

**ADVISOR REPORT  
ON  
THE 2015 DRAFT INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS  
Council Docket UD-08-02**

**Introduction**

The Advisors are deeply concerned that the draft IRP set forth by Entergy New Orleans (“ENO” or the “Company”), including the 2015 IRP Updates submitted on September 18, 2015 (“IRP Updates”), is not sufficiently supported by current data and fails to take into account relevant information in comments made by Stakeholders and Advisors since the beginning of the stakeholder process in 2014. The Company failed both to take into account information known and available to it at the time its analysis was performed and to account for changes occurring over time since its analysis was begun.

While the Advisors appreciate the time and effort the Company has spent in conducting the stakeholder process, several Intervenors state, and the Advisors agree, that the Company has consistently failed to respond to, or recognize in any way, specific important and relevant information in comments made by Stakeholders and Advisors since the beginning of the stakeholder process in 2014.<sup>1</sup>

Comments on the draft IRP were filed by the Alliance for Affordable Energy (“Alliance”), Green Coast Enterprises (“GCE”), the Greater New Orleans Housing Alliance (“GNOHA”), the Gulf States Renewable Energy Industries Association (“GSREIA”), and Building Science Innovators (“BSI”), many of whom indicated that the Company had not been sufficiently responsive to stakeholder feedback, and the Advisors agree with this concern. The Alliance states that the draft IRP contains numerous biased assumptions and restrictions in modeling that in turn limited, rather than maximized, the amount of cost-effective energy efficiency, demand response, and renewable energy in their preferred portfolio.<sup>2</sup>

The Advisors are concerned that these deficiencies led the draft IRP to select a less than optimal amount of DSM and renewable resources for the Company's preferred portfolio. The Advisors are also concerned that the Company has failed to update its IRP data as events have unfolded since the beginning of the stakeholder process. Although the Company maintains that the AURORA model is extensive and time-consuming to re-run, the Advisors note that Entergy Arkansas, Inc. (“EAI”) was able to re-run the AURORA model in three weeks after receiving comments from stakeholders to substantially address the stakeholders comments. Although the IRP Updates do include some Aurora modeling iterations, they fall far short of addressing all of the concerns which are summarized herein. ENO should also make the necessary changes in its AURORA modeling and perform additional analysis to

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<sup>1</sup> Alliance Comments at 3.

<sup>2</sup> *Id.*

incorporate changes that have happened since 2014, the beginning of IRP planning process.

### **Background**

In Resolution R-08-295, the Council set forth six necessary Components of an Integrated Resource Plan. Subsequently, in Resolution No. R-10-142 the Council revised and clarified its requirements for the Company's Integrated Resource Plan. The Council found that the IRP should include a risk analysis which balances costs with risks to customers, and should evaluate all resource options, from the perspective of both the Utility and all stakeholders, integrating both the supply- and demand-sides in a fair and consistent manner while minimizing costs to all stakeholders (not just costs to the Utility), and create a flexible plan that allows for uncertainty through a risk analysis permitting adjustment in response to changed circumstances.<sup>3</sup>

The Council's IRP Requirements, as clarified in Resolution No. R-10-142 set forth 10 steps to be taken under the six IRP Components set forth under Council Resolution R-08-295:<sup>4</sup>

1. Identify the objectives and procedures including time horizon (Component 1);
2. Collect data needed for the planning process, including a market analysis;
3. Develop several demand, energy and load profile forecasts in the detail needed to evaluate all resource options (Component 2);
4. Identify all stakeholder resource options on the demand-side and supply-side (Component 3);
5. Evaluate all demand-side resources by conducting benefit-cost analyses which include the Total Resource Cost test as well as the Ratepayer Impact Measure test, and considering any directly quantifiable environmental externalities;
6. Identify several options for an integrated plan by optimizing while recognizing constraints including transmission/distribution costs (Component 4);
7. Conduct uncertainty or scenario analyses for different economic and environmental circumstances, incorporating regulatory and legislative policies;
8. Based on the uncertainty analyses, develop a preferred resource plan that best addresses the most likely contingencies while providing flexibility for less likely scenarios;
9. Present the IRP (Component 5); and
10. Monitor, evaluate, report, and revise the IRP (Component 6).

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<sup>3</sup> Resolution R-10-142, Attachment, "Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans," p. 1.

<sup>4</sup> *Id.*

Each of the six Components also have specific requirements. Component 1 - IRP Objectives requires that the IRP state and support specific objectives to be accomplished, which include, but are not limited to, the following: (1) to optimize the integration of generation and transmission services with demand-side resource options to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost; (2) to promote the Utility's financial integrity; (3) to anticipate and mitigate risks associated with increasing fuel costs and other economic changes; (4) to comply with regulatory requirements and policies; and (5) to evaluate the appropriateness of incorporating advances in technology, including a careful mix of renewable resources.<sup>5</sup> Another important objective of resource portfolio procurement is to achieve a specified range of acceptable risk in the trade-off between price and risk.<sup>6</sup> The Council also requires that the IRP identify and quantify the costs and benefits of its resource portfolio and compare those to alternatives available in the market, to assess any directly quantifiable social and environmental effects of its choices, and to consider any certain or probable changes to the Entergy System Agreement.<sup>7</sup>

Under Component 2 - Demand and Energy Use Forecast, the Council requires that the IRP provide an annual demand (MW) and energy use (kWh) forecast by customer class for no less than a rolling ten-year planning horizon and to identify all assumptions relied upon in developing this forecast.<sup>8</sup> The Council's IRP Requirements also set forth what data must be supplied in that forecast.<sup>9</sup>

Component 3 - Supply- and Demand-Side Resources requires the IRP to identify and evaluate the Utility's existing resources used to service New Orleans ratepayer load based on their cost, including resources used to serve base-load and incremental demand, and to identify and quantify the success of its efforts to develop and implement programs that promote energy efficiency, conservation, demand-side management, distributed generation, interruptible load, and price-responsive demand.<sup>10</sup> To the extent the Utility anticipates altering its resource portfolio during the planning period, the IRP shall identify (1) the specific changes in resources anticipated, (2) the resultant change in costs to New Orleans ratepayers, and (3) a time-line for and description of those changes including the process the Utility relied upon to ensure that the new resource portfolio will provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.<sup>11</sup> The IRP Requirements also set forth which data must be provided in the IRP filing.<sup>12</sup>

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<sup>5</sup> *Id.* at p. 2.

<sup>6</sup> *Id.* at p. 2.

<sup>7</sup> *Id.* at p. 2-3.

<sup>8</sup> *Id.* at p. 3.

<sup>9</sup> *Id.* at p. 3-4.

<sup>10</sup> *Id.* at p. 4.

<sup>11</sup> *Id.* at p. 4.

<sup>12</sup> *Id.* at pp. 4-7.

Component 4 - Integration of Utility requires the IRP to explain how Entergy's current transmission system, and any planned transmission system expansions, and the Utility's distribution system are integrated into the overall resource planning process to optimize the Utility's resource portfolio and provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.<sup>13</sup> To the extent major changes in the operation of planning of the transmission system are contemplated in the planning horizon, the Utility should describe the anticipated changes and provide an assessment of the cost impact to the Company.<sup>14</sup>

Component 5 - Public Presentation of IRP requires the Utility to make its IRP available for public review.<sup>15</sup>

Component 6 - Reporting Requirements and Council Resolutions requires the Utility to file IRP status reports intended to provide the Council with an update on the Utility's progress in meeting the objectives established in the IRP.<sup>16</sup>

### **Entergy New Orleans' Draft IRP**

After a year-long stakeholder process that ran from June 2014 through June 2015, and included six technical conferences, ENO submitted its draft IRP Report on June 23, 2015. The parties submitted comments on August 31, 2015. On September 18, 2015, ENO submitted its 2015 Integrated Resource Plan ("IRP") Updates for the Final IRP Report. The Advisors recognize that Intervenors did not have the opportunity to review the September 18 IRP Updates filing prior to submitting their comments.

