Entergy Arkansas, Inc.
425 West Capitol Avenue
P. O. Box 551
Little Rock, AR 72203-0551
Tel 501 377 4457
Fax 501 377 4415

Steven K. Strickland
Vice President
Regulatory Affairs

October 31, 2012

Ms. Kristi Rhude
Arkansas Public Service Commission
P. O. Box 400
1000 Center Street
Little Rock, AR 72203

Re: APSC Docket No. 07-016-U
Entergy Arkansas, Inc. 2012 Integrated Resource Plan

Dear Ms. Rhude:

Consistent with Section 6 of Attachment 1 to the Arkansas Public Service Commission ("Commission") Order No. 6 – Docket No. 06-028-R Resource Planning Guidelines for Electric Utilities, Entergy Arkansas, Inc. ("EAI") submits the following: a) its 2012 Integrated Resource Plan (the "IRP"); b) the Stakeholder Report that was prepared in accordance with Section 4.8 of the Commission's Resource Planning Guidelines; c) the presentations made by EAI in connection with its July 31, 2012 Stakeholder Meeting; and d) EAI's responses to Stakeholder's questions at the Stakeholder Meeting.

Should you have any questions concerning this filing, please call me at (501) 377-4457 or Laura Landreaux at (501) 377-5876.

Sincerely,

/s/ Steven K. Strickland

SS
Attachments

c: All Parties of Record

Entergy

Entergy Arkansas, Inc.
2012 Integrated Resource Plan

October 31, 2012

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INTRODUCTION

This document describes Entergy Arkansas, Inc.'s ("EAI") long-term integrated resource plan ("IRP") for the period 2014 – 2023. This IRP represents a significant step, as it is the first IRP prepared for EAI operations outside of the Entergy System Agreement. EAI's process for preparing this IRP reflects the changes to EAI's planning processes resulting from its planning outside of the Entergy System Agreement. Whereas planning under the System Agreement was conducted with a view to the needs of all of the Entergy Operating Companies as a whole, EAI's development of the 2012 IRP focuses solely on the needs of EAI and its customers. Whereas an IRP developed under the System Agreement would be developed and reviewed under the guidance and direction of the Operating Committee, EAI's 2012 IRP was (i) developed by EAI's Resource Planning and Operations Staff, (ii) reviewed by EAI's Resource Planning and Operations Committee ("RPOC"), and (iii) approved by EAI's President and Chief Executive Officer, Hugh T. McDonald.

RESOURCE PLANNING OBJECTIVES

EAI has established a set of resource planning objectives to guide its development of this IRP. The planning objectives focus on four key areas: costs, risk, reliability, and sustainability. EAI's resource planning objectives are shown in Appendix A. These planning objectives were recommended by the RPOC and approved by EAI President and Chief Executive Officer, Hugh T. McDonald on May 16, 2012.

REGULATORY CONTEXT FOR EAI'S IRP

In 2006, the Arkansas Public Service Commission ("APSC") adopted an IRP rule requiring APSC-jurisdictional utilities to file an IRP at least every three years.[1] The rule required that utilities would immediately file their then-current resource plans. EAI met that obligation by filing the Strategic Supply Resource Plan ("SSRP") that was in place at that time. EAI's next resource plan was filed in 2009, and included the results and report of a stakeholder input process conducted for EAI's 2009 IRP, as well as a more comprehensive considerations of demand-side management ("DSM") and load control options.

For EAI's 2012 IRP, EAI implemented a modified approach to its stakeholder process from that taken for EAI's 2009 IRP. The modified approach sought to incorporate EAI's experience in its stakeholder process conducted for its Energy Efficiency ("EE") portfolio. This modified

[1] Order No. 6 in APSC Docket 06-028-R

approach included reviewing actual study results with stakeholders rather than high-level study assumptions and plans (as EAI did for its 2009 IRP). In July 2012, EAI conducted a lengthy stakeholder meeting during which EAI reviewed its preliminary study results, and then sought input from the stakeholders. Nearly 100 detailed questions were submitted by stakeholders, and EAI provided responses to those questions, following up with another open meeting in early September 2012 to allow stakeholders to ask clarifying questions on those responses.

PLANNING WITH UNCERTAINTY

Uncertainty is a given with long-term resource planning, as the APSC recognized in Order No. 9 in Docket No. 03-028-U:

> There are no absolutes – no guarantees – in the complicated process of long range generation planning – a process more often than not which attempts to see 10 to 20 years down the road. All any utility company can do is to make reasonable and informed assumptions about the future and test a range of outcomes based on those assumptions.[2]

For EAI, there are a number of changes to the manner in which EAI has operated its electric system that are being evaluated and/or implemented as EAI was developing its 2012 IRP, compounding the uncertainties that EAI must consider as its develops its IRP and the associated action plan. EAI provides additional details below on some of the key uncertainties and how the 2012 IRP addressed them.

Study Period

The study period for the 2012 IRP is the 10-year period 2014 – 2023. A 10-year period was used for a number of reasons. As explained in greater detail herein, significant changes to EAI's planning and operations framework (e.g., post-System Agreement operations) support a more concentrated focus on the near-term issues. The uncertainties surrounding these issues and their influences on EAI's resource needs and options render longer term IRP analysis (i.e., > 10 years) too speculative at this time. Given that adequate generation capacity appears available in the region for the next several years, and that EAI's IRP will be updated at least every three years, a 10-year study period was viewed as appropriate.

[2] Docket No. 03-028-U, Order No. 9 at 13.

Entergy System Agreement

For more than 60 years, EAI has planned and operated its resources as part of a larger integrated system – the Entergy Electric System.[3] EAI provided notice that as of December 18, 2013, it will terminate its participation in the Entergy System Agreement. Accordingly, EAI is planning for its resource needs when it will no longer operate under the terms of the System Agreement beginning December 19, 2013.

EAI's 2009 IRP noted a number of uncertainties associated with EAI's post-System Agreement operations, uncertainties that have a significant effect on EAI's long-term capacity needs. The 2009 IRP was based on the reference assumption that EAI must be able to operate on a standalone basis with a separate balancing authority after it ceases to participate in the System Agreement. However, the 2009 IRP also recognized that other arrangements are possible. Consistent with the 2009 IRP, and as explained in EAI's testimony filed throughout Docket No. 10-011-U, EAI was evaluating the potential for other arrangements for post System Agreement operations, including possible coordination agreements or reserve sharing arrangements with other utilities. As EAI noted, the result of any such alternative arrangement would tend to reduce overall resource needs for EAI as compared to standalone operations, and thus, EAI's 2009 IRP plan resulted in adequate resources to meet EAI needs under alternative assumptions.

EAI's Operations in MISO or as a Stand-Alone Entity

Although the future of EAI's post-System Agreement operations has become clearer than it was in 2009, a number of uncertainties remain regarding such operations. In Docket No. 10-011-U, EAI identified membership in the Midwest Independent System Operator ("MISO") Regional Transmission Organization ("RTO") as its preferred path to post-System Agreement operations, noting also that EAI was preparing a separate implementation path for operating as a stand-alone entity taking transmission service under the Entergy Open Access Transmission Tariff ("OATT"). As ordered by the APSC, EAI continues to preserve the stand-alone option, an option that will require a much greater amount of capacity to meet the same level of reliability. If EAI must prepare for the Stand-Alone option or is unable to join MISO by December 19, 2013, EAI's planning reserve assumption is 20%. Nonetheless, the 2012 IRP is premised on the planning assumption that EAI will be required to maintain a 12% planning reserve margin based on its annual peak load. The actual planning reserve margin that MISO will require as part of its Resource Adequacy Construct will be determined annually by MISO based on a loss of load expectation ("LOLE") analysis performed by MISO. The requirements may vary from year to year.

[3] Under the terms of the System Agreement, EAI and the Entergy Operating Companies are planned and operated as a single, integrated electric system.

EAI's Demand-Side Management Initiatives

An additional uncertainty associated with EAI's long-term resource needs stems from EAI's DSM efforts, particularly EAI's EE programs implemented pursuant to the APSC's directives. Since EAI submitted its 2009 IRP, there has been significant growth in EAI's EE and DSM programs and in the energy and demand savings produced by EAI's portfolio of programs. With the Commission's guidance, great strides have been made by EAI, as well as other utilities in Arkansas, to produce a significant increase in savings over a relatively short period of time. However, these advancements in DSM[4] require more attention be brought to the issue of how these results should be included in a utility's IRP. To understand the significance of this issue, it is helpful to contrast EAI's point of view for DSM in the 2009 IRP from the one taken in this IRP.

EAI's 2009 IRP included potential DSM based upon the 2009 DSM Potential study assuming a projected 221 MW of demand savings by 2023. These figures were based upon the consulting firm ICF International's ("ICF") estimates of market achievable potential, which were scaled down to approximately 75% of ICF's original estimates, and start dates were rolled forward from 2008. This was a conservative effort that recognized that EAI's start-up and expansion of programs would take some time to begin producing those potential results, and that a number of policy issues remained uncertain for EE in Arkansas. Accordingly, DSM was included in the 2009 IRP, but at a very conservative level, and with a cost (in nominal dollars) of $182 million over a 20-year period. EAI's projection of DSM achievements over a 10-year period was 178 MW of demand savings.

For the 2012 IRP, EAI had an additional DSM assessment study performed by ICF. For purposes of planning and preparing the 2012 IRP, EAI prepared estimates assuming that the APSC's established targets would continue to be imposed upon the utilities, leveling off at 1% savings and extending those savings out for the remainder of the 10-year study period. This methodology produced a significant reduction in demand forecasted for the planning period. The assumption of DSM from this assessment is nearly 700 MW of demand savings by 2023. Those are significant savings, coming at a significant cost, with the estimate that DSM spending at a level starting at $54 million for 2014, and increasing each year, with $77 million forecast for 2023. Overall, this assumes $750 million to be spent on DSM over the 10-year study period.

The 2012 results presented EAI's planners with a significant planning issue: should they assume 700 MW of demand savings, along with assuming the approval of $750 million of expenditures, for purposes of EAI's 10 year IRP assessment? As explained herein, EAI's planners determined

[4] DSM includes both energy efficiency and demand response, as provided in the Rules for Conservation and Energy Efficiency Programs.

the best approach was to assess this DSM assumption as a resource option to be specifically evaluated in this 2012 IRP.

EAI's Efforts to Secure Additional Capacity Resources

EAI's 2009 RFP described EAI's capacity deficit as one of the key challenges EAI needed to resolve for post-System Agreement operations, stating:

> *EAI's current portfolio of long-term resources is short of its reserve planning margin by about 589 MW, based on a 20% reserve margin. This deficit is growing with load. Absent the addition of resources, by 2014 – the time that EAI will terminate its participation in the current System Agreement – EAI's portfolio of long-term resources is expected to be 1,545 MW short of its planning reserve requirement, based on a 20% reserve margin*

As described extensively in Docket No. 10-011-U, EAI has been working for several years to address this current and future capacity deficit. EAI either has or is presenting the APSC with several requests associated with potential EAI capacity additions, the outcome of which will influence EAI's resource portfolio for its post-System Agreement operations. These include:

- Acquisition of the Hot Spring Plant – in Docket No. 11-069-U, the APSC has approved EAI's acquisition of the Hot Spring Plant and proposed Capacity Acquisition Rider. However, the closing of this transaction has been postponed while the U.S. Department of Justice continues its review of this transaction.

- Addition of the "EAI WBL" - In Docket No. 12-038-U, EAI has asked for the available wholesale baseload ("WBL") resources ("Available WBL Capacity") to be assigned to serve EAI's customers. The Available WBL Capacity represents a unique opportunity for EAI to acquire 286 MW of existing solid fuel capacity (about 2/3 nuclear capacity and 1/3 coal capacity) to serve EAI's customers. EAI has sought a decision from the APSC as to whether, on a life-of-unit basis, EAI can use those resources to serve its customers.

- Limited-term resources beginning in 2014 – EAI has been negotiating two limited-term PPAs, for a total of 795 MW of capacity, that are scheduled to commence on December 19, 2013, corresponding with EAI's transition to post-System Agreement operations. These resources were identified through a request for proposals conducted by EAI in 2011. Currently, one PPA has been executed and the other PPA is still being negotiated. The PPAs are contingent upon approval by the APSC of appropriate cost recovery. EAI has requested in Docket No. 12-038-U that the APSC determine whether the PPAs should be part of EAI's post-System Agreement resource plan and, if so, allow cost recovery by EAI for the two PPAs in a manner to be determined later.

- Hydro Peaking Capacity to Retail – EAI has approximately 10 MW of generating capacity from the Remmel Dam facility and the Carpenter Dam facility that is not in rate base. EAI plans to pursue APSC approval in the 2013 general rate case to use this capacity to service its customers.

For purposes of preparing the 2012 IRP, EAI utilized a planning assumption that these identified sources of capacity would be added to EAI's portfolio.

Future Availability of Existing Generating Units

Appendix B provides an overview of EAI's current active generation portfolio. Currently, EAI controls by ownership or long-term purchase contract approximately 5,100 MW of generating capacity. The generation mix includes approximately 2,285 MW of nuclear generation capacity, 1,209 MW of coal capacity, 1,528 MW of natural gas/oil capacity, and 94 MW of hydroelectric capacity. This generation varies greatly in age and efficiency. EAI's coal and nuclear generation was brought on line in the 1970s and 1980s and represents a supply of baseload energy at traditionally stable costs. The construction of two coal units each at the White Bluff Steam Electric Station ("White Bluff") and Independence Steam Electric Station ("ISES")[5] and two nuclear units at Arkansas Nuclear One ("ANO") was part of a strategy developed in the 1960s and 1970s to diversify the reliance on natural gas and fuel oil for generation. That effort was successful for EAI, with a significant amount of the electricity EAI supplies to its customers coming predominately from nuclear and coal generation. With the exception of the two Ouachita Plant combined cycle gas turbine ("CCGT") units EAI purchased in 2008, all of EAI's natural gas capacity is at least 42 years old. The oldest unit has been in service for over 62 years.

Developing the 2012 IRP required EAI to make assumptions about the future operating lives of generating units currently in its portfolio. Two key issues in this determination are the cost and effective date of future environmental compliance requirements and whether the investments needed to keep EAI's older gas fired units operating are economical compared to alternative capacity sources.

It is important to recognize that assumptions related to these uncertainties about operating lives of existing generating units are not actual decisions regarding the future investment in resources or the actual dates that generating units will be removed from service. Unit-specific portfolio

[5] EAI has an ownership interest only in ISES Unit 1.

decisions – e.g., sustainability investments, environmental compliance investment, or unit deactivations and/or retirements – will be made at the appropriate time and will be based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, and the cost of supply alternatives. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation and relative economics. EAI will retain the flexibility to respond to changes in circumstances up to the time that a commitment is required to be made.

Key environmental uncertainties include the requirements of rules still under development, their effective dates for compliance, the outcome of current litigation, congressional activity, and the possibility of extensions of the compliance deadlines. Another key uncertainty is the nation's long-term carbon policy. This lack of certainty adds complexity to IRP considerations. For purposes of its 2012 IRP, EAI's planning assumption is that investments will be made to install appropriate equipment at White Bluff Units 1 and 2 and at ISES Unit 1 to comply with the applicable environmental regulations and thus enable those units to continue to operate until the end of their anticipated life.

With respect to the continued operation of certain other units in EAI's portfolio, EAI has approximately 1,000 MW of active gas/oil/diesel fired units which are all at least 40 years old. Earlier in 2012, EAI conducted an assessment of this capacity, which was provided to the APSC on May 21, 2012 in Docket No. 11-069-U. Based on this assessment, EAI assumed in the 2012 IRP base case that all of its older natural gas fired generation will be deactivated before the 2016 summer peak, although actual decisions to deactivate units will be made on a unit-by-unit basis based upon the needs of customers and the economics of the units relative to available options at the time of the decision. This assessment also concluded that the Lake Catherine 4 unit should be evaluated for continued operation in this 2012 IRP. A portfolio which includes the continued operation of Lake Catherine 4 was developed, evaluated and is described below.

IRP ANALYSIS

Technology Assessment

The IRP process considers the range of alternatives available to meet EAI's planning objectives including the existing fleet of generating units, potential conventional generation resource additions, potential renewable generation resource additions, and DSM. The initial screening phase of the Technology Assessment reviewed the available generation and DSM options to identify technologies that merited more detailed analysis. Table 1 summarizes the results of the Technology Assessment for a number of technologies.

Table 1: Technology Cost Comparisons

Levelized $/MWh Over Expected Life of Resource[6,7] (Nominal$)								
		No CO_2			CO_2 Beginning 2018			
Technology[8]	Capacity Factor	Reference Gas / Coal	High Gas / Coal	Low Gas / Coal	Reference Gas / Coal	High Gas / Coal	Low Gas / Coal
2X0 CT-7FA	15%	$164	$189	$140	$174	$199	$150
CT-LM6000	15%	$187	$210	$166	$196	$220	$175
CT-LMS 100	15%	$188	$209	$168	$196	$218	$176
2X1 CCGT 7FA	15%	$194	$210	$179	$201	$217	$185
2X0 CT-7FA	65%	$94	$119	$70	$104	$129	$80
2X1 CCGT 7FA	65%	$82	$98	$67	$88	$105	$73
2X1 CCGT 7FA	90%	$73	$89	$57	$79	$95	$64
1X1 CCGT 7H	90%	$79	$95	$64	$85	$101	$70
Super Critical Pulverized Coal	90%	$85	$94	$76	$107	$116	$98
Super Critical Pulverized Coal with Carbon Capture	90%	$137	$150	$124	$140	$153	$127
Circulating Fluidized Bed	90%	$108	$119	$97	$133	$144	$122
Nuclear (Gen III)	90%	$145	$145	$145	$145	$145	$145
Onshore Wind	39%	$111	$111	$111	$111	$111	$111
Solar PV	20%	$326	$326	$326	$326	$326	$326
Biomass	75%	$119	$119	$119	$119	$119	$119

[6] Renewable Technology costs assume existing federal subsidies. Intermittent technologies include cost of integration and match-up capacity.
[7] Discount rate equals 7.81%.
[8] "CT" = Combustion Turbine; "CCGT" = Combined Cycle Gas Turbine; Configuration indicated by A X B where A indicates the number of CTs and B indicates the number of steam turbines.

At this phase of the IRP analysis a number of technologies were eliminated from further consideration based on a range of factors including technical maturity, stage of commercial development, and economics. The following technologies were found appropriate for more detailed analysis:

- Pulverized Coal – Supercritical Pulverized Coal
- Pulverized Coal – Supercritical Pulverized Coal with carbon capture
- Fluidized Bed – Atmospheric Fluidized Bed also known as "Circulating Fluidized Bed"
- Natural Gas Fired Technology
    - Simple Cycle Combustion Turbines
    - Combined Cycle Gas Turbines
    - Small Scale Aeroderivatives
- Nuclear – (Generation III Technology)
- Renewable Technologies
    - Biomass
    - On-shore Wind Power
    - Solar Photovoltaic

Following the screening level analysis, more detailed revenue requirements modeling of remaining technologies was conducted across a range of operating roles and under a range of input assumptions. The analysis resulted in the following conclusions.

- Among conventional resource alternatives CCGT and CT technologies are the most attractive. The gas-fired technologies are economically attractive across a range of assumptions concerning operations and input costs (fuel and CO_2).
- New nuclear and new coal technologies are not economically attractive near-term options relative to gas-fired technology based on current assumptions.
- Recent developments have made renewable generation less economically attractive:
    - Declines in the long-term outlook for natural gas prices have disadvantaged even the most promising renewable technologies relative to natural gas-fired resources.

- Current federal tax incentives for most renewable generation alternatives could expire as soon as year-end 2012. Solar incentives are currently expected to end in 2016.

- The outlook for national CO_2 regulation, at least in the near-term, has dimmed.

- Among renewable technologies, wind power is the most likely to be cost competitive with CCGT and CT technologies. However, under most cases wind power remains less economic than natural gas fired generation.

- Most other renewable generation technologies are not economic at this time.

Natural Gas Price Forecast

The near-term portion of the natural gas forecast is based on NYMEX forward Henry Hub gas prices. Because the NYMEX futures market becomes increasingly less liquid in months further away from the current month, the ability of NYMEX futures prices to provide a reliable view of future gas prices is limited. In recognition of this, the long-term natural gas price forecast is based on a point-of-view ("POV"). To prepare the long-term POV, reports and research prepared by a number of independent experts in the energy industry were considered, as well as additional information that may be available concerning market fundamentals.

The long term natural gas forecast used in the 2012 EAI IRP is shown in Table 2. The forecast includes sensitivities for high and low gas prices to support analysis across a range of future scenarios.

Table 2: Henry Hub Natural Gas Prices

Henry Hub Natural Gas Prices 2012 – 2031						
	Nominal $/MMBtu			Real $/MMBtu		
	Low	Reference	High	Low	Reference	High
Levelized[9]	$4.03	$5.91	$7.80	$3.42	$5.02	$6.62
Average	$4.38	$6.66	$9.15	$3.51	$5.29	$7.20
20-Year CAGR	1.77%	4.41%	6.60%	-0.21%	2.37%	4.52%

[9] Real levelized prices refer to the price in 2011$ where the NPV of that price grown with inflation over the 2012-2031 period would equal the NPV of levelized nominal prices over the 2012-2031 period when the discount rate is 7.81%.

CO_2 Assumptions

At this time, it is not possible to predict with any degree of certainty whether national CO_2 legislation will be enacted, and if it is enacted, when it would become effective, or what form it would take. In order to consider the effects of carbon uncertainty on resource choice and portfolio design, the 2012 IRP process relied on a range of projected CO_2 cost outcomes. These cases were developed working with the ICF. The low case assumes that CO_2 legislation does not occur over the 20-year planning horizon. The reference case assumes that a cap and trade program starts in 2023 with a nominal emission allowance cost of $24.12/U.S. ton and a 2012-2031 levelized cost in 2011$ of $8.10/U.S. ton.[10] The high case assumes that a cap and trade program starts in 2018 at $25.41/U.S. ton (nominal dollars) with a 2012-2031 levelized cost in 2011$s of $19.88/U.S. ton.

Load Forecast

A wide range of factors will affect electric load in the long-term, including:

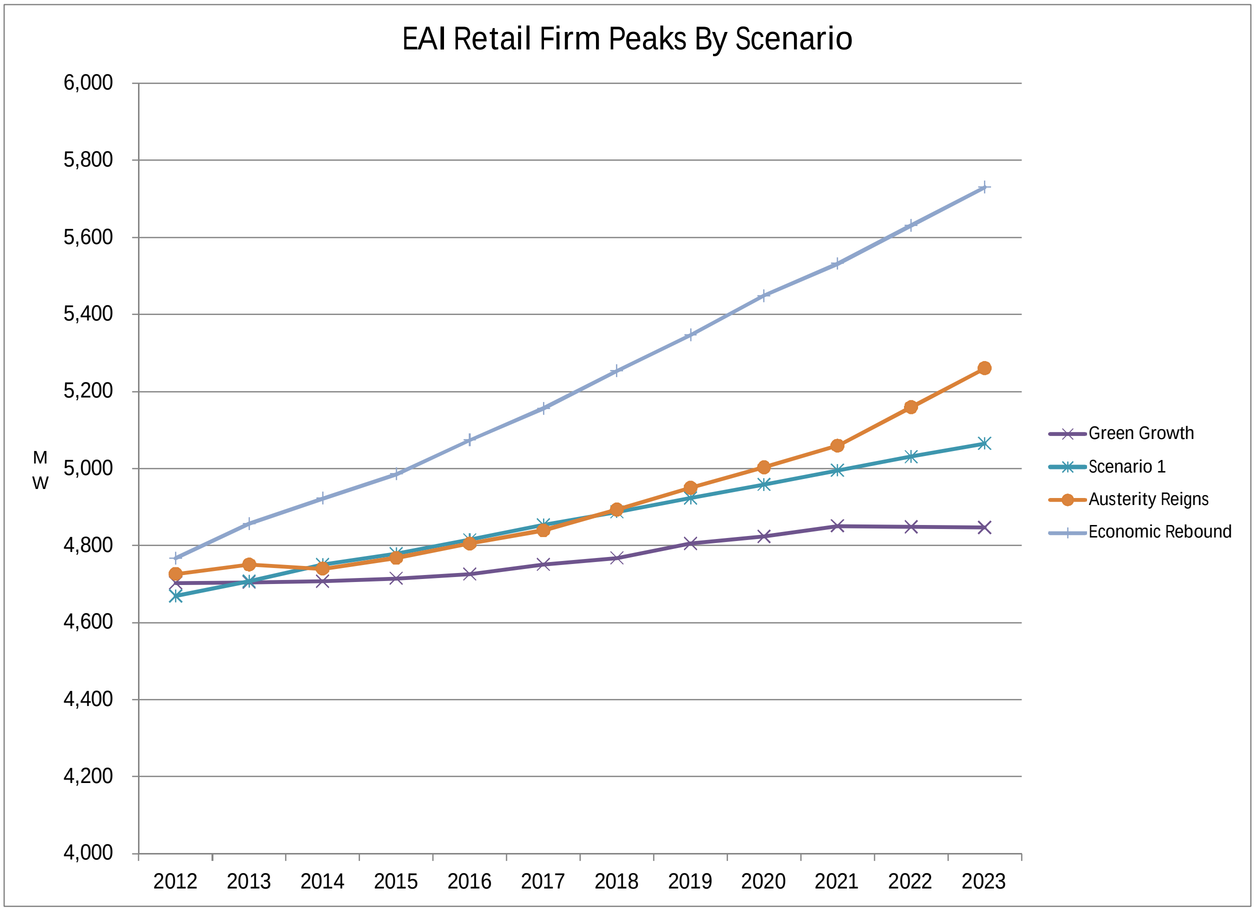
- Levels of economic activity and growth;
- The potential for technological change to affect the efficiency of electric consumption;
- Potential changes in the purposes for which customers use electricity (for example, the adoption of electric vehicles);
- The potential adoption of end-use (behind-the-meter) self-generation technologies (for example, roof top solar panels); and
- The level of energy efficiency and conservation measures adopted by customers.

Such factors may affect both the level and shape of load in the future. Peak loads may be higher or lower than projected levels. Similarly, load factors may be higher or lower than currently projected. Uncertainties in load will affect both the amount and type of resources required to meet customer needs in the future.

In order to consider the potential implications of load uncertainties on long-term resource needs, four load forecast sensitivities were prepared for the 2012 EAI IRP and are shown in Figure 1. These four sensitivities were developed to support four specific scenarios (Scenario 1, Austerity Reigns, Green Growth, and Economic Rebound) which will be described in more details below.

[10] The discount rate and levelization methodology for CO_2 prices is the same as that for natural gas prices.

Figure 1: Load Forecast Scenarios



Market Modeling

The development of the 2012 EAI IRP relied on the AURORA [11] to simulate market operations and produce a long-term forecast of the revenues and cost of energy procurement.[12] See Appendix C to view the scope of the market modeling.

AURORA is a production cost model and resource capacity expansion optimization tool that uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, environmental constraints, and future demand forecasts. AURORA's optimization process

[11] The AURORA model was selected after an extensive analysis of electricity simulation tools available in the marketplace. AURORA is capable of supporting a variety of resource planning activities and is well suited by for scenario modeling and risk assessment modeling. It is widely used by load serving entities, consultants and independent power producers.

[12] The AURORA model effectively replaces the PROMOD IV and PROSYM models that were used for many years.

identifies the set of resources among existing and potential future resources with the highest and lowest market values to produce economically consistent capacity expansion and retirement schedules. AURORA estimates price and dispatch using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. AURORA chooses from new resource alternatives based on the net present value ("NPV") of hourly market values. AURORA compares those values to existing resources in an iterative process to optimize the set of new units.

Scenarios

IRP analytics relied on four scenarios to assess alternative portfolios across a range of outcomes. The four scenarios are:

- Scenario 1 – Assumes Reference Load, Reference Gas, and no CO_2 cost
- Scenario 2 (Economic Rebound) – Assumes the U.S. economy recovers and resumes expansion at relatively high rates.
- Scenario 3 (Green Growth) – Assumes government policy and public interest drive a "green agenda" marked by government subsidies for renewable generation; regulatory support for energy efficiency; and consumer acceptance of higher cost for "green."
- Scenario 4 (Austerity Reigns) – Assumes sustained poor economic conditions in the U.S.

Each scenario was modeled in AURORAxmp Electric Market Model ("AURORA"). The resulting Market Modeling provided a basis (including projected power prices) for assessing the economics of long-term resources portfolio alternatives. Table 3 provides key scenario assumptions.

Table 3: Summary of Key Scenario Assumptions

Summary of Key Scenario Assumptions[13] [14]				
	Scenario 1	Economic Rebound	Green Growth	Austerity Reigns
Electricity CAGR (Energy GWh)	~0.8%	~1.5%	~0.3%	~1.1%
Peak Load Growth CAGR	~0.8%	~1.4%	~0.2%	~1.1%
Henry Hub Natural Gas Price ($/MMBtu)	Reference ($5.02 levelized 2011$)	Reference ($5.02 levelized 2011$)	High Case ($6.62 levelized 2011$)	Low Case ($3.42 levelized 2011$)
CO_2 Price ($/short ton)	None	Cap and trade starts in 2023 $6.56 levelized 2011$	Cap and trade starts in 2018 $16.65 levelized 2011$	None

Capacity Expansion Modeling

This step relied on the Aurora Capacity Expansion model to develop a capacity build-out for each market scenario. The Aurora Model determined the timing, amount, type, and regional location of capacity additions within the MISO South[15] footprint. Aurora adds new resources when needed to meet regional reliability requirements (planning reserve margins). Additional resources are added if market price levels are sufficiently high to make an investment in incremental capacity economically attractive. This step resulted in a capacity expansion schedule for each market scenario in the overall MISO South footprint. Results at this step of the process do not yield EAI specific portfolios.

Table 4: Results of Capacity Expansion Modeling

Results of Capacity Expansion Modeling Incremental Capacity Mix by Scenario				
	Scenario 1	Economic Rebound	Green Growth	Austerity Reigns
CCGT	9%	42%	65%	0%
CT	52%	33%	0%	67%
Sustain Existing Units	39%	25%	28%	33%
Wind	0%	1%	8%	0%
Other	0%	0%	0%	0%
Year of First Addition	2021	2021	2031	2021

[13] All CAGRs in this table: 2011-2031 (20 Years) for the market modeled in AURORA (a sub-set of the Eastern Interconnect which is about 34% of the U.S., based on 2011 GWh energy sales).

[14] Real levelized prices refer to the price in 2011$ where the NPV of that price grown with inflation over the 2012-2031 period would equal the NPV of levelized nominal prices over the 2012-2031 period when the discount rate is 7.81%.

[15] MISO South includes the Transmission footprint of the Entergy Operating Companies and the Transmission footprint of CLECO.

Total MWs[16] Added (through 2031)	6,361	13,590	2,642	8,881

Results of the Capacity Expansion Modeling which supported conclusions from the Technology Assessment discussed earlier were reasonably consistent across scenarios:

- In general, new build capacity is not required to meet overall reliability needs in the footprint defined by the Transmission facilities owned by EAI and the Entergy Operating Companies, nor is new build construction economically supported by regional market prices until the early years of the next decade.
- Gas-fired resources, Simple Cycle Gas-fired Combustion Turbines and Combined Cycle Gas Turbines are the most economically attractive technologies for new build resources in most outcomes.
- In no scenario were new nuclear or new coal found to be economically attractive options.
- In no scenario were PV or biomass built found to be economically attractive options.
- Wind generation has a limited economic role, primarily in the later years and then only in scenarios involving high gas and / or carbon.
- Investment in existing generation resources to extend operations beyond currently assumed deactivation dates may be a low-cost alternative to meet customer needs.

Portfolio Design & Risk Assessment

Portfolios were designed that met EAI's planning objectives based on EAI's identified resource needs and the screening assessments of resources that sought to identify the best available resource alternatives. The objective of this analysis was to assess the relative performance of the best resource alternatives from the screening assessments when included with EAI's existing resources and to test their performance across a range of outcomes as provided by the Scenarios.

Five portfolios were assessed:

- CT Portfolio, consisting of limited-term purchases up to 20% of resource needs and CT additions to fill the remaining resource need

[16] Intermittent resources are discounted based on contribution to planning reserves. A fifteen percent capacity value is attributed to wind.

- CCGT Portfolio, consisting of limited-term purchases up to 20% of resource needs and CCGT additions to fill the remaining resource need
- Lake Catherine 4 Portfolio, consisting of sustaining the operation of Lake Catherine 4, limited-term purchases up to 20% of resource needs and CT additions to fill the remaining resource need
- Wind Portfolio, consisting of 1,000 MW of wind resources with an effective capacity contribution of 14.7%, limited-term purchases up to 20% of resource needs and CT additions to fill the remaining resource need
- DSM Portfolio, consisting of about 700 MW of incremental DSM by 2023 and limited-term purchases up to 20% of resource needs

Each portfolio was modeled in AURORA and tested in the four Scenarios described earlier for a total of 20 cases. The results of the AURORA simulations were combined with the fixed costs of the incremental resource additions to yield the total forward revenue requirements excluding sunk costs. Results and rankings are provided in the following tables.

Table 5: NPV of Forward Revenue Requirements by Scenario

NPV of Forward Revenue Requirements (2014 – 2023) 2012$ Billions[17]					
Portfolio	CCGT	CT	Lake Catherine 4	Wind	DSM
Scenario 1	3.18	3.33	3.07	3.45	3.15
Economic Rebound	4.10	4.62	3.80	4.31	3.63
Austerity Reigns	2.97	3.19	2.83	3.42	3.07
Green Growth	3.88	3.88	3.87	3.77	3.72

Table 6: Portfolio Ranking by Scenario

Portfolio Ranking by Scenario					
Portfolio	CCGT	CT	Lake Catherine 4	Wind	DSM
Scenario 1	3	4	1	5	2
Economic Rebound	3	5	2	4	1
Austerity Reigns	2	4	1	5	3
Green Growth	4	4	3	2	1

As a basis for assessing risk, the following tables provide the results and ranking of each portfolio across all four Scenarios.

[17] The portfolio design and risk assessment net present value calculations were all based on a discount rate of 6.84% which is the EAI weighted average cost of capital as of year-end 2011.

Table 7: NPV of Forward Revenue Requirements across Scenarios

NPV of Forward Revenue Requirements Across Scenarios 2012$ Billions					
Portfolio	CCGT	CT	Lake Catherine 4	Wind	DSM
Worst Performance	4.10	4.62	3.87	4.31	3.72
Best Performance	2.97	3.19	2.83	3.42	3.07
Average Performance	3.53	3.76	3.39	3.74	3.40

Table 8: Portfolio Ranking across Scenarios

Portfolio Ranking Across Scenarios					
Portfolio	CCGT	CT	Lake Catherine 4	Wind	DSM
Worst Performance	4	5	3	5	3
Best Performance	2	4	1	2	1
Average Performance	3	4.25	1.75	4	1.75

Portfolio risk was also assessed by comparing the total forward revenue requirements excluding sunk costs relative to the highest ranked portfolio and across all four scenarios.

Table 9: NPV of Forward Revenue Requirements relative to Highest Ranked Portfolio

NPV of Forward Revenue Requirements relative to Highest Ranked Portfolio (2014 – 2023) 2012$ Millions					
Portfolio	CCGT	CT	Lake Catherine 4	Wind	DSM
Scenario 1	109	261	-	382	84
Economic Rebound	471	989	167	676	-
Austerity Reigns	149	366	-	599	247
Green Growth	154	154	142	42	-

Table 10: NPV of Forward Revenue Requirements relative to Highest Ranked Portfolio across Scenarios

Portfolio Ranking Across Scenarios 2012$ Millions					
Portfolio	CCGT	CT	Lake Catherine 4	Wind	DSM
Worst Performance	471	989	167	676	247
Best Performance	109	154	0	42	0
Average Performance	221	442	77	425	83

Summary of Findings from Analysis

- The Lake Catherine 4 Portfolio and the DSM Portfolio performed better across all the Scenarios relative to the CCGT, CT, and Wind Portfolios.
- The Lake Catherine 4 Portfolio has lower risk relative to the other portfolios because it is either the best performing portfolio or performs reasonably well across all Scenarios.
- The DSM Portfolio has lower risk relative to the other portfolios because it is either the best performing portfolio or performs reasonably well across all Scenarios.
- Considering the characteristics of the Lake Catherine 4 and DSM resources relative to EAI's existing portfolio of resources and the preference to construct a diverse resource portfolio to mitigate risk, there is merit in pursuing both the Lake Catherine 4 and additional DSM for EAI's portfolio.

ACTION PLAN

EAI has developed a comprehensive resource planning Action Plan to meet resource needs which includes eleven distinct activities. The Action Plan recognizes that there are numerous uncertainties to be considered in the IRP process, the outcome of which will influence the results significantly. A summary load and capability is shown in Table 11. The Action Plan provides for adequate capacity in all years of the plan. Additional resources are planned for the first three years of the IRP to mitigate the risk associated with completing each of the activities.

Table 11: IRP Load and Capability

EAI Load and Capability										
					(MW)					
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Firm Peak Demand	**4,750**	**4,779**	**4,815**	**4,853**	**4,887**	**4,923**	**4,959**	**4,995**	**5,030**	**5,065**
Reserve Margin (Stand Alone = 20%)	950	956	963	971	977	985	992	999	1,006	1,013
Total Requirements	**5,700**	**5,734**	**5,778**	**5,824**	**5,865**	**5,908**	**5,950**	**5,994**	**6,036**	**6,078**
Existing EAI Capacity (Retail)	4,022	3,563	3,515	3,497	3,497	3,497	3,497	3,497	3,497	3,497
Planned Resources										
- MISO Membership	380	382	385	388	391	394	397	400	402	405
- Hot Spring Power Plant	620	620	620	620	620	620	620	620	620	620
- Transactions from 2011 RFP	795	795	795							
- Available WBL	286	286	286	286	286	286	286	286	286	286
- Wholesale Hydro Capacity	10	10	10	10	10	10	10	10	10	10
- Lake Catherine 4 Sustainability Project	74	533	533	533	533	533	533	533	533	533
- DSM and EE Reference Case with Reserve Impact	181	279	366	432	490	579	649	703	730	781
Total Planned Supply	6,368	6,468	6,510	5,767	5,827	5,919	5,992	6,049	6,078	6,132
Deficit (-) / Surplus (+)	668	734	733	(57)	(37)	11	42	54	42	54

The eleven Action Plan activities, some of which were initiated prior to this IRP, are:

1. MISO Transition

   EAI will continue to transition to the MISO Resource Adequacy Construct as EAI integrates into MISO. EAI is already monitoring key MISO working groups and committees related to resource planning. Certain processes, such as the load forecasting process, will be modified. During 2013, EAI will develop a Fixed Resource Adequacy Plan[18] for the period between December 19, 2013 and May 31, 2014 and will participate in the MISO Loss of Load Expectation study for the 2014/2015 planning year. Another key planning process during and after transition will be participation in the MISO Transmission Planning Expansion Process. If the MISO transition cannot be completed or the stand-alone option cannot be terminated, EAI will need approximately 400 MW of additional capacity to meet minimum planning reserves.

2. Coal Unit Environmental Compliance

   The challenge utilities face with regards to environmental compliance is unprecedented in terms of the numbers of rules coming due simultaneously, the compressed time frame for compliance, and the continuing ratcheting down of compliance obligations. Key uncertainties include the requirements of the final rules, the outcome of current litigation, congressional activity and the possibility of extensions of the compliance deadlines. Another key uncertainty is the nation's long-term carbon policy. The industry needs a satisfactory resolution of both the current regulatory challenges and a long-term legislative solution on carbon. EAI will continue to monitor changes in environmental law at the state and federal level and evaluate options for environmental compliance for the EAI coal units.

3. Hot Spring Plant Acquisition

   EAI stands ready to complete the acquisition of the Hot Spring Plant pending final approvals by the DOJ. The Hot Spring Plant would add approximately 620 MW to EAI's fleet.

[18] Each load serving entity must submit a Fixed Resource Adequacy Plan to MISO for MISO's approval which demonstrates that the load serving entity has sufficient resources to meet all or part of its planning reserve margin requirements.

4. Purchase Power Agreements from EAI's 2011 RFP

EAI has executed one limited-term power purchase agreement and will continue to negotiate the second contract. Both contracts will be contingent upon regulatory approval on cost recovery and will add approximately 795 for the period between December 2013 and May 2017. EAI will also work to secure all of the required transmission service for these two transactions prior to June 30, 2013.

5. Available Wholesale Base Load Capacity to Retail

An APSC decision that would allow EAI to use Available WBL Capacity to serve its customers is pending in Docket No. 12-038-U. The capacity would add approximately 286 MW for the entire IRP study period.

6. Hydro Peaking Capacity to Retail

EAI will pursue APSC approval in the 2013 general rate case to use the wholesale capacity of EAI's owned Hydro units to serve its customers. This represents approximately 10 MW of added capacity to EAI's portfolio.

7. DSM and Energy Efficiency Expansion

EAI will continue with a suite of comprehensive programs, including ongoing Independent Evaluation, Measurement and Verification, and capturing any lessons learned to improve next phase of implementation. EAI will closely monitor the results from the DSM/EE programs and adjust its load forecast and resource plans as warranted. EAI will also continue to research options for DSM in the MISO market.

8. Lake Catherine 4 Reliability / Sustainability

Based on the IRP analysis, EAI is pursuing a reliability / sustainability program for the Lake Catherine 4 unit and will request in the 2013 rate case that all of Lake Catherine 4's capacity be allocated to rate base. This action item adds 74 MW in 2014 and 533 MW in 2015 through 2023.

9. Older Natural Gas Fired Unit Deactivation Decisions

The current planning assumption is that approximately 422 MW of legacy generation will be deactivated by the beginning of 2014. A follow-up review of this generation will be conducted in 2013 to determine tactical plans for this capacity. Actual decisions to deactivate generation will be made on a unit-by-unit basis based upon the needs of customers and the economics of the units relative to available options at the time of the decision.

10. Renewable Energy Assessment

EAI will continue to monitor technology developments in renewable energy as well as public policy developments. EAI will consider economically attractive renewable generation, taking into account evolving mandates and an on-going assessment of cost and availability.

11. Short- and Intermediate-Term RFPs

EAI will continuously monitor progress in the IRP Action Plan and issue short- and intermediate-term (1-3 year) RFPs for additional resources if needed to maintain adequate reserves.

Appendix A: EAI Resource Planning Objectives

Entergy Arkansas, Inc.

Resource Planning Objectives

5-17-12

PURPOSE:

The purpose of this document is to establish resource planning objectives to guide Entergy Arkansas, Inc. (EAI) resource planning and operations staff in development of EAI's Integrated Resource Plan (IRP) and to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities.

OBJECTIVES:

In developing EAI's IRP, EAI's resource planning and operations staff should consider the following resource planning objectives:

1. Policy Objectives – The development of the IRP should reflect policy and planning objectives reviewed by the EAI RPOC and approved by EAI's President and Chief Executive Officer. Those policy and planning objectives will consider and reflect the policy objectives and other requirements provided by EAI's regulators.

2. Resource Planning – The development of the IRP will consider generation, transmission, and demand-side (e.g., demand response, energy efficiency) options.

3. Planning for Uncertainty – The development of the IRP will consider scenarios that reflect the inherent unknowns and uncertainties regarding the future operating and regulatory environments applicable to electric supply planning including the potential for changes in statutory requirements.

4. Reliability – The IRP should provide adequate resources to meet EAI's customer demands and expected contingency events in keeping with established reliability standards.

5. Baseload Production Costs – The IRP should provide baseload resources that provide stable long-term production costs and low operating costs to serve baseload energy requirements.

6. Operational Flexibility for Load Following – The IRP should provide efficient, dispatchable, load-following generation and fuel supply resources to serve the operational needs associated with electric system operations and the time-varying load shape levels that are above the baseload supply requirement. Further the IRP should provide sufficient flexible capability to provide ancillary services such as regulation, contingency and operating reserves, ramping, and voltage support.

7. Generation Portfolio Enhancement – The IRP should provide a generation portfolio that over time will realize the efficiency and emissions benefits of technology improvements and that avoids an over-reliance on aging resources.

8. Price Stability Risk Mitigation – The IRP should consider factors contributing to price volatility and should seek to mitigate unreasonable exposure to the price volatility associated with the major uncertainties in fuel and purchased power costs.

9. Supply Diversity and Supply Risk Mitigation – The IRP should consider and seek to mitigate the risk exposure to major supply disruptions such as outages at a single generation facility or the source of fuel supply.

