THE POWER OF PEOPLE®

Entergy Arkansas, Inc.
2015 Integrated Resource Plan

Compiled Presentation Materials

Contents

Per request from the Stakeholder Group, this document is a compilation of all materials that have been presented to the Stakeholder Group and posted to the IRP website so far during EAI's IRP process. This document contains the following materials:

- Preliminary IRP Materials (July 15)
- Stakeholder Meeting Presentation (August 6)
- Follow-up Materials to Stakeholder Meeting (August 14)
- Response to Stakeholder Group Questions (September 3)
- Second Response to Stakeholder Group Questions (September 16)

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

July 15, 2015

Preliminary Materials for IRP Stakeholder Meeting

Preliminary | Work in progress

2015 EAI Integrated Resource Plan

Consistent with Section 6.1 of Attachment 1 to the APSC Order No. 6 in Docket No. 06-028-R Resource Planning Guidelines for Electric Utilities, EAI is beginning development of its next Integrated Resource Plan to be filed at the Commission no later than three years from the prior IRP submission, which is October 31, 2015.

The information contained in this presentation is part of the development of the 2015 EAI Integrated Resource Plan:

- Analytical Framework
- Generation Technology Assessment
- Energy and Peak Load Forecasts
- Fuel Price Forecasts
- Emissions Allowance Price Forecasts

The IRP development will be discussed in detail at the upcoming Stakeholder Meeting to be held Friday, August 7, 2015, at the MISO Energy – South Region building.

More information about the Stakeholder Meeting can be found at the website below:
http://www.entergy-arkansas.com/transition_plan/

Stakeholder Meeting Agenda

The preliminary agenda for the August 7th Stakeholder Meeting is below.

Topic	Start Time
Introduction and Meeting Objectives	8:00
Resource Planning Update	8:15
Transmission Planning Update	8:45
Demand-side Management Update	9:00
Overview of Environmental Issues	9:30
Break	*10:00*
IRP Process Overview	10:10
Generation Technology Assessment	10:25
Sales and Load Forecasts	10:50
Preliminary Results and Next Steps	11:15
Lunch	*12:00*
Stakeholder Committee Formation	1:00
Wrap-up	1:45

2012 IRP Action Plan Progress

1. MISO Transition
   - [*Complete*] EAI transitioned to the Mid-Continent ISO on December 19, 2013.
2. Coal Unit Environmental Compliance
   - [On-going] EAI continues to monitor changes in environmental law at state and federal level to evaluate options for compliance.
3. Hot Spring Plant Acquisition
   - [*Complete*] EAI acquired the Hot Spring Plant in December 2012.
4. Purchase Power Agreements from EAI's 2011 RFP
   - [*Complete*] EAI executed a power purchase agreement for Union Power Partners Unit 2 on October 22, 2012.
5. Available Wholesale Base Load Capacity to Retail
   - [*Complete*] In Order No. 12 of Docket No. 12-038-U, EAI received approval to transfer approximately 154 MW of the Available Wholesale Base Load generation to retail rates.
6. Hydro Peaking Capacity to Retail
   - [*Complete*] In Docket No. 13-028-U, 10 MW of capacity was moved to retail rates.

2012 IRP Action Plan Progress

7. DSM and Energy Efficiency Expansion
   - [*On-going*] Since 2012 EAI has added 135 MW[1] of capacity savings and 516,768 MWh of energy efficiency through its Energy Efficiency Portfolio[2].
8. Lake Catherine 4 Reliability / Sustainability
   - [Complete] The unit is now expected to operate through 2024.
9. Older Natural Gas Fired Unit Deactivation Decisions
   - [*Complete*] EAI has deactivated approximately 441 MW of legacy generation.
10. Renewable Energy Assessment
    - [*In progress*] EAI issued an RFP for renewable energy resources in May 2014. EAI is currently pursuing APSC approval of the solar energy resource selected out of the RFP.
11. Short- and Intermediate-Term RFPs
    - EAI has not had a need for a short- or intermediate-term RFP since the 2012 IRP.

1. Capacity savings are adjusted to reflect only the incremental savings added over the 2013-15 time period.
2. Accumulation of 2012, 2013 and 2014 reported and evaluated achievement.

2015 IRP Goals and Objectives

The study period for the 2015 IRP is the 20-year period of 2017 through 2036. A 20-year study period was chosen for the 2015 IRP in order for EAI to evaluate long-term trends under a broad range of possible future outcomes.

EAI established a set of resource planning objectives to guide its development of its 2012 IRP and to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities[1]. The planning objectives focus on four key areas:

- cost,
- risk,
- reliability and
- sustainability.

The 2015 IRP will also be guided by the resource planning objectives, which are described on the following slides.

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

Resource Planning Objectives (1 of 3)

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.

Resource Planning Objectives (2 of 3)

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 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.

Resource Planning Objectives (3 of 3)

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 and 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.

IRP Analytical Framework

Progress, Objectives, and a Futures-based Approach

Futures-based Approach

For the IRP to reasonably account for a broad range of uncertainty while focusing on an appropriate amount of meaningful, thoughtful modeling iterations, EAI Resource Planning is using a futures-based approach to the IRP analysis.

In this approach, a select number of “futures” were developed that represent different combinations of possible outcomes of many variables.

Major areas of uncertainty to consider:

- Sales and load growth
- Commodity price trends
- Environmental regulation and/or legislation

For each future, the AURORA Capacity Expansion tool will select (i.e., output) a 20-year resource portfolio that is economically optimal for EAI under that set of circumstances.

Overview of IRP Futures

Future 1	Future 2	Future 3
Reference Case Future	**Low Capacity Additions Future**	**High Capacity Additions Future**
• Current proposed FIP[1] scenario • Installation of required controls and use of coal over cost recovery period • Reference level assumptions for commodity price and load forecasts	• Current proposed FIP scenario • Installation of required controls and use of coal over cost recovery period • Assumes sustained reliability through end of study period for the gas units • Low sales and load growth as well as low commodity prices delay and/or decrease new capacity additions	• Approval of plan to cease using coal at White Bluff by a time certain (2028) that makes scrubber installation economically unsupportable under federal air regulations (and thus not required) • Final FIP does not require Independence scrubber installation; Assumption that similar controls required in later Regional Haze planning period (2028-2038) • High sales and load growth drive increased capacity requirements

1. Refers to the Federal Implementation Plan under the U.S. Environmental Protection Agency Regional Haze Program, a regulation to improve visibility in national parks and wilderness areas. More information available at http://www.epa.gov/visibility/actions.html.

Assumptions by Future

	Future 1 Reference	Future 2 Low	Future 3 High
Existing Resource Portfolio			
Cease to Use Coal at White Bluff	2042	2042	2028
Cease to Use Coal at Independence	2044	2044	2035
Non-EAI Coal Plants	60 years	60 years	50 years
Customer Electricity Requirements			
Energy sales and Load	Reference	Low	High
Commodity Price Forecasts			
Fuel Prices	Reference	Low	High
Environmental Allowance Prices	Reference	Low	High

Load and Capability

Load Forecast and Existing Resource Portfolio

ALL CAPACITY VALUES SHOWN ARE 2015 GVTC RESULTS

Load Forecast

Summary of Results

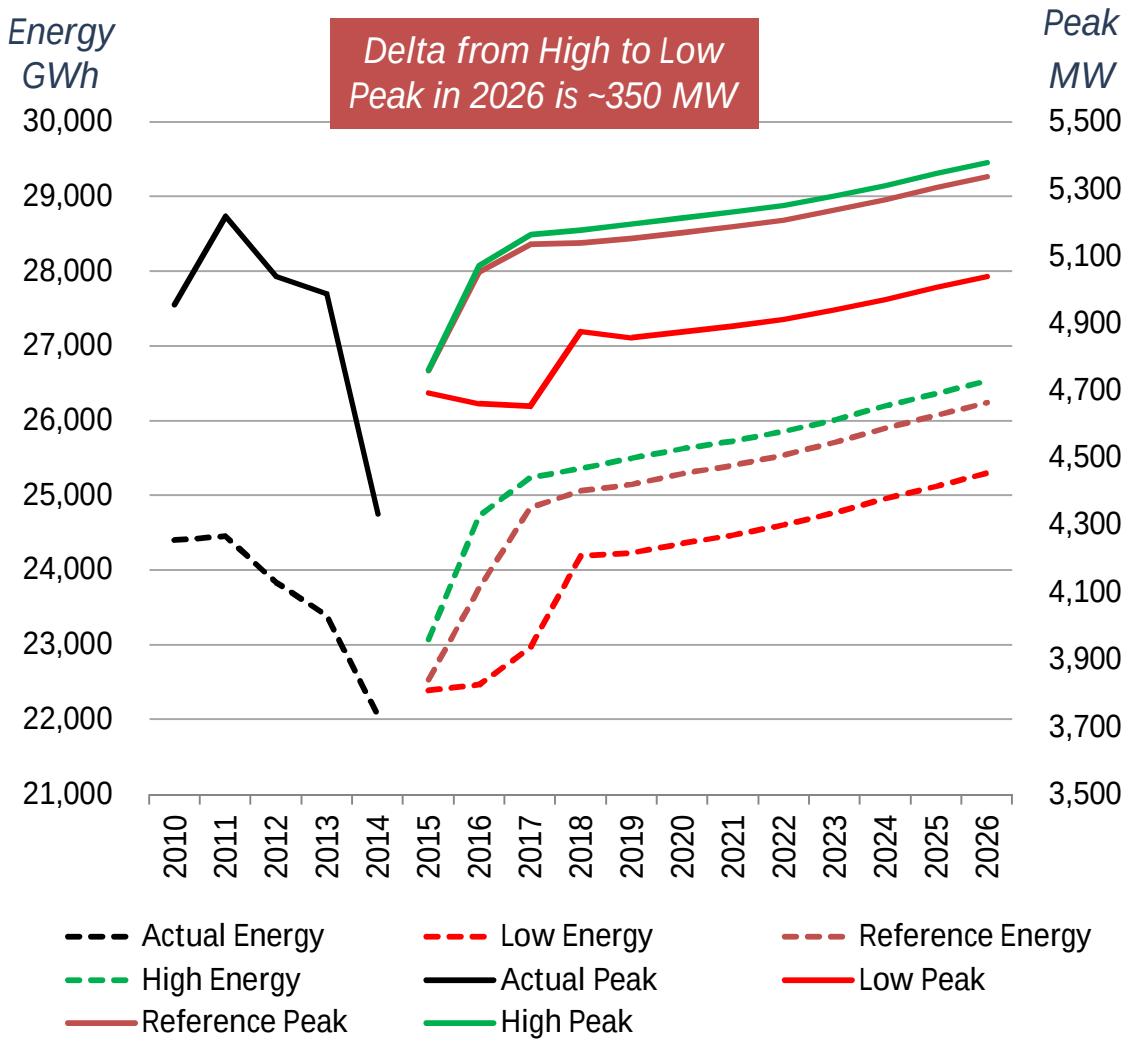
- Low and High cases driven by Economic Development assumptions (see next slide)
- DSM's reduction reaches a maximum of 95 MW in 2019

Weather

- 15-year normal, 2000-2014
- 2015 Peak Date: 8/4/2015
- 2010-12 actual peaks shown are weather normalized; 2013-14 are not weather-normalized

14-24 CAGR	Low	Ref	High
Peak	1.4%	2.0%	2.1%
Energy	1.2%	1.6%	1.7%

*Forecast as of September 1, 2014



Existing Portfolio – Owned Generation

	Total Installed Capacity (MW)	Ownership (%)	Retail Capacity (MW)	Commercial Operations Date
Arkansas Nuclear One Unit 1	834	100%	789	1974
Arkansas Nuclear One Unit 2	986	100%	933	1980
Carpenter Unit 1	31	100%	31	1932
Carpenter Unit 2	31	100%	31	1932
Hot Spring	597	100%	597	2002
Independence Unit 1	839	31.5%	228	1983
Lake Catherine Unit 4	516	100%	516	1970
Ouachita Unit 1	247	100%	247	2002
Ouachita Unit 2	241	100%	241	2002
Remmel Units 1, 2 & 3	12	100%	12	1925
White Bluff Unit 1	815	57.0%	400	1980
White Bluff Unit 2	822	57.0%	404	1981

Existing Portfolio – Purchased Generation

	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Blakely	86	11	1956
DeGray	78	10	1972
Grand Gulf	1,409	307	1985
Union Power	499	499	2003

Notes:
- The Blakely and DeGray capacity is assumed through 5/31/2019.
- The Grand Gulf capacity is assumed throughout the IRP study horizon.
- The Union Power PPA ends 5/31/2017, but EAI's acquisition of one power block is currently pending regulatory approval and would replace the PPA upon acquisition (see p. 18).

Future Portfolio – Planned Resource Additions

	Total Installed Capacity (MW)	Retail Capacity (MW)	Commercial Operations Date
Stuttgart Solar	81	81	TBD
Union Power	499	499	2003

Notes:
- These resources are currently pending regulatory approval.
- Stuttgart Solar is a 20-year PPA assumed to begin 1/1/2017.
- The Union Power capacity is assumed to be acquired by EAI and available throughout the IRP study horizon.

Existing Portfolio – Demand-side Resources

	Reduction during Peak Load Hours (MW)
Energy Efficiency	36

The peak and energy reducing impacts of EAI's Energy Efficiency programs are input to the development of the EAI sales forecast (p. 15).

	Reduction during Peak Load Hours (MW)
Demand Response	30
Interruptible Load	74

The capacity value of the Demand Response and Interruptible Load resources are included in the Load and Capability analysis and count toward EAI's planning reserve target in the same way as supply side resources.

Notes:
- Estimates above are total 2015 reductions.
- EAI's demand response include Residential Direct Load Control and Agricultural Irrigation Load Control programs.
- Demand Response and Interruptible capacity is increased to account for reserve margin and line loss value in the Load and Capability analysis.

Generation Technology Assessment

Cost and Performance

Technology Assessment Process & Overview

- An understanding of generation technology cost and performance is a necessary input to planning and decision support activities. EAI has engaged ESI to monitor and assess generation alternatives on an ongoing basis. This analysis uses a generic long-term capital structure of 11.0% ROE and 7.0% long-term debt and assumes 50% equity and 50% debt.

- The process has two main steps. First a screening level analysis is performed and then a detailed analysis is performed.

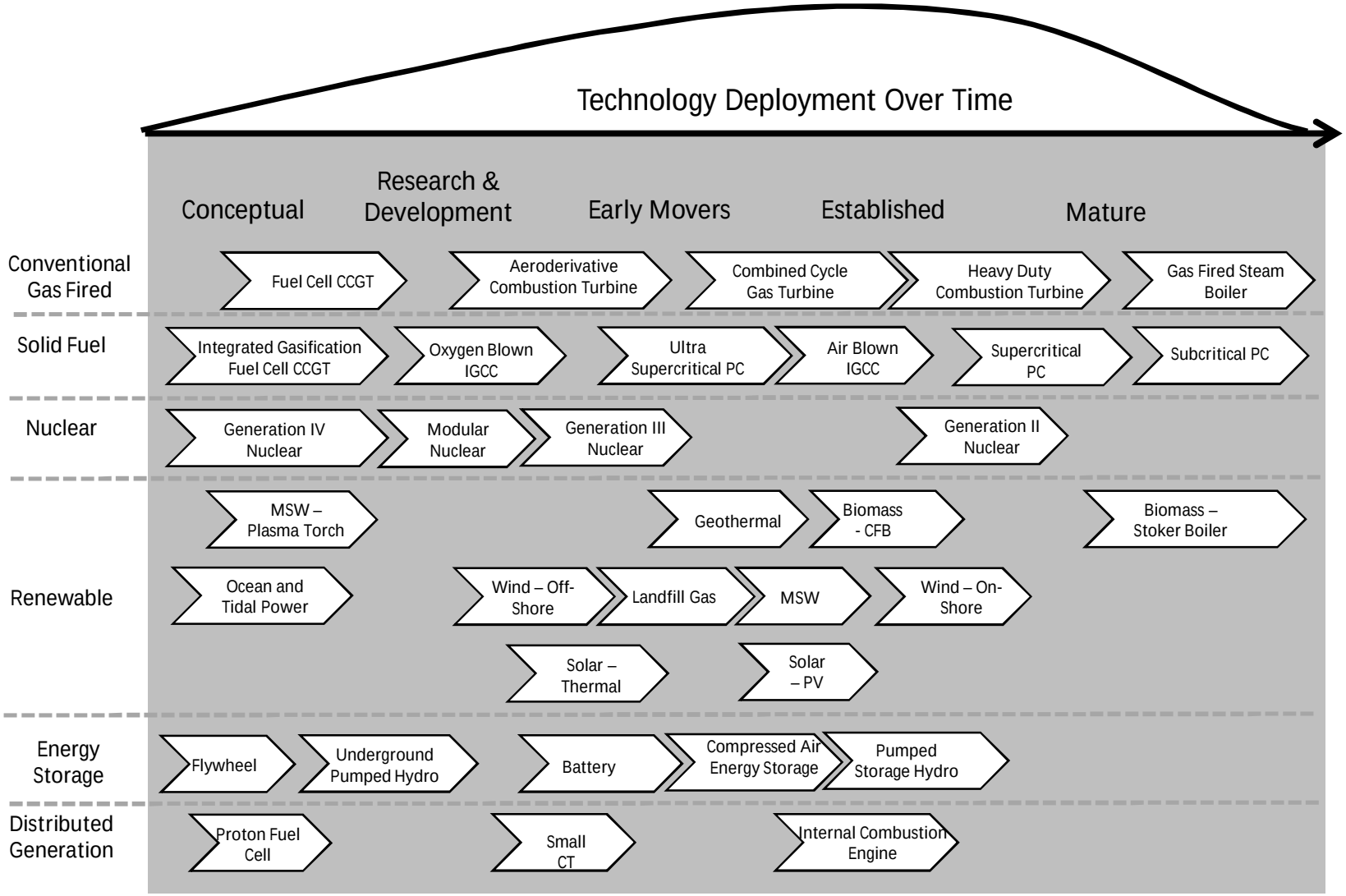
- The 2014 Generation Technology Assessment began by surveying available central state electricity generation technologies, generally those that are two megawatts or greater. The objective is to identify a reasonably wide range of generation technologies. The initial list was subject to a screening analysis to identify technologically mature alternatives which could be reasonably expected to be operational in or around the Entergy regulated service territory, except as otherwise noted.

- EAI prefers technologies that are proven on a commercial scale. Some technologies identified in this document lack the commercial track record to demonstrate their technical and operational feasibility. A cautious approach to technology development and deployment is therefore reasonable and appropriate in order to maintain system reliability and to protect EAI's customers from undue risks. EAI generally does not plan to be the "first movers" for emerging, unproven technologies.

- ESI, through this Technology Screen, has selected certain traditional and renewable generation technology alternatives which may reasonably be expected to meet primary objectives of cost, risk mitigation, and reliability. For each selected technology, Planning Analysis developed the necessary cost and performance parameter inputs into the detailed modeling used to develop the reference technologies comprising the IRP Portfolio.

- ESI will monitor for EAI the technologies eliminated as a result of the initial screen and incorporate changes into future technology assessments and IRPs.

A Variety of Available Alternatives



Technologies Screened

- Pulverized Coal
  - Subcritical Pulverized Coal
  - Supercritical Pulverized Coal
  - Ultra Supercritical Pulverized Coal
- Fluidized Bed
  - Atmospheric Fluidized Bed
  - Pressurized Fluidized Bed
- Integrated Gasification ("IGCC")
  - Oxygen-Blown IGCC
  - Air-Blown IGCC
  - Integrated Gasification Fuel Cell Combined Cycle
- Combustion Turbine / Combined Cycle / Other Natural Gas
  - Combustion Turbine
  - Combined Cycle
  - Large & Small Scale Aeroderivative
  - Steam Boiler
- Fuel Cells
  - Molten Carbonate
  - Solid Oxide
  - Phosphoric Acid
  - Proton Exchange Membrane
  - Fuel Cell Combined Cycle
- Nuclear
  - Advanced Boiling Water Reactor
  - Generation IV
  - Modular Reactors
- Energy Storage
  - Pumped Hydro
  - Underground Pumped Hydro
  - Battery
  - Flywheel
  - Compressed Air Energy Storage
- Renewable Technologies
  - Biomass
  - Solar Photovoltaic (Fixed Tile and Tracking)
  - Solar Thermal
  - Wind Power
  - Municipal Solid Waste
  - Landfill Gas
  - Geothermal
  - Ocean & Tidal

Technologies Selected For Detailed Analysis

The following technologies are being carried forward for development of detailed planning assumptions

- Pulverized Coal
  - Supercritical Pulverized Coal with carbon capture and storage*
- Natural Gas Fired
  - Combustion Turbine ("CT")
  - Combined Cycle Gas Turbine ("CCGT")
  - Large Scale Aeroderivative CT
  - Internal Combustion Engine
- Nuclear
  - Advanced Boiling Water Reactor
- Renewable Technologies
  - Biomass
  - Wind Power
  - Solar PV (Fixed Tilt and Tracking)
- Battery Storage

**Proposed EPA regulations on CO_2 have effectively eliminated all new coal plants without carbon capture.*

Technology Assumptions for Combined Cycle Application

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	1x1 F Frame CCGT	2x1 F Frame CCGT	1x1 G Frame CCGT	2x1 G Frame CCGT
Net Max Capacity (Summer)	(MW)	382	764	450	900
Installed Cost, 2014 (Summer)	($/kW)	$1,095	$1,045	$1,100	$900
Full Load Heat Rate (Summer)	(Btu/kWh)	6,900	6,750	6,650	6,650
Typical Capacity Factor	(%)	65%-85%	65%-85%	65%-85%	65%-85%
Fixed O&M (Summer)	($/kW-yr)	$17.50	$15.00	$15.50	$10.00
Variable O&M (Summer)	($/MWh)	$2.00	$2.00	$2.00	$2.00
Inlet Air Conditioning Assumption		Evaporative Coolers			
NOx Control Technology		SCR	SCR	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.01	0.01	0.01	0.01

- Cost of supplemental capacity (duct firing) assumed to be $250/kW
- Max Capacity, Installed Cost, and Fixed O&M include supplemental capacity. Heat rates reflect base capacity only.

Technology Assumptions for Peaking Applications

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	F Frame CT	G Frame CT	Large Aeroderivative CT	Internal Combustion
Net Max Capacity (Summer)	(MW)	194	250	102	18.8
Installed Cost, 2014	($/kW)	$820	$700	$1,275	$1,360
Full Load Heat Rate – Summer	(Btu/kWh)	10,200	9,600	9,125	8,440
Typical Capacity Factor	(%)	0%-10%	0%-10%	0%-40%	0%-40%
Fixed O&M	($/kW-yr)	$3.50	$3.00	$14.25	$29.25
Variable O&M	($/MWh)	$10.00	$12.50	$0.75	$2.25
Inlet Air Conditioning Assumption		-	Evaporative Cooling	Inlet Chillers	-
NOx Control Technology		Dry Low NOx burners	Dry Low NOx burners	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.03	0.03	0.01	0.01

Technology Assumptions for Solid Fuel Application

Cost & Performance Appropriate For Technology Deployment in MISO South		PC With 90% CCS
Net Max Capacity	(MW)	800
Installed Cost, 2014	($/kW)	$4,900
Full Load Heat Rate – Summer	(Btu/kWh)	13,200
Levelized Fuel Cost	($/mmbtu)	$3.12
Typical Capacity Factor	(%)	85%
Fixed O&M	($/kW-yr)	$140.00
Charging Cost	($/MWh)	n/a
Expected Useful Life		40

Technology Assumptions for Renewable Applications

Cost & Performance Appropriate For Technology Deployment in MISO South		Biomass	Nuclear	Wind	Solar PV (fixed tilt)	Solar PV (tracking)	Battery Storage (Lead Acid Batteries)
Net Max Capacity	(MW)	100	1,310	200	100	100	50
Installed Cost, 2014	($/kW)	$4,760	$8,000	$2,050	$2,300	$2,550	$2,400
Full Load Heat Rate – Summer	(Btu/kWh)	12,900	10,200	-	-	-	-
Levelized Fuel Cost	($/mmbtu)	$3.04	$0.90	-	-	-	-
Typical Capacity Factor	(%)	85%	90%	48%	21%	24%	20%
Fixed O&M	($/kW-yr)	$104.60	$115.60	$22.10	$19.00	$23.00	$0.00
Charging Cost	($/MWh)	n/a	n/a	n/a	n/a	n/a	$25.00
Expected Useful Life		30	40	25	25	25	20

- Capacity for these technologies is not significantly affected by ambient air temperature.
- All O&M is considered fixed.
- Wind capacity factor representative of resources located in mid-west geographical area.

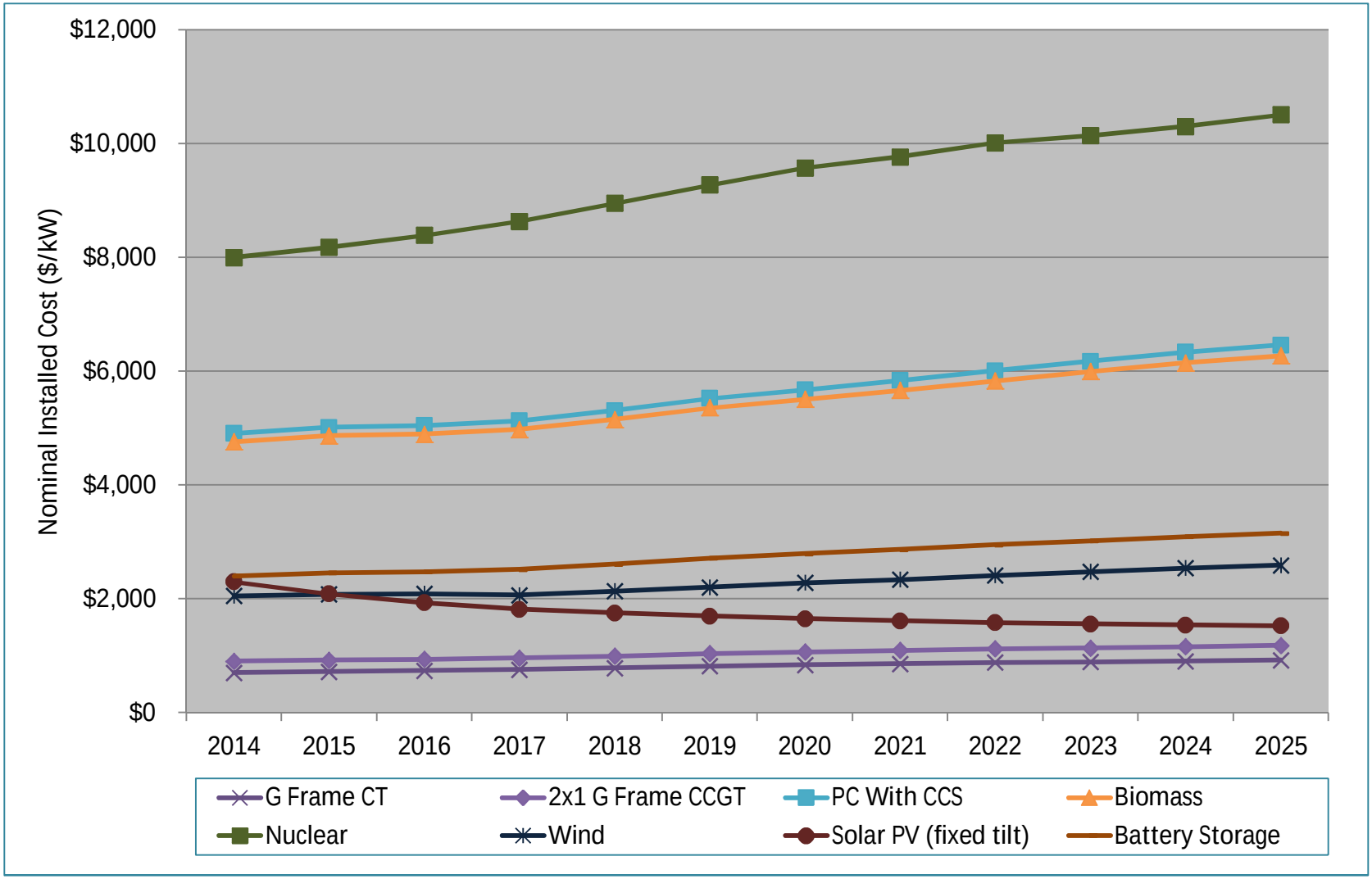
Additional Supply Considerations

Schedule and location can influence which technology is preferred for a given application

Technology	Time to Market	Environmental	Gas Supply	Flexibility
CCGT	◐	●	◐	◐
Frame CT w/ SCR	◕	●	◐	◐
Small Aeroderivative	●	●	○	◕
Large Aeroderivative	◕	●	○	◕
Internal Combustion Engine	●	◐	●	●
Nuclear	○	◕		○
Coal	◔	○		●
Wind	●	●		○
Solar	●	●		○
Considerations included in category	• Permitting Requirements • Lead time of major components • Engineering Required • Installation Time	• Impact of Non-Attainment Zone • NOx Emissions • SOx Emissions • COx Emissions • Residual Fuel	• Gas Pressure Required	• Ramp Rate • Turndown Ratio • Start Time • Performance at Part Load

Considerations are scored relative to each other ● *Most favorable* ○ *Least Favorable*

Capital Cost Projections



Commodity Price Forecasts

Fossil Fuels, Solid Fuel and Air Emissions Allowances

LEVELIZED PRICES SHOWN ARE FOR THE PERIOD 2017-2036

Fuel Price Forecasts

Levelized 2015 $/MMBtu	Reference	Low	High
Henry Hub Natural Gas Price	$4.89	$3.50	$7.68
EAI Coal Plants	$2.43	$2.12	$3.54
Non-EAI Coal Plants in Entergy Region	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	High Case (Price Varies by Plant)
Coal Plants in Non Entergy Regions	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	High Case (Price Varies by Plant)

Notes:
- EAI Owned Plants: volume weighted average based on plant specific pricing which includes current contracts
- Forecast as of May 1, 2015

CO_2 Price Forecast

Levelized 2015 $/short ton	Reference	Low	High
CO_2	$10.02 ($CO_2$ pricing begins in 2020)	None	$29.68 ($CO_2$ pricing begins in 2020)

Cross-State Air Pollution Rule (CSAPR) Forecast

Levelized 2015 $/ton	Reference
Seasonal NO_X	$5.19
Annual NO_X	$51.93
SO_2 Group 1	$15.09
SO_2 Group 2	$26.32

Notes:
- Low and High sensitivities were not developed for this program.
- Arkansas is subject to compliance under the Seasonal NOX program only.
- Source: Energy Ventures Analysis, 2015.