The Alliance argues that the Draft IRP shows numerous biases against Energy Efficiency programs, and contains no renewable energy at all, despite their proven cost effectiveness.<sup>17</sup> The Alliance also argues that Entergy's draft IRP reflects an internal process that maximized bias while minimizing stakeholder and intervenor input.<sup>18</sup> The Alliance contends that the draft IRP contains numerous biased assumptions and restrictions in modeling that in turn limited, rather than maximized, the amount of cost-effective energy efficiency, demand response, and renewable energy in their preferred portfolio.<sup>19</sup> The Alliance also argues that ENO failed to comply with Council priorities to substantially increase the resiliency of the grid through investments in demand side management programs and renewable energy within the IRP docket.<sup>20</sup> The Alliance believes that there are enough demonstrable biases against DSM and flaws in the IRP modeling process to warrant

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<sup>13</sup> *Id.* at p. 7.

<sup>14</sup> *Id.* at p. 7.

<sup>15</sup> *Id.* at p. 7.

<sup>16</sup> *Id.* at p. 7.

<sup>17</sup> Alliance Comments at 2.

<sup>18</sup> *Id.* at 3.

<sup>19</sup> *Id.*

<sup>20</sup> *Id.*

an additional technical conference on the subject.<sup>21</sup> The Alliance urges the Council to require that significant substantive changes be made in the IRP before the final report is submitted for their approval.<sup>22</sup>

The Advisors agree that there are several elements related to cost and assumptions concerning resource options in the IRP that are problematic and resulted in an under-valuing of DSM and renewable resources and an over-valuing of natural gas resources.

#### **A. Demand-Side Management**

The Company's draft IRP contains several deficiencies that result in the IRP under-valuing demand-side resources and failing to consider all relevant demand-side measures ("DSM") determined to be cost effective in the initial screening of the DSM Potential Study.

- The Intervenors point out several flaws in the Company's DSM modeling that result in increasing the cost and limiting the kWh reduction achieved per DSM measure.
- More free-ridership costs were assumed by modeling high incentives without incrementally raising the incentive level over time.
- The number of DSM measures considered was constrained by not determining cost-effectiveness against other resources in the IRP.
- Insufficient information was provided in the draft IRP to understand what impact varying levels of DSM would have on revenue requirements when sales of excess energy (off-system sales) are considered
- The Alliance argues that the Council should direct the Company to increase energy efficiency program budgets and ensure their stability over a longer program horizon.<sup>23</sup>

The Advisors agree that ENO's approach to IRP modeling restricted the amount of DSM, and that a consensus to remedy this concern must be achieved among the Company and all stakeholders.

##### *1. Cost of DSM Measures*

The Alliance states that the cost of implementing DSM measures suggested by ICF are substantially more expensive than those found by the American Council for an Energy Efficient Economy ("ACEEE") in their national review of actual utility energy

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<sup>21</sup> *Id.* at 9.

<sup>22</sup> *Id.*

<sup>23</sup> *Id.* at 2.

efficiency program costs in 20 states between 2009-2012.<sup>24</sup> The Alliance notes that ICF's leveled cost per kWh range from \$0.05 to \$0.09 compared to ACEEE average actual costs of \$0.016 to \$0.048 per kWh.<sup>25</sup> The Alliance states that in particular, the Small Business Solutions, Residential Home Audit & Retrofit, Commercial Prescriptive & Custom programs, Home Energy Use Benchmarking, and Energy Star Air Conditioning, which together account for the largest share of savings, are out of line with the costs found by ACEEE.<sup>26</sup> The Alliance also notes that ICF's assumed costs are also far higher than those reported in EAI's 2014 energy efficiency report.<sup>27</sup>

GCE notes that Entergy reports that it found prior energy efficiency programs delivered at \$0.05 per kWh but has not explained clearly why it would opt to invest in more expensive resources over a planning horizon that permits EE and DSM to be implemented effectively.<sup>28</sup>

GNOHA states that it is unclear why ENO is opting for more expensive resources throughout this planning period when there are lower cost options that account for energy efficiency.<sup>29</sup>

The Advisors are similarly concerned that the Company appears to have placed an unusually high cost upon DSM measures relative to industry references which show that kWh savings can be achieved at lower cost of DSM than modeled by the Company. To address this concern of stakeholders and Advisors, the Company should determine the specific costs and assumptions that would explain and support the differences in ICF's DSM leveled costs per kWh relative to other industry references for purportedly similar measures.

The Alliance also argues that Entergy's approach to modeling in the IRP has restricted the amount of DSM selected in several ways, including: modeling against the MISO marketplace rather than head-to-head with proposed supply resources, incurring more free ridership costs by modeling high incentives without phasing, cream skimming, and lack of clear strategies for off system sales.<sup>30</sup> While the subject of off-system sales has been raised repeatedly in the current and previous IRP cycles, there is still no practical information provided in the Draft IRP to understand what impact varying levels of DSM investment would have on utility revenue requirements when sales of excess energy are factored in.<sup>31</sup>

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<sup>24</sup> *Id.* at 3.

<sup>25</sup> *Id.* at 4.

<sup>26</sup> *Id.* at 4.

<sup>27</sup> *Id.* at 4.

<sup>28</sup> GCE Comments at 1.

<sup>29</sup> GNOHA Comments at 2.

<sup>30</sup> Alliance Comments at 8.

<sup>31</sup> *Id.* at 9.

The Advisors agree that ENO's lack of supportive information on the use of off-system sales limits the understanding of what will be the impact on the utility's revenue requirement by integrating higher levels of DSM in ENO's recommended portfolio.

The Advisors note that the costs of implementing DSM measures used by the Company in its analysis are substantially more expensive than those found in (a) the American Council for an Energy Efficient Economy (ACEEE) national review of utility energy efficiency program costs in 20 states between 2009 – 2012, and (b) the EAI "2014 Program Portfolio Annual Report Excel Workbook". The Advisors recommend that the Company be required to reconcile the development of the DSM cost estimates used in ENO's 2015 IRP with DSM cost figures consistent with credible industry information, such as those used by EAI.

## 2. *Projected Benefits of DSM*

The Alliance argues that ICF has understated the benefits of DSM.<sup>32</sup> The Alliance believes that the full value of the DSM measure over its life cycle should be used rather than its value over the 20-year planning period.<sup>33</sup>

The Company made no adjustments to represent the long-term kWh reduction impacts of DSM measures – the net present value of long-term benefits was truncated by the Company's use of a 20-year analysis.

Relative to the recognition of long term benefits of DSM, the Advisors note that the Company has failed to provide workpapers for the slides related to the total benefit and total cost comparison and DSM programs net benefit analysis presented in the "2015 ENO IRP Interim Milestone Follow-up for the Advisors" (Milestone 4).

However, the Advisors note that long-term costs and benefits for both supply resources and demand side resources were truncated by using a 20 year planning period. No adjustments were made to account for the long-term impacts of either supply or demand-side resources beyond the planning period.

Most utility IRPs use a planning period such as a 20-year term. Any revisions to the modeling algorithm would have to be applied to all resource options, and would likely require a substantial effort. Also, increasing uncertainty exists with an extended planning period. If these impacts were to be recognized by discounting the impacts that are projected beyond the planning period using a net present value calculation, such calculation adjustments would have to be applied consistently to all supply and demand side resources. The issue of recognizing long term costs and benefits within a defined planning period is a core assumption in optimizing DSM within an integration of all resource options. Such an adjustment would likely

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<sup>32</sup> *Id.* at 7.

<sup>33</sup> *Id.*

involve changes to the modeling algorithms which would be more substantive than revising input costs and assumptions. Several stakeholder technical conferences would likely be required to achieve agreement on these revisions to the IRP process. Such a calculation adjustment would have to recognize the timing differences between supply resources added in large increments at discrete intervals of years, and demand resources added annually with estimated costs only in the initial year of implementation.