10. Locational Considerations - The IRP should consider the uncertainty and risks associated with dependence on remote generation and its location relative to EAI's load so as to enhance the certainty associated with the resource's ability to provide deliver power to EAI's customers.

11. Reliance on Long-Term Resources – EAI will meet reliability requirements primarily through long-term resources, both owned assets and long-term power purchase agreements. While a reasonable utilization of short-term purchased power is anticipated, the emphasis on long-term resources is to mitigate exposure to supply replacement risks and price volatility, and ensure the availability of resources sufficient to meet long-term reliability and operational needs. Over-reliance on limited-term purchased power (*i.e.*, power purchased for a one to five year term) exposes customers to risk associated with market price volatility and power availability.

12. Sustainable Development – The IRP should be developed consistent with EAI's vision to conduct its business in a manner that is environmentally, socially and economically sustainable.

Appendix B: EAI Generation Resources

EAI Generation Resources based on Summer Ratings

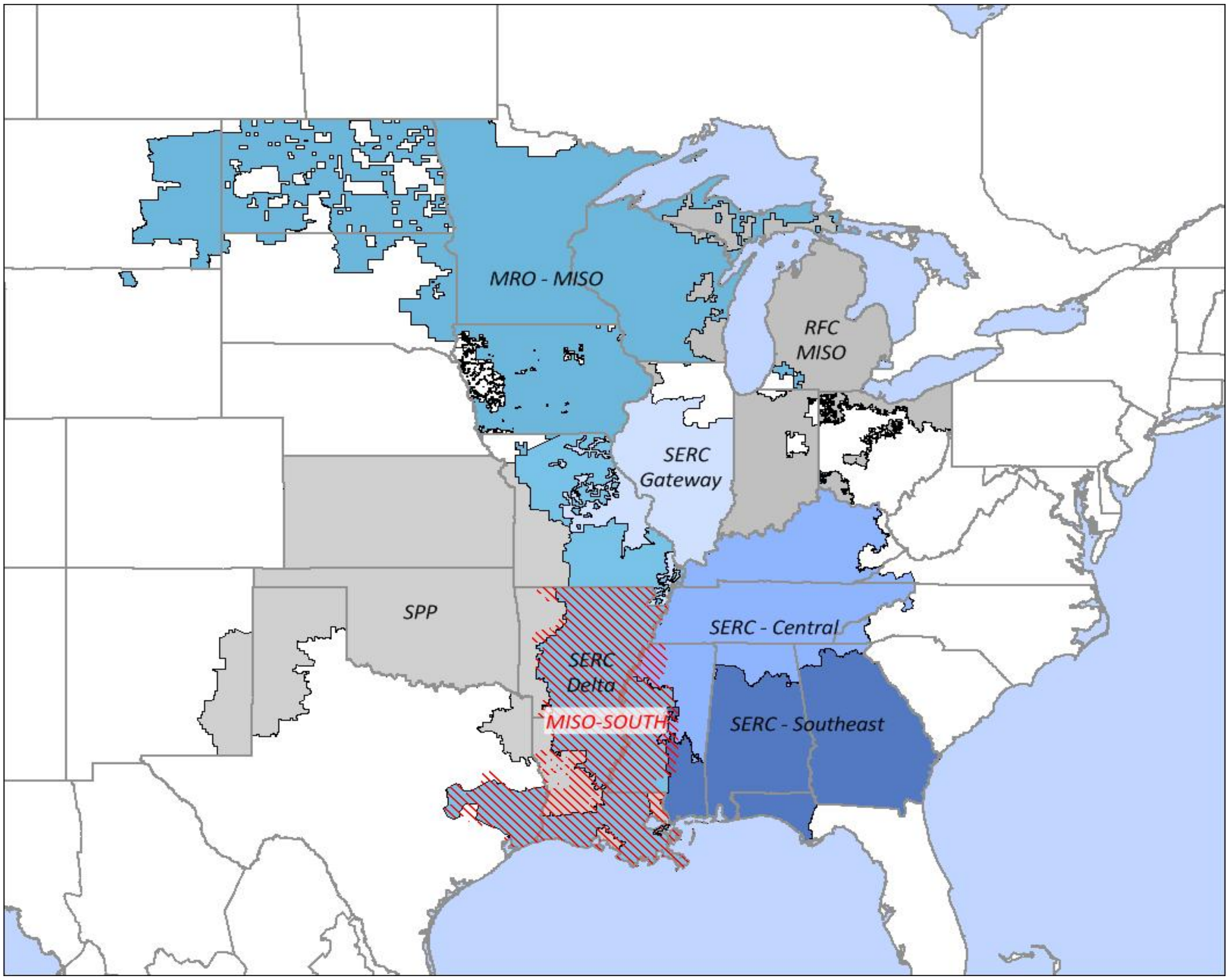
OWNED CAPACITY	Total Capacity (MW)	Ownership %	EAI Owned (MW)	Retail Capacity (MW)	Wholesale Capacity (MW)	Commerical Operations Date
ANO Unit 1	834	100%	834	718	116	1974
ANO Unit 2	989	100%	989	852	137	1980
Carpenter Unit 1	31	100%	31	27	4	1932
Carpenter Unit 2	31	100%	31	27	4	1932
Couch Unit 2	123	100%	123	106	17	1954
Independence Unit 1	836	31.5%	263	227	37	1983
Lake Catherine Unit 1	48	100%	48	41	7	1950
Lake Catherine Unit 2	45	100%	45	39	6	1950
Lake Catherine Unit 3	96	100%	96	83	13	1953
Lake Catherine Unit 4	533	100%	533	459	74	1970
Lynch 3	110	100%	110	95	15	1954
Lynch Diesel	5	100%	5	4	1	1967
Mabelvale Unit 1	14	100%	14	12	2	1970
Mabelvale Unit 2	14	100%	14	12	2	1970
Mabelvale Unit 3	14	100%	14	12	2	1970
Mabelvale Unit 4	14	100%	14	12	2	1970
Ouachita 1	255	100%	255	255	-	2002
Ouachita 2	257	100%	257	257	-	2002
Remmel Unit 1	4	100%	4	3	1	1925
Remmel Unit 2	3	100%	3	3	0	1925
Remmel Unit 3	4	100%	4	3	1	1925
White Bluff Unit 1	815	57.0%	465	400	64	1980
White Bluff Unit 2	844	57.0%	481	414	67	1981

PURCHASED CAPACITY	EAI Purchased (MW)	Retail Capacity (MW)	Wholesale Capacity (MW)	Commerical Operations Date
Blakely	11	9	2	1956
DeGray	10	9	1	1972
Grand Gulf - Non-Retained Share	360	310	50	1985
Grand Gulf - Retained Share	102	-	102	
Total - Owned and Purchased	5,116	4,390	726	

Nuclear	2,285	1,881	404
Coal	1,209	1,041	168
Hydro	94	81	13
Gas/Oil	1,528	1,387	141
	5,116	4,390	726

Appendix C: Scope of AUORA Modeling

Scope of AUORA Modeling



10/29/2012

Entergy Arkansas, Inc., Integrated Resource Plan Stakeholder Report

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I. Introduction

On July 31, 2012, Entergy Arkansas, Inc., ("EAI") hosted an Integrated Resource Plan ("IRP") Stakeholder Committee Meeting. The meeting was attended by numerous parties, which included EAI customers, utilities, non-utility power suppliers, and government agency employees. The meeting consisted of various presentations by EAI on its 2012 Integrated Resource Plan, an opportunity for the Stakeholders to ask questions about the IRP Presentations, and an opportunity to organize a Stakeholder Committee Consistent with the Commission's Resource Planning Guidelines.

The Committee notes that Attachment No. 1 to this Report consists of separate Comments by Mr. Paul Chernick on behalf of Audubon Arkansas. Audubon Arkansas states "Audubon Arkansas's opinions are reflected only in the Attachment to the report. Audubon Arkansas does not necessarily endorse or agree with the Stakeholder Report as written."

II. Stakeholder Committee Participants

Attachment No. 2 to this Report are Sign-In Sheets from EAI's July 31, 2012 meeting.

Subsequent to the July 31, 2012 Stakeholder Meeting, various Stakeholder Committee participants submitted data requests to EAI. EAI provided responses to these data requests in due course and held a second meeting with Stakeholders on September 6, 2012 to allow for follow-up questions.

III. Reservation of Rights

The Stakeholders appreciated the opportunity to participate in both EAI's Stakeholder meeting and the subsequent process of the drafting of this report. The Stakeholders would like to make it clear, however, that although their participation in this Stakeholder advisory process was useful and appropriate, the views expressed in this Stakeholder Report do not represent the views of any single party with regard to the subjects addressed herein. Each of the individual Stakeholders intends to continue to fully participate in EAI's Integrated Resource Planning process as allowed under the Commission's Resource Planning Guidelines and in any and all specific docketed proceedings which will follow the filing of this Stakeholder Report and the filing of EAI's IRP. Accordingly, the Stakeholders hereby reserve the right to participate fully in any future proceeding associated with EAI's 2012 IRP and any future resource acquisition that may spring from that IRP process and raise any appropriate argument therein.

IV. Stakeholder Concerns

A. EAI must plan to acquire the lowest cost reliable resources that are reasonably available.

The Commission established formal Resource Planning Guidelines for Arkansas's electric public utilities ("IRP Guidelines") in Docket 06-028-R. These Guidelines "create a regulatory framework that requires electric utilities in the state to plan for and meet their service obligations in the most prudent, reliable, and cost-effective manner possible." APSC Docket 06-028-R, Order No. 6 at 1.

Utilities have an obligation under Arkansas law to provide to consumers the lowest cost reliable energy supplies that are reasonably possible.[1] Such resources could include demand side management programs, industrial combined heat and power facilities, investor owned generating plants, consumer owned distributed generation, energy efficiency programs, additional maintenance on existing generation, power purchase contracts, or purchase or construction of a bricks and mortar generating plant. If a particular resource is the lowest cost reliable resource available to serve the utility's customers, the utility has a legal obligation to produce or acquire it.

Likewise, EAI should not acquire any type of resource if it is not expected to be the lowest long term cost resource option available. The straightforward language of ACA § 23-4-103 means that cost minimization for ratepayers and the continued assurance of reliability must remain the primary goals of EAI's resource planning.

Utilities and their shareholders must be held financially responsible for their planning decisions, and allowed to profit from decisions that turn out well as well as suffer financial losses from poor decisions. Without this symmetrical profit and loss

[1] Arkansas Code Annotated § 23-4-103 requires that EAI's rates for electric utility service be just and reasonable. In the same vein, EAI's resource acquisition costs must also be just and reasonable. Just and reasonable means that the cost to the customer is as low as reasonably possible. In *City of El Dorado v. Arkansas Public Service Commission*, 235 Ark. 812, 817, 362 S.W.2d 680, 683-684 (1963) the Arkansas Supreme Court specifically stated:

> ***It is the duty of the Company to operate in such manner as to give to the consumers the most favorable rate reasonably possible.*** This stems from the fact that the State has given the Company the exclusive right to sell and distribute gas to its customers. Consequently the Company bears a trust relationship to its customers and must conduct its operations on that basis and not as if it were engaged in a private business with no restrictions as to the income it could earn. (emphasis added)

incentive, authorized rates of return in excess of the risk free cost of capital cannot be justified.

B. Compliance with Environmental Regulations

The Company's IRP presentations identified a number of environmental regulatory changes at the federal level that have or will impact EAI's operations during the planning period which are likely to impose emissions limits or scrubber requirements on its generating units. These rules include:

- Cross-State Air Pollution Rule -- Published in Federal Register August 8, 2011, Effective Date January 1, 2012. Established reduced emission budgets for NOx and/or SO2 and limited allowance trading. On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit reversed and remanded the rule for exceeding the EPA's statutory jurisdiction. According to the Court, EPA had improperly required states to reduce their emissions by more than the amount of "significant emissions" that they produced, and imposed mandatory Federal Implementation Plans rather than allowing the states to implement their own plans.

- Mercury and Air Toxics Standards -- Published in Federal Register May 3, 2011. Effective Date February 16, 2012. Compliance with MATS requirements starts April 16, 2015 (two one-year extensions are possible).

- Regional Haze -- EPA published its final rule disapproving most of the emission limits in the Arkansas Regional Haze State Implementation Plan (SIP) in the Federal Register on March 12, 2012. EPA must either approve an ADEQ submitted SIP or promulgate a Federal Implementation Plan by March 11, 2014.

- National Ambient Air Quality Standards – These air quality standards have been and will continue to be ratcheted down over time. New standards for particulates are expected to be published by December 2012.

- Cooling Water Intake Structures (Section 316(b)) -- Proposed Rule published in Federal Register April 20, 2011. Final Rule due in July 2013. Implementation expected between 2018 – 2020

- Coal Ash -- A Final Rule expected in late 2012. If regulated under Subtitle C states will be required to either adopt the listing in the hazardous waste regulations before requirements are effective (2+ years) If regulated under Subtitle D, the rule will be effective within 6 months after rule finalized

- Green House Gases -- On June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit upheld EPA's greenhouse gas ("GHG") regulations, including the "Tailpipe Rule" making GHGs subject to regulation under the Clean Air Act and the "Tailoring Rule" which allows some flexibility to reduce adverse regulatory impact.

These new rules and the uncertainty associated with their application could impose significant costs on EAI and its customers. Unfortunately, as demonstrated by the Ms. Myra Glover's Environmental Regulatory Update, EAI appears to be taking a wait and see approach to the new environmental regulations. At Slide 25 of her presentation, she stated that "EAI continues to evaluate options for environmental compliance for the EAI coal units" and that "EAI has not determined what compliance technology may be required and when". Further, EAI, in its response to AEEC Data Request 1-3, further advised AEEC that "no decision regarding environmental controls at any of EAI's coal plants has been made."

Consumers are concerned that this wait and see attitude will impose significantly more costs on them than would be the case if EAI were proactively planning to comply with the applicable statutes and regulations in a timely manner. EAI should take every reasonable preliminary step to ensure that it installs all required environmental controls associated with the federal and state environmental protection regime in a timely manner that minimizes costs to consumers. The required controls are likely to be very expensive, even if the company acts promptly.[2] If EAI waits until the last minute to install the necessary environmental controls, its costs are likely to be significantly higher than they

[2] EAI originally estimated the total cost to install scrubbers at the White Bluff Plant to be more than one billion dollars. See APSC Docket 09-024-U, EAI Petition for Declaratory Judgment, at pages 3-4.

otherwise would have been. Further, failure to timely implement the new environmental regulations, could, in a worst case scenario, require EAI to shutter its existing coal units which would adversely impact EAI's resource diversity and increase costs for its customers.

Notwithstanding the above, the decision-maker should look only at actual, concrete, objectively verifiable costs in determining what resources should be developed as a result of this IRP process and should not lard their coal plant compliance cost estimates with extra costs designed to make alternative resources like gas, wind or solar power more attractive than they would otherwise be.

C. <u>EAI should provide additional information to the Commission and its Stakeholders.</u>

EAI should provide additional information on the major underlying assumptions of the IRP, such as environmental regulatory requirements, load growth, load loss, weather variability, customer class breakdown, and selected projected econometric parameters. Among these issues are:

a. What Environmental Regulatory Requirements will apply to the Company's generating assets, when will the company be required to comply with the various new regulations, what will compliance cost, and what can the company begin doing now to limit costs later?

b. (i) How do EAI's customer rates and resource plans compare to those of utilities in neighboring states? (ii) What is the cost of living and of doing business in EAI's service territory compared to neighboring states? (iii) How can EAI operate so as to reduce its costs over time?

In the end, transparency in EAI's modeling assumptions will benefit both EAI and its customers.

D. Reliability:

As indicated above, Arkansas law, particularly ACA § 23-3-113 (a), requires EAI to provide "adequate and efficient service, instrumentalities, equipment, and facilities" necessary to "promote the safety, health, comfort, requirements and convenience of its patrons, employees, and the public." This means, that EAI must provide reliable electric service to its customers. Consumers understand that reliability has a price. However unreliable service also has a price. Service disruptions can in some cases cost a utility's customers a great deal of money, particularly in cases where the disruption damages the customers' facilities and equipment or disrupts delicate industrial processes.

As we see it, electric service must be reliable to meet the statute's requirement regarding adequacy and efficiency. EAI must therefore ensure that the utility resource acquisition process does not result in degradation of service reliability to consumers. The costs of resource-specific service disruptions (and the associated cost of backup resources) should not be ignored. Consistent with this, the IRP should develop an objective metric of a target level of reliability that reflects customers' valuation of reliability to residential, commercial and industrial customers.

E. Quantifying rate impact on different customer classes:

Each portfolio evaluated by the EAI will have a different expected costs and levels of risk. Further, the IRP should measure expected costs/ rates associated with different portfolios of resources evaluated in the IRP process, since EAI cannot reasonably satisfy its mandate to provide service to its customers at the lowest reasonable cost if it does not know what the costs are and which customer classes will pay them.

F. Innovative Rate Designs could benefit both the Company and its retail customers.

Consumers believe that the Company should identify and examine rate and program options that promote efficient investment and consumption decisions by electricity end-users, including but not limited to the following:

- Establishing options for comprehensive cost-based, time-sensitive rates (both time of day and seasonal) to give proper price signals to consumers.
- Ensuring that demand-related costs are properly identified and recovered exclusively through demand charges-not kwh energy charges-in rates for customers with demand billing.
- Ensuring that only cost-effective energy efficiency measures are implemented and that no customer class is required to subsidize energy efficiency program costs caused any another class.
- Setting EAI's retail rates based on peak responsibility cost allocation methods rather than methods that reflect some implied benefits received scheme such as the Commission has allowed in all of EAI's recent rate cases, including Dockets 06-101-U and 09-084-U.
- Offering innovative demand-response programs (for example, interruptible rates with buy through options).

As Consumers see it, EAI's retail rates for its various customer classes varies widely from the company's actual cost of service for each such class. This problem exists for a variety of reasons, including the historical use of piecemeal, shotgun-style rates and riders that focus on sub-levels of utility operations, existing interclass cost subsidies, and the general lack of time-sensitive rates available to customers. Utility rates can only promote efficient investment and consumption decisions if they accurately reflect the costs that a particular customer imposes on the system. Moreover, when customers cannot easily determine the actual net cost of their consumption, they cannot make reasoned and efficient decisions about electricity consumption.

As a first step in addressing this problem, Consumers urge EAI to develop and implement options for comprehensive time-sensitive electricity rates (for example, optional time-of-day and seasonal rates) for all customer classes in the rate case it plans to file during 2013. Such rates would clearly inform ratepayers that "on-peak" consumption costs more than "off-peak" consumption, thereby encouraging both conservation and strategic off-peak load growth.

G. Comments of Attorney General Concerning Report Section IV. (F).

The AG respectfully disagrees with Section IV(F) on several specific points. First, we do not believe that contentious cost allocation methodologies are appropriate for an integrated resource plan. Second, the central organizing principle of rate design should be encouraging behavior that minimizes costs. Third, while increasing the complexity of rate design may help customers make lower cost consumption choices, the cost of that complexity to the customer reading the bill and the utility forced to administer it should be considered. The AG supports optional time of use pricing for residential customers, but disagrees that residential customers bills should be made any more difficult to understand than they already are.

Resource Insight, Inc.

Audubon Arkansas Comments

on Entergy's 2012 IRP

Prepared by
Paul Chernick

At the Request of
Ellen Fennell

September 26, 2012

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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:

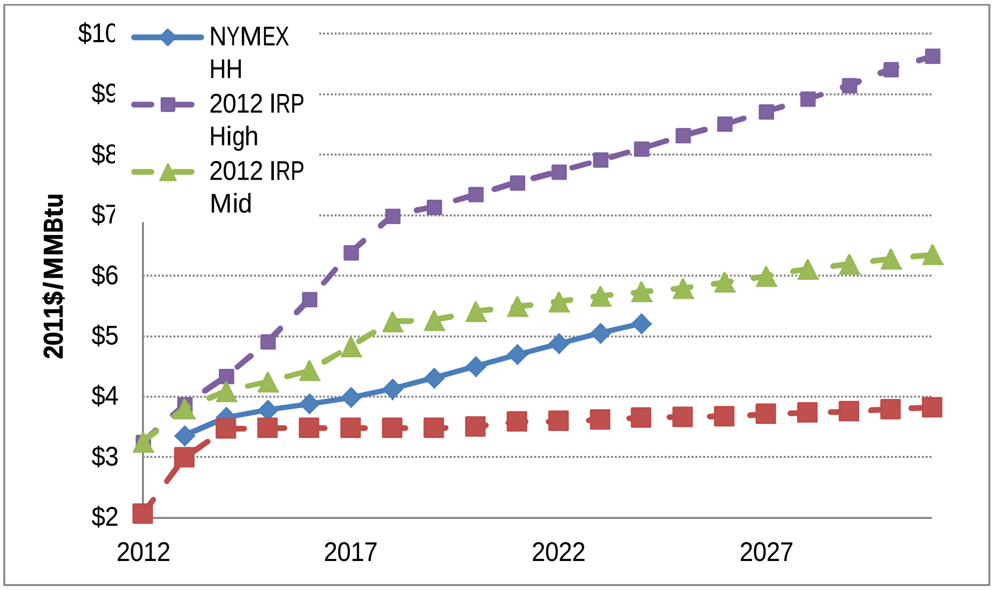
- significant overstatement of likely future gas prices;
- continued understatement of energy-efficiency potential and the benefits of gas conservation;
- failure to conduct economic analysis of the following four resource decisions assumed in the IRP:
    - continued operation of Entergy's coal plants,
    - 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

[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.

number of participants, 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

[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.

is described as "ICF program assumption." With proper program design, HVAC contractors, 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%

[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.

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.

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.

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[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:

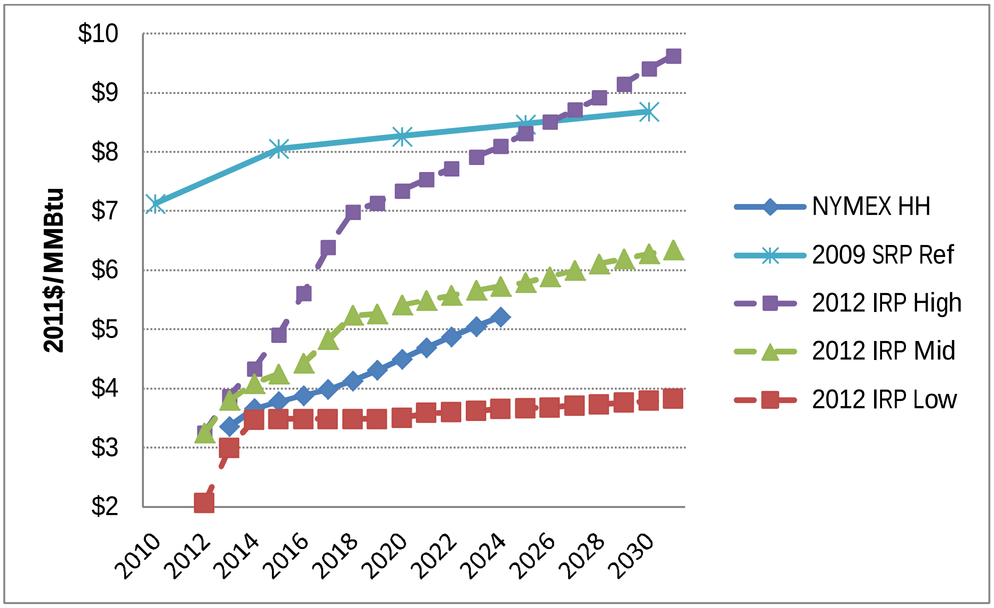
- understating the capital costs, operating costs and energy usage of selective catalytic reduction (SCR) for NOx control and sorbent injection for mercury control, in part due to errors in transcribing data from consultant reports;
- including the costs of 85% SO_2 removal, even though Entergy's own 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	$/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%	50	MJMEUC	$46	$613
				12.3%	75	Independence P&L		
				6.6%	40	Kansas Power Pool		
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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Entergy. 2012f. "Entergy Arkansas, Inc Response to Questions from Stakeholders at the July 31, 2012 Integrated Resource Planning (IRP) Meeting." Little Rock: Entergy Arkansas

Entergy. 2012g. "Entergy Arkansas Integrated Resource Plan General Review: Load and Capability, Assumptions, Stakeholder Input from 2009" presentation at the July 31 2012 Entergy Arkansas Stakeholder Meeting.

Entergy. 2012h. "Preliminary 2012 EAI Integrated Resource Plan (IRP) Action Plan" presentation at the July 31 2012 Entergy Arkansas Stakeholder Meeting.

Zindler, Ethan. 2012. "Overcapacity and New Players Keep Wind Turbine Prices in the Doldrums" Bloomberg New Energy Finance 6/3/2012.

ARKANSAS ADVANCED ENERGY ASSOCIATION

September 28, 2012

Mr. Kurt Castleberry
Entergy Arkansas, Inc.

VIA E-MAIL

RE: EAI 2012 Integrated Resource Plan (IRP)

Mr. Castleberry,

Please find attached the comments and concerns of the Arkansas Advanced Energy Association, a member of the Stakeholder Group which participated in EAI's 2012 Integrated Resource Plan.

Our members appreciate the opportunity to participate in this important process and look forward to working with EAI in the future.

Sincerely,

Stephen K. Patterson
Executive Director
501-537-0190
501-658-1215 - M

AAEA Comments Regarding Entergy Arkansas's Integrated Resource Plan
October 1st, 2012

IRP Process

AAEA appreciates EAI for the quality of its Integrated Resource Plan (IRP) presentations, the information provided to stakeholders, and the company's efforts to answer questions and provide additional information. However, we find fault in the structure and process of the IRP proceedings. First and foremost, AAEA does not characterize the IRP as a true participatory process by the company and stakeholders. Company conclusions were derived well before stakeholder meetings and thus presented as a *fait accompli*. Stakeholders were unable to work with the company in a fully participatory process to examine supply side and demand side energy options.

Second, the IRP timeline was much too condensed. Stakeholders saw the draft IRP for the first time on July 31st, and were given until August 13, or two weeks, to submit questions on information that was technical, time consuming, and difficult to fully comprehend. Following EAI's answers to stakeholder questions distributed on September 1, these final comments contained in this document were due from stakeholders by the end of September. Thus stakeholders were handicapped in understanding and responding to the load requirements, the company's calculations, and the scenarios and portfolio options presented. Stakeholders were therefore unable to engage in the process effectively. For a more meaningful and participatory stakeholder process, EAI should have hosted several more stakeholder meetings beginning earlier in the year.

This has been AAEA's first experience with a utility's IRP process. Based on this experience, the association will ask the Arkansas Public Service Commission (APSC) to initiate a rule-making process for integrated resource planning (as was done in Louisiana) that provides a participatory process for stakeholders that starts at least one year prior to the IRP's submission to the Commission.

Demand Side Management

The AAEA is supportive of EAI's Demand Side Management plan and the proposed megawatt-hour (MWh) savings as forecasted in the IRP. EAI's energy savings of about 0.75% of 2010 total energy sales is a reasonable expectation over the 10-year period. Should the APSC order a higher Energy Efficiency Resource Standard (EERS) in 2014 and should the State of Arkansas update energy codes for commercial and residential owners, we expect EAI to modify its DSM programs to reflect an increase in MWh energy savings and a reduction in system MWs needed to meet capacity levels.

Renewable Energy

AAEA is disappointed with EAI's treatment of renewable energy for generating electricity over the ten-year period of the IRP. While the company did perform an economicanalysis that included renewables, that analysis raised many questions within AAEA. We question how EAI concludes that renewables are unattractive as cost-effective generators over the 10-year period in contrast to its southern utility peers including AEP/SWEPCO, OG&E, and even Alabama Power, whose Vice President, Matt Bowen, stated that the utility's purchase of 202MW of Oklahoma wind power last year "provides real savings for our customers." It is our opinion that EAI should have included at least 200 MW of renewable energy in its final recommendation to, at a minimum, gain the experience, the knowledge and portfolio diversity that comes from incorporating renewable energy into its generation fleet in Arkansas. This does not consider the numerous environmental benefits, local job creation, and economic development benefits for the State of Arkansas. Even at EAI's inflated cost figures for renewables, wind energy finished very close in cost to natural gas. Below are AAEA's specific comments about EAI's treatment of renewable energy in the IRP.

Wind Analysis

The EAI analysis assumed wind at a cost of $137/MWh (without incentives) and $112/MWh (with incentives). Both cost assumptions are well more than double the market's current PPA pricing[1]. These figures include a $34 "Capacity Matchup Fee" and an additional $14 for "Flexible Capability Cost", which is apparently intended to cover the spinning reserve (i.e. wind integration charge). Upon investigation of the cost-buildup spreadsheet provided by EAI, the AAEA believes these charges are overstated and, at a minimum, duplicative.

Regarding the "Capacity Matchup Fee", EAI's spreadsheet indicates an assignment of 39% for the Renewable Capacity Factor and 5% for the Renewable Capacity Value. Both of these values are low. The 39% RCF value appears to be an industry average value for U.S. based wind resources. However, it does not accurately depict the higher capacity factor values that are readily available to EAI from wind resources located in the

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[1] DOE 2011 Wind Technologies Report
http://www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf

Midwest and Southwest United States. Based upon our research, as well as the DOE's 2011 Wind Technologies Report[2] (see Figure 29, page 46), a more appropriate RCF value of 45% should be used. (In fact, 50% net capacity factors are quite common in the Midwest and Southwest due to recent advances in turbine blade technology.) Additionally, EAI's use of 5% for the Renewable Capacity Value is low. According to the Midwest Independent System Operator's (MISO) website, MISO assigned a system wide capacity value of 14.7% to wind resources in 2012[3]. Since EAI has announced that it will be joining the MISO, it seems reasonable that EAI should incorporate the same system-wide Renewable Capacity Value to wind resources as is used by MISO. Incorporating these two recommendations into the EAI calculations substantially lowers EAI's Capacity Matchup Cost for wind resources by almost $8/MWh.

Regarding EAI's "Flexible Capability Cost", AAEA believes EAI's cost buildup has errors, resulting in a very high charge of $14/MWh. In fact, the charge of $14/MWh determined by EAI appears to be higher than any other comparable "wind integration" charges known to the industry.[4] The industry typically allocates $3 - $8/MWh for this purpose (2011 Wind Technologies Report, pages 63-67). Based upon AAEA's review of EAI's spreadsheet, it appears that EAI has incorrectly allocated both Fixed Cost and Energy Cost components to their Flexible Capacity Cost calculation. Since EAI's Capacity Matchup Fee already captures the cost of capacity related to the installation of

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[2] http://www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf

[3] https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2011/20111109/20111109%20LOLEWG%20Item%2002%20%20Wind%20Capacity%20Credit.pdf

[4] Page 63-67 of 2011 Wind Technologies Report http://www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf

new CTs (see prior paragraph), there should be no reason for EAI to charge wind resources with a *second* capacity based charge entitled “Fixed Cost.” Even if EAI could somehow prove the Fixed Cost component is justified, there appear to be errors and significant incorrect assumptions within their calculations. For instance, EAI again used a faulty RCF value of 39%. They also assume, without explanation, a 50% multiplier called “Percent of Time Flexible Capability Required.” (Apparently, the 50% multiplier is the amount of time that EAI believes a CCGT will be inefficiently dispatched and thereby replaced by a CT). However, in EAI’s original estimates for CCGT resources, EAI states that CCGTs possess a 65% Capacity Factor. If wind resources possess a 45% Capacity Factor, how does EAI conclude that CCGTs will be dispatched inefficiently 50% of the time due to wind resources? The percentage difference between .65 and .45 is only 31%; therefore, EAI’s 50% assumption is obviously flawed.

Even if the additional $49 were deemed to be appropriate, the resulting assumptions of $63/MWh (with incentives) and $87/MWh (without incentives) remain much higher than wind’s current cost -- as low as $30 -$40/MWh at the busbar (2011 Wind Technologies Report, Page 52). As stated by the DOE[5]:

“…In fact, levelized PPA prices in the $30-$40/MWh range – currently achievable (at least with the PTC) in many parts of the interior U.S. – are fully competitive with the range of wholesale power prices seen in 2011…”

[5] Page 52 DOE’s 2011 Wind Technologies Market Report
http://www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf

Excluding the afore-mentioned excessive charges, the analysis demonstrates that wind is extremely competitive with CCGT (EAI's preferred generation source) and, in some scenarios is about 25% less expensive. Accordingly, EAI's comparative analysis must be considered significantly flawed. It does not serve the interests of Arkansas, its citizens or ratepayers, and is a disservice to the wind industry.

Combined Heat and Power From Biomass

AAEA is also disappointed that EAI did not quantify the potential for or consider the opportunity for biomass-derived Combined Heat and Power (CHP) as a generation source of electricity in the IRP. New federal air quality requirements offer an opportunity for EAI to expand CHP with industrial customers that will have to retire oil or coal boilers or will have to retrofit with air quality controls or retrofit with natural gas boilers or CHP; in some cases, biomass systems may be an attractive option.

AAEA encourages the owners of boilers to convert to CHP using biomass feedstocks, thus contributing to renewable electricity generation and the economy of Arkansas. The utility could work with industrial customers to build/expand CHP facilities with EAI or the partnership selling both power and steam to the host. This approach avoids a loss of sales to the utility and a large capital expense to the steam host.

Time of Use Rates

AAEA endorses the recommendation of the Arkansas Electric Energy Consumers to urge EAI to implement time-sensitive rates for all customer classes. Time-sensitive rates would lead to greater energy conservation during "on-peak" hours and contribute to more "off-peak" energy use. The present flat rate, i.e., a one-size-fits- all approach works against energy conservation and the development and use of renewable energy sources.

Legacy Deactivation

AAEA supports EAI's plan to deactivate 422 MWs of legacy generation of gas/oil/diesel-fired units as well as other legacy units that are under consideration. We encourage EAI to develop, over the next ten years, a diverse and balanced portfolio of renewable electricity generation that incorporates biomass-fired combined heat and power, stand alone biopower, solar, and wind generation to complement its existing conventional powered fleet. The results could help EAI meet its expanded future generation capacity requirements, support in-state job creation and economic development (particularly when using locally-source biomass feedstocks), help sustain Arkansas's renewable energy equipment manufacturers, and result in numerous environmental benefits. Business as usual may achieve capacity requirements and may arguably result in some job creation but it achieves none of the other aforementioned benefits for the State of Arkansas.

2012 Stakeholder Report Attachment No. 2

Stakeholder Meeting Sign In Sheets

SIGN IN SHEET
Entergy Arkansas, Inc.
IRP (Integrated Resource Planning) Stakeholder Meeting
Verizon Arena, 1 Verizon Arena Way
North Little Rock, AR
July 31, 2012

NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
Rick Smith	EAI	425 W. Capitol, LR.	501-377-3530	rsmit18@entergy.com.
Paul Bachmuth	Tradewind		913-433-8850	pbachmuth@tradewindenergy.com
Denise Jeter	EAI	425 W. Capitol LR	501-377-3686	djeter90@entergy.com
KEVIN LARSON	MISO	701 CITY CENTER DR Carmel IN	317-249-5829	Klarson@misoenergy.org
Aliana Brenske	APSC	1000 Center	501-682-5656	Abrenske@psc.state.ar.us
Myra Glover	ESI		281-297-3306	mglover@entergy.com
George Heintzen	Conway Corp	PO Box 99	501 450-6019	george.heintzen@conwaycorp.net
Ken Smith	AAEA	14 PARK DRIVE	501-912-1090	Ken@KLSmithConsulting.com
JAKE RICE	CWL	400 EAST MONROE JONESBORO AR	870-930-3395	jrice@jonesborocwl.org
BRIAN DONAHUE	AEEC	PO BOX 567 JACKSONVILLE AR	501-246-1120	bdonahuelaw@comcast.net
Mitchell Simpson	AEDC-AEO	900 W. Capitol, LR	501-682-1060	msimpson@arkansasedc.com
JEREMY TOWNSEND	CLEAResult	1 Allied Drive #1600	501-221-4005	jtownsend@clearesult.com

SIGN IN SHEET
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North Little Rock, AR
July 31, 2012

NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
Matt Suffern	EAI	~~200~~ 425 W Cap	3775855	
Shawn McMurray	A Hy. General	323 Center St., Suite 200	682-1053	
Eddy Moore	APSC	1000 Center St.	682-5800	emoore@psc.state.ar.us
Wesley Hunt	EAI	425 W. Capitol	4303	whunt1@entergy.com
Cousins, Steve	Lion Oil	1000 McHenry El Dorado AR	8708647120	steve.cousins@lionoil.com
Tim Scott	AEO	900 W. Capital LR	5016822433	
J.D. Lowery	AEO	" "	501-682-7678	

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SIGN IN SHEET

Entergy Arkansas, Inc.
IRP (Integrated Resource Planning) Stakeholder Meeting
Verizon Arena, 1 Verizon Arena Way
North Little Rock, AR
July 31, 2012

NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
CHARLES LONG	ENTERGY	EHQ	601-985-2260	clong1@entergy.com
DON ERBACH	Paschall Strategic			
SCOTT TROTTER	Entergy/Outside Counsel		501 603-9000	

SIGN IN SHEET
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North Little Rock, AR
July 31, 2012

NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
Matt Wolf	EAI		501-620-5761	hwolf1@entergy.com
Phil Carter	EAI		281-297-3588	wcarter@entergy.com
William Ball	Stellar Son		501-993-0032	bill@stellarson.com
Valerie Boyce	APSC	1000 Center LR 72201	501 682 5827	valerie_boyce@psc.state.ar.us
Robert Swain	APSC			robert_swain@psc.state.ar.us
Lovita Griffin	APSC	1000 Center St	501-6825659	LGriffin@psc.state.ar.us
Jeff McGee	EAI		501-377-3976	JMcGee@Entergy.com
Rick Henley	CVL	P.O. Box 1289 [illegible], AR 72[illegible]	870-[illegible]-3567	RHENLEY@[illegible]
Robert Robinette	EAI		501-377-4294	rrobine@entergy.com
Tim Davis	APSC		501-682-5720	kdavis@psc.state.ar.us
Becky Turner	Entegra		813 301 4925	rturner@entegrapower.com

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SIGN IN SHEET

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Verizon Arena, 1 Verizon Arena Way
North Little Rock, AR
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NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
Jeremy Champlin	Entergy	425 W Capitol LR AR	501-377-5959	jchampl@entergy.com
Clark Cotten	APSC	1000 Center	682-5714	ccotten@psc.state.ar.us
Mike Por	ADEQ	5301 Northshore Dr	682-0770	porta@adeq.state.AR.us
[illegible]	ABC	1615 Grigsby Ford	501-332-6793	rhice@brick.com
Paul Chernick	RII / Audubon	5 Water St, Arlington MA	781-646-1505	pchernick@resourceinsight.com
Terry Kessinger	ICF I			tkessinger@comcast.net
John Elkins	ABC	1000 center St.		jelkins@psc.state.ar.us
MATT KLUCHER	APSC	1000 Center St	501-682-5773	mklucher@psc.state.ar.us
DAVID PICKLES	ICF	7160 N. Dallas Pkwy 340 Plano TX	972 841 2567	dpickles@icfi.com
WALLY NIXON	APSC	1000 Center St.	501-682-5797	wnixon@psc.state.ar.us
E. Bonner	Entergy / URP	102 N. Ashley St, Tampa, FL Suite 1900 33602	813-205-8797	ebonner@entergy-power.com
Chip Estes	Utilicom	Box 70 Flora MS	769-233-4006	chipestes@gmail.com

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SIGN IN SHEET

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Verizon Arena, 1 Verizon Arena Way
North Little Rock, AR
July 31, 2012

NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
Elizabeth Kaiser	GDS Associates			elizabeth.kaiser@gdsassociates.com
Glen Hooks	Sierra Club	1308 W. 2nd LR, AR 72201	501 324 9280	glen.hooks@sierraclub.org
Robert Shields	AECC	1 Cooperative Way LR AR	501-570-2408	rshields@aecc.com
Stephanie Fowler	Entergy	Malvern, AR	501 844-2155	sfowle1@entergy.com
Erica Mahony	AG's office	323 Center St, Ste 200	501-682-3625	erica.mahony@arkansasag.gov
John Bethel	PSC	1000 Center	501 682 1794	john_bethel@psc.state.ar.us

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Entergy Arkansas, Inc.
IRP (Integrated Resource Planning) Stakeholder Meeting
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North Little Rock, AR
July 31, 2012

NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
Kurt Castleberry	EAI			kcastle@entergy.com
Phil Harris	Entergy Fossil			pharris@entergy.com
Charles DeGeorge	ESI			cdegeor@entergy.com
Colette Green	EAI			cgreen1@entergy.com
Jisso Russ	ESI			jruss2@entergy.com
Susan Davidson	EAI			sdavids@entergy.com
Rao Konidena	MISO			RKONIDENA@MISOENERGY.org
Steve Strickland	EAI			sstrick@entergy.com
Matt Hollowell	Benton Utilities			matth@bentonar.org
Glen Hooks	Audubon			
Ron Bowen	CWL Jonesboro, AR			rbowen@jonesborocwl.org
Gabe Munoz	EAI			gmunoz@entergy.com

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SIGN IN SHEET

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North Little Rock, AR
July 31, 2012

NAME	COMPANY / ORGANIZATION	BUSINESS ADDRESS	TELEPHONE	EMAIL ADDRESS
Elana Davis	APSC	1000 Center St, Little Rock, AR	501-682-5658	edavis@psc.state.ar.us
Regina Butler	APSC	✓ ✓ ✓ ✓ ✓ ✓	501-683-0005	
Paul Bachmuth	TradeWind Energy	16105 W. 113th St. Lenexa, KS 66219	913-433-8850	pbachmuth@tradewindenergy.com

Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

501-682-0730
FAX: 501-682-0753
www.adeq.state.ar.us

Mike Porta, PE
Assistant Chief
Air Division
Porta@adeq.state.ar.us

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Entergy Arkansas, Inc.
Integrated Resource Plan
Stakeholder Committee Meeting

July 31, 2012

Today's Agenda

Agenda Item	Presenter	Time
Introduction and Meeting Objectives	Kurt Castleberry	8:30 – 9:00
EAI Resource Planning History	Kurt Castleberry	9:00 – 9:30
EAI Current Capacity Position	Matt Wolf	9:30 -10:00
Break		10:00 – 10:15
EAI's Role in Transmission Planning	Kurt Castleberry	10:15 – 10:30
Overview of Environmental Issues	Myra Glover	10:30 – 11:15
Demand Side Management and Energy Efficiency	Richard Smith	11:15 – 12:00
Lunch		12:00 – 1:00

Today's Agenda (Cont'd)

Agenda Item	Presenter	Time
Generation Technology Assessment & Production Cost Analysis	Charles DeGeorge	1:00 – 2:00
Preliminary Resource Plans	Matt Wolf	2:00 – 2:45
Break		2:45 – 3:00
Stakeholder Committee Formation	Stakeholders	3:00 – 4:00
EAI Respond to Written Stakeholder Questions	EAI	4:00 – 4:45
Wrap-up and Adjourn	Kurt Castleberry	4:45 – 5:00

What is the Purpose and Objective of Today's Meeting?

- Discuss EAI's Integrated Resource Plan process, assumptions, preliminary plans and schedule
- Allow stakeholders an opportunity to organize a committee to develop the Stakeholder's Report

EAI Statistics

Peak Load (2011)	5,178 MW
Retail Sales (2011)	21,583,567 MWh
# Retail Customers (2011 year-end)	695,397
# Active Electric Generating Units	26
# Power Plant Sites	13
Generating Capacity (Summer 2012 Ratings)	
- Nuclear	2,285 MW
- Coal	1,209 MW
- Gas / Oil	1,528 MW
- Hydro	94 MW
Total Capacity (Retail and Wholesale)	5,116 MW
Transmission Lines (miles)	4,744
Distribution Lines (miles)	37,455

What is Integrated Resource Planning?

"…..a utility planning process which requires consideration of all reasonable resources for meeting the demand for a utility's product, including those which focus on traditional supply sources and those which focus on conservation and the management of demand."

" The process results in the selection of that portfolio of resources which best meets the identified objectives while balancing the outcome of expected impacts and risks for society over the long run."

- Source: APSC's Resource Planning Guidelines

Who Comprises the Stakeholder Committee and Why Stakeholder Involvement?

The Stakeholder Committee is comprised of:

"…..retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area."

Why?

"The reason for stakeholder involvement is to open up the planning process and provide an opportunity for others with an interest in the planning process to provide input as a check on the reasoning of a utility during the development of the resource plan."

