Alliance for Affordable Energy
Review of Entergy New Orleans IRP

Introduction

On October 9, 2012, Entergy New Orleans (Entergy or ENO) provided a draft of its 2012 Integrated Resource Plan (IRP) to the Alliance for Affordable Energy (the Alliance) and the Council Advisors. This document represents the Alliance's review of that draft IRP, supplemented by information provided by ENO in connection with a series of meetings and conference calls regarding the IRP. Since ENO has chosen to designate all the documents it provided as Highly Sensitive Protected Information (HSPI), these comments will often refer to public documents released by Entergy Arkansas, Inc. (EAI) in connection with its 2012 IRP. The secret ENO IRP methodologies do not depart significantly from the public EAI methodologies.

The ENO IRP exhibits a number of problems, which collective substantially decrease its value as a planning tool for the City Council. Those problems can be grouped under two headings, as follows:

- understatement of cost-effective energy-efficiency potential;
- overstating the costs of wind power.

The next two sections discuss these two groups of problems.

Understatement of Cost-Effective Energy-Efficiency Potential

Entergy New Orleans understates the amount of energy efficiency that would be cost-effective to include in its IRP in three ways:

- understating potential customer participation,
- understating the benefits of energy-efficiency in the xx process,
- screening out energy-efficiency found to be cost-effective in the screening phase by a use of a non-standard screening test in the xx phase.

Understating Participation Potential

In its analysis of energy-efficiency potential for Entergy, the consulting firm ICF assumed severe constraints on potential participation, using the following three mechanisms:

- low ceilings on the percentage of customers that will accept high-efficiency equipment, regardless of incentive levels or quality of the program design;
- further steep reductions in acceptance for any measure with payback longer than instantaneous for non-residential customers and longer than a year for residential customers; and
- long ramp-up periods.

Remarkably, ICF does not link its participation forecasts to program design, other than an estimate of the effect of higher incentives. In reality, by providing the right kinds of services and incentives to the right parties (e.g., customers, landlords, architects, building engineers, HVAC contractors, dealers, and distributors), a well-designed program can achieve savings greater than those of Entergy's high case without always offering such high incentives. Entergy's high case is achievable and cost-effective and should be considered a minimum case for all subsequent resources analysis. As explained below, even the high case radically understates the efficiency potential.

Low Acceptance Ceilings

Energy Arkansas provided only one detailed example of ICF's participation methodology, for the installation of a high-efficiency central air conditioner when an existing unit is replaced in a single-family home. In that case, ICF assumed that only 30% of customers would ever accept the high-efficiency unit under any incentive. ICF refers to this input assumption as the Program Market Acceptance Rate, although the assumption is not a function of program design. ICF provides no basis for this value, for which it can cite no source other than "ICF program assumption." ICF maintained that did not assume any particular program design, so the assumption is really about customer reactions to a technology, rather than to a program. It is possible that ENO could design programs so complicated and annoying that 70% of customers would reject the more efficient air conditioner or water heater that was otherwise indistinguishable from the standard unit, even if there were no difference in cost, but that is a completely unrealistic scenario. With proper program design, HVAC contractors, dealers, and distributors find the high-efficiency units to be the most profitable to stock, sell, and install; customers have found that selecting the efficient units has no downside; and participation has been nearly universal.

Entergy apparently used Program Market Acceptance Rates below 30% for most residential measures and many non-residential measures. The acceptance rates appear to vary with sub-sector and sometimes end-use, rather than the barriers associated with specific measures (e.g., difficulty of retrofitting high-efficiency equipment, aesthetic concerns).

Payback-Based Reductions

Even after assuming that no energy-efficiency program could ever get a majority of customers to select equipment with higher-than-standard efficiency, Entergy and ICF chose to further adjust down acceptance rates to a remarkable degree. ICF developed "customer stated payback acceptance" curves, which purport to describe actual customer acceptance rates for various payback periods. The curves are estimate separately for residential and non-residential customers.