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2015 Integrated Resource Plan

August 7, 2015
2015 IRP Stakeholder Meeting

2015 IRP Meeting Overview

- Welcome
- Safety
- Introductions

Agenda

Topic	Start Time	Name
Introduction and Meeting Objectives	8:00	Kurt Castleberry
Resource Planning Update	8:15	Matt Wolf
Transmission Planning Update	8:45	Melinda Montgomery
Demand-side Management Update	9:00	Richard Smith
Overview of Environmental Issues	9:30	Kelly McQueen
Break	*10:00*	
IRP Process Overview	10:10	Kandice Fielder
Generation Technology Assessment	10:25	Charles DeGeorge
Sales and Load Forecasts	10:50	Charles John
Preliminary Results and Next Steps	11:15	Kandice Fielder
Lunch	*12:00*	
Stakeholder Committee Formation	1:00	Kandice Fielder
Wrap-up	1:45	Kurt Castleberry

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

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 2015 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

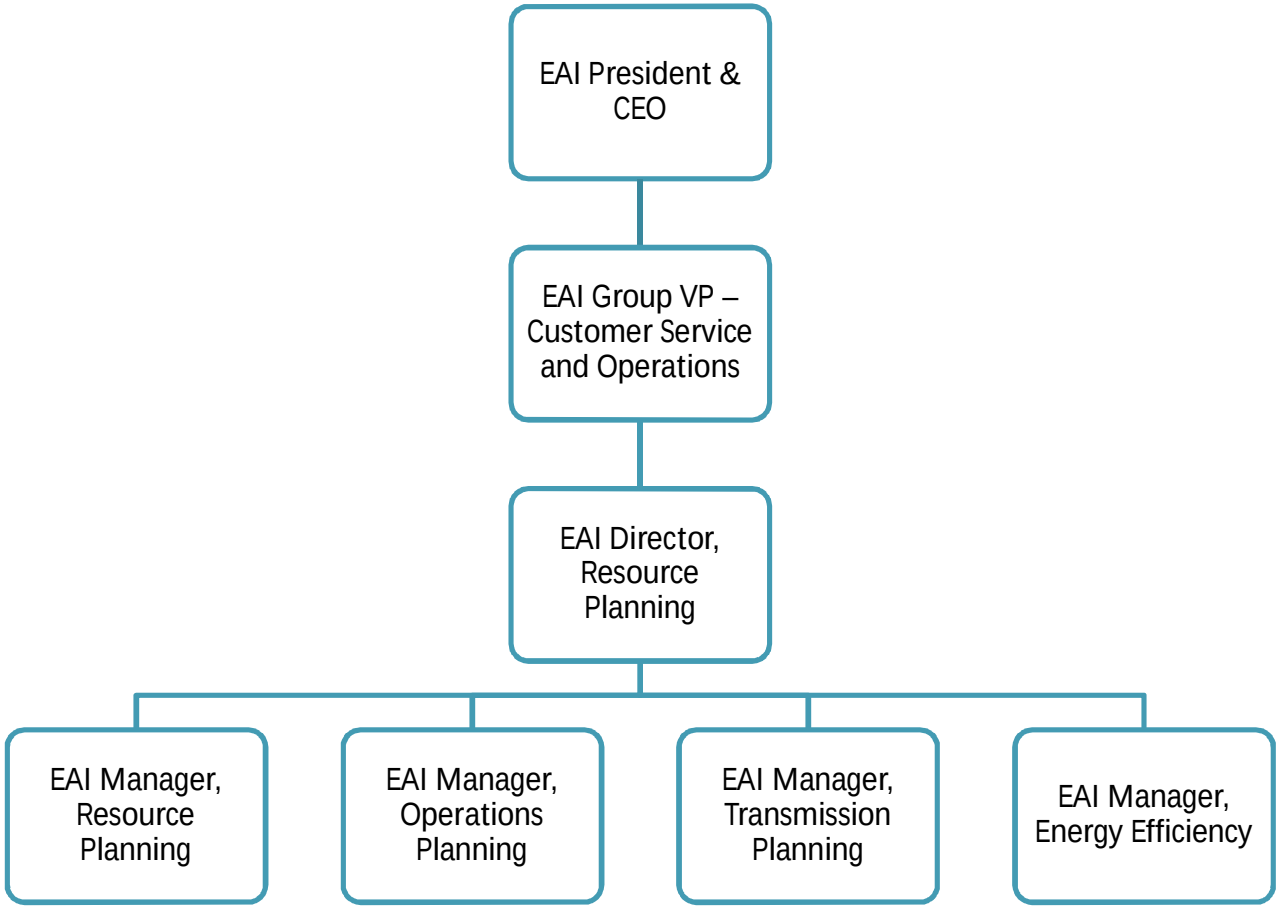
ACTIVITY	DATE
Stakeholder meeting	August 7
Stakeholder / EAI interaction (as needed)	August 7 – October 2
Stakeholders finalize Stakeholder Report and provide to EAI	October 16
EAI finalizes IRP and files written report with the APSC including Stakeholder Report	October 31

Ground Rules

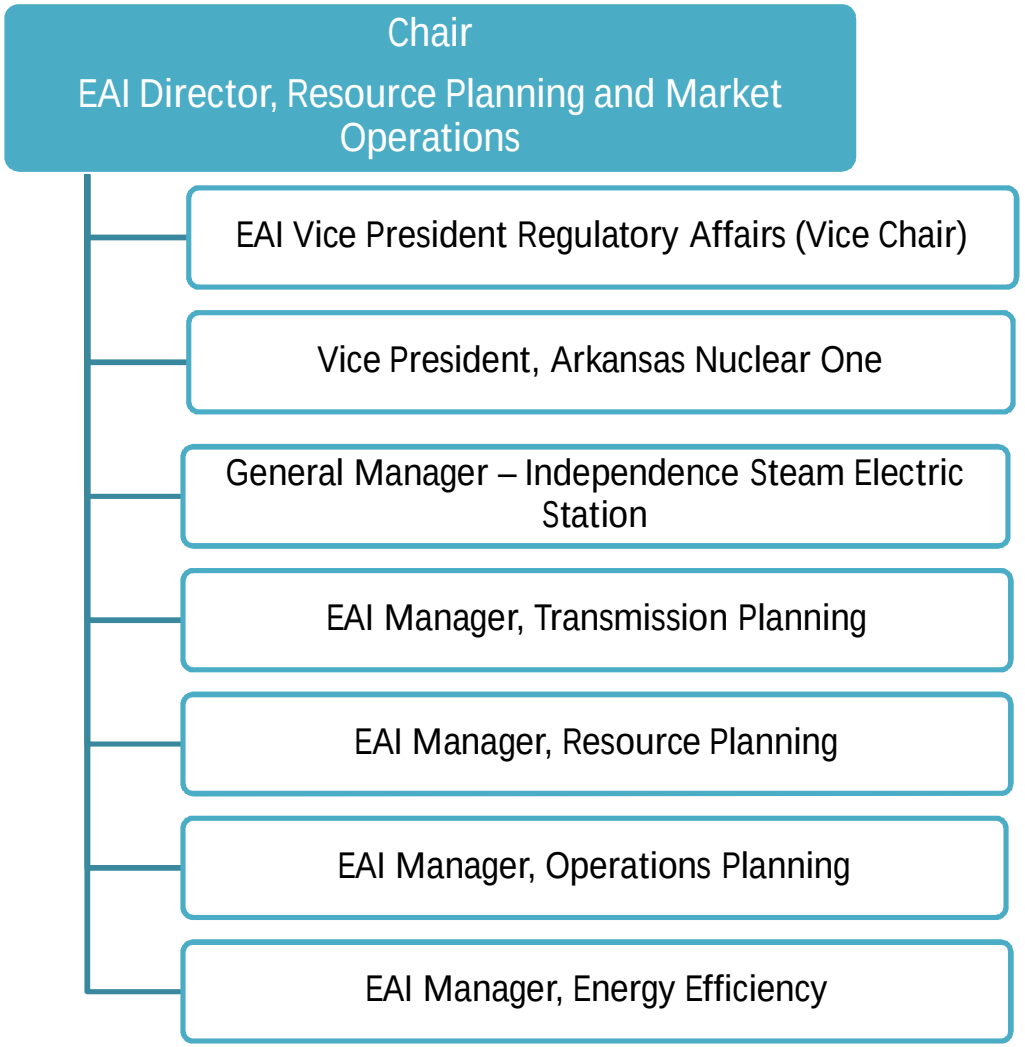
- A lot of material – Need to stay on schedule
- Ask questions but time constraints may limit number of questions allowed. However, EAI will answer ALL stakeholder questions either in today's meeting or the written questions and their answers will be posted @ http://entergy-arkansas.com/transition_plan/
- 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)



Questions / Comments

Resource Planning Update

Resource Planning Update

- Review the Action Plan from EAI's 2012 IRP Report.

- Update the Stakeholders on key Resource Planning Activities.

2012 IRP Action Plan

1. MISO Transition
2. Coal Unit Environmental Compliance
3. Hot Spring Plant Acquisition
4. Purchase Power Agreements from EAI's 2011 RFP
5. Available Wholesale Base Load Capacity to Retail
6. Hydro Peaking Capacity to Retail
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8. Lake Catherine 4 Reliability / Sustainability
9. Older Natural Gas Fired Unit Deactivation Decisions
10. Renewable Energy Assessment
11. Short- and Intermediate-Term RFPs

#1 MISO Transition

- Integration into MISO took place on December 19, 2013
- EAI customers saved an estimated $46 Million during the first year
  - Reduced capacity requirements are estimated at 344 MW
- EAI has successfully participated in three MISO Planning Resource Auctions
  - Transitional auction, 2014/15 auction, 2015/16 auction
  - Modified the Optional Interruptible Service Rider (OIS-R) and registered as a Load Modifying Resource (LMR) for the 2015/16 auction.
- EAI recently filed a report detailing EAI participation in the MISO Auctions in APSC Docket No. 10-011-U

Action Items #2, #3 and #4

#2 The Environmental Compliance update will be provided by Kelly McQueen

#3 Hot Springs Plant Acquisition

- EAI completed the acquisition in December 2012.
- Added approximately 600 MW to EAI's portfolio.

#4 Purchase Power Agreements from EAI's 2011 RFP

- EAI executed a PPA with Union Power Partners in October 2012.
- APSC approval was obtained in APSC Docket No. 12-038-U.
- Added approximately 500 MW for the period of December 19, 2013 through May 31, 2017.
- Contract negotiations for a second proposal selected in the 2011 RFP was concluded without execution of a contact.

#5 - Available Wholesale Base Load Capacity

- In APSC Docket No. 12-038-U, EAI offered to move approximately 286 MW of capacity that has previously been used to serve the wholesale sector and 59 MW of capacity from its retained share of the Grand Gulf Nuclear Plant to serve retail customers.

- The docket was settled with 186 MW of nuclear based generation from the Arkansas Nuclear One units being transferred to serve retail customers.

Action item #6 and #7

#6 Hydro Peaking Capacity to Retail

- The wholesale allocation factor was updated in APSC Docket No. 13-028-U.
- Added approximately 10 MW.

#7 DSM and Energy Efficiency Update will be provided by Richard Smith.

Since 2012, incremental EE installations have contributed to approximately 135 MW savings across EAI's peak.

#8 - Lake Catherine 4 Reliability / Sustainability

- Lake Catherine 4 is a 516 MW gas fired unit that was originally scheduled to deactivate at the end of 2014.
- A Reliability/Sustainability program was developed and implementation is on-going.
- The unit is currently expected to be available through May 31, 2025.
- Adds approximately 516 MW.

#9 – Older NG Fired Unit Deactivation Decisions

- Since the 2012 IRP, EAI deactivated approximately 420 MW of older natural gas / diesel fired generation.
- Total generation retirements since the 2012 IRP totaled approximately 964 MW across 13 units.
- Two more older units totaling approximately 28 MW are planned to retire at the end of May 2016.

10 – Renewable Energy Assessment

- EAI issued an RFP for both traditional and renewable resources on May 5, 2014.

- EAI entered into a contract on April 3, 2015.
  - 20 year PPA for approximately 81 MW.
  - Energy deliveries to begin no later than May 31, 2019.
  - Expect 20 to 40 MW of capacity at peak.

- Approval of the PPA is pending before the APSC in Docket No. 15-014-U.

11 – Short- and Intermediate-Term RFP

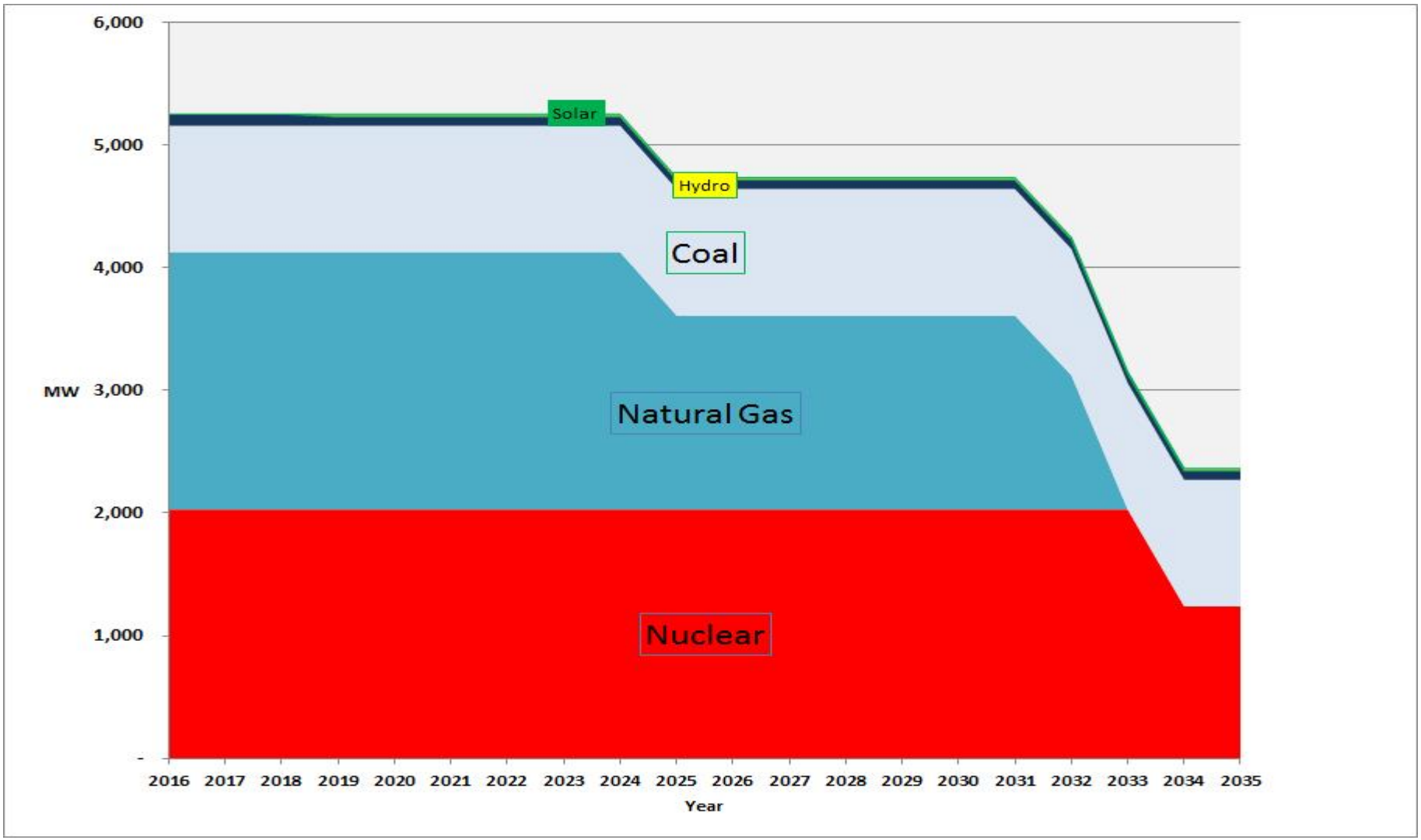
- EAI elected to issue an RFP for long-term renewable and intermediate resources on May 5, 2014.
- EAI entered into an asset purchase agreement with Union Power Partners on December 8, 2014, to acquire power block 2 which will add approximately 495 MW to EAI's portfolio.
- APSC approval is pending in Docket No. 14-118-U as well as required federal reviews /approvals.

Resource Planning Summary

- Completed: (summer ratings)
  - MISO Membership: +344 MW
  - Hot Spring Power Plant: +600 MW
  - EE / DSM: +135 MW
  - Wholesale Capacity: +186 MW
  - Wholesale Hydro Capacity: +10 MW
  - Lake Catherine 4: +516 MW
  - Retirements: -964 MW

- Planned:
  - UPP Power Block 2: +495 MW
  - Stuttgart Solar PPA: +20 MW

EAI Supply Side Resources – Existing and Planned



Questions / Comments

Transmission Planning Update

Transmission Planning Update

- What has changed since 2012.
- What hasn’t changed.
- Transmission Planning analysis

What has changed since 2012 in Transmission Planning

- EAI joined MISO
  - EAI responsible for its transmission plans, apart from the System Agreement companies
  - New regional and interregional planning processes for transmission projects
  - New economic planning process
- New planning standards that apply to all Transmission Planners

What hasn't changed in Transmission Planning

- EAI is responsible for planning to meet reliability standards and local planning criteria.
- Our focus remains on providing reliable service to customers and maintaining reasonable rates.
- We still use an open and transparent stakeholder process in transmission planning, including discussion of alternatives.

Recent Transmission Projects at a Glance

		APPENDIX A			APP B
	Total	Future/in-progress	Complete	Est. Cost	Studied for Future
Pre-Planned	23	10	13		-
MTEP 14	31	21	8	$66M	2
MTEP 15*	19	8	-	$128 M	5
MTEP 16**	15	9	-	Not yet final	6

Pre-planned projects are those that had already been through the planning process before EAI joined MISO.
*MTEP 15 process is still in progress. Approval of projects to occur in December 2015.
**MTEP 16 local planning is on-going. Projects and costs are not yet final.
Appendix A are those projects approved by the MISO Board, or submitted for study in the current year requesting approval.
Appendix B are those projects that are farther in the future. They are submitted for study but not for approval in the current planning cycle.

Transmission Planning and the IRP

- Should the 2015 IRP Action Plan guide EAI to pursue and evaluate options for additional generating resources (for example, through an RFP), transmission analysis of resource options will be done to determine transmission impact.
- Analysis will include the transmission topology and limit information including planned projects from MISO's regional MTEP plan.

Questions / Comments

Demand-side Management Update

DSM Progress since 2012

This section is to outline the progress EAI has made with DSM and DR since the 2012 IRP.

- In 2011, the Commission established DSM Targets of:
  - 0.25% of retail sales in 2011,
  - 0.5% retail sales in 2012, and
  - 0.75% of retail sales in 2013.
- In 2014, the Commission extended the target 0.75% of retail sales.
- In 2015, the Commission again extended program at a Target level of 0.9% of retail sales.
- All programs are to be based upon the Comprehensiveness orders made in December 2010 and further program design requirements for weatherization and Commercial and Industrial Programs in 2013.
- Going forward, the Commission is requiring the RECC method of determining avoided capacity cost which reduces cost effectiveness of DSM and DR when compared to levelized avoided capacity cost, as is best practices in all other jurisdictions.
- Forward looking targets have not yet been established. However, EAI has planned using a strategy of flat achievement and cost adjusted for inflation in this IRP.

2012-14 DSM Achievement

DSM and Energy Efficiency Expansion

– Since 2012 EAI has added 135 MW[1] of peak period savings and 501,691 MWh of at-the-meter energy efficiency through its Energy Efficiency Portfolio[2].

	Evaluated Achievement		
	2012	2013	2014
Energy Savings (KWH)[3]	107,626,826	188,556,802	205,506,894
Demand Reduction (KW)[3]	23,261	49,900	63,045
DR Budget	$8,669,000	$6,793,000	$7,605,000
DSM Budget	$30,940,000	$51,633,000	$57,849,000
Total Budget	$39,609,000	$58,426,000	$65,454,000
Actual Spend	$28,395,000	$53,032,000	$59,914,000
Percent of Sales (Evaluated)	0.51%	0.90%	1.00%
Total Resource Cost Ratio	1.2	2.2	3.4

1. Peak savings are adjusted to reflect only the incremental savings added over the 2012-14 time period.
2. Accumulation of 2012, 2013 and 2014 reported and evaluated achievement.
3. The savings in the table above do not include T&D adjustment.

2015 DSM Projected Achievement

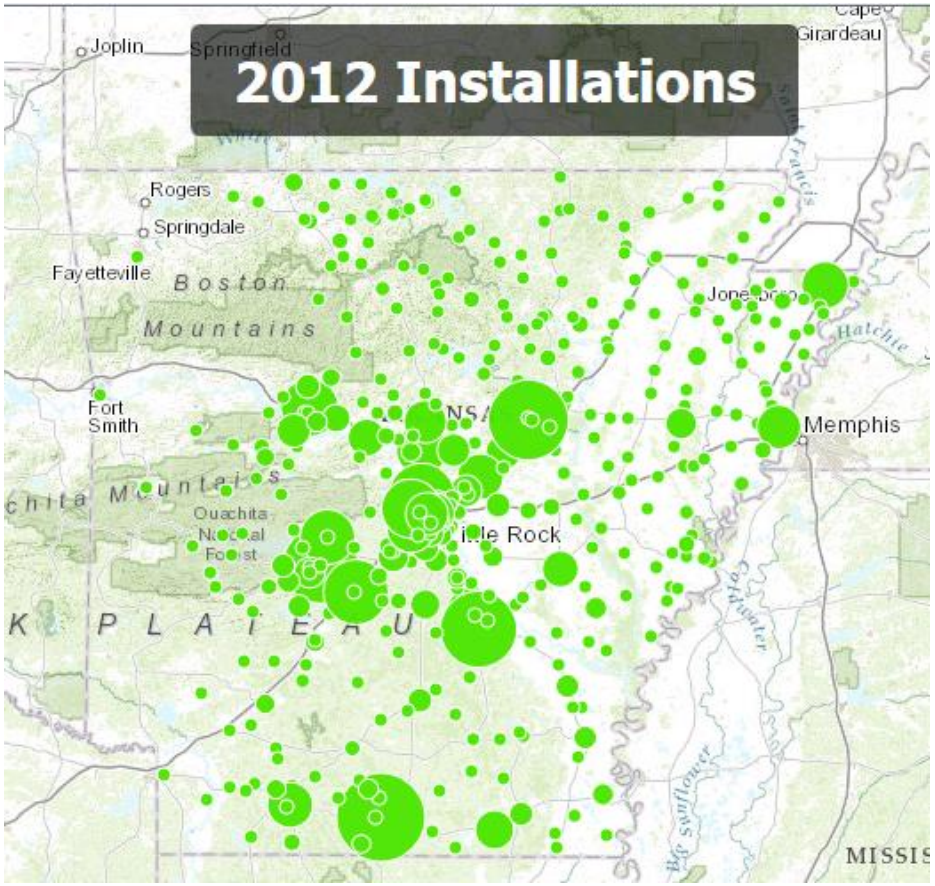
- EAI is on track to achieve and exceed our 2015 DSM and DR target of 178,869 MWHs subject to retroactive Technical Resource Manual ("TRM") updates and Independent EM&V Results.
- The 2015 Plan is demonstrated below:

	2015
Energy Savings (KWH)*	235,798,383
Demand Reduction (KW)*	79,300
DR Budget	$8,929,000
DSM Budget	$62,249,000
Total Budget	$71,178,000
Actual Spend	
Percent of Sales (Evaluated)	1.15%
Total Resource Cost Ratio	1.8

*The savings in the table above do not include T&D adjustment.

