Resource Insight, Inc.

Audubon Arkansas Comments

on Entergy's 2012 IRP

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1. Introduction

On July 31 2012, Entergy Arkansas, Inc. (Entergy) conducted a stakeholder meeting at which it presented a summary of its 2012 Integrated Resource Plan (IRP). Audubon Arkansas attended that meeting, which was held in Little Rock. These comments are Audubon Arkansas's response to that presentation as supplemented by Entergy's responses to questions.

Several aspects of the IRP are laudable, including the recognition that Entergy has substantial and continuing energy-efficiency potential and that new coal and nuclear plants are not viable resources over the planning horizon. Unfortunately, the IRP embeds five groups of errors that substantially decrease its value as a planning tool for the Arkansas PSC and other parties. Those five groups of errors are as follows:

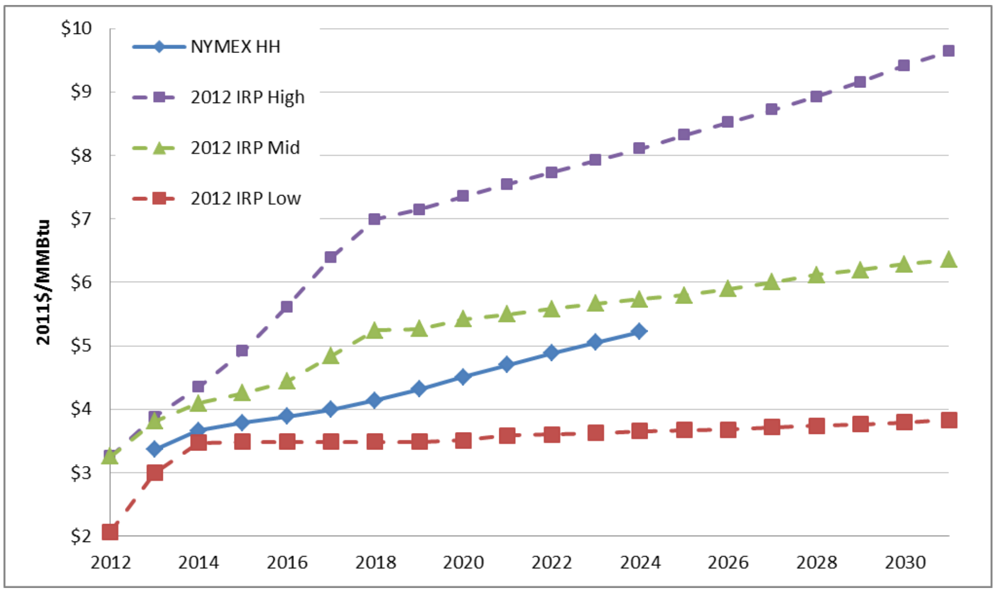
- significant overstatement of likely future gas prices;
- continued understatement of energy-efficiency potential and the benefits of gas conservation;
- failure to conduct economic analysis of the following four resource decisions assumed in the IRP:
    - continued operation of Entergy's coal plants,
    - transfer of wholesale baseload capacity to retail service,
    - retirement of several hundred megawatts of gas-steam and combustion-turbine capacity,
    - transfer of wholesale peaking capacity to retail service;
- ignoring the option of purchasing existing modern gas-fired power plants from merchant generators;
- overstating the costs of wind power.

The next four sections discuss these four groups of problems, in order. Before the IRP is used to support any resource decision, these problems should be corrected.

2. Overstatement of Future Gas Prices

Natural-gas prices affect many important resource decisions, including whether to refurbish Entergy Arkansas's existing gas steam units and whether to spend hundreds of millions of dollars to keep the White Bluff and Independence coal plants in operation. The mid-range Henry Hub gas prices used in Entergy's IRP are considerably higher than current futures prices; see Figure 1.[1] Through 2019, the futures prices are closer to Entergy's low prices than its mid-range prices.