Another possible option would be to compare the results from the current IRP methodology with those from an alternate methodology for incorporating DSM in the planning period. The screened energy efficiency measures from the DSM Potential Study could be incorporated into the demand and energy forecasts, instead of using the screened energy efficiency measures as an IRP resource input. Then resource options (less energy efficiency) could be evaluated against the revised demand and energy forecast (which includes energy efficiency). Demand Response measures would still be evaluated in the IRP capacity expansion modeling.

The IRP Updates did not revise the amount of energy efficiency DSM in the draft IRP results, but only recognized the demand response programs evaluated in the DSM final report. The Advisors believe that revising the IRP to reflect the full term of life value of all resources rather than the value over the 20-year planning term would not warrant an extensive delay in the IRP procedural schedule.

### 3. *Participation Rates and Achievable Potential of DSM*

The Alliance argues that ICF's projected decline in DSM savings potential ignores the potential of ongoing innovation.<sup>34</sup>

The Alliance also argues that comparing New Orleans DSM targets only to Southern states in 2010-2012 is flawed.<sup>35</sup> The Alliance argues that the states selected for comparison by ICF rank at the bottom of the ACEEE annual scorecard for energy efficiency and therefore should not be used as a model.<sup>36</sup> The Alliance states it is preposterous to think that by looking at extremely low performing states during a period of equally low political leadership on DSM, one would be able to get a snapshot of achievable potential for a highly motivated jurisdiction like New Orleans.<sup>37</sup> The Alliance also argues that it is flawed to compare ENO's program to state-wide programs rather than city-wide programs.<sup>38</sup> The Alliance states it is fundamentally wrong to suggest that the hot, humid climate explains lower energy efficiency performance in Southern states instead of acknowledging the political realities in those states.<sup>39</sup> The Alliance claims there is strong reason to believe that

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<sup>34</sup> *Id.* at 5.

<sup>35</sup> *Id.*

<sup>36</sup> *Id.*

<sup>37</sup> *Id.*

<sup>38</sup> *Id.*

<sup>39</sup> *Id.*



such historic underinvestment means a greater level of low cost energy efficiency opportunities remain readily available in the New Orleans region.<sup>40</sup>

GNHOA states that ICF's projection of 0.6% as an achievable target for Energy Efficiency is based on the wrong peer group because it is reported as an achievable target for programs serving entire states, including rural areas, etc.<sup>41</sup> GNHOA argues that investor-owned utilities serving cities are able to achieve much higher savings.<sup>42</sup> The GNHOA argues that the Council should direct ENO to plan for annual energy savings goals on par with top performing utilities serving cities.<sup>43</sup>

The Alliance also argues that ICF's projections of achievable potential do not comport with the recent EAI IRP filings in Arkansas -- EAI is on track to achieve 1.27% annually for 2016-2018, while ICF projects only 0.6% annually for the entire twenty-year period of the ENO IRP.<sup>44</sup> The Alliance argues that low assumed participation rates are unduly restricting the size of DSM programs in the IRP and unnecessarily extending the ramp up period for highly cost effective energy efficiency investments.<sup>45</sup> The Alliance explains that because there are now several years of actual Energy Smart program activity, we can see that it is the restricted size of program budgets, and not a lack of customer willingness to participate, that has limited the deployment of cost-effective energy efficiency in New Orleans.<sup>46</sup> The Alliance contends that each year Entergy has fully expended the allocated Energy Smart budget, for programs well before the year is over, resulting in interested customers being turned away.<sup>47</sup> If potential program participants are being turned away at any time during the year, as is the case with Energy Smart in New Orleans, the limiting factor is not market penetration or cost effectiveness, it is inappropriately limited budgets.<sup>48</sup>

The Advisors note that ENO has informed them that it had \$29,257.45 in funds carried forward from Year 3 to Year 4 of the Energy Smart program and a \$367,928.62 total incentive balance remaining at the end of Year 4.

Building Science Innovators ("BSI") argues that the proposed DSM program success is paltry compared to what is already working at other utilities and a robust DSM program can more quickly close the gap between supply and demand than the investment in a new expensive, fossil fuel generating plant.<sup>49</sup>

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<sup>40</sup> *Id.*

<sup>41</sup> GNOHA Comments at 2.

<sup>42</sup> *Id.*

<sup>43</sup> *Id.*

<sup>44</sup> Alliance Comments at 6.

<sup>45</sup> *Id.* at 7.

<sup>46</sup> *Id.*

<sup>47</sup> *Id.*

<sup>48</sup> *Id.* at 23.

<sup>49</sup> BSI Comments at 2.

The Advisors note that the EAI 2015 IRP used the same resource selection, the same two consultants (CLEAResult and ICF), the same modeling architecture (AURORA), and the same forecasting approach, yet the EAI 2015 IRP results provide for twice the amount of DSM than the ENO 2015 IRP (1.27% of annual sales versus 0.6% of annual sales). Furthermore, EAI has projected to exceed its DSM and DR goals set by the APSC for 2015.

The Advisors conclude that the draft IRP did not provide enough information on the IRP DSM input and modeling process which selected the number of participants (DSM measures) based on the cost and amount of reduction per DSM measure. This information is necessary to understand the cost and kWh used in optimizing the amount of DSM relative to other resources, and is the basis for the DSM participants resulting from the IRP analysis. The DSM potential study assumptions for assumed participation rates and extended ramp-up periods require additional support from credible results of other utility energy efficiency programs, or the ENO Energy Smart program. No reference was made to the experience and results of four program years of Energy Smart in New Orleans to confirm the number of participants, estimated reduction, incentive payments and total cost for similar DSM/EE measures used as DSM inputs in the IRP.

The Advisors believe that Entergy has demonstrated the ability to exceed the 2015 IRP proposed DSM levels. In Entergy's recent IRP filings in Arkansas, Entergy indicated that they intend to achieve a 1.27% annual reduction for the period 2016 – 2018, compared to ENO's projected DSM savings potential of just 0.6% annually for the IRP 20 year planning period (after four years of Energy Smart). The draft IRP should have included this comparison and reconciled the difference.

#### 4. *DSM Program Selection and Design*

The Alliance argues that greater nuance in phased deployment of increasingly higher DSM incentives (to a point) should enable all potential participants to benefit, while saving money for program deployment.<sup>50</sup> Without taking steps to raise the incentive level incrementally over time, the cost of free ridership is greater for high incentive levels.<sup>51</sup> The process of skimming the most effective energy efficiency measures prior to modeling the others reduces the total DSM investment to a minimum level.<sup>52</sup> Whereas adding additional measures until the full portfolio of programs has been brought up to the line of cost-effectiveness maximizes the amount of DSM investment.<sup>53</sup> The Alliance argues that the excess cost savings for some DSM measures should be applied to increase the number of additional DSM measures such that the size of the full DSM portfolio as a whole is maximized.<sup>54</sup>

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<sup>50</sup> Alliance Comments at 8.

<sup>51</sup> *Id.*

<sup>52</sup> *Id.*

<sup>53</sup> *Id.*

<sup>54</sup> *Id.* at 23.