- Source: APSC's Resource Planning Guidelines

EAI and Stakeholder Committee – Roles and Responsibilities

- **EAI will:**
  - » *"organize and facilitate meetings of a Stakeholder Committee for resource planning purposes"*
  - » *"make a good faith effort to properly inform and respond to the Stakeholder Committee"*
  - » Include a Report of the Stakeholder Committee with EAI's October 2012 Integrated Resource Plan filing

- **The Stakeholder Committee:**
  - » *"shall develop their own rules and procedures"*
  - » *"Stakeholders should review utility objectives, assumptions and estimated needs early in the planning cycle"*
  - » Develop a report of the Stakeholder Committee and provide to EAI

Stakeholder Process Timeline

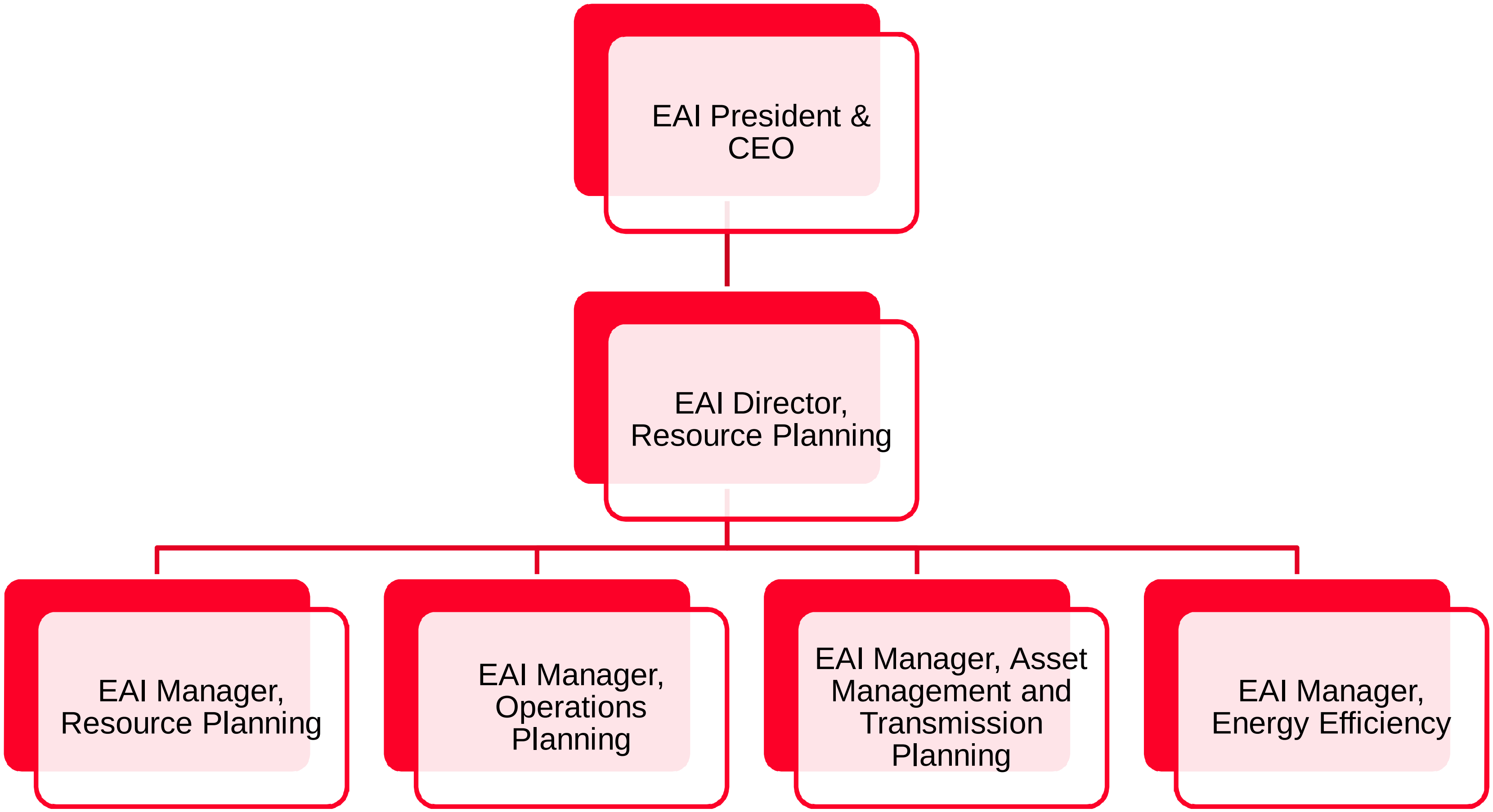
ACTIVITY	DATE
Stakeholder meeting	July 31
Stakeholder / EAI interaction (as needed)	August 1 – September 30
Stakeholders finalize Stakeholder Report and provide to EAI	October 1 – 30
EAI finalizes IRP and files it with the APSC including Stakeholder Report	October 1 - October 31

Ground Rules

- A lot of material – Need to stay on schedule
- Ask questions but time constraints may limit number of questions allowed. However, EAI will answer ALL stakeholder questions either in today's meeting or the questions and their answers will be posted @ http://entergy-arkansas.com/transition_plan/
- Cards are available at each table for written questions. Please use these cards for the more extensive questions. EAI will answer these questions at the end of today's session or will post answers at the above link
- Stay on topic – Do not interject questions or comments related to other issues.
- Keep side-bar discussions to a minimum
- EAI will endeavor to respond to questions or get information to Stakeholder Committee members as quickly as is practical

EAI Resource Planning Organization and Governance

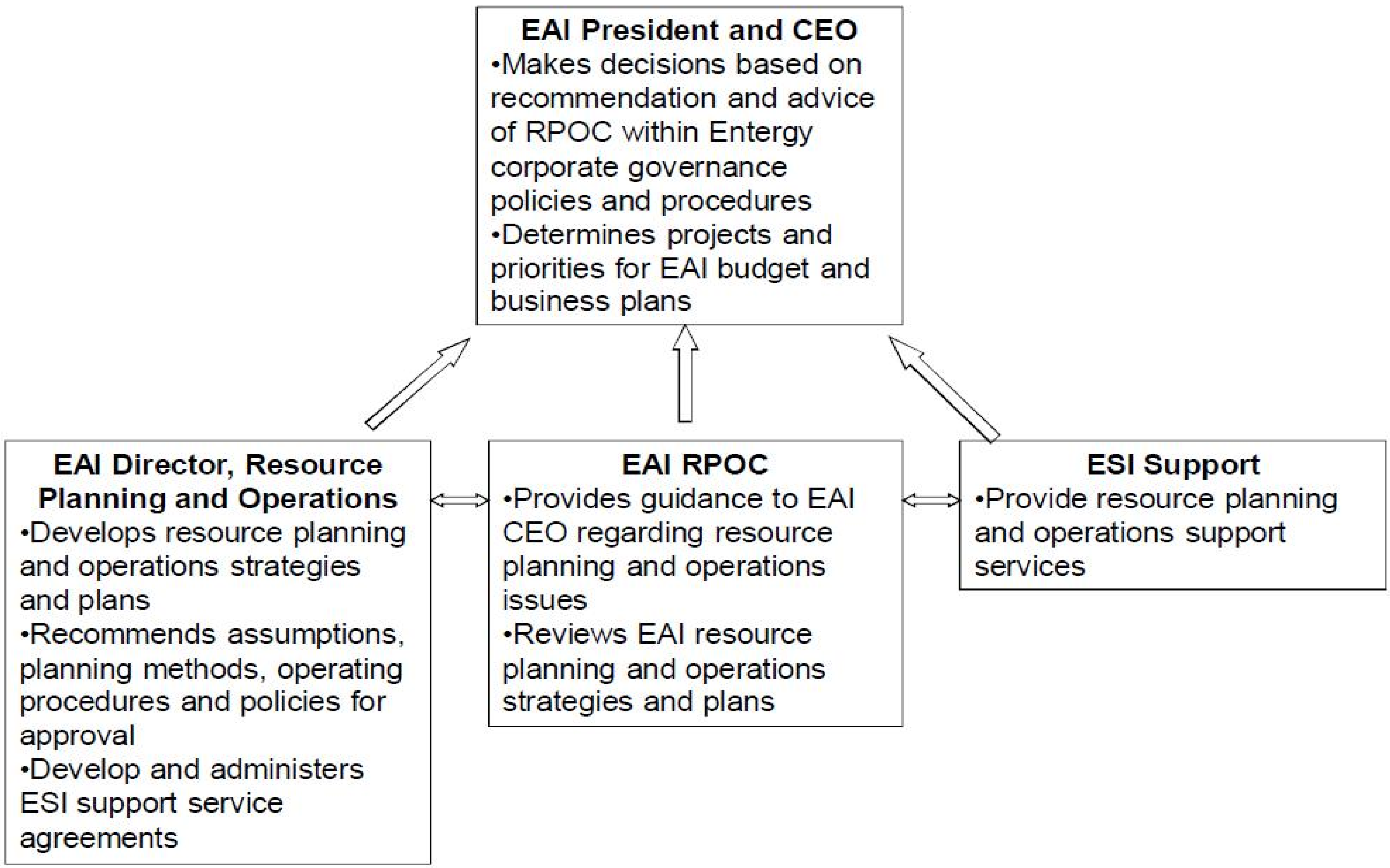
EAI Management Structure with Key Roles for Resource Planning and Operations



EAI Resource Planning and Operations Committee (RPOC)

- Chair
  EAI Director, Resource Planning and Operations
  - EAI Vice President Regulatory Affairs (Vice Chair)
  - EAI Legal Counsel (Secretary)
  - ESI Director - EAI Jurisdictional Finance
  - ESI Vice President - System Planning and Operations
  - ESI Director – Fossil Operation NW Region
  - ESI Vice President - Nuclear Operations
  - EAI Manager, Resource Planning
  - EAI Manager, Operations Planning

EAI Resource Planning and Operations Governance



EAI / ESI Support Services Agreement

Services that EAI may continue to utilize from the System Planning and Operations organization may include, but are not limited to:

1. Performing load forecasting and technical support for integrated resource planning and operations
2. Providing technical support for EAI's transmission service arrangements and evaluation of potential economic transmission upgrades
3. Arranging for non-nuclear fuel supplies
4. Providing technical support for generation resource procurement
5. Performing real-time operations for EAI's generation fleet, and operating plans, including planned and maintenance outages for EAI's generation fleet
6. Buying and selling capacity and energy on behalf of EAI, including providing administration services for contractual arrangements, and power supply accounting and settlements for power and energy
7. Representing EAI in industry and stakeholder committees

EAI Resource Planning Objectives

EAI Resource Planning Objectives

EAI has adopted the following resource planning objectives to guide EAI's Integrated Resource Plan (IRP) and to meet requirements of the APSC Resource Planning Guidelines for Electric Utilities:

1. **<u>Policy Objectives</u> – The development of the IRP should reflect policy and planning objectives reviewed by the EAI RPOC and approved by EAI's President and Chief Executive Officer. Those policy and planning objectives will consider and reflect the policy objectives and other requirements provided by EAI's regulators.**

2. **<u>Resource Planning</u> – The development of the IRP will consider generation, transmission, and demand-side (e.g., demand response, energy efficiency) options.**

EAI Resource Planning Objectives

3. Planning for Uncertainty – The development of the IRP will consider scenarios that reflect the inherent unknowns and uncertainties regarding the future operating and regulatory environments applicable to electric supply planning including the potential for changes in statutory requirements.

4. Reliability – The IRP should provide adequate resources to meet EAI's customer demands and expected contingency events in keeping with established reliability standards.

5. Baseload Production Costs – The IRP should provide baseload resources that provide stable long-term production costs and low operating costs to serve baseload energy requirements.

EAI Resource Planning Objectives

6. Operational Flexibility for Load Following – The IRP should provide efficient, dispatchable, load-following generation and fuel supply resources to serve the operational needs associated with electric system operations and the time-varying load shape levels that are above the baseload supply requirement. Further, the IRP should provide sufficient flexible capability to provide ancillary services such as regulation, contingency and operating reserves, ramping, and voltage support.

7. Generation Portfolio Enhancement – The IRP should provide a generation portfolio that over time will realize the efficiency and emissions benefits of technology improvements and that avoids an over-reliance on aging resources.

8. Price Stability Risk Mitigation – The IRP should consider factors contributing to price volatility and should seek to mitigate unreasonable exposure to the price volatility associated with the major uncertainties in fuel and purchased power costs.

EAI Resource Planning Objectives

9. <u>Supply Diversity and Supply Risk Mitigation</u> – The IRP should consider and seek to mitigate the risk exposure to major supply disruptions such as outages at a single generation facility or the source of fuel supply.

10. <u>Locational Considerations</u> – The IRP should consider the uncertainty and risks associated with dependence on remote generation and its location relative to EAI's load so as to enhance the certainty associated with the resource's ability to provide power to EAI's customers.

11. <u>Reliance on Long-Term Resources</u> – EAI will meet reliability requirements primarily through long-term resources, both owned assets and long-term power purchase agreements. While a reasonable utilization of short-term purchased power is anticipated, the emphasis on long-term resources is to mitigate exposure to supply replacement risks and price volatility, and ensure the availability of resources sufficient to meet long-term reliability and operational needs. Over-reliance on limited-term purchased power (*i.e.*, power purchased for a one to five year term) exposes customers to risk associated with market price volatility and power availability.

EAI Resource Planning Objectives

12. <u>Sustainable Development</u> – The IRP should be developed consistent with EAI's vision to conduct its business in a manner that is environmentally, socially and economically sustainable.

Questions / Comments

Entergy Arkansas Integrated Resource Planning History - Overview

July 31, 2012

Entergy

Objective

- Review resource planning activities since EAI gave notice that it would exit the Entergy System Agreement

Significant Resource Planning Events

2005 EAI gives notice to exit the Entergy System Agreement

2006 Energy Efficiency Docket Opened

2008 Ouachita Power Plant Purchase completed

2009 White Bluff Environmental Controls Analysis completed for CAVR

2009 EAI IRP filed with APSC

2009 EAI Stand-Alone Plan filed with APSC

2011 Hot Springs KGen acquisition announced

2011 MISO Announcement

2011 RFP Issued for up to 750 MW

2012 Deactivation Analysis Completed

Negotiating with two bidders from 2011 RFP

2012 Application made to add certain wholesale base load resources to serve EAI's retail load

2012 IRP Development

2005 – "Notice"

- The Entergy Operating Companies have operated as a pool utilizing some form of a system agreement since 1951
- Due to the outcome of litigation at the FERC regarding the current System Agreement, EAI gave its 96-month notice to withdraw from the System Agreement on December 19, 2005
- Departure Day (D-Day) is December 19, 2013
- EAI must have in place systems to operate an electric system and sufficient capacity and reserves to serve its customers

2006 – Energy Efficiency

- In 2006, the APSC opened the energy efficiency and conservation docket (06-004-R)
- In 2007, EAI filed its first application for approval of energy efficiency programs and energy cost rate rider
- (More details to follow in Richard Smith's presentation)

2008 – Closed Ouachita Acquisition

- RFP issued in 2006
- A purchase agreement was executed by EAI in 2007 to buy the Ouachita Power facility from Cogentrix Energy, Inc.:
  - 789 MW nominal
  - Combined Cycle
- Transaction was completed in September 2008.
  - EAI owns two of the three trains in the plant
  - Entergy Gulf States Louisiana, LLC owns one train

2009 – Stand-Alone Plan

- In 2008 EAI began developing preliminary estimates of the cost and structure needed for EAI to plan and operate outside the Entergy System Agreement

- EAI filed these cost estimates with the APSC in 2009

- Technical conferences were held in 2010 regarding this option

2009 – White Bluff Environmental Controls

- EAI requested a Declaratory Order from the Commission finding that the addition of a Flue Gas Desulfurization system and Low Nitrogen Oxide Burners and Separated Overfire Air at White Bluff for compliance with the Clean Air Visibility Rule ("CAVR") is in the public interest (APSC Docket 09-024-U)
- A petition for a variance from the October 15, 2013 compliance deadline for the CAVR was granted by the Arkansas Pollution Control and Ecology Commission in 2010
- EAI withdrew its Declaratory Order request in May 2010
- Myra Glover's Presentation will provide more details on the current status

2011 – KGen Hot Spring Plant

- RFP issued in 2009
- EAI announces plan to purchase the Hot Spring Plant in July 2011
  - 620 MW
  - Combined Cycle
- APSC approved the acquisition on July 11, 2012
- Awaiting clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the ''HSR Act'')

2011 – MISO Announcement

- Entergy Operating Companies announced on April 25, 2011 that they intended to join MISO as a fully integrated transmission owning member
- What is MISO?
  - A Regional Transmission Organization
    - Maintains reliability of the transmission system
    - Administers a regional transmission tariff
    - Facilitates a transmission expansion planning process
    - Manages an energy market
    - Ensures that adequate resources are available to serve load

2011 – MISO (Continued)

- EAI is working towards integrating into MISO when EAI exits the Entergy System Agreement (December 19, 2013)

- EAI will continue to be responsible for planning the resources needed to meet its customer's demand

2011 – RFP Issued

- EAI issued an RFP for up to 750 MW limited term resources
- In November 2011, EAI selected two proposals for additional negotiations
- In February 2012, EAI executed letters of intent with both counterparties
- In June 2012, EAI made an application with the APSC for approval of a capacity cost recovery rider
- EAI expects to finalize definitive purchase power agreements with both counterparties in the near future

2012 Wholesale Base Load Capacity

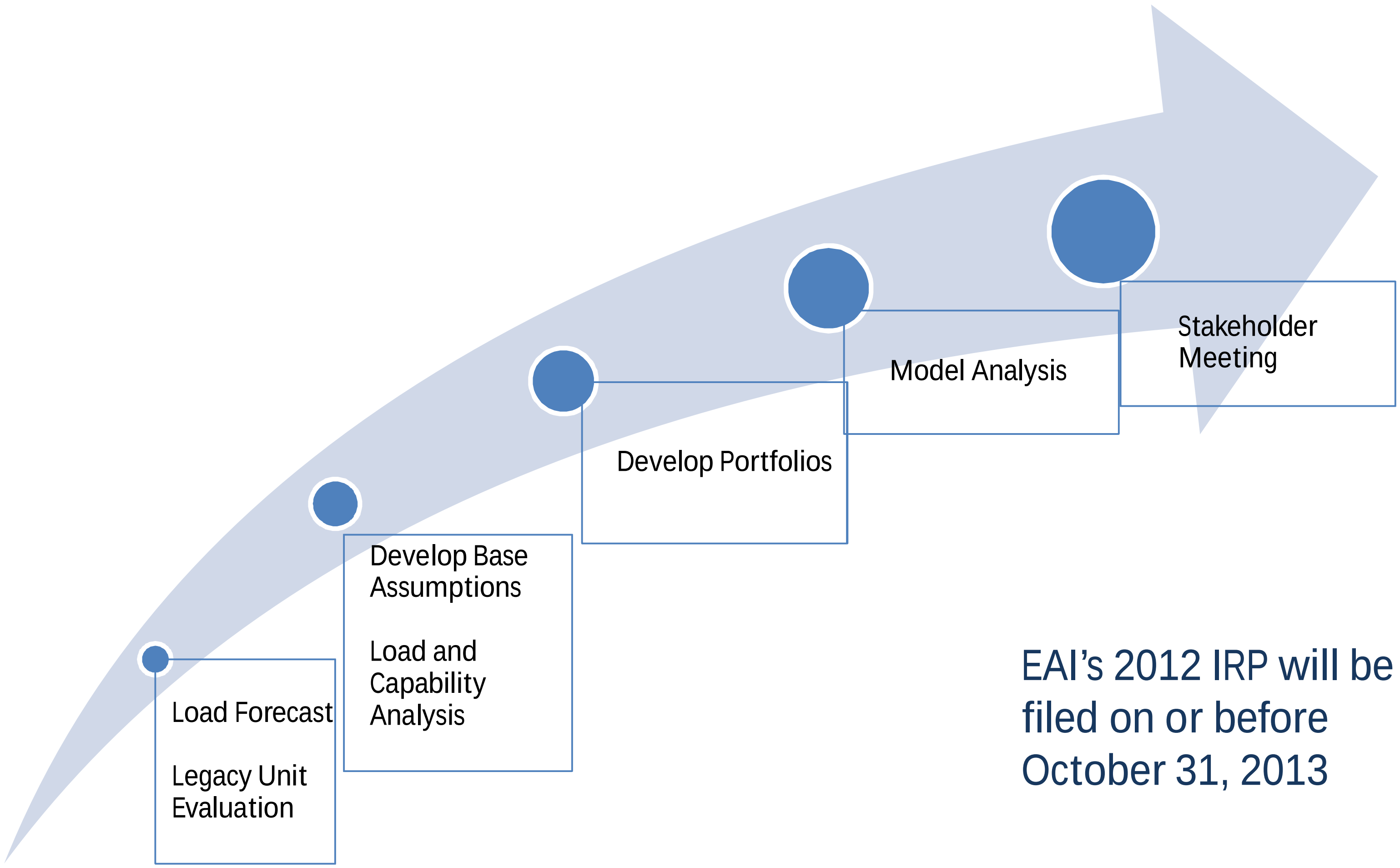
- A portion of the generation capacity that EAI owns is not currently in retail rates

- In June 2012, EAI made an application to the APSC seeking to return a portion of this capacity to retail rates (APSC Docket No. 12-038-U):

2013:	100 MW
2014 and beyond:	186 MW
================================	
Total	286 MW

- The capacity is fueled by nuclear and coal
  - 184 MW nuclear
  - 102 MW coal

2012 IRP Development



EAI's 2012 IRP will be filed on or before October 31, 2013

Questions / Comments

Entergy Arkansas Integrated Resource Plan
General Review

- Load and Capability
- Assumptions
- Stakeholder Input from 2009

July 31, 2012

Entergy

Purpose

- Give an overview of EAI's current capacity position
  - Load Forecast
  - Existing Generation Capability

- Describe the base assumptions and the focus of the IRP model analysis

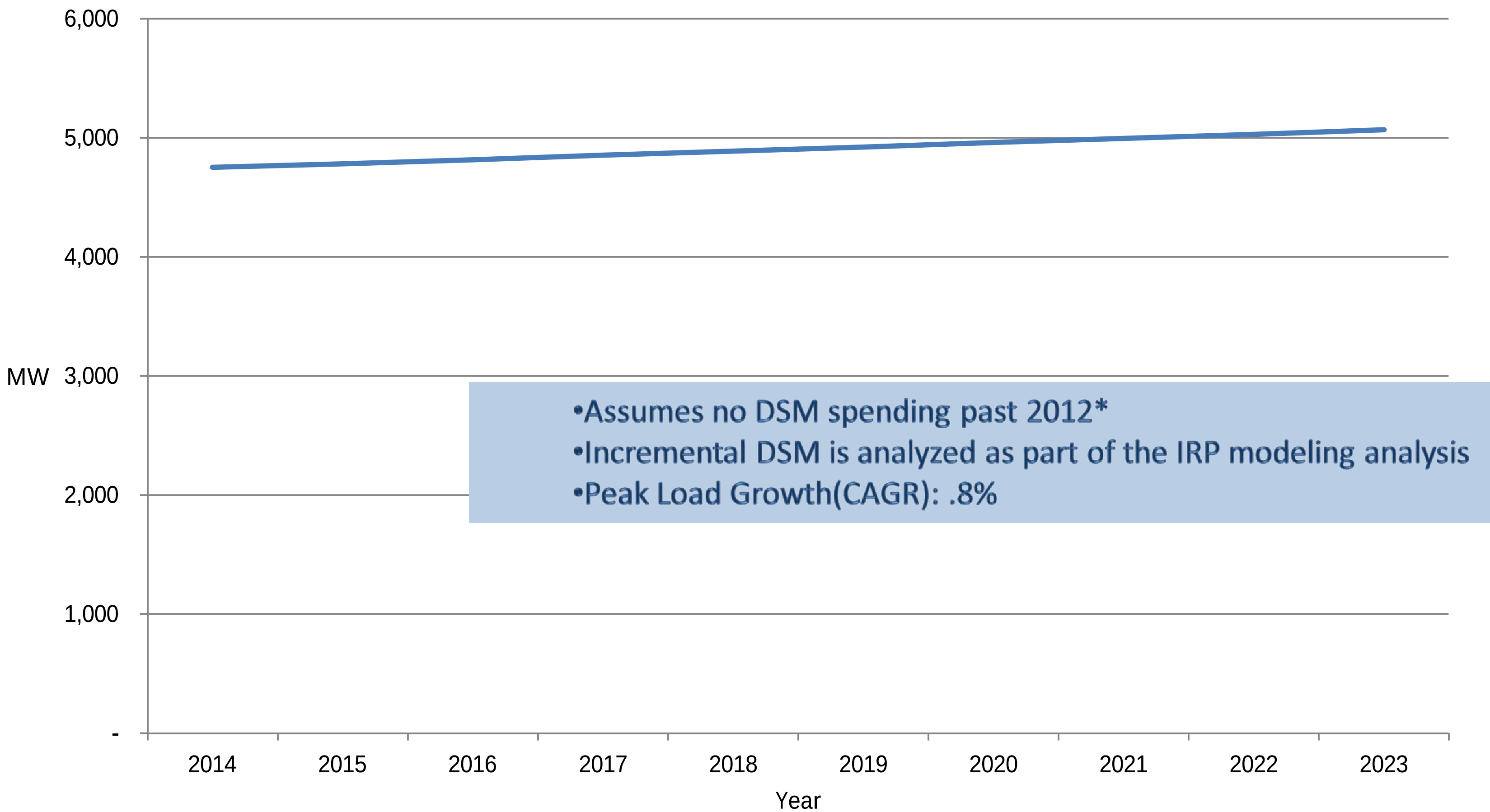
- Review the stakeholder committee input from 2009, and how EAI sees IRP addressing that input

IRP Study Period

- The study period for the 2012 IRP is 10 years (2014 – 2023)
- Reasons:
  - Significant changes to EAI's planning and operations framework supports a more concentrated focus on the near-term issues:
    - MISO Transition
    - Post-Entergy System Agreement Transition
    - The uncertainties surrounding these issues and their influences on EAI's capacity needs and options render longer term (i.e., > 10 years) too speculative
  - Adequate generation capacity in the region for the next several years

Load and Capability

EAI Retail Load Forecast (Includes existing DSM) Base Case (Scenario 1)



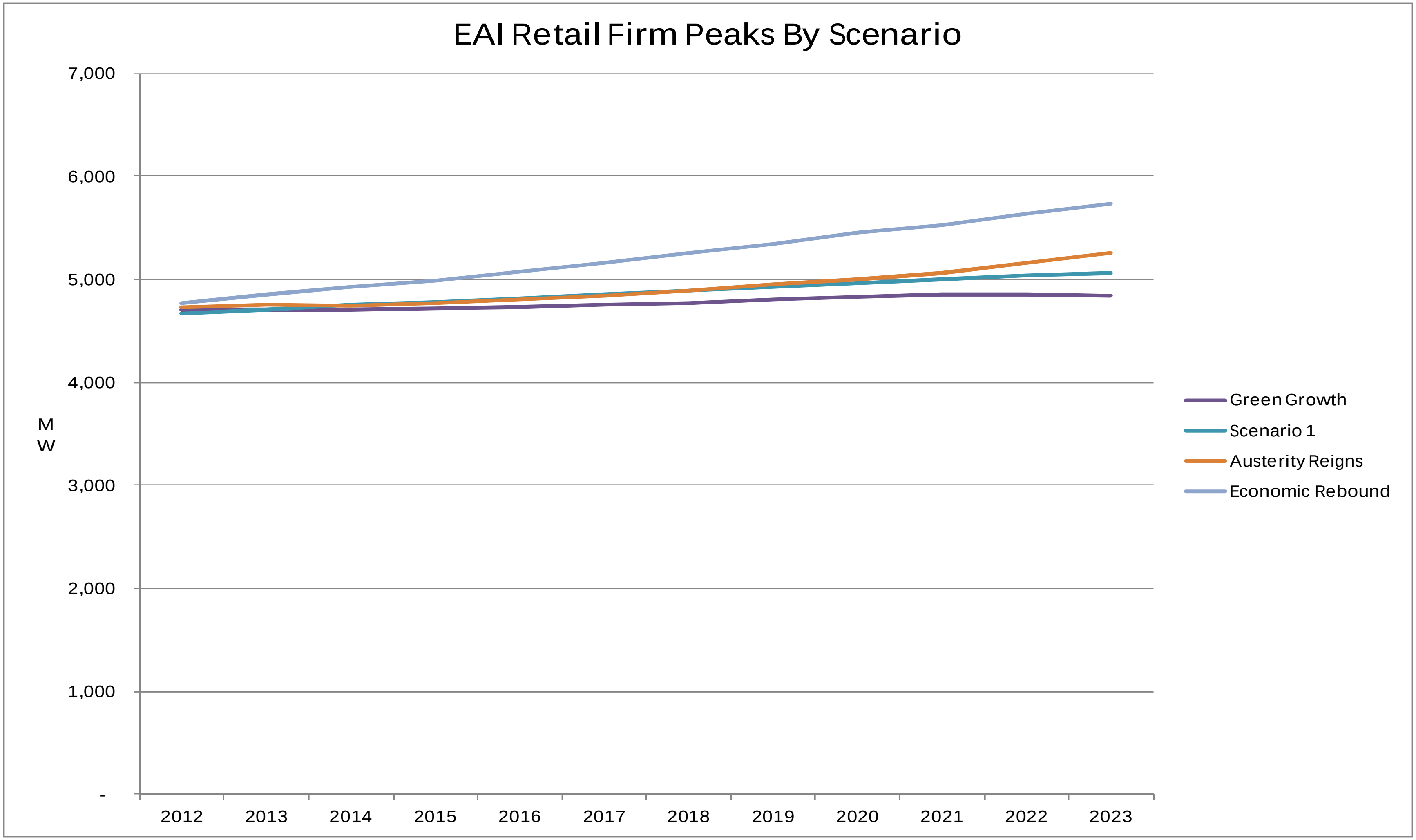
*Note that EAI's Three-Year Plan projects demand reductions of about 50 MW, which was not included in EAI's load and capability

EAI's Planning Scenarios

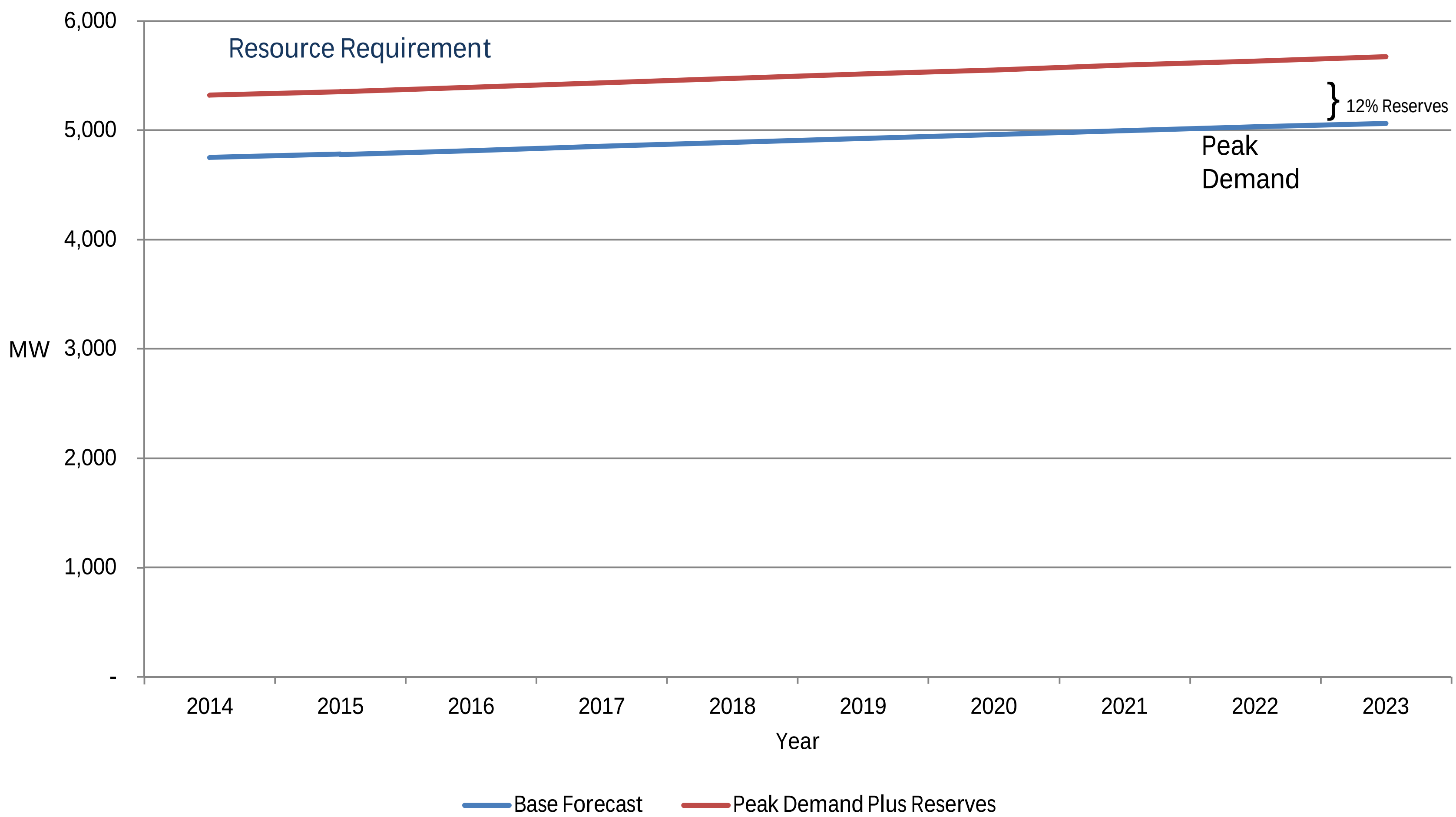
- IRP analytics will rely on four scenarios to assess alternative portfolio strategies under varying market conditions. Additional information regarding the scope of and assumptions used in the market modeling are provided in other slides. The four scenarios are:
  - Scenario 1 (Assumes Reference Load, Reference Gas, and no CO_2 cost)
  - Scenario 2 (Economic Rebound)
  - Scenario 3 (Green Growth)
  - Scenario 4 (Austerity Reigns)

- More information on scenarios is provided in the modeling analysis presentation

Forecast Scenarios
(Used in Modeling Analysis)



Resource Requirements
(Assumes a Planning Reserve Requirement equal to 12% of EAI's Peak Load)



Current Active Capability

- Total Active Generation: 5,116 MW

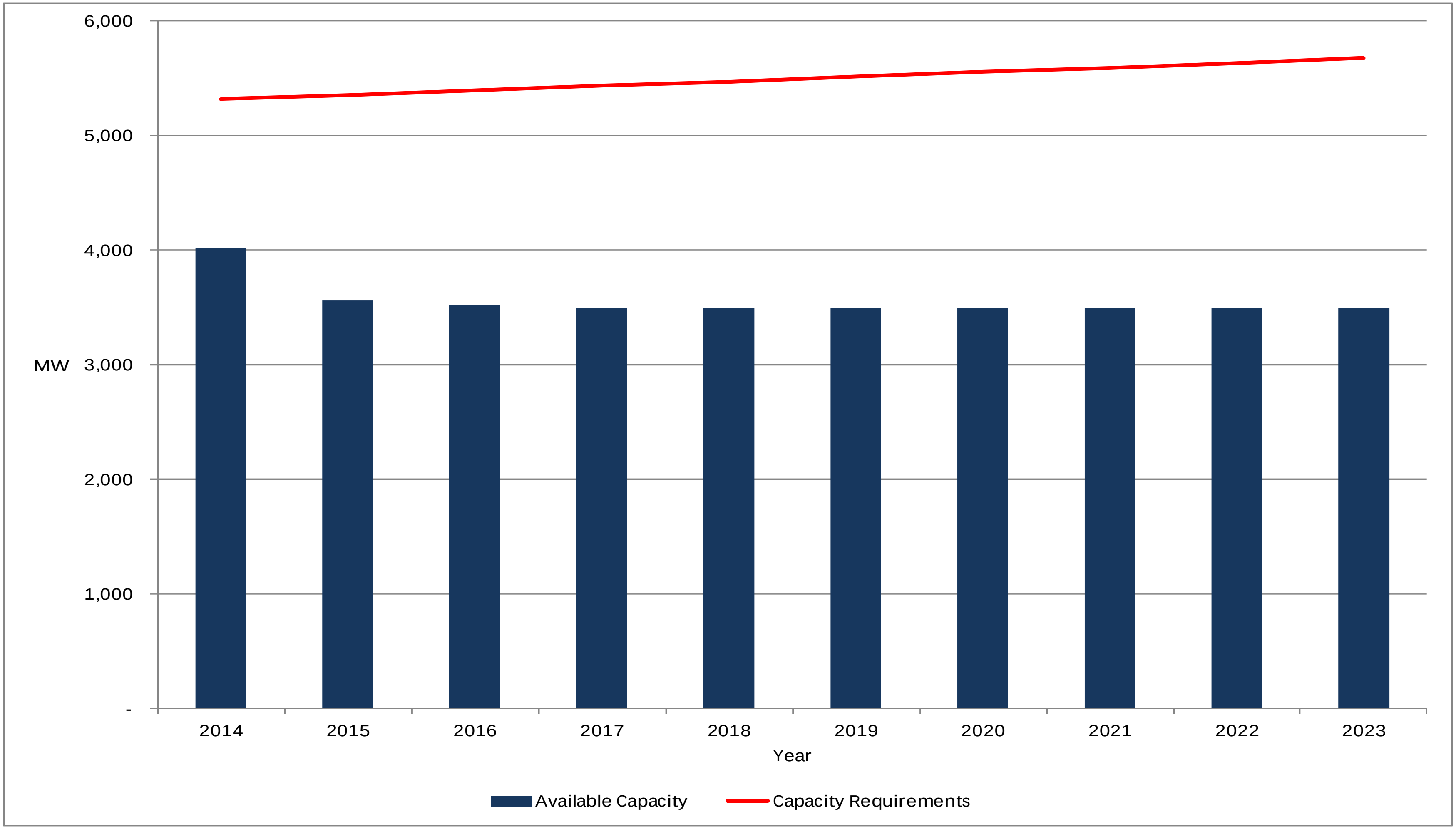
Wholesale Capacity:	726 MW
Retail Capacity:	4,390 MW
Total	5,116 MW

- Wholesale capacity is not in rate base.