The residential curve is estimated from five data points, while the non-residential curve is estimated from 15 data points. Entergy presents three long-term projections of cost-effective energy-efficiency program savings, for low, reference, and high incentive levels, corresponding to incentives that bring payback to three, two and one year, respectively.

For a one-year payback (essentially a 100% internal rate of return), ICF reports that over 90% of residential customers will accept the efficient technology, but that only 68% of non-residential customers would do so. ICF does not identify the source of the data, so it is not clear what program (if any) produced such low acceptance for such extraordinary return. For a two-year payback, ICF estimates that the payback acceptance would drop to 68% for residential customers and 44% for non-residential customers.

These payback acceptance curves appear to contradict ICF's assumption that only a small percentage of customers will participate in most programs. After all, if ICF has observed 90% acceptance with a one-year payback, that seems to belie the claim of an arbitrary 30% acceptance ceiling.

With a 30% Program Acceptance, these payback-acceptance assumptions result in only about 20% of residential customers and 13% of non-residential accepting high-efficiency equipment. Table 1 summarizes the effect of ICF's two-part limitation on efficiency potential.

Table 1: ENO Market-Share Computations

Case	Payback (Years)	Payback Acceptance	Program Acceptance	Maximum Market Share
Residential				
Low	3	51%	30%	15%
Reference	2	68%	30%	20%
High	1	91%	30%	27%
Non-Residential				
Low	3	28%	30%	8%
Reference	2	44%	30%	13%
High	1	68%	30%	20%

Using the ICF's payback acceptance curves without the arbitrary and undocumented acceptance ceilings would result in potential estimates several times higher than ENO has assumed. Those larger achievable savings, if ENO were to pursue them, would greatly reduce the need for additional supply resources.

Long Ramp-Up Periods

Even after two rounds of arbitrary and unrealistic reductions in potential, ICF assumes that program acceptance will be further reduced over many years, due to the need to phase in some factor in program participation (customer acceptance of equipment that looks and works just like standard equipment, but uses less energy? ENO's ability to communicate with its customers?) In the public example, ICF posits an eight-year phase-in and assumes that even a one-year payback cannot encourage more than 4.1% of customers who are replacing their air conditioner to select the more-efficient model in the first year of the program.

Entergy has not provided the basis of these long ramp-up periods, or the shape of the ramp-up over time. The first-year ramp-up is described as an "ICF program assumption," and ICF provides no basis for the ramp-up shape. These very slow acceptance patterns are inconsistent with experience in other jurisdictions that have implemented effective programs.

Understating Energy-Efficiency Benefits

Generation Capacity Value

The ENO Draft IRP shows no avoidable generation resource additions for ENO until 2020, when its 171-MW share of the Amite South CCGT would be added (Table 13). In the Optimization process (discussed further in the next section), ENO limited the value of capacity avoidable by DSM:

> Since ENO DSM was being tested, supply-side resource addition changes were limited to the Amite South DSG Sub Area (the sub-area which includes the City of New Orleans)…. In the case of Scenario 1, there was no change in supply-side Resources additions between the No DSM case and the DSM Flight #5 case. (p. 30)

In other words, ENO gave DSM no credit for avoiding any supply-side resource in the reference scenario through 2031, and it is not clear that any DSM ever got any credit for avoiding supply. At best, in some of the side scenarios, DSM may have been credited with avoiding any capacity in 2020 or later.

This modeling is clearly biased against DSM, since ENO can sell excess capacity off-system, the other Entergy system companies need capacity starting immediately, and the Entergy System Agreement provides for payments by other system companies for any excess capacity that ENO may have.

Table 2 shows Entergy's projection of supply additions for the 4-Company (Texas and Louisiana) system, from Table 10 of the Draft System IRP. Some of the resources for 2013–2016 may be met with competitive suppliers for industrial customers in Texas, but Entergy needs more than 200 additional megawatts by 2017. In the face of this enormous capacity need, ENO's assumption that a few hundred megawatts of load reduction from energy-efficiency (plus avoided reserve requirements) is unreasonable.