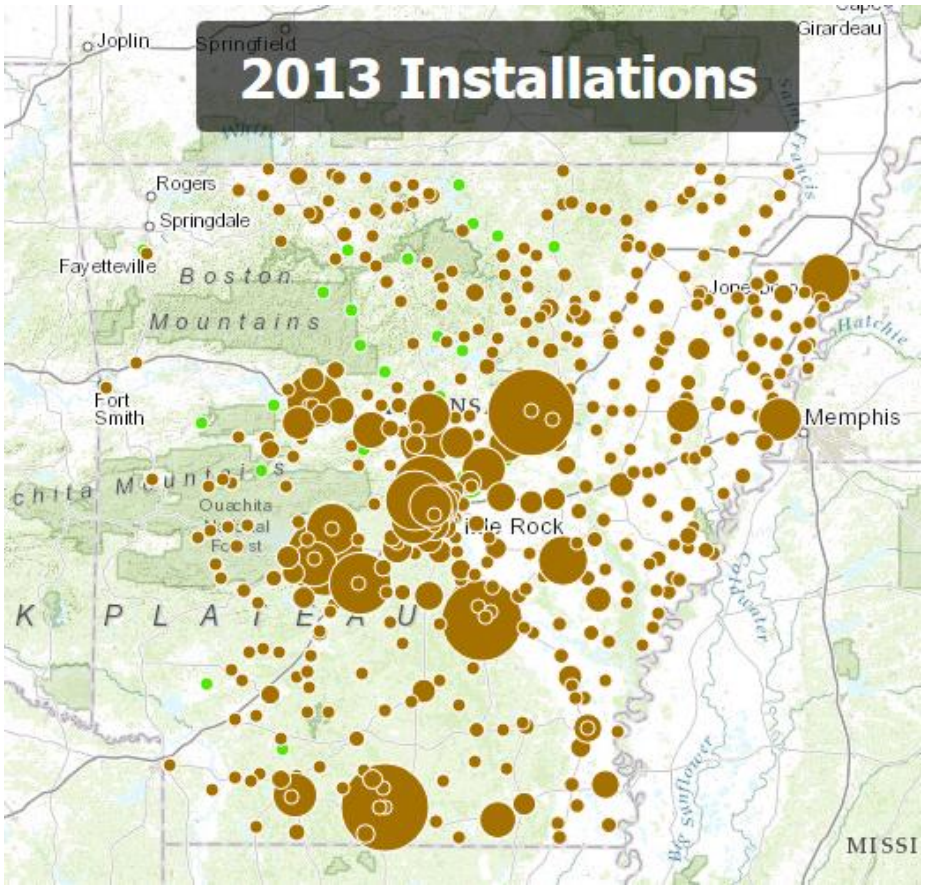
Where DSM and DR Are Occurring – 2012

2012 Achievements



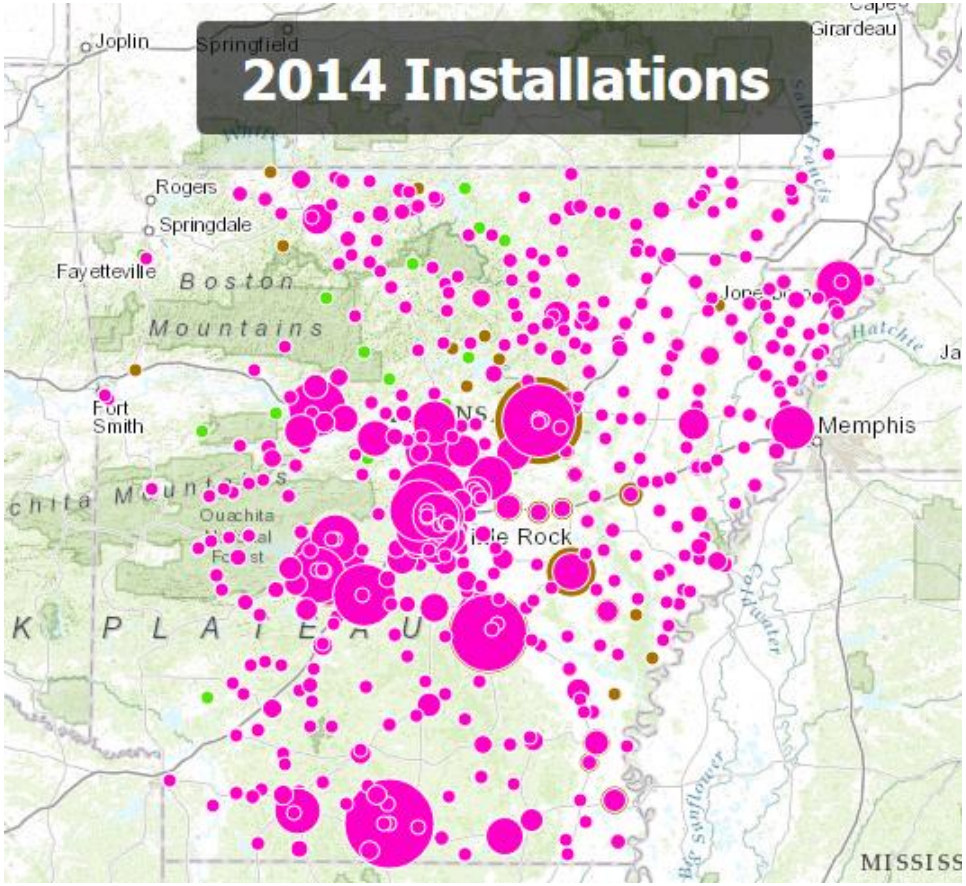
Where DSM and DR Are Occurring – 2012-13

2012 and 2013 Achievements



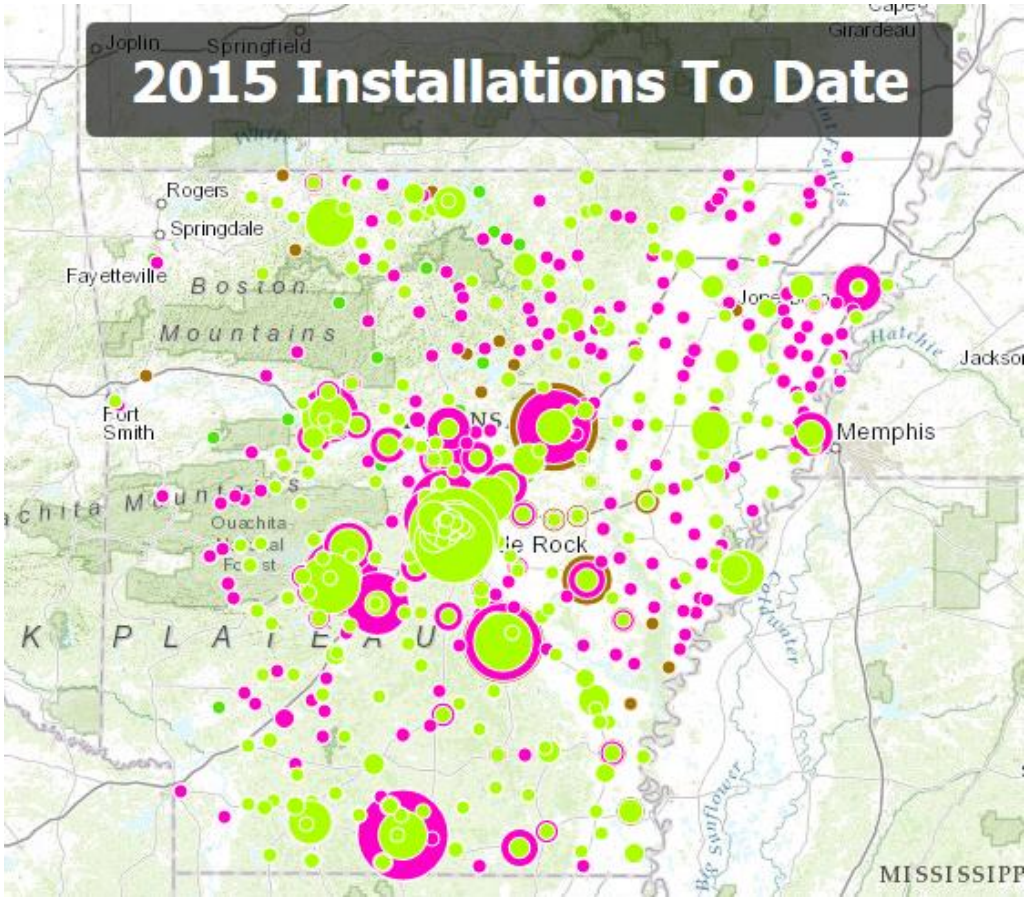
Where DSM and DR Are Occurring – 2012-14

2012 through 2014 Achievements



Where DSM and DR Are Occurring – 2012-15

2012 through 2015 Achievements



Proxy for the Next Three Year Plan

- EAI had prepared to file a Three Year Plan covering 2016 through 2018 before the Three Year Plan filing was delayed until June of 2016.
- Our 2016 DSM and DR plan reflects the first year of the 2016 through 2018 Three Year Plan.
- The 2016 through 2018 Plan included the following:
  - The RECC Method of avoided capital cost,
  - Consideration of EM&V uncertainties,
  - Plan to attempt to maximize performance incentives of 120% of utility target.

Proxy for the Next Three Year Plan

- EAI Proxy for the 2016 through 2018 Three year plan
- Plan is subject to change based upon final regulatory decisions in 2015, TRM and EM&V updates.

	Projected		
	2016	2017	2018
Energy Savings (KWH)*	260,304,000	260,304,000	260,306,000
Demand Reduction (KW)*	100,200	100,200	110,700
DR Budget	$7,163,000	$6,588,000	$7,210,000
DSM Budget	$58,801,000	$59,871,000	$59,261,000
Total Budget	$65,964,000	$66,459,000	$66,471,000
Actual Spend			
Percent of Sales (Evaluated)	1.27%	1.27%	1.27%
Total Resource Cost Ratio	2.3	2.3	2.3

*The savings in the table above do not include T&D adjustment.

Four Types of DSM in Planning

Customer-sponsored DSM	Existing Utility-sponsored DSM	Incremental Utility-sponsored DSM	Interruptible Loads/DR
• Improvements in energy efficiency and conservation that occur without Utility involvement. • An assumption for this type of DSM is included in the Retail Sales Forecast.	• Generally, large scale, regulator approved programs that provide incentives to go above and beyond efficiency standards. • An assumption for the impact of existing programs is included in the Retail Sales Forecast.	• These programs are like existing Utility programs but require regulatory approval to implement. • An assumption for incremental programs is included in the Retail Sales Forecast.	• Programs that provide the Utility with the right to curtail service to a participating customer. • These resources are modeled like a supply side resource.

2015 IRP Utility-sponsored DSM Assumptions

- Existing Utility-sponsored DSM: The energy saving and peak reducing impacts of these programs are reflected in the actual historical customer usage data which is an input to the Sales and Load forecasts.
- Incremental Utility-sponsored DSM: Since the Arkansas DSM Potential Study was still underway and no direction regarding future DSM Targets was available at the time, EAI assumed 0.9% of retail sales above forecast without DSM (above naturally occurring DSM) as the DSM proxy within the Sales and Load forecasts.
  - This results in an annual incremental reduction in sales of 165,468 MWh[1] and assumes a 10-year measure degradation curve.
  - Any free ridership, or overlap between the Customer-sponsored DSM and the Incremental Utility-sponsored DSM, is also accounted for so that the impacts are not double-counted.

1. Based on 2013 Program Year planned net annual savings, Docket No. 07-085-TF Doc 443

2015 IRP DSM Assumption Principle Based

EAI remains committed to DSM and DR as long the achievement can be accomplished in a cost effective manner when compared to a utility future avoided or delayed generation cost and full cost recovery remains in place.

Also, EAI continues to investigate opportunities for advance metering infrastructure which may enhance the future DSM and DR portfolio.

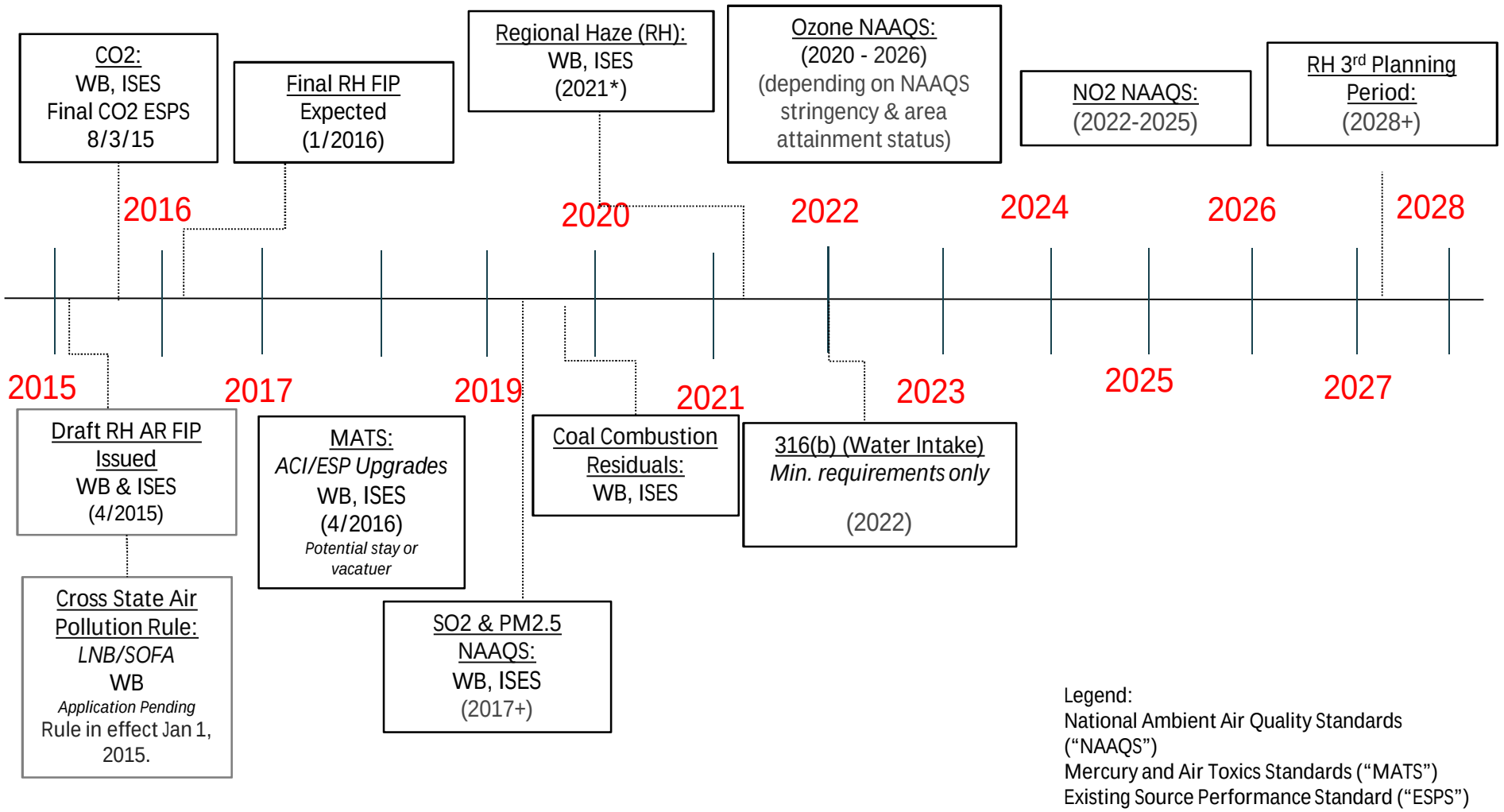
Questions / Comments

Overview of Environmental Issues

Overview of Environmental Issues

- Potential Environmental Compliance Timeline
- MATS
- Regional Haze
- CSAPR & NAAQS (SO2 and Ozone)
- Clean Power Plan (CO2)

Potential Environmental Compliance Timeline



Legend:
National Ambient Air Quality Standards ("NAAQS")
Mercury and Air Toxics Standards ("MATS")
Existing Source Performance Standard ("ESPS")

Entergy

Overview of Environmental Issues - MATS

MATS:

- Extensions granted/compliance April 2016
- ACI/ESP upgrades complete – WB/ISES
- Commissioning/testing ongoing
- 6/30/15 Supreme Court decision
- D.C. Circuit to decide whether MATS is stayed, vacated or remains in effect pending remand to EPA
  - Expected decision by end of year 2015

Overview of Environmental Issues – Regional Haze

Regional Haze:

- April 8, 2015 proposed Federal Implementation Plan:
  - Lake Catherine 4: BOOS (BART)
  - White Bluff: LNB/SOFA and dry FGD (BART)
  - Independence: LNB/SOFA and dry FGD (Reasonable Progress)
    - Also taking comment on dry FGD only
- Comment Deadline extended to August 7, 2015
- EAI Comments:
  - Independence should not have been included as AR is below the "Glidepath"
  - Proposes long term, multi-unit approach:
    - White Bluff : Cease to use coal in 2027/2028
    - White Bluff & Independence: LNB/SOFA within 3 years of final FIP and lower SO2 rate in 2018
- Final FIP expected in 1Q2016

Overview of Environmental Issues – CSAPR & NAAQS

CSAPR:

- May 1, 2015: CSAPR begins for seasonal program states
- WB: LNB/SOFA permit application pending
- July 2015: D.C. Circuit overturns state budgets in several states (not AR)

1 hour SO2 NAAQS:

- Pursuant to consent decree
  - State proposed designations for areas around WB and ISES due: September 2015
  - EPA designation expected: July 2016
- Not expected to be an independent driver of controls at either plant

8 hour Ozone Standard:

- Current standard: 75 ppb (primary and secondary standards)
- Court ordered deadlines:
  - December 1, 2014 – Proposed revised NAAQS
  - October 1, 2015 – Final revised NAAQS
- Not expected to be an independent driver of controls at either plant

Overview of Environmental Issues – Clean Power Plan

Clean Power Plan:

- June 2015 Proposed Rule
- August 3, 2015 Final Rule issued along with:
  - Final New Source Performance Standards
  - Proposed Federal Plan
- Still under review

	Proposed interim rate	Final Rule interim rate	Proposed Final rate	Final Rule final rate
AR	968	1304	910	1130

Overview of Environmental Issues – Clean Power Plan

Clean Power Plan Timeline

Summer 2015	• August 3, 2015 - Final Clean Power Plan
1 Year	• September 6, 2016 – States make initial submittal with extension request or submit Final Plan
3 Years	• September 6, 2018 - States with extensions submit Final Plan
7 Years	• January 1, 2022 - Compliance period begins
15 Years	• January 1, 2030 - CO_2 Emission Goals met

Questions / Comments

BREAK

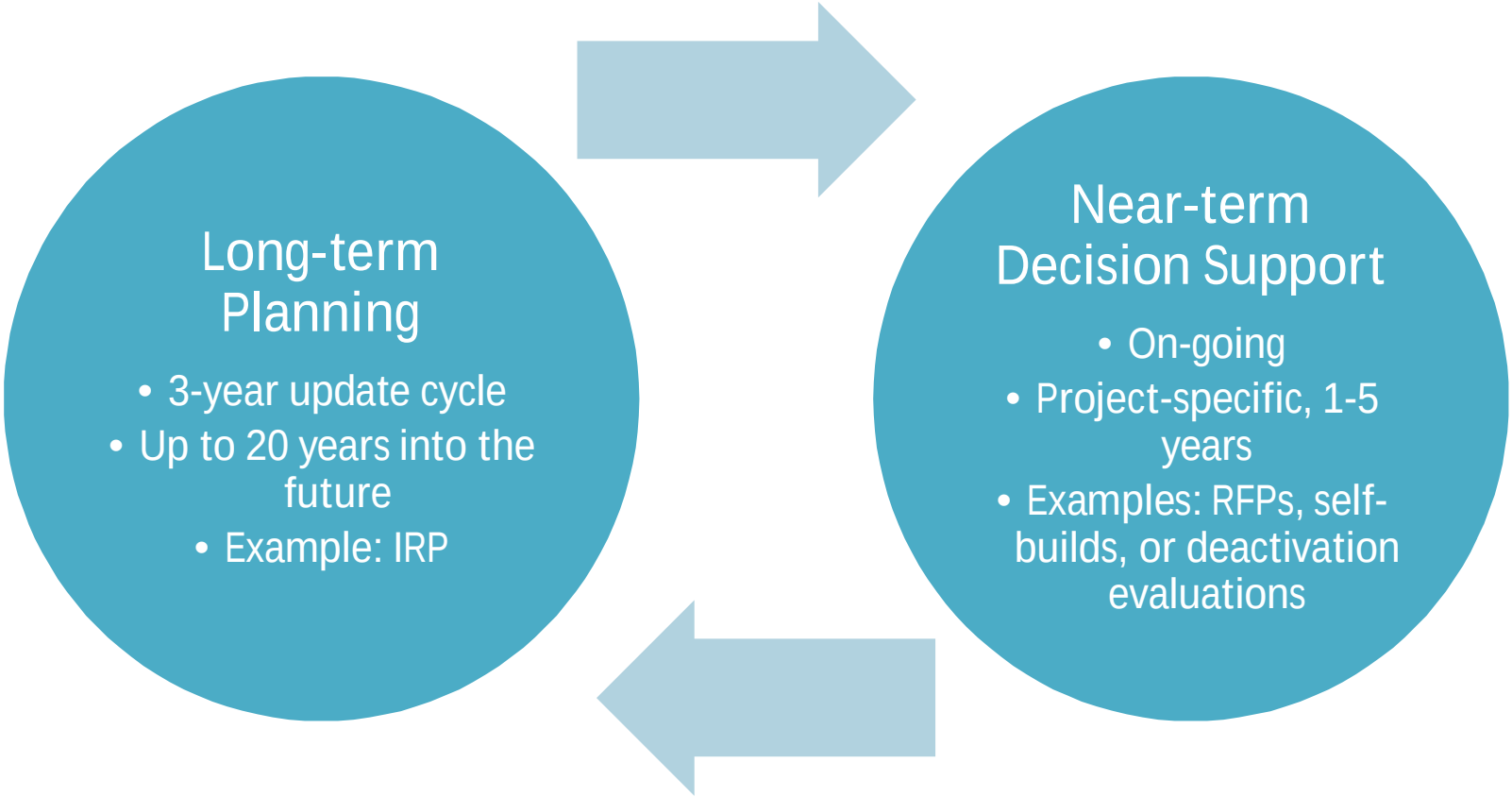
IRP Process Overview

Agenda

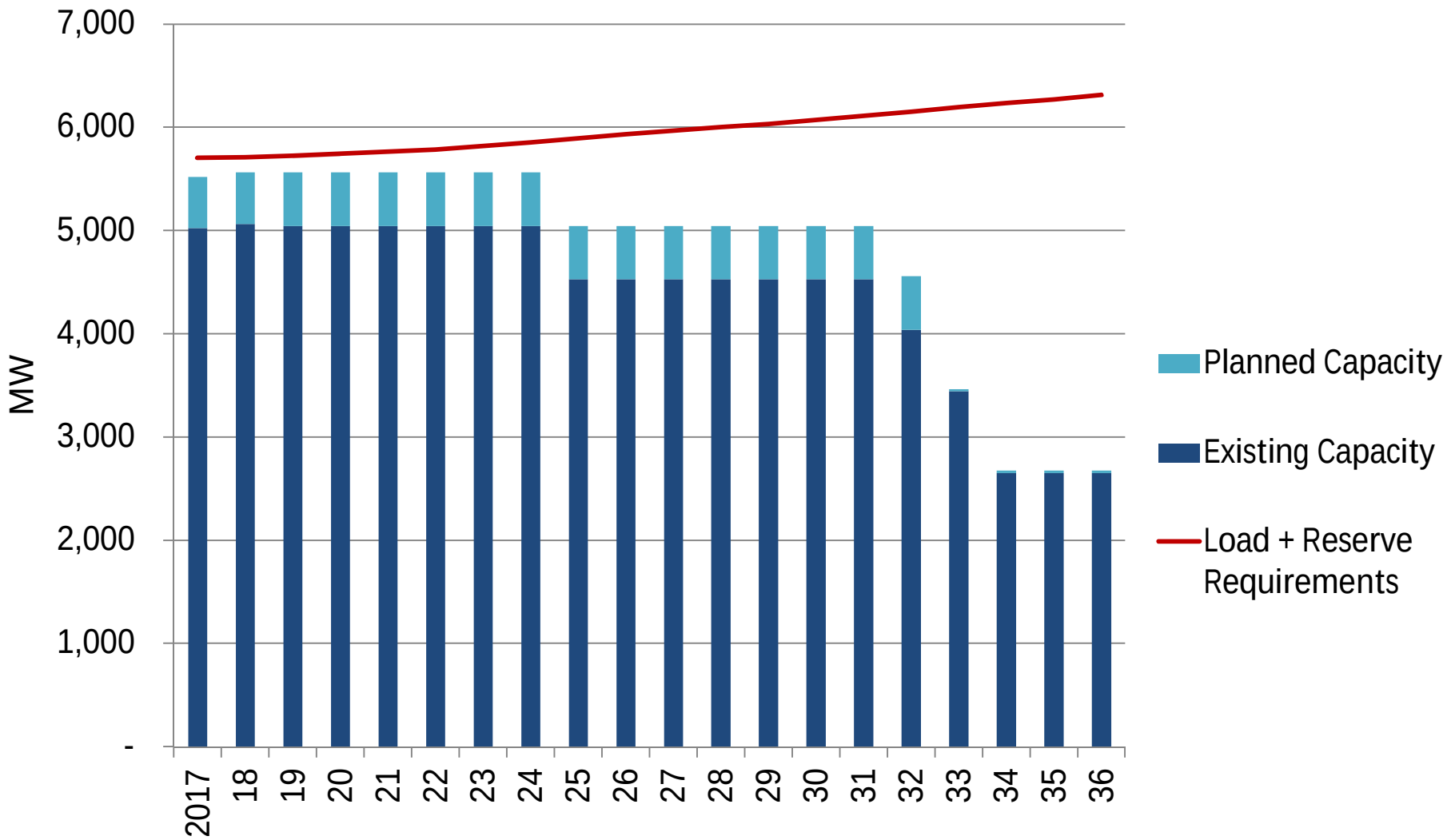
Topic	Start Time	Name
Introduction and Meeting Objectives	8:00	Kurt Castleberry
Resource Planning Update	8:15	Matt Wolf
Transmission Planning Update	8:45	Melinda Montgomery
Demand-side Management Update	9:00	Richard Smith
Overview of Environmental Issues	9:30	Kelly McQueen
Break	*10:00*	
IRP Process Overview	10:10	Kandice Fielder
Generation Technology Assessment	10:25	Charles DeGeorge
Sales and Load Forecasts	10:50	Charles John
Preliminary Results and Next Steps	11:15	Kandice Fielder
Lunch	*12:00*	
Stakeholder Committee Formation	1:00	Kandice Fielder
Wrap-up	1:45	Kurt Castleberry

Resource Planning Process

The IRP has an important role in EAI's resource planning by providing guidance on long-term themes and tendencies. However, the nature of the IRP analysis is not appropriate for tactical resource decisions, which follows a separate evaluation process.



EAI's Future Capacity Needs



Questions / Comments

GENERATION TECHNOLOGY ASSESSMENT

Technology Assessment Process & Overview

- An understanding of generation technology cost and performance is a necessary input to planning and decision support activities. EAI has engaged ESI to monitor and assess generation alternatives on an ongoing basis. This analysis uses EAI' capital structure.

- The process has two main steps. First a screening level analysis is performed and then a detailed analysis is performed.

