Entergy Arkansas, Inc.
2018 Integrated Resource Plan

Entergy

Stakeholder Meeting
Wednesday, June 6, 2018
entergy-arkansas.com/IRP

Welcome

- Safety
- Wi-Fi Details
- Introductions

Agenda

Topic	Start Time	Presenter
Check-in/Breakfast	8:30	
Introduction and Meeting Objectives	9:00	Kurt Castleberry
Resource Planning Update	9:10	Kandice Fielder
Operations Planning Update	9:30	Joel Plessinger
Transmission Planning Update	9:40	Brad Cullipher
Demand-side Management Update	9:55	Gerardo Galdamez
Break	10:15	
Sales and Load Forecasts	10:30	Charles John
Overview of Environmental Issues	10:55	David Triplett
Generation Technology Assessment	11:25	Daniel Boratko
Lunch	11:50	
IRP Process Overview	12:45	Kandice Fielder
IRP Futures Development	1:05	Caleb Bales
Preliminary Results and Next Steps	1:25	Kandice Fielder
Stakeholder Committee Formation	2:00	
Wrap-up	2:50	Kandice Fielder

Meeting Objectives

- 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."

Source: APSC's Resource Planning Guidelines

Stakeholder Committee

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."*

EAI and Stakeholder Committee – Roles and Responsibilities

EAI	Stakeholder Committee
"organize and facilitate meetings of a Stakeholder Committee for resource planning purposes"	*"shall develop their own rules and procedures"*
"make a good faith effort to properly inform and respond to the Stakeholder Committee"	*"Stakeholders should review utility objectives, assumptions and estimated needs early in the planning cycle"*
Include a Report of the Stakeholder Committee with EAI's October 2018 Integrated Resource Plan filing	Develop a report of the Stakeholder Committee and provide to EAI

Stakeholder Process Timeline

ACTIVITY	DATE
Stakeholder meeting	June 6
Stakeholder / EAI interaction (as needed)	June 6 – October 1
Stakeholders finalize Stakeholder Report and provide to EAI	October 17
EAI finalizes IRP and files written report with the APSC including Stakeholder Report	October 31

Questions and Answers

- Questions are welcome but time constraints may limit the number of questions allowed during today's meeting.
- However, EAI will answer ALL stakeholder questions either in today's meeting or written questions and their answers will be posted @ http://entergy-arkansas.com/IRP/.
- 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.
- EAI will endeavor to respond to questions or provide information to Stakeholder Committee members as quickly as is practical.

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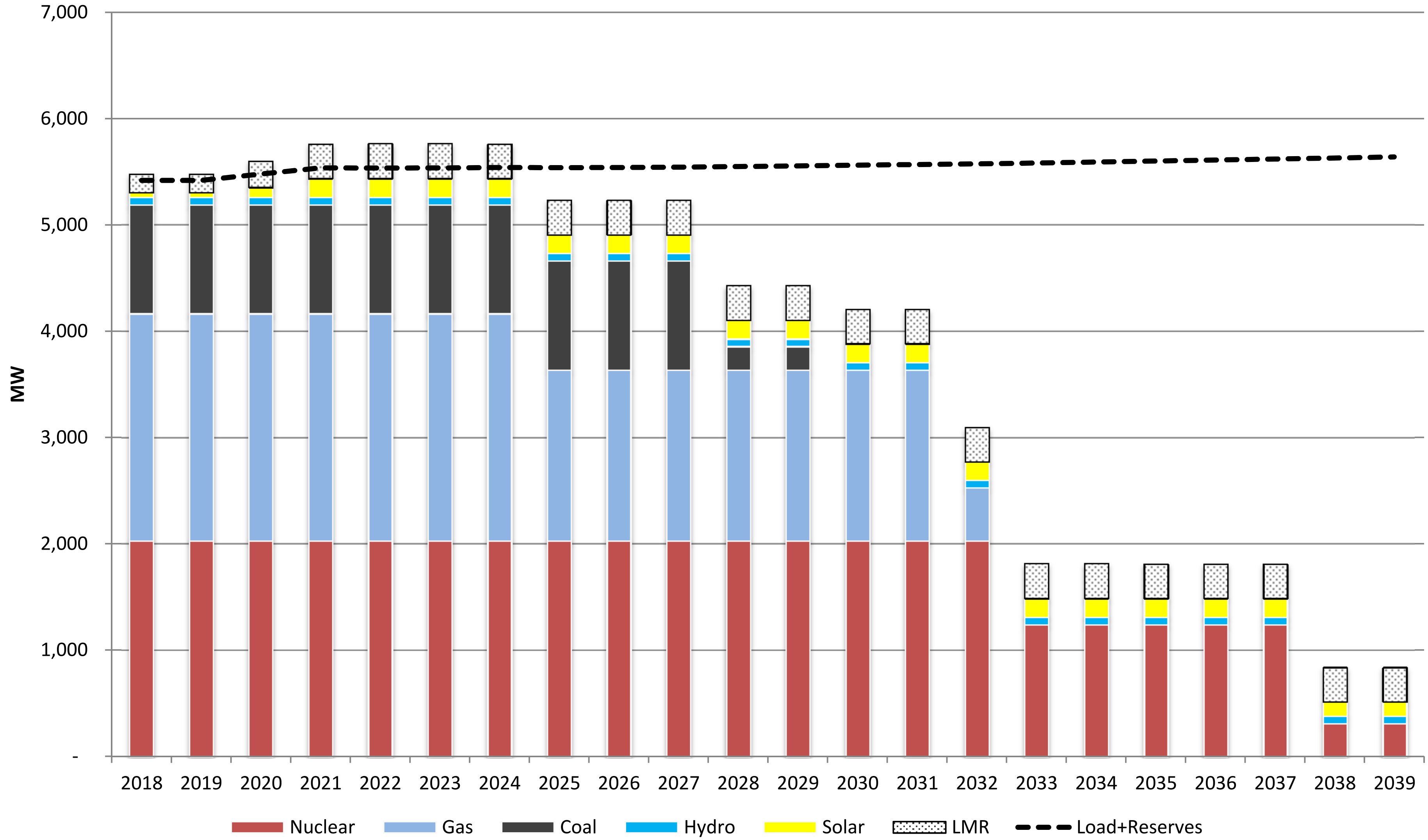
RESOURCE PLANNING UPDATE

Resource Planning Update

- Review the Action Plan from the 2015 IRP Report
- Update the Stakeholders on Resource Planning activities

Load and Capability Position



Note: Solar is shown at 50% of nameplate capacity.

2015 Integrated Resource Plan

The 2015 IRP utilized the Capacity Expansion Model in AURORA to identify the optimal incremental resources (based on minimizing EAI's production cost) to fill EAI's projected generation resource needs under three future scenarios.

2015 IRP Results	Future 1 Reference Case	Future 2 Low Case	Future 3 High Case
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%

2015 IRP Action Plan

- ✓ Coal Environmental Compliance
- ✓ Clean Power Plan
- ✓ Complete Acquisition of Power Block 2 from the Union Power Station
- ✓ Continue Participation in Energy Efficiency
- ✓ Supply-side Resource Additions
- ✓ Stakeholder Engagement Process

Coal Environmental Compliance

- EAI continues to maintain environmental compliance while operating the White Bluff and Independence Steam Electric Stations.
- A detailed update will be provided later in the agenda for today's meeting.

Clean Power Plan

- Since the Clean Power Plan was published in the Federal Register in October 2015, there have been various legal challenges.
- Currently, the EPA is proposing to repeal the Clean Power Plan and is conducting a public comment process seeking input on what a replacement rule would look like.

Complete Acquisition of Power Block 2 from the Union Power Station

- EAI acquired Power Block 2 of the Union Power Station in March 2016.
- The resource provides more than 500 MW of reliable capacity to serve customers' load.

Continue Participation in Energy Efficiency

- Since 2015, incremental energy efficiency additions have contributed to a savings of more than 150 MW across EAI's summer peak.

	2015	2016	2017
Actual kW	30,536 kW	45,126 kW	49,828 kW
kW+T&D[1] +12% RM	37,200 kW	54,974 kW	60,702 kW

[1] *Transmission & Distribution losses total 8.77%.*

Supply-side Resource Additions

- Since the 2015 IRP, EAI has selected two long-term Power Purchase Agreements (PPAs) for solar PV resources.
  - The Stuttgart Solar PPA started June 1, 2018, and is from an 81 MW, fixed-tilt solar PV resource.
  - If approved, the Chicot Solar PPA is expected to start no later than December 31, 2020, and will be from a greenfield 100 MW, single-axis tracking solar PV resource.

Stakeholder Engagement Process

- As will be discussed in more detail later in the agenda for today's meeting, the 2018 IRP includes efforts to address feedback received in the 2015 IRP Stakeholder Report, including:
  - additional analysis of energy efficiency and demand-side resources,
  - optimization modeling of potential EE resources, and
  - updated technology cost assumptions for solar and wind resources.