Unit Deactivation Assumption

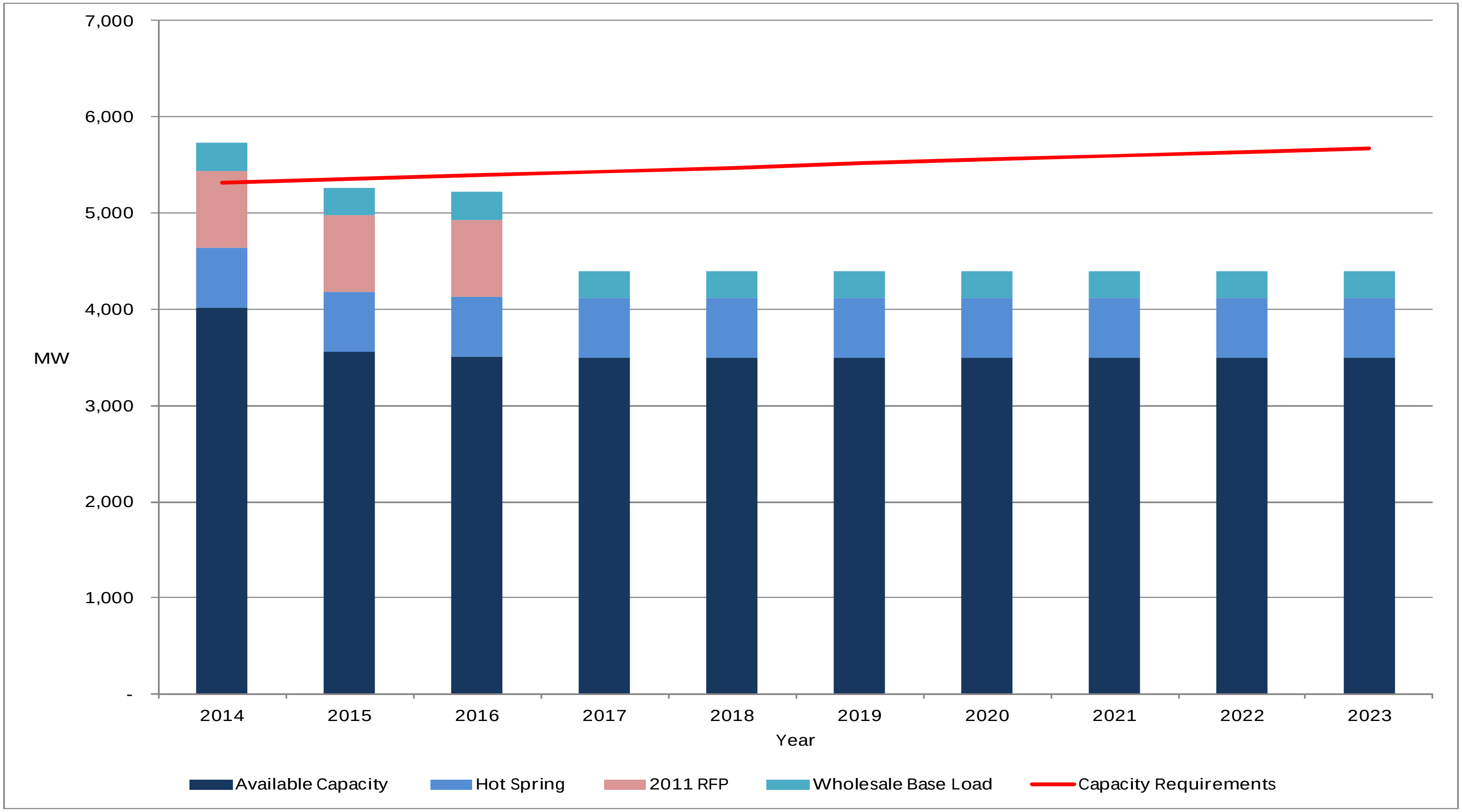
- EAI has approximately 1,000 MW of active gas/oil/diesel fired units which are all at least 40 years old
- EAI completed an assessment of this capacity on May 18, 2012 and filed that assessment with the APSC on May 21, 2012 in Docket No. 11-069-U
- For the 2012 IRP base case (Scenario 1), EAI is assuming that all the legacy gas generation will be deactivated before the 2016 summer peak, although actual decisions to deactivate units will be made on a unit-by-unit basis based upon the needs of customers and the economics of the units relative to available options at the time of the decision
- The continued operation of Lake Catherine 4 is being evaluated as part of the 2012 IRP

Capacity Position – Current Active Retail Capacity

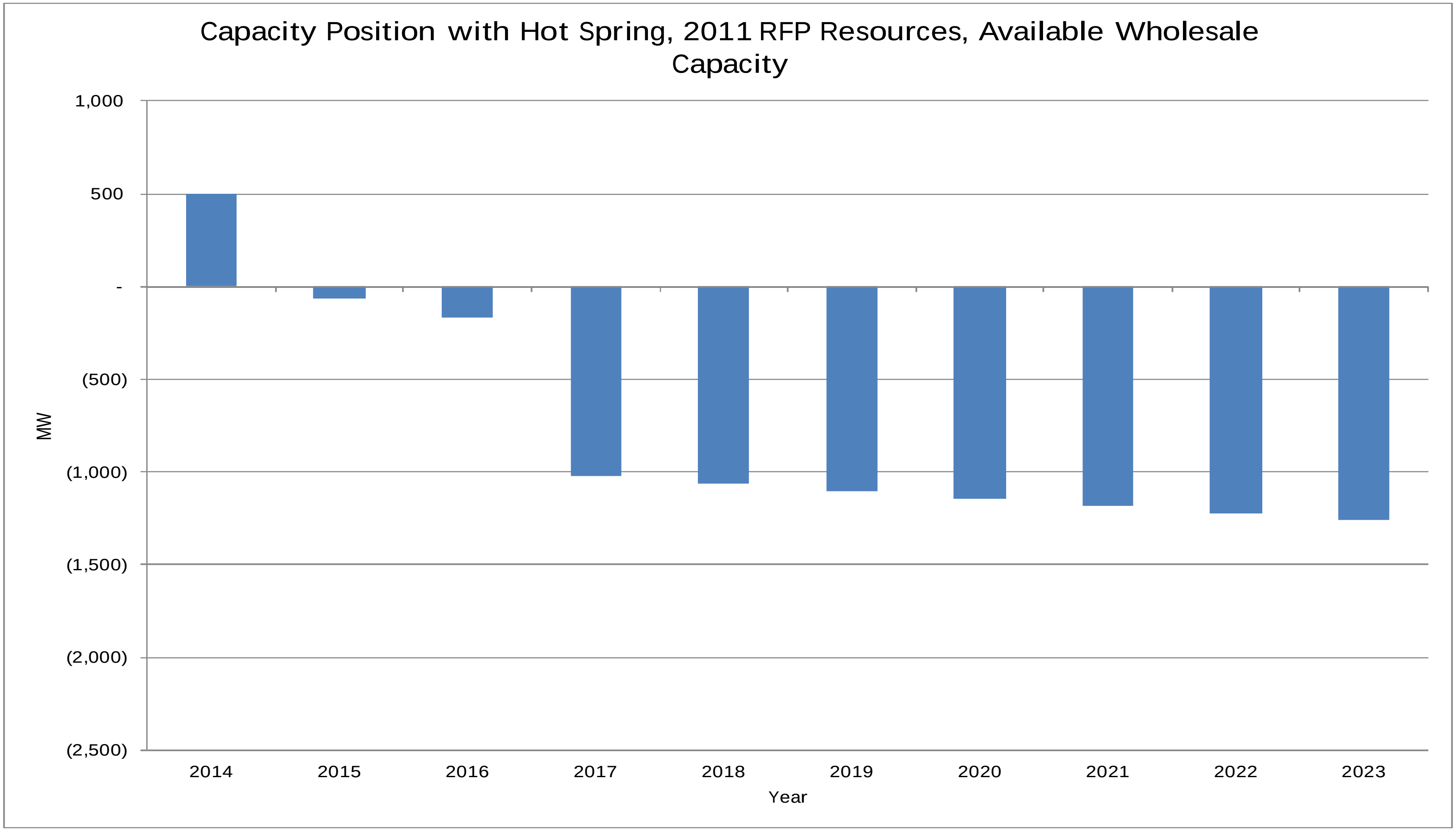


Planned Resources Added

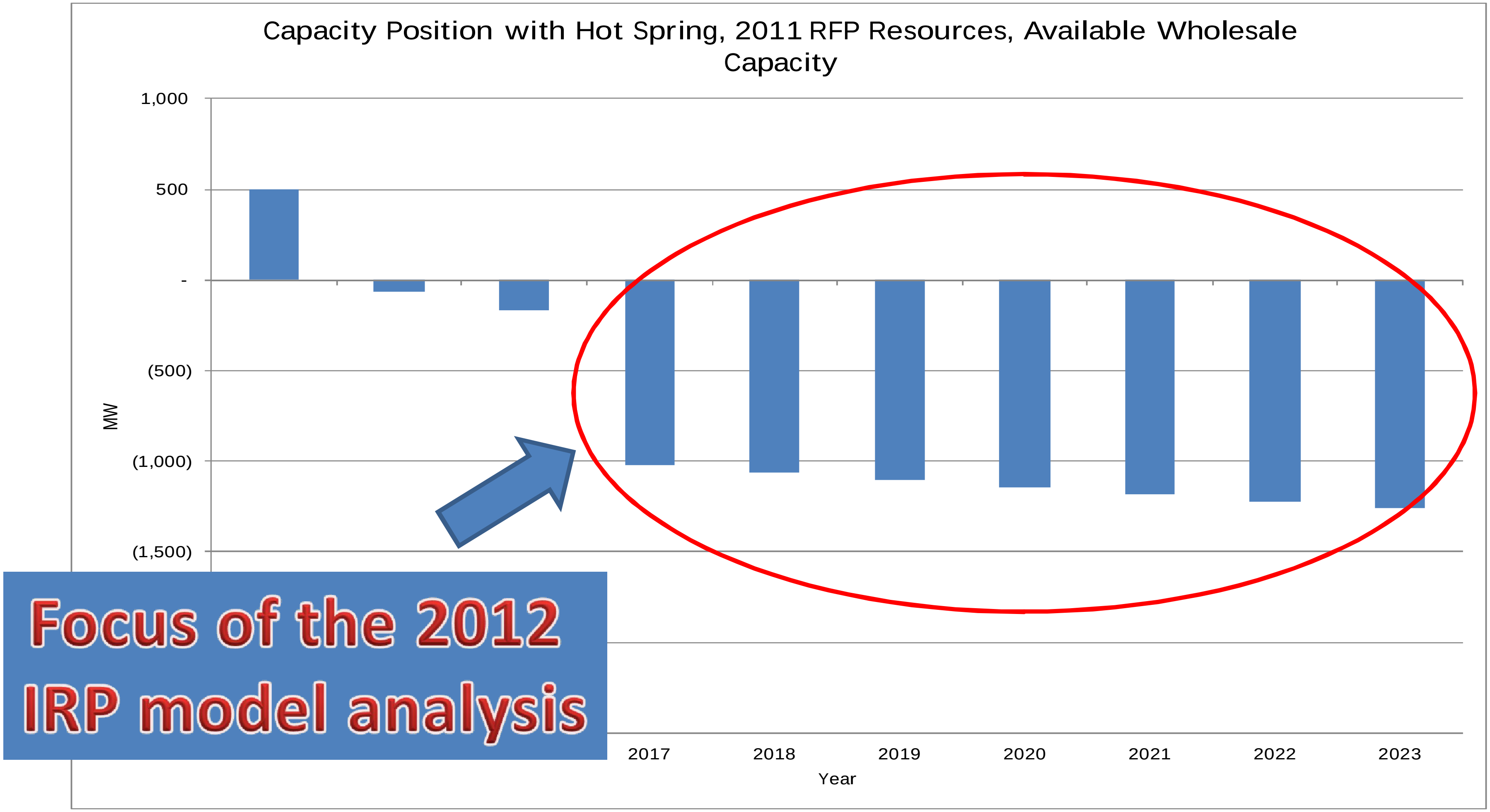
(Hot Spring Power Plant, 2011 RFP Transactions, Wholesale Base Load Capacity)



Net Capacity Position



Net Capacity Position



Options Evaluated

- Five different portfolios were designed for the model evaluation
- Each portfolio included limited or short-term market purchases up to 20% of EAI's needs
- Each portfolio was evaluated under the four different scenarios described earlier
- Again, more details will be provided in the modeling analysis presentation

Portfolio Design for Model Runs

Portfolio	New Combustion Turbine Capacity	New Combined Cycle Generation Capacity	Extend the life of Lake Catherine #4	1000 MW of Wind Generation	Demand Side Management	Limited Term Market Purchases
Portfolio 1	X					X
Portfolio 2		X				X
Portfolio 3	X		X			X
Portfolio 4	X			X		X
Portfolio 5					X	X

Stakeholder Input From 2009 IRP

Stakeholder Input Overview

- In preparing scenarios and portfolios for review, EAI reviewed stakeholder concerns that were provided in the stakeholder process conducted for EAI’s IRP filed October 31, 2009

2009 Stakeholder Concerns

A. *EAI must plan to acquire the lowest cost reliable resources that are reasonably possible*
B. *Consideration of non-mandated, non-monetized social and environmental factors in its IRP analysis.*
C. *EAI should provide additional information on its need for automatic generation control for load following generation owned by third parties*
D. *EAI should work to reduce TLRs on its system*
E. *EAI should provide additional information to the Commission and its Stakeholders.*
F. *If EAI is short capacity resources in a given planning scenario, how is that deficiency met in the plan? Will EAI conduct an RFP to meet those needs?*
G. *Demand Side Management*
H. *Distributed Generation and CHP*
I. *Renewable Generation*
J. *Reliability*
K. *Quantifying rate impact on different customer classes.*
L. *Advanced metering technology for residential and commercial customers*

Questions / Comments

BREAK

Post-ESA Transmission Infrastructure Planning

EAI IRP Stakeholder Meeting

July 31, 2012

Transmission Planning Process

- When EAI exits the Entergy System Agreement, EAI will:
  - Become a transmission customer under a FERC-approved OATT
    - MISO Tariff, if EAI is a member of MISO
    - Entergy OATT, if EAI operates on a stand-alone basis
  - Take network service for its retail load

Transmission Planning Process

- EAI will participate in the transmission planning process under the applicable tariff
  - The transmission planning process may impact the deliverability of generation supply that must be considered in the development and implementation of EAI's resource plan
  - Participation is required to support certain functions associated with the planning, construction and operation of EAI's transmission facilities
  - EAI Resource Planning and Operations Staff will be active participants in the transmission planning processes

Transmission Planning Process

- EAI Staff will conduct the generation resource planning for EAI's customer
  - Separately from the generation resource planning conducted on behalf of the other Operating Companies
  - Will include the consideration of potential economic transmission projects to reduce production costs for EAI's customers

Transmission Planning Process

- FERC has required transmission owners that are part of a holding company system to provide transmission services, including planning their transmission facilities, on a system-wide, integrated basis

Transfer Control to MISO (I)

- In the event EAI obtains the requisite approvals to transfer functional control of its transmission facilities to MISO
  - MISO Tariff requires EAI, as a Transmission Owner, to support certain transmission planning functions
- Upon MISO integration, EAI will be participating in the MISO bottom-up MISO Transmission Expansion Planning process that MISO conducts
- EAI will participate as a member of any MISO committee that is allowed under MISO governance and tariff provisions

Transfer Control to MISO (II)

- Under Attachment B to the Transmission Owners Agreement, “[t]o fulfill their roles in the collaborative process for the development of the Midwest ISO Plan, the Owners shall develop expansion plans for their transmission facilities while taking into consideration the needs of
  – connected loads, including load growth,
  – new customers and new generation sources within the Owner’s system, and
  – known transmission service requests

Transfer Control to MISO (III)

- Under NERC Standard TPL-001-2, "[e]ach Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request."
  – Given these requirements, at a minimum EAI will have to coordinate with the other Operating Companies when engaging in transmission planning even if EAI is the only Operating Company that integrates into MISO

MISO Transmission Expansion Planning Process (MTEP)

- EAI's participation in MISO transmission planning processes would include participation in MISO MTEP process information exchange events
  - Regional Planning meeting including participation of all sub-regions
  - Sub-regional planning meetings
  - Sub-regional Technical Study Task Force meeting

Questions / Comments

Environmental Regulatory Update

Entergy Arkansas, Inc.
Integrated Resource Plan
Stakeholder Committee Meeting

Myra Glover, Entergy Services Inc.

July 31, 2012

I. EAI's Environmental Stewardship

II. Overview of EPA rules –status and next steps

- Cross-State Air Pollution Rule
- Mercury and Air Toxics Standards
- Regional Haze
- NAAQS
- 316(b)
- Coal ash
- GHGs

III. Implications

EAI's Environmental Stewardship

- For the 10th straight year, Entergy Corporation has been recognized as a leader in sustainability by the Dow Jones Sustainability Index (DJSI). DJSI North America evaluates the largest North American companies based on long-term economic, environmental and social criteria. Entergy Corporation was one of only 13 U.S. utilities included on that list.

- Entergy Corporation's environmental strategy includes our third voluntary greenhouse gas commitment through 2020, which represents 20 years of continuous greenhouse gas emission stabilization.

Anticipated Timeline for Compliance with Environmental Regulations

Cross State Air Pollution Rule:
All Units

(May 2013)

Coal Combustion Residuals:
White Bluff
Independence

(2013 – 2014)

Mercury & Air Toxics Standards:
White Bluff
Independence
(April 2015)

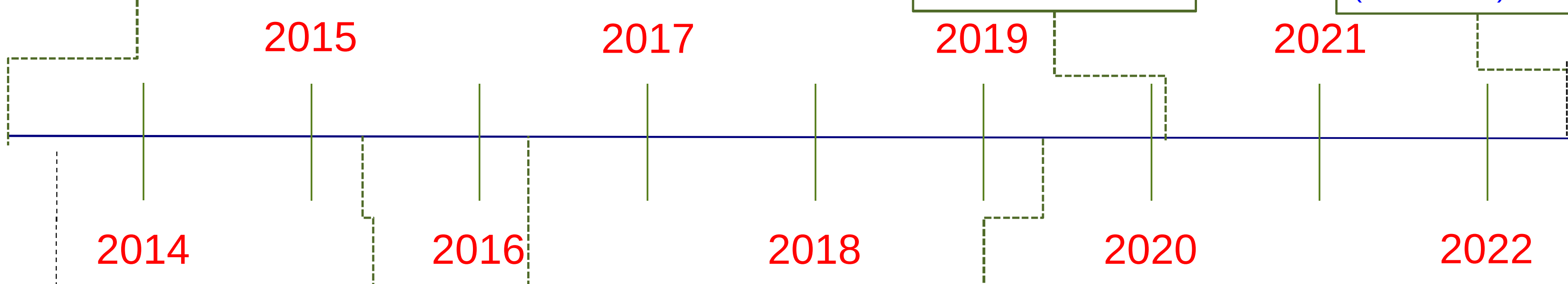
Mercury & Air Toxics Standards:
White Bluff
Independence
(April 2016)
(With one year extension granted)

National Ambient Air Quality Standards for SO_2:
White Bluff
Independence
(2017-2019)

Clean Air Visibility Rule:
White Bluff
(April 2019)

316 –B (Water Intake)
Lake Catherine
White Bluff
Independence
Ritchie
(Jan. 2020)

National Ambient Air Quality Standards for NOx:
Possible All Units
(2022-2025)



Cross-State Air Pollution Rule (CSAPR)

- This final rule was published in August 8, 2011 to replace the 2005 Clean Air Interstate Rule (CAIR).
- The Cross State Air Pollution Rule requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and PM non-attainment.
  - Scheduled to go into effect January 1, 2012.
  - Established state emission budgets for NOx and/or SO_2
  - The rule allows sources to trade emission allowances with other sources within the same program. Trading is limited by "assurance provisions" or state emission ceilings.

Reaction to Final CSAPR

- 45 entities filed petitions for reconsideration with EPA.
- Numerous negotiations with EPA resulted in proposed modification to final rule in October 2011.
- 19 Parties petitioned for a stay of the rule on October 26, 2011.
- The court stayed CSAPR on December 30, 2011.
- EPA required to reinstate CAIR pending resolution of CSAPR litigation.
- Court activities/litigation
  - Parties submitted legal briefs to the court by January 17, 2012.
  - Oral arguments held April 2012.
  - Expecting a court decision soon.

EPA Remains Committed to CSAPR

- February 7, 2012, EPA revised 2012 and 2014 State emission budgets and delayed until 2014 implementation of CSAPR's assurance penalty provisions (limited trading)

- May 30, 2012, EPA issued a Final Rule that finds that participation in CSAPR satisfies regional haze requirements (RHR).
  - SIPs implementing CSAPR can be used as a substitute for source-specific BART.
  - SIPs relying on CAIR were disapproved.

- June 12, 2012, EPA published in the Federal Register another final rule, again adjusting CSAPR emission budgets.

- The final rule is effective on August 13, 2012.

Mercury and Air Toxics Standard (MATS)

- February 16, 2012, EPA finalized the Mercury and Air Toxics Standards (MATS) for power plants.

- This final rule established national emissions standards for hazardous air pollutants for existing coal- and oil-fired power plants and new source performance standards for EGUs.

- Affects approximately 1,350 EGUs at 525 facilities
  - Approximately 1,200 coal-fired boilers at approximately 450 facilities
  - Approximately 150 oil-fired boilers at approximately 75 facilities

- Compliance with MATS requirements starts April 16, 2015, with two possible one year extensions

MATS Compliance Requirements

Implementation

- 3 years to comply, with possible one year extension granted by permitting authority (State);
- 4th year extension applies to staggering of controls for reliability, permitting, labor or resource availability constraints; may apply to construction of replacement generation
- 5th year extension may be granted through administrative orders if necessary for a specific documented reliability concern

Coal Unit Standards High Rank Coal

- Mercury; 1.2 lb/Tbtu or 0.013 lb/GWh
- Non-mercury metallic emissions; 0.030 lbs/MMBtu or 0.30 lb/MWh (filterable PM)
- Acid gases; 0.0020 lb/MMBtu or 0.02 lb/MWh HCl
- Organic HAPs; work practice standards

Oil-fired Unit Standards

- Created limited use category for oil fired units with an annual CF < 8% on oil over each two year period after the compliance date
- Standards for HAPs metals, acid gases (HCl and HF) and Organic HAPs

MATS Impacts on Unscrubbed Coal Units

Mercury Controls	• **Install Activated carbon injection** • **Install mercury CEMs or sorbent trap**
Acid Gases Controls	• **Possible installation of Dry Sorbent Injection or Scrubber** • **Install HCl CEMs or conduct quarterly stack tests**
Non-mercury Metallic HAPS (PM **standards**)	• **Possible Installation of fabric filter bag houses or possible ESP upgrades** • **Install PM CEMs or conduct quarterly stack tests**
Organic HAPS	• **Perform efficiency tune up of combustion unit**

Regional Haze Rule

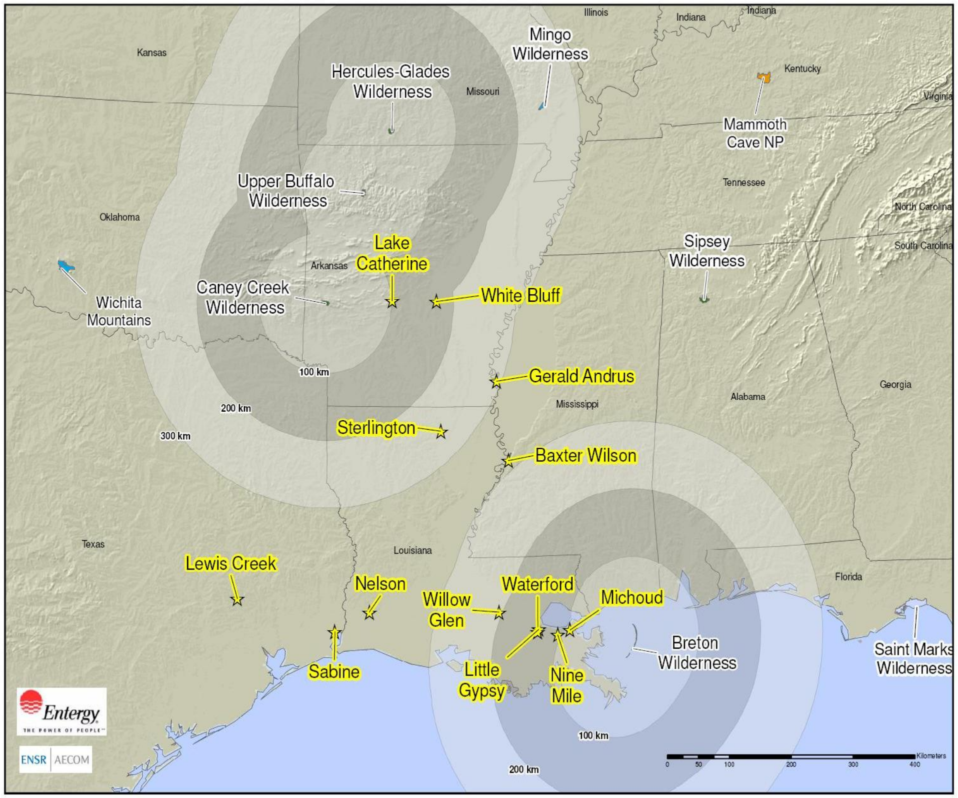
The Regional Haze Rule require eligible units that contribute to the visibility degradation of a Class I area (national park or national scenic area) to install controls to reduce emissions of NOx, SO_2, and particulate matter.

Eligible units are those that were built between 1962 and 1977 and have the potential to emit more than 250 tons a year of visibility impairing pollution.

Four Class 1 areas within 150km of EAI BART eligible facilities: Caney Creek, Upper Buffalo, Hercules Glade, and Mingo Wilderness.

Best Available Retrofit Technology (BART) is described in the Regional Haze Rule for Affected Units.

Arkansas Dept. of Environmental Quality developed State Implementation Plan to reduce SO_2 and NOx at affected facilities.



Adopted into State Regulation 19 on September 28, 2007.

Regional Haze Rule
Arkansas

- March 12, 2012, EPA published in the Federal Register its final rule disapproving most of the emission limits in the Arkansas Regional Haze State Implementation Plan (SIP).
    - Within 24 months following the final disapproval, EPA must either approve an ADEQ submitted SIP or promulgate a Federal Implementation Plan (FIP).
    - EPA expressed a preference for a SIP if the ADEQ submits a revised plan that EPA can approve before the expiration of the mandatory FIP clock for the portions of the SIP that were disapproved in the final rulemaking.
    - Stakeholders are working with ADEQ to conduct Best Available Retrofit Analyses which will address the disapproved portions of the Arkansas Regional Haze SIP.

Regional Haze Rule

- June 7, 2012, EPA published in the Federal Register its final rule finding that state participation in Cross-State Air Pollution Rule (CSAPR) programs satisfy regional haze requirements.
- States can substitute participation in CSAPR for source-specific Best Available Retrofit Technology (BART) for sulfur dioxide and/or nitrogen oxides emissions from power plants that are subject to the regional haze rule.
  - EPA determined that participation by power plants in CSAPR's trading programs results in greater visibility improvements than source specific BART.
  - CSAPR = BART for NOx and SO2 in annual programs.
  - CSAPR = BART for NOx in seasonal program.
- The rule disapproves state implementation plans that rely on the Clean Air Interstate Rule (CAIR).
- The rule finalized federal implementation plans that replace reliance on CAIR with reliance on CSAPR.

National Ambient Air Quality Standards (NAAQS)

- NAAQS continually ratcheted down over time.
  - Ozone – 1997, 2008, 2011
  - PM 2.5 – 1997, 2006, 2012
  - "Transport Rule" developed to address 1997 and 2006 standards.

- EPA implementing 2008 ozone standard.
  - On April 30, 2012 final rule released designating the non-attainment areas for Ozone.
  - Attainment dates set for each non-attainment category.

- New 1-hour NO_2 and SO_2 standards issued in 2010.
  - On July 17, 2012, the U.S. Court of Appeals for the D.C. Circuit issued a decision upholding the 1-hour NO_2 National Ambient Air Quality Standard.

- State Implementation Plans
  - Establishes requirements for in-state sources.

- On June 15, 2012 EPA announced the reduction of the PM 2.5 standard for ambient air. The final standard to be issued by December 14, 2012

Cooling Water Intake Structure 316(b)

- Rule proposal published in Federal Register April 20, 2011.
  - EPA Published a Notice of Data Availability on June 12, 2012
  - Final Rule was due July 27, 2012 (Court ordered deadline)
  - On July 18, 2012 deadline extended one year.
  - Implementation expected 2018 – 2020.
- Affects all facilities with design intake capacity greater than 2 million gallons per day that use more than 25% of water withdrawal for cooling purposes
  - Approximately 890 steam electric generating units likely to require modifications
- More prescriptive than remanded rule
  - Fine mesh screens with fish handling systems designated as BTA for impingement standards.
  - State agencies will select site-specific requirements for entrainment standards.
  - Cooling towers not selected as BTA for either at national level.

Cooling Water Intake Structure 316(b) Implications

- Facilities with intake flow greater than 2 MGD must demonstrate compliance with impingement standards
  - Intake flow velocity less than 0.5 ft/sec

    \- OR -
  - Annual average impingement mortality less than 12% with monthly average impingement mortality less than 31%

- Facilities with intake flow greater than 125 MGD must also demonstrate compliance with entrainment standards regardless of the source water body type
  - Will require a number of peer reviewed studies
  - Site-specific requirements determined by state permitting authority
  - Timeline for implementation and compliance is negotiated with the permitting agency
- Rule also includes entrapment standards

Coal Combustion Residuals

- EPA proposed 2 options in June 2010:
  - Subtitle C, “Special” hazardous waste listing.
    - Beneficial use exempt from regulation.
  - Subtitle D (non-hazardous waste) regulations.

- Final Rule expected in late 2012 or first quarter 2013.
  - If regulated under Subtitle C, each state has to adopt the listing in the hazardous waste regulations before requirements are effective (2+ years).
  - If regulated under Subtitle D, rule goes into effect within 6 months after rule finalized.

EPA's GHG Regulations Upheld

On June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld EPA's greenhouse gas ("GHG") regulations**:**

- The GHG Endangerment Finding - the foundation for EPA's regulation of GHGs under the Clean Air Act.

- Tailpipe Rule – made GHGs subject to regulation under the CAA, triggering the applicability of PSD and Title V permitting programs.

- Tailoring Rule – temporarily raises the statutory thresholds for PSD and Title V permitting requirements to avoid an overwhelming number of newly regulated sources.

GHG Rules Focus on Largest Emitters

- New facilities with GHG emissions of at least 100,000 tons per year (tpy) carbon dioxide equivalent (CO_2e) will be required to obtain Prevention of Significant Deterioration (PSD) permits

- Existing facilities that emit 100,000 tpy of CO_2e and make changes (Modified Sources) increasing the GHG emissions by at least 75,000 tpy of CO_2e, must also obtain PSD permits

Applicability of the GHG New Source Performance Standards (NSPS)

- This new rule is based on the assumption that Natural Gas Combined Cycle technology constitutes the best system of emissions reductions.

- Applies only to new fossil-fuel-fired electric utility generating units (EGUs)
    - EGUs include:
        - fossil-fuel-fired boilers,
        - integrated gasification combined cycle (IGCC) units
        - stationary combined cycle turbines

- The rule is an output-based emission standard of 1,000 pounds of CO_2e per MWh

Applicability of GHG NSPS

Sources are grouped into one New Source Performance Standard source category:

- Gas
- Oil
- Coal refuse
- Coal
- Pet coke-fired EGUs

Exempt Sources include:

- Transitional Sources
- Simple Cycle Turbines
- Peaking Units

Implications

Potential Impacts

- The challenge utilities face is unprecedented in terms of:
  - The number of rules coming due simultaneously.
  - The compressed timeframe for compliance with the near-term rules.
  - The continuing ratcheting down of compliance obligations.
- Approximately 34 GW of coal-fired generation retirements have been announced already.
- Will require significant amount of investment.
- Key factors and uncertainties:
  - What will final rules look like
  - Litigation
  - Congressional activity
  - Impact of 2012 elections
  - Will there be extensions?

Industry's Predicament

- And still no long-term carbon policy exists
    - Without a long term carbon policy, industry faces the possibility of uneconomic investments.
    - Industry needs satisfactory resolution of both the current regulatory challenges and a long-term legislative solution on carbon to allow for the most efficient transition to a cleaner generation fleet.

EAI Power Plants

- EAI continues to evaluate options for environmental compliance for the EAI coal units.
- EAI has not determined what compliance technology may be required and when.
- Work is on-going.

Questions / Comments

Meet Future Energy Needs Through Cost Effective Demand Side Management

July 31, 2012

Demand Side Management's Role in Resource Planning

Presentation Objective:

Review / Discuss the process for integrating DSM into the overall resource planning process

What This Presentation Includes:

- Changes in Regulatory Framework Since the last IRP
- EAI's achievement of Energy Efficiency activities to date
- Benefit Cost Analysis Changes
- The process used to identify the cost effective DSM opportunity for the Entergy Arkansas, Inc. (EAI) service area
- High level results of DSM potential study
- The role DSM can play in meeting future resource needs for Entergy Arkansas
- Next steps and framework needed to move forward

Demand Side Management's Role in Resource Planning

<u>Presentation Objective Continued:</u>

What This Presentation Doesn't Include:

- Detailed DSM program design

What is Demand Side Management (DSM)

Demand Side Management (DSM) is a set of actions, activities or measures that impacts energy use, energy use patterns or customer behavior as it relates to energy consumption. DSM includes:

- ***Conservation***: Activities / actions that reduce energy use through changes in life style and the reduction in energy consumption through activities such as increasing thermostat settings on air conditioning equipment in the summer, lower thermostat settings on water heaters, turning off lights when not in use, etc. Conservation activities typically require little to no investment by the customer to reduce energy usage.

- ***Energy Efficiency***: Activities / actions that typically require an investment to achieve lower energy usage, such as, improving insulation levels, sealing heating and cooling ducts, weather stripping, caulking, the purchase of more efficient appliances etc.

- ***Demand Response***: Activities or actions that result in changes to energy use patterns that may or may not reduce overall energy usage. Demand response programs are utilized to lessen customer usage / demand during peak periods or those times when the cost to supply energy is more expensive. Programs in this area include Time of Use (TOU) rates, load control programs such as AC or pool pump switches, etc.

Regulatory Framework

Arkansas' Regulatory Framework has Improved Significantly Since the last IRP.

EAI is allowed to recover

- Program cost concurrently with true up after each year is completed
- Lost contribution to fixed costs (LCFC) concurrently with true up each year of program completion and adjusted for independent evaluation.
- Performance incentives based upon completed year and with independent evaluated results

EAI has Regulatory Guidance for

- Program/ Portfolio comprehensiveness, including a portfolio comprehensiveness Checklist and targets[1]
- Benefits and Objectives within the Rules for Conservation and Energy Efficiency Programs, and
- All energy savings and demand reduction results are adjusted based upon an independent and robust Evaluation Measurement & Verfication ("EM&V")

The Regulatory Framework has Implemented and Approved:

- Self- Direct Options for Customers
- A Technical Resource Manual ("TRM") and updating process
- Conservation and Energy Efficiency Rules ("CEE")
- Collaboratives for ongoing energy efficiency development

1) Subject to adjustments associated with Large Commercial and Industrial Customer Self-Directed Option.

Regulatory Framework

- Annual Commission Mandated Annual Targets, as a percent of 2010 Weather Adjusted MWh Sales
  - 2011: 0.25% = 52,706 MWh
  - 2012: 0.50% = 105,413 MWh
  - 2013: 0.75% = 158,119 MWh

- Adjustments to Annual Targets Associated with Commercial and Industrial Self – Direct Option

	2012	2013
Impact to Overall 2012 and 2013 Targets	8.3%	10.2%
Impact to Commercial and Industrial Customer Classes	12.2%	15.3%

- Commission has ordered an 80% Net-To-Gross (“NTG”) Multiplier[2] for all programs but CFL and those are now at 63% NTG. The gross energy savings EAI is estimating on a portfolio basis to meet the Commission targets are as follows:

  - The gross goals in 2011 is 65,883 MWh
  - The gross goals for 2012 is 147,292 MWh
  - The gross goals for 2013 is 215,554 MWH
  - The three year gross goal of program plans are 428,729 MWh or 2% of 2010 weather adjusted sales.

2) 80% NTG was limited to 2011 plan. In 2011 a settlement was approved that reduced the CFL lighting NTG from 0.8 to 0.63. In 2012, all program NTGS are to be evaluated based upon Arkansas achievements and through an independent EM&V Consultant. The EM&V Consultant’s work is reviewed by Independent Evaluator Monitor reporting to the General Staff of the APSC

Regulatory Framework

Seven criteria (Check-List) were established in the Comprehensiveness Order on December 10, 2010 (Docket No. 08-144-U, Order No. 17). The Check List is to help the commission decide whether annual EE programs are comprehensive. The seven additional criteria are as follows:

- Provide, either directly or through identification and coordination the education, training, marketing, or outreach needed to address market barriers;
- Include adequate budgetary, management, and program delivery resources to plan, design, implement, oversee and evaluate EE programs;
- Reasonably address all major end-uses;
- Address to the maximum extent reasonable the needs of customers at one time, in order to avoid cream-skimming and lost opportunities;
- Take advantage of opportunities to address the needs of targeted customer sectors (schools, large retail stores, agricultural users, or restaurants) or to leverage non-utility program resources such as state or federal tax incentives, rebates, or lending programs;
- Enable the delivery of all achievable, cost-effective EE within a reasonable period and maximize net benefits to customers and the utility; and
- Have adequate EM&V procedures to support program management and improvement, calculation of energy, demand and revenue impacts, and resource planning decisions

Regulatory Framework

The Commission also established both formal and informal collaboratives

- Self Direct Collaborative was completed in 2011 with rules for commercial and industrial customers the provision to apply for a self direct certificate and opt out of utility programs and cost recovery riders.
- EM&V Collaborative in 2011 was instrumental in obtaining Commission approval for rules for independent Evaluation, Measurement and Verification ("EM&V"), established a Technical Resource Manual ("TRM"), identified an Independent Evaluation Monitor ("IEM") that reports to the APSC General Staff and is responsible for managing the TRM, Filing summary reports of the independent EM&V consultants and assisting with continued decision masking of the continuing EM&V Collaborative.
- More informally directed the utilities to work to identify ways to modify programs to deliver inter-utility and inter fuel programs to customers and report on results.

EAI Energy Efficiency Achievements

- Existing Approved Programs
  - EAI filed a new Program plan in March of 2011 in to meet the Commission mandated targets and check list.
  - On June 30, 2011 the APSC approved 16 programs through the end of 2013.
  - For the reminder of 2011 EAI was busy identifying implementing consultants, database providers, EM&V consultants, negotiating contracts for new programs and expanding EAI staff to manage these expanded programs.

EAI Energy Efficiency Achievements
Evolution from Quick Start to Comprehensive Programs

2010
$3.9 Million

RESIDENTIAL PROGRAMS

2013
$19 Million

Quick Start Program	Target Market		Corresponding Comprehensive Program & New Programs	Target Market
Residential Energy Solutions	Single family homes	→	Home Energy Solutions	Single family homes
CFL	All residential	→	Lighting & Appliances	All residential
AC Tune-Up	All homes with Central AC	→	Residential Cooling Solutions	All homes with Central AC
AR Weatherization	Low Income	→	AR Weatherization	Low Income
			ENERGY STAR New Homes	New construction
			Multifamily & Mobile Home Energy Solutions	Multifamily & mobile homes
			Benchmarking	All residential
			Direct Load Control	All homes with Central AC

2010
$6.9 Million

C&I PROGRAMS

2013
$33 Million

Quick Start Program	Target Market		Corresponding Comprehensive Program & New Programs	Target Market
Large C&I Energy Solutions	100 kW or larger facilities	→	C&I Prescriptive	100 kW or larger facilities
Large C&I Standard Offer	100 kW or larger facilities	→	C&I Custom	100 kW or larger facilities
Small Commercial Energy Solutions	<100 kW facilities	→	Small Commercial Direct Install	<100 kW facilities
AC Tune-Up	<100 kW facilities	→	Small Commercial Cooling Solutions	<100 kW facilities
CitySmart	City government	→	CitySmart	City government
Irrigation Pump Load Control	Agriculture	→	Irrigation Pump Load Control	Agriculture
			Agriculture Energy Solutions	Farms & Agribusiness

EAI Energy Efficiency Achievements

- Budgets and First Year Basis cost of existing program plans.
  - 2010 actual spending[3] was $10,713,000 or $0.24/kWh on First Year Basis without NTG
  - 2011 budgeted spending is $18,685,000 or $0.28/kWh on First Year Basis without NTG, $0.35/kWh on First Year Basis with 0.8 NTG adjustment included.
  - 2012 budgeted spending is $ 39,109,000 or $27/kWh on First Year Basis without NTG, $0.34/kWh on First Year Basis with 0.8 NTG adjustment included
  - 2013 budgeting spending is $ 52,566,000 or $0.24/kWh on First Year Basis without NTG, $0.30/kWh on First Year Basis with 0.8 NTG adjustment included
- Program Costs are Competitive Nationally
- Programs are expanding with decreasing the cost per kWh

3) 2010 values do not include a 5% budget for independent EM&V nor cost of database (Around $4 Million dollars for the three year period).

EAI Energy Efficiency Achievements Program Cost are Competitive Nationally

EAI's proposed programs are also very cost-effective vis-a-vis EAI's peers; as is EAI's financial commitment.

Investor Owned Utility Administered Program Spending, 2009

Investor Owned Utility State	Program Cost ($Million)	Program Cost as % Revenue	$/kWh
Pacific Gas & Electric Co CA	$523.1	4.7%	$0.99
Interstate Power and Light Co IA	$60.0	4.5%	$1.40
Massachusetts Electric Co MA	$90.2	4.3%	$0.76
Southern California Edison Co CA	$404.9	3.4%	$0.57
United Illuminating Co CT	$29.9	3.3%	$1.65
Idaho Power Co ID	$34.8	3.3%	$0.88
Entergy Arkansas Inc. (2013) AR	$52.6	3.2%	$0.32
Puget Sound Energy Inc. WA	$70.7	3.2%	$0.37
Baltimore Gas & Electric Co MD	$87.6	3.1%	$1.21
Western Massachusetts Elec Co MA	$12.4	3.1%	$0.99
The Narragansett Electric Co RI	$27.1	3.0%	$0.87
Northern States Power Co - Minnesota MN	$75.8	2.2%	$1.66
Nevada Power Co NV	$50.0	2.0%	$0.33
PacifiCorp OR	$80.8	1.9%	$0.52
Avista Corp WA	$17.6	1.8%	$0.51
MidAmerican Energy Co IA	$42.4	1.7%	$0.89
Florida Power & Light Co FL	$186.1	1.6%	$2.08
Public Service Co of Colorado CO	$43.9	1.6%	$9.71
Connecticut Light & Power Co CT	$53.3	1.6%	$0.86
Progress Energy Florida Inc FL	$80.3	1.5%	$2.02
Tampa Electric Co FL	$32.2	1.5%	$2.55
Kansas City Power & Light Co MO	$18.8	1.4%	$1.68
Public Service Co of NH NH	$15.5	1.4%	$0.86
Public Service Co of NM NM	$12.1	1.2%	$0.50
Alabama Power Co AL	$56.3	1.0%	$3.90
Arizona Public Service Co AZ	$25.6	0.8%	$0.24
Consumers Energy Co MI	$22.2	0.6%	$0.41
Duke Energy Ohio Inc OH	$13.3	0.5%	$0.59
Union Electric Co MO	$13.7	0.5%	$1.30
Progress Energy Carolinas Inc NC	$21.0	0.5%	$3.99
Consolidated Edison Co-NY Inc NY	$31.4	0.4%	$1.92
Georgia Power Co GA	$28.7	0.4%	$1.30

Notes:

Source: U.S. EIA Form 861 Data, 2009

$/kWh is on a "first year" basis. That is, annual program spend divided by incremental savings achieved in the same year. Average=$1.50/kWh and Median=$0.94/kWh.

Average program cost as % revenue=2.04% and median=1.68%

Results of EAI Energy Efficiency Efforts

- 2011 reported evaluated savings energy savings was 41,958 MWH or 79.6% of APSC target.
- Sum of evaluated energy reductions since 2009 energy efficiency programs have delivered 134,277 MWh of sales reduction or 0.64% of 2010 sales.
- Demand Reduction is 58 MWs. 9.4 MWs of demand reduction is due to demand response programs and 48.6 is due to energy efficiency programs.
- The amount of incremental cost associated with energy efficiency since 2009 is $ 29.4 Million and $0.22 per kWh on a First Year Cost basis.

Benefit Cost Changes
Portfolio Benefit Cost Analysis of Three Year Plan

Benefit Cost Analysis Result For Comprehensive Portfolio Filed in March of 2011

Test	Results	
Participant Cost	NPV (all participants)	$ 104,913,427
	Benefit-cost ratio	1.93
	NPV (average participant)	$39
Ratepayer Impact Measure (RIM)	NPV	$ 45,064,288
	Benefit-cost ratio	1.20
	Lifecycle revenue impact per kWh	-$0.000166
	2011 revenue impact per kWh	$0.000920
	2012 revenue impact per kWh	$0.000922
	2013 revenue impact per kWh	$0.000835
Total Resource Cost (TRC)	NPV	$ 125,137,685
	Benefit-cost ratio	1.89
	Levelized cost per kWh	$0.076
Program Administrator Cost (PAC)	NPV	$ 174,516,441
	Benefit-cost ratio	2.89
	Levelized cost per kWh	$0.049

Benefit Cost Changes
Updated Portfolio Benefit Cost Analysis

2012 Updated Benefit cost analysis of Programs filed in March 2011.

- Updates include of 2011 achieved results
- updated avoided capacity and energy cost, and
- more discrete application of avoided cost based upon time of day avoided cost.

Test	Results	
Participant Test (PC)	NPV	115,214
	Benefit Cost Ratio	2.05
	Levelized $ per kWH	0.09
Ratepayer Impact Test (RIM)	NPV	72,894
	Benefit Cost Ratio	1.50
	Levelized $ per kWH	0.09
Total Resource Cost Test (TRC)	NPV	52,083
	Benefit Cost Ratio	1.31
	Levelized $ per kWH	0.09
Program Administrator Test (PAC)	NPV	129,927
	Benefit Cost Ratio	2.45
	Levelized $ per kWH	0.09

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Objectives & Deliverables

- In June 2012 (final report pending), ICF completed an updated DSM Potential Study for the period 2012-2031 assessing the potential for EAI. The results of which provide a basis for long-term planning. The ICF Study considered a Low, Reference and High Level of spending on a full range of potential Arkansas DSM programs and associated DSM peak load and energy reduction.

- Study objective: Develop high level, long-run achievable DSM program potential estimates suitable for inclusion in Entergy's IRP analysis.
  - *Achievable program potential* is the level of savings assumed to be reasonably achievable in the course of the planning horizon, given market barriers that may impede customer participation in utility programs. Achievable potential varies depending on program incentive structure, marketing efforts, energy costs, and other market factors, as well the regulatory treatment of the utility’s programs
  - 3 scenarios: Low, Reference & High

- EAI Contracted with ICF International to Provide the Following Deliverables
  - Program loadshapes
  - Program cost estimates
  - Study report

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Interpreting the estimates

- The purpose of the study was to provide to EAI loadshapes and costs representing a reasonable set of long-run assumptions about achievable DSM program potential.

- The long-run nature of the study means the estimates are not designed to be used for:

    - Program planning, or
    - Utility goal setting

Some key differences between long-run potential study & short-run DSM program plan

Study Activity/ Characteristic	Long-Run (IRP, 10-20 years)	Short-Run (Program Plan, 1-3 years)
Measure Review	Expansive/broad	Less expansive/more specific than in long-run study
Measure Analysis	Analyze universe of representative measures that could be implemented over long run.	Analyze currently offered measures, plus changes/additions per codes & standards, emerging technologies, and EM&V results.
Goal of Final Measure List	Groups of measures included should be reasonably representative of savings and costs within end-uses, over the long-run.	Measures should generally have well-understood performance in the short-run (exceptions for items like emerging technologies/pilots).
Program Review	Broad and representative	More likely to include currently offered programs with limited expansions, or contractions.
Program Design	Very high level/representative	Very specific
Program Costs	Estimated long-run average costs. Broad cost categories (incentive & non-incentive). Long-run average costs tend to be lower than short-run planning costs, especially for studies covering immature markets.	Based on current program costs. More specific cost categories (incentive, admin, marketing, training, EM&V, etc.).
Participation Model	Based more on measure and market economics, taking into account recent program performance (if available).	Based more on current program performance, or recent performance of similar programs in comparable jurisdictions, taking into account measure and market economics.
Uncertainty of Estimates	High, especially in territories with immature programs.	Low to medium depending on program maturity.

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas – Potential Study ICF Overview

- **ICF International**
  - A global consultancy based in the Washington area with offices around the U.S., Canada, U.K., Belgium, Brazil, China, India, Russia
  - 4500 professionals, about 1700 of whom work on energy and environment, 350 full time energy-efficiency professionals
  - More than 20 years of public/private energy efficiency experience
  - One of the leading U.S. energy efficiency delivery companies:
    - Currently implement about 130 state/utility EE programs around the U.S.
    - Supported Federal programs including, ENERGY STAR® for over 10 years
    - Performed over 30 potential studies and program plans for utilities and state agencies

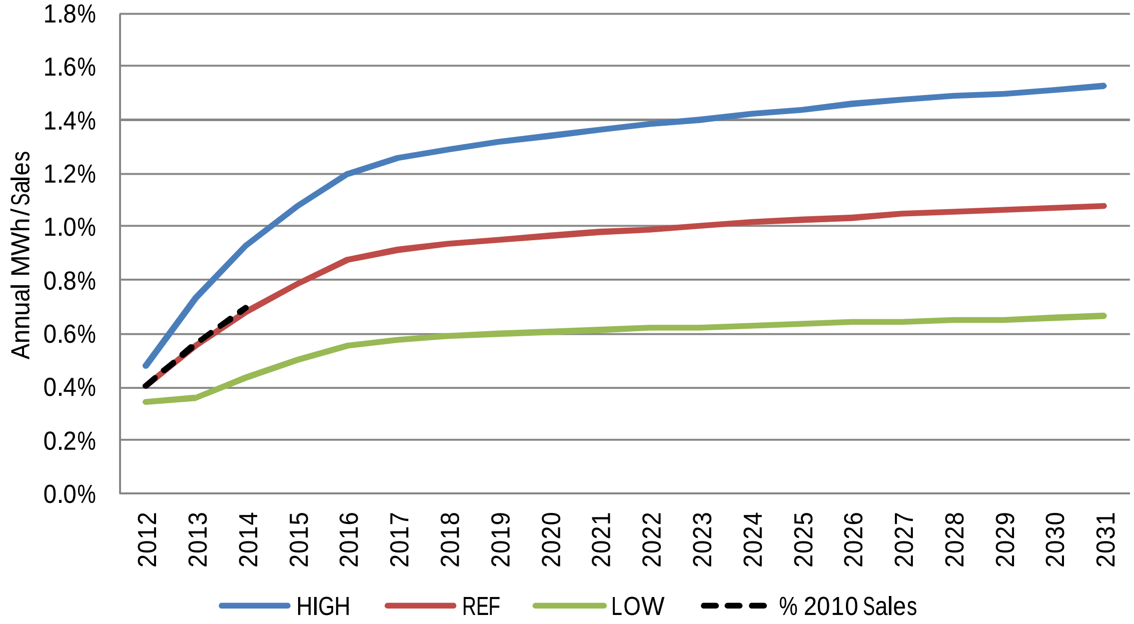
Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Interpreting the estimates – uncertainty

- All long-run economic forecasts are subject to high levels of uncertainty.
- Medium to high uncertainty for energy efficiency estimates, especially given evolving nature of fuel costs and the economy.
- Very high uncertainty for demand response estimates given uncertainty about AMI deployment.
- Used best data available at the time of the analysis.
- Assumes EAI continues receiving favorable regulatory treatment for programs (cost recovery, LCFCs, shareholder incentive).