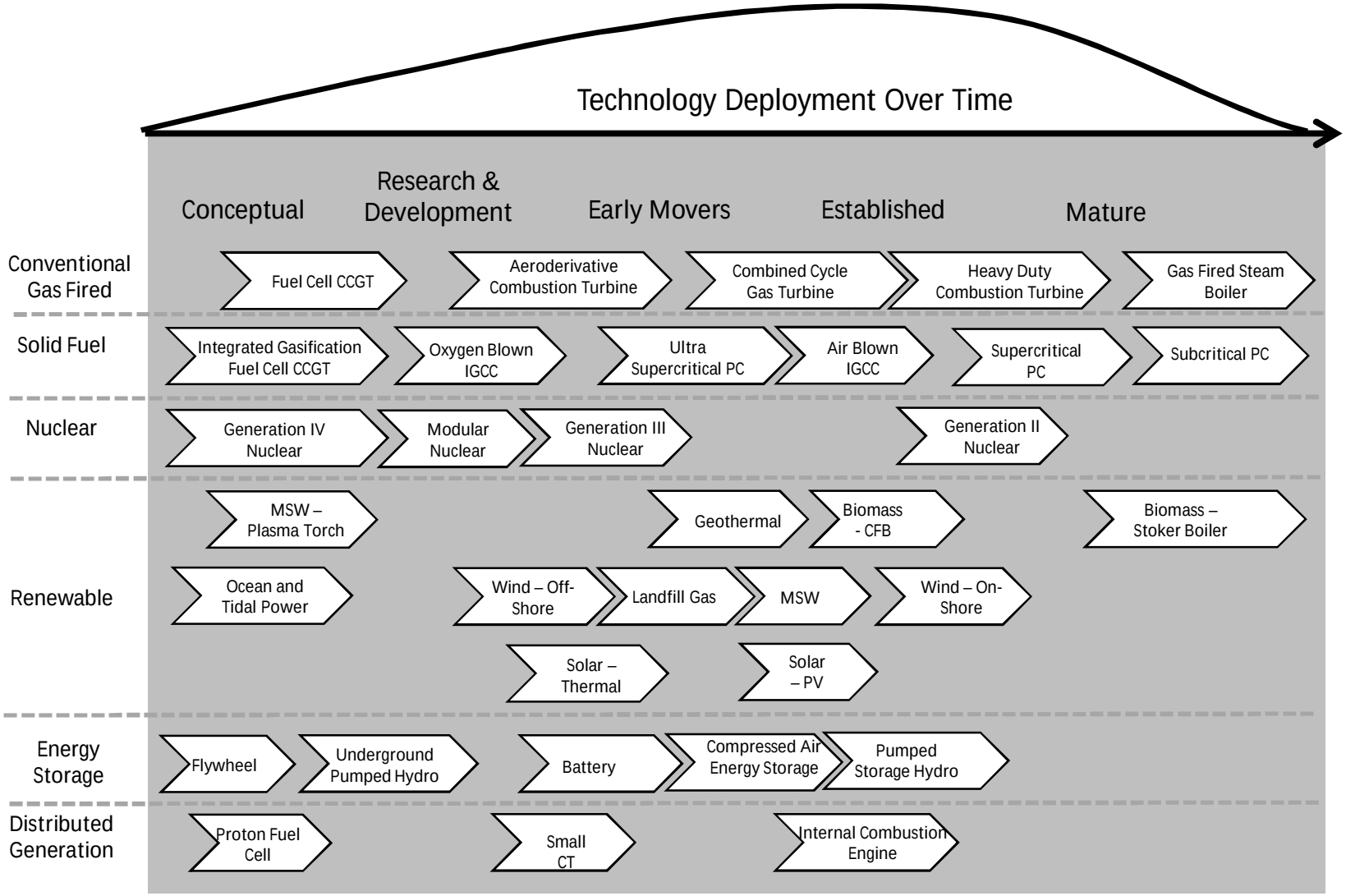
- The 2015 Generation Technology Assessment began by surveying available central state electricity generation technologies, generally those that are two megawatts or greater. The objective is to identify a reasonably wide range of generation technologies. The initial list was subject to a screening analysis to identify technologically mature alternatives which could be reasonably expected to be operational in or around the Entergy regulated service territory, except as otherwise noted.

- EAI prefers technologies that are proven on a commercial scale. Some technologies identified in this document lack the commercial track record to demonstrate their technical and operational feasibility. A cautious approach to technology development and deployment is therefore reasonable and appropriate in order to maintain system reliability and to protect EAI's customers from undue risks. EAI generally does not plan to be the "first movers" for emerging, unproven technologies.

- ESI, through this Technology Screen, has selected certain traditional and renewable generation technology alternatives which may reasonably be expected to meet primary objectives of cost, risk mitigation, and reliability. For each selected technology, Planning Analysis developed the necessary cost and performance parameter inputs into the detailed modeling used to develop the reference technologies comprising the IRP Portfolio.

- ESI will monitor for EAI the technologies eliminated as a result of the initial screen and incorporate changes into future technology assessments and IRPs.

A Variety of Available Alternatives



Technologies Screened

- Pulverized Coal
  - Subcritical Pulverized Coal
  - Supercritical Pulverized Coal
  - Ultra Supercritical Pulverized Coal
- Fluidized Bed
  - Atmospheric Fluidized Bed
  - Pressurized Fluidized Bed
- Integrated Gasification ("IGCC")
  - Oxygen-Blown IGCC
  - Air-Blown IGCC
  - Integrated Gasification Fuel Cell Combined Cycle
- Combustion Turbine / Combined Cycle / Other Natural Gas
  - Combustion Turbine
  - Combined Cycle
  - Large & Small Scale Aeroderivative
  - Steam Boiler
- Fuel Cells
  - Molten Carbonate
  - Solid Oxide
  - Phosphoric Acid
  - Proton Exchange Membrane
  - Fuel Cell Combined Cycle
- Nuclear
  - Advanced Boiling Water Reactor
  - Generation IV
  - Modular Reactors
- Energy Storage
  - Pumped Hydro
  - Underground Pumped Hydro
  - Battery
  - Flywheel
  - Compressed Air Energy Storage
- Renewable Technologies
  - Biomass
  - Solar Photovoltaic (Fixed Tilt and Tracking)
  - Solar Thermal
  - Wind Power
  - Municipal Solid Waste
  - Landfill Gas
  - Geothermal
  - Ocean & Tidal

Technology Assumptions for Combined Cycle Application

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	1x1 F Frame CCGT	2x1 F Frame CCGT	1x1 G Frame CCGT	2x1 G Frame CCGT
Net Max Capacity (Summer)	(MW)	382	764	450	900
Installed Cost, 2014 (Summer)	($/kW)	$1,095	$1,045	$1,100	$900
Full Load Heat Rate (Summer)	(Btu/kWh)	6,900	6,750	6,650	6,650
Typical Capacity Factor	(%)	65%-85%	65%-85%	65%-85%	65%-85%
Fixed O&M (Summer)	($/kW-yr)	$17.50	$15.00	$15.50	$10.00
Variable O&M (Summer)	($/MWh)	$2.00	$2.00	$2.00	$2.00
Inlet Air Conditioning Assumption		Evaporative Coolers			
NOx Control Technology		SCR	SCR	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.01	0.01	0.01	0.01

- Cost of supplemental capacity (duct firing) assumed to be $250/kW
- Max Capacity, Installed Cost, and Fixed O&M include supplemental capacity. Heat rates reflect base capacity only.

Technology Assumptions for Peaking Applications

Cost & Performance Appropriate For Technology Deployment in MISO South	Units	F Frame CT	G Frame CT	Large Aeroderivative CT	Internal Combustion
Net Max Capacity (Summer)	(MW)	194	250	102	18.8
Installed Cost, 2014	($/kW)	$820	$700	$1,275	$1,360
Full Load Heat Rate – Summer	(Btu/kWh)	10,200	9,600	9,125	8,440
Typical Capacity Factor	(%)	0%-10%	0%-10%	0%-40%	0%-40%
Fixed O&M	($/kW-yr)	$3.50	$3.00	$14.25	$29.25
Variable O&M	($/MWh)	$10.00	$12.50	$0.75	$2.25
Inlet Air Conditioning Assumption		-	Evaporative Cooling	Inlet Chillers	-
NOx Control Technology		Dry Low NOx burners	Dry Low NOx burners	SCR	SCR
NOx emissions, post control	(lbs/MMBtu)	0.03	0.03	0.01	0.01

Technology Assumptions for Solid Fuel Application

Cost & Performance Appropriate For Technology Deployment in MISO South		PC With 90% CCS	Nuclear
Net Max Capacity	(MW)	800	1,310
Installed Cost, 2014	($/kW)	$4,900	$8,000
Full Load Heat Rate – Summer	(Btu/kWh)	13,200	10,200
Levelized Fuel Cost	($/mmbtu)	$3.12	$0.90
Typical Capacity Factor	(%)	85%	90%
Fixed O&M	($/kW-yr)	$140.00	$115.60
Charging Cost	($/MWh)	n/a	n/a
Expected Useful Life		40	40

Technology Assumptions for Renewable Applications

Cost & Performance Appropriate For Technology Deployment in MISO South		Biomass	Wind	Solar PV	Battery Storage (Lead Acid Batteries)
Net Max Capacity	(MW)	100	200	100	50
Installed Cost, 2014	($/kW)	$4,760	$2,050	$2,300	$2,400
Full Load Heat Rate – Summer	(Btu/kWh)	12,900	-	-	-
Levelized Fuel Cost	($/mmbtu)	$3.04	-	-	-
Typical Capacity Factor	(%)	85%	48% *	26%	20%
Fixed O&M	($/kW-yr)	$104.60	$22.10	$19.00	$0.00
Charging Cost	($/MWh)	n/a	n/a	n/a	$25.00
Expected Useful Life		30	25	25	20

- Capacity for these technologies is not significantly affected by ambient air temperature.
- All O&M is considered fixed.

* Wind capacity factor representative of resources located in mid-west geographical area.

Additional Supply Considerations

Schedule and location can influence which technology is preferred for a given application

Technology	Time to Market	Environmental	Gas Supply	Flexibility
CCGT	◐	●	◐	◐
Frame CT w/ SCR	◕	●	◐	◐
Small Aeroderivative	●	●	○	◕
Large Aeroderivative	◕	●	○	◕
Internal Combustion Engine	●	◐	●	●
Nuclear	○	◕		○
Coal	◔	○		●
Wind	●	●		○
Solar	●	●		○
Considerations included in category	• Permitting Requirements • Lead time of major components • Engineering Required • Installation Time	• Impact of Non-Attainment Zone • NOx Emissions • SOx Emissions • COx Emissions • Residual Fuel	• Gas Pressure Required	• Ramp Rate • Turndown Ratio • Start Time • Performance at Part Load

Considerations are scored relative to each other ● *Most favorable* ○ *Least Favorable*

Technologies Selected For Detailed Analysis

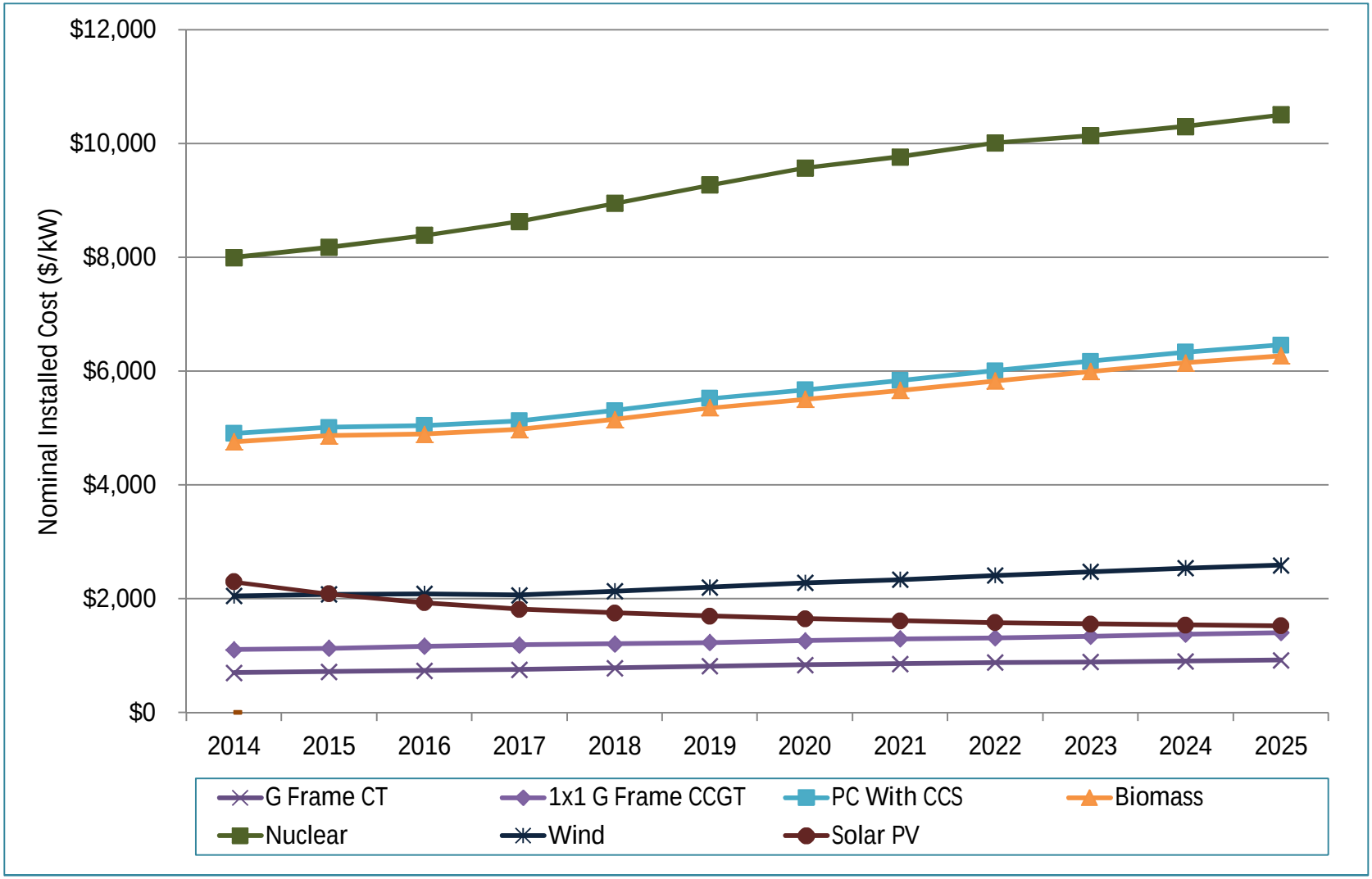
The following technologies are being carried forward for development of detailed planning assumptions and production cost modeling

- Pulverized Coal
  - Supercritical Pulverized Coal with carbon capture and storage*
- Natural Gas Fired
  - Combustion Turbine ("CT")
  - Combined Cycle Gas Turbine ("CCGT")

**Proposed EPA regulations on CO_2 have effectively eliminated all new coal plants without carbon capture.*

- Nuclear
  - Advanced Boiling Water Reactor
- Renewable Technologies
  - Biomass
  - Wind Power
  - Solar PV

Capital Cost Projections



Questions / Comments

Sales and Load Forecasts

Load Forecast Process

- The load forecasting process begins with historical monthly sales volumes
  - 2006 – 2013
  - Theoretically sound, statistically valid

- Calculate a sales forecast using an econometric model meant to determine the relationship between sales, economics, energy efficiency, and weather

- Apply sales forecast and normal weather to regressions to calculate monthly peaks

EAI Load Forecasts for IRP

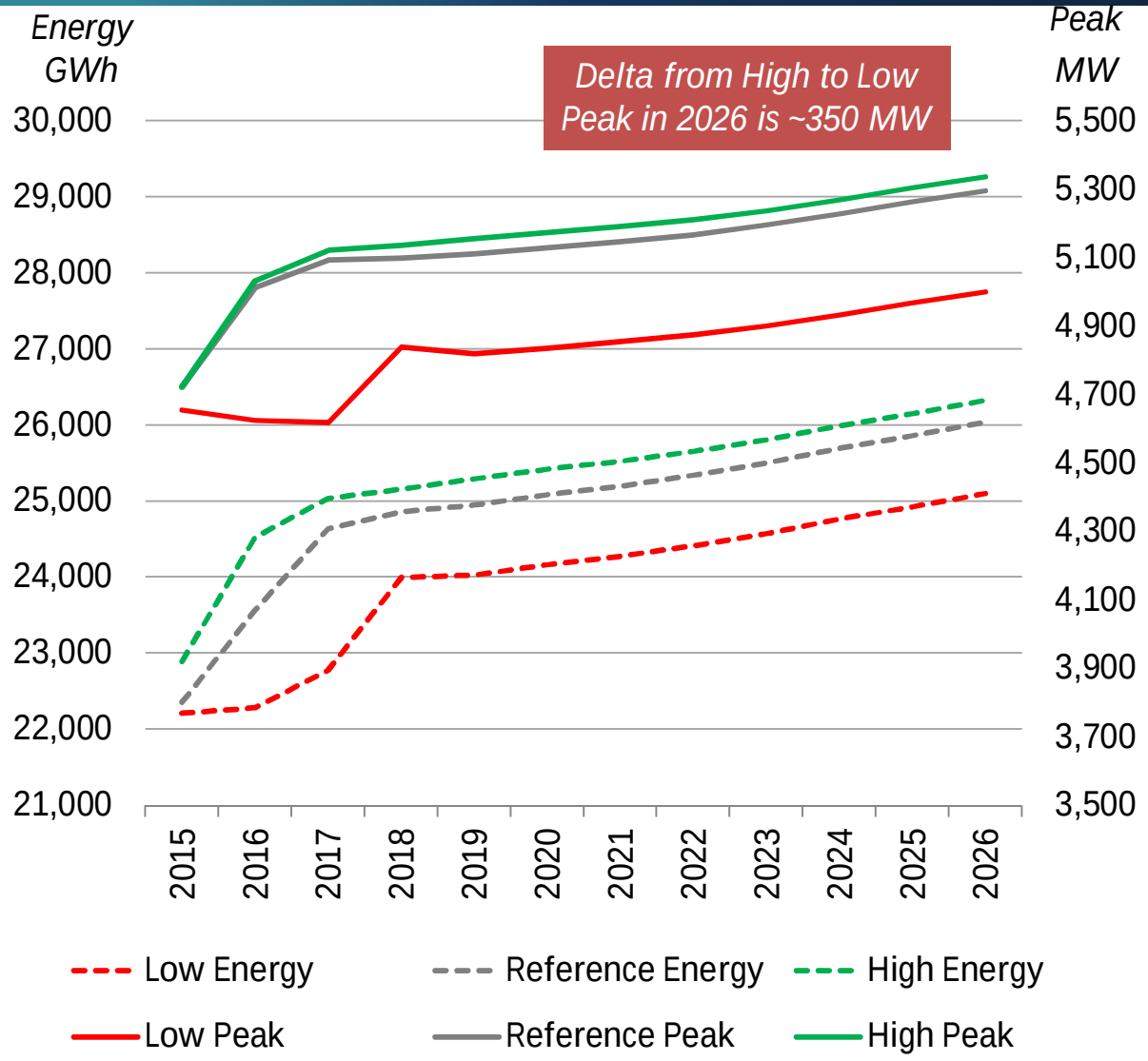
Summary of Results

- Low and High cases driven by scenarios around Economic Development assumptions
- Most of growth is concentrated in the Large Industrial segment

Uncertainties

- On-time completion and/or size of ED projects
- Possible changes to DSM targets

14-24 CAGR	Low	Ref	High
Peak	1.4%	2.0%	2.1%
Energy	1.2%	1.6%	1.7%



Economic Outlook

- The economic outlook for the Entergy region of Arkansas remains healthy.
  - At the time of the IRP load forecast, the 10 year (2014-2024) CAGR for gross state product was 1.8%.
  - The current 10 year CAGR for this same period is 2.0%.

- According to the Federal Reserve, the state's leading index* for May shows expected growth from 0 - 1.5%. For reference, the leading indices for Oklahoma and Louisiana are negative.

- Federal energy efficiency standards – particularly concerning lighting, refrigeration, and furnaces – will continue to put downward pressure on usage per customer, primarily in the residential and commercial sectors.

- The success of EAI's energy efficiency programs is expected to continue which will further dampen peak demand.

** Measure of non-farm payroll, unemployment, wages, and average hours worked in manufacturing; Published by the Philadelphia Fed*

Questions / Comments

Preliminary Results and Next Steps

The 2015 Integrated Resource Plan

The study period for the 2015 IRP is the 20-year period of 2017 through 2036. A 20-year study period was chosen in order for EAI to evaluate long-term trends under a broad range of possible future outcomes.

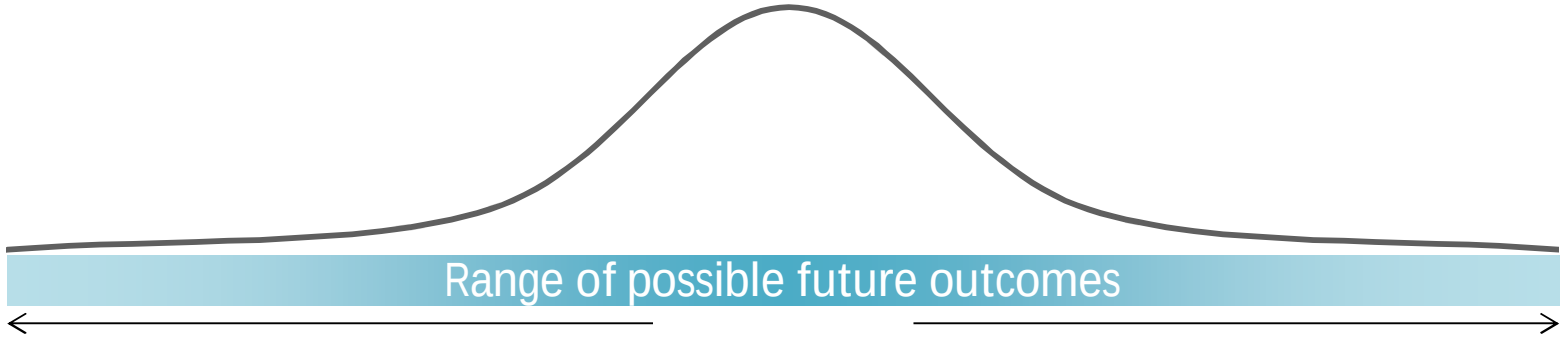
The 2015 IRP will be guided by a set of resource planning objectives EAI originally established to guide its development of its 2012 IRP and to meet the requirements of the APSC Resource Planning Guidelines for Electric Utilities[1]. The planning objectives focus on four key areas:

- cost,
- risk,
- reliability and
- sustainability.

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

Broad Range of Uncertainties

EAI is currently facing a broad range of uncertainties that impact resource planning. Some possible combinations of future outcomes will drive a higher need for additional generating resources and some will driver a lower need. The IRP reasonably bookends this range of possible outcomes.

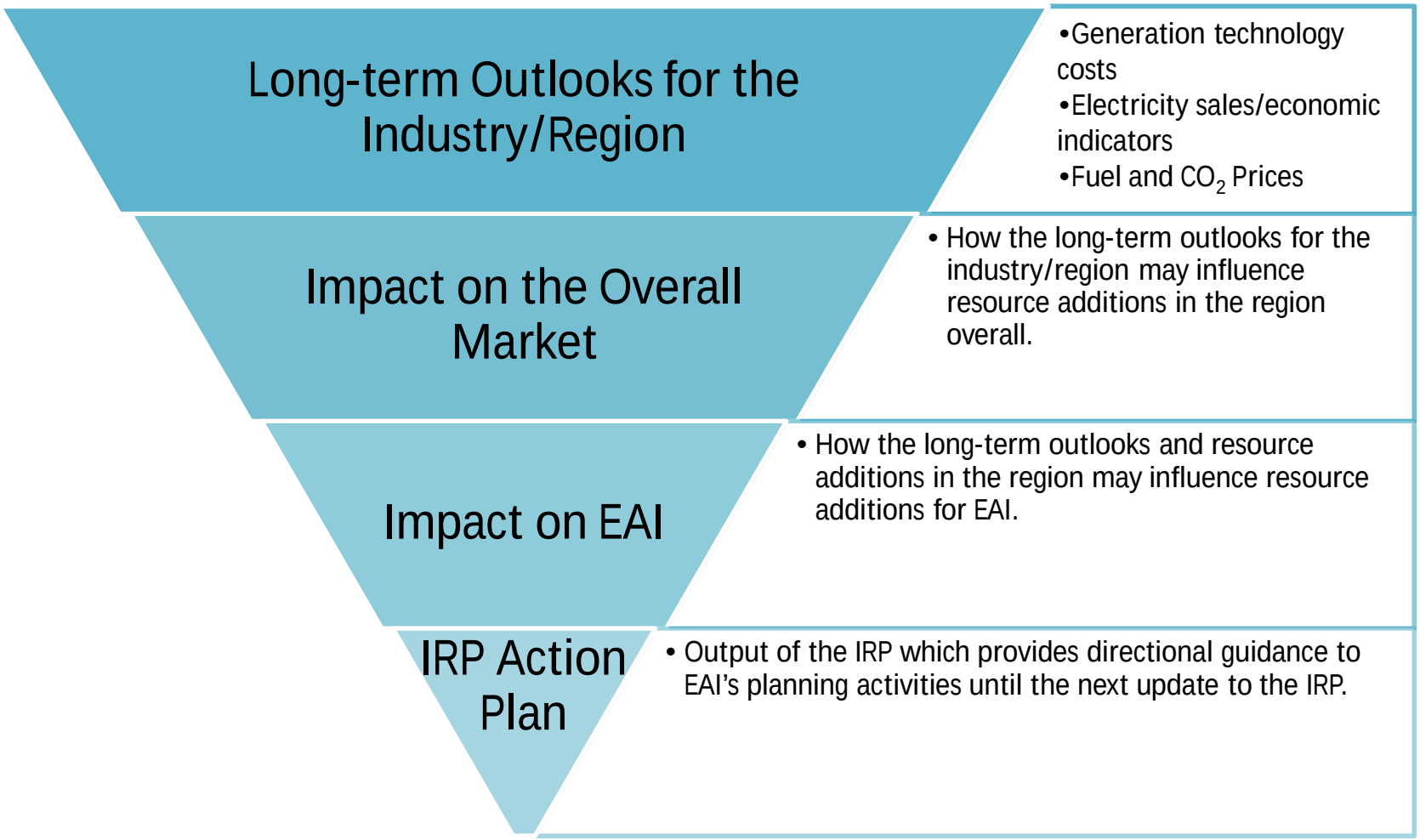


Low sales growth
Low fuel prices
No CO_2 price
Extended availability of existing units

Expected Case

High sales growth
High fuel prices
High CO_2 price
Reduced availability of existing units

Development of the IRP



Futures-based Approach

For the IRP to reasonably account for a broad range of uncertainty while focusing on an appropriate amount of meaningful, thoughtful modeling iterations, EAI Resource Planning is using a futures-based approach to the IRP analysis.

In this approach, three “futures” were developed that represent different combinations of possible outcomes of many variables.

Major areas of uncertainty to consider:

- Sales and load growth,
- Commodity price trends,
- Environmental regulation and/or legislation.

Future 1 – Reference Case

Future 1 represents EAI's Reference Case, or mid-point, of the range of uncertainties.

White Bluff and Independence	- Assume the currently proposed Regional Haze FIP - Install scrubbers in 2021 - Continue to use coal through end of 60-year useful life
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	Reference Case
Henry Hub Natural Gas Price Forecast*	$4.89/MMBtu
Coal Price Forecast*	$2.46/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast*	$10.02/short ton; pricing begins in 2020

*2015$, levelized for the period 2017-36

Future 2 – Low Capacity Additions Case

Future 2 represents EAI's Low Capacity Additions Case, which bookends the lower end of the range of uncertainties in terms of assumptions that would drive the least amount of incremental capacity needs.

White Bluff and Independence	- Assume the currently proposed Regional Haze FIP - Install scrubbers in 2021 - Continue to use coal through end of 60-year useful life
CCGT Units	Assume CCGTs are available and operating through the end of the IRP study period
Electric Sales & Load Forecasts	Low Case
Henry Hub Natural Gas Price Forecast*	$3.50/MMBtu
Coal Price Forecast*	$2.20/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast*	No price for CO_2 throughout IRP study period

*2015$, levelized for the period 2017-36

Future 3 – High Capacity Additions Case

Future 3 represents EAI's High Capacity Additions Case, which bookends the higher end of the range of uncertainties in terms of assumptions that would drive the highest amount of incremental capacity needs.