GCE argues that the Draft IRP fails to evaluate potential sources on a cost effective basis to develop the optimal portfolio, instead portfolios were created with an arbitrary goal of energy efficiency included in the portfolio as opposed to allowing the model to determine exactly how much cost effective energy efficiency could be achieved.<sup>55</sup>

The Advisors conclude that not enough information was provided in the draft report regarding the selection of DSM programs input into the IRP modeling process. The draft report provides no specifics on this point.

a. Load Control and Dynamic Pricing

The Alliance states that Council should direct the company to include DSM programs that are shown to be cost-effective, and accessible by all customers in a class, including dynamic pricing and load control.<sup>56</sup> The Alliance argues that Direct Load Control should also be included in the Preferred Portfolio, particularly Residential Direct Load Control.<sup>57</sup> It is unclear why the company chose to exclude these DSM programs from their portfolio.<sup>58</sup> It is also confusing that Commercial and Industrial Load Control was not included in the portfolio since there is already an interruptible load tariff and customer who continues to receive a benefit in rate, despite never being called upon to reduce their load.<sup>59</sup> The Alliance also argues that the Company should also pursue Volt VAR Optimization.<sup>60</sup>

The Advisors note that demand response (DR) programs were virtually neglected by the Company in their initial draft IRP (prior to the IRP Updates), even though the initial screening indicated that DR programs were the most cost-effective programs among the DSM options. By way of contrast, EAI budgeted \$8 million for DR in their 2015 IRP plan, which is 12.5% of their DSM budget for 2015. More support is needed regarding how ENO optimized DR in long-term planning. Residential Direct Load Control and Residential and Commercial Dynamic Pricing were the three demand response programs that were included among the 24 programs in the ICF potential study with high cost-effectiveness ratios, but these DR programs were not selected in the portfolios of the initial draft IRP report (although recognized in the IRP Updates). The reason for eliminating these DR programs in the initial draft IRP was never provided by ENO.

Several other demand response measures are notably absent in the initial draft IRP or the IRP Updates. Interruptible or curtailable loads for industrial or large commercial were not considered. Only load control of residential central air

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<sup>55</sup> GCE Comments at 1.

<sup>56</sup> Alliance Comments at 2.

<sup>57</sup> *Id.* at 22.

<sup>58</sup> *Id.*

<sup>59</sup> *Id.*

<sup>60</sup> *Id.* at 25.

conditioning was included for evaluation in the initial screening of DSM. This measure was estimated to provide only a small percent of ENO peak reduction, and was not included in the initial draft IRP preferred portfolio. No residential water heater or any form of commercial load control was evaluated, even though many commercial measures were listed in the DSM screening analysis with processes that are often enrolled in demand response programs of independent aggregators of load management.

Only “non-enabled” dynamic pricing was considered in the draft 2015 IRP, assuming that dynamic pricing could be implemented without any changes to existing metering or costs. However, in the 2012 IRP, “enabled” dynamic pricing for residential and non-residential, as well as interruptible rates, were evaluated with substantial demand savings estimates in the final 2012 DSM potential study. Specifically, the enabled dynamic pricing measures were estimated to provide substantially higher demand savings than non-enabled dynamic pricing measures. No explanation was provided for excluding these DR measures in ENO’s 2015 IRP.

The Advisors also note that in its September 18 filing of IRP Updates, ENO’s IRP process did recognize the three demand response programs that were selected as IRP inputs in the final DSM Potential Report, leading to an additional 35 MW load reduction by 2034 for a total load reduction from all DSM programs by 2034 of 86 MW.

b. Smart Meters

The Alliance applauds Entergy's interest in upgrading to advanced meters that would enable dynamic pricing and increase the potential for residential savings of 27.5% of peak demand.<sup>61</sup>

The Advisors note that current projections indicate that 50% of the industry residential meters are expected to be advanced metering infrastructure (“AMI”) by the end of 2015. Given the increasingly widespread availability of AMI, as well as the estimate of potential savings as referenced in the previous paragraph, demand response measures enabled by such technology should have been evaluated in the IRP. Measures that should have been evaluated include dynamic pricing using time differentiated metering or AMI measures should have been evaluated and considered for both residential and commercial customers over the 20-year planning period. Exclusion of these measures from evaluation in the IRP is unreasonable considering the current and projected saturation of AMI in Louisiana and nationally.

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<sup>61</sup> *Id.* at 21.

### c. Multifamily Unit Measures

The Alliance argues that energy efficiency programs should not exclude customers who do not own single-family units.<sup>62</sup> The Alliance urges the Council to direct the company to ensure families in multi-family housing in New Orleans have access to robust programs.<sup>63</sup> The Alliance argues that there needs to be more clarity regarding which measures are available for which residential customers, it appears that the only multi-family unit programs available are common area lighting and hot water management with faucet/aerators.<sup>64</sup>

The Advisors note that multifamily units represent a significant opportunity for DSM. Programs for multifamily units should be available, comprehensive and clearly described.

#### 5. *IRP Requirements for Evaluation of Demand-Side Resources*

There is some inconsistency of intervenor positions on whether demand-side resources should be treated comparably to supply-side resources, and the Advisors note that it has become increasingly evident that there appears to be insufficient data to do a true apples-to-apples comparison of the costs and benefits of supply-side resources to demand-side resources.

The Alliance notes that one conflict between the manner in which DSM is being evaluated in the IRP and political/economic reality is that when electricity prices are comparatively low, as they are now, DSM resources are more intensively screened out.<sup>65</sup> However, when electricity prices rise, it is less economically and politically feasible to deepen investments in energy efficiency.<sup>66</sup> Therefore, it is appropriate that the Council acknowledge that the time to deepen investments in energy efficiency is now, precisely because the cost of electricity is low, rather than the opposite.<sup>67</sup>

GCE argues that the Council should direct ENO to include demand-side resources on the same basis as supply-side resources so that the cost of additional investments, such as in energy efficiency programs and DSM over and above the package included in the demand forecast, can be evaluated on a cost per kW and cost per kWh basis in comparison with the supply-side resources described.<sup>68</sup>

GNHOA urges the Council to direct ENO to include demand-side resources on the same basis as supply-side resources so that the cost of additional investments, such

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<sup>62</sup> *Id.* at 2.

<sup>63</sup> *Id.*

<sup>64</sup> *Id.* at 23.

<sup>65</sup> *Id.* at 24.

<sup>66</sup> *Id.* at 8.

<sup>67</sup> *Id.*

<sup>68</sup> GCE Comments at 1.

as in energy efficiency programs and DSM over and above the package included in the demand forecast, can be evaluated on a cost per kW and cost per kWh basis in comparison with the supply side resources described.<sup>69</sup>

The Advisors are sympathetic to the Alliance's argument that DSM is disadvantaged in the IRP analysis when electricity prices are comparatively low. Greater economic benefit is gained from demand-side management when electricity supply costs are high than when they are low. However, this is a natural result of a comparison of supply-side resources to demand-side resources on an equal footing -- whenever the projected cost of supplying electricity is low according to most credible references, the benefits of demand-side management will be lower.

The Advisors note that in some other retail jurisdictions, the trend is increasingly toward setting a goal for DSM independently from an IRP process and requiring the IRP process to simply apply the goal, similar to the manner in which Renewable Portfolio Standards are set. While the Council has heretofore declined to adopt an Energy Efficiency Resource Standard, preferring to address ENO's energy efficiency goal through the triennial IRP process, in light of the difficulty of fairly applying the process to DSM, the Council may want to consider all IRP process options available under the Council's existing IRP Requirements, including whether to include Council-approved levels of energy efficiency in the energy forecast as an additional option to be evaluated, as well as the results from the IRP optimization of DSM generated by ENO's IRP analysis. The additional option of incorporating DSM in the load and energy forecast rather than as an IRP input to be optimized was not considered, but was used by Entergy in the EAI 2015 IRP where the Arkansas Public Service Commission ("APSC") has set independent targets for DSM.

## **B. Supply-Side Cost Inputs**

The Company also has failed to properly support its cost analysis for supply-side resources, which has resulted in an under-valuing of renewable resources. The IRP contains flaws in the cost assumptions used for renewables and traditional energy resources, the failure to include a carbon cost estimate in the reference case, and failure to take any non-energy costs and benefits into account.