2018 Integrated Resource Plan

OPERATIONS PLANNING UPDATE

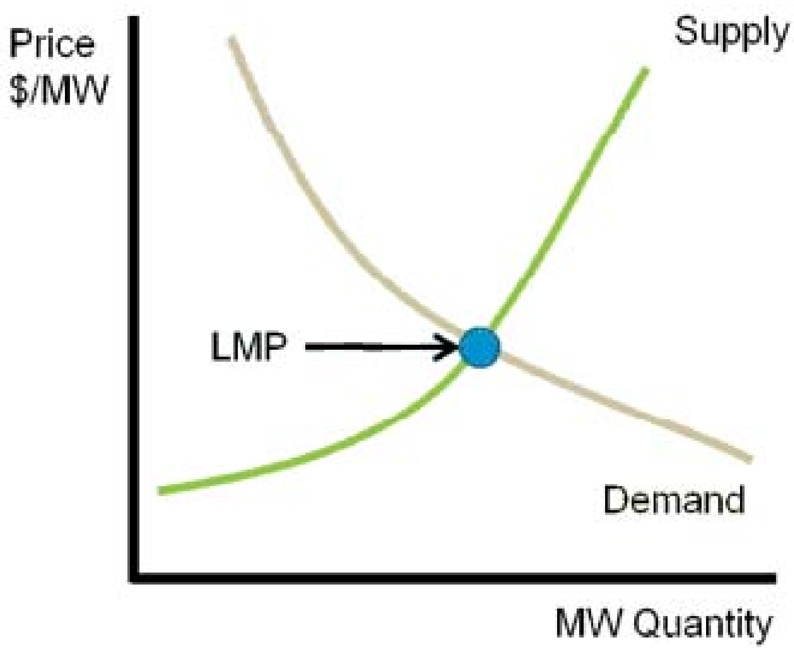
MISO Membership

- EAI is a Member and Market Participant in the Midcontinent Independent System Operator, Inc. (MISO) regional transmission organization.

Source: misoenergy.org

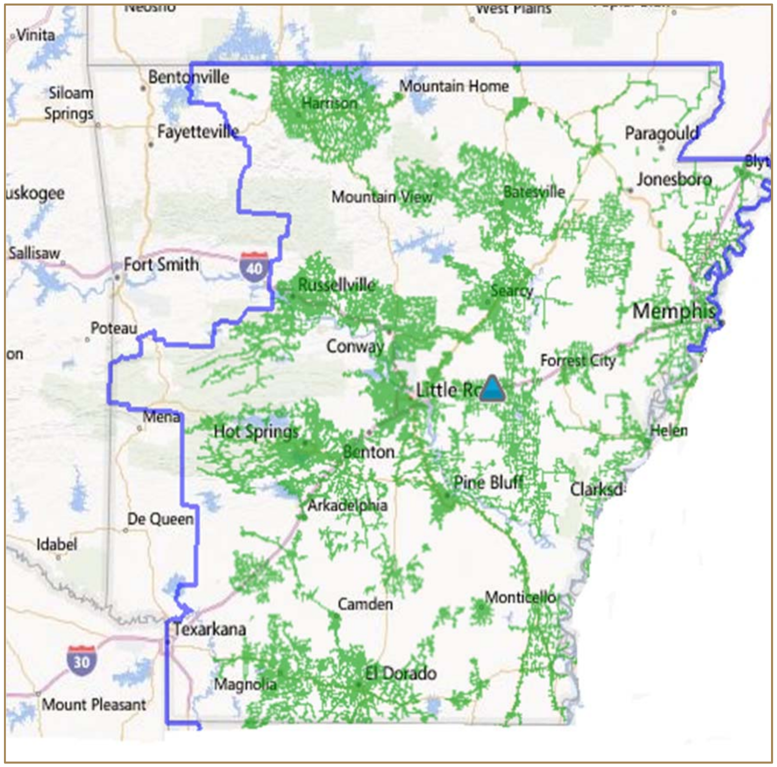
MISO Market Participation

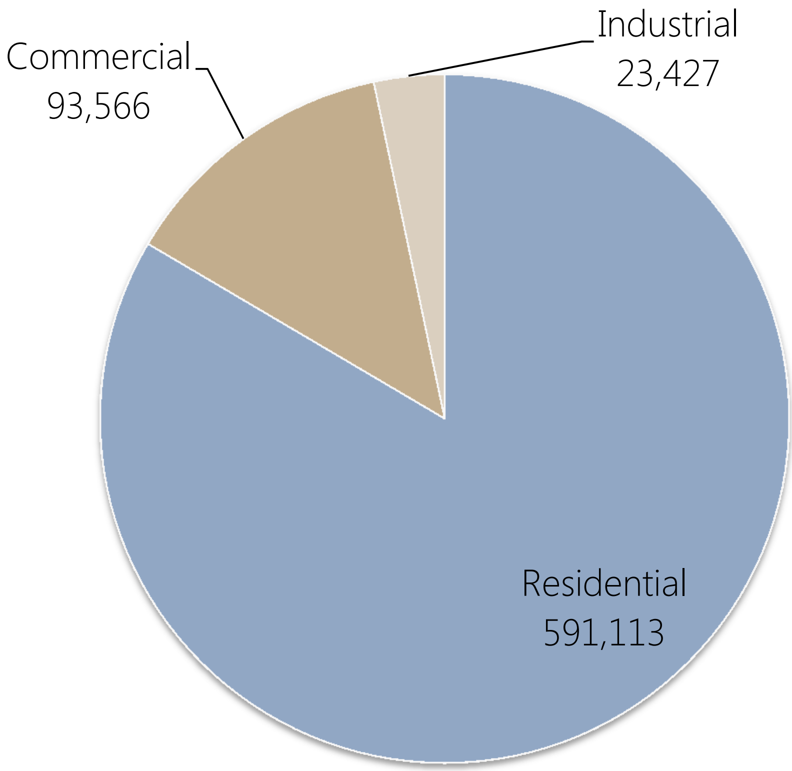
- All of EAI's generation and load-modifying resources, as well as EAI's customers' load, are bid into the MISO market.



Source: misoenergy.org

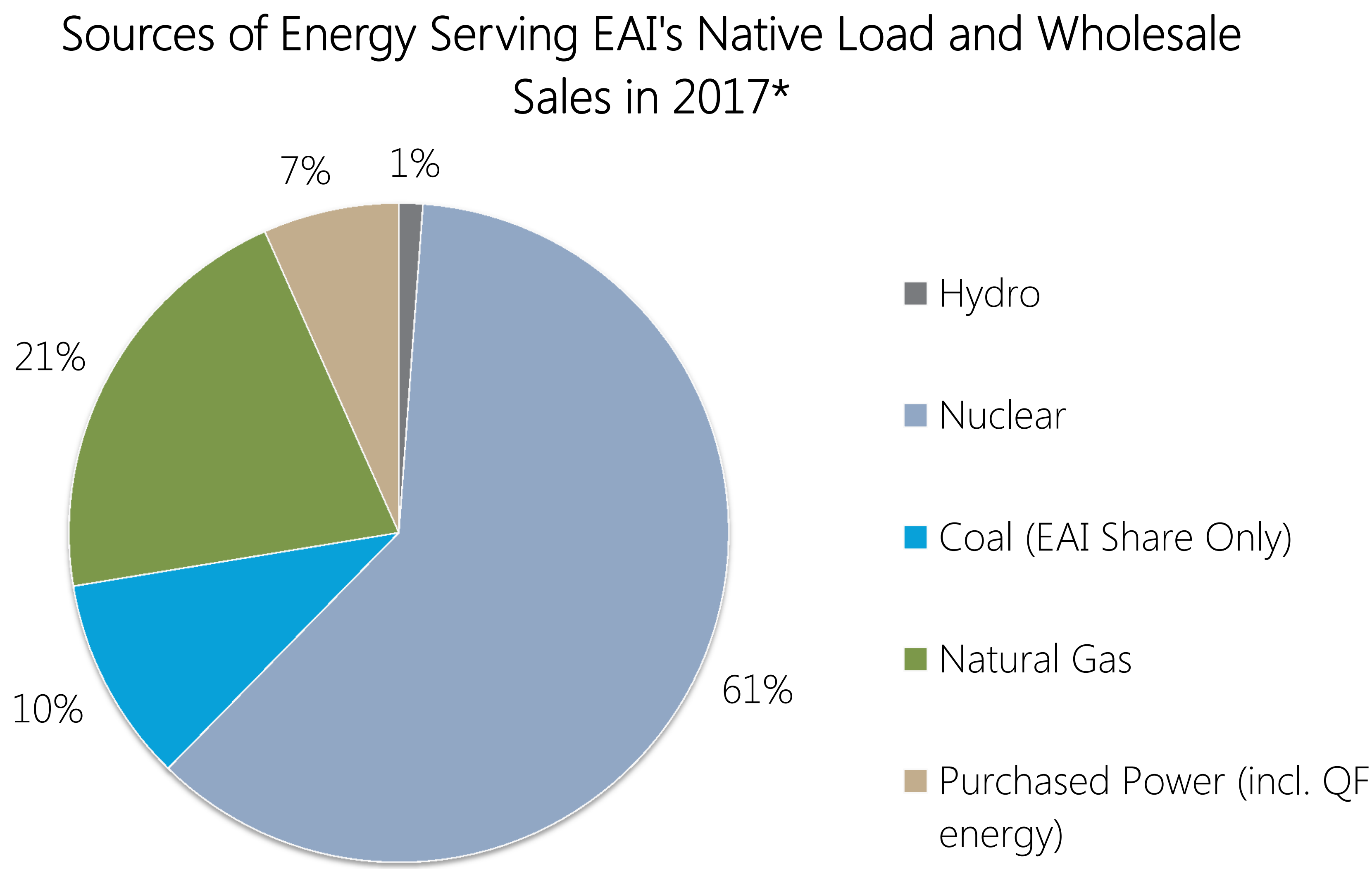
EAI Serves Approximately 709,000 Customers