White Bluff and Independence	- Approval of plan to cease using coal at White Bluff by a time certain (2028) that makes scrubber installation economically unsupportable under federal air regulations, and thus not required. - Final FIP does not require Independence scrubber installation; assumption that similar controls are required in later Regional Haze planning period (2028-38)
CCGT Units	Assume 30-year useful life
Electric Sales & Load Forecasts	High Case
Henry Hub Natural Gas Price Forecast*	$7.68/MMBtu
Coal Price Forecast*	$3.67/MMBtu (volume weighted average for EAI units)
CO_2 Price Forecast*	$29.68/short ton; pricing begins in 2020

*2015$, levelized for the period 2017-36

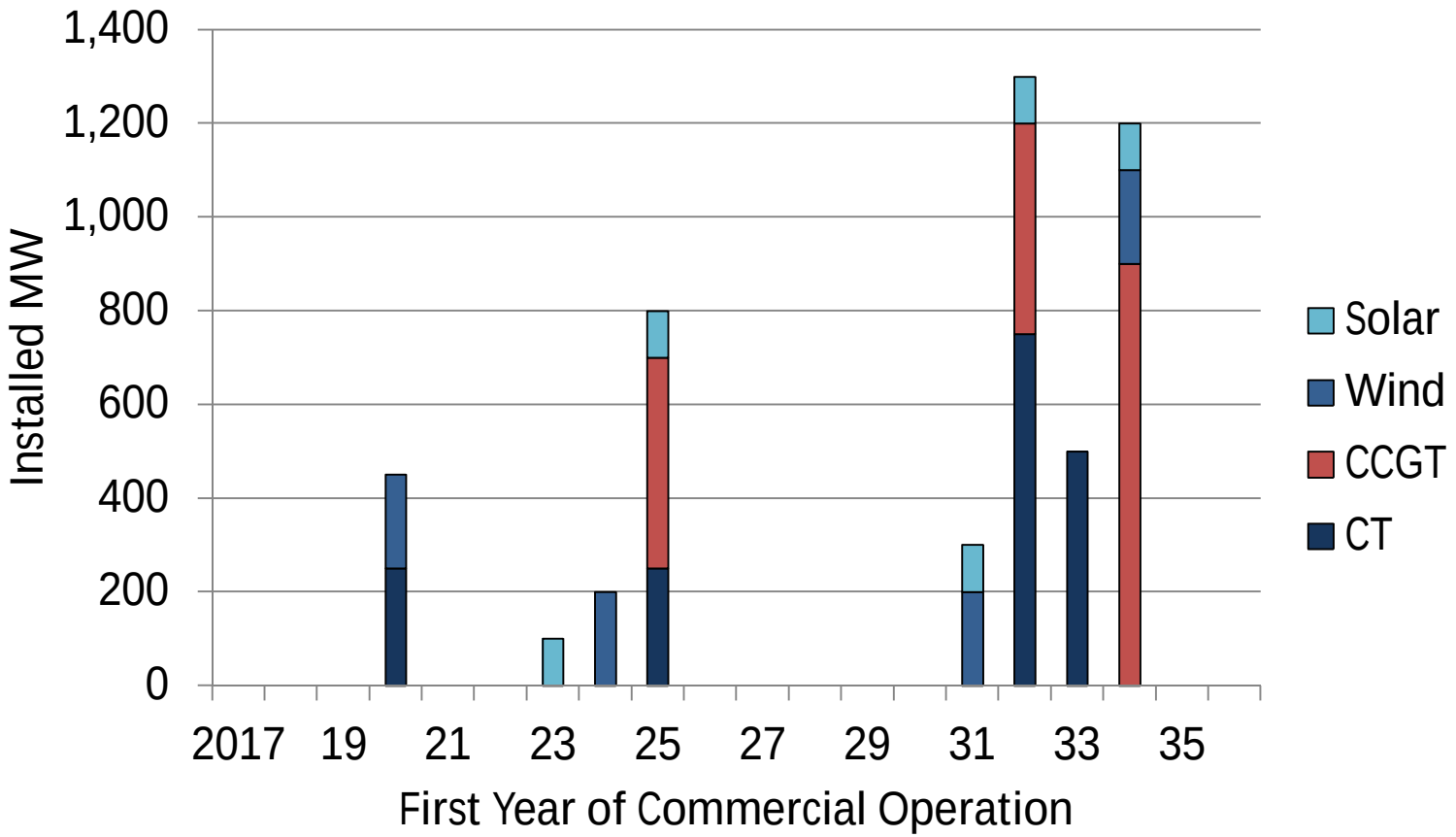
AURORA Portfolio Optimization

For each future, the AURORA Portfolio Optimization tool will select (i.e., output) a 20-year resource portfolio that is economically optimal for EAI under that set of circumstances.

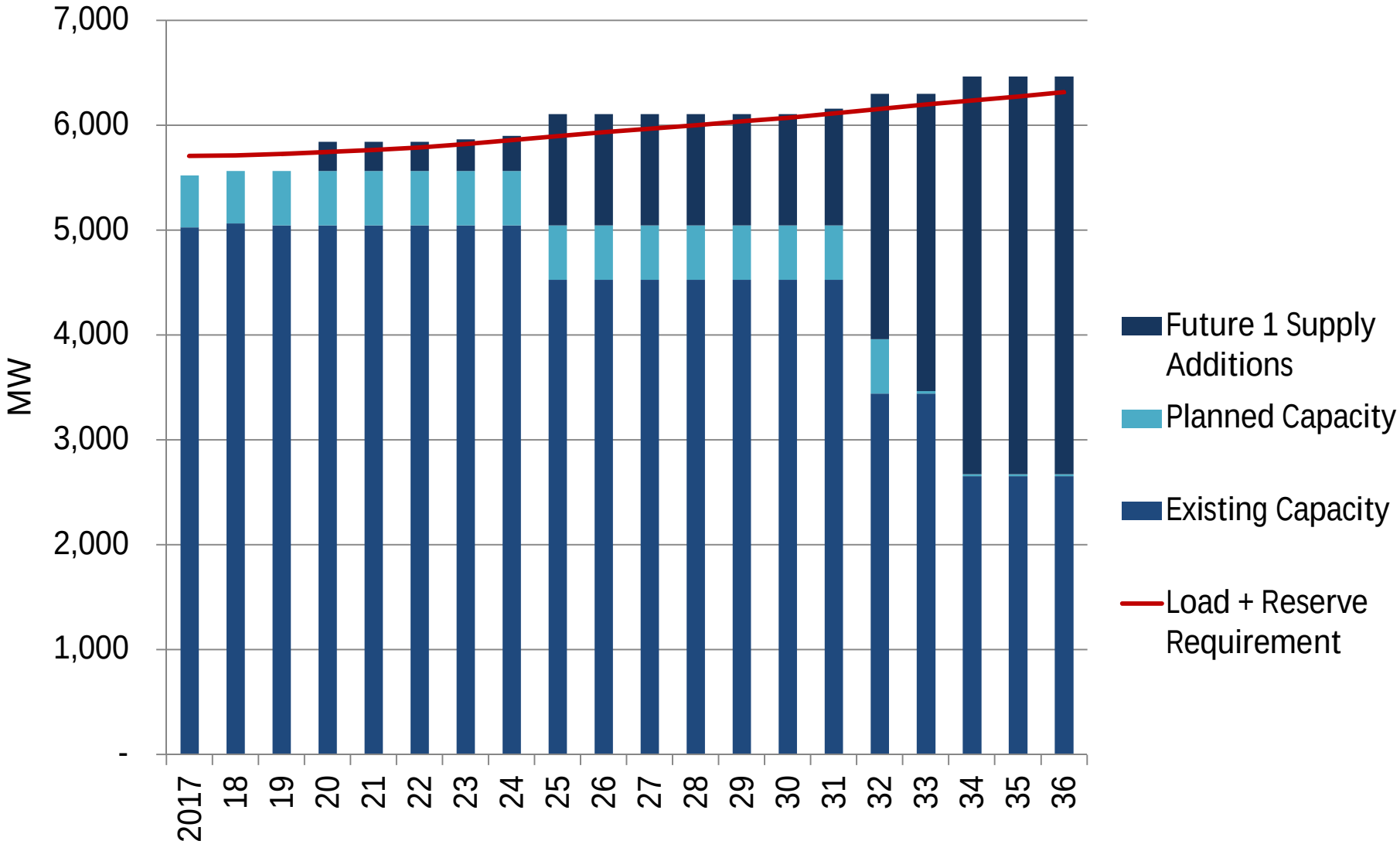
The model adds incremental generating resources whenever needed in order to maintain the target reserve margin (12% of EAI peak load). The model selects the resource alternative that is most valuable in the market.

The following slides show the incremental supply additions select by the AURORA Portfolio Optimization tool as well as the Load and Capability for each future. The model results show installed capacity and the Load and Capability shows effective capacity. The effective capacity is 25% for solar resources, 14.7% for wind resources and 100% for CT and CCGT resources.

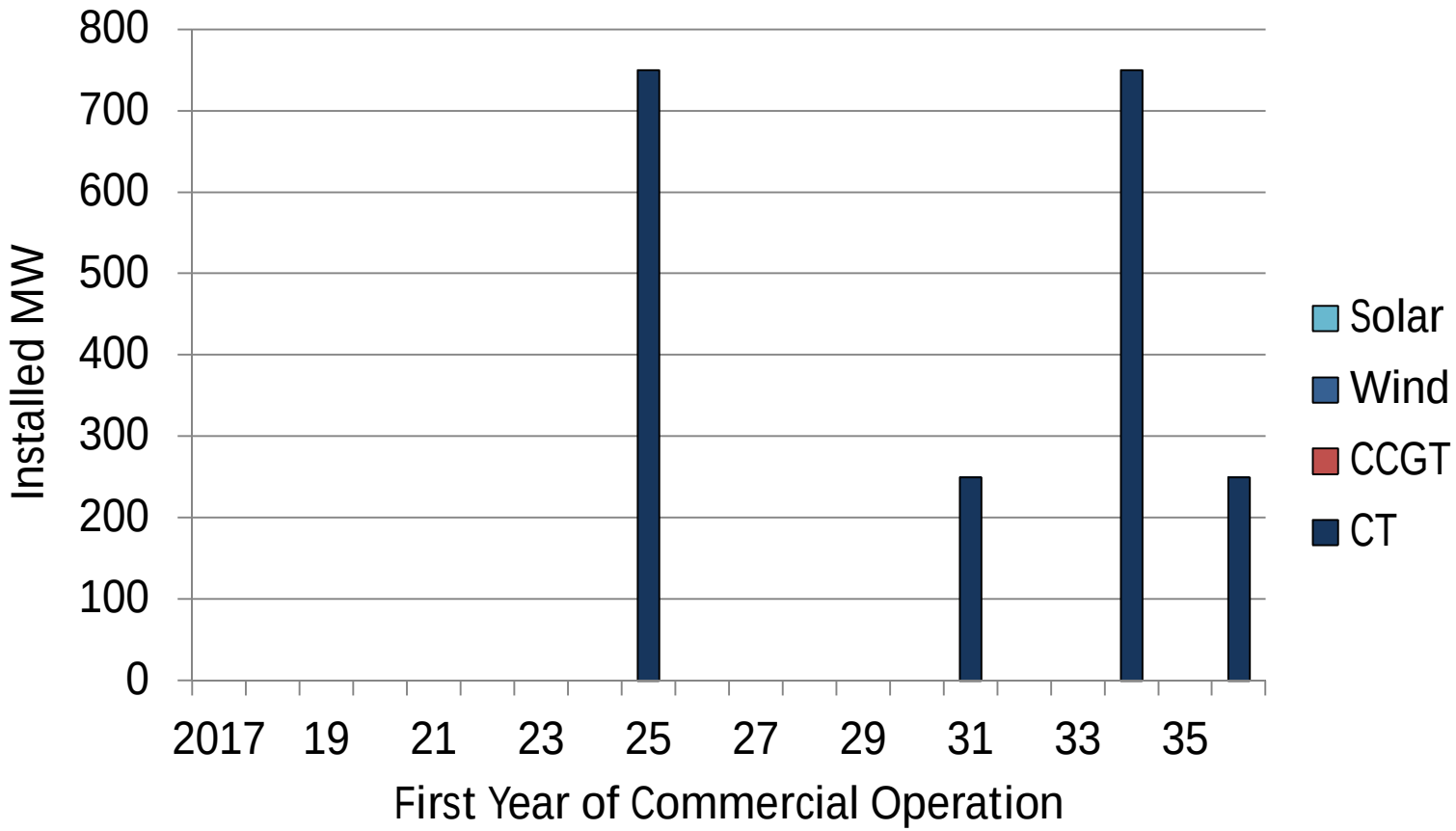
Future 1 – Portfolio Optimization Model Results



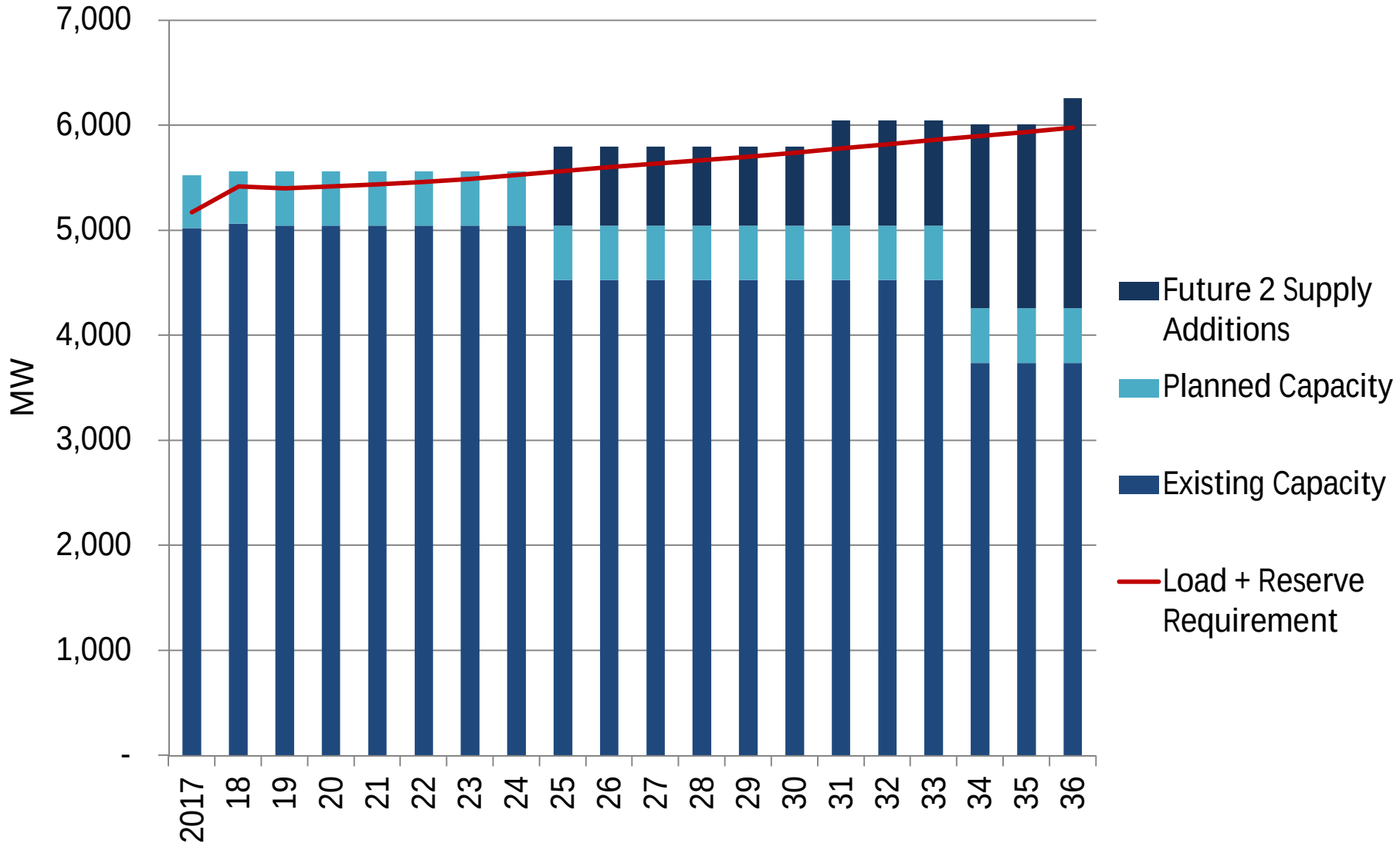
Future 1 – Load & Capability Position



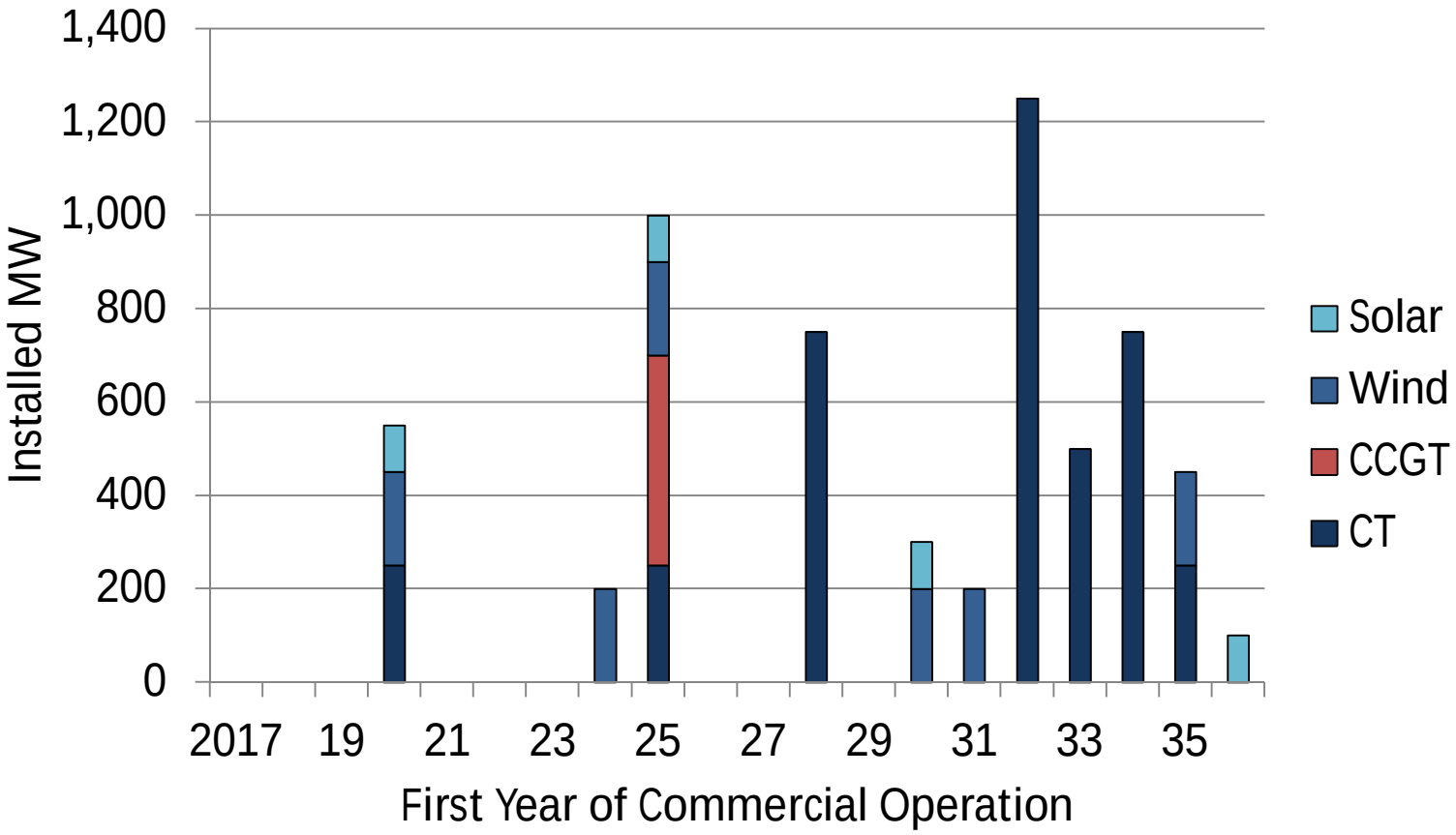
Future 2 – Portfolio Optimization Model Results



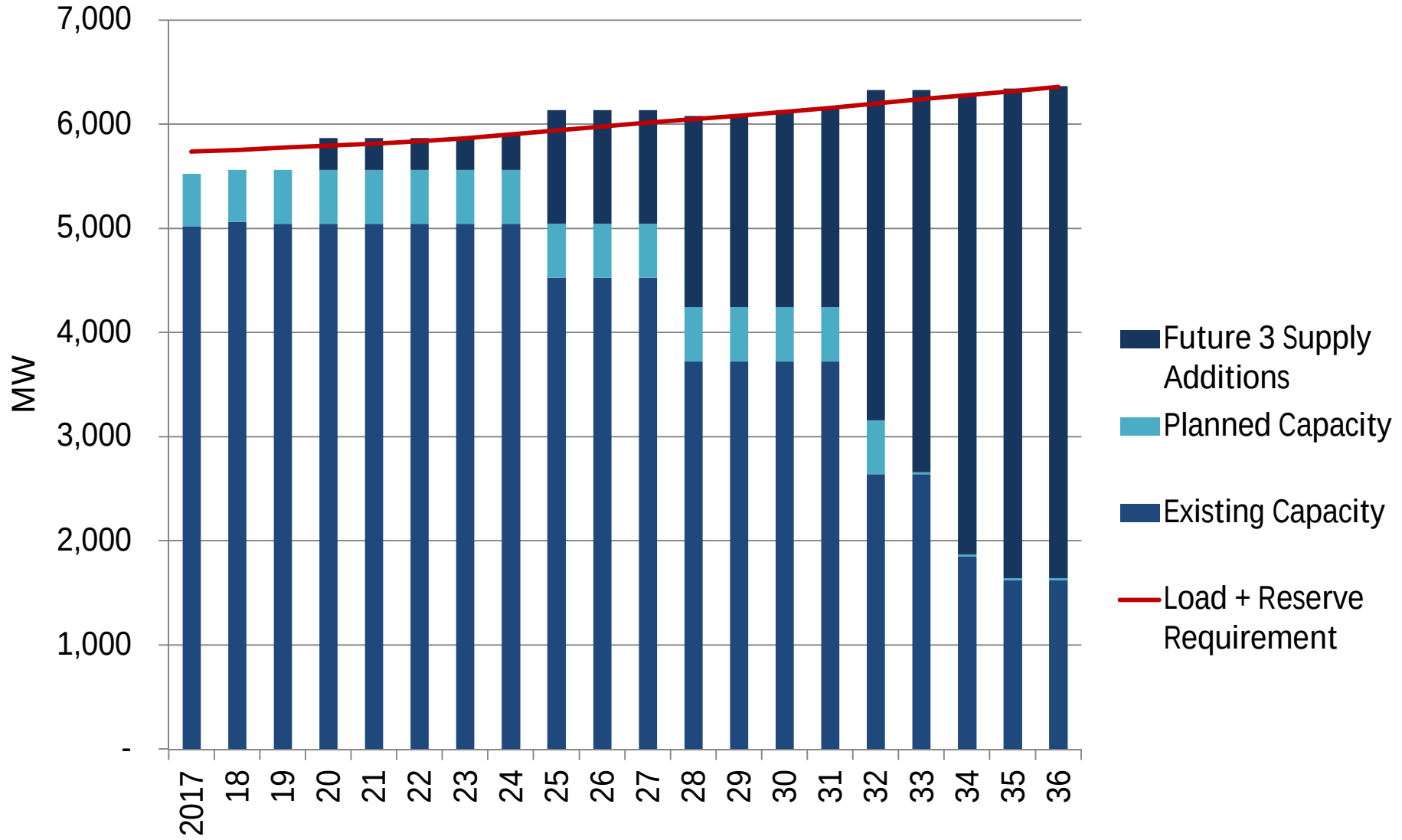
Future 2 – Load & Capability Position



Future 3 – Portfolio Optimization Model Results



Future 3 – Load & Capability Position



Summary of Model Results

While facing a broad range of uncertainty, the EAI IRP analysis reasonably bookends the future and provides a set of data points for EAI Resource Planning to evaluate.

Observations of long-term trends within and between the futures will guide the development of EAI's 2015 IRP Action Plan which will outline actions for the next one to three years.

2017-36	Future 1	Future 2	Future 3
Total Incremental Installed Capacity	4,850 MW	2,000 MW	6,050 MW
CT/CCGT Capacity Additions	73.2%	100%	73.6%
Renewable Capacity Additions	26.8%	0%	26.4%
Incremental Capacity Additions Begin	2020	2025	2020
Load + Reserve Requirements in First Year of Capacity Addition	5,743 MW (2020)	5,564 MW (2025)	5,793 MW (2020)

Next Steps in IRP Development

- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

After Lunch: Stakeholder Session

Stakeholder Process

After lunch, stakeholders will reconvene in the meeting room. Once the stakeholder group has completed their discussions, they'll notify the Entergy group to return to the meeting room.

We'll discuss next steps and answer any remaining questions before adjournment.

Questions / Comments

Wrap-up and Next Steps

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

August 14, 2015
Follow-up Material to 2015 IRP Stakeholder Meeting

Follow-up Materials to the 2015 IRP Stakeholder Meeting

The following information is provided as a supplement to the information provided during the August 7th Stakeholder Meeting in response to stakeholder questions and feedback from that meeting.

Any additional requests for information may be sent to EAI at EAIIRP@entergy.com.

Lifecycle Resource Cost for 2015 Resources

Levelized $2015/MWh; based on 2015 installation

Based on EAI Cost of Capital [1]		No CO_2			With CO_2 [2]		
Technology	Capacity Factor	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
G Frame CT	10%	$153	$195	$137	$160	$201	$143
Large Aeroderivative CT	40%	$97	$137	$82	$103	$142	$87
Internal Combustion	40%	$104	$141	$90	$110	$146	$95
1x1 G Frame CCGT	65%	$66	$94	$54	$70	$99	$58
2x1 G Frame CCGT	65%	$61	$89	$49	$65	$94	$53
PC With CCS	85%	$150	$219	$99	$153	$222	$101
Biomass	85%	$167	$316	$133	$167	$316	$133
Nuclear	90%	$134	$146	$134	$134	$146	$134
Wind (No Subsidy)	48%[3]	$54	$54	$54	$54	$54	$54
Solar PV (30% ITC)	26%	$75	$75	$75	$75	$75	$75

1. Includes capacity Levelized Nominal Lifecycle Cost of Resources Deployed in 2015, $/MWh. Lifecycle cost is based on assumed capacity factors for screening purposes. Projected capacity factors calculated by the Aurora production cost model may result in different lifecycle resource costs.
2. CO_2 emissions cost based on IRP reference case; begins in 2020 at $1.39/U.S. ton nominal $, reaches $32.10/ton in 2035
3. Capacity factor representative of mid-west geographical region

Sales & Load Forecasts

- What was the growth from 2004-2014?
  - EAI's weather adjusted retail sales compound annual growth rate from 2004-2014 was 0.4%.