### *1. Cost Assumptions for Renewables*

The Alliance states that Entergy's preferred portfolio includes no renewable energy resources for 20 years.<sup>70</sup> The Alliance asserts that ENO's principal argument against renewable energy are rooted in its own high installed cost assumptions, a range of unconventional and inconsistently applied charges, and unconventional capacity-related costs it imposed on wind and solar due to the intermittent nature of

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<sup>69</sup> GNHOA Comments at 1.

<sup>70</sup> Alliance Comments at 9.

renewable energy generation.<sup>71</sup> The Alliance argues that the Company used installed and generated wind energy cost assumptions that are significantly higher than, and out of line with, contemporary market norms.<sup>72</sup> The Alliance asserts that Entergy used (1) excessively high installed cost assumptions; (2) irregular "match ups" leading to inflated levelized cost of energy lifecycle resource costs; and (3) non-standard, inconsistently applied, or unexplained additional fees and charges for out-of-state wind contracts.<sup>73</sup> Furthermore, the Alliance argues, by de-emphasizing energy generation in favor of capacity and obscuring the potential value of off-system sales, the natural advantages of wind energy have been further marginalized in the IRP.<sup>74</sup>

The Alliance states that Entergy's assumed installed cost of \$2,050 per kW for wind is far higher than the \$900-\$1,300 per kW range cited by the Lawrence Berkeley National Laboratory ("LBNL") in its 2013 Wind Technologies Market Report and approximately 30% higher than the decade's highest single year average prices in 2008.<sup>75</sup> The Alliance also argues that the Company uses uncited and unexplained high lifecycle resource costs, assuming \$102-\$115/MWh Levelized Cost of Energy rather than the LBNL's average Levelized Cost of Energy of \$25 for 2013.<sup>76</sup>

The Alliance argues that it was not appropriate, and not industry standard practice, for Entergy to add "match up" costs to the price of wind to reflect the cost of running another plant to offset the intermittency of wind, and that this unreasonably disadvantaged wind power in the analysis.<sup>77</sup> The Alliance argues that the inconsistencies in the application of the "match up" charges in Entergy's analyses raise serious concerns that the wind cost figures used by the utility throughout the IRP process were arbitrary and without credible factual basis.<sup>78</sup> The Alliance also observes that the Company failed to consider the price of wind power obtainable through a PPA, it only used the price for Louisiana-based new wind development.<sup>79</sup>

The Alliance also notes that the draft IRP projects decreasing amounts of power purchase agreements, which is to the shareholders' benefit, but prices for wind energy are markedly lower than the costs of a new gas plant built and operated by the company.<sup>80</sup> The Alliance also argues that distributed generation should be planned for, not against, and solar PV should not be treated as a load reduction, but as a planned addition of new renewable energy.<sup>81</sup>

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<sup>71</sup> *Id.*

<sup>72</sup> *Id.*

<sup>73</sup> *Id.* at 9-10.

<sup>74</sup> *Id.* at 10.

<sup>75</sup> *Id.* at 10, 13.

<sup>76</sup> *Id.*

<sup>77</sup> *Id.* at 11-12.

<sup>78</sup> *Id.*

<sup>79</sup> *Id.* at 13.

<sup>80</sup> *Id.* at 18.

<sup>81</sup> *Id.* at 26.

The Gulf States Renewable Energy Industries Association ("GSREIA") argues that cost assumptions used to evaluate the portfolios presented by Entergy New Orleans do not appear to reflect the current renewable energy market, and are instead outdated and skewed in favor of fossil fuels.<sup>82</sup> GSREIA asserts that the costs used by Entergy are much higher than those seen in recent PPA prices and findings in other jurisdictions.<sup>83</sup> GSREIA also notes that the Company did not incorporate lower renewable pricing data offered by the parties in their comments on the Milestone 3 technical conference materials, claiming it was too late in the process to make such a change.<sup>84</sup>

GSREIA argues that the Company, the Council, and their Advisors should acknowledge the unreliability of the cost assumptions when choosing the preferred portfolio, and that if the biases inherent in the information presented by ENO were taken into account, GSREIA would expect there to be no significant difference in cost between a portfolio with renewable energy and a portfolio without.<sup>85</sup>

GSREIA argues that IRP plans submitted by other Entergy subsidiaries can be used as a reference when considering the addition to utility scale renewable energy.<sup>86</sup> For example, EAI recently announced plans to add 81 MW of solar energy in the form of a photovoltaic generating facility covering nearly 500 acres.<sup>87</sup> EAI executed a 20-year power purchase agreement with NextEra Energy Resources for the project, which was the result of an RFP required by the action plan for the 2012 Entergy Arkansas IRP.<sup>88</sup>

GSREIA argues that the Council could further its policy that the development of solar energy projects should be a priority by directing Entergy New Orleans to issue a Request for Proposals to renewable energy developers to give a clear picture of the costs and characteristics of truly viable utility solar projects in New Orleans.<sup>89</sup> GSREIA argues that it is essential that the language and requirements set forth in the RFP be guided by a third party (i.e. an Independent Monitor) in order to eliminate any biases that might deter a qualified developer from responding.<sup>90</sup>

BSI argues that ENO failed to consider zero-capital-cost customer-owned solar power plants.<sup>91</sup>

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<sup>82</sup> GSREIA Comments at 3.

<sup>83</sup> *Id.*

<sup>84</sup> *Id.* at 3-5.

<sup>85</sup> *Id.* at 6.

<sup>86</sup> *Id.*

<sup>87</sup> *Id.*

<sup>88</sup> *Id.*

<sup>89</sup> *Id.* at 8.

<sup>90</sup> *Id.*

<sup>91</sup> BSI Comments at 2.



The Alliance also takes issue with the Company's reliance upon the proprietary 2013 CERA report.<sup>92</sup> It notes that reliance on a proprietary report makes it impossible for intervenors to ascertain the validity of the numbers.<sup>93</sup> GSREIA also challenges the use of the CERA report by Entergy, arguing that it is inappropriate for the basis of the portfolio evaluation to be information that cannot be disclosed to the public or to intervenors in the proceedings.<sup>94</sup> BSI also took issue with the use of the "black box" CERA report for data for utility scale solar resources.<sup>95</sup> BSI argues that ENO should be directed not to utilize "proprietary" data prepared by outside parties which cannot be examined by other parties or the public.<sup>96</sup>

The Advisors note that ENO was able as of September 18 to make the CERA report available to parties willing to enter into a non-disclosure agreement with CERA. While this does allow interested intervenors to review the data, the Advisors remain concerned that the information cannot be entered into the record and that the study in question dates to 2013.

The Advisors are also concerned that the Company has used cost figures for renewable resources that are high relative to factual sources. The Advisors agree that renewable resources were input into the IRP modeling with installed cost and levelized cost assumptions which were substantially higher than DOE and LBNL factual references filed at the LPSC, NREL, and published information for recent contracts for utility-scale renewable resources. Despite ENO's comments that the capacity match-up cost for wind resources was only considered in screening resource alternatives for economic feasibility, it is not clear how the higher levelized cost for wind was determined in the IRP. Also, no explanation was provided for the reduction in the capacity match-up cost for wind that was provided in the earlier documentation.

The Advisors note that the IRP Updates include information concerning a breakeven analysis showing installed costs for the CT Wind, CT Solar, and CT Solar\_Wind portfolios to be competitive with the CT Portfolio. The breakeven installed cost of wind and solar resources would appear to be consistent with many of the industry references cited previously, but this was still not addressed in the IRP Update.

The Advisors support the suggestion by GSREIA that ENO be instructed to conduct an RFP for renewables to identify renewable projects feasible for New Orleans and to gain more accurate information regarding the costs and deliverability of such projects.

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<sup>92</sup> Alliance Comments at 14.

<sup>93</sup> *Id.*

<sup>94</sup> GSREIA Comments at 5.

<sup>95</sup> BSI Comments at 2.

<sup>96</sup> *Id.* at 3.

