relevance of actual demand reduction measured in MW in contrast to energy reductions expressed as a percentage of sales. It has no impact on the analysis or meaning of the report.

ENO 1-3:

Please refer to page 4 of the Optimal Potential Study. Figure 1 references Electric Energy Savings Relative to Sales Forecast, but does not provide the quantification of savings in terms of annual MWh achieved by sector or by scenario. Please provide the MWh potential savings values calculated by Optimal that support Figure 1 for each year of the planning horizon by sector and by scenario, along with workpapers supporting the calculations.

Response:

Please see HSPM Attachment 1-3, which provides the requested annual savings, by scenario and by measure within each scenario. These results are the output of a proprietary model consisting of interlinked Excel spreadsheets with embedded VBA code. No further supporting workpapers will be provided.

ENO 1-4:

Please refer to page 7 of the Optimal Potential Study and Table 6. Given that the percentage of administrative costs approved by the Council in Resolution R-17-623 for the current Energy Smart programs is roughly 50%, please explain why the proposed budgets start with roughly 25% administrative costs in 2018. Please also provide the point of reference for the program administrative costs for both energy efficiency ("EE") and demand response ("DR") and describe in detail how these cost values were determined and what components are, and are not, included in the Optimal Potential Study's definition of "administrative costs."

Response:

Administrative costs tend to decrease as percent of total costs as programs achieve higher levels of savings. Because all scenarios examined in the potential study are significantly more aggressive than current Energy Smart efforts, we determined it was more appropriate to use administrative cost ratios seen in other jurisdictions that achieve savings levels closer to that shown to be available in this potential study. The administrative costs in the study include all non-incentive costs, including marketing, outreach, administration, and EM&V. They do not include any performance incentives earned by the utility. Please refer to page 74 of the Potential Study for additional information on how the administrative costs were developed. For demand response, administrative costs are based on the levels found in the other programs reviewed for the study.

ENO 1-5:

Please refer to page 74 of the Optimal Potential Study, specifically the statement "Data were sourced from recent program performance in New England, the MidAtlantic states, and Minnesota, totaling 8 individual utility or state- wide portfolios. All of these portfolios are generating savings substantially greater than Entergy New Orleans' current programs, and are likely to be a better predicted of the administrative costs needed to achieve the level of savings found by our maximum achievable and program potential analyses. The average administrative costs for the various program types range from 25 percent to 37 percent of total program costs."

a. Please state why Optimal relied on estimates from other jurisdictions instead of Council-approved, administrative cost percentages as the starting point in its analysis.

Response:

See response to ENO 1-4.

b. Please explain why Optimal chose to base its comparison of administrative costs on utilities in geographic regions with weather/climates and population demographics that bear little resemblance to those of New Orleans. Please also state why Optimal did not sample any utilities from the south eastern United States when comparing administrative costs.

Response:

See response to ENO 1-4. Administrative cost percentages are largely dependent on the level of savings achieved in the program, program design and delivery models, and the efficiency of program delivery by the utility. The climate in any particular region has little bearing on the administrative needs of program delivery.

c. Please describe in detail any adjustments Optimal made to the sourced data, or any analyses Optimal performed, to account for reductions in economies of scale or other efficiencies associated with the administrative costs in the identified "state-wide portfolios" that would not be possible to achieve with administrative costs for the smaller, City-wide Energy Smart program.

Response:

Optimal made no such adjustments. As stated in the response to ENO 1-4, we developed administrative costs appropriate for the level of efficiency potential found in our study, which is substantially greater than the current Energy Smart program.

d. To the extent Optimal did not perform the analyses or make the adjustments described above, please explain why Optimal did not do so.

Response:

See response to ENO 1-5c.

ENO 1-6:

Please refer to page 8 of the Optimal Potential Study and Tables 7 and 8. Please state whether the Residential Direct Load Control reductions assume the implementation of Advanced Metering Infrastructure ("AMI"). If so, in what year did Optimal assume ENO's implementation of AMI implementation would be completed?