Note: 2017 data; approximately 750 Governmental customers (not shown)

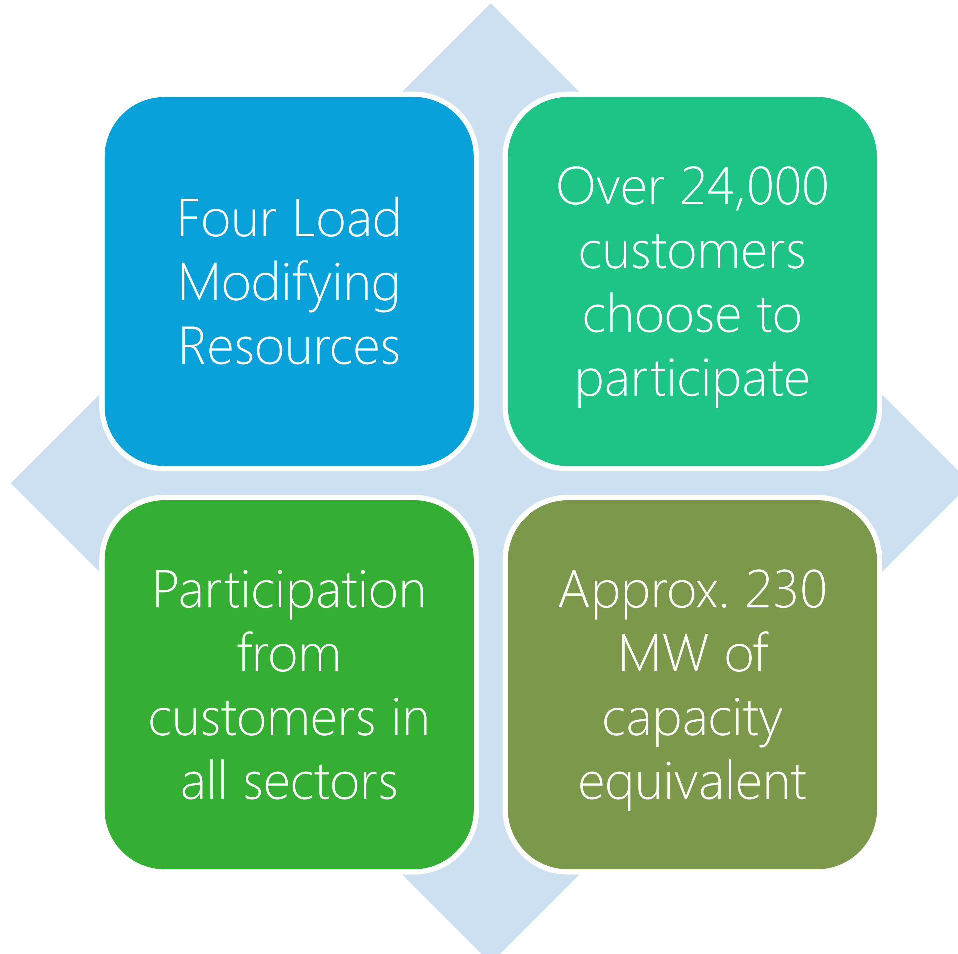
EAI Resource Portfolio



** Includes owned and contracted capacity and energy; Based on billing data as of 2/13/2018*

Load Modifying Resources

- In addition to its supply-side portfolio of resources, EAI also has capacity and energy resources on the customer side of the meter.



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TRANSMISSION PLANNING UPDATE

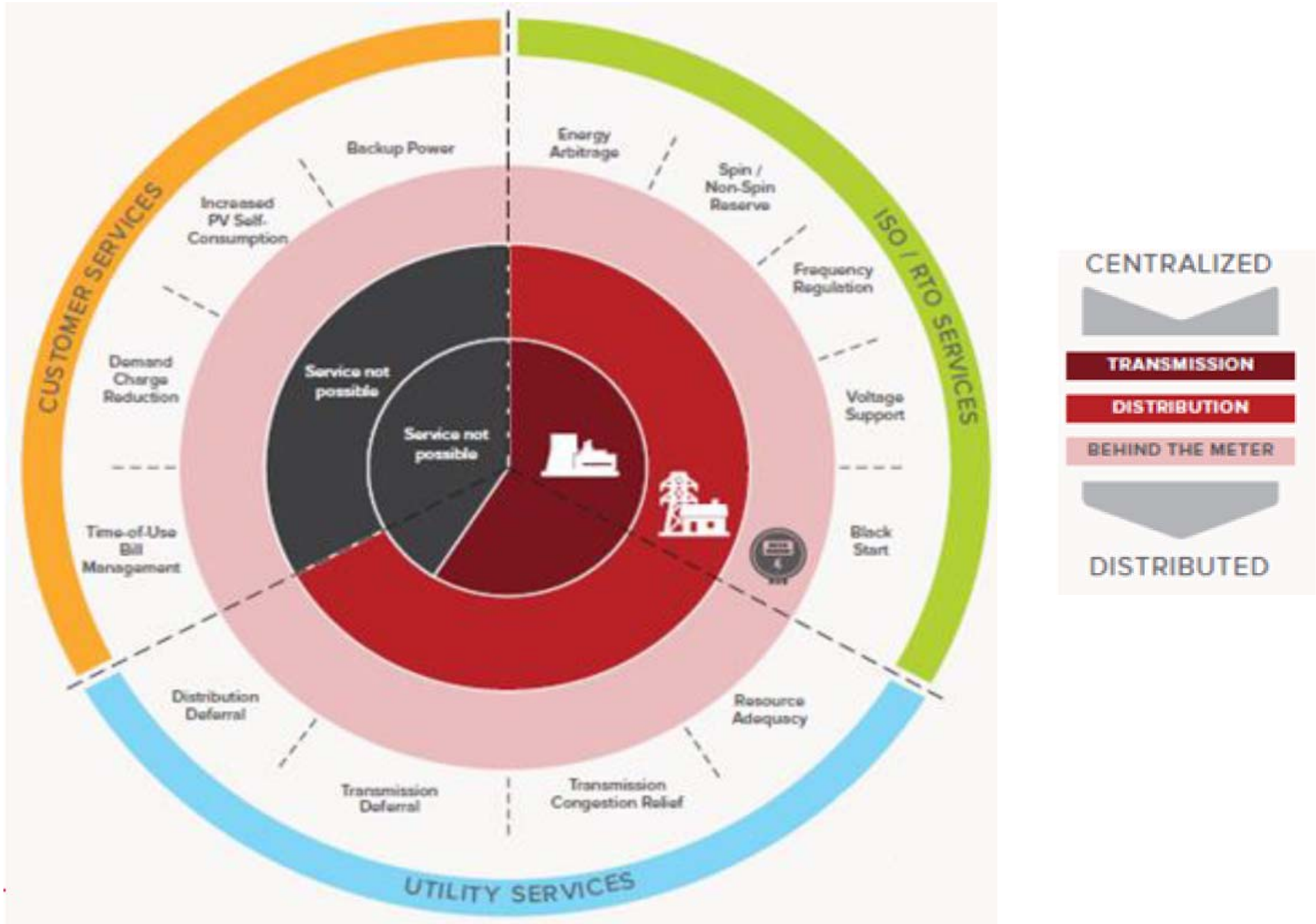
Transmission Planning Update

- What has changed since the 2015 IRP
- What hasn't changed
- Transmission Planning Update

What has changed since 2015 in Transmission Planning

- EAI not only continues to develop plans to improve the Reliability of the Bulk Electric System through traditional Transmission investments, but we also assess Non-Traditional Transmission Solutions (NTAs).
- One of these NTAs incudes Energy Storage. If strategically located, various improvements to the Bulk Electric System can be obtained from this technology.
- These improvements include:
    - Frequency Regulation
    - Peak Load Shaving
    - Transmission Congestion Relief
    - Voltage Support
    - Black Start Capability
    - Backup Power for Load Centers

General Use Cases for Energy Storage Devices



What hasn't changed in Transmission Planning

- EAI is still responsible for planning transmission projects that will meet NERC reliability standards and Entergy's local transmission planning criteria.
- Our focus remains on providing cost effective, economic, and reliable service to our customers.
- We use an open and transparent stakeholder process in Transmission Planning which involves several stakeholder meetings held by MISO's Planning Subcommittee.