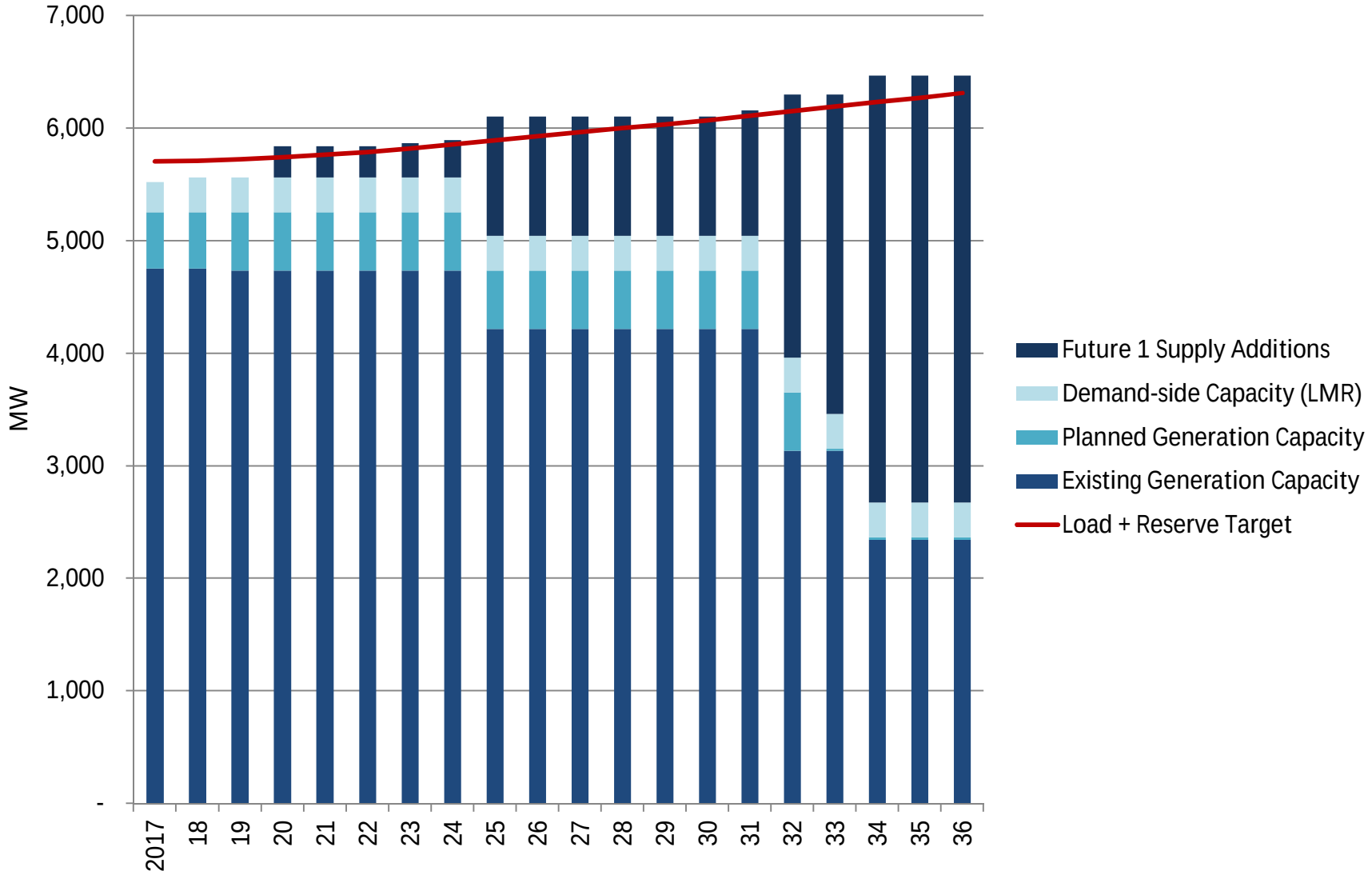
- What is the long term growth rate without the step increases in the load?
  - The 10 year CAGR for load from 2018-2028 for each of the scenarios is around 0.5%, with a slightly lower growth rate of around 0.45% for the low scenario. There are no industrial step increases in the load beyond 2018.

Load & Capability Position

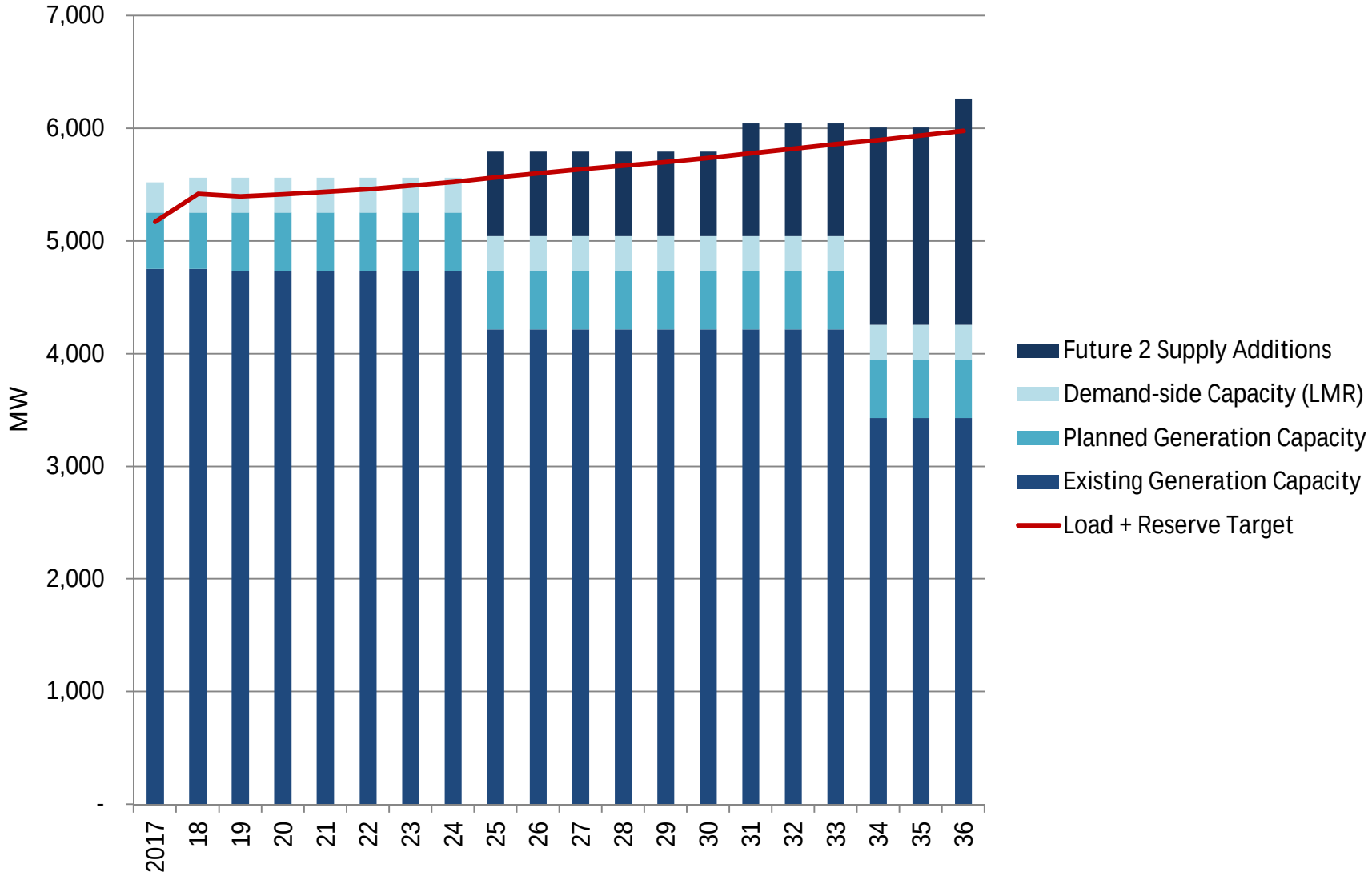
The following three slides show EAI's load plus reserves compared to capacity resources for each of the three IRP Futures. No values have changed from the August 7 presentation; however, the capacity value from EAI's demand side resources has been identified separately for clarification purposes.

The effective capacity is shown, which is 25% for solar resources, 14.7% for wind resources, based on the assumed capacity credit value from MISO, and 100% for CT, CCGT and demand-side capacity resources.

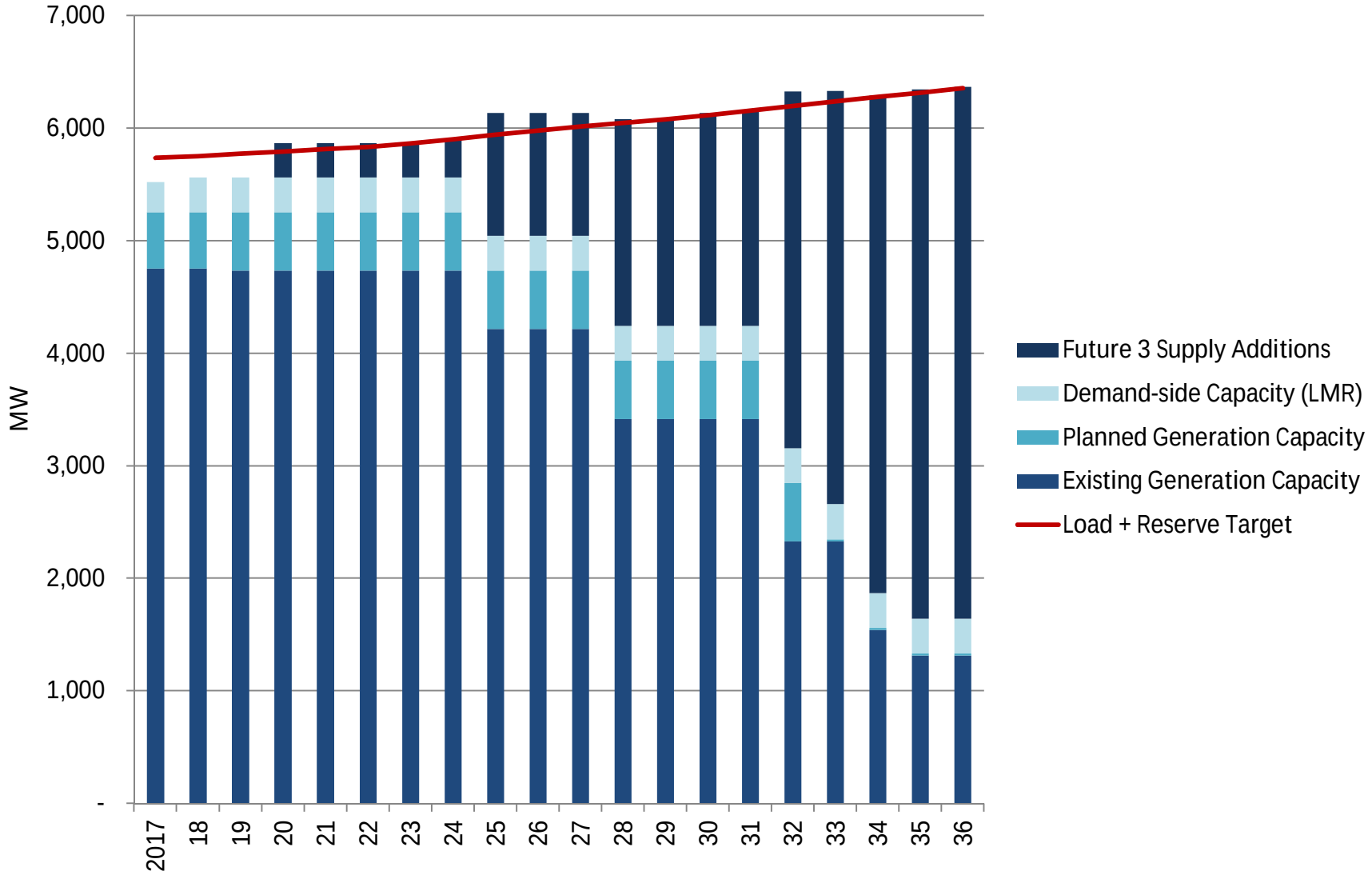
Future 1 – Load & Capability Position



Future 2 – Load & Capability Position



Future 3 – Load & Capability Position

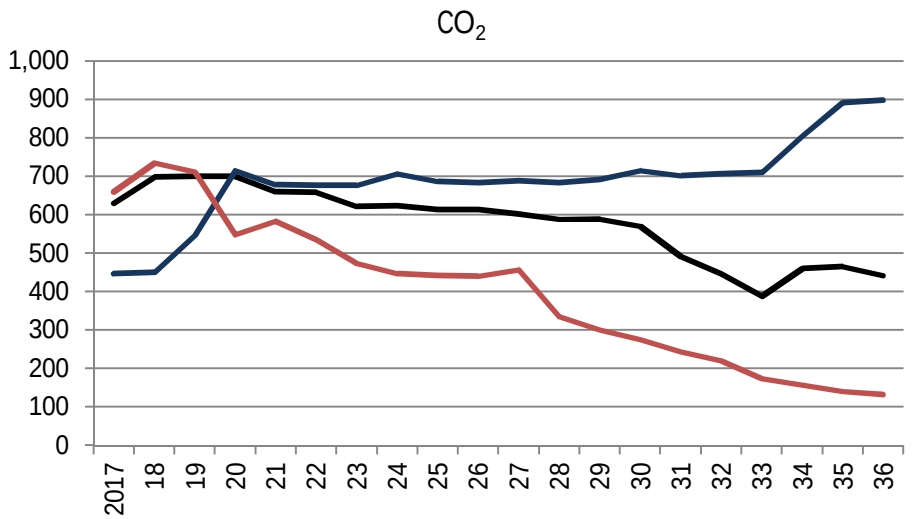


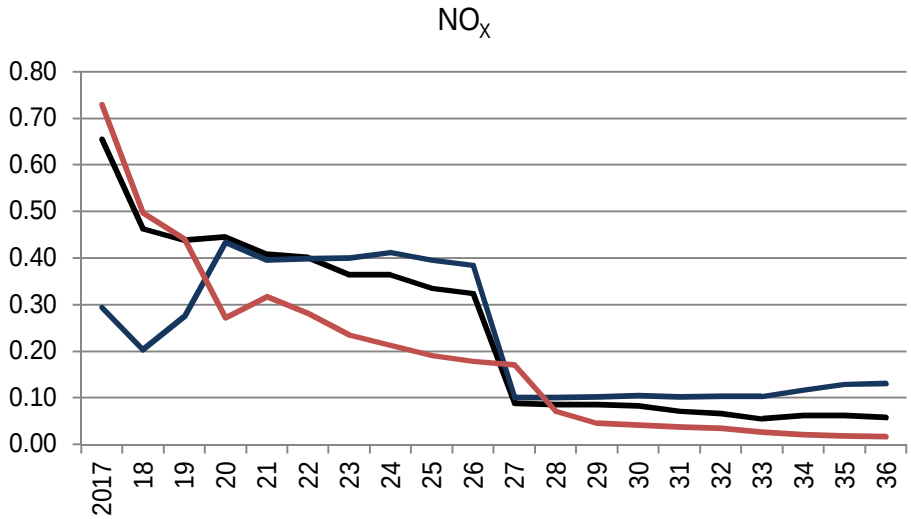
Annual Projected Emissions

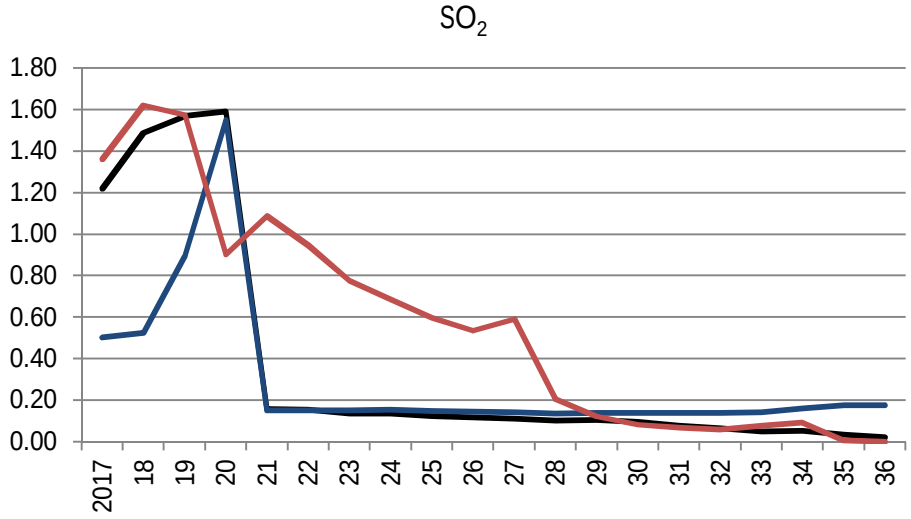
Based on modeled net generation, emissions rates (lb./MWh) have been calculated for each future. The rates are calculated as total emissions from EAI's existing and incremental resources divided by EAI's total existing and incremental generation.

Included in this calculation are all supply side resources including hydro and nuclear resources as well as EAI's resources located outside of Arkansas. No adjustment has been made for assumed demand side (EE) resources.

Future 1 Future 2 Future 3







Response to Written Questions

- Are the technology capacity factors a net or gross capacity factor?
  - The capacity factors (shown on slide 104) are net capacity factors.

Next Steps in IRP Development

- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

THE POWER OF PEOPLE®

Entergy Arkansas, Inc.
2015 Integrated Resource Plan

September 3, 2015
Response to Stakeholder Group's Meeting Notes

EAI Response to Stakeholder Group

EAI received meeting notes on 8/13/2015 from Ken Smith on behalf of the Stakeholder Group. The notes, compiled by Jim Wimberly, included requests for additional information and analysis.

The following slides are EAI's response to the Stakeholder Group's requests.

Item #1

1. Organizational
   - Kurt Castleberry replied to Ken Smith's email offering to arrange meeting rooms and make EAI folks available to participate in meetings, as needed, with reasonable notice.
   - Stakeholder Report will be completed by October 15.

EAI Response: Item #2 (1 of 3)

2. Alternate future generation scenarios requested by the SG
   - An additional AURORA Portfolio Optimization model run has been completed in response to the SG's request for the future supply additions assuming White Bluff and Independence cease to use coal in 2028. The assumptions for this new model run and preliminary results are shown on the following slides.
   - The SG's request for the future supply additions assuming White Bluff and Independence are fully operational and all CCGT plants are extended is the same as Future 2 as presented at the 8/7/15 IRP Stakeholder Meeting with one difference. The difference is that it would assume no scrubber installations at White Bluff and Independence. This difference would not affect the supply additions.

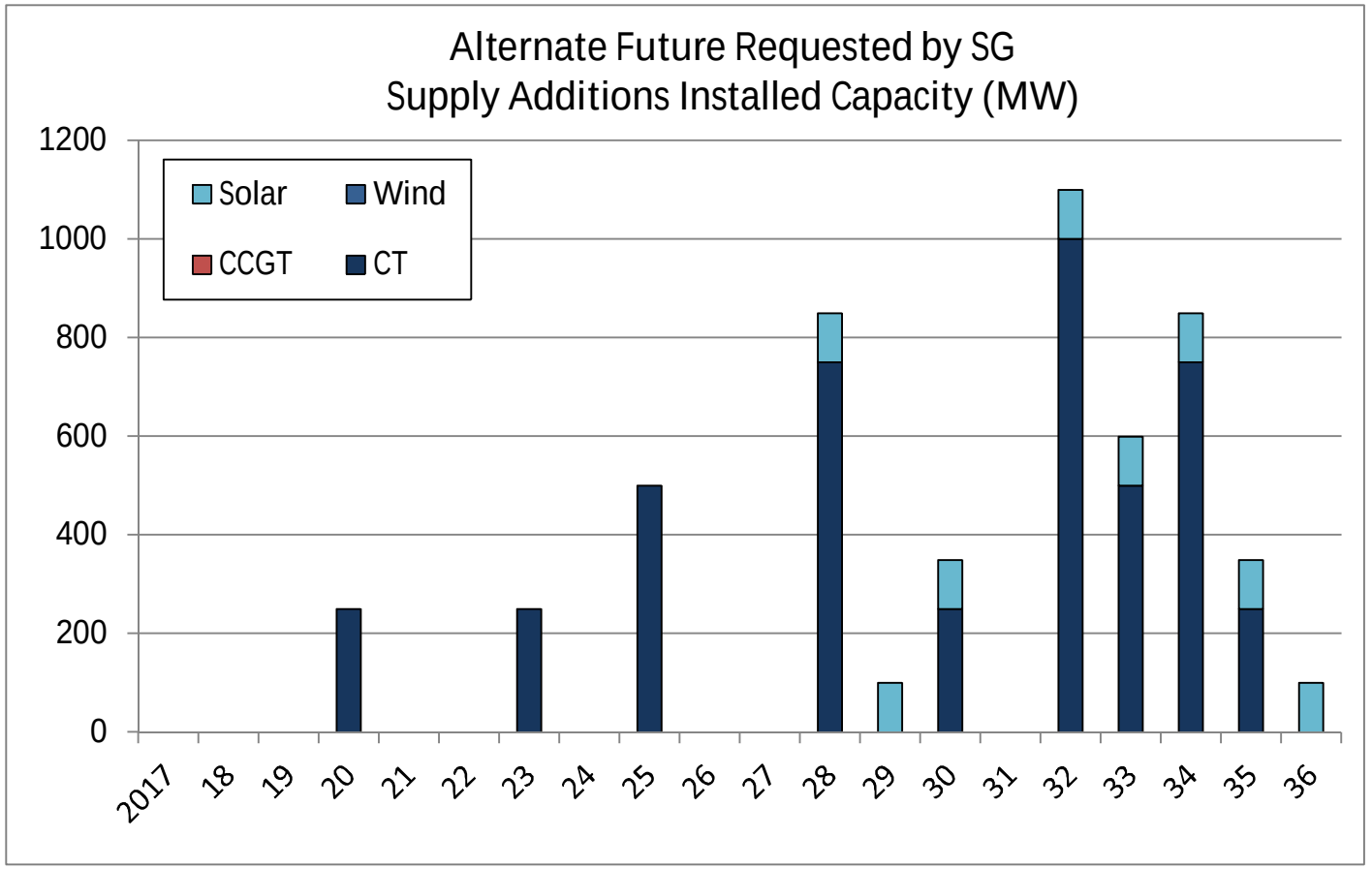
EAI Response: Item #2 (2 of 3)

The alternate future requested by the SG assumes White Bluff ceases to use coal in 2028 and Independence in 2035. EAI is not aware of a potential future outcome that would require Independence cease to use coal or shut down in 2028.

The SG request to vary the cost for solar resources (item #5) is also included in this model run at a 2015 installed cost of $1,400/kW, as opposed to EAI's current long-term point-of-view, which is $2,300/kW.

	Alternate Future
Existing Resource Portfolio	
Cease to Use Coal at White Bluff	2028
Cease to Use Coal at Independence	2035
EAI Existing CCGTs	30 years
Solar Technology Cost	$1,400/kW
Customer Electricity Requirements	
Energy sales and Load	Reference
Commodity Price Forecasts	
Fuel Prices	Reference
Environmental Allowances	Reference

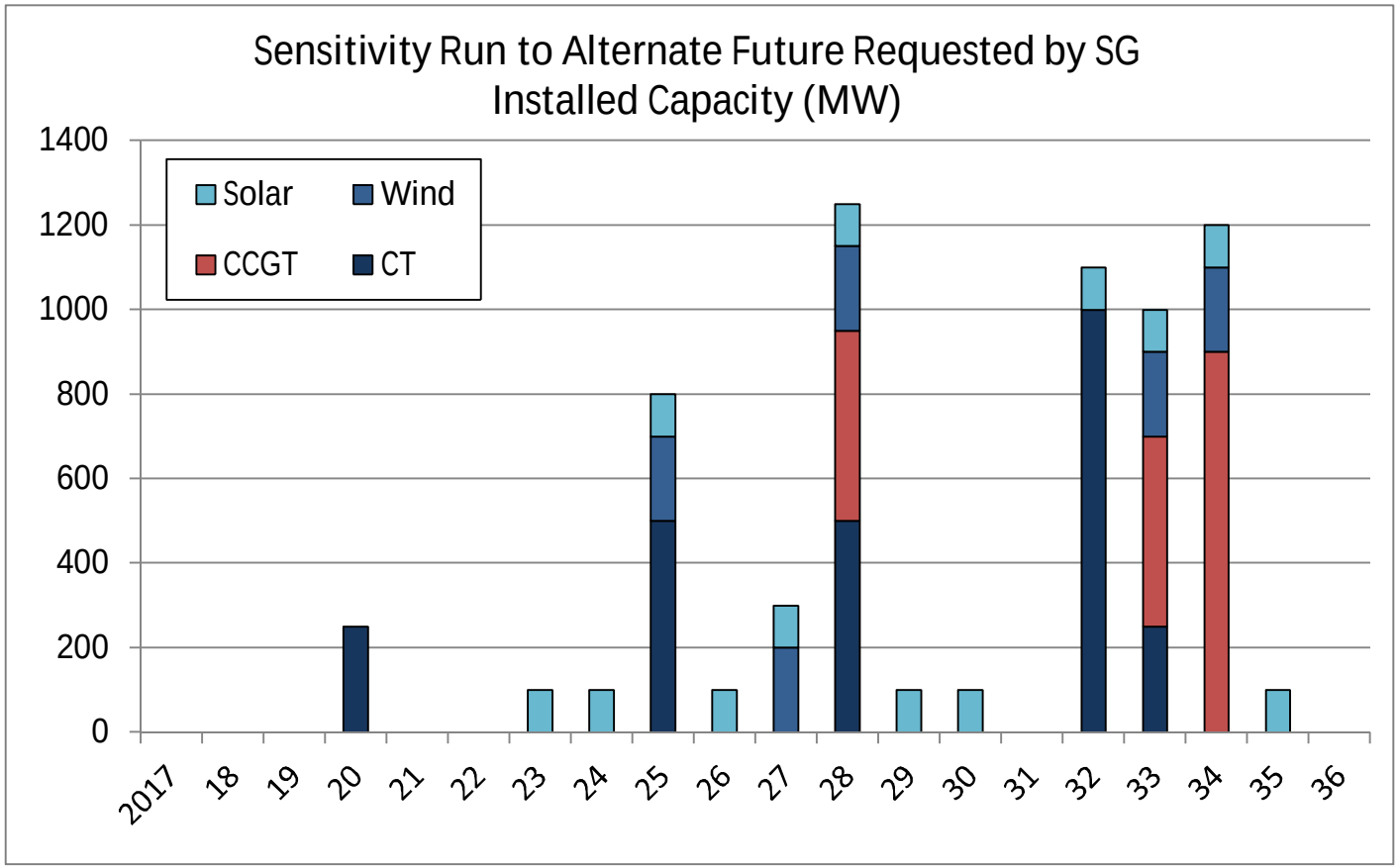
EAI Response: Item #2 (3 of 3)



EAI Response: Item #2 Additional Analysis (1 of 2)

- After observing that the Portfolio Optimization model run for the Alternate Future selected eight solar resources, a sensitivity run was completed in which we forced the model to select an additional four solar resources, for a total of twelve solar resources. The rest of the portfolio was optimized by the model.
- The composition of the sensitivity case portfolio is different from the fully optimized portfolio resulting from the initial model run, but the total effective capacity and costs are very close.
- The results of the additional model run is shown on the following slide.