## 2. *Cost Assumptions for Traditional Energy Sources*

The Alliance is concerned about the long-term natural gas price forecast used in the modeling.<sup>97</sup> It believes there are a number of demand pressures, including coal retirements, the expected Louisiana industrial boom, natural gas powered vehicles, exports of natural gas, and potential fracking regulations, that will exert upward pressure on the market cost of natural gas in the mid/long term future, and by investing solely in one fossil fuel over the time horizon, ENO directly ties consumer pocketbooks to a single, potentially volatile, fuel market.<sup>98</sup>

The Alliance states that the Company's current portfolio and the portfolio modeled over the planning horizon include a large percentage of nuclear generation, making assumptions that the nuclear assets currently available to New Orleans will continue as a foregone conclusion, with no additional costs.<sup>99</sup> The Alliance argues that the Company should have included \$500 million to \$1.5 billion for the renewal of the reactor license in its cost analysis of its nuclear assets since the assets are scheduled for re-licensing during the planning period.<sup>100</sup>

The Alliance argues that fuel cost volatility is well known, and increased environmental regulations are likely, therefore the Council should direct the company to add more non-fuel dependent resources to the final planning document in order to address these risks.<sup>101</sup>

The Advisors agree that the draft IRP does not include enough information concerning the costs and assumptions of existing resources. The draft IRP does not explain whether or not the expensive costs of nuclear relicensing were included in the cost modeling. Additionally, the Company should provide supporting details in response to the questions regarding the cost of equity estimates for the high and low cases under the financing assumptions.

The Advisors note that in its draft 2015 IRP report, ENO used outdated fuel forecast information. However, in its 2015 IRP, EAI recognized additional information available on natural gas and carbon price assumptions to address stakeholders' comments in their IRP process.<sup>102</sup> ENO should similarly update its fuel forecast accordingly.

- a. Natural Gas forecast last updated as of July 2014.
- b. Long-Term CO2 price forecast last updated as of April 2013.

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<sup>97</sup> Alliance Comments at 15.

<sup>98</sup> *Id.* at 15-16.

<sup>99</sup> *Id.* at 17.

<sup>100</sup> *Id.*

<sup>101</sup> *Id.* at 2.

<sup>102</sup> Reported in EAI's response to stakeholders groups' ("SG") request for additional information and analysis on September 3, 2015.

The Advisors also note that EAI performed additional IRP scenario analysis for stakeholders within a recent three week period using assumptions that the White Bluff and Independence plants will cease to use coal in 2028 and 2035 respectively. In the additional analysis, EAI also included additional solar resources as per stakeholders' request.<sup>103</sup>

### 3. *Environmental Costs*

The Alliance argues that the draft IRP is flawed because environmental costs of the coal plant assets were not included in the reports.<sup>104</sup> Coal plants will be impacted by CAIR, CSAPR, MATS, CCR, Clean Water Act "316(b)" Rule, ELG, NAAQS, Carbon and GHG Regulations and the Regional Haze Rule.<sup>105</sup>

The Alliance argues that the Council should direct the company to include an appropriate cost of carbon assumption in the reference case.<sup>106</sup> The Alliance urges the use of data collected by the well-respected firm CDP to follow a fact-based approach in setting the right carbon price.<sup>107</sup>

BSI argues that ENO failed to fully take into account the impact of the EPA's Clean Power Plan, which has been in an open development process for several years and was formally mandated several months ago.<sup>108</sup>

The United States Environmental Protection Agency's Clean Power Plan ("CPP") has been under development in an open and public process since the EPA released its proposed Clean Power Plan on June 2, 2014. Given the significant likelihood that the CPP may impose significant carbon-related costs that could impact the competitiveness of various supply and demand-side resources, the Advisors agree that the Company should have updated the IRP to reflect developments in the CPP. The Advisors understand that the August 3, 2015 final Clean Power Plan differed in significant respects from the initial draft CPP filed in June 2014. However, even though the plan was tentative and still changing, the Company had sufficient notice that the CPP is likely to increase carbon-related costs to incorporate some level of carbon costs into its reference case.

The draft IRP does not explain whether any additional costs of coal plants resulting from the new Clean Power Plan, 111(d) were included in the cost modeling. A Synapse Energy Economics report states that 79% of the IRPs released in 2014-2015 include a carbon cost in their reference case scenario.

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<sup>103</sup> Reported in EAI's response to stakeholders groups' ("SG") request for additional information and analysis on September 3, 2015.

<sup>104</sup> Alliance Comments at 15.

<sup>105</sup> *Id.*

<sup>106</sup> *Id.* at 2, 14-15.

<sup>107</sup> *Id.* at 15.

<sup>108</sup> BSI Comments at 2.

#### 4. *Non-Energy Costs and Benefits*

GCE argues that the Council should direct ENO to include in the IRP a description of non-energy values that are likely to be present and material to decisions about investment in resources.<sup>109</sup> In particular, GCE argues that the Council should direct ENO to include in the IRP a reasonable estimate of value of energy savings, preferably the EPA's CPP methodology.<sup>110</sup>

GNOHA argues that we know that the non-energy costs are greater than zero, some number should be used even if only an estimate.<sup>111</sup> GNOHA urges the Council to direct ENO to include in the IRP a description of non-energy values that are likely to be present and material to decisions about investment in resources.<sup>112</sup>

The Alliance also argues that Entergy failed to identify and quantify non-energy benefits to a reasonable level, as required.<sup>113</sup>

The Council has required that the Company develop a method of tracking non-energy related net benefits. While the Council has not yet required that such non-energy benefits be quantified with specificity in the IRP process, the Advisors believe it has become evident that some estimate of non-energy benefits would be more appropriate than using a value of zero. Costs related to non-energy benefits should be considered in addition to the electric revenue requirements determined by the IRP process.

#### **C. Other Issues Related to the Draft IRP Report**

Several additional issues in Entergy's draft IRP report have been noted by the Advisors and raised by the intervenors.

##### 1. *Selection of a CT Resource*

The Advisors support the selection of an appropriately sized CT resource to be built within the City of New Orleans, but not to the exclusion of viable renewable energy technologies. The city's susceptibility to storms and potential for transmission islanding mean that some level of dispatchable generation within the city's borders is necessary for reliability and resiliency purposes.<sup>114</sup> Although renewable generation may be able to fulfill a portion of this role in the future as utility-scale energy storage solutions continue to develop, the imminent retirement of the

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<sup>109</sup> GCE Comments at 2.

<sup>110</sup> *Id.* at 2-3.

<sup>111</sup> GNOHA Comments at 3.

<sup>112</sup> *Id.*

<sup>113</sup> Alliance Comments at 7.

<sup>114</sup> Recognizing that if the city were completely isolated, no available or planned resources would be capable of serving the entire 1000 MW peak load of ENO.

Michoud units does not permit the exclusion of the consideration of dispatchable generation in New Orleans.

BSI argues that the Council should prohibit ENO from shutting down Michoud if ENO's membership in MISO is jeopardized without Michoud.<sup>115</sup> It urges the Council require ENO to have a long-term agreement for zonal resource credits in place prior to closing Michoud.<sup>116</sup>

The Company has presented information regarding the level of repair and maintenance needed at the Michoud units to the Advisors that has satisfied the Advisors that investment in an appropriately sized CT unit will result in lower costs and greater reliability of electrical service to New Orleans than continuing to run the Michoud units.