Transmission Projects At a Glance

		APPENDIX A			APP B
	Total	Future/in-progress	Complete	Est. Cost Remaining	Studied for Future Years
Pre-Planned	24	1	23	$43.7 M	
MTEP 14	27	2	25	$ 5.5 M	
MTEP 15	16	5	11	$ 75.1 M	
MTEP 16	20	11	9	$ 98.9 M	
MTEP 17	14	14	0	$283.3 M	
MTEP 18 *	31	19	0	$192.6 M	12
MTEP 19 **	8	4		N/A	4

*MTEP 18 process is still in progress. MISO approval of projects to occur in December 2018.
**MTEP 19 local planning is currently ongoing. 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 2018 IRP Action Plan guide EAI to pursue and evaluate options for additional generating resources (e.g. through an RFP), transmission analysis of resource options will be performed to evaluate transmission impact.
- Analysis will include the current and future transmission topology and rating information, including future planned transmission projects submitted and approved in MISO's MTEP transmission plan.

Inverter Based Resources and Transmission Disturbances

- With the growing amount of inverter based resources (particularly solar PV resources) that are penetrating the Bulk Electric System, many of the traditional characteristics of the grid will change.
- Currently EAI has several large generating resources with a large rotating mass. These units act like shock absorbers for our Transmission system that can withstand system disturbances much greater than a smaller generator connected through inverters.
- Adding large loads, or industrial customers starting a motor, disturbs the system.
- Faults on the system are very extreme disturbances that can cause system failures if not contained properly.
- NERC has identified adverse characteristics of inverter based resource performance during recent disturbances that pose a reliability risk to the Bulk Electric System.
- The Canyon 2 Fire in southern California on October 9, 2017 is a prime example of a disturbance on the transmission system that subsequently resulted in the loss of 900 MW's of solar PV generation. Analysis of the event identified several incorrect inverter based settings that were recently communicated throughout the NERC community.
- Consultations with inverter manufacturers must be performed to ensure the NERC recommended settings are being utilized.

Future IBRs vs. Existing EAI Fleet.

Inverter Based Resources (IBRs)	Conventional Resources

• Produce direct current (“DC”) electricity
  • Requires an inverter consisting of power electronics to connect to the AC system
• Solar generation has no rotating mass and thus does not add to system inertia
  • Can be extremely sensitive to system disturbances like faults, loss of load, loss of generation, etc. and trip unexpectedly
• Inverter can produce real power (MW) and/or reactive power (MVAR)
• Technology is proven to deliver energy into a strong system
  • Delivery to a “weak” system is unproven
  • A system devoid of inertia (generation with mass) will become weak
	• Produce alternating current (“AC”) electricity
	  • Connects directly (through a step-up transformer) to the AC system
	• Heavy rotating machine has inertia which acts as a stabilizing force on the system
	  • Large generators “ride through” system disturbances because the speed of the rotor cannot change instantaneously
	• Generator can produce real or reactive power via its control systems

2018 Integrated Resource Plan

DEMAND-SIDE MANAGEMENT UPDATE

DSM Progress Since 2015

This section outlines the progress EAI has made with DSM and DR since the 2015 IRP.

- In 2015, the Commission extended programs at a target level of 0.9% of retail sales.
- In 2016, the official "next" 3 year plan was filed. All programs were based upon the Comprehensiveness orders made in December 2010 and further program design requirements for weatherization and Commercial and Industrial Programs in 2013.
- Currently, the Commission requires the RECC method of determining avoided capacity cost which reduces the cost effectiveness of DSM and DR when compared to levelized avoided capacity cost, as is best practice in all other jurisdictions. During this time Non Energy Benefits (NEBs) were also added to CE tests.
- Targets were set at 0.9% of Weather Adjusted Sales, adjusted for self direct opt-outs, for the 2017 and 2018 program years with the target increasing to 1.0% for the 2019 Program Year.
- Planning for the subsequent three year plan is currently underway and will cover the 2020-2022 timeframe. Targets are currently being planned, with EAI on record as supporting continuation of the 1.0% targets for the duration of this plan.

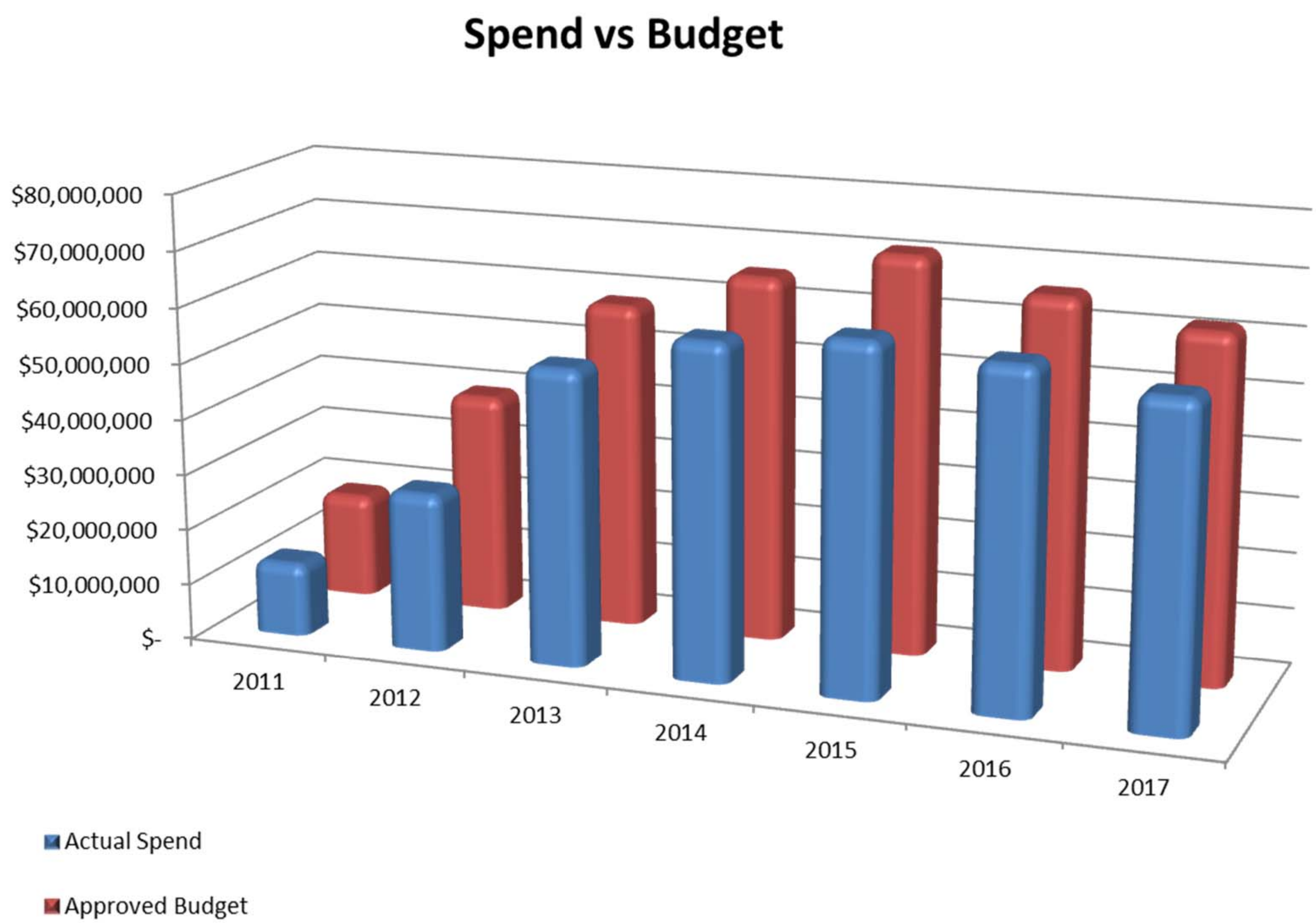
2018 DSM Projected Achievement

- EAI is on track to achieve and exceed our 2018 DSM and DR target of 260,268 MWh subject to retroactive Technical Resource Manual ("TRM") updates and Independent EM&V Results.
- The 2018 Plan is demonstrated below:

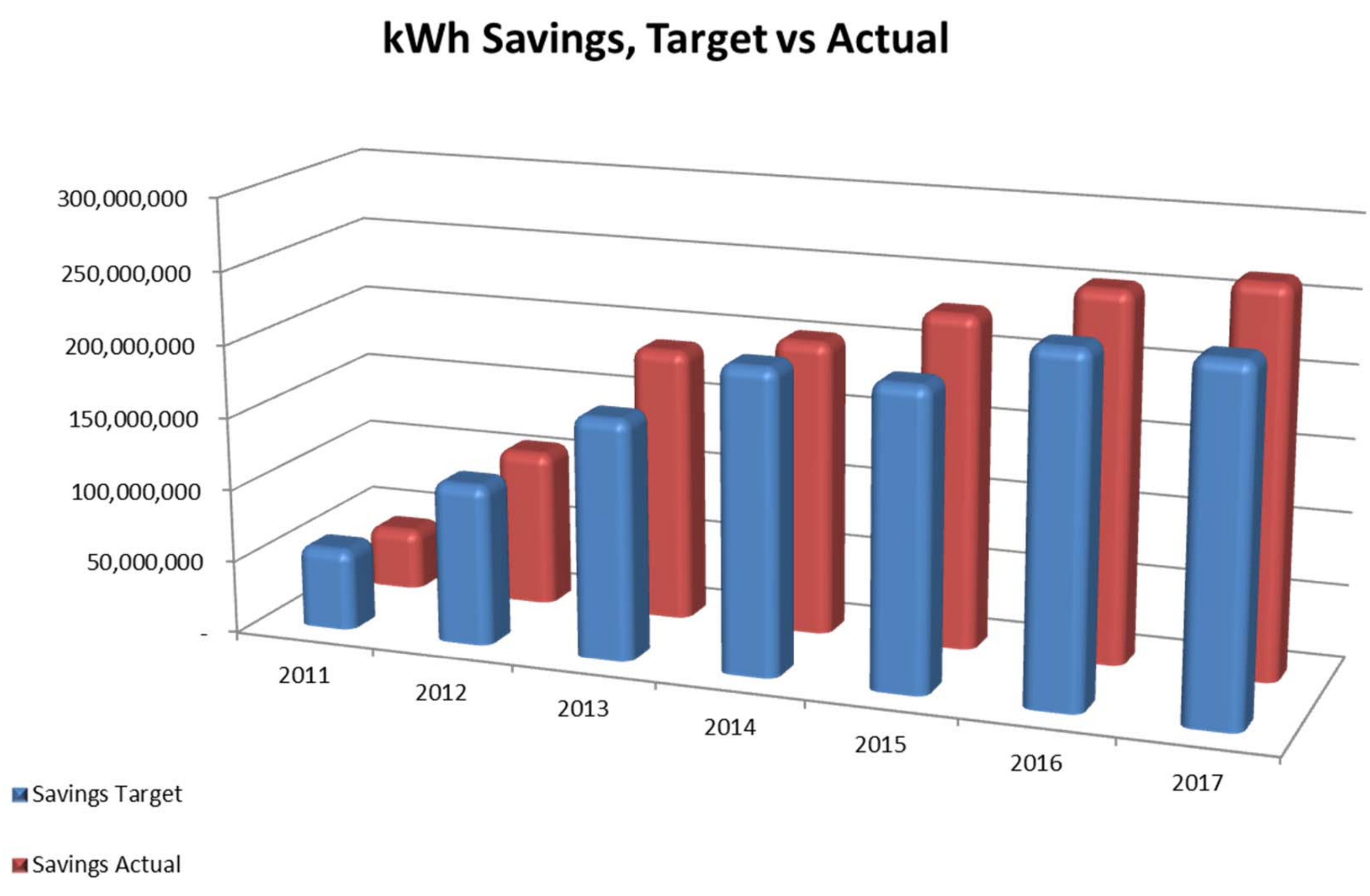
	2018
Energy Savings (KWH)*	260,268,000
Demand Reduction (KW)*	130,600
DR Budget	$6,279,000
DSM Budget	$56,533,000
Total Budget	$62,812,000
Total Resource Cost Ratio	1.8

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

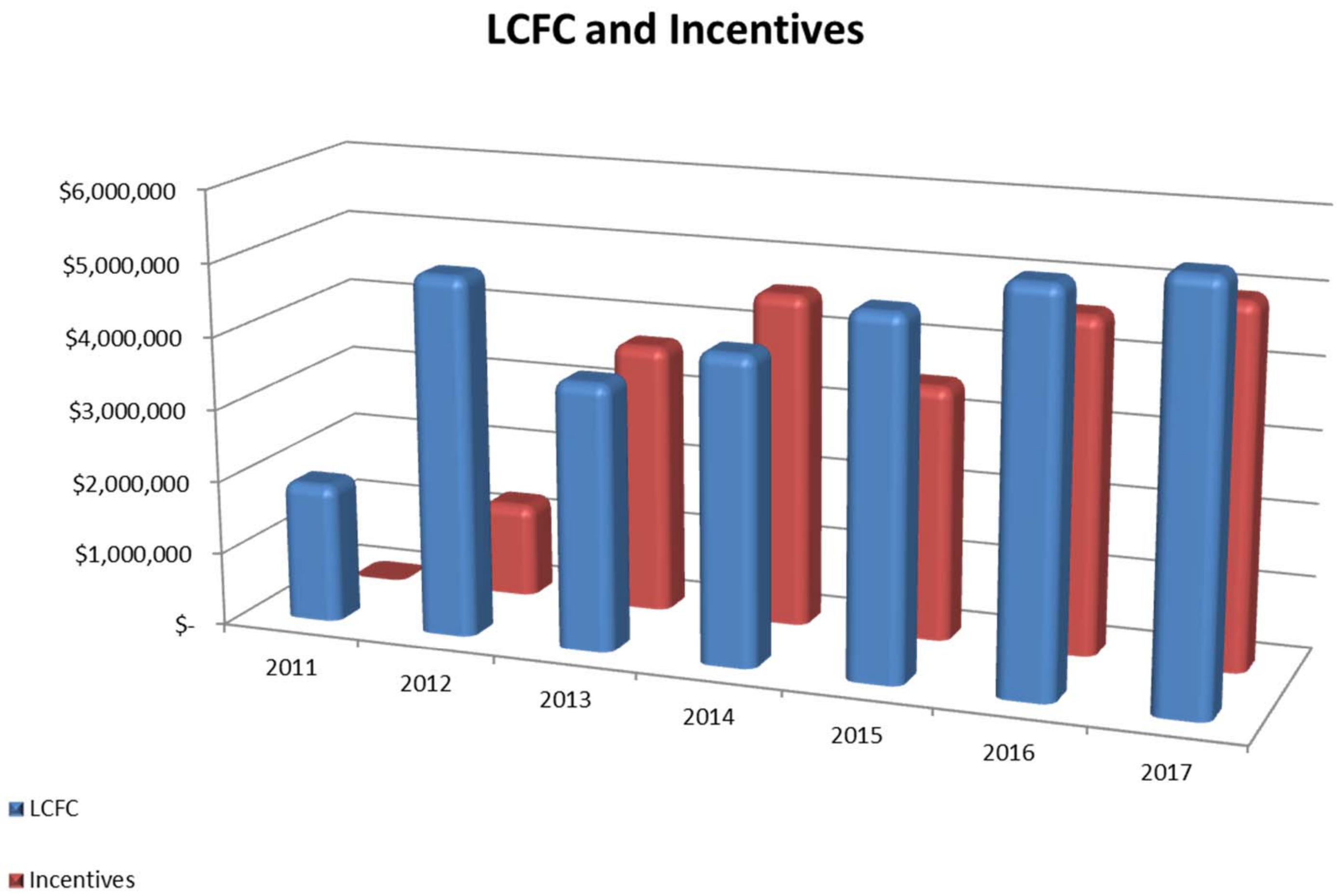
DSM and DR Trends Over The Years



DSM and DR Trends Over The Years



DSM and DR Trends Over The Years



Projection vs Actual Comparison

	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
	Actual		
	2016	**2017**	**2018**
Energy Savings (KWH)*	253,289,913	264,991,920	260,268,000
Demand Reduction (KW)*	45,126	49,828	130,600
DR Budget	$7,855,090	$6,267,837	$6,279,000
DSM Budget	$58,108,627	$55,766,930	$56,533,000
Total Budget	$65,963,717	$62,034,767	$62,812,000
Actual Spend	$60,270,107	$57,115,534	
Percent of Sales (Evaluated)	1.57%	1.49%	1.80%
Total Resource Cost Ratio	2.5	3.8	1.8

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

The Next Three Year Plan

- EAI is preparing to file a Three Year Plan covering 2020 through 2022.
- Work is being done in tandem with our partners who currently support our portfolio of programs.
- The work currently being done includes:
  - Measure mix evaluation,
  - Consideration of EM&V uncertainties,
  - Consideration of what actual kWh targets will be,
  - Continued emphasis on Cost Benefit Analysis which is being greatly influenced by EAI's avoided capacity costs,
  - Impact of future technologies and product offerings:
    - *e.g.,* AMI
  - Will DR be offered going forward?