Response:

We made no assumptions about AMI penetration for the Residential DLC and ADR demand response scenarios. This is because most Bring-Your-Own-Thermostat programs only require an internet connection and do not require AMI. Most "learning thermostats" do not require AMI to function and cannot connect to all models smart meters.

ENO 1-7:

Please refer to page 9 of the Optimal Potential Study, specifically the statement, "Importantly, all of these rate options can be implemented in a way that does not change the total revenue collected from customers, which means neither the customers as a whole or the utility are disadvantaged."

a. In order to keep "customers as a whole" from being disadvantaged, would costs need to be reallocated within or between customer classes such that some customers would pay a greater share of the overall revenue requirement than they currently do?

Response:

The quoted statement refers to the revenue neutrality of the various rate design options. All rate design proposals included in this analysis are revenue neutral, meaning the level of revenue expected does not change from the baseline assumption. This analysis also only pertains to residential customers, so there is no reallocation of revenue collection between customer classes.

b. If the answer to subpart (a) above is in the affirmative, please provide the cost allocations developed by Optimal or ACEEE designed to achieve this result, including all documents and workpapers used in the development thereof.

Response:

ACEEE or Optimal Energy did not design cost allocations for the purpose of this analysis.

ENO 1-8:

Please refer to page 56 of the Optimal Potential Study at Table 38. Please also refer to page 58 and the statement "Revenue neutral rate approaches are designed to recover the same level of revenue in the analysis period, which is one year for this analysis."

a. Please explain why Optimal and/or ACEEE applied the results of this single-year analysis with the 20-year results of the DSM and DR potential analysis in one table.

Response:

Savings from rate design do not accumulate like savings from energy efficiency measures with a measure life of more than one year. Therefore the cumulative saving potential from rate design included in Table 38 is the same every year.

b. Do the rate design approaches analyzed remain "revenue neutral" after year one? If not, please describe the relative changes in rates to customers.

Response:

To the extent that a new rate design leads to increased or decreased electric usage, total revenue may also increase or decrease in future years. If this occurs, it can be addressed in a future rate case.

ENO 1-9:

Please identify all members of the Delphi panels referenced in Appendix A of the Optimal Potential Study.

Response:

Please see Attachment 1-9.

ENO 1-10:

Please refer to page 14 of the Optimal Potential Study.

a. Please identify the Program Years associated with the savings that were added back as an adjustment to the sales forecast.

Response:

These values were provided by ENO in response to Optimal Data Request 1-4 (h).

b. Please identify the level of savings added back to sales forecast for each year of the planning horizon.

Response:

See response to part a.

ENO 1-11:

Please refer to page 16 of the Optimal Potential Study, specifically to the statement, "For summer, on-peak hours are weekdays between 11 AM and 9 PM," which differs from the statement in Appendix C, p. 87, "Summer on-peak is April-October, 9 AM-9 PM, weekdays."

a. Please confirm what hours were included in the Summer on-peak period.

Response:

Summer Peak period is from 11 AM-9 PM.

b. Please identify the basis for defining a peak period as 10 or 12 hours of the day.

Response:

This is based on the hourly pricing from MISO. The peak period was chosen to represent times of higher energy costs, but not limited to only those hours with the very highest energy costs. It is designed to better capture the value of energy reductions resulting from energy efficiency based on the overall pattern of their timing, rather than the value of peak demand reduction during periods of maximum system load.

c. Please describe in detail why this definition of peak periods should be different than the peak periods identified in the New Orleans Technical Reference Manual and/or by the Midcontinent Independent System Operator ("MISO").

Response:

The TRM defines the “peak period” as weekday non-holidays from 4-5 pm, where the temperature exceeds 90 degrees. This is the peak period for demand, relative for determining system capacity needs. The “peak period” referenced above is a peak period for energy – times of day that don’t necessarily drive capacity additions, but where the energy is still more expensive than average for the year. The same reasoning applies to the MISO-defined peak period.