Bottom-up study approach

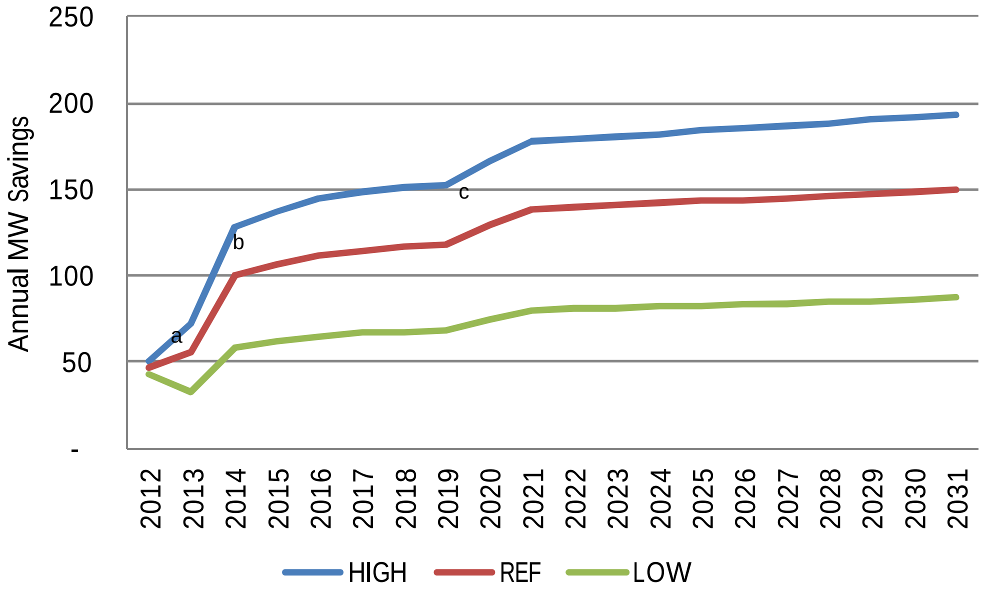
1. **Data collection**. Utility data, baseline customer and building data, measure data and program data. Development and sourcing of non-deemed measure savings estimates and characteristics.
2. **Baseline characterization**. Electricity use by sector by building type and end-use. Utility sales forecast.
3. **Measure analysis**. Measure cost-effectiveness testing. Consideration of non-cost-effective measures for inclusion.
4. **Program analysis.** Grouping measures into programs. Program cost and participation estimation. Calculation of reference case achievable potential estimates.
5. **Scenario analysis.** Development of high and low achievable potential estimates.
6. **Benchmarking.** Comparison of estimates from this study to those from other recent Southern studies.

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual net MWh savings estimates as % sales



INC. SAVINGS/SALES	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
HIGH	0.5%	0.7%	0.9%	1.1%	1.2%	1.3%	1.3%	1.3%	1.3%	1.4%	1.5%
REF	0.4%	0.6%	0.7%	0.8%	0.9%	0.9%	0.9%	1.0%	1.0%	1.0%	1.1%
LOW	0.3%	0.4%	0.4%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%
% 2010 Sales	0.4%	0.6%	0.7%								

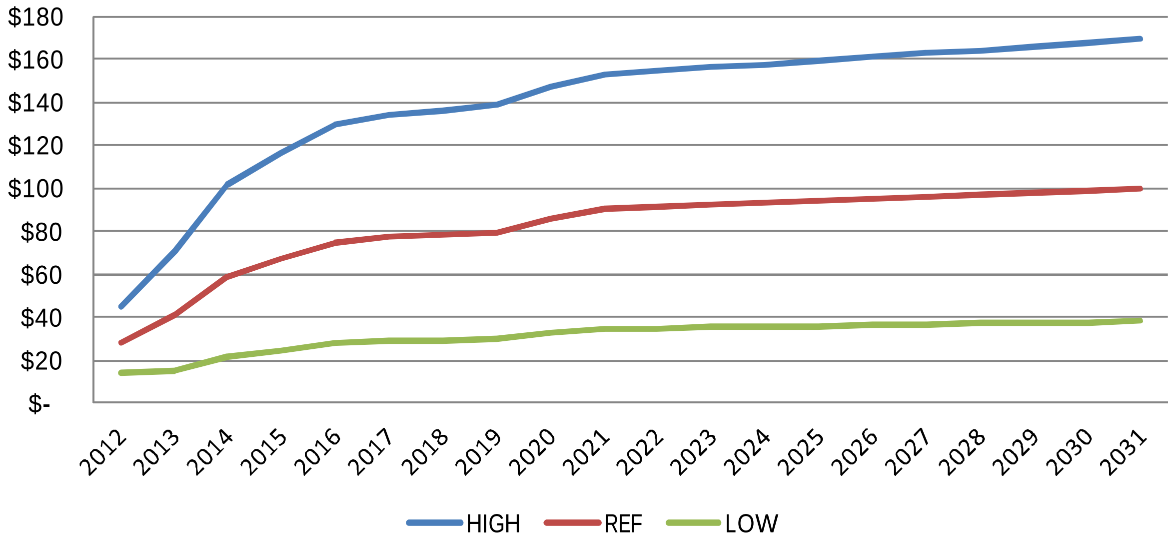
Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual net MW savings estimates



ANN. MW Savings	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
HIGH	51	72	129	138	145	148	151	153	167	178	193
REF	46	55	100	107	112	115	117	118	129	138	150
LOW	42	33	58	62	65	66	68	68	75	80	87

a. Leveling-off of new Agricultural Irrigation Load Control enrollments
b. Programs *not* included in current EAI portfolio added (except per below)
c. Commercial dynamic rates added (consistent with AMI schedule)

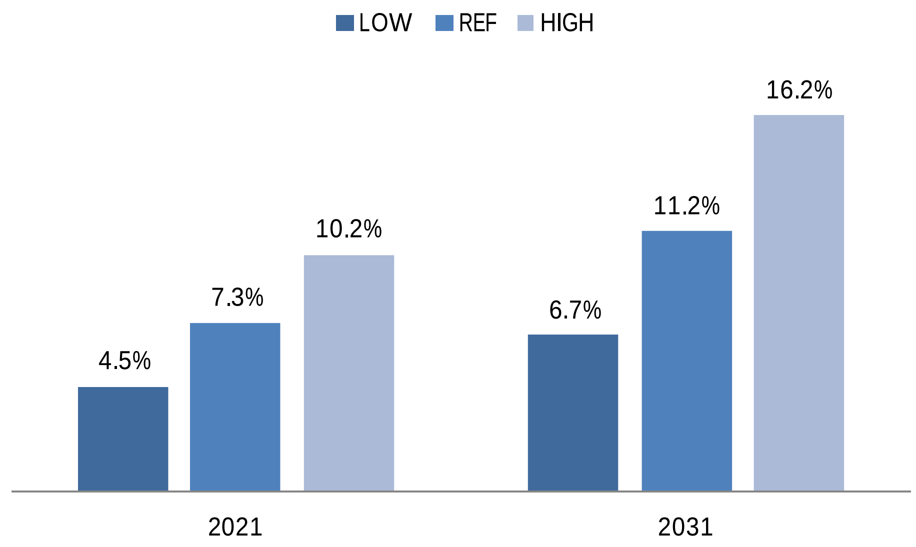
Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Program cost estimates (Real 2011$)



Portfolio cost-effectiveness test result estimates

- Total Resource Cost (TRC) Test = 2.2
- Program Administrator Cost (PAC) Test = 2.9
- Participant Cost Test (PCT) = 3.9
- Ratepayer Impact Measure(RIM) Test = 0.9

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Cumulative net MWh savings estimates as % of sales (10 & 20 year estimates)



Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Benchmarking– comparison of this study's estimates to those studies from other recent Southern studies

Study	Primary Author	Study Comm-issioned or Sponsored by	Year Released	Study Time Horizon	Method-ology	Type of Achievable Potential	10 Year Savings Estimate	20 Year Savings Estimate
Entergy Arkansas (this study)	ICF International	Entergy, Corp.	2012	20 Year	Bottom-up	Achievable Low	4.5%	6.7%
						Achievable Reference	7.3%	11.2%
						Achievable High	10.2%	16.2%
Tennessee Valley Authority	Global Energy Partners	TVA	2011	20 Year	Bottom-up	Achievable Low	5.1%	10.6%
						Achievable High	9.8%	19.8%
Missouri Statewide	KEMA	MO PSC	2011	10 Year	Bottom-up	Three Year Payback Achievable Net	3%	N/A
						One Year Payback Achievable Net	7%	N/A
Missouri Statewide	ACEEE	ACEEE	2011	10 Year	Top-Down	Achievable program	6.4%	N/A
Arkansas Statewide	ACEEE	ACEEE	2011		Top-Down	"Medium" Case Achievable	9.8% by 2025	
U.S. National Study, Southern Region	Electric Power Research Institute	EPRI	2009	20 Year	Bottom-up	Maximum Achievable	10.0%	11.1%
						Realistic Achievable	4.4%	8.1%
Review of Southern EE Studies	Georgia Tech	Georgia Tech	2009	N/A	Meta-Study	Maximum Achievable	1.2% per year	
						Realistic Achievable	0.9% per year	

*Savings estimates are cumulative unless otherwise noted. Some studies did not develop 10 and 20 year savings estimates, rather estimates were developed that are one or two years shorter or longer in time frame. For the above table approximations were made for the purposes of benchmarking. All studies shown are long-term in nature and therefore subject to high levels of uncertainty.

Estimates from this study are most comparable to those from the other bottom-up studies (EPRI, TVA, KEMA). Estimates from this study are similar, if somewhat higher, than estimates from these studies.

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Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measures

- Key sources
  - AR deemed savings
  - ICF building simulations
  - FERC (some Demand Response measures)
- Many non-deemed measures added. Key additions include:
  - Retrocommissioning
  - Advanced new buildings
  - Lighting measures, particularly LEDs
  - Mini-split ACs
  - Industrial

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measure Types Analyzed & Included

Measure Type

	New Construction		Retrofit		Replace-on-Burnout		Totals	
	Analyzed	Included	Analyzed	Included	Analyzed	Included	Analyzed	Included
Non-Residential Measures	96	36	777	182	76	38	949	256
% Sector Total	10%	14%	82%	71%	8%	15%		27%
Residential Measures	164	34	378	213	216	130	758	377
% Sector Total	22%	9%	50%	56%	28%	34%		50%
Grand Total	260	70	1155	395	292	168	1707	633
% Grand Total	15%	11%	68%	62%	17%	27%		37%

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measure Analysis

Measure Included?	Measure TRC>=1?		Total
	No	Yes	
No	934	140	1075
Yes	58	575	633
Grand Total	992	715	1707

Measure TRC test = PV(avoided costs over measure life) ÷ PV(measure incremental costs)

Passing TRC test value =1.0

Measures passing TRC but not included (140)

- Majority of measure applications not cost-effective (cool roofs)
- Duplicative measures (2” v. 3” hot water heater wrap)
- Measures targeting converted residences

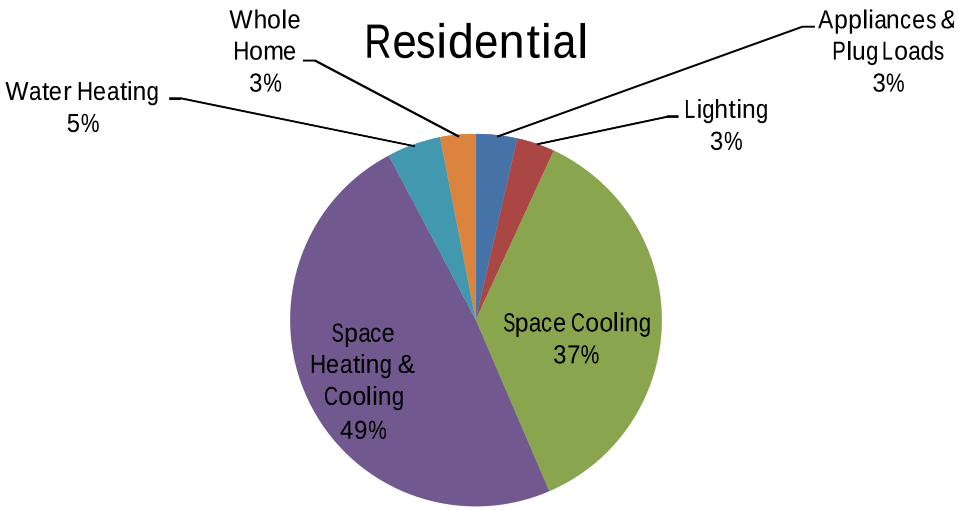
Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Measure Analysis – cont.

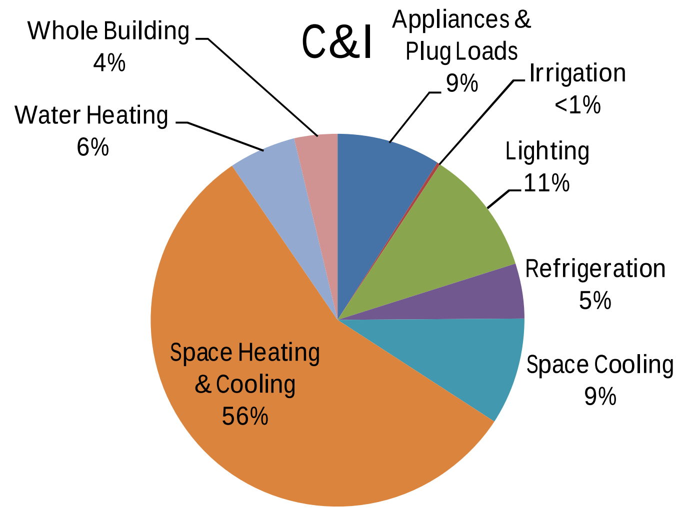
Measure Included?	Measure TRC>=1?		Total
	No	Yes	
No	934	140	1075
Yes	58	575	633
Grand Total	992	715	1707

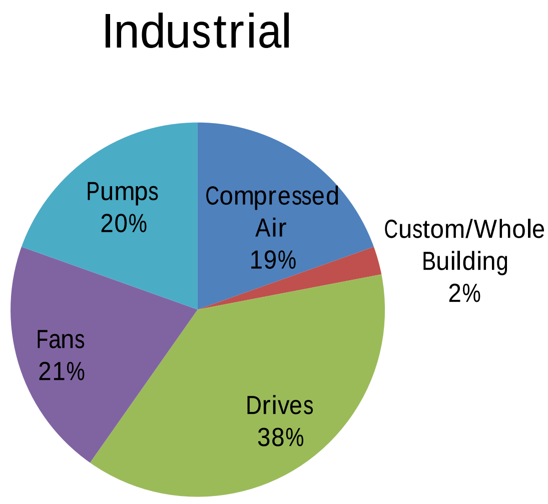
Measures not passing TRC but included (58)

- Majority of measure applications cost-effective (attic knee wall insulation)
- Policy measures (weatherization)
- Declining costs (LEDs)

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Distribution of Measure Types Analyzed, by Sector & End Use







Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Programs modeled

ICF then bundled the measures into programs that resemble the EAI's comprehensive programs.

Those that were not similar to EAI's Comprehensive Programs were bundled separately.

	Modeled Program Name	Relevant Sector(s)	Type	EAI Compre-hensive Program?
1	Residential Lighting and Appliances	Residential	EE	Yes
2	Residential Cooling Solutions	Residential	EE	Yes
3	Home Energy Solutions	Residential	EE	Yes
4	Energy Efficiency Arkansas	Residential	EE	Yes
5	AR Weatherization	Residential	EE	Yes
6	Benchmarking	Residential	EE	Yes
7	ENERGY STAR Homes	Residential	EE	Yes
8	Mobile Homes	Residential	EE	Yes
9	Multifamily	Residential	EE	Yes
10	C&I Prescriptive	C&I	EE	Yes
11	City Smart	Government	EE	Yes
12	Commercial Custom	C&I	EE	Yes
13	Small Commercial	Small Commercial	EE	Yes
14	Agricultural Energy Solutions	Agricultural	EE	Yes
15	Direct Load Control	Residential	DR	Yes
16	Agricultural Irrigation Load Control	Agricultural	DR	Yes
17	Commercial New Construction	Commercial	EE	No
18	Retrocommissioning	Commercial	EE	No
19	Industrial	Industrial	EE	No
20	Interruptible Rate	Large C&I	DR	No
21	Enabled Pricing (Non-Res)	Commercial	DR	No
22	Non-Enabled Pricing (Non-Res)	Commercial	DR	No
23	Enabled Pricing (Res)	Residential	DR	No
24	Non-Enabled Pricing (Res)	Residential	DR	No

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Estimating Participation – Two Approaches

- Market Adoption Curve Approach (Approach A)
  - Combines research on customers' financial motives with research on the diffusion of innovative technologies in the marketplace.
  - Usually applied to programs where payback acceptance is important to customer decision making, e.g.,
    - Mass Market programs (e.g., Residential Lighting)
    - Replace-on-burnout measures
    - Small to mid sized retrofit
- Program Experience Approach (Approach B)
  - Usually applied programs where payback acceptance is not as important to customer decision making, or where ICF program data or experience is more accurate than the market adoption curve approach.
    - Large retrofit/whole building (e.g., Residential Solutions, Retrocommissioning)
    - New home construction
    - Custom

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Participation approach by program

	Modeled Program Name	Relevant Sector(s)	Type	EAI Compre-hensive Program?	Participation Approach
1	Residential Lighting and Appliances	Residential	EE	Yes	A
2	Residential Cooling Solutions	Residential	EE	Yes	A
3	Home Energy Solutions	Residential	EE	Yes	B
4	Energy Efficiency Arkansas	Residential	EE	Yes	B
5	AR Weatherization	Residential	EE	Yes	B
6	Benchmarking	Residential	EE	Yes	B
7	ENERGY STAR Homes	Residential	EE	Yes	B
8	Mobile Homes	Residential	EE	Yes	A
9	Multifamily	Residential	EE	Yes	A
10	C&I Prescriptive	C&I	EE	Yes	A
11	City Smart	Government	EE	Yes	B
12	Commercial Custom	C&I	EE	Yes	B
13	Small Commercial	Small Commercial	EE	Yes	A
14	Agricultural Energy Solutions	Agricultural	EE	Yes	A
15	Direct Load Control	Residential	DR	Yes	B
16	Agricultural Irrigation Load Control	Agricultural	DR	Yes	B
17	Commercial New Construction	Commercial	EE	No	A
18	Retrocommissioning	Commercial	EE	No	B
19	Industrial	Industrial	EE	No	A
20	Interruptible Rate	Large C&I	DR	No	B
21	Enabled Pricing (Non-Res)	Commercial	DR	No	B
22	Non-Enabled Pricing (Non-Res)	Commercial	DR	No	B
23	Enabled Pricing (Res)	Residential	DR	No	B
24	Non-Enabled Pricing (Res)	Residential	DR	No	B

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Scenarios

	Scenario		
Variable	Low	Reference	High
Incentive Simple Payback Target (Years)	3	2	1
Incentive Min. (% Incremental Cost)	10%	25%	50%
Incentive Max. (% Incremental Cost)	50%	75%	100%

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Other program inputs

- Costs
  - Long-run
  - EAI filed programs
  - ICF program experience
- Net-To-Gross
  - 0.80 for each program, per APSC order

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Utility assumptions

- Average avoided energy and capacity costs and discount rate provided by Entergy SPO.
- EAI 2011 retail rates escalated at same rate as avoided costs.
- Gas savings included for electric measures, where applicable. No “gas” measures included.
- Advanced meter deployment schedule.
- MISO benefits were included in the Potential Study. The Benefit Cost Analysis was adjusted to reflect a cost reduction in the Reserve Capacity cost.

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Treatment of codes & standards

Residential

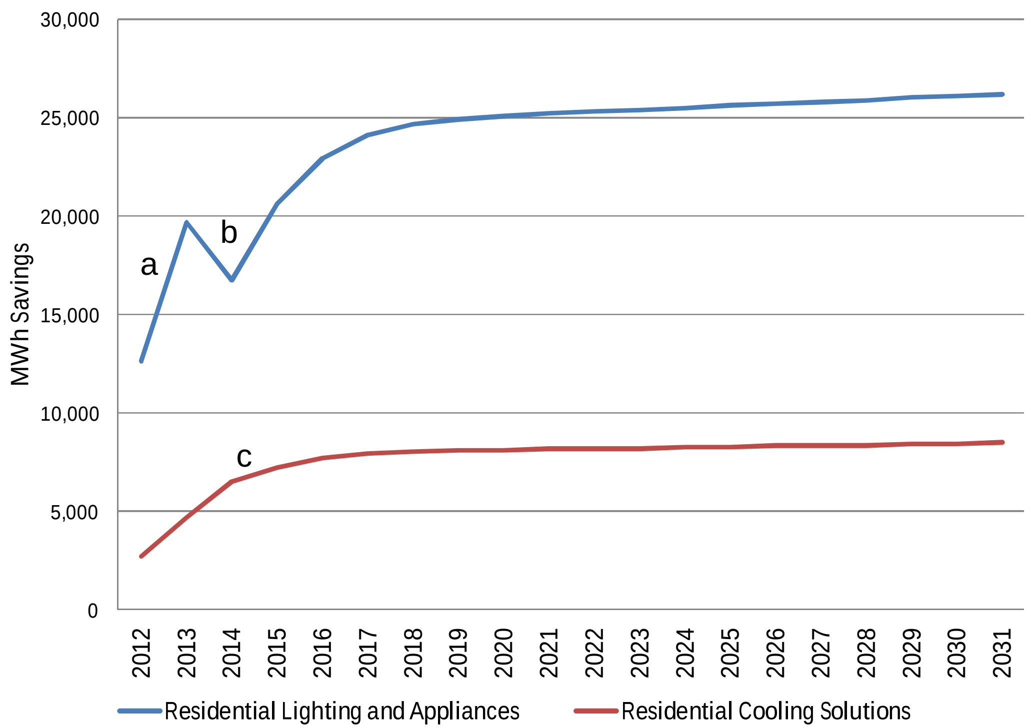
- Deemed savings
- IECC 2003* for non-deemed retrofit & new construction measures
- EISA 2007
  - Lighting: Changed CFL and lighting baselines according to EISA/DOE schedule (2012, 2013 or 2014 depending on bulb wattage)
  - CACs & HPs: Changed baseline from SEER 13 to SEER 14 in 2015

Commercial

- Deemed savings (assumes ASHRAE 90.1-2001*)
- ASHRAE 90.10-2010 for non-deemed retrofit & new construction measures

*Adopted AR building energy code at time of study

Process to Identify Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Treatment of codes & standards – cont.

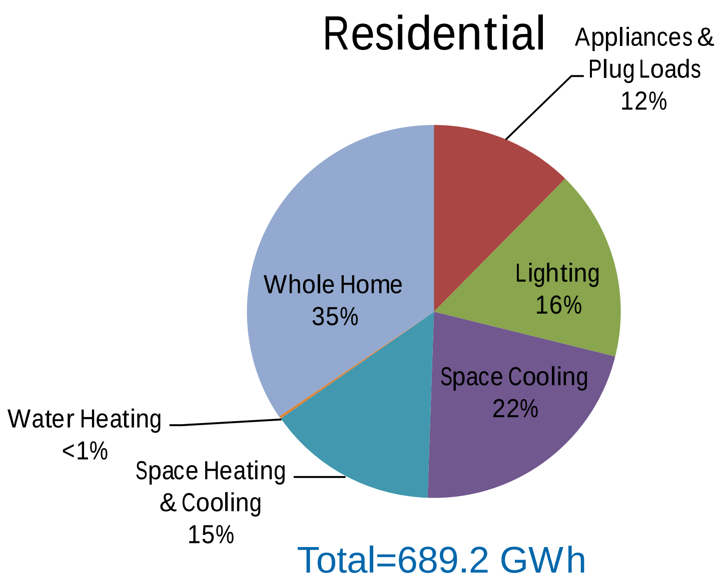


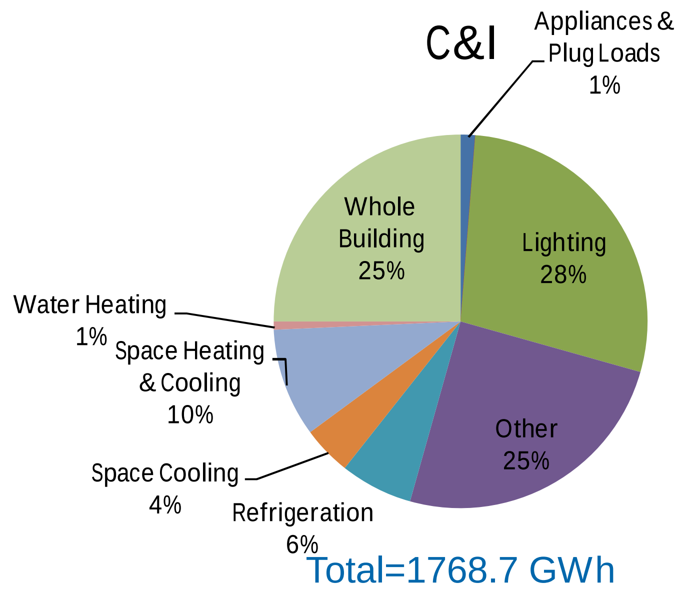
a. 27W CFL with 100W Florescent baseline phased-out
23W CFL with 75W Florescent baseline phased-out

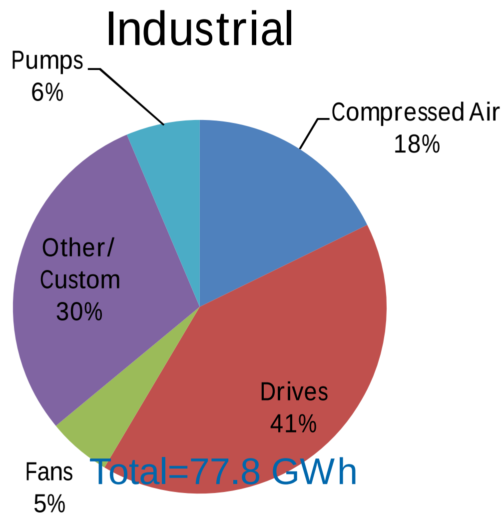
b. 11W CFL with 40W Florescent baseline phased-out
15W CFL with 60W Florescent baseline phased-out
Program continues with CFLs and LEDs with EISA compliant Halogen baselines

c. Shift from SEER 13 to SEER 14 baseline for residential ACs and heat pumps has a comparatively smaller impact on program trajectory

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Distribution of net 2031 cumulative electric savings, by sector & end use, reference case







Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual Net MWh savings estimates by program, Reference Case

			Incremental Electricity Savings - MWh										
Type	Sector	Program Name	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
EE	Residential	Residential Lighting and Appliances	12,588	19,691	16,771	20,621	22,931	24,098	24,642	24,912	25,073	25,194	26,185
EE	Residential	Residential Cooling Solutions	2,728	4,732	6,489	7,249	7,719	7,925	8,023	8,079	8,119	8,153	8,471
EE	Residential	Home Energy Solutions	2,863	3,832	4,809	6,372	9,691	9,728	9,765	9,802	9,839	9,877	10,259
EE	Residential	Energy Efficiency Arkansas	-	-	-	-	-	-	-	-	-	-	-
EE	Residential	AR Weatherization	2,832	2,843	2,854	2,864	2,875	2,886	2,897	2,908	2,919	2,930	3,044
EE	Residential	Benchmarking	15,030	7,543	7,572	7,601	7,630	7,659	7,688	7,717	7,747	7,776	8,078
EE	Residential	ENERGY STAR Homes	1,376	1,658	2,219	3,675	5,589	5,610	5,632	5,653	5,675	5,696	5,917
EE	Residential	Mobile Homes	493	856	1,173	1,361	1,449	1,488	1,506	1,516	1,524	1,530	1,590
EE	Residential	Multifamily	963	1,671	2,291	2,658	2,830	2,905	2,941	2,962	2,976	2,989	3,105
EE	Non-Residential	C&I Prescriptive	20,385	35,823	49,757	58,469	63,071	65,609	67,296	68,664	69,927	71,166	84,776
EE	Non-Residential	City Smart	6,256	8,519	10,877	11,109	11,347	11,589	11,837	12,090	12,348	12,612	15,581
EE	Non-Residential	Commercial Custom	14,747	22,593	30,768	31,425	32,096	32,782	33,482	34,198	34,928	35,675	44,073
EE	Non-Residential	Small Commercial	1,814	3,138	4,292	4,965	5,272	5,398	5,449	5,472	5,484	5,493	5,553
EE	Non-Residential	Agricultural Energy Solutions	498	879	1,226	1,447	1,568	1,638	1,687	1,729	1,768	1,806	2,232
EE	Residential	Commercial New Construction	-	-	-	1,967	3,463	4,820	5,676	6,136	6,395	6,573	7,999
EE	Non-Residential	Retrocommissioning	-	-	-	1,907	3,893	5,962	6,087	6,214	6,344	6,477	7,972
EE	Non-Residential	Industrial	2,203	3,811	5,212	6,029	6,402	6,555	6,618	6,646	6,661	6,671	6,744
DR	Residential	Direct Load Control	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Agricultural Irrigation Load Control	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Interruptible Rate	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Enabled Pricing (Non-Res)	-	-	-	-	-	-	-	-	-	-	-
DR	Residential	Enabled Pricing (Res)	-	-	-	-	-	-	-	-	-	-	-
DR	Residential	Non-Enabled Pricing (Res)	-	-	-	-	-	-	-	-	-	-	-
DR	Non-Residential	Non-Enabled Pricing (Non-Res)	-	-	-	-	-	-	-	-	-	-	-
		Total Portfolio	84,776	117,590	146,308	169,718	187,825	196,654	201,227	204,698	207,728	210,617	241,580

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Annual Net MW savings estimates by program, Reference Case

	Incremental Electricity Savings - MW										
Program Name	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
Residential Lighting and Appliances	3.0	5.1	5.8	6.9	7.4	7.7	7.8	7.9	7.9	8.0	8.3
Residential Cooling Solutions	1.0	1.8	2.5	2.8	2.9	3.0	3.0	3.1	3.1	3.1	3.2
Home Energy Solutions	1.3	1.7	2.1	2.8	4.2	4.3	4.3	4.3	4.3	4.3	4.5
Energy Efficiency Arkansas	-	-	-	-	-	-	-	-	-	-	-
AR Weatherization	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Benchmarking	5.2	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.8
ENERGY STAR Homes	0.4	0.5	0.7	1.1	1.7	1.7	1.7	1.7	1.7	1.7	1.8
Mobile Homes	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Multifamily	0.1	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
C&I Prescriptive	4.7	8.3	11.5	13.4	14.4	15.0	15.3	15.5	15.8	16.0	18.4
City Smart	0.8	1.1	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7	2.1
Commercial Custom	2.7	4.1	5.6	5.7	5.8	6.0	6.1	6.2	6.4	6.5	8.0
Small Commercial	0.7	1.2	1.6	1.8	1.9	2.0	2.0	2.0	2.0	2.0	2.0
Agricultural Energy Solutions	0.1	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.7
Commercial New Construction	-	-	-	0.4	0.6	0.9	1.1	1.1	1.2	1.2	1.5
Retrocommissioning	-	-	-	0.3	0.7	1.1	1.1	1.1	1.1	1.2	1.4
Industrial	0.3	0.5	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9
Direct Load Control	11.3	18.1	27.2	27.3	27.5	27.6	27.7	27.8	27.9	28.0	29.1
Agricultural Irrigation Load Control	13.5	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6	13.1
Interruptible Rate	-	-	24.7	24.7	24.7	24.7	24.8	24.8	24.8	24.9	25.1
Enabled Pricing (Non-Res)	-	-	-	-	-	-	-	-	-	4.5	5.5
Enabled Pricing (Res)	-	-	0.2	0.4	0.7	0.9	1.3	1.5	8.8	11.0	11.5
Non-Enabled Pricing (Res)	-	-	0.1	0.2	0.3	0.4	0.6	0.7	4.0	5.0	5.2
Non-Enabled Pricing (Non-Res)	-	-	2.6	2.7	2.7	2.8	2.9	2.9	3.0	3.1	3.8
Total Portfolio	46.0	55.3	100.1	106.6	112.1	114.6	116.5	117.9	129.5	138.2	150.3

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Program costs, Reference Case

			Annual Program Cost Estimates ($Millions)										
Type	Sector	Program Name	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2031
EE	Residential	Residential Lighting and Appliances	$3.3	$5.7	$7.4	$8.6	$9.2	$9.4	$9.6	$9.6	$9.7	$9.7	$10.1
EE	Residential	Residential Cooling Solutions	$1.5	$2.6	$3.5	$4.0	$4.2	$4.4	$4.4	$4.4	$4.5	$4.5	$4.7
EE	Residential	Home Energy Solutions	$3.1	$4.1	$5.1	$6.8	$10.4	$10.4	$10.4	$10.5	$10.5	$10.6	$11.0
EE	Residential	Energy Efficiency Arkansas	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
EE	Residential	AR Weatherization	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.9
EE	Residential	Benchmarking	$1.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.6	$0.6	$0.6
EE	Residential	ENERGY STAR Homes	$0.6	$0.8	$1.0	$1.7	$2.6	$2.6	$2.6	$2.7	$2.7	$2.7	$2.8
EE	Residential	Mobile Homes	$0.2	$0.3	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
EE	Residential	Multifamily	$0.4	$0.7	$0.9	$1.1	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.3
EE	Non-Residential	C&I Prescriptive	$5.6	$9.8	$13.6	$15.9	$17.1	$17.7	$18.1	$18.4	$18.7	$19.0	$21.9
EE	Non-Residential	City Smart	$1.6	$2.2	$2.9	$2.9	$3.0	$3.0	$3.1	$3.2	$3.2	$3.3	$4.1
EE	Non-Residential	Commercial Custom	$3.8	$5.9	$8.0	$8.1	$8.3	$8.5	$8.7	$8.9	$9.1	$9.2	$11.4
EE	Non-Residential	Small Commercial	$0.9	$1.6	$2.2	$2.6	$2.8	$2.8	$2.8	$2.9	$2.9	$2.9	$2.9
EE	Non-Residential	Agricultural Energy Solutions	$0.2	$0.4	$0.6	$0.7	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$1.0
EE	Residential	Commercial New Construction	$0.0	$0.0	$0.0	$0.5	$0.8	$1.1	$1.3	$1.4	$1.5	$1.5	$1.8
EE	Non-Residential	Retrocommissioning	$0.0	$0.0	$0.0	$0.2	$0.4	$0.6	$0.6	$0.6	$0.6	$0.6	$0.8
EE	Non-Residential	Industrial	$0.7	$1.3	$1.7	$2.0	$2.1	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2
DR	Residential	Direct Load Control	$1.1	$1.7	$2.6	$2.6	$2.6	$2.6	$2.6	$2.6	$2.6	$2.6	$2.7
DR	Non-Residential	Agricultural Irrigation Load Control	$2.2	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6	$1.7	$1.7	$1.7	$2.1
DR	Non-Residential	Interruptible Rate	$0.0	$0.0	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.9
DR	Non-Residential	Enabled Pricing (Non-Res)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.3	$2.8
DR	Residential	Enabled Pricing (Res)	$0.0	$0.0	$0.1	$0.2	$0.3	$0.4	$0.6	$0.8	$4.3	$5.4	$5.6
DR	Residential	Non-Enabled Pricing (Res)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.2	$0.3	$0.3	$1.9	$2.4	$2.5
DR	Non-Residential	Non-Enabled Pricing (Non-Res)	$0.0	$0.0	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9	$0.9	$1.1
		Total Portfolio	$28.1	$40.8	$58.4	$66.8	$74.8	$77.0	$78.6	$79.7	$85.6	$90.3	$99.7

*Real 2011 $

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Cost-effectiveness estimates, Reference Case

Type	Program Name	TRC Test	PAC Test	RIM Test	PCT Test
EE	Residential Lighting and Appliances	1.8	2.4	0.7	4.2
EE	Residential Cooling Solutions	1.1	1.2	0.6	3.0
EE	Home Energy Solutions	1.0	1.5	0.6	2.5
EE	Energy Efficiency Arkansas				
EE	AR Weatherization	1.3	1.3	0.5	4.6
EE	Benchmarking	1.6	1.6	0.6	4.3
EE	ENERGY STAR Homes	1.4	3.5	0.7	3.0
EE	Mobile Homes	1.2	1.4	0.5	3.9
EE	Multifamily	1.2	1.4	0.5	3.6
EE	C&I Prescriptive	2.4	3.0	0.9	4.5
EE	City Smart	1.6	2.4	0.8	2.9
EE	Commercial Custom	1.9	3.1	0.9	3.2
EE	Small Commercial	1.6	1.9	0.7	3.0
EE	Agricultural Energy Solutions	1.3	1.8	0.7	2.6
EE	Commercial New Construction	3.9	5.3	1.0	7.2
EE	Retrocommissioning	4.4	6.2	1.0	7.6
EE	Industrial	1.7	2.1	0.8	3.3
DR	Direct Load Control	6.5	7.4	7.4	0.8
DR	Agricultural Irrigation Load Control	4.9	4.3	1.0	N/A*
DR	Interruptible Rate	27.5	7.7	1.2	N/A*
DR	Enabled Pricing (Non-Res)	1.6	2.3	0.9	2.5
DR	Enabled Pricing (Res)	2.6	2.4	2.4	1.1
DR	Non-Enabled Pricing (Res)	1.9	2.5	2.5	N/A*
DR	Non-Enabled Pricing (Non-Res)	4.5	4.0	1.0	N/A*
	Total Portfolio	2.2	2.9	0.9	3.9

*Assumed participant costs are zero.

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: Demand Response Programs

		Sectors Modeled/Covered				
DR Measure/Program Type	Existing Program	Resi-dential	Small Comm-ercial	Large Comm-ercial	Industrial	Agri-cultural
Agricultural Irrigation Load Control	X					X
Direct Load Control	X	X				
Dynamic Pricing without Enabling Technology		X	X	X		
Dynamic Pricing with Enabling Technology		X	X	X		
Interruptible Rate				X	X	

- Existing DR program savings and participation informed by EAI Comprehensive Plan
- Other DR program assumptions informed by 2009 FERC National DR Study
- All DR programs assumed to be “opt-in”
- DR analysis did include reduced reserve margins associated with MISO benefits

Cost Effective Achievable DSM At Entergy Arkansas - Potential Study: AMI Schedule

Total cumulative meter deployments

	Existing 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EAI	800	3,703	6,606	11,392	21,165	35,824	55,370	74,916	89,575	479,214	753,023	757,495

Yellow shading indicates the years in which each OpCo engaged in full deployment of AMI
Full Deployment: includes all customer classes except the top 150 Industrials and Cogens
Years before full deployment include targeted deployments primarily to the Residential Customer class (for simplifying purposes use the residential class only)

Subject to very high uncertainty

- Smart meters are another tool in a utility's continuing effort to reduce costs to customers and to improve service reliability
- Entergy is not planning widespread deploying of smart meters
- Pilot tests to validate technologies and economics
  - Pilot demand response programs
    - Arkansas - irrigation load control pilot for farmers
  - Beginning very limited, targeted deployments (0-5%)
    - Hard to read, frequent disconnection/reconnection
    - Considering further tests on voltage control
    - Considering developing and offering a pre-pay program
  - Voluntary option for customers to assist with monthly budgeting
  - Eliminates security deposits and late fees

EAI 2012 IRP Development
DSM Assumptions

- The Potential Study began in October of 2011.

- Best available information was used to value the energy efficiency potential
  - 2010 cost of capital information.
  - 2011 load forecast

- All the energy efficiency savings beginning in 2007 and concluding in 2011are included in the base case and projected energy savings based upon Commission approved programs through 2012 are included in the base case.
  - 2012 Energy savings – 128,055 MWH
  - 2012 Demand reductions – 50.7 MW

- Evaluation of DSM in the 2012 EAI IRP
  The DSM assumption will be modeled as one of five potential portfolios; the other four portfolios assume supply side resource additions. Each portfolio will be evaluated within each of the four IRP scenarios and the total cost of service for each portfolio will be compared to find the lowest cost portfolio option. This methodology allows for demand side resources to be compared alongside supply side resources for long-term planning of EAI's portfolio mix.

EAI 2012 IRP Development
DSM Assumptions

- Proposed Assumptions for 2012 EAI IRP
  For EAI, which has on-going DSM efforts, the assumptions for long-term planning (IRP) are consistent with programs in EAI's current DSM portfolio assuming a Reference Level of potential as contemplated in the ICF Study.

- The following charts show the underlying DSM assumptions and provide an annual view of DSM Potential and cost for EAI. Note that 2012 DSM Potential is shown at zero because that potential has already been reflected in the four load forecasts developed for the EAI IRP.

EAI 2012 IRP Development : DSM Programs

ICF Potential Study – Six Bundled Loadshapes

Bundle	Type	Programs
1	DR	Interruptible Rate Direct Load Control Agricultural Irrigation Load Control
2	EE	Retrocommissioning Commercial New Construction Energy Star Homes Commercial Custom C&I Prescriptive
3	DR	Non-enabled Dynamic Pricing Enabled Dynamic Pricing
4	EE	City Smart Residential Lighting and Appliances Industrial
5	EE	Small Commercial Agricultural Energy Solutions Benchmarking Home Energy Solutions
6	EE	Mobile Homes Multifamily Arkansas Weatherization Residential Cooling Solutions

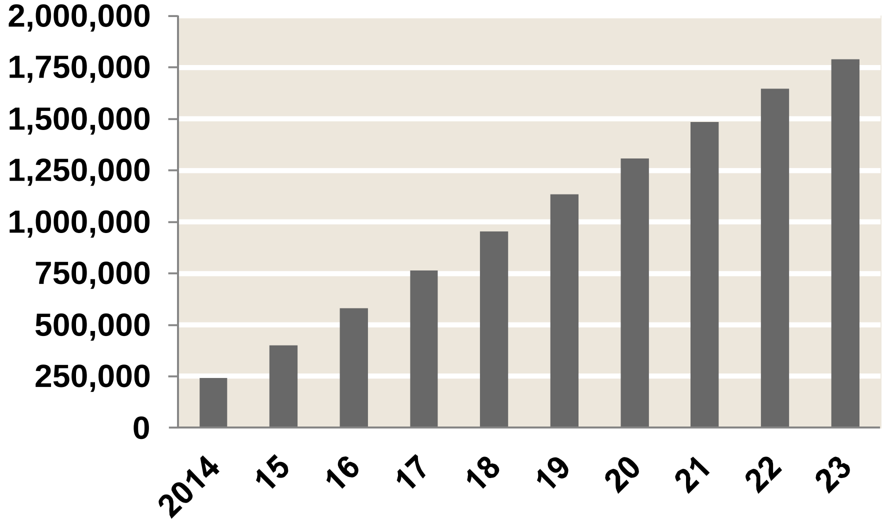
IRP DSM Portfolio – Single Aggregated Loadshape

Type	Programs
DR	~~Interruptible Rate~~ Direct Load Control Agricultural Irrigation Load Control ~~Non-enabled Dynamic Pricing~~ ~~Enabled Dynamic Pricing~~
EE	Retrocommissioning Commercial New Construction Energy Star Homes Commercial Custom C&I PrescriptiveCity Smart Residential Lighting and Appliances Industrial Small Commercial Agricultural Energy Solutions Benchmarking Home Energy Solutions Mobile Homes Multifamily Arkansas Weatherization Residential Cooling Solutions

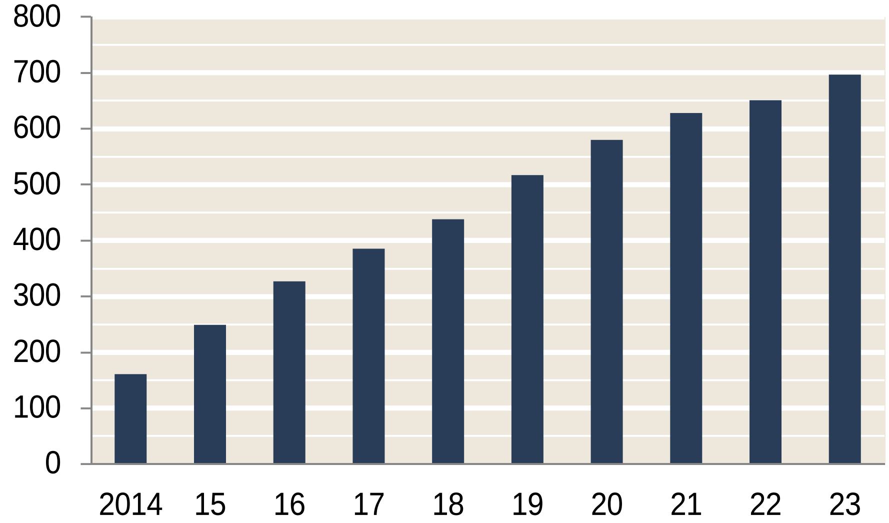
Hourly DSM impacts in 2012 of the ICF Potential Study are substracted from the hourly DSM impacts in all subsequent years of the EAI IRP DSM load shape.