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. • These resources are modeled like a supply side resource.	• Programs that provide the Utility with the right to curtail service to a participating customer. • These resources are modeled like a supply side resource.

2018 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: The actual target setting work with the PWC is still underway and is currently being evaluated by the APSC. EAI, along with the other IOUs, APSC staff, and the AG are in support of setting targets at 1.0% of 2018 Sales.
  - This would result in an annual incremental reduction in sales of approximately 208,880 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 accounted for so the impacts are not double-counted.

[1] *Based on 2017 Weather Adjusted Sales projected to 2018*

2018 IRP DSM Assumption Principle Based

- EAI remains committed to DSM and DR as long as 1) the achievement can be accomplished in a cost effective manner when compared to utility future avoided or delayed generation cost, and 2) full cost recovery remains in place.

2018 Integrated Resource Plan

BREAK – WILL RESUME AT [10:30]

2018 Integrated Resource Plan

SALES AND LOAD FORECASTS

Forecast Discussion

- Reference Case process, inputs, and assumptions
- Reference Case forecast overview
- Reference Case forecast
- IRP scenario drivers
- IRP scenario peak forecasts

Reference Case Process, Inputs, and Assumptions

- Hourly forecast based on monthly energy from the BP18-U sales forecast (November 2017).
- Regression period looked back at electricity consumption activity from January 2010 through August 2017.
- Normal weather based on 20 year temperatures (1997-2016).
- Peaks developed using historical hourly retail load data from the MISO settlements process and similar pre-MISO process.
- Revenue class shapes developed using hourly MISO load data proportioned based on class shapes from Load Research.
- Projections use historical data for load, temperatures (CDDs and HDDs), kWh consumption volume, historical peak-to-energy relationships, and transmission & distribution losses.

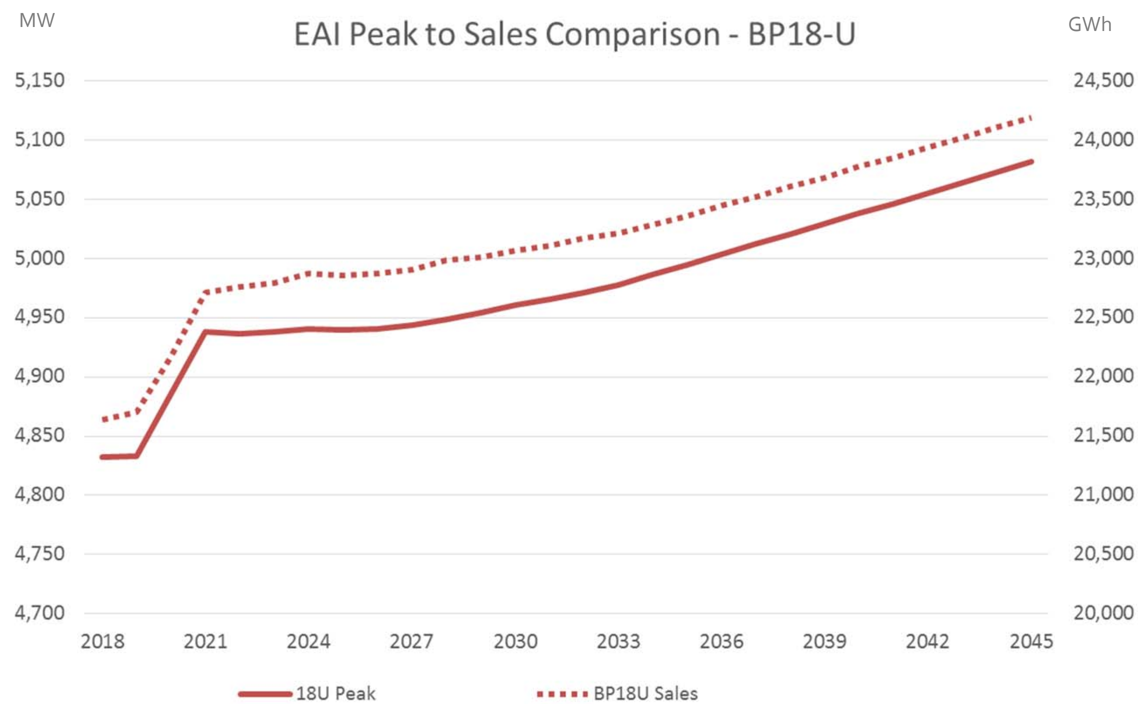
Reference Case Forecast Overview

- Energy efficiency continues to exert downward pressure on residential and commercial average use per customer (UPC).
  - Residential UPC is expected to decline -0.6%/yr. offset by customer growth of 0.4%/yr. through 2036.
  - Commercial UPC is expected to decline -1%/yr. offset by customer growth of 1%/yr. through 2036.
- EAI's annual incremental DSM programs are expected to reduce consumption by ~260GWh per year, which is carried through the forecast horizon. With the build-up from prior years' programs, EAI is expecting consumption reductions of ~1,200 GWh by 2025 versus a scenario with no DSM programs.
- AMI implementation is phased-in gradually from 2019-2021, reducing residential and commercial sales by a total of 1.5% by 2022.
- Expected levels of additional rooftop solar yields a small reduction to both the peak and to the load shapes.
- Significant growth (~5%) is expected from the Industrial class.

Reference Case Forecast

Outlook Summary

- Significant growth in sales and peak load through 2021, largely due to Industrials.
- Moderate growth thereafter due to continued increases in residential and commercial customer counts.
- DSM programs will continue to reduce consumption across all customer classes.
- AMI implementation and related programs will otherwise reduce consumption by a total of 1.5% by 2022.



Item/CAGRS>>	2017-22	2017-27	2017-37
Energy (MWh)*	1.4%	0.8%	0.5%
Peak (MW)	0.2%	0.1%	0.1%

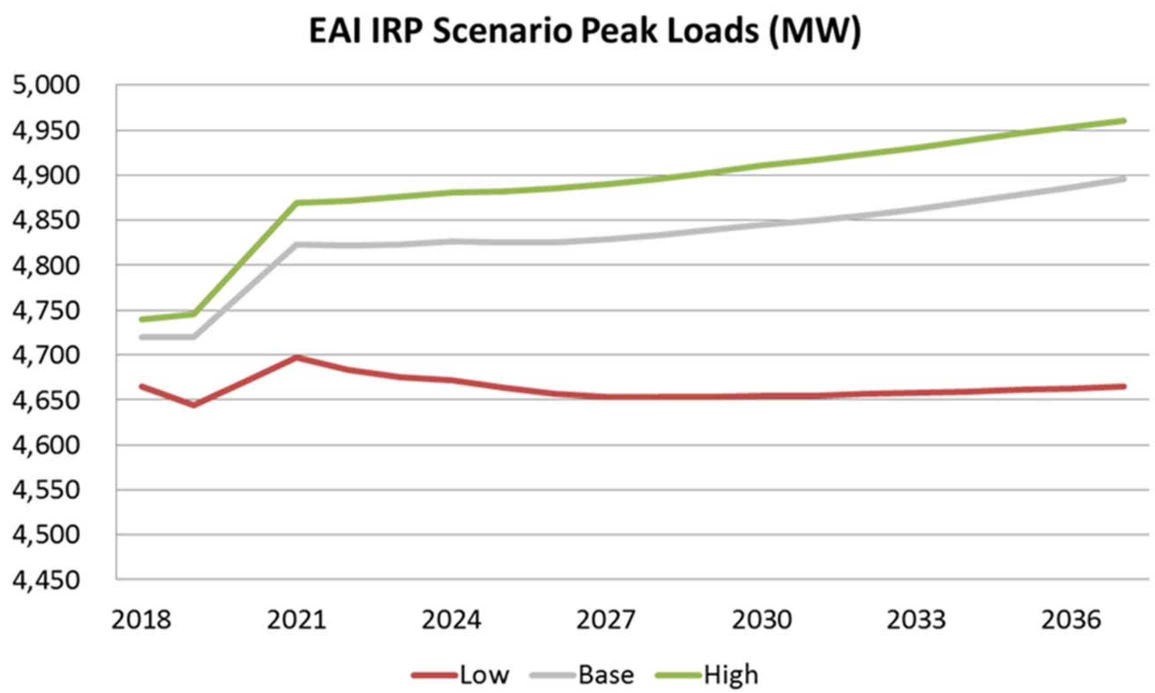
** Based on estimated 2017 weather-normalized volumes*

IRP Scenario Drivers

Class	Item	Low	High	Driver for High/(Low) Scenario
Residential	Customer count growth	-15%	+25%	Customer count growth could be higher/(lower) than expected
Residential	kWh/customer	-25%	+25%	Energy efficiency, mix of single vs. multi family residences
Commercial	Customer count growth	-25%	+10%	Customer count growth could be higher/(lower) than expected
Commercial	kWh/customer	-25%	None	Energy efficiency in lighting, refrigeration, HVAC
Commercial	Electricity price	+10%	None	Higher prices push commercial customers towards lower consumption and more EE spending (-.20 elasticity)
Industrial	Sales volumes	-20%	+10%	Improving/(worsening) economic conditions

Scenario Load Forecasts

- Significant growth through 2021 is from the Industrial class. Otherwise, peak load growth is moderate across all scenarios.
- Peaks are expected to grow more slowly than energy volumes due to:
  - The effects of energy efficiency and EAI's DSM programs.
  - More sales volume growth in the higher load factor industrial class.