ENO 1-12:

Please refer to page 16 of the Optimal Potential Study, specifically the statement, “As indicated earlier, if the net present value of the future stream of benefits (energy and demand, but also other societal benefits such as gas, water, or maintenance savings) exceeds the costs, then the measure is considered cost effective.”

a. Please confirm that the definition of the Total Resource Cost (“TRC”) test in the California Practice Manual, which is specified in the Council’s IRP Rules (Sec. 5A) as the cost-effectiveness test to be used in the IRP modeling, does not contemplate inclusion of societal benefits in the cost/benefit calculation.

Response:

The definition of the Total Resource Cost Test in the California Standard Practice Manual allows the types of benefits listed above (gas, water, and maintenance). It does not include benefits from decreased externalities, which are not included as benefits in this potential study. The use of the word “societal” to describe resource savings other than electric energy and other savings that accrue to program participants was incorrect.

b. Please provide the source for the version of a TRC cost/benefit calculation that does allow the inclusion of societal benefits as applied in the Optimal Potential Study.

Response:

See response to part a.

c. Please identify the total percentage of the overall TRC benefits for each measure resulting from the inclusion of “other societal benefits” as described above?

Response:

See Attachment 1-12.

d. Please identify any measures that would not have achieved a TRC value of 1.0 or greater but for the inclusion of the "other societal benefits" as described above.

<u>Response</u>:

The only two measures that would not pass the TRC without the other non-electric benefits are "Optimized HVAC Control/Distribution" and "Advanced RTU Controls." The cost-effectiveness of these measures is a result of their reduction of both electric and gas consumption.

<u>ENO 1-13:</u>

Please refer to page 17 of the Optimal Potential Study. Please identify the methodology for adjusting ENO's average line loss calculations to marginal line losses and provide the marginal line loss values used in developing the Optimal Potential Study along with supporting workpapers.

<u>Response</u>:

We Assume that marginal line losses are 50% higher than average line losses. This is from a study from the Regulatory Assistance Project (RAP). See Attachment 1-13 for the full study.

<u>ENO 1-14:</u>

Please refer to page 17 of the Optimal Potential Study, specifically the statement "we used a discount rate of three percent to better reflect the public policy nature of energy efficiency programs," and to page 69.

a. Please identify the public policy statements of the Council that approve the use of a three percent discount rate as related to energy efficiency programs.

<u>Response</u>:

Optimal is not aware of any such statements by the Council. Regardless, Optimal's contract with and signed by the City of New Orleans states that we will use a discount rate "appropriate for an analysis of public purpose programs with low risk, typically between 2.5 and 5 percent."

b. Please confirm that the Federal Energy Management Program, which is administered by the U.S. Department of Energy and relies on government funding for projects, uses a discount rate tied to long-term government debt to assess costs and benefits.

<u>Response</u>:

Optimal is not aware of any evidence that would either confirm or refute this statement, nor would the answer to this question have any bearing on the results of the Potential Study.

c. Please identify any examples of retail utility-implemented energy efficiency programs where the utility uses a long-term government debt rate as a discount rate for evaluating program costs and benefits.

<u>Response</u>:

Optimal did not perform a comprehensive analysis of discount rates used in various jurisdictions as part of this analysis. That said, we are aware of several jurisdictions that use real discount rates of 3 percent or less to evaluate efficiency program costs and benefits, including Rhode Island (0.46%), Massachusetts (0.46%), the District of Columbia (1.9%), and New Hampshire (2.84%).

<u>ENO 1-15:</u>

Please refer to page 34 of the Optimal Potential Study and the statement, "Different assumptions regarding free-ridership and spillover." Please identify all assumptions that Optimal made about free ridership, "spillover," or Net to Gross values in its analysis.