EAI Response: Item #2 Additional Analysis (2 of 2)



EAI Response: Items #3 and #4

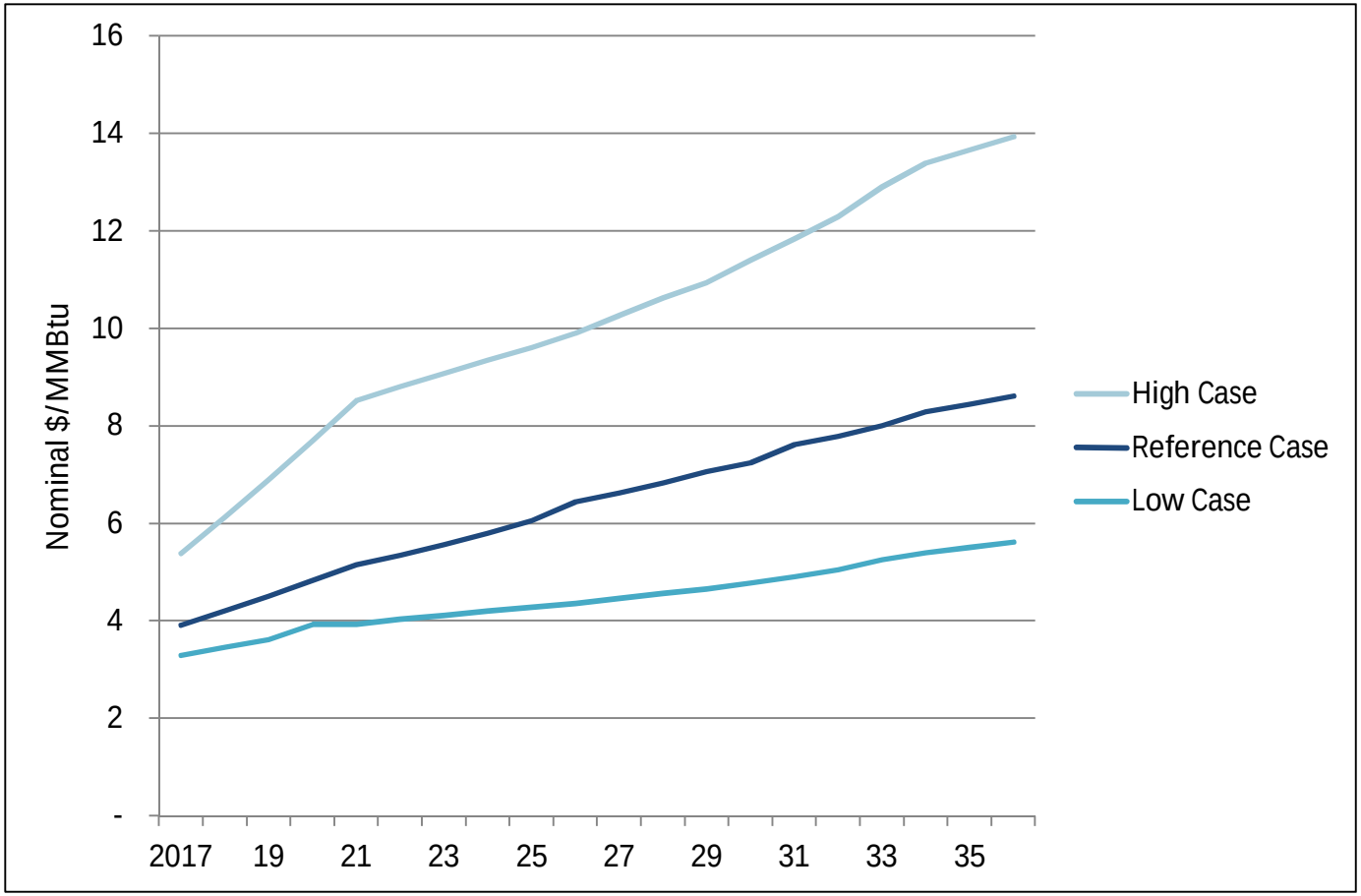
3. Graphic Outputs
   - See slides 5 through 9 of the "Follow Up to Aug 7 IRP Stakeholder Mtg.pptx" posted to EAI's IRP Website on 8/14/2015 or slides 107 through 109 of this document.

4. Life Cycle Costs
   - See slide 3 of the "Follow Up to Aug 7 IRP Stakeholder Mtg.pptx" posted to EAI's IRP Website on 8/14/2015 or slide 104 of this document.

EAI Response: Item #5 (1 of 3)

5. Sensitivity analyses on energy costs
   - The requested additional AURORA Portfolio Optimization model run described on slides 116-117 of this document considers a lower installed cost assumption for new solar resources.
   - The SG refers to SWEPCO's IRP for cost of wind power, which appears to be reasonably aligned with EAI's point-of-view on wind costs for long-term resource planning. EAI's assumption of $54/MWh for a 48% capacity factor is in-line with SWEPCO's assumptions which range from $47-$60/MWh at a 45%-56% capacity factor.
   - Additional information on the natural gas and carbon price assumptions used in EAI's IRP analysis, which cover a reasonably broad range of outcomes, are shown on the following slides.

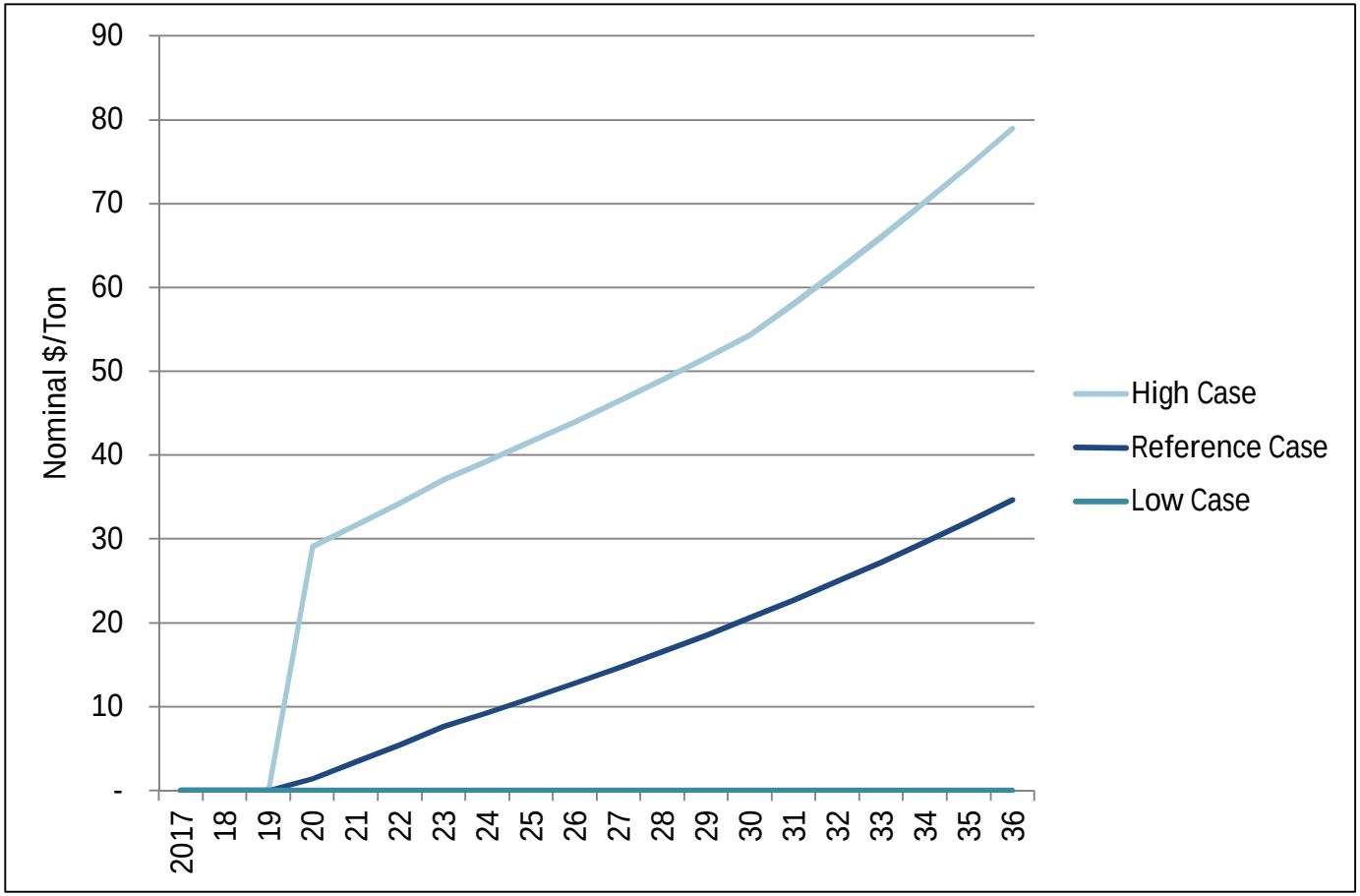
Item #5 (2 of 3)


Henry Hub Natural Gas Price
Reference Case (Future 1), Low Case (Future 2), High Case (Future 3)
Nominal $/MMBtu
16
14
12
10
8
6
4
2
-
2017
19
21
23
25
27
29
31
33
35
High Case
Reference Case
Low Case

Item #5 (3 of 3)

Carbon (CO_2) Price

Reference Case (Future 1), Low Case (Future 2), High Case (Future 3)



Next Steps in IRP Development

- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

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Entergy Arkansas, Inc.
2015 Integrated Resource Plan

September 16, 2015
Response to Stakeholder Group's Meeting Notes

EAI Response to Stakeholder Group

During the Stakeholder Group conference call that took place on 9/3/2015, EAI received new requests for documentation and additional analysis.

The following slides are EAI's response to the Stakeholder Group's requests.

Supplemental Documentation (1 of 3)

Q: What are the assumed capacities of incremental resources?

A: This information was originally presented by EAI at the August 7th Stakeholder Meeting in Little Rock and is available on slides 68-71 of that presentation. For reference, a summary of a few of resource types are summarized below. The model is limited to adding one each of solar and wind resources per year.

Technology Type	Net Max Capacity (MW)
Solar	100
Wind	200
CT	250
CCGT	450

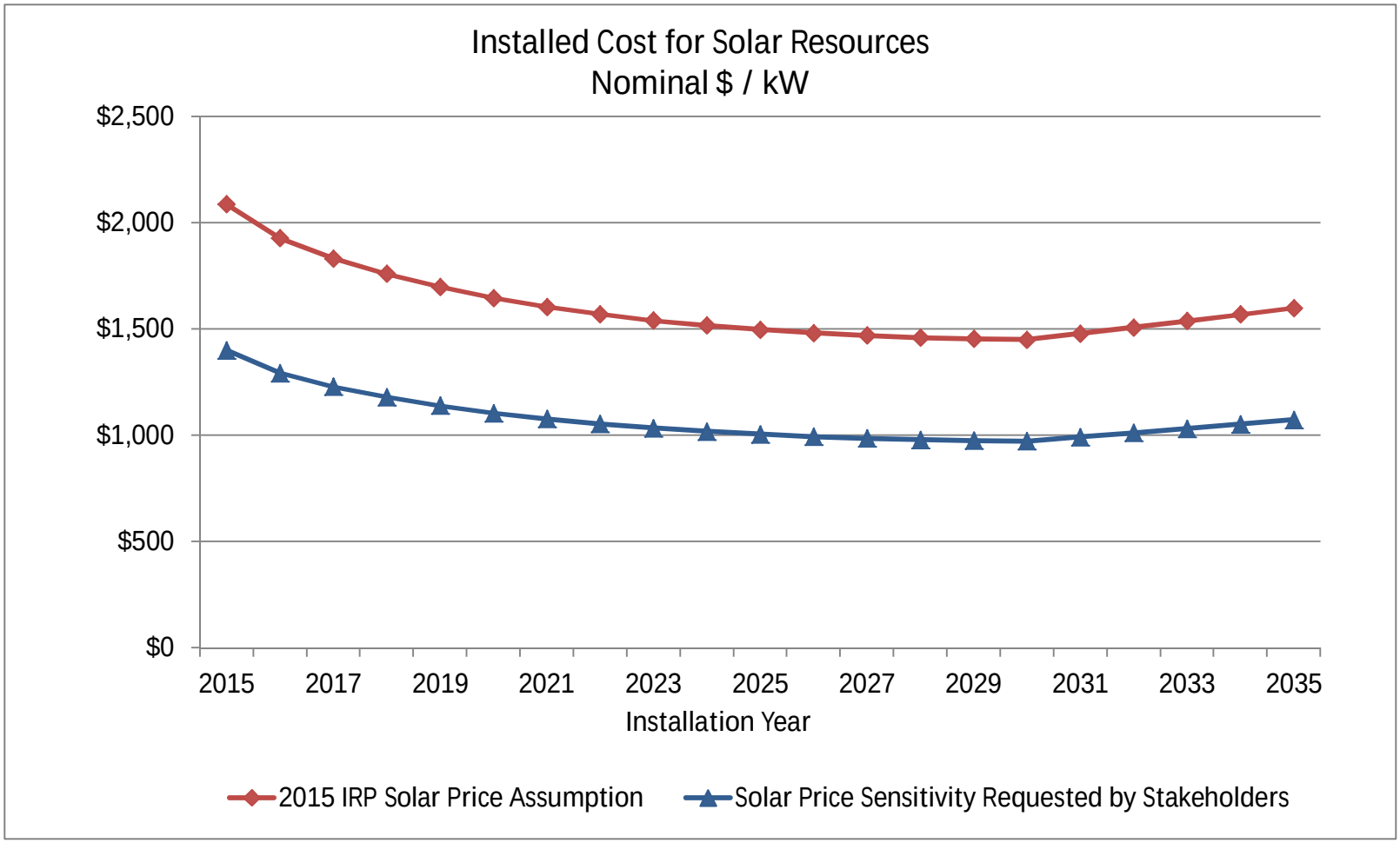
Supplemental Documentation (2 of 3)

Q: What is the forward price curve and LCOE for solar technology in the alternate future requested by stakeholders?

A: The following slide (#166) shows the forward price curve for both the $1,400/kW installed cost assumption that was used in the alternate future provided to the SG on Sept. 3 as well as the assumption used in EAI's 2015 IRP Futures 1-3.

Slide #167 shows the LCOE table provided to the SG on Aug. 14 amended to include additional line items for the solar and wind technologies assumptions used in the alternate futures modeled in response to SG's requests.

Solar Resource Forward Price Curve



Lifecycle Resource Cost for 2015 Resources

Levelized $2015/MWh; based on 2015 installation

Based on EAI Cost of Capital [1]		No CO_2			With CO_2 [2]		
Technology	Capacity Factor	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
G Frame CT	10%	$153	$195	$137	$160	$201	$143
Large Aeroderivative CT	40%	$97	$137	$82	$103	$142	$87
Internal Combustion	40%	$104	$141	$90	$110	$146	$95
1x1 G Frame CCGT	65%	$66	$94	$54	$70	$99	$58
2x1 G Frame CCGT	65%	$61	$89	$49	$65	$94	$53
PC With CCS	85%	$150	$219	$99	$153	$222	$101
Biomass	85%	$167	$316	$133	$167	$316	$133
Nuclear	90%	$134	$146	$134	$134	$146	$134
Wind (No Subsidy)	48%[3]	$54	$54	$54	$54	$54	$54
Solar PV (30% ITC)	26%	$75	$75	$75	$75	$75	$75
Stakeholder Group Solar PV (30% ITC)	26%	$49	$49	$49	$49	$49	$49
Stakeholder Group Wind (No Subsidy)	48%[3]	$47	$47	$47	$47	$47	$47

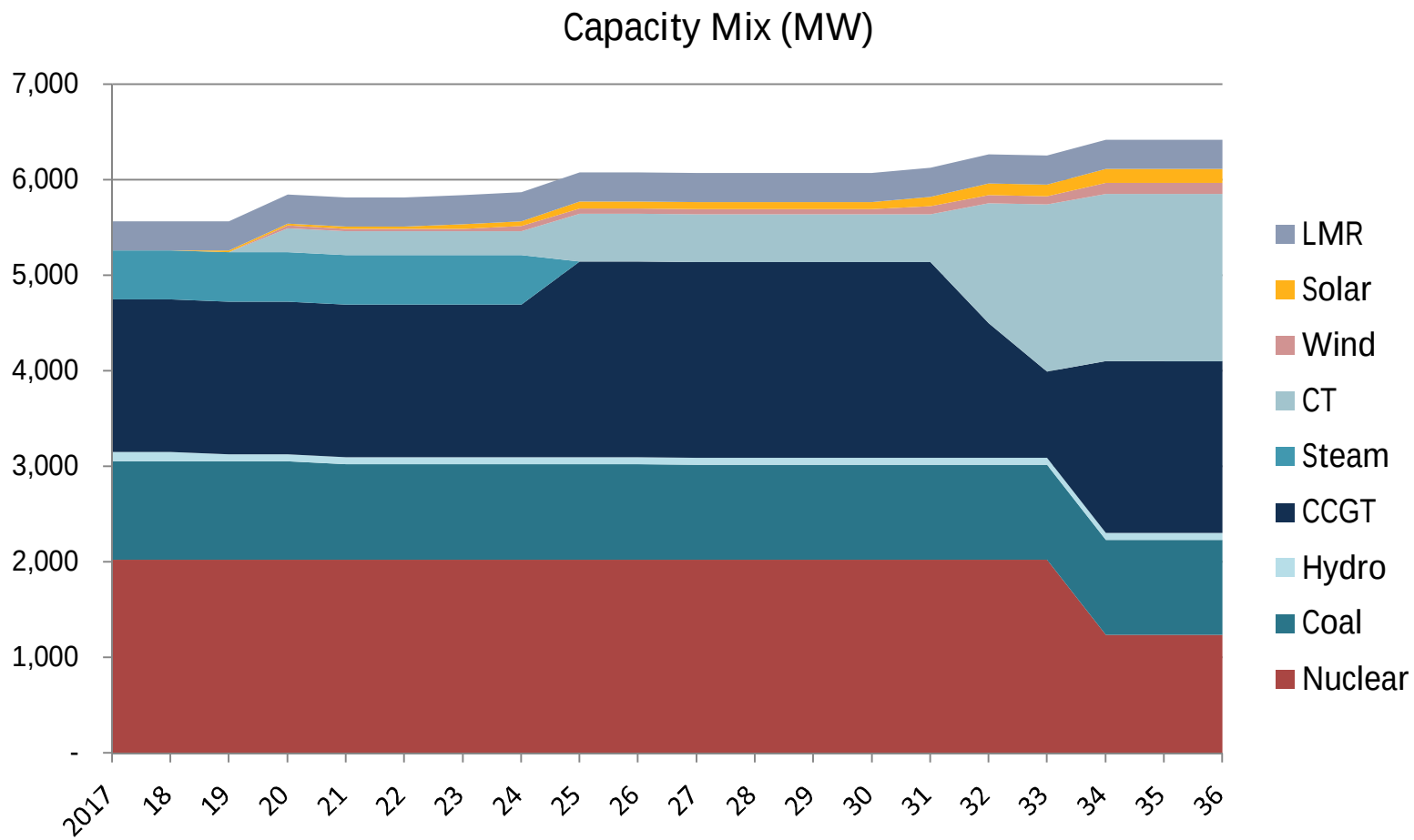
1. Includes capacity Levelized Nominal Lifecycle Cost of Resources Deployed in 2015, $/MWh. Lifecycle cost is based on assumed capacity factors for screening purposes. Projected capacity factors calculated by the Aurora production cost model may result in different lifecycle resource costs.
2. CO_2 emissions cost based on IRP reference case; begins in 2020 at $1.39/U.S. ton nominal $, reaches $32.10/ton in 2035
3. Capacity factor representative of mid-west geographical region

Supplemental Documentation (3 of 3)

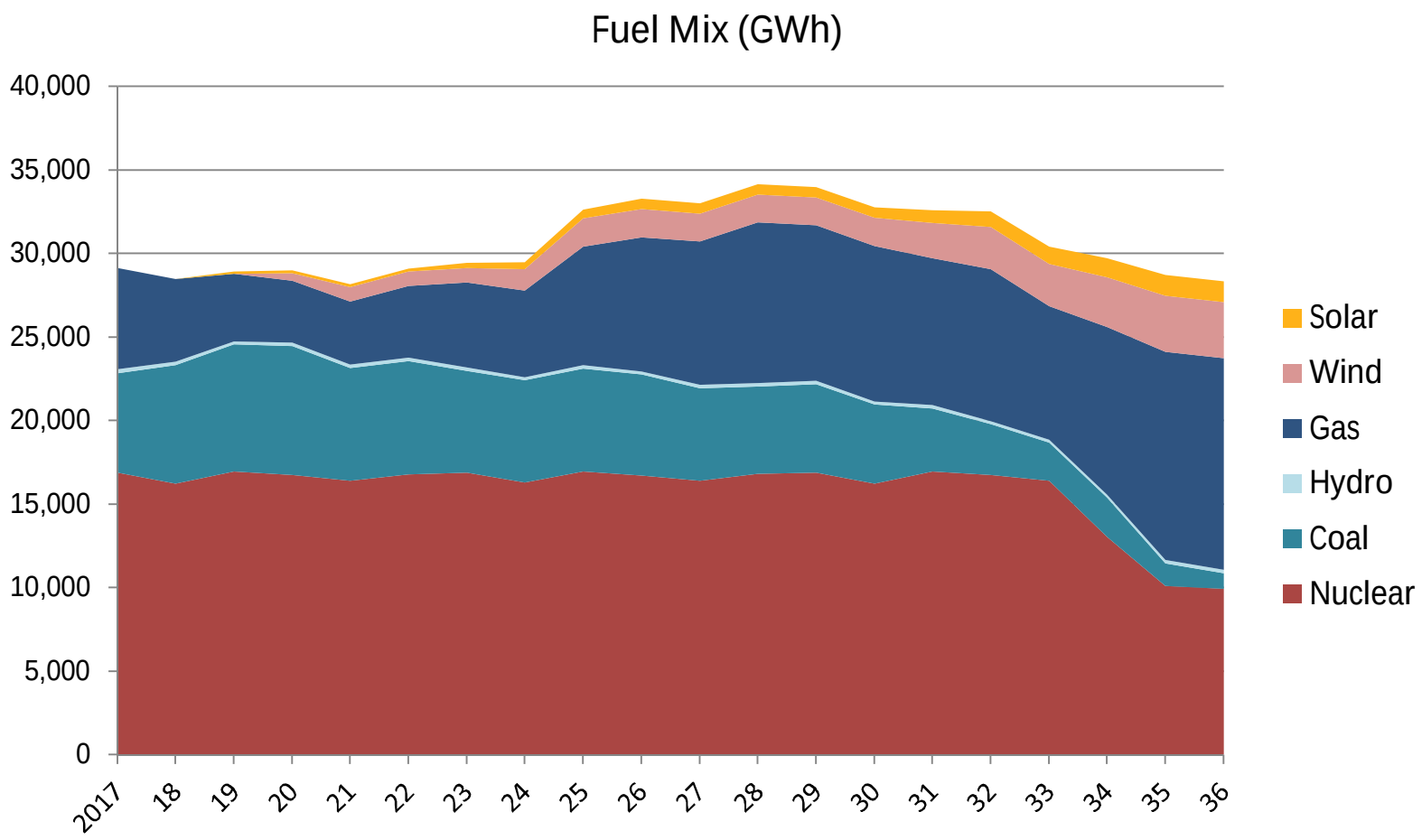
During the SG conference call that took place on Sept. 3, the SG requested that EAI provide charts showing the capacity and generation mix for each future. The following slides (#169-#174) show the mix of capacity (MW) and energy (GWh) from 2017 through 2036 for Futures 1, 2 and 3.

The fuel mix shown on the following slides includes energy used to serve native load and supply sales into the market.

Future 1 – Portfolio Diversity (Capacity)

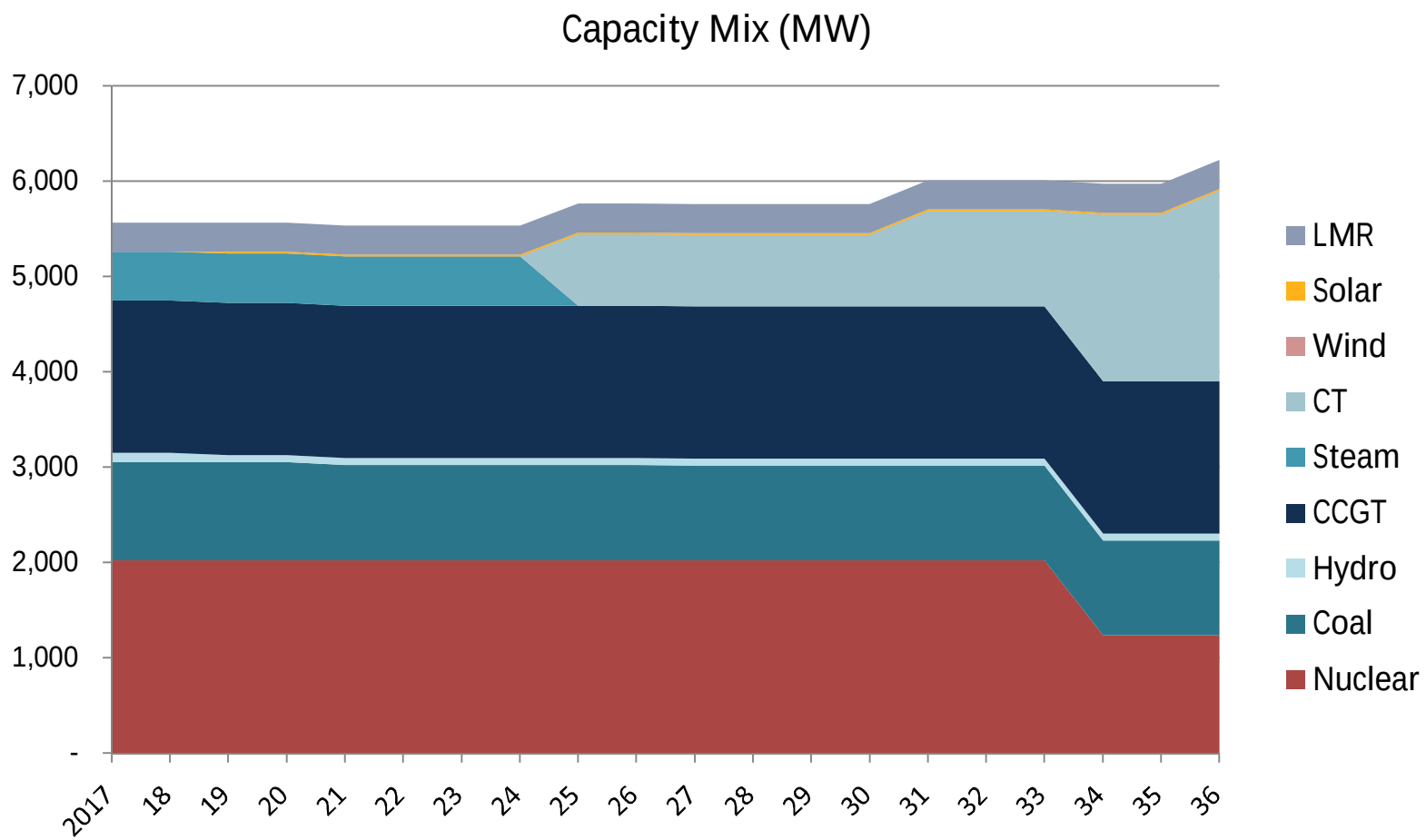


Future 1 – Portfolio Diversity (Energy)

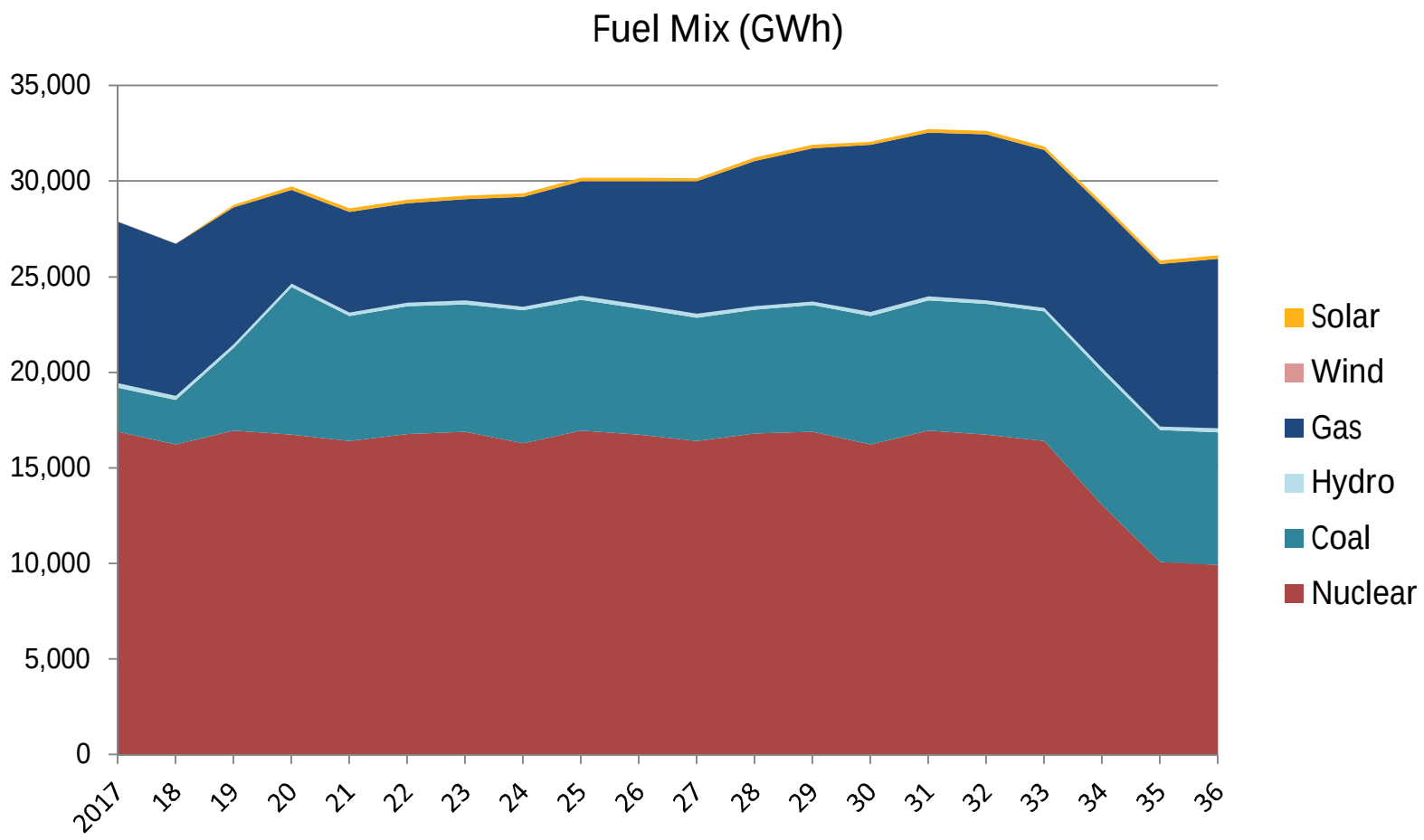


The fuel mix shown includes energy used to serve native load and supply sales into the market.