Figure 1: Entergy and Henry Hub Natural Gas Forecasts and Futures



Both the NYMEX market participants and Entergy's forecasting staff attempt to capture much the same set of considerations (resource potential, changing technology, environmental regulations, demand from consumers, power generation, and exports). However, it is important to recall that the NYMEX prices are real prices, produced by the combined projections of a large number of partici-

[1]The nominal futures prices traded on the NYMEX exchange are deflated at 2% to 2011, for comparability with the Entergy's (2012a, 10) forecasts. References to the IRP, not released as of the writing of this memo in September 2012, refer to Entergy's description of the plan in various presentations and documents.

pants, rather than the opinions of a small group of Entergy employees. Market participants lay out actual money on the accuracy of their expectations, with strong incentives not to overpay or undercharge, while Entergy's forecasters are paid to produce text and tables, not financial results.

If market participants, or anyone else with funds to invest, believed that the Entergy gas-price forecast was really more dependable than the NYMEX futures, they would make their decisions based on that forecast. In the current situation, those smart gas users and speculators would lock in all the gas they might conceivably want through the futures market, while the smart sellers would refuse to sell at those prices. The speculators would experience large gains, the net buyers would save large amounts of money, and sellers would increase their revenues. Market participants would flock to follow the advice of those prescient forecasters.[2]

With all that buying and little selling, futures prices would rise toward the forecast prices, eliminating the price differentials and the opportunity for windfalls. It does not appear that most market participants have been convinced that Entergy's forecasts provide any significant information about the direction of future gas prices.

While fuel-price forecasts are simply opinions, market prices can be turned into hedges, locking in current forward prices for future delivery. Hence, if Entergy decided that it wanted to build a gas plant in 2016, it could lock in gas prices for several years through the futures markets or similar contracts. Entergy cannot lock in its forecast prices.

The futures market is particularly valuable for updating price forecasts in periods of rapid change in underlying factors. Futures for the out years (2015 and beyond) fell steadily from early 2011 through April 2012, and have traded in a narrow range since. The Entergy forecast may have been developed prior to April 2012, in which case the Entergy forecasters would not have all the information available to the market.

[2]Forecasters who claim to know better than the market are often asked, "If you're so smart, why aren't you rich?"

3. Understatement of Energy-Efficiency Potential

Entergy Arkansas presents three long-term projections of cost-effective energy-efficiency program savings, for low, reference, and high incentive levels. The projected incremental annual savings from the high portfolio (which includes paying incentives that result in one-year paybacks for efficiency investments) are 1.2% annually by 2016, and higher percentages in later years (Entergy 2012b, 21).

The ICF analysis from which this projection was derived (described by Entergy 2012b, 54–59) does not recognize the effect of program design on customer acceptance, other than through 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 the basis of all subsequent resources analysis.

While Entergy's high-case projection of efficiency gains is impressive, the ICF study actually underestimates the potential by including some assumptions that unrealistically depress energy-efficiency potential. So while the ICF study for Entergy shows that at least 1.2% annual efficiency gains are possible, that study should be taken to establish the minimum that Entergy could likely achieve, not the maximum.

3.1. Treatment of Gas Savings

Entergy's analysis understates the cost-effectiveness of programs that would save both electricity and gas in two ways. First, the analysis ignores all gas-only measures that could be delivered through potentially comprehensive programs, such as Home Energy Solutions (Entergy 2012b, 36; Response 3-15). Once contractors are at the home (or commercial building), they can implement measures that save gas, producing additional net benefits to offset the fixed costs of the site visit, the initial audit or inspection, and other program costs. Since Entergy intends to increase "coordination with over lapping gas utilities" (Entergy 2012b, 51), the programs will include gas-only measures, in addition to measures that save electricity.