<u>Response</u>:

Please see Attachment 1-15.

<u>ENO 1-16:</u>

Please refer to page 36 of the Optimal Potential Study, specifically the statement, "Another type of risk relates to the construction of new generation facilities. These facilities may take 10 years or longer to begin producing power…" Please identify the types of generation facilities that require at least 10 years to construct and provide all documents evidencing that a 10 year construction period is likely for any such generation facilities identified.

<u>Response</u>:

By construction we mean the entire end-to-end process, including initial scoping, getting commission approval, detailed planning and designing, securing necessary permits, and actual construction. We did not identify for this project specific technologies and/or projects that have required more than 10 years from conception to power production. Regardless, the referenced statement relates to the risk that MAY occur from meeting forecast load requirements with newly constructed generating plants, relative to the risk of implementing energy efficiency programs. Our cost-effectiveness analysis did not include any value for this risk, and whether or not any specific generating facility takes 5, 10, or 20 years to be constructed has no bearing on the results of the potential study.

ENO 1-17:

Please refer to page 42 of the Optimal Potential Study. Please describe the rationale for applying a 3% discount rate to evaluate cost effectiveness of DR programs.

Response:

Please see answer to 1-14 a. There is no reason why the discount rate used for DR should be different than that used for EE.

ENO 1-18:

Please refer to page 54 of the Optimal Potential Study, specifically Figures 18 and 19. Please provide all documents, workpapers, and any other inputs and assumptions that support the annual program costs identified for the DR programs.

Response:

Please see Attachment 1-18.

ENO 1-19:

Please refer to page 58 of the Optimal Potential Study, specifically the statement, "This structure [TOU Rates] more accurately reflects the cost to serve residential customers throughout the day."

a. Please provide all documentation, workpapers, and/or other analyses that demonstrate that the TOU rates identified in the Optimal Potential Study reflect the cost to serve ENO's customers.

Response:

The Potential Study makes no claim that the TOU rates examined in the study precisely reflect the cost to serve ENO's customers at any particular time of day, although they are based on existing ENO rates, customer load research provided by ENO, and a simplified analysis based on revenue neutrality. The quoted statement is based on the simple and widely-held assumption of a higher cost to serve during periods of higher overall energy consumption and a lower cost to serve in periods of lower overall consumption.

b. Please identify and provide the billing determinants utilized to develop TOU rates that accurately reflect ENO's cost of serving its customers throughout the day; include the workpapers that support any such billing determinants.

Response:

The billing determinants were based directly on the load research sample provided by Entergy New Orleans. Please refer to ADV-1-11_ENO RES-24 2017.xlsx for more information.

c. Please state whether the characteristics of a utility's particular generating portfolio and the utility's participation in, and reliance on, capacity and energy markets to serve its customers' load could affect the cost to serve its residential customers throughout the day.

Response:

The specific details of production plant costs could affect the cost of service for residential customers. Differences in the details of the cost to serve throughout the day would not have a significant impact on the results of the study.

d. Can data obtained from AMI be beneficial in developing TOU rates that accurately reflect the cost to serve residential customers throughout the day?

Response:

In the abstract, more granular data on customer consumption could improve the development of time of use rates, but such data would be unlikely to change the overall conclusion of our analysis, which is that TOU rates will result in some amount of shifting of consumption from periods of higher system consumption and higher rates to periods of lower consumption and lower rates.

e. If the answer to subpart (d) above is in the affirmative, please describe in detail the type of analysis that would be required to utilize data obtained from AMI in order to develop TOU rates that accurately reflect the cost to serve residential customers throughout the day. Please identify the time period over which AMI data should be collected in order to enable such analyses to be as accurate as possible.

Response:

Designing the requested analysis was not part of the scope of this potential study.

ENO 1-20:

Please refer to page 70 of the Optimal Potential Study.

a. Please describe the method through which Optimal aligned the historical hourly Locational Marginal Prices ("LMPs") with the annual forecast LMPs and provide any supporting workpapers.