BSI also argues that Entergy should be required to stop investing in any new generation resources for the foreseeable future, and should satisfy any peaking power needs with purchases from the MISO market.<sup>117</sup>

The Alliance argues that the Company's singular focus on self-build leaves other more affordable and cleaner options off the table.<sup>118</sup> The Alliance believes that building a 250 MW peaking unit essentially eliminates the opportunity to invest in cleaner technologies that are proven cost competitive by the same Draft IRP.<sup>119</sup>

The Alliance does not believe that the choice of building a gas-fired CT plant to address peak-load and capacity issues was a choice made as a result of the IRP process.<sup>120</sup> AURORA did not choose the CT plant, which did not rank as well as a CCGT plant.<sup>121</sup> The difference between the CT and CCGT portfolios is roughly the same as the difference between the CT and the heavily biased portfolios with wind and/or coal.<sup>122</sup> The Alliance expects that the wind/solar portfolios will be much more competitive if the biases against DSM, solar and wind, and those favoring natural gas are corrected.<sup>123</sup>

The Alliance argues that the Company recommends a course of action that precludes better alternatives for the foreseeable future.<sup>124</sup> The Alliance argues that if New Orleans were to follow Entergy's preferred portfolio, the City would be locked into a rigid course with little hope of changing direction.<sup>125</sup> The Alliance argues that the

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<sup>115</sup> BSI Comments at 12.

<sup>116</sup> *Id.* at 13.

<sup>117</sup> *Id.* at 8.

<sup>118</sup> Alliance Comments at 2.

<sup>119</sup> *Id.*

<sup>120</sup> *Id.* at 18.

<sup>121</sup> *Id.*

<sup>122</sup> *Id.*

<sup>123</sup> *Id.*

<sup>124</sup> *Id.* at 19.

<sup>125</sup> *Id.* at 18.

opportunity to take advantage of federal tax incentives for wind is soon closing, because Tax Credit for wind is a 30% tax incentive that is available for wind developers until December 31, 2016.<sup>126</sup> Since peak capacity is the area of greatest need, the Alliance suggests investments in DSM instead of a CT plant as the more cost-effective choice.<sup>127</sup>

The Advisors disagree with the assertion that the construction of an appropriately sized CT is not necessary and would preclude the pursuit of cleaner, cheaper resources. While the Advisors do agree that there may be a more beneficial combination of renewable resources, demand-side management and a new CT resource than what is proposed for the preferred portfolio in the draft IRP, the Advisors do not agree that renewable resources and demand-side management alone can solely address the reliability needs of the city and the need for rapid storm recovery capability.

The Advisors recommend that the Company be required to re-evaluate its decisions regarding renewable resources and the appropriate level of DSM, as discussed above, and to size a new CT accordingly.

## 2. *Union Power Block 1*

The Alliance argues that after the Council's resolution to consider the purchase of the 500 MW of Union Power Station in Arkansas, the planning reality for ENO changed considerably, and along with changes to ENO's options as a result of the dissolution of the System Agreement, materially affects the long-term planning modeled in this draft IRP.<sup>128</sup> The Alliance argues that this is a draft produced at considerable expense in response to a Council order, while actual resource planning is conducted outside the proceeding.<sup>129</sup> The Alliance claims that the IRP does not capture the real costs associated with the circumstances of the company, and does not meet the requirements set forth in the IRP order.<sup>130</sup>

GNOHA argues that the acquisition of the Union plant should go through the same process as the IRP – *i.e.* ENO and the Council should rigorously and fairly assess the investment on the basis of present value of future revenue requirements from customers, and the investment should be compared against alternatives, including demand-side investments on a per kWh basis.<sup>131</sup>

The Advisors note that subsequent to the comment deadline for Intervenors, the Company filed IRP Updates that incorporate the proposed Union Power Block 1 purchase. The Advisors note that the IRP process does not typically drive any

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<sup>126</sup> *Id.*

<sup>127</sup> *Id.* at 21.

<sup>128</sup> *Id.* at 18.

<sup>129</sup> *Id.*

<sup>130</sup> *Id.* at 19.

<sup>131</sup> GNOHA Comments at 4.

specific resource acquisition, rather it creates a guideline for the utility to follow when making resource decisions. Any specific resource acquisition still needs to be submitted to the Council and thoroughly vetted. Such is the case with Union Power Block 1. The opportunity to purchase Union Power Block 1 did not arise, and could not have been anticipated, until somewhat late in the IRP stakeholder process and the Advisors are satisfied that the Company has revised its draft IRP to reflect to proposed acquisition in a timely manner. The goal of the IRP process is to create a plan that is flexible enough to allow the Company to respond to unanticipated opportunities and changes in the market.

### 3. *Load and Energy Forecasts*

The Alliance notes that Entergy's peak load forecast shows growth, which is inconsistent with recent declines in the peak load.<sup>132</sup>

The Advisors agree that the Company's load and energy forecasts are outdated and should be revised. EAI performed additional sensitivity analysis on energy cost based on updated information on future supply additions available in EAI's system.<sup>133</sup> ENO should similarly perform additional analysis as well to reflect changes on current load and energy forecast for ENO's 2015 IRP. The additional analysis should include:

- a. Net energy metering (NEM) amount consistent with the amounts shown in ENO's report on Examination of Opportunities for and Effects of Consumer-Based Renewable Technologies in the City of New Orleans on NEM.
- b. The load and energy forecast should agree with the forecast used in the most recent Business Plan. (Not disclosed)

The Advisors also note that the draft IRP excluded the west bank (Algiers) even though the transaction was announced in the Algiers rate case AIP on June 20, 2014 and the Milestones in the IRP process started on June 27, 2014.

### 4. *AURORA Model*

The Alliance argues that the AURORA model is biased towards capacity growth, which is why DSM, solar and wind do not perform as well in the modeling.<sup>134</sup> The Alliance argues that a different model, such as the PLEXOS model used by SWEPCO should be considered.<sup>135</sup>

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<sup>132</sup> Alliance Comments at 22-23.

<sup>133</sup> Reported in EAI's response to stakeholders groups' ("SG") request for additional information and analysis on September 3, 2015.

<sup>134</sup> Alliance Comments at 24-25.

<sup>135</sup> *Id.*

The AURORA modeling inputs the Company used for DSM program cost and corresponding kW/kWh reductions need further substantiation and comparison with other references of DSM costs and reductions. Examples of other references include EAI's 2015 IRP and other Entergy Operating Companies, and other credible sources of DSM costs.

The Advisors find no compelling reason that ENO should not use the AURORA model for the IRP process. No deficiencies are evident that are inherent within the AURORA model, which has been used successfully by several major national utilities in their integrated resource planning. However, the focus or objective of the AURORA modeling shifted from the Company's purpose of supporting customer needs as a vertically integrated utility to the utility responding to the MISO market economics and requirements. The focus of the AURORA modeling should be on supplying resources to ENO customers (determined by long-term optimization of resources) while selling any resulting short-term excess to the market. The Company's use and construct of the AURORA model drove the selection of a CCGT-based preferred resource portfolio due to a credit from excess energy sales in the MISO market, regardless of ENO actual customer needs.

#### 5. *Resilience*

The Alliance argues that grid hardening and resilience is currently absent.<sup>136</sup> The trend of increasing storm severity is completely ignored in the resource planning, and will be of significant future cost to ratepayers if ignored.<sup>137</sup> GCE argues that the City's goals, as embodied in the "Resilient New Orleans: Strategic Actions to Shape Our Future City" report released August 10, 2015 should be incorporated into the IRP.<sup>138</sup>

The Advisors recommend that the Company review the "Resilient New Orleans: Strategic Actions to Shape Our Future City" report and identify any elements of that report that might be appropriate for inclusion in the IRP.

#### 6. *Energy Storage*

BSI argues that ENO failed to include batteries in the model despite the fact that batteries were already price competitive at the beginning of the IRP process and have dramatically declined in price in the past year.<sup>139</sup>

The Advisors recognize that electricity storage, including utility-scale storage, is becoming increasingly affordable. The Advisors are aware that ENO currently has a project exploring the pairing of storage with solar, and the Advisors encourage ENO

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<sup>136</sup> Alliance Comments at 15.

<sup>137</sup> *Id.*

<sup>138</sup> GCE Comments at 3.

<sup>139</sup> BSI Comments at 2.



to consider evaluating and exploring the feasibility and affordability of electricity storage solutions.