2017 – 2027 CAGRs

Item	Low	Ref.	High
Energy (MWh)	0.1%	0.8%	1.0%
Peak (MW)	-0.2%	0.1%	0.2%

2017 – 2037 CAGRs

Item	Low	Ref.	High
Energy (MWh)	0.1%	0.5%	0.6%
Peak (MW)	-0.1%	0.1%	0.2%

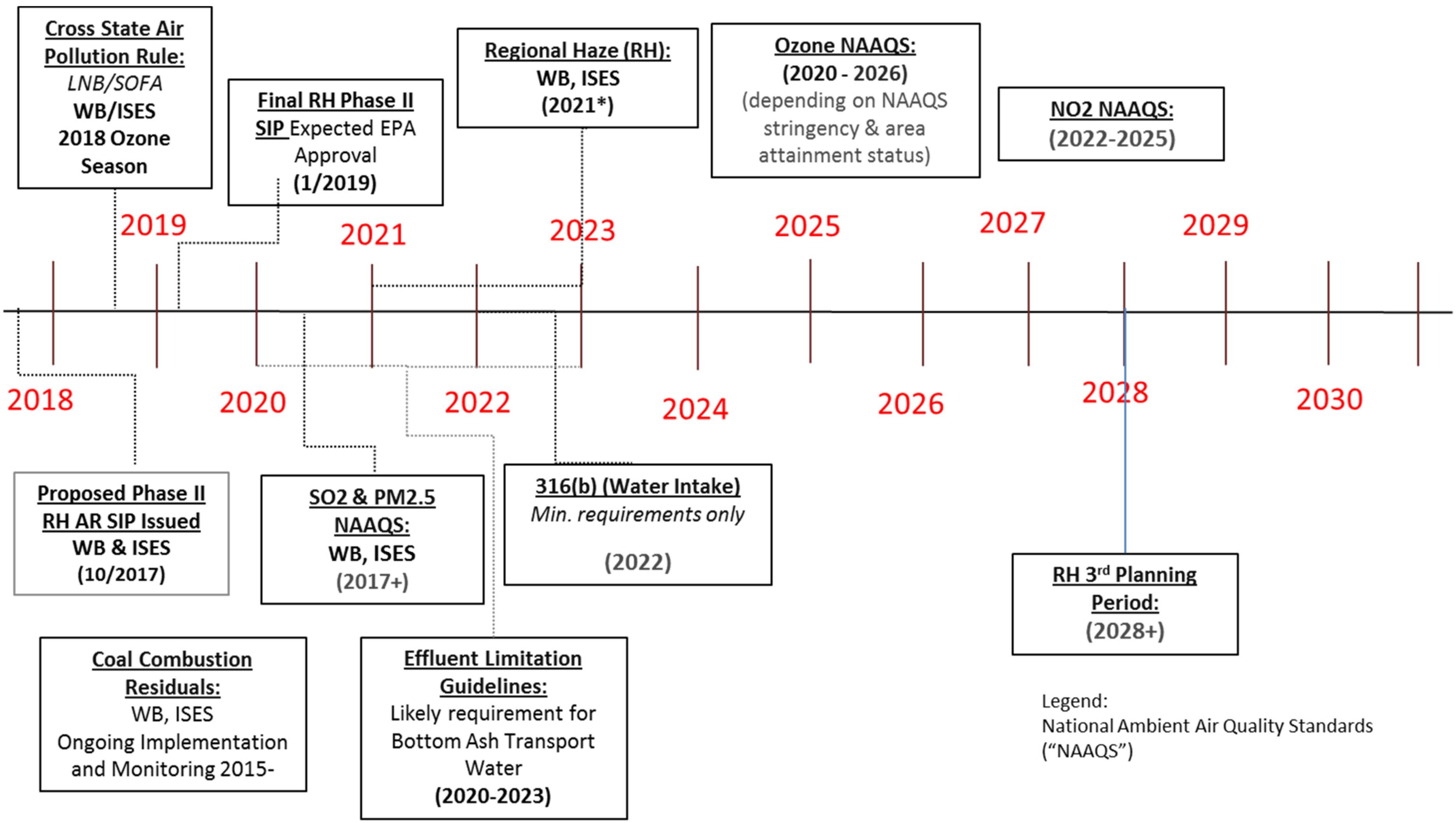
2018 Integrated Resource Plan

ENVIRONMENTAL UPDATE

Overview of Environmental Issues

- Potential Environmental Compliance Timeline
- CSAPR
- Regional Haze
- NAAQS (PM2.5, SO2, and Ozone)
- Coal Combustion Residuals (CCR)
- Effluent Limitation Guideline (ELG)
- Cooling Water Intake (316(b))
- Clean Power Plan (CO_2)

Potential Environmental Compliance Timeline



Legend:
National Ambient Air Quality Standards
("NAAQS")

CSAPR

CSAPR:

- New ozone-season NOx allowance budget applicable in Arkansas for CY2018 ozone season.
- New budget represents an approximately 39% reduction from prior year allowance budget.
- Low-NOx Burners and Separated Overfire Air (LNB/SOFA) installed on Arkansas coal units as part of CSAPR strategy.
- New LNB/SOFA systems first operated in:
  - WB2 – June 2017
  - IN1 – October 2017
  - IN2 - December 2017
  - WB1 - June 2018

Regional Haze

Regional Haze:

- Final FIP issued by EPA on October 27, 2016.
    - Required NOx compliance (bifurcated limit) by April 27, 2018.
    - Required SO2 compliance (0.06 lb SO2/MMBtu) by October 27, 2021.
- Source-specific NOx limits replaced via EPA approval of ADEQ Phase I (NOx) SIP.
    - SIP requires that NOx be addressed via CSAPR > BART.
    - Approved by EPA effective March 14, 2018.
    - Significantly greater flexibility for demonstrating compliance.

Regional Haze

Regional Haze:

- ADEQ proposed Phase II (SO_2) SIP on October 31, 2017.
- Proposal would require the use of low-sulfur coal (0.6 lb SO_2/MMBtu, 30-day rolling avg) at both White Bluff and Independence.
- Comment period ended February 2, 2018.
- Comments submitted by numerous parties.
- ADEQ currently developing response to comments and final SIP package.
- ADEQ expected to provide draft final SIP package to EPA Region 6 for review in Summer 2018.

NAAQS

Annual PM2.5 NAAQS:

- Lower Standard (12μg/m3) finalized by EPA In 2012.
- All Arkansas counties currently in attainment.

1 hour SO2 NAAQS:

- To meet a July 2, 2016 court-ordered deadline, EPA designated Jefferson County as "Unclassifiable/Attainment". Independence County was designated as "Unclassifiable" primarily due to EPA's interest in a nearby large emitter. ADEQ has worked with Entergy and representatives of nearby source to pursue innovative modeling approach which demonstrates attainment for Independence County.
- Anticipate formal request to re-designate Independence County as "Unclassifiable/Attainment" in near-term.

8 hour Ozone Standard:

- Current standard: 70 ppb (primary and secondary standards)
- All Arkansas counties currently in attainment.
- ADEQ currently developing long-range transport SIP to address good neighbor provisions of CAA.

Coal Combustion Residuals (CCR)

- Enforcement is primarily through Citizen Suits. After the WIIN Act, EPA does have enforcement power for violations of the CCR Rule ("open dumping") but is not anticipated to use it under this Administration.
- Regulates CCR under Subtitle D of RCRA as a special waste. The rule sets Federal, self-implementing standards on CCR management practices, landfills (both new and existing), and ash ponds (both new and existing), and potentially could require upgrades or closure of existing on-site CCR disposal facilities. The rule is enforceable by EPA as well as through Citizen Suits.
- As required, the following materials documenting compliance actions for existing regulated CCR landfills at WB and ISES have been prepared and posted to the Facility Operating Record and the publically available CCR websites current copies of:
  - Various operating plans - Fugitive Dust Control Plans, Run-on/Run-off Control Plans, Landfill Closure and Post Closure Plans.
  - Annual Operating Reports – Landfill Inspection Reports stamped by a PE and Annual Fugitive Dust Control Reports.
  - PE certifications of monitoring well networks and selection of Statistical Method.
  - 2017 Annual Groundwater Monitoring and Corrective Action Report.