Even if the Entergy system need no additional resources, ENO could reduce costs to its customers by reducing load and either selling the capacity to other utilities or getting a credit from the other Entergy companies for its excess.

Table 2: Supply Needs in Entergy System

	Need Anywhere	Need in Amite South
2013	115	
2014	115	
2015	115	
2016	115	
2017	333	
2018	1,503	
2019	1,883	
2020	1,386	570
2021	1,808	570

Transmission and Distribution Value

It is our understanding that ENO used avoided T&D costs of less than $22/kW-year in the screening of energy-efficiency; this value is far too low. Most estimates of avoided T&D costs are over $50/kW-year, and $100/kW-year would be more typical. Given the transmission constraints into the Amite South and Downstream of Gypsy areas, avoided transmission costs are likely to be higher for ENO than for Entergy as a whole.

Worse still, it does not appear that Entergy credits energy-efficiency with avoiding any T&D costs in the Optimization phase, when most of the energy-efficiency selected in the screening phase is eliminated.

Screening Out Cost-Effective Efficiency in Optimization

Normally, any energy-efficiency resources that pass the Total Resource Cost (TRC) test in the screening phase would be included in the final resource plan. An energy-efficiency resource with TRC benefits greater than its TRC costs will reduce total costs borne by utility ratepayers and should thus be implemented.

ENO started following the normal approach, identifying cost-effective energy-efficiency resources using the TRC. While ENO grossly understated the energy-efficiency potential, by understating potential participation, the identified cost-effective reductions in energy and peak demand are considerable. At that point, ENO developed a novel trick to throw most of the cost-effective energy-efficiency out of the IRP.

Rather than adjusting the load forecast downward by the amount of the cost-effective energy-efficiency resources, and selecting supply resources to fill in any deficiencies, ENO used the Program Administrator test (which treats the incentive as a cost) to weed out energy-efficiency portfolios that include incentives above the low level. This manipulation of the IRP process is documented in the "Portfolio Optimization Process" section of the Draft IRP.[1]

In three of ENO's scenarios, ENO accepts the low-incentive, low-savings levels of DSM bundles 2 and 4 (included in DSM Flight 5) and rejects any upgrade to reference or high savings levels. In the Green Growth scenario, ENO upgrades bundles 2 and 4 and includes the low level of DSM bundle 5 (reaching DSM Flight 11).[2] These resource decisions make no sense. In terms of the total costs and benefits, the reference and high levels of any bundle would be more cost-effective than the low level of the same bundle, since the higher-savings options would have the same measure costs for each measure implemented, while the program overhead costs (administration, training of installers and trade allies, advertising) would be spread over more MW and GWh of savings. Yet ENO has arbitrarily chosen to cut off these programs at the low-incentive level, by counting the incentives as costs to ENO and not as benefits to the participants.

The ENO 2012 resource plan should include all the energy-efficiency savings identified for the high-savings case in bundles 2, 4, and 5 (the cost-effective programs). Future IRPs should correct the errors in the potential study and increase the energy-efficiency component accordingly.

Overstating the Costs of Wind Power

The IRP overstates the costs of wind energy in at least four ways. First, Entergy estimates an $87.64/MWh direct cost for wind energy installed in 2012 at a 39% capacity factor (2012 Generation Technology Assessment: Generation Technology Cost & Performance, January 2012 Update, p. 73), which is much higher than the

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[1] With respect to DSM, this section actually de-optimizes the resource plan, by removing cost-effective resources previously identified.

[2] Bundles 1 and 3 consist of load control measures, while bundle 6 does not pass ENO's TRC test.

costs reported by neighboring utilities. According to the DOE (2012 XX), contracts for wind power signed in 2011 for projects in the "wind belt," which includes Oklahoma, Missouri, Texas and Kansas, averaged \$32/MWh, with some projects as low as \$28/MWh. Without the Production Tax Credit, these projects would cost less than \$55/MWh. Turbine costs continue to fall, according to Zindler (2012 xx) of Bloomberg New Energy Finance, "because of excess capacity and new low-cost competitors."