Future 2 – Portfolio Diversity (Capacity)

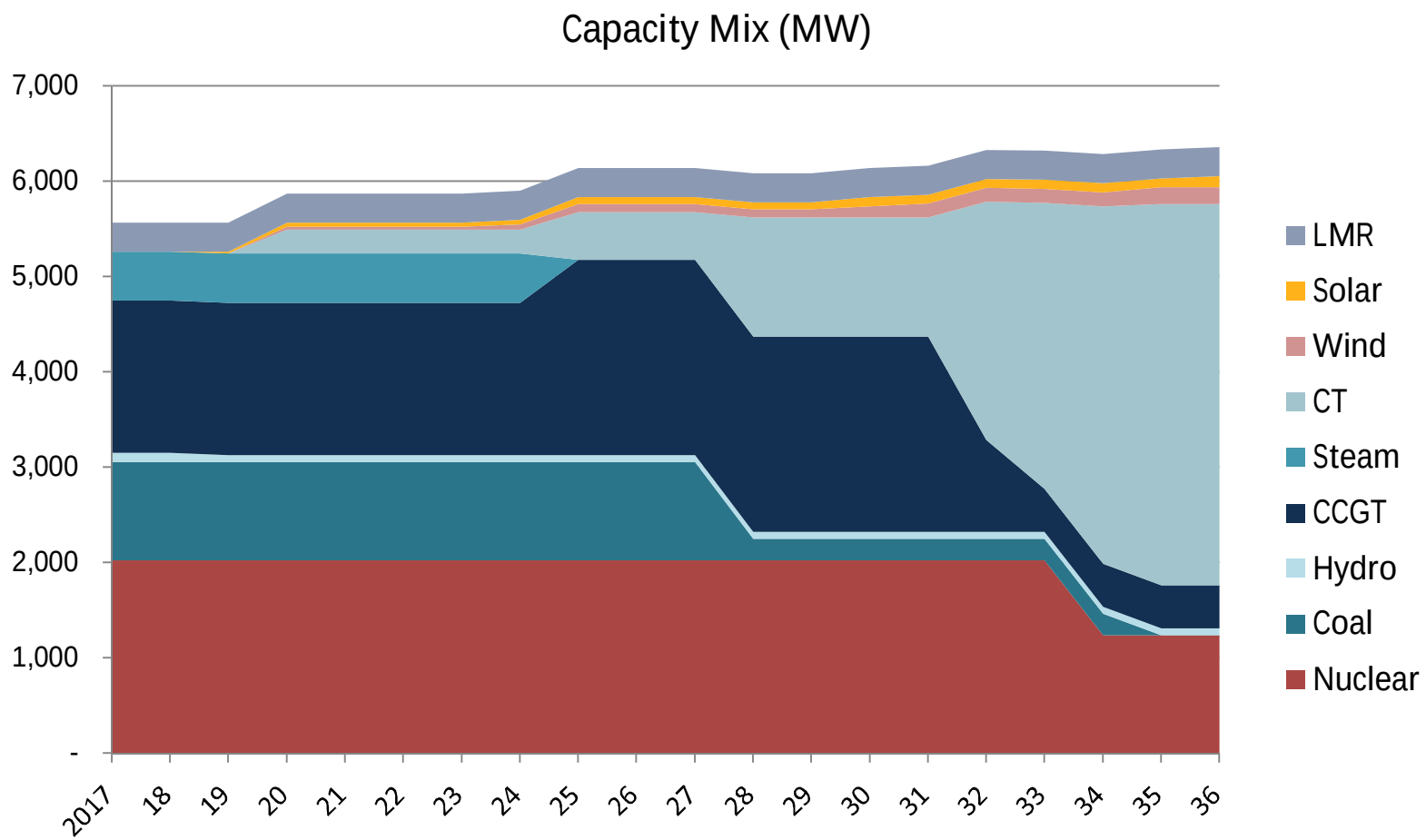


Future 2 – Portfolio Diversity (Energy)

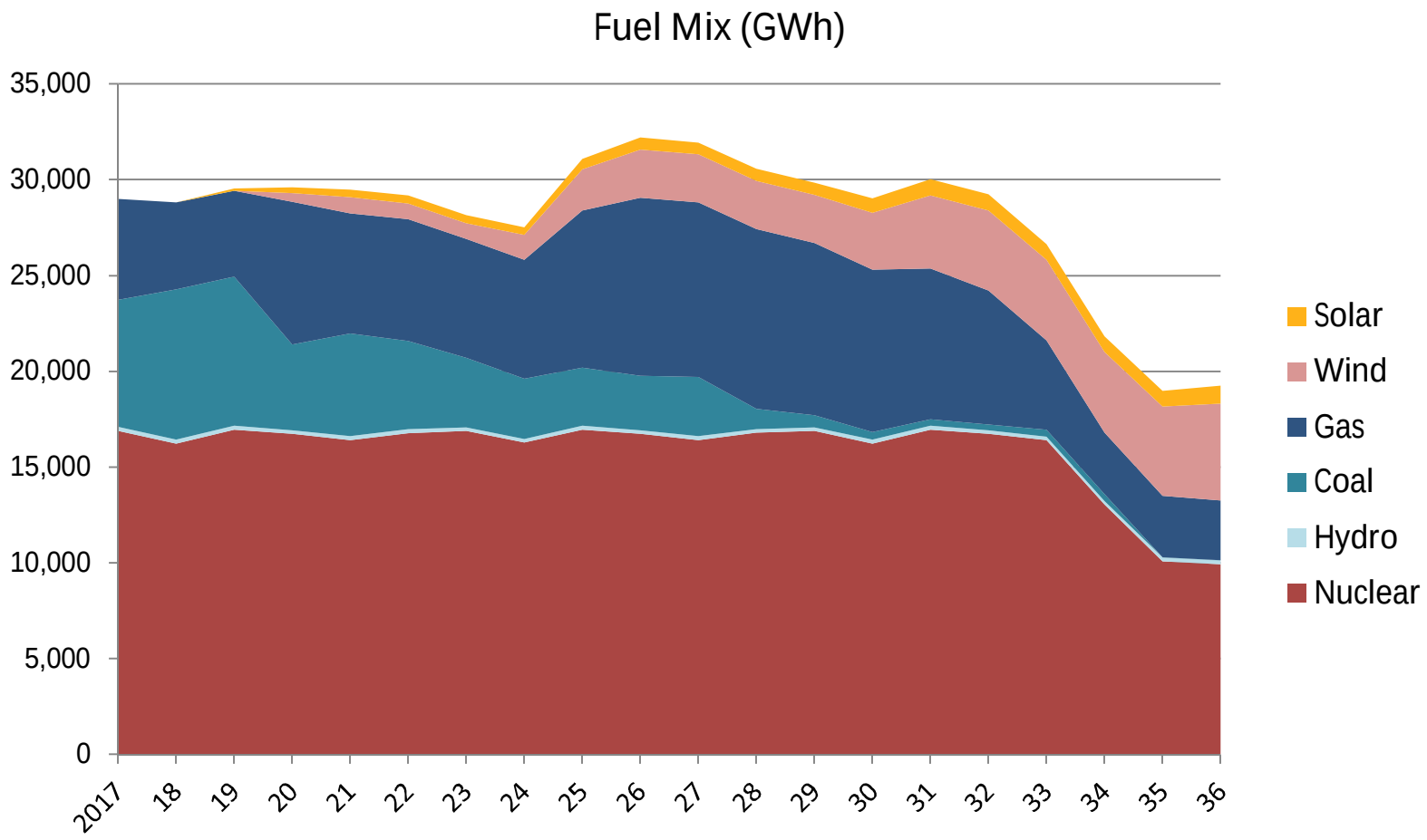


The fuel mix shown includes energy used to serve native load and supply sales into the market.

Future 3 – Portfolio Diversity (Capacity)



Future 3 – Portfolio Diversity (Energy)



The fuel mix shown includes energy used to serve native load and supply sales into the market.

Additional Analysis

Per SG request, an additional AURORA Portfolio Optimization model run is being developed, which is similar to the Alternate Future provided to the SG on 9/3/2015, with one change.

In response to feedback from the SG, an additional pricing option for wind resources is being made available in the model to meet EAI's future supply needs.

	Alternate Future
Existing Resource Portfolio	
Cease to Use Coal at White Bluff	2028
Cease to Use Coal at Independence	2035
EAI Existing CCGTs	30 years
Solar Technology Cost	$1,400/kW
Wind Technology Cost	$1,800/kW and $2,050/kW
Customer Electricity Requirements	
Energy sales and Load	Reference
Commodity Price Forecasts	
Fuel Prices	Reference
Environmental Allowances	Reference

Next Steps in IRP Development

- Provide results of additional Portfolio Optimization run (described on slide #175) as soon as it is available,
- Engage with stakeholders, as requested, through early October
- Develop 2015 IRP Action Plan
- Receive and review Stakeholder Report
- File IRP Report no later than October 31

THE POWER OF PEOPLE®

Entergy Arkansas, Inc.
2015 Integrated Resource Plan

September 25, 2015
Response to Stakeholder Group's Meeting Notes

EAI Response to Stakeholder Group

During the Stakeholder Group conference call that took place on 9/17/2015, EAI received a few questions that required a follow-up response.

The following slides are EAI's response to the Stakeholder Group's requests.

Wind Cost Calculation

Q: For the lower cost wind option used in the SG-requested model runs, what are the other inputs that combine with the $1,800/kW to arrive at the $47/MWh levelized cost?

A: The SG requested that EAI perform a Portfolio Optimization model run with the wind pricing used in SWEPCO's recent IRP, which is the basis for EAI using $47/MWh levelized cost for a new wind resource. EAI estimated that $1,800/kW installed cost (in 2014) would yield $47/MWh levelized cost of electricity using all original assumptions and calculations and changing only the installed cost. The primary assumptions that were held constant are EAI's capital structure, 25 year unit life, Fixed O&M, and capacity factor. The effect of lowering the installed cost from $2,050/kW to $1,800/kW while maintaining all other assumptions results in $47/MWh levelized cost of electricity.

LCOE Data

Q. Please provide EAI's thoughts on the report titled *"The levelized Cost of Electricity from Exiting Generation Resources"*? Does EAI have the data needed to perform the calculation for EAI's existing resources?

A. In general, Levelized Cost of Electricity ("LCOE") calculations have limited usefulness in utility resource planning and are generally utilized only in conducting a very high level assessment of technology options. Indeed, the report referenced in the question indicates (at page 3) that it is designed " to provide a baseline from which policymakers can assess the cost of replacing existing plants with new ones." The methodology outlined in the report relies on data that is available to the public via FERC Form 1 data submissions and EIA Survey Form 860 data submissions. EAI bases its planning decisions regarding existing units on unit-specific information, and thus, EAI sees no value in performing LCOE calculations on its existing resources.

Aggregated CHP Facilities

Q. Does EAI have any concerns or know of any regulatory constraints that would prohibit a single PPA from being sourced from two or more Combined Heat and Power ("CHP") facilities?

A. The only retail regulatory constraint of which EAI is aware is that the PPA would have to be determined to be in the public interest by the Arkansas Public Service Commission. EAI would consider such proposals as long as the proposals met the requirements of a specific Request for Proposals, Federal and state regulatory requirements, and MISO tariff and business practice requirements.

Additional Analysis - Assumption

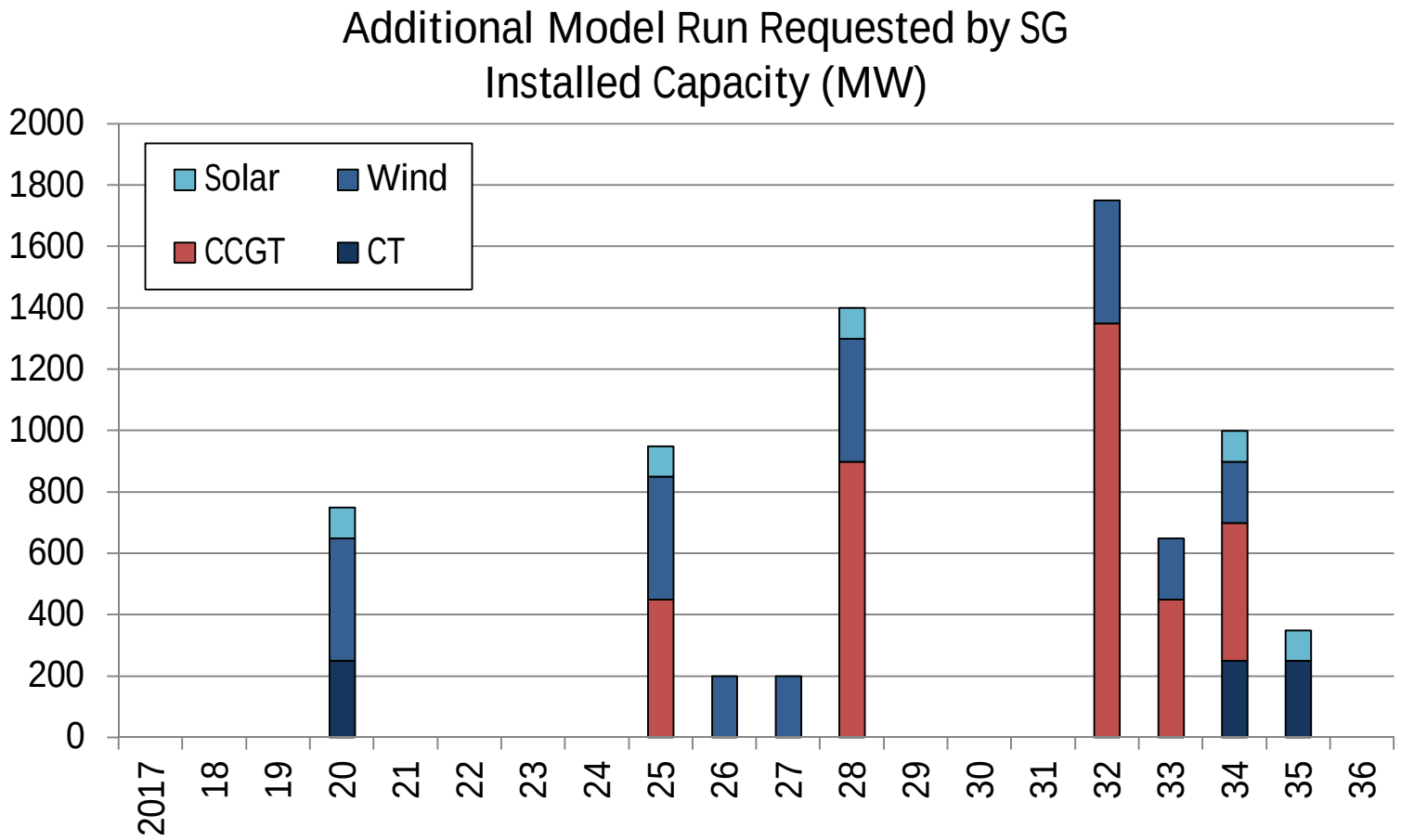
Per SG request, an additional AURORA Portfolio Optimization model run was completed, which is similar to the Alternate Future provided to the SG on 9/3/2015, with one change.

In response to feedback from the SG, an additional pricing option for wind resources is being made available in the model to meet EAI's future supply needs.

The resulting supply additions are shown on the following slide.

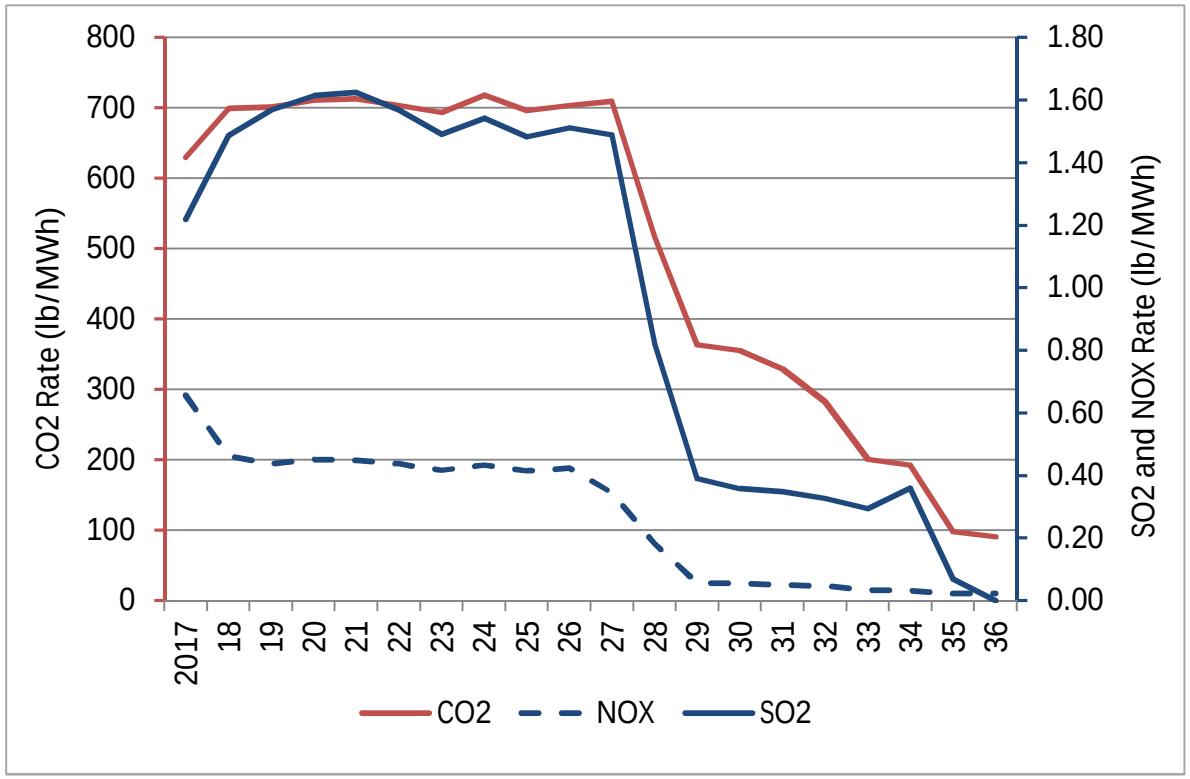
	Alternate Future
Existing Resource Portfolio	
Cease to Use Coal at White Bluff	2028
Cease to Use Coal at Independence	2035
EAI Existing CCGTs	30 years
Solar Technology Cost	$1,400/kW
Wind Technology Cost	$1,800/kW and $2,050/kW
Customer Electricity Requirements	
Energy sales and Load	Reference
Commodity Price Forecasts	
Fuel Prices	Reference
Environmental Allowances	Reference

Additional Analysis - Results



Additional Analysis - Emissions

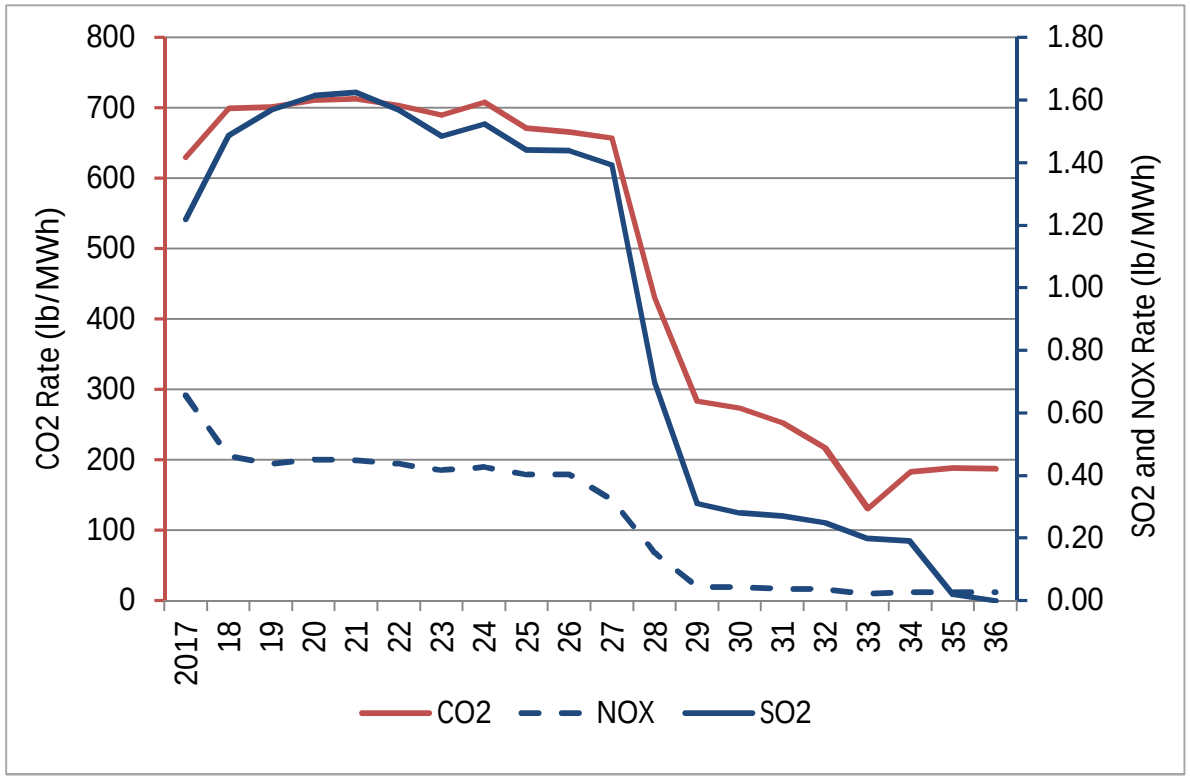
The emissions rates shown below correspond to the first model run completed in response to the SG's request, which is described on slide 153.



Included in this calculation are existing EAI-owned generation, including hydro and nuclear generation, located in AR, MS and LA, as well as future generation as optimized by AURORA.

Additional Analysis - Emissions

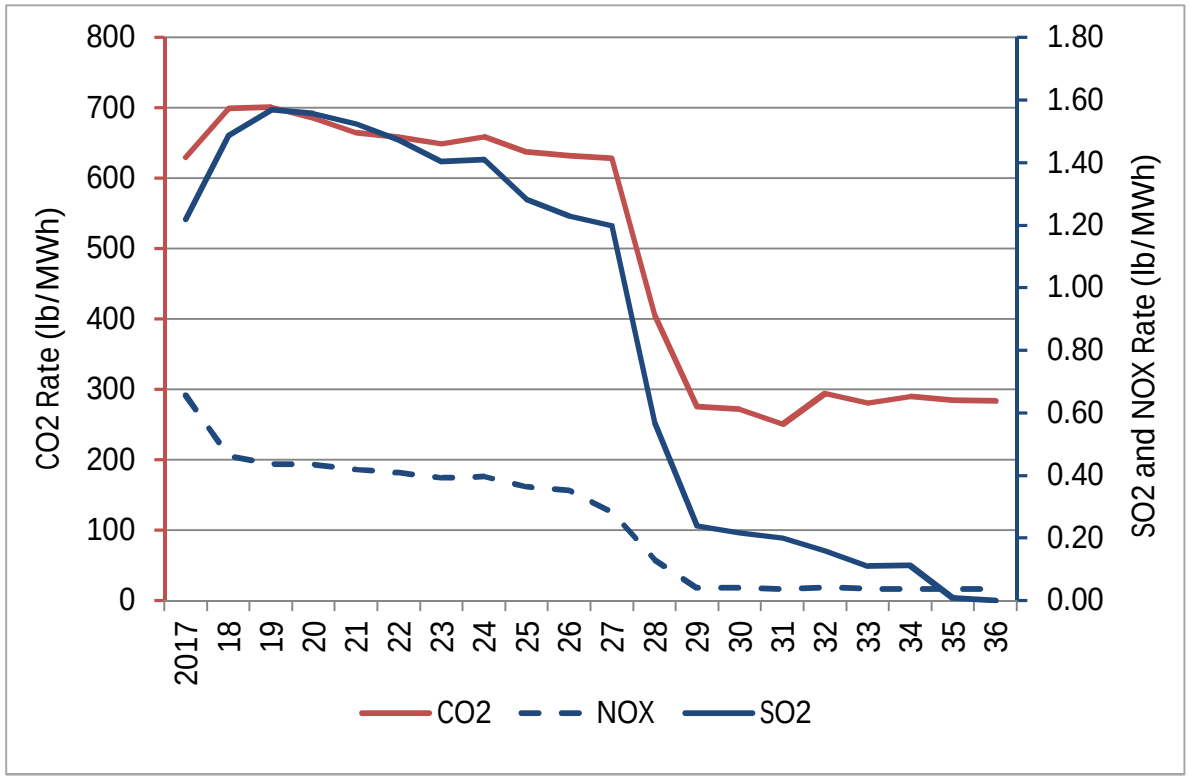
The emissions rates shown below correspond to the second model run completed in response to the SG's request, which is described on slide 155.



Included in this calculation are existing EAI-owned generation, including hydro and nuclear generation, located in AR, MS and LA, as well as future generation as optimized by AURORA.

Additional Analysis - Emissions

The emissions rates shown below correspond to the third model run completed in response to the SG's request, which is described on slide 175.



Included in this calculation are existing EAI-owned generation, including hydro and nuclear generation, located in AR, MS and LA, as well as future generation as optimized by AURORA.