### 7. *Risk Analysis*

BSI argues that ENO has failed to perform an industry-standard risk analysis.<sup>140</sup>

The Advisors agree that the Company failed to provide a risk assessment of the type described in Component 3, item number 15 of the Electric Utility Resource Planning Requirements of the Council of the City of New Orleans (“Council IRP Requirements”). The sensitivity analysis provided was insufficient with respect to all new supply sources relying solely on natural gas. The Company also failed to provide annual results for each of the 32 cases detailed as described in Component 3, item number 16 of the Council IRP requirements.

### 8. *Rate Structure/Revenue Recovery Methodology*

BSI recommends revision in rate structure in order to stimulate DSM which will work together, help finance each other and close the supply/demand gap within a few years.<sup>141</sup> BSI believes that either (1) incentivizing much more robust, extensive, and cost-effective energy-efficiency retrofits; (2) incentivizing the installation of better energy storage systems in every building; or (3) incentivizing and providing legislative support for Community Solar could displace 300 MW of peak demand in 5 years.<sup>142</sup>

BSI also argues that the Council should replace decreasing block rates with increasing block rates for residential customers and increases in the peak demand charges for other customers, as well as a menu of targeted, performance-based rates.<sup>143</sup> BSI states the cost of the rebate program need not exceed 5% of what ENO projected to spend for the proposed solar option.<sup>144</sup> BSI argues this will empower the marketplace to close the gap.<sup>145</sup> BSI submits that the marketplace will do it faster and cheaper than ENO’s proposal.<sup>146</sup> BSI urges the Council to then use the extra income from these rate increases to first completely fund the rebates and then lower the cost of energy for consumers whose consumption is limited to the first block within the rates.<sup>147</sup>

BSI argues that the Council should not pick the winner, or allocate or segregate resources among (1) subsidizing energy efficiency retrofits in buildings; (2) using

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<sup>140</sup> BSI Comments at 2.

<sup>141</sup> *Id.* at 4.

<sup>142</sup> *Id.* at 7.

<sup>143</sup> *Id.* at 5.

<sup>144</sup> *Id.*

<sup>145</sup> *Id.*

<sup>146</sup> *Id.*

<sup>147</sup> *Id.* at 6.

price signals to temporarily lower demand (demand response or “DR”); (3) subsidizing renewable energy installations; (4) subsidizing battery installations, (5) installing smart meters throughout the ENO building stock; (6) changing the rate structure from declining blocks to inclining blocks; (7) changing demand charges to “utility peak demand charges”; (8) customers earn a 50% demand charge discount if they buy into a solar farm or install a rooftop system sufficiently large to displace at least 30% of their annual consumption; (9) ruling that kWh's generated at a solar farm cannot be banked for future use, energy not consumed in a five-minute generation period is used to discount bills for low-income ratepayers, or set 10% to be allocated to low income; (10) facilitating solar farms on key lots and/or economically distressed real estate; (11) instituting a rebate schedule to incentivize reduction in peak demand; (12) providing a mechanism whereby any ENO customer can sell power quality services, *i.e.*, spinning reserve and/or frequency regulation, to ENO or MISO at competitive rates; (13) mandate that Real Estate Multi-listing services publicize energy ratings, if available; and (14) invite input by educational institutions, other industries, or NGO's to propose regulatory changes or rebates that can invite their services or further lower ENO's DSM costs.<sup>148</sup> BSI argues the Council should create a carrot and stick approach that applies graduated charge increases and rebates to engage and transform the marketplace.<sup>149</sup>

BSI supports decoupling by which ENO can earn a profit without investing in new power plants.<sup>150</sup> BSI wants ENO to earn more profit without adding new generating equipment.<sup>151</sup> Accordingly, BSI recommends (1) ENO should not be allowed to own new generating plants; instead (2) ENO should be rewarded for facilitating a future where the ratepayers of New Orleans have lower electricity bills, enjoy improved electricity outlet reliability, and use less fossil-fuel generated electricity.<sup>152</sup>

The Advisors are interested in the development of innovative rate structures, but such considerations are outside the scope of this proceeding. Rate structure alternatives, notwithstanding the demand response measures which are evaluated in the IRP process, should be examined and adopted through rate cases filed before the Council, the next of which is currently anticipated to be filed in 2018. Rate cases permit the Council to review the impact of changes to the rates and rate structures on customer bills. The Advisors also note that there are currently open proceedings regarding decoupling and net metering pending before the Council that would be appropriate fora to examine many of the issues identified by BSI.

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<sup>148</sup> *Id.* at 5, 7-8.

<sup>149</sup> *Id.*

<sup>150</sup> *Id.* at 6, 8.

<sup>151</sup> *Id.*

<sup>152</sup> *Id.*

## 9. 2012 IRP Action Plan

The use of 2012 IRP Action Plan as directed by R-13-363 should be carried through into the 2015 IRP. The Company has failed to explain how it is using the 2012 Action Plan relative to its purpose.

### D. Revising the IRP Analysis

The Alliance argues that the Council should require that significant substantive changes be made in the IRP before the final report is submitted for their approval.<sup>153</sup> The Alliance recommends the Council require the company to re-draft their IRP to address the deficiencies detailed in their comments.<sup>154</sup> GCE urges the Council to direct ENO to submit a new draft IRP within 30 days responding to the four deficiencies laid out in their comments and including a new section devoted to energy efficiency.<sup>155</sup>

BSI argues that draft IRP should be rejected and ENO should be directed to perform a new IRP utilizing a robust risk analysis similar to that performed by other utilities which takes into account:<sup>156</sup>

1. One alternative resource plan is to “build nothing”;
2. CO2 emission price in light of recent EPA Clean Power Plan announcement;
3. Economics of battery storage when grid installed vs. consumer installed;
4. Economics of PV when utility owned vs consumer owned; and
5. Economics of DSM in all four of its various forms:
  - a. Energy efficiency
  - b. Demand response
  - c. PV installations
  - d. Battery installations

BSI also offers the following recommendations to improve the IRP process (in order of importance):<sup>157</sup>

- Compensate intervenors when their contribution to a regulatory decision saves money.
- Mandate that the IRP process has complete transparency.

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<sup>153</sup> Alliance Comments at 2.

<sup>154</sup> *Id.*

<sup>155</sup> GCE Comments at 4.

<sup>156</sup> BSI Comments at 3.

<sup>157</sup> *Id.* at 6.

- Mandate that the IRP process is dynamically responsive to changes in fact.
- Mandate that the IRP conforms to industry standards in IRP quality including, but not limited to risk analysis.
- Mandate that an independent third party produces the analysis, runs the meetings, and collects and publishes information.
- Provide for a minimum test for passing or failing the IRP process.

The Advisors agree that the draft IRP needs to be revised in several respects, as discussed herein. However, the Advisors oppose starting this triennial IRP process over entirely from the beginning. The Company and many stakeholders have invested a significant amount of time, energy, and resources in the development of the draft 2015 IRP. The Advisors recommend that the Company make as many revisions as possible prior to filing their final IRP Report with the Council in October, and seek such reasonable time if necessary to properly address the issues raised herein. Once the final IRP Report has been filed, the Council can issue a resolution establishing the further necessary procedural deadlines for its examination and consideration of the IRP report.

The Advisors note that several of the points suggested by BSI are already contained in the Council's IRP Requirements, which require an IRP consistent with industry standards and open for public review that provides for flexibility to respond to unanticipated/unlikely market scenarios that may arise. The Advisors do not recommend that the Council compensate intervenors for their comments or require a third party to perform the IRP analysis.

**CERTIFICATE OF SERVICE**  
**Docket No. UD-08-02**

I hereby certify that I have this 25th day of September, 2015, served the required number of copies of the foregoing report upon all other known parties of this proceeding, as listed below, by email.

s/ *Jerry A. Beatmann, Jr.*

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