Second, Entergy understated the benefits of measures that save both gas and electricity by using an avoided gas cost of "$0.386/ccf in 2011 and escalated at 2.0% per year" (Response 3-15). This is about $3.77/MMBtu in 2011 dollars. Both Entergy gas-price forecasters and the NYMEX market participants are expecting prices much higher than $3.77/MMBtu in 2011 dollars within a couple years (see Figure 1). Since most gas at retail is used in the winter, when prices are higher than the average over the year, and since gas utilities need to maintain reserve capacity for extreme cold snaps, the avoided retail gas cost should be considerably higher than the annual market prices shown in Figure 1.

3.2. Understatement of Potential Customer Participation

The ICF analysis 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;
- long ramp-up periods.

Low Acceptance Ceilings

In the presentation, Energy Arkansas provided only one detailed example of ICF's methodology, for the installation of a high-efficiency central air conditioner when an existing unit is replaced in a single-family home.[3] In that case, ICF assumed that only 30% of customers would ever accept the high-efficiency unit ("Program Market Acceptance Rate" in Entergy 2012b, 56). ICF provides no basis for completely unrealistic value, for which the source is described as "ICF program assumption." With proper program design, HVAC contractors,

[3]In Response 3-16, Entergy acknowledges that the example provided in its DSM presentation (Entergy 2012b) used the wrong payback-acceptance curve, using the non-residential curve for a residential measure. These comments discuss that example because it is the only publically available example of the ICF-Entergy approach.

dealers, and distributors will find the high-efficiency units to be the most profitable to stock, sell, and install, and participation will be nearly universal.

Even though Question 3-16a asked for the "spreadsheets shown in Appendix A, for all measures," which would include the program market acceptance rate for each measure, Entergy did not provide those rates. Instead, it provided the post-incentive payback (from which the "payback acceptance" discussed in the next section can be computed) and "Maximum Annual Market Share (S_{max})," which is the product of the Program Market Acceptance Rate and the payback acceptance.[4] Backing out the Program Market Acceptance Rate indicates that Entergy used rates below the 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

To make matters worse, ICF assumed that even its feeble 30% ceiling on program market acceptance ceiling would be reduced by the refusal of 32% of residential customers to accept the efficient unit with a one-year payback (Entergy 2012b, 56, "Customer stated payback acceptance" of 68%). That estimate is based on some sort of curve-fitting exercise, using 15 data points, only 3 of which represent paybacks of less than two years (Entergy 2012b, 55). ICF does not identify the source of the data, so it is not clear what program (if any) produced such low acceptance for an investment with a 100% internal rate of return.[5] Nor does ICF explain how a supposedly observed 68% acceptance can be consistent with its arbitrary 30% acceptance ceiling. In any case, ICF combines its 30% acceptance ceiling with its 68% "payback acceptance" to set a maximum market share for the efficient air conditioner of 20.4% (Entergy 2012b, 56), which is even less realistic than its 30% ceiling.

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[4]These data are provided in the HSPI Addendum 1 to response 3-16a (Entergy 2012c). Contrary to Entergy's claims, that addendum contains no information whose release would "result in competitive damage to Entergy, ultimately causing harm to Arkansas retail ratepayers" (Confidential Information Cover Sheet for response 3-16 Addendum 1). Entergy does not compete with any other party in providing ratepayer-funded energy-efficiency programs to ratepayers, the data would not be useful to any such competitor (not least because much of it is clearly incorrect), and to the extent that some party used it to offer improved energy-efficiency services to ratepayers, that would benefit Arkansas retail ratepayers rather than harm them. The likeliest explanation for the HSPI designation is that Entergy is embarrassed by the poor quality of its analysis and wishes to limit circulation of that information.

[5]Perhaps ICF chose data from a program that required the customer to do most of the work of designing and implementing the measures, or that required changes in the appearance or operation of the participant's building or equipment.