EAI 2012 IRP Development : Incremental Utility-Sponsored DSM Potential Forecast

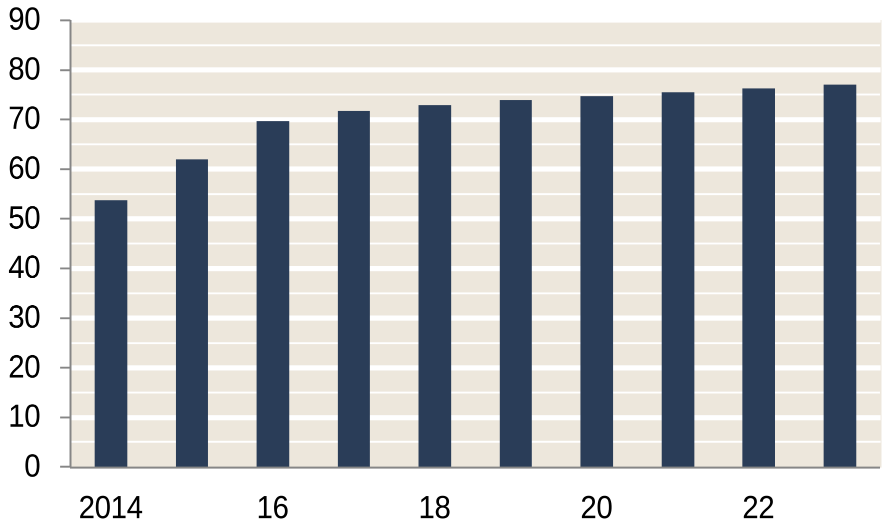
*Annual Energy Savings (MWh)**



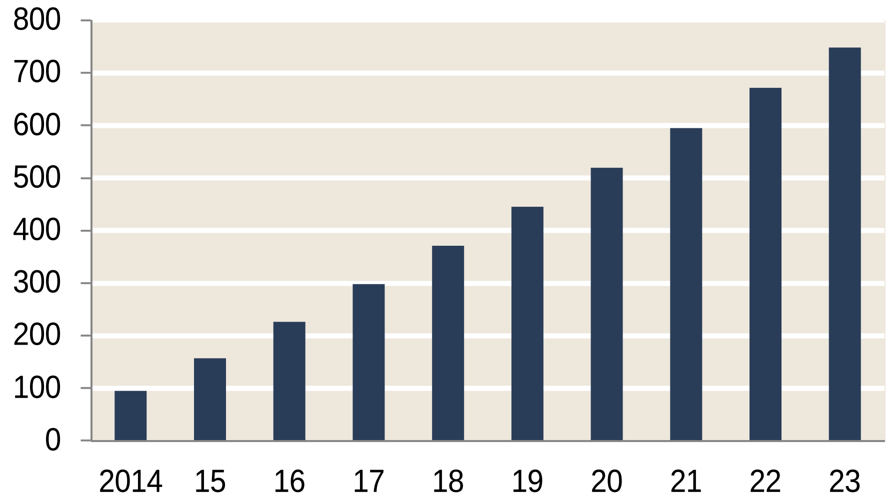
Peak Reduction (MW)*



Annual DSM Program Cost ($M)



Cumulative Program Cost ($M)



*In order to obtain specified benefit in a given year spending from 2012 through that year is required.

EAI 2012 IRP Development : Miscellaneous

- The remaining driver in the achievement of the energy efficiency potential is tariff driven savings that must have new technology installed to communicate such energy cost with customers and measure the results of customer usage.
- Presently Entergy Arkansas is thinking AMI technology is the preferred technology, and Entergy Arkansas has matured in our thinking of the roll out of AMI technology to a more measured point of view to ensure the technology can be proven to deliver promised results.
- None of the energy efficiency potential study demand reduction associated with the AMI technology was included in the IRP.

Energy Efficiency and the Future at EAI

- ASPC Targets have not been established beyond 2013. Based upon Commission orders EAI anticipates annual Energy Efficiency targets to be at least 0.75% of annual sales post NTG adjustments.

- Avoided cost have decreased significantly resulting in several of the existing programs to become non-cost effective, though the portfolio of programs continue to be cost effective.

- EAI is anticipating to file a portfolio of programs for 2014 through 2016 sometime in 2013. EAI is awaiting EM&V results to inform next portfolio filing; however, with information known today, EAI would plan to file the same programs with some modifications for measure changes and more coordination with over lapping gas utilities, minor adjustments in marketing and increased budgets to meet the potential 0.75% per year reduction targets.

NEXT STEPS

- Continue with EAI Suite of comprehensive programs, have independent Evaluation, Measurement and Verification completed and capture lessons learned to improve next phase of DSM implementation for 2014 through 2016.
- Continue to move forward with the development and implementation of enabling technologies (AMI / Smart Grid) at a measured pace to ensure technology can deliver energy efficiency results.

APPENDIX

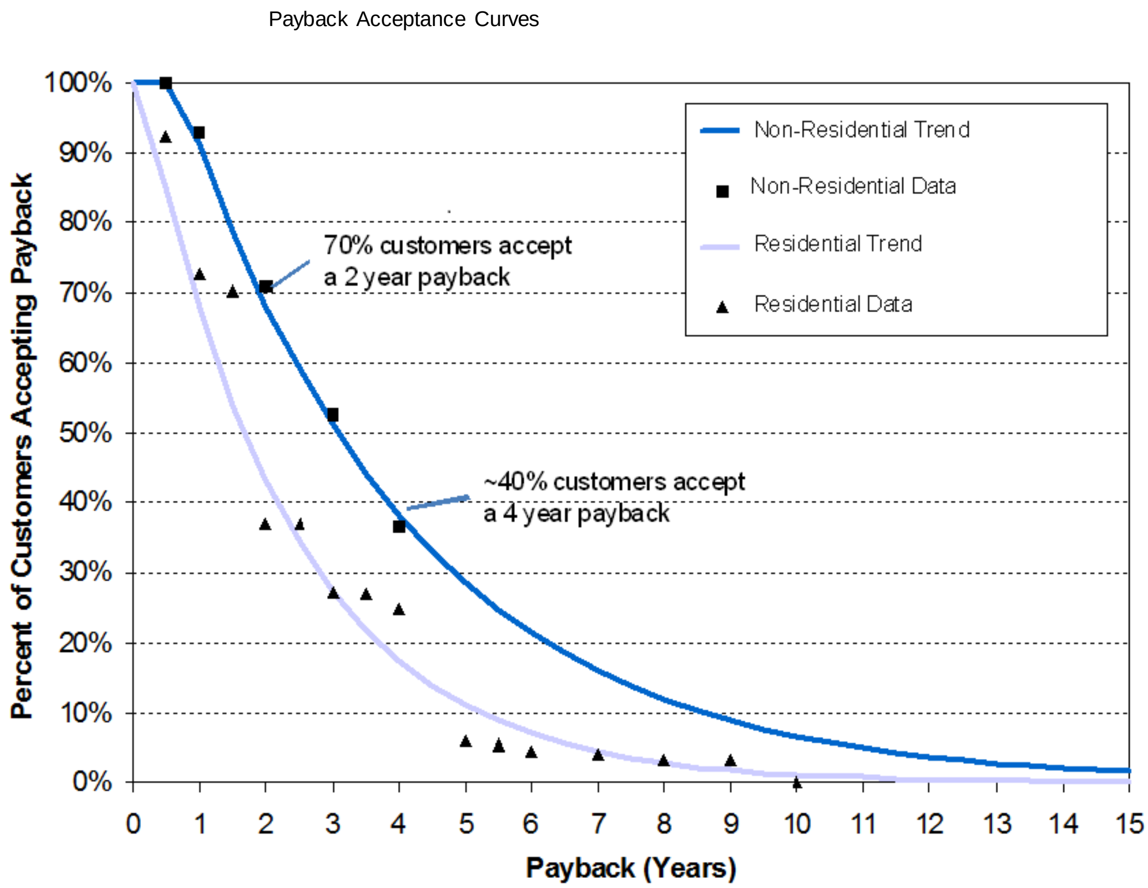
Participation Approach A – illustrative example

Measure Information

Program Name	ENERGY STAR Air Conditioning
Measure ID	16
Sector	Residential
Sub-Sector	SingleFamily&Duplex
End Use	HVAC
Technology Type	AC/Gas Heat
Efficient Measure	Central AC Replacement
Efficient Measure Definition	SEER 15
Base Measure Definition	SEER 13
Unit Name	ton

Incentive Calculations	Value	Source/Calculation
Residential retail electricity rate-kWh	$0.09	Utility
Residential retail capacity charge-kW	$0.00	Utility
Residential retail gas rate-therm	$0.85	Utility
Base Measure Life	15	Deemed Savings
Total Incremental Cost	$238.00	Deemed Savings
Annual kWh Savings	417.33	Deemed Savings
Annual kW Summer-Peak Savings	0.12	Deemed Savings
Annual Gas Savings	0	Deemed Savings
Annual Bill Savings	$37.91	Annual Energy Savings by Participant
Pre-rebate payback	6.3	Total Incremental Cost/Annual Bill Savings
Incentive Assumptions		
Minimum Incentive Level	25%	Reference case assumption
Maximum Incentive Level	75%	Reference case assumption
Post-rebate Payback Target	2	Reference case assumption
Incentive as % of Incremental Cost	68%	MAX(MIN(Minimum Incentive Level,1-Post-rebate Payback Target /Pre-rebate payback))
Incentive	$162.18	Incentive as % of Incremental Cost X Total Incremental Cost
Post-rebate payback	2	(Total Incremental Cost-Incentive)/Annual Bill Savings

Participation Approach A - cont.



Participation Approach A - cont.

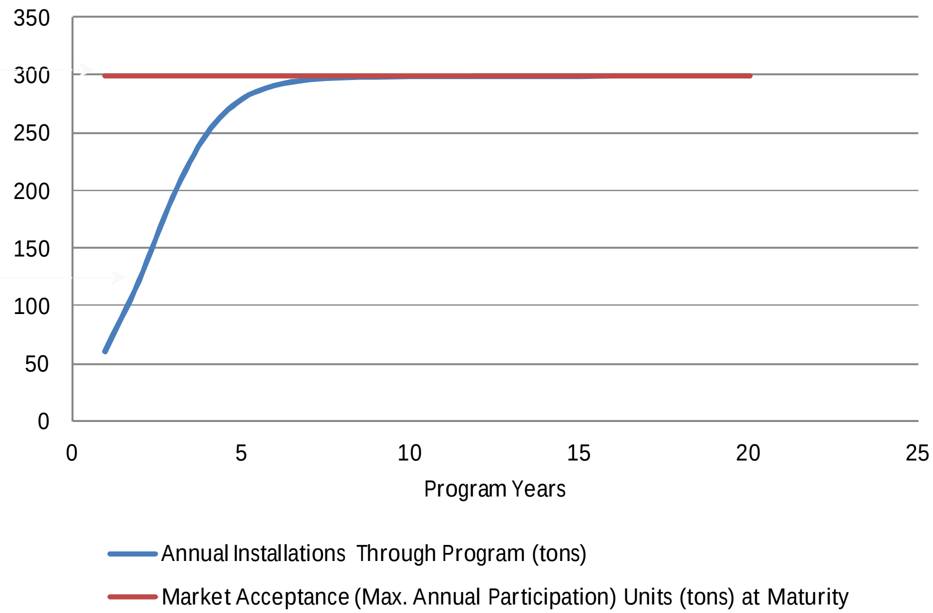
Applicability Factors	Value	Source/Calculation
Share of SingleFamily&Duplex Dwellings	87%	Utility
Measure Units per Sub-Sector Unit	3	Average size of unit (3 tons)
Applicability	32%	Percent of homes with AC/Gas Heat
Feasibility/Distribution	18%	ICF
Not Yet Adopted	100%	For ROB=100% For Retrofit=(1-Saturation of Efficiency Technology)
Annual Replacement Eligibility	7%	For ROB=1/Measure Life For Retrofit=100%

Program Assumptions	Value	Source/Calculation
Payback acceptance formula coefficient "a"	1.22	ICF market research
Payback acceptance formula coefficient "b"	-0.29	ICF market research
Customer stated payback acceptance	68%	Payback acceptance = 1.22 Years*exp(post rebate payback*b)
Program Market Acceptance Rate	30%	ICF program assumption
Ramp-up Rate	5	ICF program assumption
Ramp-up Shape	100%	ICF program assumption
Program Start Year	2012	
Program Implementation Period (Years)	20	
First Year Participation Estimates		
Maximum Annual Market Share (Smax)	20.4%	Program Market Acceptance Rate X Customer stated payback acceptance
First Year Share of Installations (So)	4.1%	Maximum Annual Market Share (Smax)/Ramp-up Rate

Participation Approach A-cont.

Maximum estimated annual installations

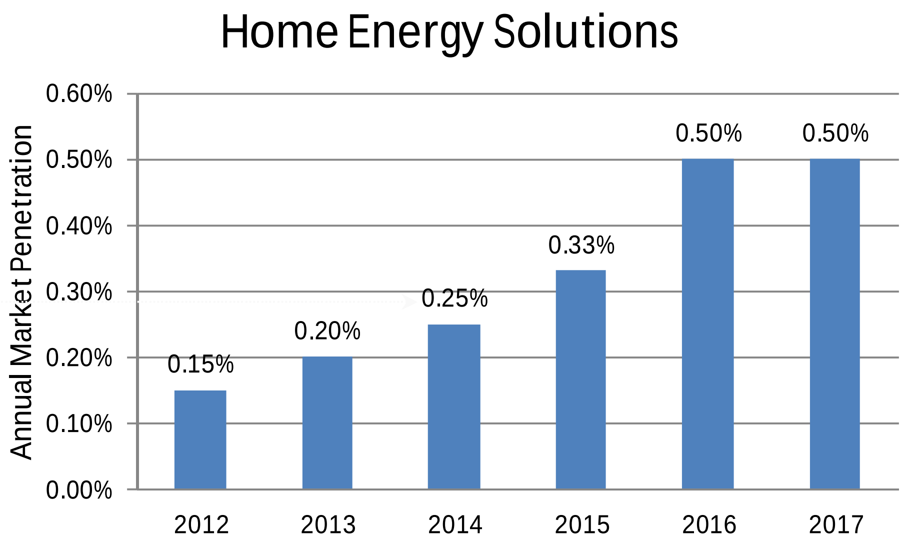
“S-curve” – participation ramps up to maximum annual installations



Participation Projections	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2031**
Number of Residential Customer	141,609	144,537	145,094	145,309	145,352	145,323	145,276	145,230	145,170	145,111	145,060	144,952
Average Annual Residential Growth Rate (2012 to 2031)	*0.0143%*											
Single Family & Duplex Customers	123,766	126,326	126,344	126,362	126,380	126,398	126,416	126,434	126,452	126,471	126,489	126,670
Customers with A/C and Gas Heat	39,732	40,554	40,560	40,565	40,571	40,577	40,583	40,589	40,594	40,600	40,606	40,664
Not Yet Adopted Efficient Measure	39,732	40,554	40,560	40,565	40,571	40,577	40,583	40,589	40,594	40,600	40,606	40,664
Total Measure Units (tons)	119,196	121,661	121,679	121,696	121,714	121,731	121,748	121,766	121,783	121,801	121,818	121,993
Feasibility (tons)	21,455	21,899	21,902	21,905	21,908	21,912	21,915	21,918	21,921	21,924	21,927	21,959
Failing Feasible Units, Units Eligible for Replacement (tons)	1,430	1,460	1,460	1,460	1,461	1,461	1,461	1,461	1,461	1,462	1,462	1,464
Units reporting acceptable payback		994	995	995	995	995	995	995	995	996	996	997
Market Acceptance Units at Maturity		*298*	*298*	*298*	*298*	*299*	*299*	*299*	*299*	*299*	*299*	*299*
Annual Participation (%)		4.1%	8.3%	13.3%	17.0%	19.0%	19.9%	20.2%	20.4%	20.4%	20.4%	20.4%
Annual Installations (tons)		60	121	194	249	278	291	296	298	298	299	299
Cumulative Installations (tons)		60	180	374	623	901	1192	1487	1785	2083	2382	4470

Participation Approach B – illustrative example

Annual market penetration estimates manually entered



Based on

- Current Entergy program performance
- The EAI Comprehensive Program Plan
- ICF program experience

Participation approach by program

	Modeled Program Name	Relevant Sector(s)	Type	EAI Compre-hensive Program?	Participation Approach
1	Residential Lighting and Appliances	Residential	EE	Yes	A
2	Residential Cooling Solutions	Residential	EE	Yes	A
3	Home Energy Solutions	Residential	EE	Yes	B
4	Energy Efficiency Arkansas	Residential	EE	Yes	B
5	AR Weatherization	Residential	EE	Yes	B
6	Benchmarking	Residential	EE	Yes	B
7	ENERGY STAR Homes	Residential	EE	Yes	B
8	Mobile Homes	Residential	EE	Yes	A
9	Multifamily	Residential	EE	Yes	A
10	C&I Prescriptive	C&I	EE	Yes	A
11	City Smart	Government	EE	Yes	B
12	Commercial Custom	C&I	EE	Yes	B
13	Small Commercial	Small Commercial	EE	Yes	A
14	Agricultural Energy Solutions	Agricultural	EE	Yes	A
15	Direct Load Control	Residential	DR	Yes	B
16	Agricultural Irrigation Load Control	Agricultural	DR	Yes	B
17	Commercial New Construction	Commercial	EE	No	A
18	Retrocommissioning	Commercial	EE	No	B
19	Industrial	Industrial	EE	No	A
20	Interruptible Rate	Large C&I	DR	No	B
21	Enabled Pricing (Non-Res)	Commercial	DR	No	B
22	Non-Enabled Pricing (Non-Res)	Commercial	DR	No	B
23	Enabled Pricing (Res)	Residential	DR	No	B
24	Non-Enabled Pricing (Res)	Residential	DR	No	B

LUNCH

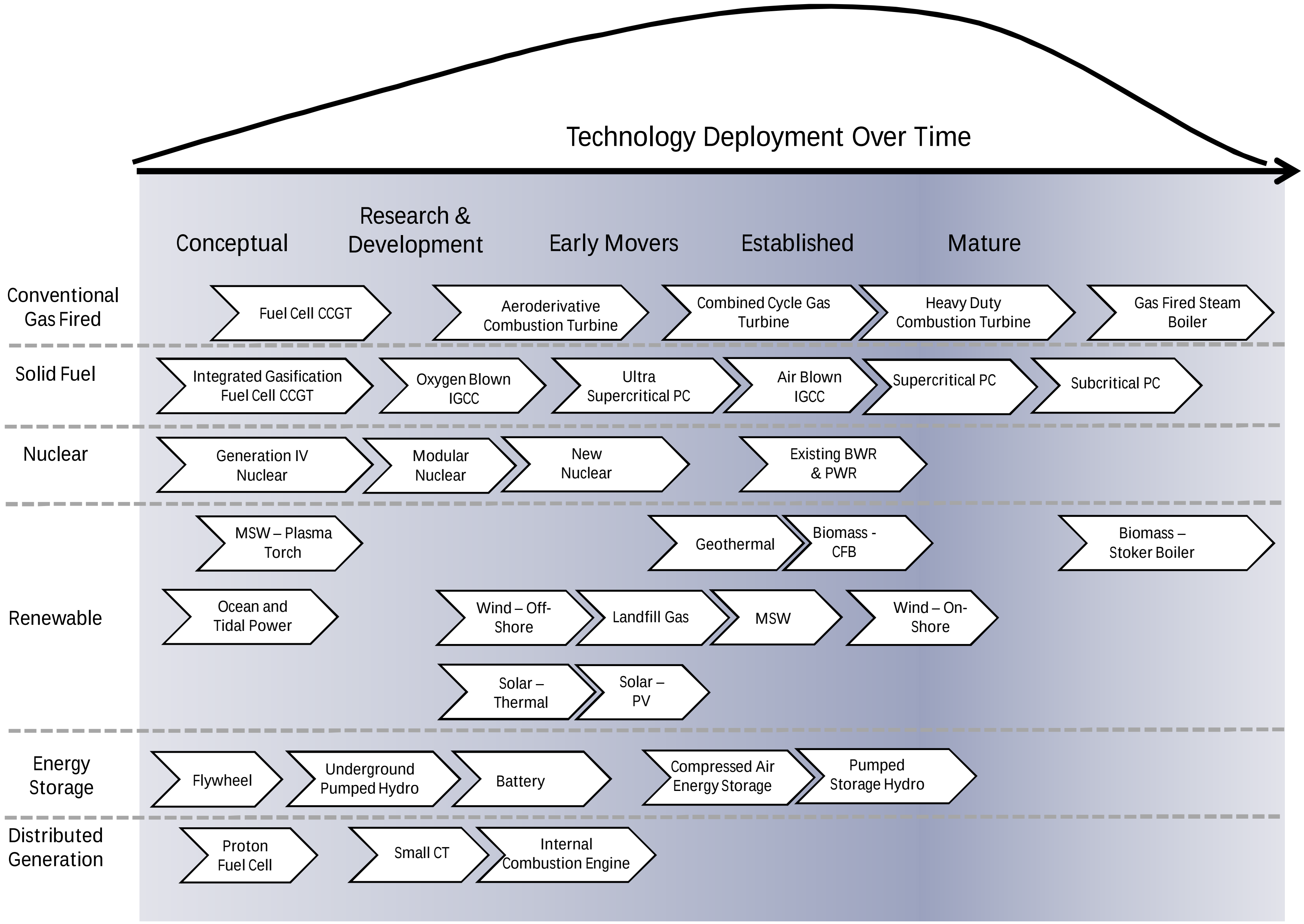
SPO Planning Analysis

Generation Technology Assessment & Production Cost Analysis

EAI Stakeholder Meeting

July 31, 2012

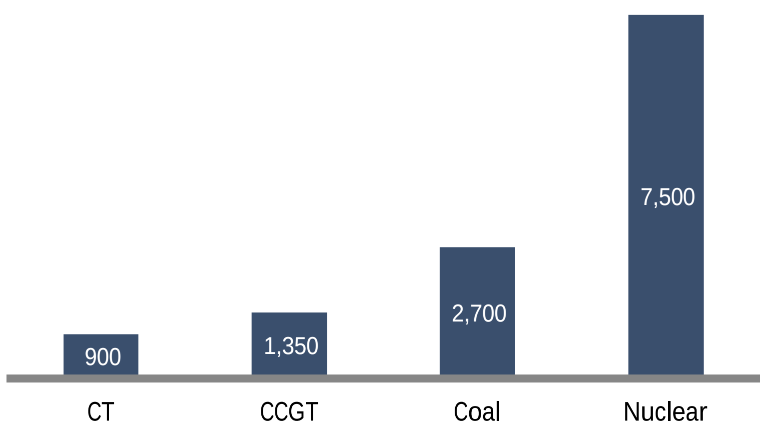
Technology Life Cycle



Conventional Alternatives

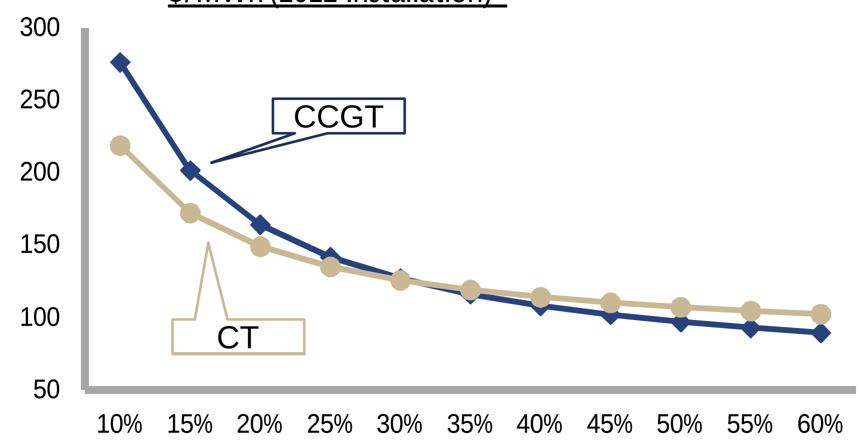
Gas Fired CT / CCGT offers Lowest Capital Cost

Installed Cost (2011$/kW)



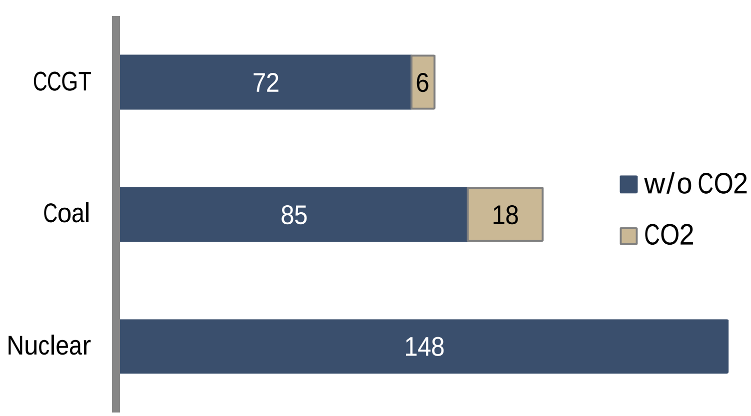
CT is preferred over CCGT below about 30% Capacity Factor

$/MWh (2012 Installation)*



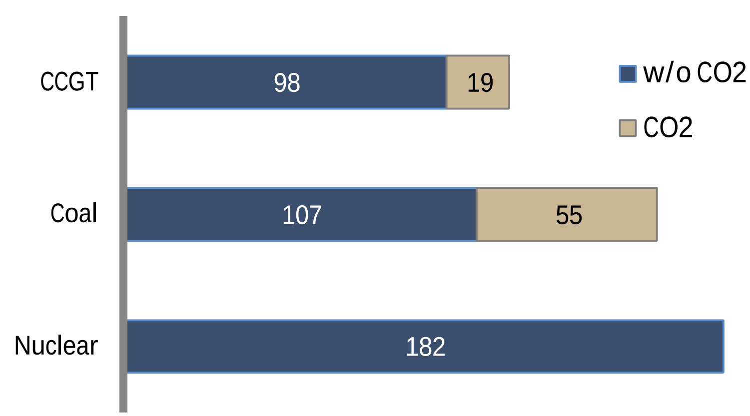
For base load CCGT is low cost alternative in 2012 . . .

Bus Bar Cost/MWh (90% Capacity Factor)*



And in 2022

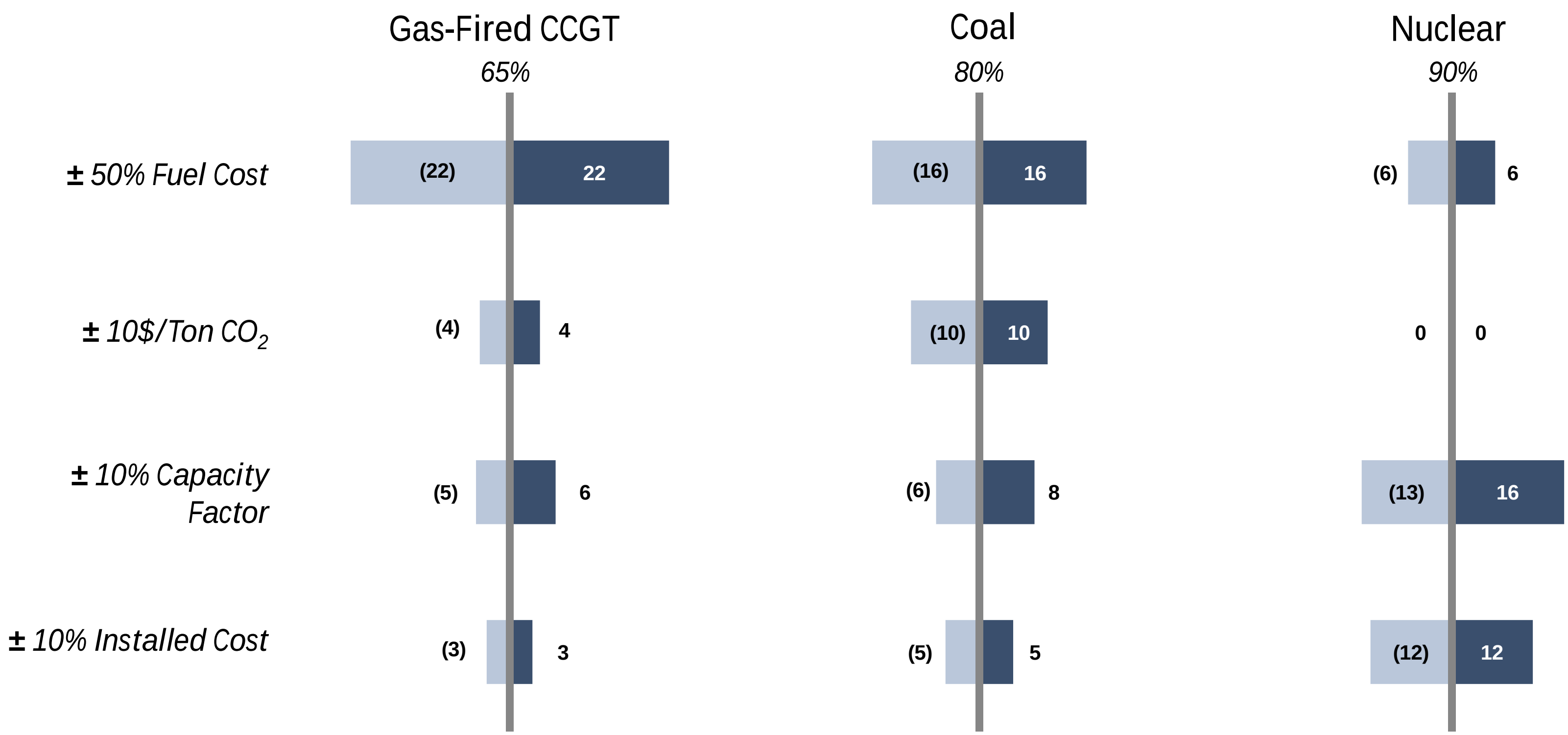
Bus Bar Cost $/MWh (90% Capacity Factor)*



*Bus bar cost levelized in nominal $/MWh over expected life of resource (30 years CCGT & CT, 40 years coal and nuclear). CO_2 compliance cost begins in 2023 and escalates over time.

Sensitivities

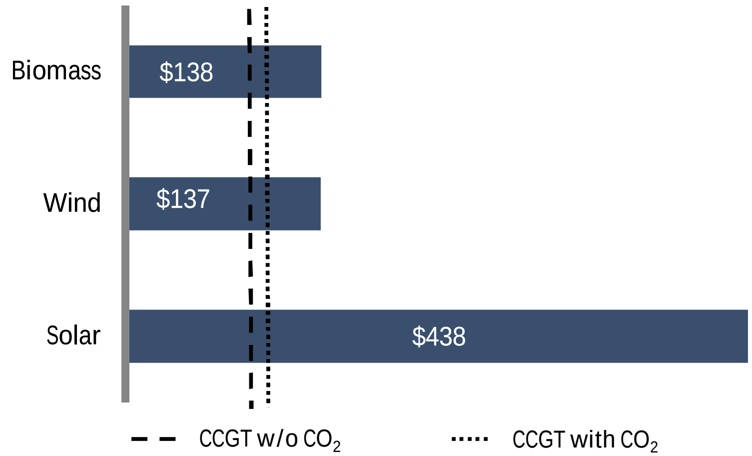
*Gas-fired CCGT economics remain favorable across range of assumptions**



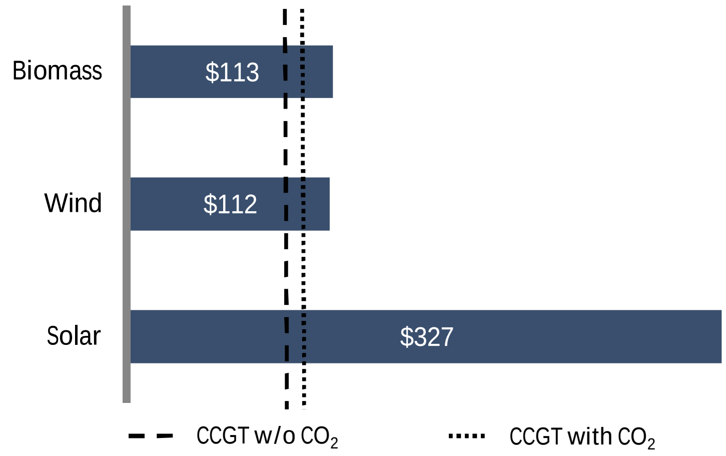
*Bus bar cost levelized in nominal $/MWh over expected life of resource (30 years CCGT & CT, 40 years coal and nuclear). CO_2 compliance cost begins in 2023 at $24.12/U.S. and escalates over time at about 7% per year. Cost based on 2012 COD.

Renewable Alternatives

$/MWh Without Incentives*

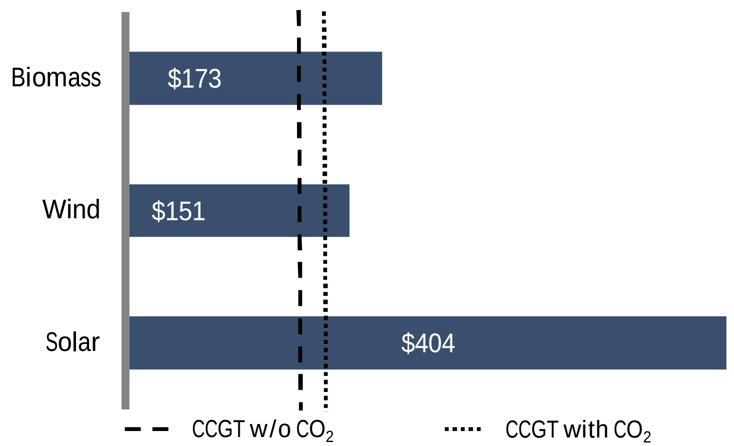


$/MWh With Incentives*

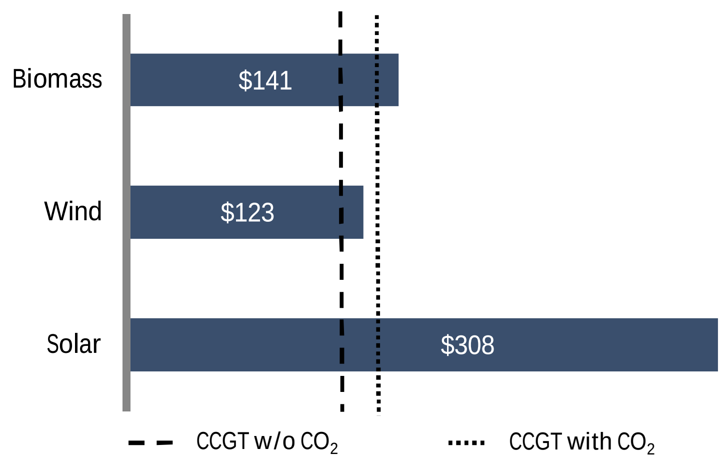


2022 In Service Date

$/MWh Without Incentives*



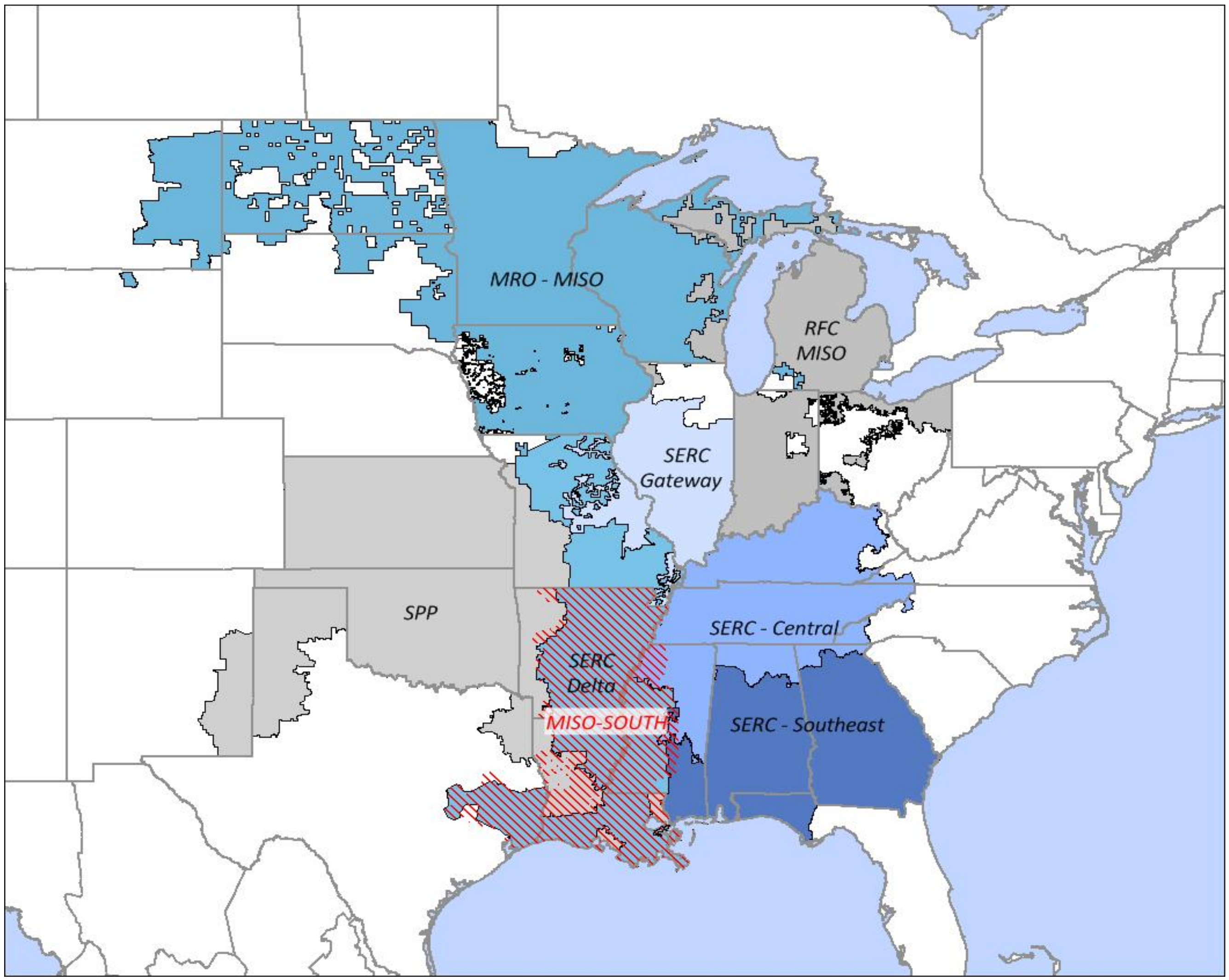
$/MWh With Incentives*



*Bus bar cost levelized in nominal $/MWh over expected life of resource (30 years CCGT & CT, 40 years coal and nuclear). CO_2 compliance cost begins in 2023 and escalates over time.

Scope of Aurora Market Modeling For IRP

Entergy Region and surrounding regions were modeled . . .



Supply Cost Assessment Overview

Aurora Production Cost Model

AURORA is used to simulate the hourly operation of the MISO and 1st tier power markets over the study period 2014 – 2023.

Includes a zonal representation that reflects transmission transfer capability limitations.

Includes a load forecast for each modeled entity and each generating unit is modeled individually.

Additional constraints are modeled to reflect operational limitations and requirements, including:

- Balancing Authority reserve requirements;
- Zonal reserve requirements;
- Generating unit forced outage rates; and
- Generator unit maintenance

All of the generators are committed and dispatched to serve the combined load at the lowest variable cost subject to the constraints.

Results in hourly power prices that are representative of the Locational Marginal Prices (LMP) for each zone.

Supply Cost Assessment

Variable production cost is measured as:

Cost of Service = Load Payment
+ Generation Cost
– Generation Revenue

To assess the total supply cost of each portfolio of resources, the incremental fixed cost of the resources that comprise the portfolio is added to the variable production cost of service.

Market Modeling Overview

IRP analytics will rely on four scenarios to assess alternative portfolio strategies under varying market conditions. Additional information regarding the scope of and assumptions used in the market modeling are provided in other slides. The four scenarios are:

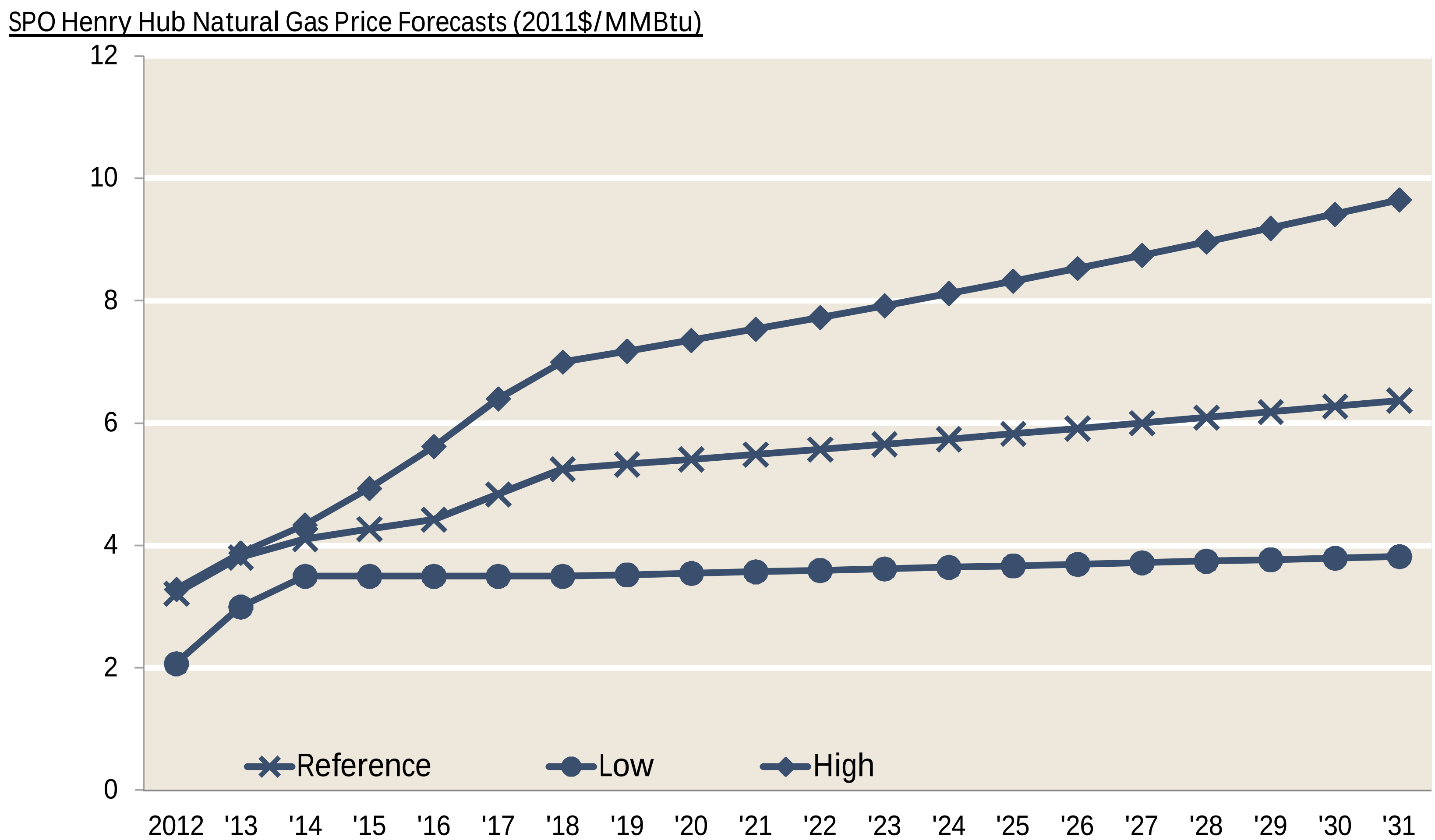
- Scenario 1 (Assumes Reference Load, Reference Gas, and no CO_2 cost)
- Scenario 2 (Economic Rebound)
- Scenario 3 (Green Growth)
- Scenario 4 (Austerity Reigns)

- More information of Scenarios 2-4 are found on the following page.