Second, Entergy adds in \$34.01/MWh of a "Capacity Matchup Cost" (2012 Generation Technology Assessment, p. 73) to the cost of wind. While ENO does not appear to have provided an explanation of this component in this IRP process, Entergy did file an explanation in Arkansas ("Entergy Arkansas, Inc. response to questions from Stakeholders at the July 31, 2012 Integrated Resource Planning (IRP) Meeting," August 20, 2012, p. 3). The \$34.01/MWh represents Entergy's estimate of the cost of 0.95 MW of new combustion turbine capacity per MW of nameplate wind capacity. This cost, combined with the assumption that MISO will credit Entergy with 0.05 MW of firm capacity per MW of installed wind capacity, would result in each nameplate megawatt of wind capacity (with the additional combustion turbines) providing one MW of firm capacity credit. Entergy then compares the combined wind-and-combustion-turbine cost to that of a new combined-cycle plant at a 65% capacity factor (2012 Generation Technology Assessment, p. 73 xx Casey: I can get a non-HSPI cite from AEI, if you want). It appears that Entergy's computation is intended to supplement wind with enough combustion-turbine capacity so that the wind-CT combination provides the same reliability as a combined-cycle plant. This treatment contains at least the following three errors:

- The IRP does not reflect any benefits from the combustion turbines, such as energy margins when the market price of energy exceeds the fuel cost of the combustion turbine, or the value of operating reserves provided by quick-start combustion turbines.
- The cost of the combustion-turbine capacity is based on new construction, not the much lower cost of purchasing underutilized merchant combustion turbines.
- Entergy would add more CT capacity than needed to make bring a MWh of wind energy up to the reliability contribution of a MWh of CCGT energy. Every hundred gigawatt-hours of combined-cycle output at a 65% capacity factor would provide about 18 MW of firm capacity, while the same 100 GWh of the wind-CT

combination would provide 29 MW of firm capacity.[3] Reducing the capacity factor of the gas combined-cycle to the wind-CT capacity factor of 39% would increase the levelized combined-cycle by $23/MWh.[4] Adding just enough combustion-turbine capacity to make the two options equivalent (about 0.55 MW of CT per MW of installed wind) would similarly decrease the cost of the wind option by about $20/MWh.

Third, Entergy adds a "Flexible Capability Cost" of $14/MWh, based on assumptions that (1) more than half the gas capacity supplementing the wind capacity would be combined-cycle rather than combustion-turbine capacity and (2) that this combined-cycle capacity would operate inefficiently, apparently to provide spinning reserves for the wind. This computation is also flawed in several ways, including the following assumptions:

- that additional "flexible capacity" (which Entergy does not define) would be needed in 50% of hours,
- that the combustion turbines would not provide sufficient flexibility,
- that a requirement for some capacity service in 50% of hours equates to the need for combined-cycle capacity equal to half the wind capacity (i.e., that a time fraction can be converted to a capacity fraction),
- that the additional hypothetical combined-cycle capacity would be new construction, rather than the less expensive purchased capacity,
- that none of the profit from operating the additional combined-cycle capacity should be credited against the flexibility cost.

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[3] Producing 100 GWh from a CCGT would require 100 ÷ (8.76 × 0.65) = 17.6 MW. The wind-CT combination would be 100 ÷ (8.76 × 0.39) = 29 MW of wind (valued at about 1.5 MW of capacity) and 29 × 95% = 27.5 MW of CT.

[4]This 39% capacity factor would also be more realistic than the 65% or 90% capacity factors assumed in various parts of Entergy's analysis, since Entergy's combined-cycle plants have been operating at lower capacity factors. In 2011, the entire Entergy utility combined-cycle fleet (Ouachita 1–3, Acadia, Perryville and Attala) operated at an average 38% capacity factor.