Audubon's Question 3-16c asked Entergy to "Please provide the source documents for the observed data points" for the payback-acceptance curve in Entergy (2012b, 55) and specifically to describe the program designs used in each of the program underlying the observed data points (since poor design would suppress participation) and whether the raw data were adjusted to reflect the "Program Market Acceptance Rate" ceiling.[6] Unfortunately, Entergy failed to respond to this question, so the Commission cannot determine whether ICF correctly measured the input data for its payback-acceptance curve.[7]

Long Ramp-Up Periods

Even after two rounds of arbitrary and unrealistic reductions in potential, ICF imposes an eight-year phase-in of the constrained ultimate program acceptance (Entergy 2012b, 56, 57). ICF 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.

Entergy declined to respond to the question "Would ramp-up faster than 5 years be 'achievable'?" (Response 3-16f).

In the HSPI spreadsheet attached to Response 3-16, Entergy reveals that it used a different ramp-up pattern than in the example, but with a similarly long ramp-up period.

[6] Since ICF uses the payback curve to adjust downward its "Program Market Acceptance Rate" ceiling, the payback curve should be computed relative to ICF's assumed ceiling. For example, if the Acceptance Rate ceiling is 30% and the observed participation rate is 21% with a one-year payback, the payback curve point should be stated as 70%, so that 30% × 70% = 21%, as observed.

[7] The only portion of Response 3-16c that bears at all on the derivation of the payback curve is the statement that "Nothing changes in [the payback curve] due to anything in slide 56 [including the Program Market Acceptance Rate]," which certainly suggests that ICF should not be applying the Program Market Acceptance Rate.

4. Failure to Screen Planned Resource Decisions

The IRP assumes that Entergy will make the following resource decisions, without any economic analysis:

- continued operation of Entergy's coal plants,
- transfer of wholesale baseload capacity to retail service,
- retirement of several hundred megawatts of gas steam and combustion turbine capacity,
- transfer of wholesale peaking capacity to retail service.

4.1. Continued Operation of Coal Plants

Perhaps the largest issue facing Entergy in the next few years is the choice of whether to upgrade the White Bluff and Independence coal plants, to meet a number of environmental requirements. (Entergy 2012d). When asked how the cost of continuing to operate the coal plants under worst-case environmental requirements (high-effectiveness scrubber, selective catalytic reduction, baghouse, activated-carbon injection, high-performance screens, special handling of combustion wastes, etc.) compared to the costs of combined-cycle plants, Entergy responded as follows:

> For planning purposes, Entergy estimated the cost of adding environmental controls and continuing to operate the coal plants under a worst case scenario similar to those described in Docket No. 09-024-U. Entergy concluded from those analyses that it is reasonable to assume that Entergy's coal plants will continue to operate when compared to the cost of new CCGTs. Entergy recognizes that the outcome of this analysis is dependent upon input assumptions, including potential carbon regulation and future natural gas prices. (Response 3-6)

This response is not reassuring. In Docket No. 09-024-U, concerning the retrofit of White Bluff, Entergy made a number of errors, including the following:

- assuming unrealistically low costs for required environmental controls,
- using unduly high natural gas prices,
- ignoring the option of purchasing excess capacity,
- assuming that a replacement combined-cycle unit would operate baseload, rather than operating as economic, with much of the replacement energy coming from low-cost off-peak market purchases.

In the environmental area, Entergy made at least the following errors in Docket No. 09-024-U:

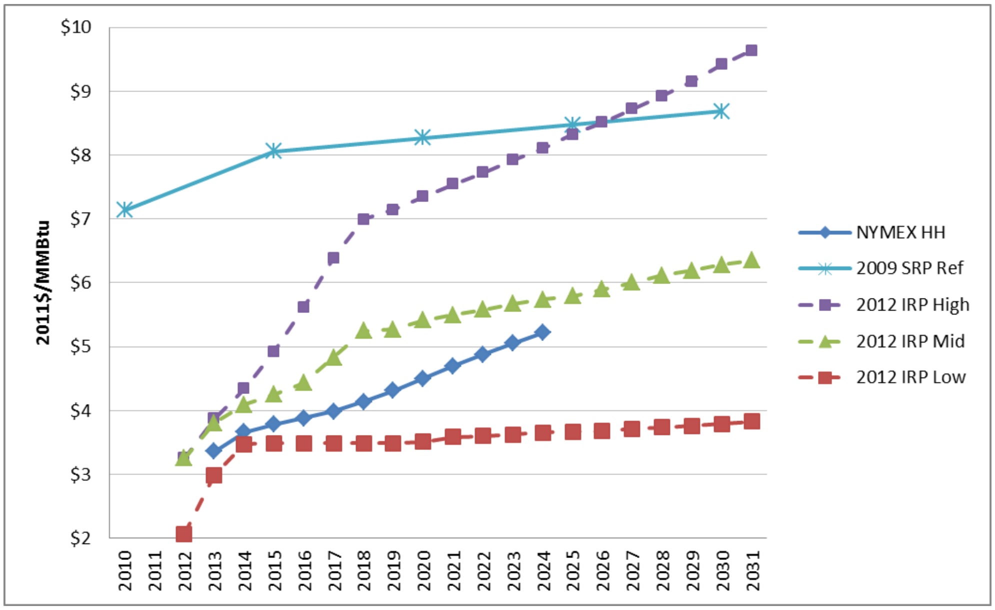
- understating the capital costs, operating costs and energy usage of selective catalytic reduction (SCR) for NOx control and sorbent injection for mercury control, in part due to errors in transcribing data from consultant reports;
- including the costs of 85% SO_2 removal, even though Entergy's own best-available-technology analysis assumed 92.5% SO_2 removal;
- assuming it could make do with installation of a dry scrubber, rather than a more effective and expensive wet scrubber;
- ignoring the cost of sorbent injection for control of sulfuric-acid-mist emissions.

Collectively, those corrections increase the net present value of coal continuation at White Bluff by hundreds of millions of dollars over the Entergy's estimate. If the errors were repeated in the analyses reported in Entergy's response, the costs of continuing to operate both White Bluff and Independence may have been seriously understated.

In the current IRP, Entergy appears to assume that compliance with the Cross-State Air Pollution Rule will allow it to avoid more stringent NOx control requirements under the BART standard of the Regional Haze Rule. This assumption leads Entergy to the conclusion that low-NOx burners will be adequate, and that selective catalytic reduction would not be required. As Entergy notes, the Rule is vacated (Response 3-5), leaving the Entergy coal plants vulnerable to meeting the stricter requirements under BART.

In terms of natural-gas prices, Entergy's analysis in Docket No. 09-024-U used price forecasts contemporaneous with Entergy's 2009 System Resource Plan. Figure 2 compares the reference gas prices from the 2009 SRP to the gas prices that Entergy (2012a, 10) projected in the 2012 IRP presentation. The 2009 reference-price forecast was greater than the current high forecast through 2025 and was more than $2.50/MMBtu greater than the current mid-range gas forecast through the forecast period.

Figure 2: Natural Gas Forecasts, Docket 09-024-U and Today



Revising the 2009 gas prices to current expectations would almost certainly eliminate any economic benefit from continued operation of the coal plants, even with optimistic assumptions about required environmental retrofits.

4.2. Transfer of Wholesale Baseload Capacity to Retail Service

For the IRP, Entergy (2012e, 12) simply assumes that ratepayers would benefit from using the 286 MW of Wholesale Baseload (WBL) capacity being freed up in 2013 and 2014. Entergy Arkansas offers no justification for this assumption (Response 3-22). WBL comprises about 184 MW of Arkansas Nuclear and Grand Gulf, 22 MW of the Independence-1 coal unit, and 80 MW of the White Bluff coal plant (Castelberry 2012, Exhibit KWC-2).

In Docket No. 12-038-U, Entergy estimates that the levelized cost of WBL over 30 years would be $64/MWh (plus any carbon charges), compared to $83/MWh for a new gas combined-cycle plant (Castleberry 2012, Chart 2). This comparison is seriously flawed, in at least the following ways:[8]

[8]The input assumptions are summarized by Castleberry (2012, 23).