Scenario Storylines

	Scenario 2	Scenario 3	Scenario 4
	Economic Rebound	Green Growth	Austerity Reigns
General Themes	• U.S. economy recovers and resumes expansion at relatively high rates. Improved domestic energy supply and productivity improvements keep current manufacturing/industrial base competitive.	• Government policy and public interest drive a "green agenda" marked by government subsidies for renewable generation; regulatory support for energy efficiency; and consumer acceptance of higher cost for "green." • Overall economic conditions are good with moderate GDP growth which enables investment in energy infrastructure.	• Sustained poor economic conditions in U.S. – low GDP. • Economic issues trump environmental concerns in public policy and consumer attitude.
Power Sales	• Economic growth and new uses for electric power drive power sales. New power uses more than offset energy efficiency gains. Technology improvements drive electric demand and vehicles grow at a steady pace. EVs are about an 12% of the light duty fleet by 2031.	• Moderate economic growth stimulates power demand. • However, decline in electricity intensity resulting from energy efficiency measures provides a countervailing force. • Consistent with green agenda, electric vehicles represent about a quarter of the light vehicle fleet by 2031, slightly muting de-electrification.	• Poor economic conditions result in low growth in demand for power. Electric vehicles don't catch on. Due to low power prices, relaxation of some efficiency standards and consumer's unwillingness to invest in energy efficiency, electricity intensity and therefore KWh sales growth and peak demand is higher than expected.
Climate Policy	• Carbon capture & storage required when commercially available for all new power generation. • Mild cap and trade for power in 2023.	• Cap & trade for carbon (power sector only) starting in 2018. • New coal must have CCS.	• Neither Congress nor EPA regulate CO_2. (no carbon cost).
Energy Policy	• Primarily market solutions. Slow but steady move toward a cleaner environment driven by innovation.	• Clean energy standard enacted. • Government subsidies for renewable generation , new nuclear & EVs.	• Renewable subsidies end. Government has little appetite for new policy. No new state RPSs.
Fuels	• Although demand is strong, technology allows supply to keep pace. Fuel prices stay in reasonable check.	• Natural gas prices are driven higher by EPA regulation of fracking & local opposition. Coal and oil prices also high.	• Low fuel prices, but natural gas and coal still plentiful as E&P cost are also lower.

Henry Hub Natural Gas Forecast



Natural Gas Assumptions

System Planning & Analysis has produced three gas price curves which are proposed for use in the development of the 2012 IRP. The curves are summarized in the following tables.

2012- 2031 Nominal $ per MMBtu			
	Low	Reference	High
Levelized*	$3.97	$5.79	$7.58
Average	$4.38	$6.66	$9.15
19 Yr. CAGR	5.37%	5.75%	7.96%

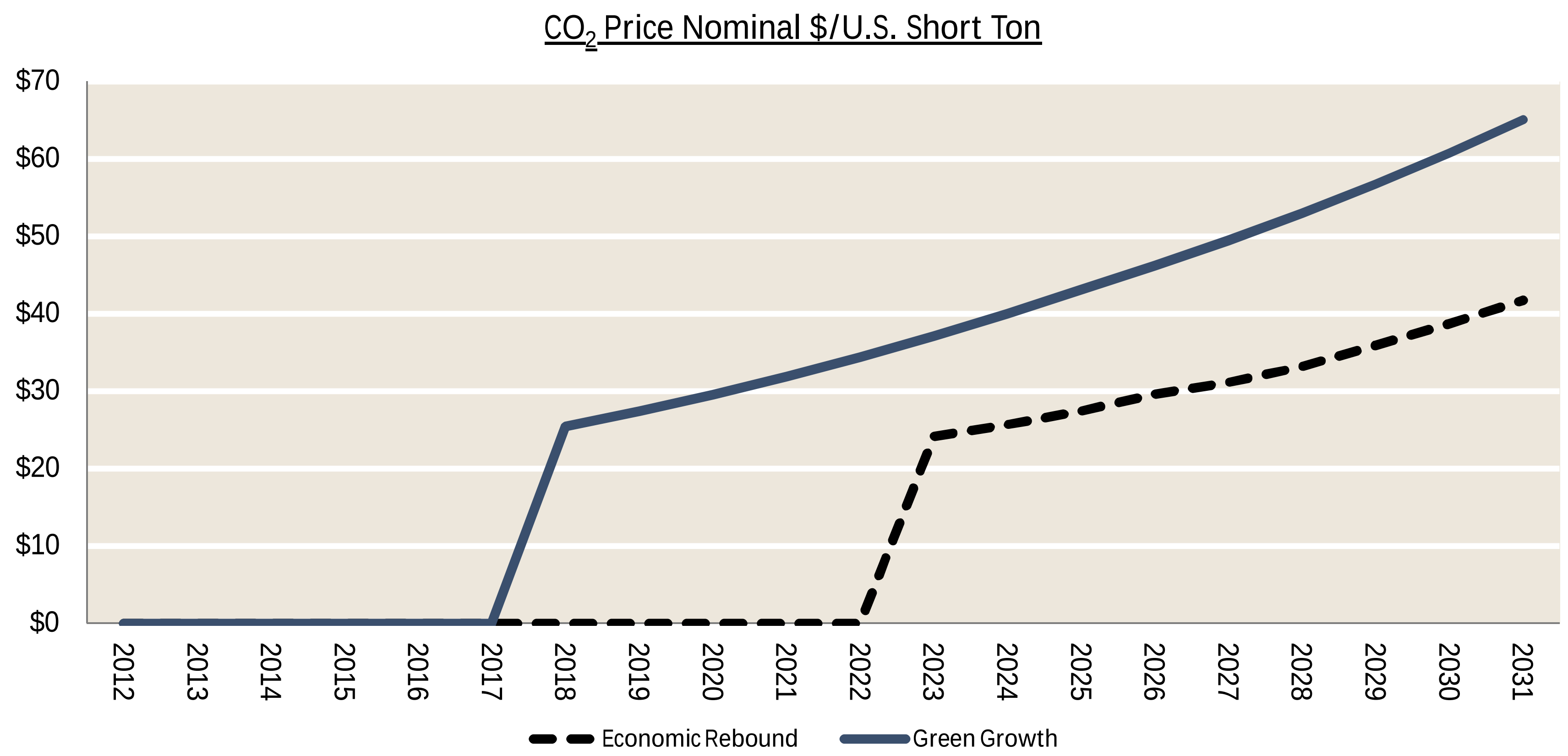
**Real prices levelized at 7.25% discount rate*

2012- 2031 Real 2011$ per MMBtu			
	Low	Reference	High
Levelized*	$3.41	$4.95	$6.47
Average	$3.51	$5.29	$7.20
19 Yr. CAGR	3.29%	3.67%	5.84%

Forecast based on January 13 Market Close.

2012 IRP Carbon Assumptions

Reference Case and Austerity Reigns scenarios assume no direct CO_2 regulation. The Economic Rebound and Green Growth Scenarios assume cap and trade programs beginning in 2023 and 2018, respectively.



Market Model Inputs (2012-2031)

	Scenario 1	Economic Rebound	Green Growth	Austerity Reigns
Electricity CAGR (Energy GWh)	~0.8%	~1.5%	~0.3%	~1.1%
Energy CAGR (w/o Elec. Vehicles)	Not materially different	~1.4%	~0.1%	Not materially different
Peak Load Growth CAGR	~0.8%	~1.4%	~0.2%	~1.1%
Henry Hub Natural Gas Prices ($/MMBtu)	$4.96 levelized 2011$	Same as Reference $4.96 levelized 2011$	High Case ($6.48 levelized 2011S	Low Case ($3.40 levelized 200x)
WTI Crude Oil ($/Barrel)	$93 levelized 2011$	$127 levelized 2011$	High Case $209 levelized 2011$	Low Case $53 levelized 2011$
CO_2 ($/short ton)	None	Cap and trade starts in 2023 $6.56 levelized 2011$	Cap and trade starts in 2018 $16.65 levelized 2011$	None
Conventional Emissions Allowance Markets	CAIR	CSAPR starts 2013	CSAPR starts 2013	CAIR
Delivered Coal Prices – Entergy Owned Plants (Plant Specific Includes Current Contracts) $/MMBtu	Reference Case (Vol. Weighted Avg. $2.66 levelized 2011$)	Same as Reference Case (Vol. Weighted Avg. $3.40 levelized 2011$)	High Case (Vol. Weighted Avg. $3.40 levelized 2011$)	Low Case (Vol. Weighted Avg. $2.27 levelized 2011$)
Delivered Coal Prices – Non Entergy Plants In Entergy Region	Mapped to similar Entergy Plant	Mapped to Similar Entergy Plant	Mapped to Similar Entergy Plant	Mapped to Similar Entergy Plant
Delivered Coal Prices – Non Entergy Regions	Reference Case - Varies By Region	Same as Reference Case - Varies By Region	High Case – Varies By Region	Low Case – Varies By Region
Coal Retirements Capacity (GW)*	54 GW	54 GW	115 GW	25 GW
New Nuclear Capacity (GW)*	7 GW	8 GW	25 GW	2 GW
New Biomass (GW)*	0.1 GW	0.1 GW	7 GW	0.1 GW
New Wind Capacity (GW)*	57 GW	68 GW	80 GW	22 GW
New Solar Capacity (GW)*	0.9 GW	1 .0 GW	2 GWs	0.3 GW

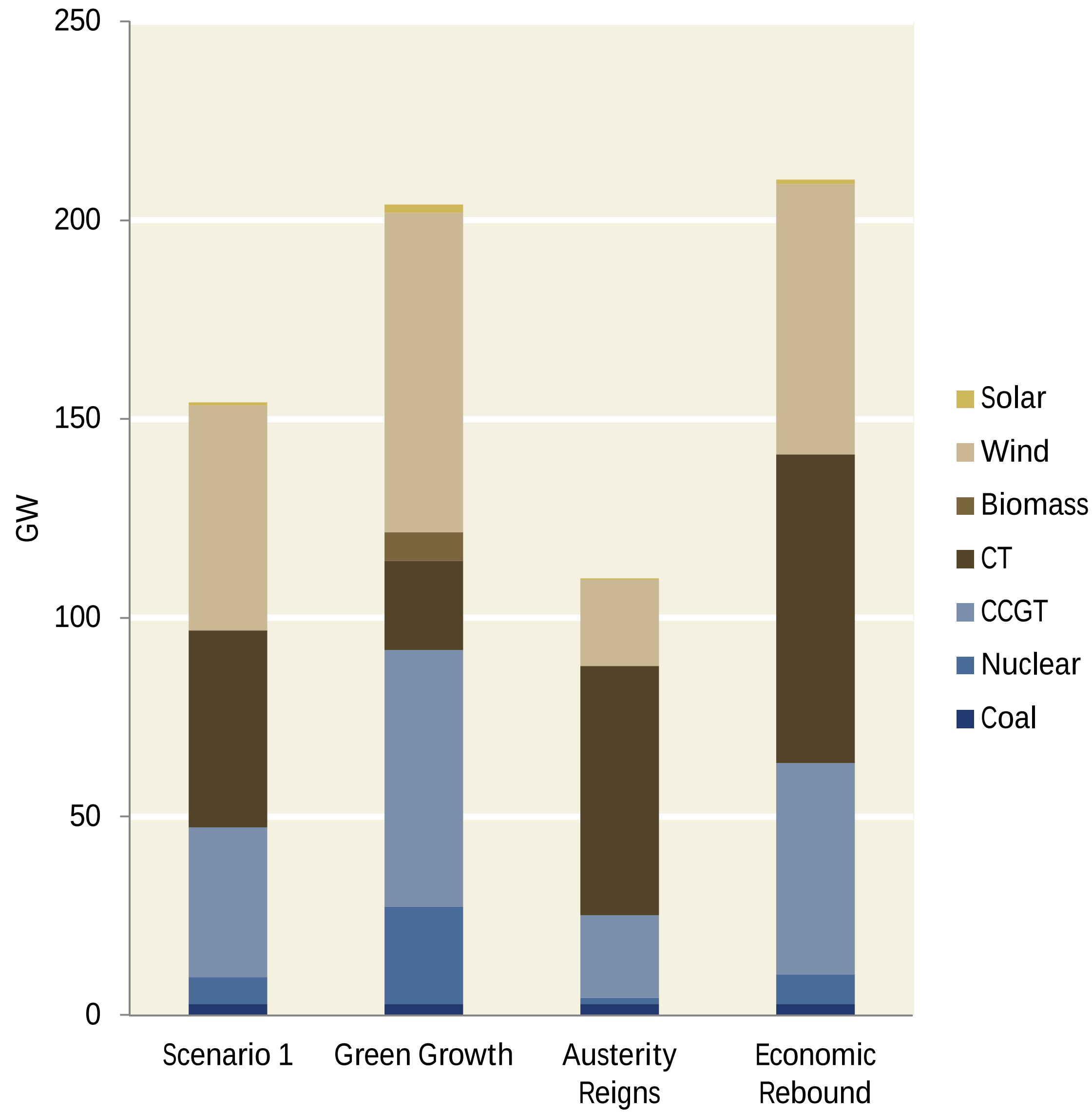
*Figures shown are for the period 2012-2031 covering a sub-set of the Eastern Interconnect which is approximately 34% of total U.S. 2011 TWh electricity sales. Gas and Coal additions other than 5 GW currently under construction handled through the Aurora capacity expansion algorithm. Non coal retirements are assumed to occur when resource reaches 60 years old unless an earlier retirement date has been announced. Entergy regulated plant assumed deactivations based on internal forecasts and do not change by scenario.

Note: Levelized prices refer to the price in 2011 dollars where the NPV of that price grown with inflation over the 2012-2031 period would equal the NPV of levelized nominal prices over the 2012-2031 period when the discount rate is 9.25%.

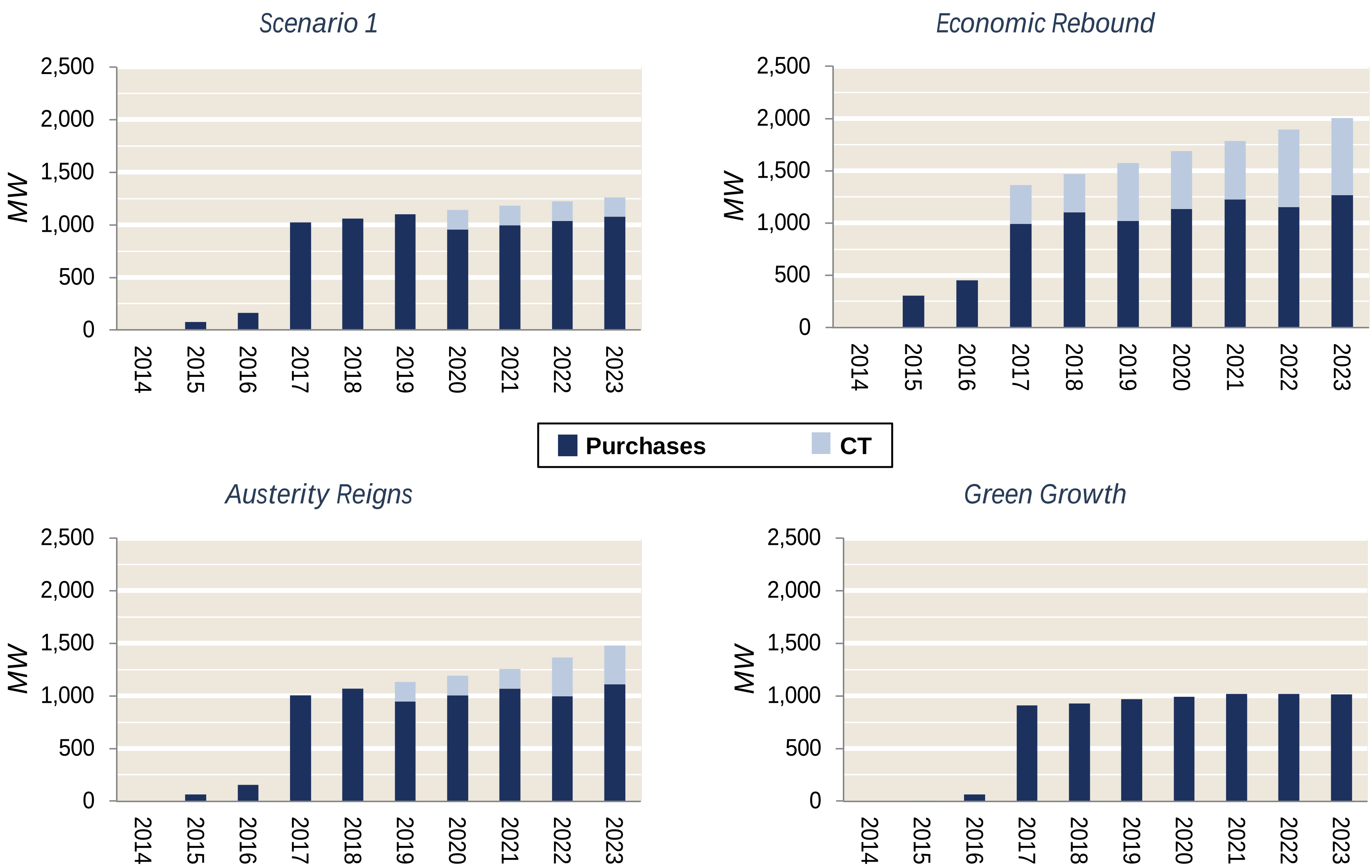
Capacity Additions In Modeled Market 2012-2031

Capacity Expansion

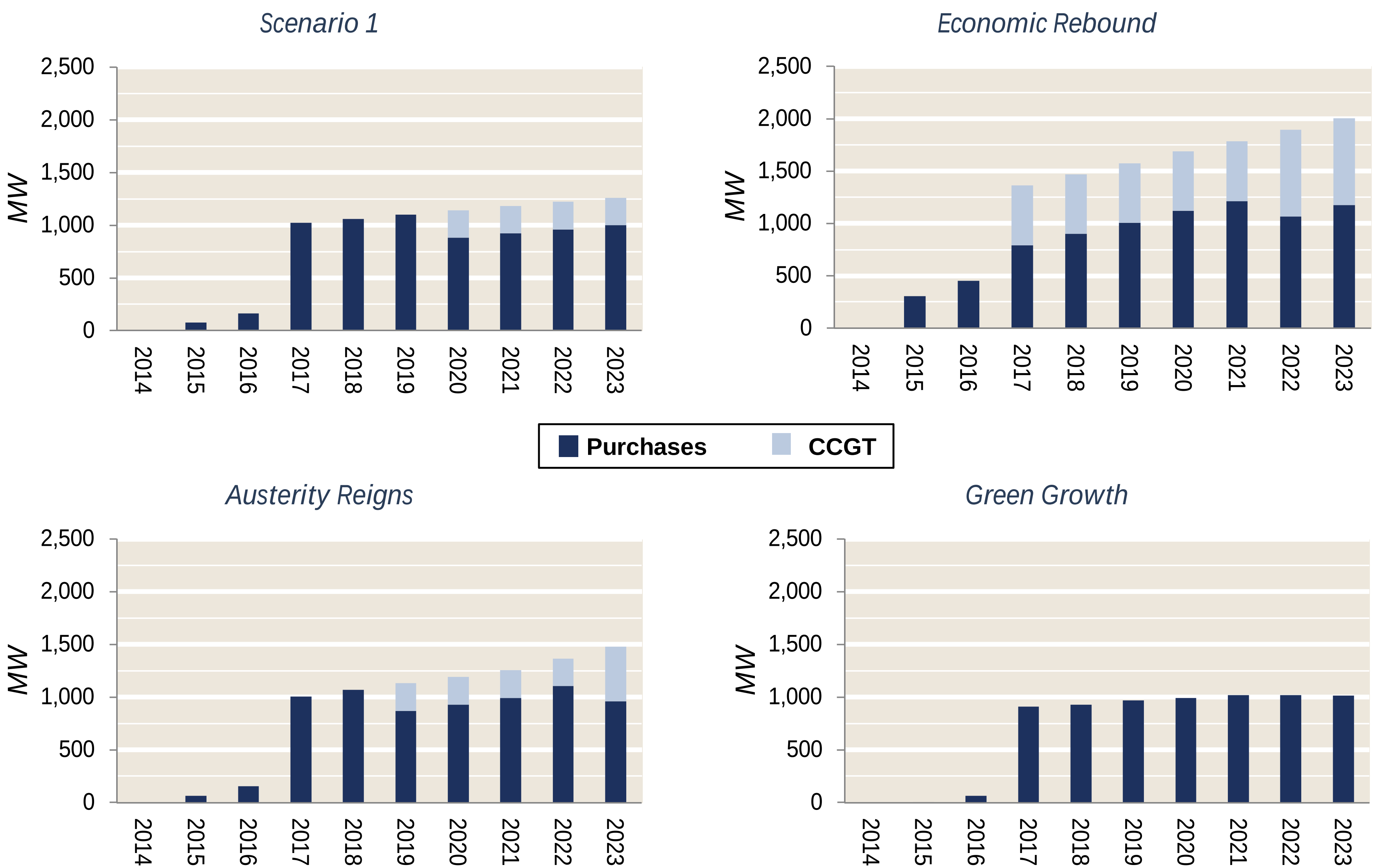
The scenarios differ in regards to the amount and type of capacity added in the market over the planning horizon. The differences reflect specific input assumptions for some technologies (nuclear, biomass, wind, solar) and automatic capacity expansion results, i.e., model-selected additions for others (coal, CCGT and CT). Capacity expansion results shown to the right relate to the overall modeled market (not Entergy Operating Companies specific). The "market" had about one third of U.S. energy sales in 2011.



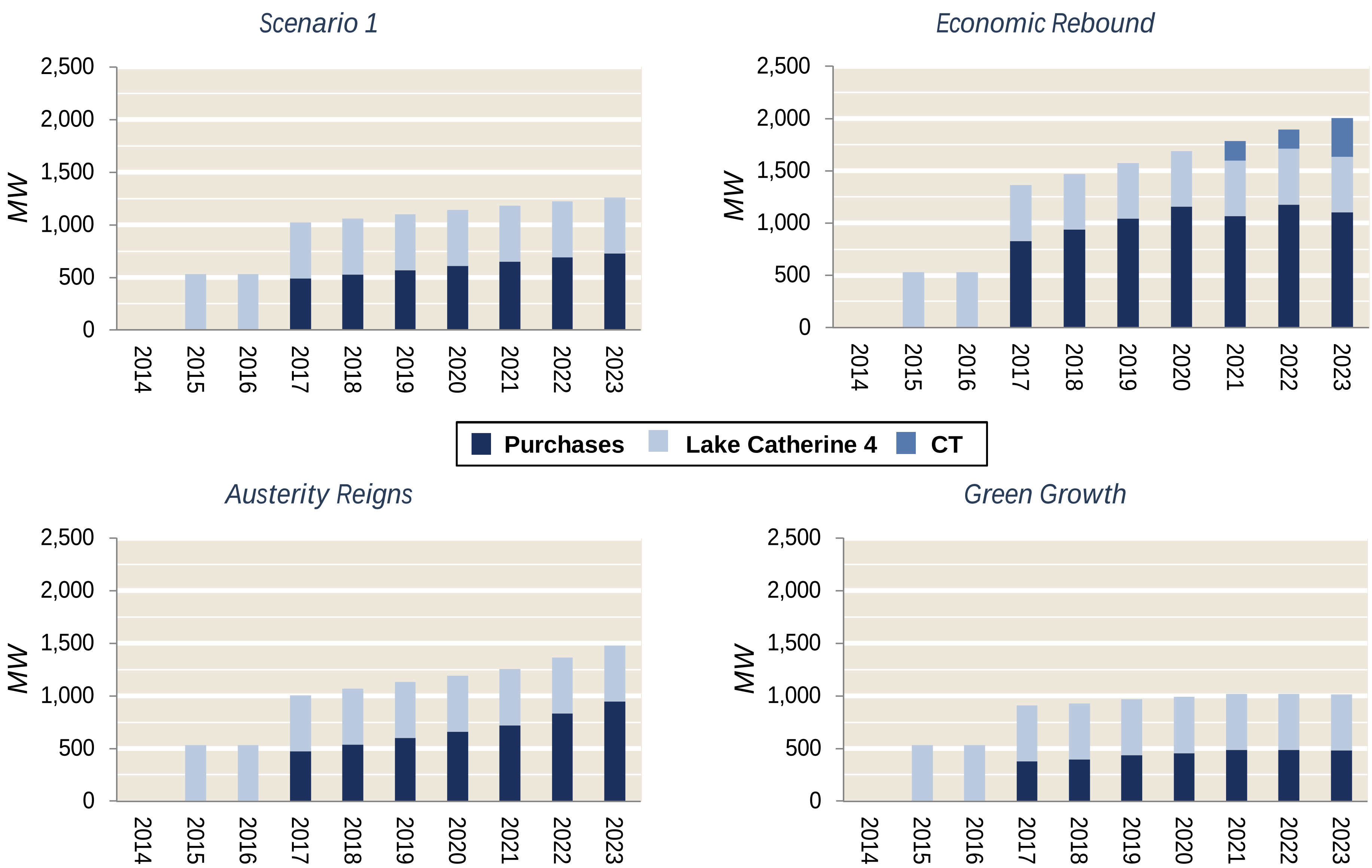
EAI Portfolio 1 – Resource Additions by Scenario



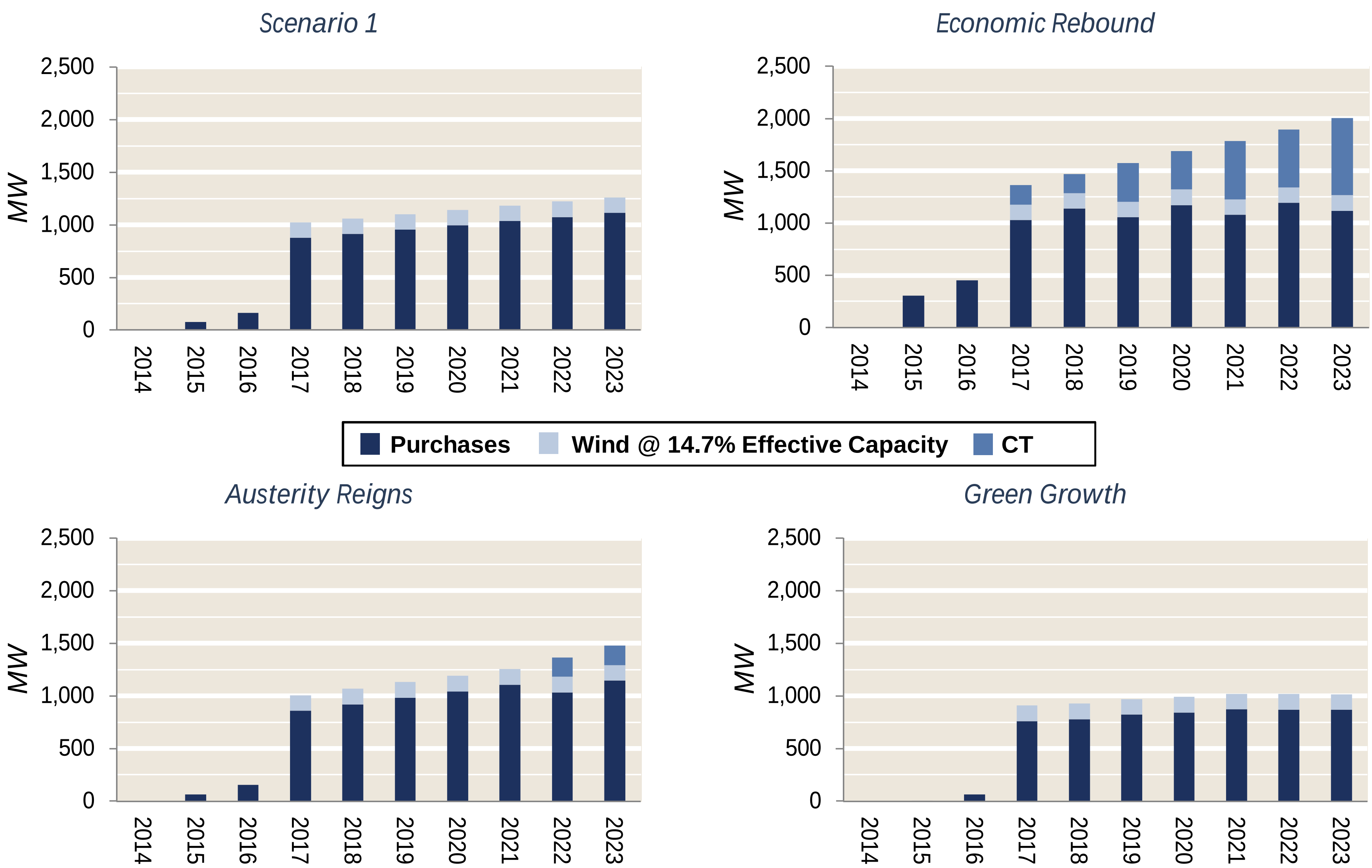
EAI Portfolio 2 – Resource Additions by Scenario



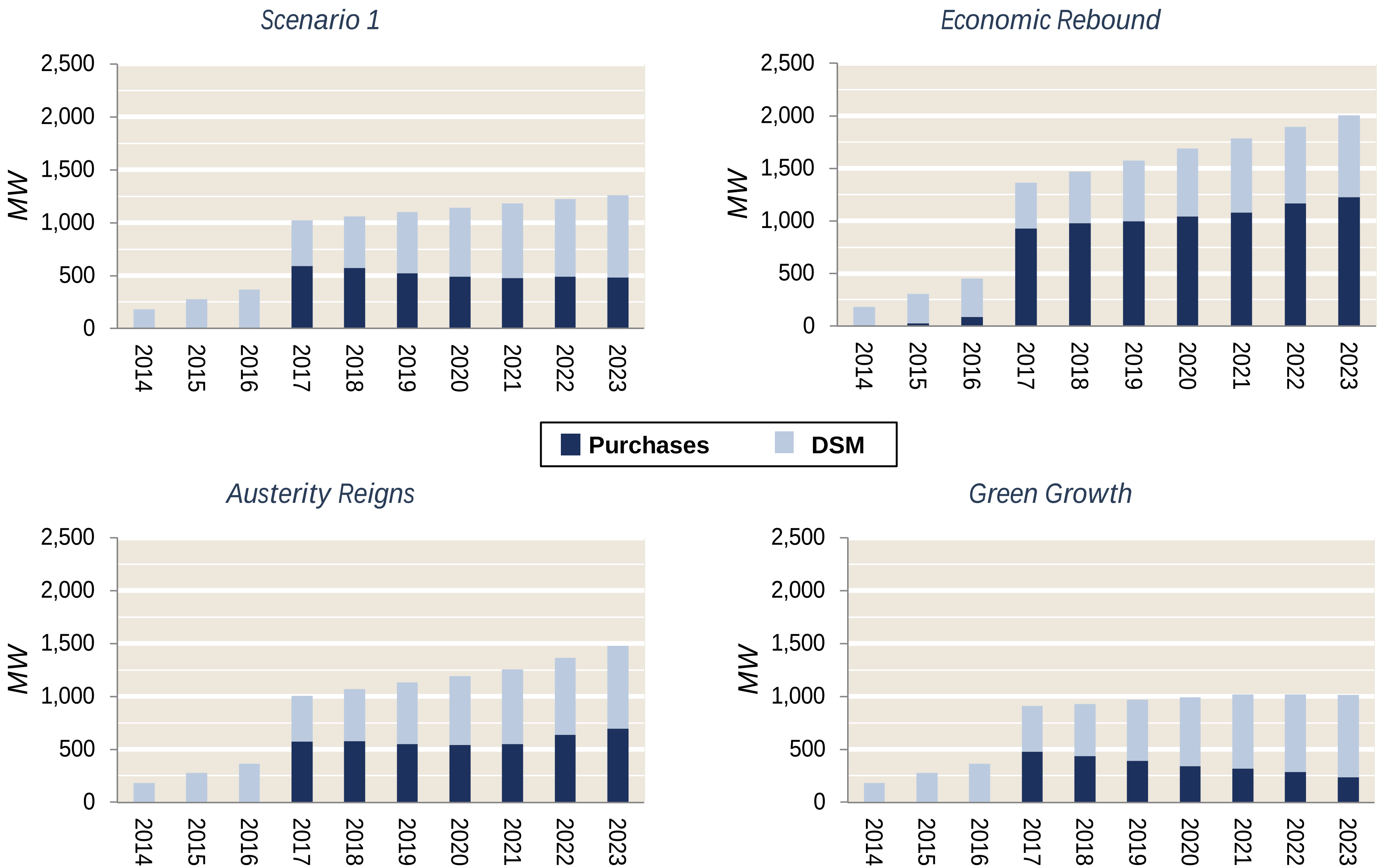
EAI Portfolio 3 – Resource Additions by Scenario



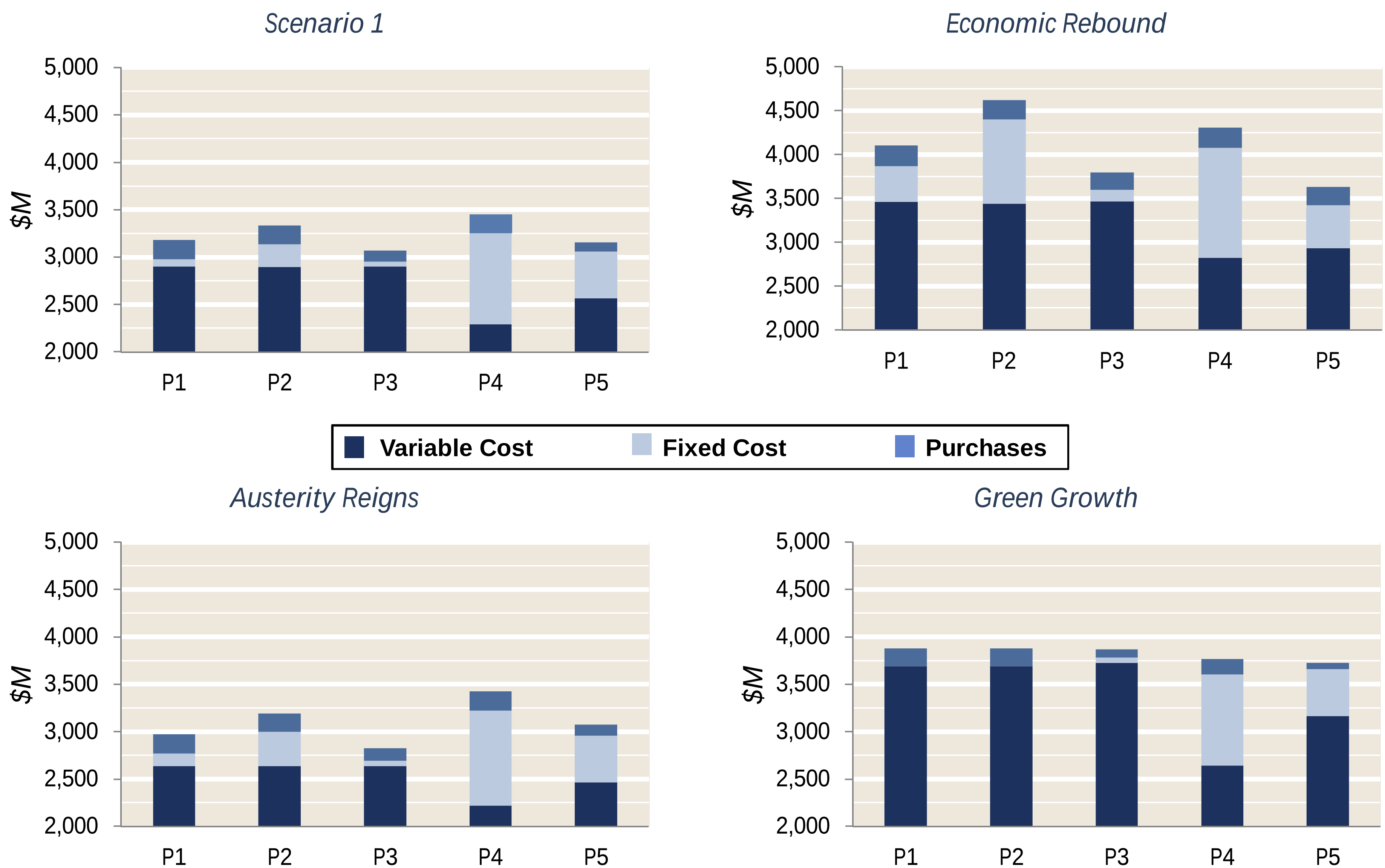
EAI Portfolio 4 – Resource Additions by Scenario



EAI Portfolio 5 – Resource Additions by Scenario

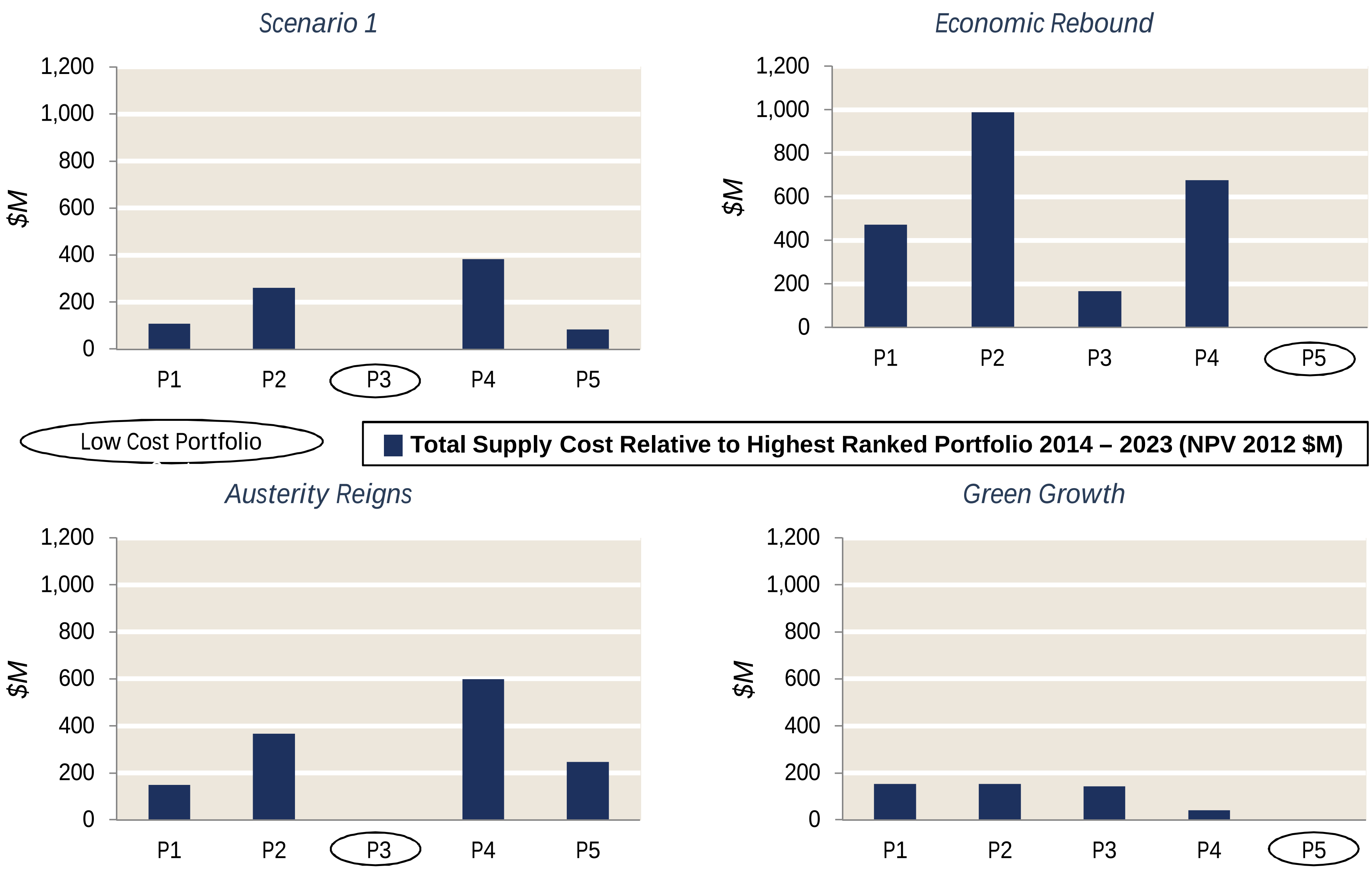


Total Supply Cost 2014 – 2023 (NPV 2012 $M)*

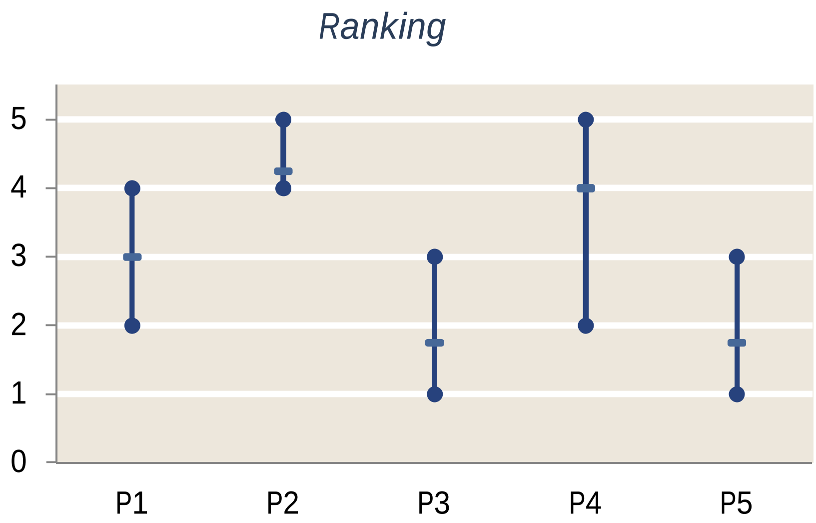


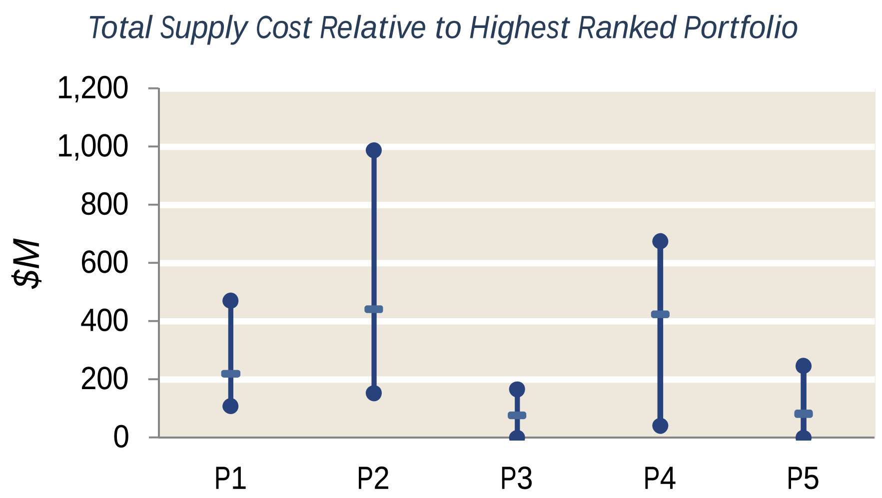
Variable cost refers to total EAI cost of service as modeled in Aurora, fixed cost is incremental resources only

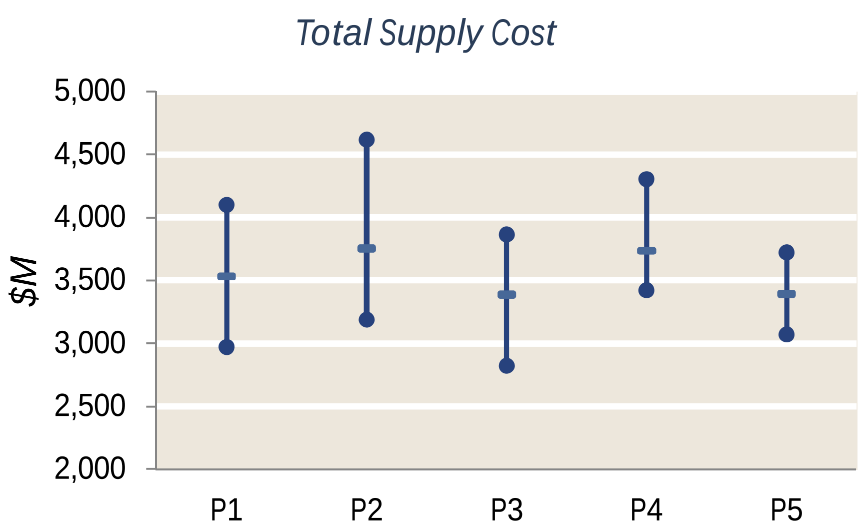
Relative Portfolio Ranking Total Supply Cost



Portfolio Ranking







Preliminary 2012 EAI Integrated Resource Plan (IRP) Action Plan

EAI Stakeholder Meeting

July 31, 2012

Entergy

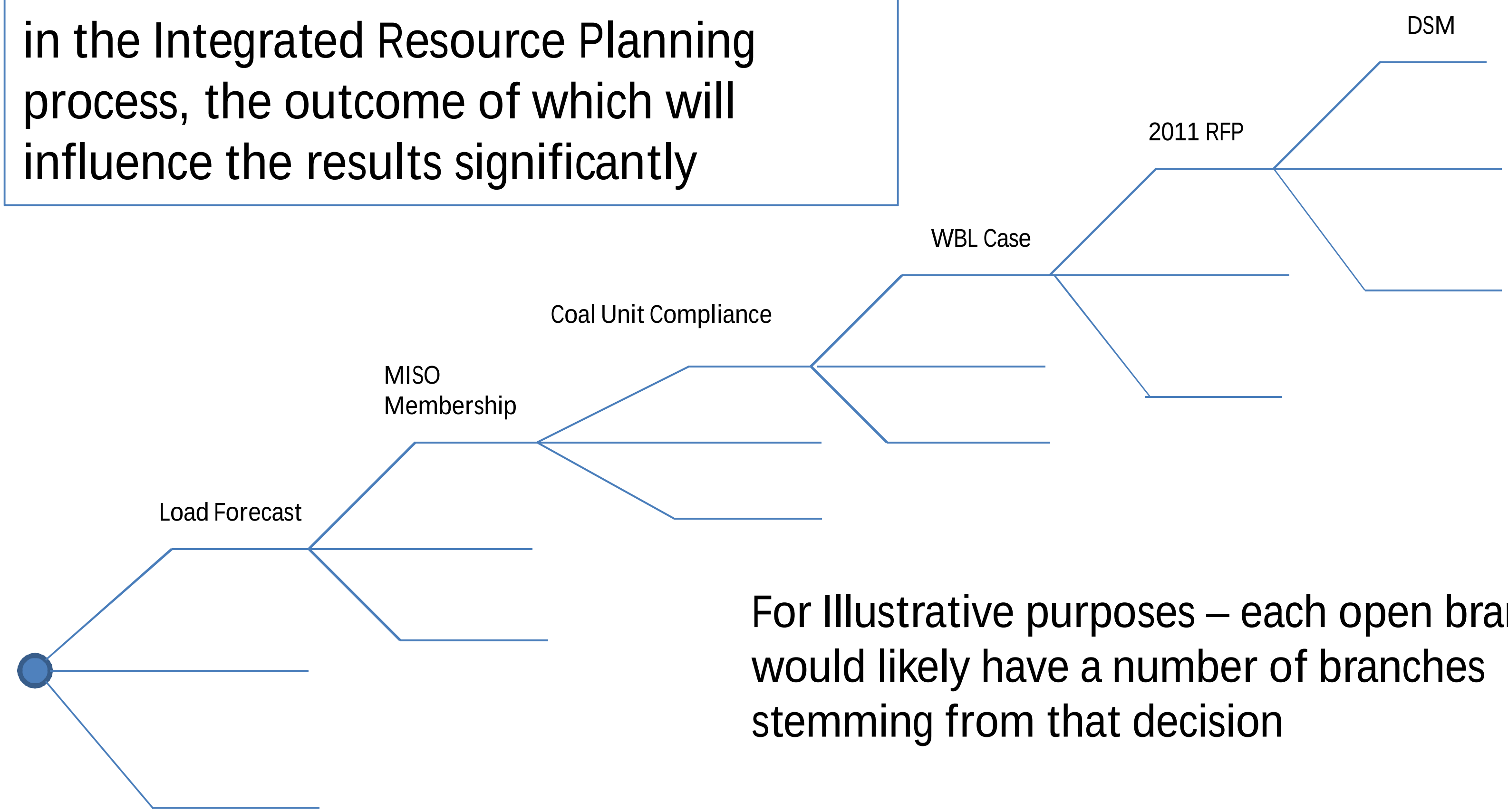
EAI IRP - Action Plan

- EAI has developed a preliminary action plan for stakeholder review.

