Questions to Entergy Regarding 2015 Integrated Resource Plan Draft

1. What were the assumptions for energy sold into MISO under each scenario? Please include the prices for each generating source.
2. What options are available within MISO, through PPAs, or other means to meet capacity / reserve requirements besides Entergy self-build?
3. What financial benefits do ratepayers gain when Entergy self-builds rather than accessing capacity / energy from the best alternative means?
4. When are ENO's peak periods that require additional capacity (specifically what hours, days, and months) after Michoud is retired?
5. Please provide seasonal load data for comparison against the generation / load reduction potential of new wind, solar, and / or DSM resources.
6. Please provide hourly load profiles for peak season and shoulder months
7. Please provide the seasonal and hourly generation profiles that were used when modeling each wind resource considered for the IRP, while indicating where the resource would be located, its size, and any other significant characteristics for comparison with other supply alternatives.
8. Were wind resources modeled specifically against the planned deficit in ENO capacity following the retirement of Michaud units 2 and 3, or against all ENO capacity?
9. Please provide information on the cost of modeled wind resources, the cost of the marginal power the wind resource was compared against, and the related cost benefit results. If wind resources were modeled against the planned deficit following Michaud 2 and 3 and against all ENO capacity, please provide this information for each analysis.
10. How much capacity credit is ENO assigning for wind resources?
11. When is peak for wind in ENO territory?
12. How much capacity credit is ENO assigning for solar resources?
13. When is peak for pv solar in ENO territory?
14. How much capacity credit is ENO assigning for DSM/demand response resources?
15. Please describe in detail what factors and assumptions were used in Figure 13 of the Draft IRP for:
    a. Variable Supply Cost
    b. DSM Fixed Cost
    c. Non-Fuel Fixed Costs of Incremental Additions
    d. Capacity Purchases

16. For each of the portfolios in Figure 13, how much energy, from what generating resource, and at what price was assumed to be sold to the market outside of Orleans?
17. For each of the other three scenarios, how much energy, from what generating resource, and at what price was assumed to be sold to the market outside of Orleans?
18. The Variable Supply Cost for the Solar Portfolio on Figure 13 is over a third of the Variable Supply Cost for the CT Portfolio (approx. $600 compared to $1,500). What accounts for the surprisingly high variable supply cost for solar?
19. In Figure 2 of the Draft IRP, why is the cost of wind projected to increase over time?
20. Figure 2 in the Draft IRP seems to be concerned with capital outlay by Entergy, and therefore the cost of gas appears not to include fuel costs. Is this correct?
21. Wind resources are typically acquired through PPAs and would not therefore have a capital outlay cost for ENO. Did Entergy price wind for what it would cost to build in New Orleans or what it would cost to acquire a PPA?
22. Natural gas volatility is not captured in the preferred scenario - Industrial Renaissance. Florida and Louisiana public service commissions have recently allowed gas hedging specifically to address future uncertainty around natural gas pricing. Please explain in detail why Entergy believes that natural gas prices will remain consistently low for the next 20 years.
23. What is the levelized cost of energy for each of Entergy's existing generating units (including fuel prices)?
24. What is the expected levelized cost of energy for ENO's proposed CT addition (including fuel prices)?
25. SWEPCO recently acquired wind contracts for $32 / Mwh, yet ENO found wind to be uneconomical. What is the levelized cost of energy for the wind resources modeled by ENO?
26. In their comments filed on April 28th, 2015, the Gulf States Renewable Energy Industries Association filed attachments pertaining to the cost of renewable energy resources.
    a. Did you review the pricing figures identified in the SWEPCO draft IRP and the SWEA comments to ELL / EGSL IRP that were attached to the GSREIA filing?
    b. Did you incorporate any of the pricing data or other recommendations from these filings. If so, specifically what changes were made to the ENO IRP that reflect the pricing data and recommendations from these filings.
    c. What are the specific reasons ENO chose not to adopt the remainder of the recommendations by GSREIA and SWEA on wind resources?
    d. What are the substantive differences in the cost of accessing wind resources within MISO that distinguish it from SPP where SWEPCO is getting their wind resources,?

e. What are the most cost effective wind resources that have been acquired by utilities in the MISO network over the past two years or are currently available for PPA.

27. While Entergy is also developing IRPs for other service territories, the City Council has directed Entergy New Orleans to produce a plan that is specifically tailored to and optimized for Orleans Parish. In this context, why is the reference case called Industrial Renaissance? Are there significant industry expansion projects expected in Orleans Parish during the planning period? Are the industry expansion plans in other parts of Entergy's service territories in any way driving the planning process and portfolio recommendations in New Orleans?
28. Please provide the study on solar costs that ENO mentioned in the Milestone 4 stakeholder meeting. At the conference, Entergy staff stated that the costs of utility-scale solar used in the modeling process was derived from a specific study commissioned by ENO.
29. Please explain why the preferred portfolio does not have a price on carbon over the 20 year planning period.
30. Please provide the analysis for the 10 energy efficiency programs that were eliminated from the draft IRP based on the Industrial Renaissance portfolio.
31. Please provide analysis regarding the 2 demand response (DR) programs that were eliminated from the final draft.
32. What factors identified when re-assessing the limitations of modeling to date with DR could be relevant to other resource alternatives?
33. What are the terms of ENOs current DR initiatives?
34. What costs have been incurred under the current DR arrangements?
35. What customer categories were assessed for DR potential?
36. What value is assigned to the energy avoided by activating DR?
37. For DSM, did ENO use the High incentive level for the co-optimization analysis?
38. It appears that the high incentive level is able to achieve 14.5% of peak load by 2034. Did the analysis ramp up DSM or keep the incentives level over the 20 year planning period?
39. ENO was to include non-energy benefits in the analysis. Please list the NEBs and explain how these savings were factored into the draft.
40. What were the program costs and benefits for each of the DSM programs at the low, reference, and high incentive levels (in each of the scenarios?)
41. Appendix F: Do avoided costs include fuel costs?
42. Please provide the numbers for DSM co-optimization.
43. Please provide the levelized cost for each of the 24 DSM programs.
44. Energy efficiency costs $0.05/kWh. What is the kWh cost of the other resource options?
45. Reliability is an important factor but the draft IRP does not have any transmission or distribution upgrade plans. Why?