- The coal plants face major environmental retrofits. For some of those retrofits Entergy has no estimates, while for others Entergy's estimates appear understated, as discussed in Section 4. Several coal units of vintages similar to White Bluff and Independence (including units of neighboring utilities, such as PSO's Northeastern and SWEPCO's Welch 2) will be retiring early, to avoid the costs of environmental retrofits. Early retirement of the Entergy coal plants would increase the levelized cost of the WBL.
- The analysis assumes that all three nuclear units will operate through 2043. However, the operating permits for these plants expire in May 2034 for ANO 1, July 2038 for ANO 2, and November 2044 for Grand Gulf. Weighted by the WBL capacity from each unit, the average end of the operating license is December 2037, for a life of 24 years, six years less than Mr. Castleberry's assumed life for the WBL.
- Entergy's $1,524/kW estimate for the capital cost of the gas combined-cycle plant appears significantly overstated. The TVA recently completed the John Sevier Combined Cycle Facility in northeast Tennessee, with approximately 880 MW of summer net capability to the TVA system, for about $30 million less than its budgeted cost of approximately $820 million, or less than $1,000/kW. (TVA 2011 Form 10-K, 51; "TVA's John Sevier Combined Cycle Plant Begins Commercial Operation," TVA Press Release, April 30 2012).
- The analysis of the WBL alternatives ignored the option of purchasing combined-cycle, described in Section 4.4.
- The cost comparison assumes that "natural gas prices are $7.13/MMBtu (2014$) levelized over a 30-year period." The IRP's assumed gas prices, levelized in nominal terms, are about $6.30/MMBtu, about $5.30/MMBtu levelized in 2014 dollars (Entergy 2012f, 3) The $1.83/MMBtu cost difference, converted to nominally-levelized costs, would reduce the combined-cycle cost by about $16/MWh, over 80% of the supposed difference between WBL and combined-cycle costs. As shown in Section 2, the IRP gas-price forecasts appear to be high compared to long-term market prices.
- Entergy admits that "baseload [operation] may not necessarily be indicative of traditional CCGT operations," but computed the combined-cycle cost if it were operated baseload "to allow Entergy to evaluate the costs of new build options on a similar basis" (Castleberry 2012, note 10). This treatment seriously biases the analysis against combined-cycle plants, which operate only on-peak, allowing the utility to use lower-cost energy (e.g., wind,

nuclear, must-run steam) in low-cost hours. Entergy declined to provide any data on CCGT capacity factors in and around its territory (Response 3-17). In 2011, even with very low gas prices, Entergy's own Ouachita 1 & 2 combined-cycle plant operated at only an 18% capacity factor, and the entire Entergy utility combined-cycle fleet (Ouachita 1–3, Acadia, Perryville and Attala) operated at 38% capacity factor. In most hours, a combined-cycle-based baseload option would consist of purchasing low cost energy (or not selling low-value excess energy), resulting in much lower average costs per MWh than forcing a combined-cycle to run around the clock.

4.3. Retirement of Gas-Fired Generation

The IRP assumes that all the "approximately 1,000 MW of active gas/oil/diesel fired units" (or "legacy gas generation") "will be deactivated before the 2016 summer peak" (Entergy 2012g, 10) and that "approximately 422 MW (363 MW retail) of legacy generation will be deactivated by the beginning of 2014" (Entergy 2012h, 19). Continued operation of Lake Catherine 4 is considered as a potential resource addition (Entergy 2012h, 17).

The IRP simply assumes the retirement of that gas capacity, based on a very simplistic analysis (Entergy 2012c). That analysis assumes that life extension for the gas plants would require operation of the plant for all twelve months, even though they have historically operated only in the summer. Perhaps as a result, the analysis assumes fixed O&M expenses for some plants that are two or three times the historical cost of active operation and several times the cost of keeping the plants in reserve.