- The action plan is subject to change prior to EAI filing the 2012 IRP.

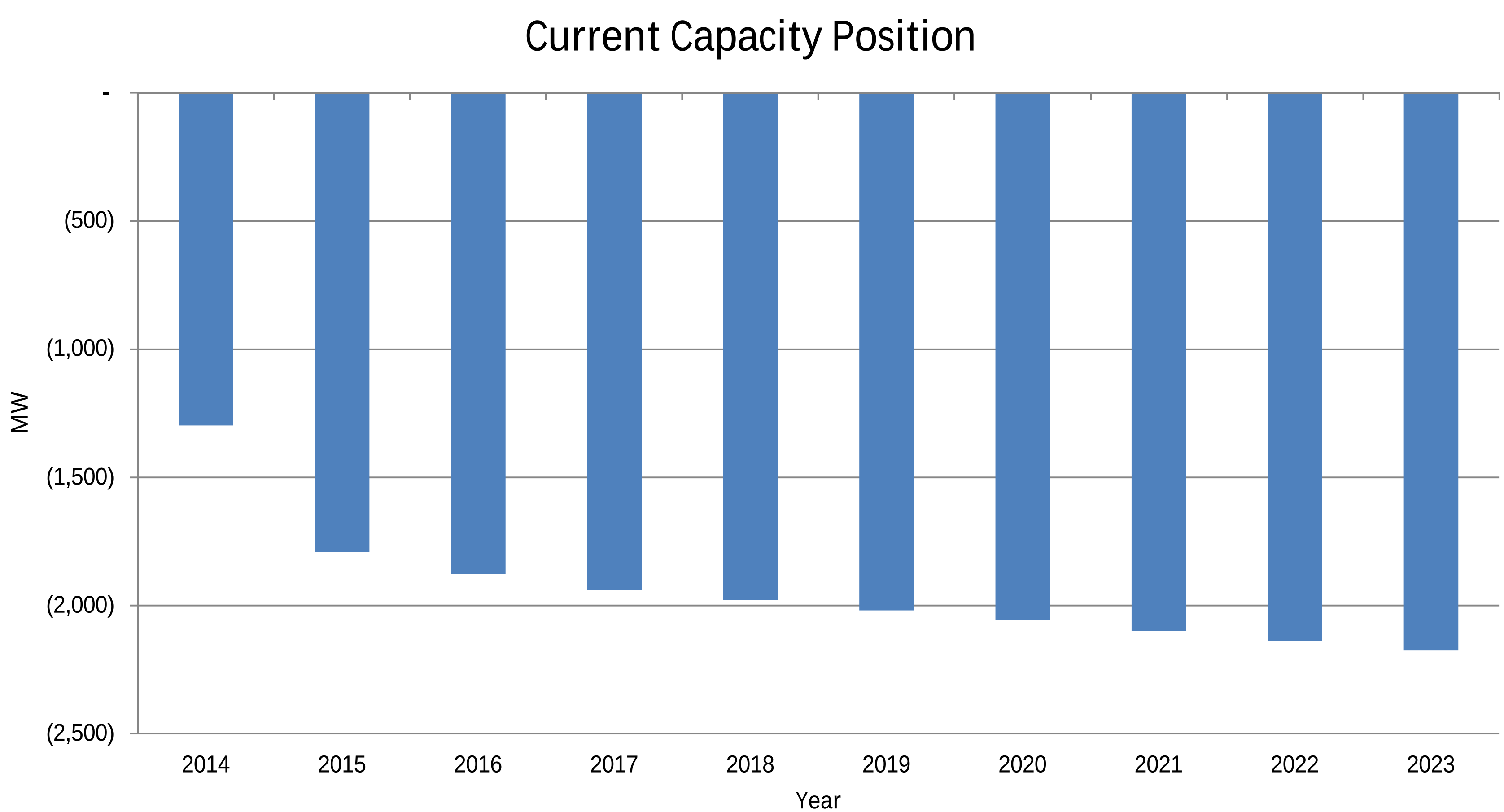
Action Plan – Managing Risk

The action plan recognizes that there are numerous uncertainties to be considered in the Integrated Resource Planning process, the outcome of which will influence the results significantly



For Illustrative purposes – each open branch would likely have a number of branches stemming from that decision

Current Capacity Position



IRP Action Plan - Overview

1. MISO Transition
2. Coal Unit Environmental Compliance
3. Hot Spring Power Plant Acquisition
4. 2011 RFP Transactions
5. Available Wholesale Base Load Capacity to Retail
6. Wholesale Peaking Capacity to Retail
7. DSM and Energy Efficiency Expansion
   (2012 In Progress, 2013 and beyond is planned)
8. Lake Catherine 4 reliability / sustainability
9. Legacy Unit Deactivation Decisions
10. Renewable Energy Assessment
11. Short-Term RFPs

In Progress

Planned

On-going

#1 - MISO Transition

A. Transition to the MISO Resource Adequacy Construct (RAC) as EAI integrates into MISO

- Develop a fixed resource adequacy plan and participate in MISO LOLE study
- Modify planning processes as needed for the MISO RAC
  - Coincident Peak Forecasting
  - UCAP verses ICAP

B. Participate in the MISO Transmission Expansion Process (MTEP)

#2 - Coal Unit Environmental Compliance

A. Monitor changes in environmental law at state and federal levels

B. Monitor the progression of the Flint Creek case at the APSC and permitting at ADEQ

C. Evaluate options for environmental compliance (e.g. MATS, Regional Haze, etc.)

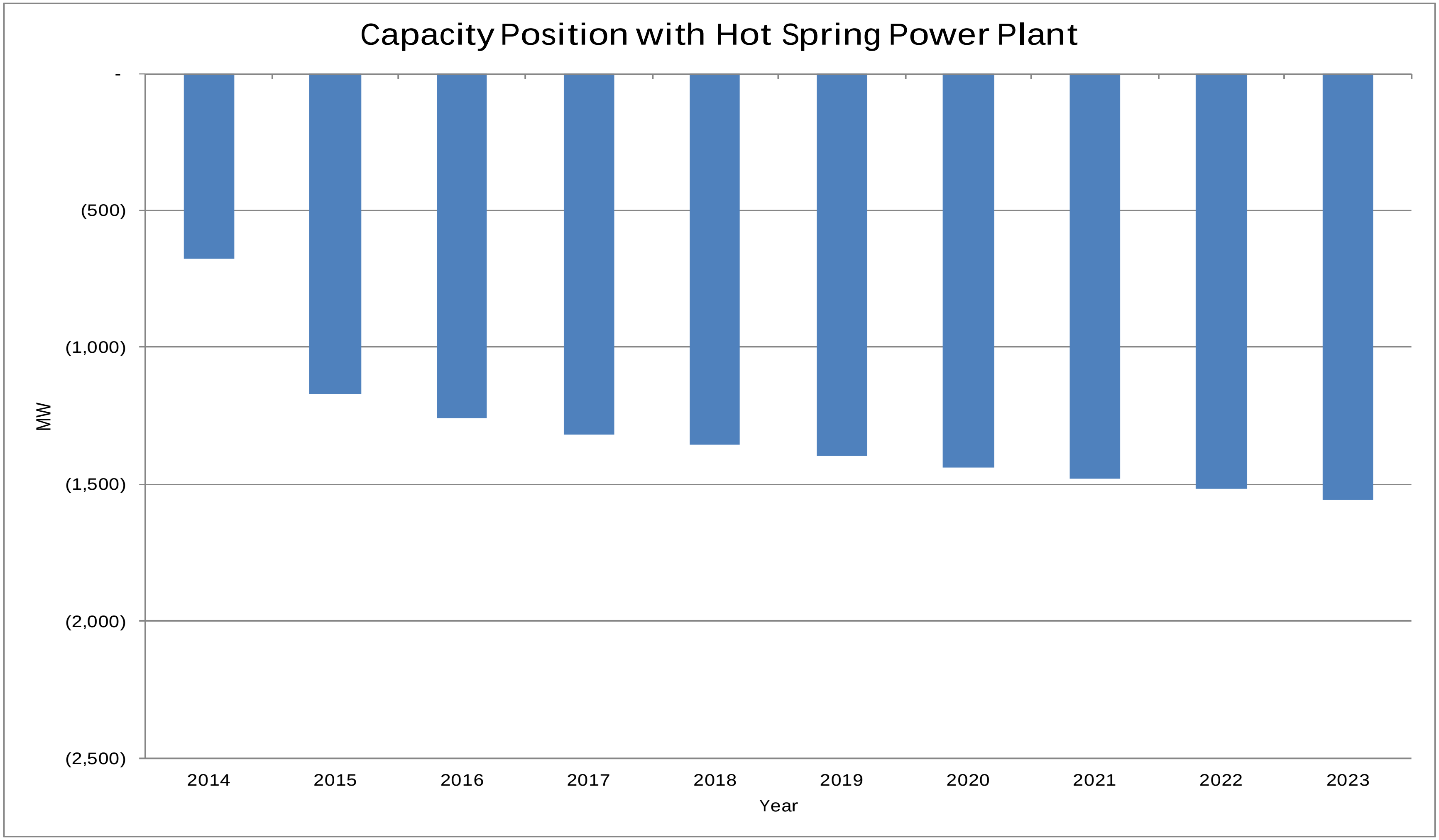
D. Work with co-owners to keep them advised of compliance planning progress

#3 - Hot Spring Power Plant Acquisition

A. Complete Hot Spring Power Plant acquisition pursuant to the July 11, 2012 APSC order in Docket No. 11-069-U

B. Adds approximately 620 MW of CCGT capacity to the EAI fleet

Hot Spring Power Plant Acquisition



#4 - 2011 RFP Transactions

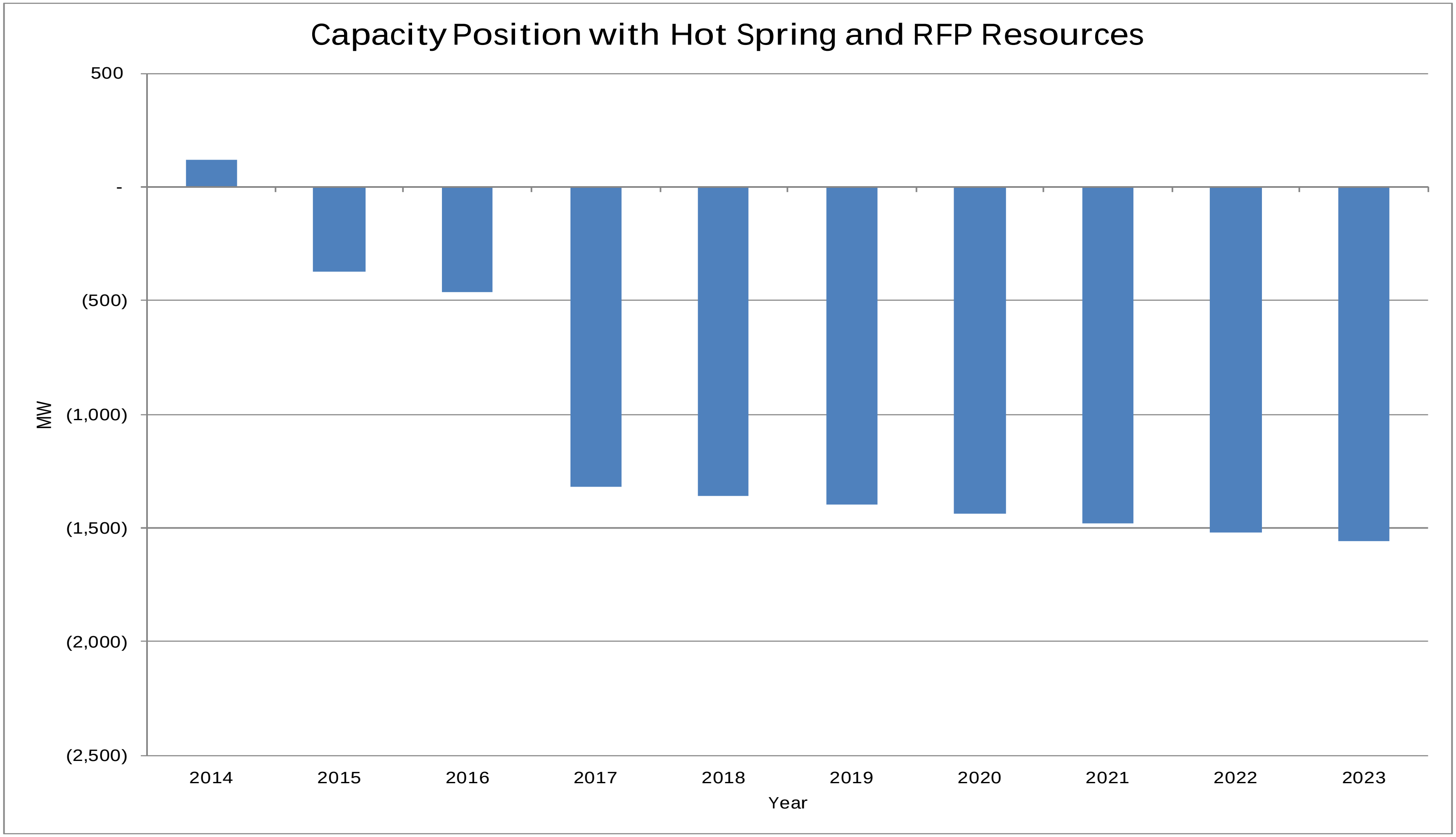
A. Complete negotiations on resources from the 2011 RFP

B. Continue to pursue approval of a capacity cost recovery rider in Docket No. 12-038-U

C. Secure transmission service for both transactions no later than June 30, 2013

D. Adds approximately 795 MW from December 2013 through May 2017

Hot Spring and RFP Resources Added



#5 – Available Wholesale Base Load (WBL) Capacity to Retail

A. Continue to pursue APSC approval to return the WBL capacity to retail rate base in Docket No. 12-038-U

B. Provides approximately 286 MW of additional resources:
   - 184 MW Nuclear Capacity
   - 102 MW Coal Capacity

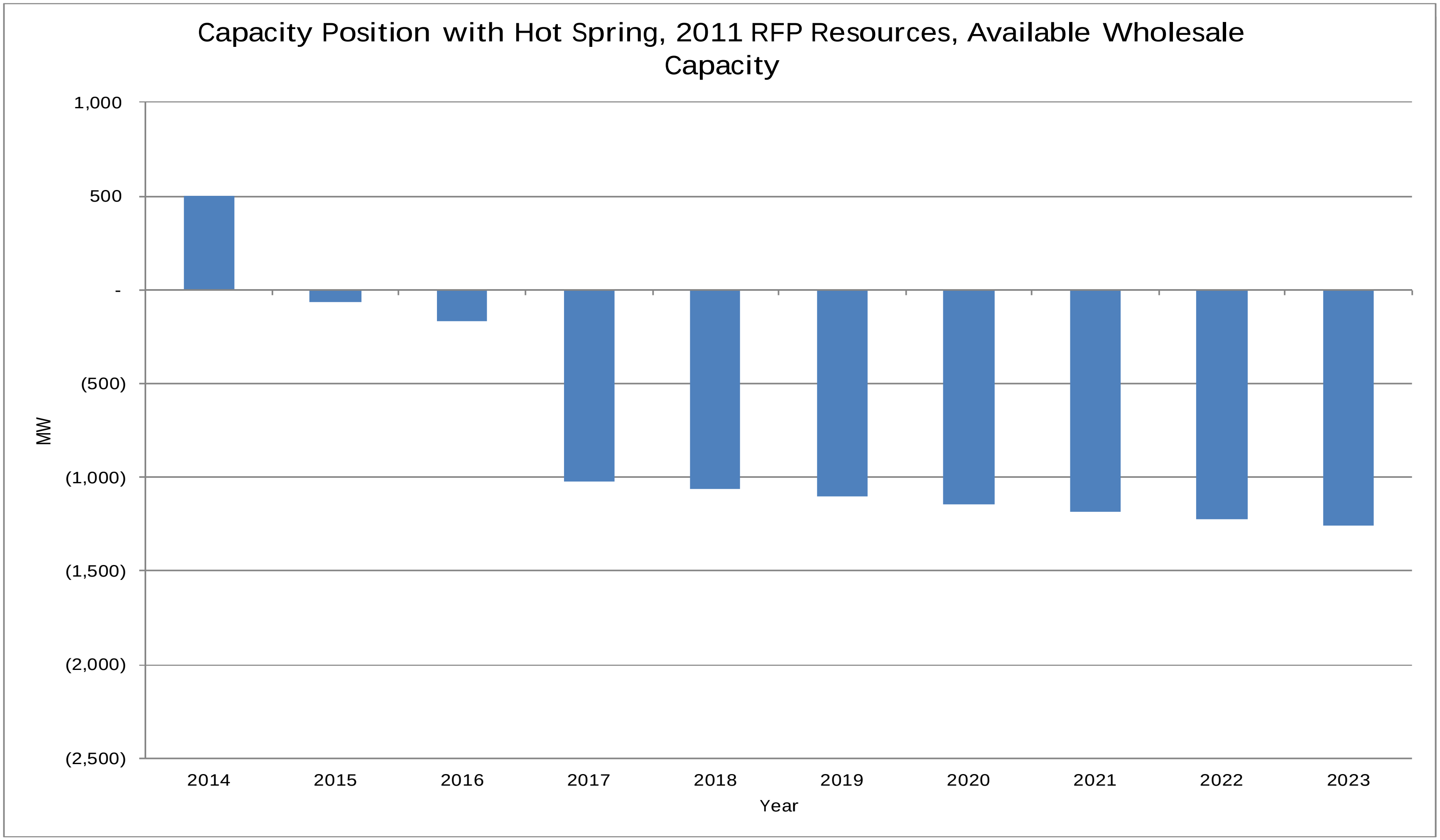
#6 - Wholesale Peaking Capacity to Retail

A. Pursue APSC approval to return the Wholesale peaking capacity to retail rate base in the 2013 general rate case

B. Results in the following capacity additions:

2014:	95 MW
2015:	21 MW
2016:	13 MW
2017 – Forward	10 MW

With Hot Spring, 2011 RFP Resources and Available Wholesale Capacity



#7 - Demand Side Management and Energy Efficiency Expansion (2012 In Progress / 2013 and Beyond Planned)

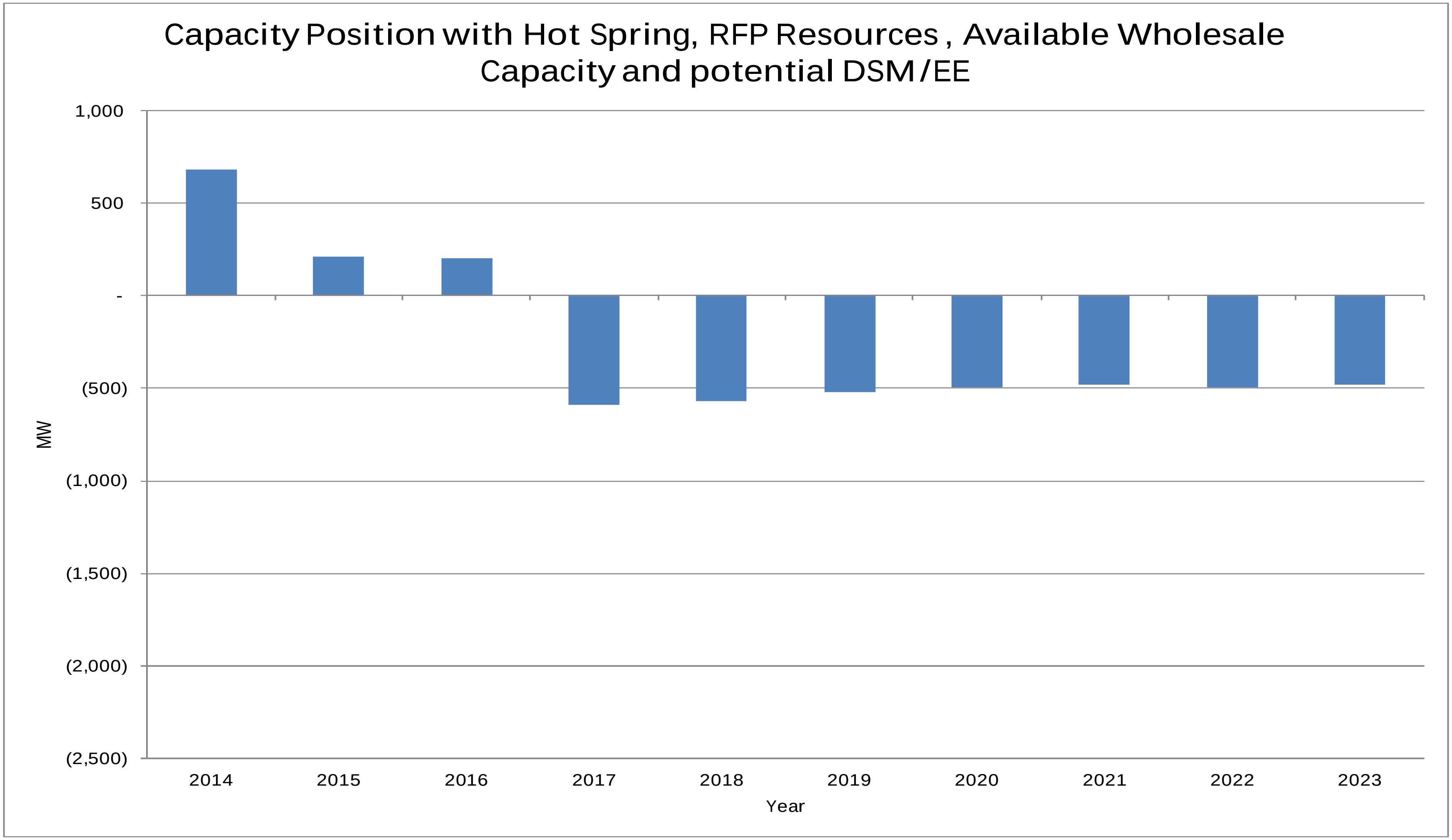
A. Continue with suite of comprehensive programs, including ongoing independent Evaluation, Measurement and Verification, capturing any lessons learned to improve next phase of implementation

B. Continue to move forward with the development and implementation of enabling technologies (AMI / Smart Grid) at a measured pace to ensure technology can deliver results

C. Monitor results and adjust load forecast and resource plans as warranted

D. Continue to research options for DSM in the MISO market

Demand Side Management and Energy Efficiency Added

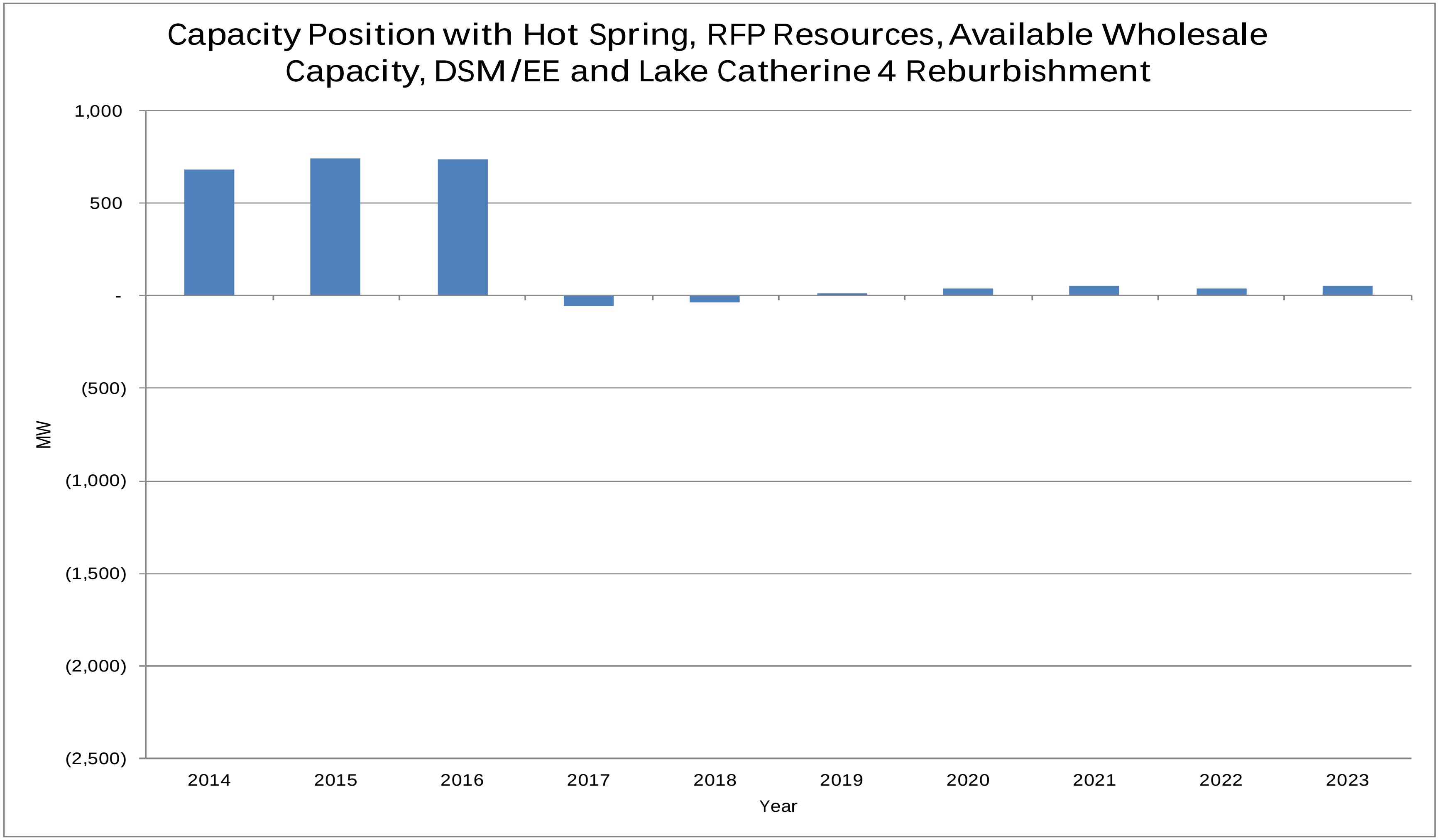


#8 – Lake Catherine 4 Reliability / Sustainability Program

A. Update project cost estimates in 2012

B. Develop a detailed project schedule and budget to complete reliability / sustainability program

Lake Catherine Unit 4 Refurbishment



#9 – Legacy Deactivation Decisions

A. The current long-term planning assumption is that approximately 422 MW (363 MW retail) of legacy generation will be deactivated by the beginning of 2014

B. A follow-up review of this generation will be conducted over the remainder of 2012 and 2013 to determine tactical plans for this capacity

C. Actual decisions to deactivate generation will be made on a unit-by-unit basis based upon the needs of customers and the economics of the units relative to available options at the time of the decision

#10 - Renewable Energy Assessment

A. Continue to monitor:
   - technology developments in renewable energy
   - public policy developments

B. Consider economically attractive renewable generation, taking into account evolving mandates and an on-going assessment of cost and availability

#11 – Short-Term RFPs

A. Continuously monitor progress on IRP Action Plans

B. Issue short-term (1 year) RFPs for additional capacity if needed to maintain reserve margins

Questions / Comments

BREAK

Stakeholder Session

Entergy Arkansas, Inc response to questions from Stakeholders at the July 31, 2012 Integrated Resource Planning (IRP) Meeting

August 20, 2012

#	Question	Answer
1	Who were the parties to the CSAPR lawsuit?	USCA Case # 11-1302 *EME Homer City Generation LP v. EPA*. There were multiple petitioners.
2	Which court in the CSAPR case in?	The United States Court of Appeals for the D.C. Circuit
3	What is the equivalent level of energy production associated with 100,000 tons of CO2?	For 100,000 tons Co2 Typical Coal Plant – 2138 lb CO2/MWhr or 93,566 MWhr Typical Gas Plant – 1465 lb CO2/MWhr or 136,528 MWhr Typical Combustion Turbine Plant – 1341 lb CO2/MWhr or 149,087 MWhr Typical Combined Cycle Plant – 855 lb CO2/MWhr or 234,004 MWhr
4	What is the % energy savings associated with energy efficiency program over time?	See slide 21 of Richard Smith's presentation from the July 31 IRP meeting. http://entergy-arkansas.com/content/transition_plan/demand_management.pdf
5	Does EAI limit the term of purchase power contracts?	No, EAI evaluates PPAs that may be proposed to it regardless of the term of the offer.
6	What happens to EAI's resource planning if ITC owns the transmission system?	Assuming EAI joins MISO, EAI will be a transmission customer under the OATT whether EAI owns the transmission system or not, and in any case, EAI will participate in the MISO transmission planning process.

7	What environmental controls will be required if the final version of the CSAPR don't change much?	It is anticipated that Low NOx Burners and Separated Overfired Air would be installed on one or both of the units at White Bluff if CSAPR doesn't change significantly.
8	How big must a unit be to be subject to the NSPS for GHG?	40 CFR Part 60--Standards Of Performance For New Stationary Sources - Fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)). Proposed Standards of Performance for Greenhouse Gas Emission for New Stationary Sources: Electric Utility Generating Units for Electric Utility Generating Unit that Commences Construction After April 13, 2012 - Electric Utility Generating Unit with a base load rating of more than 73 MW (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel.
9	Do the tests at the bottom of slide 22 of Richard Smith's presentation only apply to the reference case forecast?	Yes
10	Is the primary test for DSM the resource cost test?	Yes. EAI uses the results of theTotal Resource Cost test as the primary tool to evaluate cost effectiveness of energy efficiency.
11	What % funding is assumed for the DSM potential reference case modeled in the IRP?	The cost of energy efficiency included in the EAI IRP starts around 2.3% and grows to around 4.5% over the ten year period. These percentages are based upon 2011 EAI retail revenues in the 2011 Arkansas report filed at the APSC.
12	Please provide more details on the assumptions behind the levelized bus bar cost of the different generation technologies. Please break down the wind analysis to its components of integration cost, dispatch costs and energy costs. Are incentives accounted for in your analysis?	Please see below for a break- down of the assumptions and the details of the calculations

Levelized Bus Bar Cost:

Line No.	Description	Measure	Formula	CCGT Without CO2	CCGT With CO2	Biomass w/o Incentive	Biomass w/ Incentive	Wind w/o Incentive	Wind w/ Incentive	Solar PV w/o Incentive	Solar PV w/ Incentive
1	Installed Cost (2012 $'s)	($/kW)		$1,395	$1,395	$4,856	$4,856	$2,033	$2,033	$5,166	$5,166
2	Levelized Fixed Charge Rate (LFCR)	(%)		14.1%	14.1%	13.1%	13.1%	14.7%	14.7%	11.8%	11.8%
3	Levelized Annual Fixed Charge	($/kW-yr.)	[Ln. 1 * Ln. 2]	$196.33	$196.33	$636.72	$636.72	$299.42	$299.42	$607.47	$607.47
4	Capacity Factor	(%)		65%	65%	80%	80%	39%	39%	20%	20%
5	Energy Generation	(MWh/MW)	[8760 hrs. * Ln. 4]	5,694	5,694	7,008	7,008	3,416	3,416	1,752	1,752
6	Levelized Annual Fixed Charge	($/MWh)	[Ln. 3 *1000 / Ln.5]	$34.48	$34.48	$90.86	$90.86	$87.64	$87.64	$346.73	$346.73
7	Levelized Incentive (ITC or PTC)	($/MWh)		$0.00	$0.00	$0.00	$24.59	$0.00	$25.00	$0.00	$110.49
8	Levelized Annual Net Fixed Charge	($/MWh)	[Ln. 6 - Ln. 7]	$34.48	$34.48	$90.86	$66.27	$87.64	$62.64	$346.73	$236.24
9	Levelized Variable O&M Cost	($/MWh)		$3.10	$3.10	$3.72	$3.72	$1.19	$1.19	$0.00	$0.00
10	Heat Rate	(MMBtu/MWh)		6.950	6.950	11.000	11.000	-	-	-	-
11	Levelized Fuel Cost	($/MMBtu)		$6.29	$6.29	$3.93	$3.93	-	-	-	-
12	Levelized Energy Cost	($/MWh)	[Ln. 10 * Ln. 11]	$43.71	$43.71	$43.23	$43.23	$0.00	$0.00	$0.00	$0.00
13	CO2 Emissions Rate	(lbs./MMBtu)		118.9	118.9	-	-	-	-	-	-
14	CO2 Emissions	(lbs./MWh)	[Ln. 10 * Ln. 13]	826.4	826.4	-	-	-	-	-	-
15	Levelized CO2 Cost	($/Ton)		$0.00	$13.43	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
16	Levelized Emissions Cost	($/MWh)	[Ln. 14 / 2000 * Ln. 15]	$0.00	$5.55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
17	Levelized Capacity Matchup Cost	($/MWh)	[Ln.24]	$0.00	$0.00	$0.00	$0.00	$34.01	$34.01	$62.83	$62.83
18	Levelized Flexible Capability Cost	($/MWh)	[Ln. 44]	$0.00	$0.00	$0.00	$0.00	$14.24	$14.24	$27.77	$27.77
19	Levelized Total Bus Bar Cost	($/MWh)	[Ln. 8 + Ln. 9 + Ln. 12 + Ln. 16 + Ln. 17 + Ln. 18]	$81.29	$86.84	$137.81	$113.22	$137.08	$112.08	$437.33	$326.84

Note: Book lives assumed are 30 years for CT, CCGT, and Biomass; 25 years for Solar PV; and 20 years for Wind

Levelized Capacity Matchup Cost:

Line No.	Description	Measure	Formula	CCGT Without CO2	CCGT With CO2	Biomass w/o Incentive	Biomass w/ Incentive	Wind w/o Incentive	Wind w/ Incentive	Solar PV w/o Incentive	Solar PV w/ Incentive
20	Installed Cost of a CT	($/kW)						$929	$929	$929	$929
21	Levelized Fixed Charge Rate (LFCR) for CT	(%)						13.2%	13.2%	13.2%	13.2%
22	Levelized Annual Fixed Charge for a CT	($/kW-yr.)	[Ln. 20 * Ln. 21]					$122.31	$122.31	$122.31	$122.31
23	CT Capacity Value	(%)						100%	100%	100%	100%
24	Renewable Capacity Value	(%)						5%	5%	10%	10%
25	Capacity Matchup Requirement	(%)	[Ln. 23 - Ln. 24]					95%	95%	90%	90%
26	Capacity Matchup Cost	($/kW-yr.)	[Ln. 22 * Ln. 25]					$116.20	$116.20	$110.08	$110.08
27	Renewable Capacity Factor	(%)						39%	39%	20%	20%
28	Renewable Energy Generation	(MWh/MW)	[8760 hrs. * Ln. 27]					3,416	3,416	1,752	1,752
29	Renewable Capacity Matchup Cost	($/MWh)	[Ln. 26 * 1000 / Ln. 28]					$34.01	$34.01	$62.83	$62.83

Levelized Flexible Capability Cost:

Flexible Capability provided by the subsitution of a CCGT for a CT

CCGT	Biomass	Wind	Solar PV

Line No.	Description	Measure	Formula	Without CO2	With CO2	w/o Incentive	w/ Incentive	w/o Incentive	w/ Incentive	w/o Incentive	w/ Incentive
--- Fixed Cost ---											
30	Installed Cost of a CCGT	($/kW)						$1,395	$1,395	$1,395	$1,395
31	Levelized Fixed Charge Rate (LFCR) for CCGT	(%)						14.1%	14.1%	14.1%	14.1%
32	Levelized Annual Fixed Charge for a CCGT	($/kW-yr.)	[Ln. 30 * Ln. 31]					$196.33	$196.33	$196.33	$196.33
33	Installed Cost of a CT	($/kW)						$929	$929	$929	$929
34	Levelized Fixed Charge Rate (LFCR) for CT	(%)						13.2%	13.2%	13.2%	13.2%
35	Levelized Annual Fixed Charge for a CT	($/kW-yr.)	[Ln. 33 * Ln. 34]					$122.31	$122.31	$122.31	$122.31
36	Levelized Fixed Charge Differential	($/kW-yr.)	[Ln. 32 - Ln. 35]					$74.02	$74.02	$74.02	$74.02
37	Percent of Time Flexible Capability Requirec	(%)						50%	50%	50%	50%
38	Levelized Fixed Charge for Flexible Capabilit	($/kW-yr.)	[Ln. 36 * Ln. 37]					$37.01	$37.01	$37.01	$37.01
39	Renewable Capacity Factor	(%)						39%	39%	20%	20%
40	Renewable Energy Generation	(MWh/MW)	[8760 hrs. * Ln. 39]					3,416	3,416	1,752	1,752
41	Levelized Flexible Capability Fixed Cost	($/MWh)	[Ln. 38 * 1000 / Ln. 40]					$10.83	$10.83	$21.12	$21.12
--- Energy Cost ---											
42	Part Load Heat Rate Penalty for a CCGT	(MMBtu/MWh)						0.650	0.650	0.650	0.650
43	Levelized Cost of Natural Gas	($/MMBtu)						$6.29	$6.29	$6.29	$6.29
44	Part Load CCGT Energy Cost	($/MWh)	[Ln. 42 * Ln. 43]					$4.09	$4.09	$4.09	$4.09
45	CCGT Capacity Factor	(%)						65%	65%	65%	65%
46	Percent of Time Flexible Capability Requirec	(%)						50%	50%	50%	50%
47	Annual Part Load Generation	(MWh/MW)	[8760 hrs. * Ln. 45 * Ln. 46]					2,847	2,847	2,847	2,847
48	Annual Part Load Energy Cost	($/kW-yr.)	[Ln. 44 * Ln. 47 / 1000]					$11.64	$11.64	$11.64	$11.64
49	Renewable Capacity Factor	(%)						39%	39%	20%	20%
50	Renewable Energy Generation	(MWh/MW)	[8760 hrs. * Ln. 49]					3,416	3,416	1,752	1,752
51	Levelized Flexible Capability Energy Cost	($/MWh)	[Ln. 48 * 1000 / Ln. 50]					$3.41	$3.41	$6.64	$6.64
--- Total Cost ---											
52	Levelized Flexible Capability Total Cost	($/MWh)	[Ln. 41 + Ln. 51]					$14.24	$14.24	$27.77	$27.77

Entergy Arkansas, Inc follow-up responses to questions from Stakeholders at the September 6, 2012 Integrated Resource Planning (IRP) Meeting

September 14 , 2012

#	Question	Answer
1	What capacity factor was assumed in the production cost analysis for the wind generation in portfolio 5?	The capacity factor used in the Aurora production cost modeling analysis of the portfolios is the same as the assumption in the technology screening analysis which is 39%.
2	How much cost is associated with the non-cost effective measures that have a TRC less than 1.0?	$19 MM is the estimated accumulated costs for 2012 through 2021.