Response:

The meaning of this question is not clear. Optimal did not conduct any analysis to "align" historical hourly LMPs with annual forecast LMPs. The Potential Study, at page 70, describes the process by which we created avoided costs for future years using the forecast hourly LMPs provided by ENO in response to Advisors Data Request 3-003. Forecast LMPs for 2018 were analyzed using a pivot table to calculate the average price for each costing period. The table below summarizes this output. This process was repeated for 2022 forecast LMPs. Avoided costs by costing period for Years 2019 through 2021 were developed by applying the relative magnitude across the four periods for 2018 to the annual forecast LMPs provided by ENO in response to Advisors Data Request 2-1, File #11. Years 2023 through 2037 were developed in the same manner by applying the Year 2022 result to the annual forecast LMPs. See HSPM Appendix 1-20A for more detail.

b. Please identify the source of the loadshapes for each sector and end use and provide all supporting documentation and workpapers.

Response:

As stated on page 72 of the Potential Study, we relied on loadshapes provided by the Electric Power Research Institute (EPRI), in their "Loadshape Library" which can be found at http://loadshape.epri.com/. See Attachment 1-20B. These hourly loadshape data were processed to generate a loadshape using the four energy costing periods using a data processing routine written in R. See Attachment1-20C for the output of this process.

c. Please describe the method through which avoided capacity costs were determined and accounted for and provide any supporting workpapers.

Response:

Avoided capacity costs were taken from ENO's response to Optimal's data request 1-5.

ENO 1-21:

Please refer to page 72 of the Optimal Potential Study, specifically the statement, "For purposes of the simple payback analysis, only the variable portion of rates was included. For residential customers, we estimated a price of 8.5 cents/kWh." Please describe in detail the method through which Optimal estimated the variable portion of the retail rate and provide all supporting workpapers.

<u>Response</u>:

Optimal reviewed rate tariffs available on the ENO website. We averaged the summer rate and winter tail block rate and summed up all riders and adjustments that are charged on a per kWh basis. We limited our review to “basic” residential tariffs in effect for the majority of customers.

<u>ENO 1-22:</u>

Please identify the source of the end use level sales disaggregation data provided in Appendix B of the Optimal Potential Study.

<u>Response</u>:

Residential sales disaggregation comes from the West South Central Census Zone in the 2009 Residential Energy Consumption Survey from the Energy Information Agency. Commercial sales disaggregation comes from the West South Central Census Zone in the 2012 Commercial Building Energy Consumption Survey from the Energy Information Agency.

<u>ENO 1-23:</u>

Please refer to Appendix D – Measure Characterization.

a. Please state whether the percent savings identified is the percentage savings over the baseline energy of the equipment.

<u>Response</u>:

Yes, percent savings represents percent savings over baseline energy of the equipment.

b. Please state whether the measure costs provided represent cost per kWh saved.

<u>Response</u>:

Yes, measure costs represent cost per annual kWh saved.

c. Please provide the applicability and feasibility factors used in developing this Appendix.

<u>Response</u>:

The percent savings numbers from the appendix don’t reflect the applicability and feasibility factors. Those factors are applied later in the calculation process. See Attachment 1-23 for the factors.

ENO 1-24:

Please identify the source of, or the analysis employed to develop, the forecasted retail and carbon costs utilized in the Optimal Potential Study. Please provide any supporting documents or workpapers used to develop these costs.

Response:

Forecasted carbon costs were taken from ENO's response to Optimal data request 1-6. We did not forecast retail rates.

Respectfully submitted,

DENTONS US LLP

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Responses to Entergy New Orleans, LLC's First Set of Requests for Information has been served upon "The Official Service List" via electronic mail and/or U.S. Mail, postage properly affixed, this 1st day of October, 2018.

/s/ Jay Beatmann

J. A. "Jay" Beatmann, Jr.