The analysis compares the (apparently overstated) costs of maintaining the existing gas plants with estimates of prices for short- and long-term purchases of peaking capacity, including purchases from other MISO regions. The IRP does contemplate some short-term RFPs as a contingency resource, but does not specifically project acquisition of the types of resources that Entergy projects will be less expensive than the existing gas plants.

While Entergy may be correct that some or all of the existing peakers could be cost-effectively replaced with purchases, the Commission should expect to see much more sophisticated analysis of any such proposal. Most importantly, Entergy should not (1) retire the peakers based on the assumption that they can be replaced with cheap outside peaking capacity and then (2) use those retirements to justify much more expensive resources, such as the acquisition of WBL or life extension for the coal plants.

4.4. Transfer of Wholesale Peaking Capacity to Retail Service

In its IRP, Entergy assumes it will "return the Wholesale peaking capacity to retail rate base" (Entergy 2012, 13). If Entergy's assessment of the peaking capacity is correct, nearly 80% of the capacity would be returned in 2014 (when Entergy expects a capacity surplus in any case) and retired in 2015, and another 10% would be retired by 2017. These transactions are not likely to be beneficial to ratepayers and should not be included in the IRP without specific supporting analysis.

5. Neglecting Option of Purchasing Existing Plants

The IRP assumes that acquiring additional gas-fired combined-cycle capacity would require building a new combined-cycle plant, at a cost of $1,395/kW in 2012 dollars. This is not realistic. Several thousand megawatts of combined-cycle capacity are owned by merchant generators in Entergy's territory and the well-interconnected neighboring Southwest Power Pool. Some of these are listed in Table 1 below. This capacity is generally not committed to serving load, and is sold in the spot market or under short-term contracts.

The two Arkansas plants, Pine Bluff and Union Power, are in the Entergy control area, as are Cottonwood and several additional plants in Mississippi and Louisiana.

Table 1: Merchant Combined-Cycle Capacity in the Southwest Power Pool or Entergy's Arkansas Territory

Plant and Owner	State	Summer Net MW
Oneta Energy Center[a]		
Calpine Central LP	Okla.	886
Dogwood Energy Facility[b]		
Dogwood Energy LLC	Mo.	449
Eastman Cogeneration Facility		
Eastman Cogeneration LP	Tex.	402
Green Country Energy[c]		
Green Country LLC	Okla.	263
Coughlin Power Station		
Cleco Evangeline LLC	La.	732
Kiamichi Energy Facility		
Kiowa Power Partners LLC	Okla.	1,178
Cottonwood Energy Facility		
NRG	Tex.	1,279
Pine Bluff Energy Center		
Pine Bluff Energy LLC	Ark.	192
Union Power Station		
Union Power Partners LP	Ark.	2,020
Total		7,401

[a] The 886 MW at Oneta Energy Center is net of a 200-MW sale to Southwestern Public Service Company (Calpine 2010 Annual Report at 66) through May 2019.

[b] The 449 MW at Dogwood Energy Facility is net of the recent sales of a total of 165 MW to municipal utilities

[c] The 263 MW at Green Country Energy is net of the 520 MW PPA with Public Service Company of Oklahoma that will be in effect from June 2012 through February 2022 (Exelon 10-K at 295).

Sales prices for some of the merchant combined-cycle gas plants that have sold in Arkansas, the Southwest Power Pool, and Texas in recent years are shown below in Table 2. These past sales provide some indication of the market value of combined-cycle plants. The average of the transaction prices in 2011 and 2012 was about $420/kW, or about $470/kW excluding the plants in the Electric Reliability Council of Texas territory. That price is a little over a third of the cost Entergy assumed for a new combined-cycle plant.

Table 2: Sales of Combined-Cycle Plants in and Around the Southwest Power Pool

Seller	Plant Name	State	Closing Date	Sold	Summer Capacity (MW)[a]	Acquirer	Purchase Price $M	Purchase Price $/kW
NRG Energy	McClain	Okla.	7/9/04	77%	377	Okla. G&E	$160	$425
CLECo	Perryville	La.	6/30/05	100%	831	Entergy LA	$170	$205
Central Mississippi Generating	Attala	Miss.	3/31/06	100%	500	Entergy MS	$88	$176
Calpine	Aries/Dogwood	Mo.	2/7/07	100%	677	Kelson	$234	$345
Cogentrix Energy	Ouachita	La.	5/4/07	100%	904	Entergy AR	$198	$219
Calpine	Acadia Energy	La.	8/17/07	50%	1,376	Cajun Gas Energy	$189	$137
GE Energy Financial Services	Green Country	Okla.	10/2/07	100%	904	J-Power USA Generation	$240	$265
Cogentrix	Southaven	Miss.	5/9/08	100%	904	TVA	$461	$510
Kelson	Redbud	Okla.	9/30/08	100%	1,338	Okla. G&E	$852	$637
Tennessee Valley Authority	Southaven	Miss.	10/6/08	70%	633	Seven States Power	$345	$545
Acadia Power	Acadia 1	La.	Feb '10	100%	580	CLECo	$304	$524
Kelson	Cottonwood	Texas	Aug '10	100%	1,279	NRG Energy	$525	$410
Entergy	Harrison	Texas	Dec '10	61%	550	East and North Texas Coops	$219	$654
PSEG	Odessa	Texas	1/13/11	100%	1,000	High Plains Diversified Energy	$335	$335
PSEG	Guadelupe	Texas	1/13/11	100%	1,000	Wayzata Investment	$351	$351
Acadia Power	Acadia 2	La.	4/29/11	100%	580	Entergy LA	$300	$517
Sequent	Wolf Hollow	Texas	5/13/11	100%	720	Exelon	$305	$424
Kelson	Magnolia	Miss.	Aug '11	100%	863	TVA	$436	$505
KGen Partners	Hinds	Miss.	2012	100%	520	Entergy AR	$206	$396
KGen Partners	Hot Spring	Ark.	2012	100%	630	Entergy MS	$253	$408
Kelson	Dogwood	Ark.	3/11	8.2% 12.3% 6.6%	50 75 40	MJMEUC Independence P&L Kansas Power Pool	$46	$613
GDF Suez	Hot Spring	Ark.	5/13/11	100%	641	AECC	$240	$374

[a]Summer capacity reported by owner or U.S. EIA.

In its subsequent studies (including the analyses of whether to continue operating the coal plants, and of whether to transfer the WBL capacity to retail use), Entergy should compare those costs to (among other alternatives) the market price of gas combined-cycle plants. That will be much lower than the $196/kW-year fixed cost used in the IRP analysis.

6. Overstatement of Wind Costs

The IRP overstates the costs of wind energy in at least four ways. First, Entergy uses estimates of the direct costs for wind energy ($63/MWh with incentives and $89/MWh without) that are much higher than the costs reported by neighboring utilities (Entergy 2012f, 3). According to the DOE (2012), 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) of Bloomberg New Energy Finance, "because of excess capacity and new low-cost competitors."

Second, Entergy adds in $34/MWh of a "Capacity Matchup Cost," representing 0.95 MW of new combustion turbine capacity per MW of nameplate wind capacity (Entergy 2012f, 3). 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. 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.
- The IRP apparently plans to supplement wind with combustion-turbine capacity to create a wind-CT combination that is as reliable as a combined-cycle plant. However, Entergy would add more CT capacity than needed for this purpose.

> Every hundred megawatt-hours of combined-cycle output at a 65% capacity factor would provide about 18 MW of firm capacity, while the same 100 MWh of the wind-CT combination would provide 29 MW of firm capacity. Reducing the capacity factor of the gas combined-cycle to the wind-CT capacity factor of 39% would increase the levelized combined-cycle by \$21/MWh.[9] 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 (Entergy 2012f, 3). 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.

[9]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, as discussed above on page 13.

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