Effluent Limitation Guideline (ELG)

- Regulates NPDES discharges associated with Steam Electric Plants and provides for the implementation of technology based permit limits associated with these plants.
  - November 3, 2015 - EPA published the final rule.
  - Facilities (Coal Plants) will have a zero discharge requirement associated with bottom ash transport water (BATW) with compliance dates stretching between 2018-2023.
  - In 2017 Rule was revisited by EPA and compliance dates were reset between 2020 and 2023.
  - Dates were pushed back to give EPA time to re-write the rule.
  - New rule expected by 2020 with new requirements associated with BATW.

Cooling Water Intake - 316(b)

- Regulates cooling water intake structures and water withdrawals at existing facilities. Focuses on standards related to impingement, entrainment, and entrapment.
  - August 15, 2014 - EPA published the final rule.
  - Facilities are required to choose one of seven options to reduce impingement.
  - Facilities that withdraw at least 125 MGD must conduct entrainment studies.
  - New units added to an existing facility are required to reduce mortality equivalent to one with closed cycle cooling.
  - Entergy worked with ADEQ and technical consultants to develop the appropriate information to submit with the NPDES Permit renewal applications.
  - NPDES Permit Renewal Applications were submitted January 1, 2017.
    - Expecting minimal requirements (including intake volume monitoring)
    - Do not anticipate large capital projects at any facility due to 316(b).

Clean Power Plan/CO_2

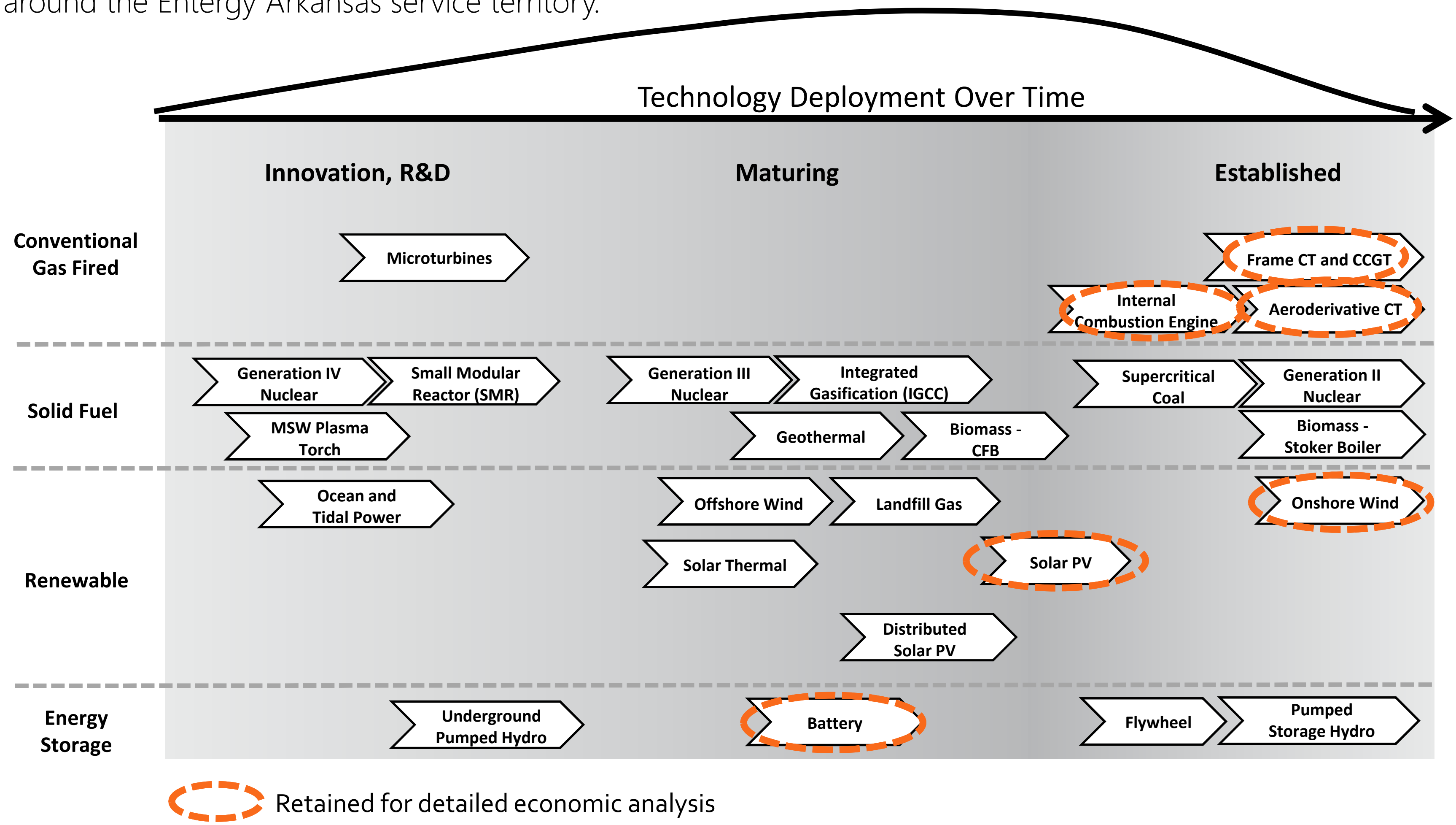
- Clean Power Plan Replacement

2018 Integrated Resource Plan

GENERATION TECHNOLOGY ASSESSMENT

The Screening Process Narrows the Focus of Economic Modeling

The technology evaluation includes surveying available central station electricity generation technologies (>2MW). The objective is to identify as wide a range of technologies that are reasonable to consider. Alternatives evaluated are technologically mature and could reasonably be expected to be operational in or around the Entergy Arkansas service territory.



Gas Resource Alternative Assumptions

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017 $/kW-yr]	Variable O&M [2017 $/MWh]	Heat Rate [Btu/kWh]	Assumed Capacity Factor [%]	Levelized Real Cost of Electricity (2020$)
Combined Cycle Gas Turbine (CCGT)	*1x1 501JAC*	510	$1,238	$17.02	$3.14	6,400	80%	$50
	2x1 501JAC	1020	$1,090	$11.12	$3.15	6,400	80%	$47
Simple Cycle Combustion Turbine (CT)	*501JAC*	300	$833	$2.84	$13.35	9,400	10%	$134
Aeroderivative CT	*LMS100PA*	102	$1,543	$5.86	$2.90	9,397	20%	$123
Reciprocating Internal Combustion Engine (RICE)	*7x Wartsila 18V50SG*	128	$1,642	$31.94	$7.30	8,401	30%	$107

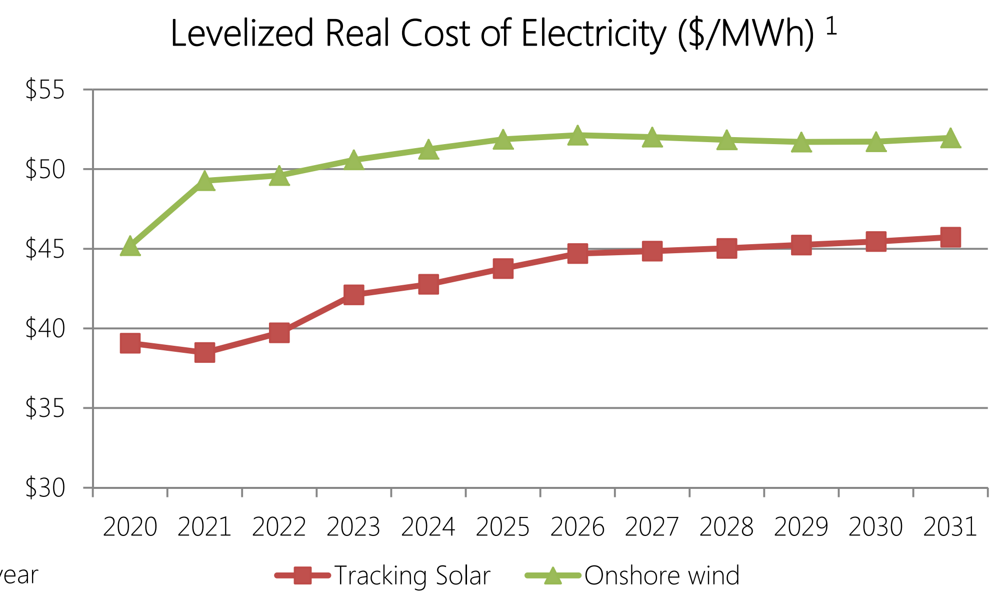
Renewable Resource Assumptions (Solar PV & Wind)

Levelized Real Cost of Electricity ($/MWh-AC) [1]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Solar Tracking [2]	$39	$38	$40	$42	$43	$44	$45	$45	$45	$45	$45	$46
Onshore Wind [3]	$45	$49	$50	$51	$51	$52	$52	$52	$52	$52	$52	$52

Other Modeling Assumptions

	Solar	Wind
Fixed O&M (2017$/kW-yr-AC)	$16	$23.46
Useful Life (yr)	30	25
MACRS Depreciation (yr)	5	5
Capacity Factor	26%	41%
DC:AC	1.35	N/A
Hourly Profile Modeling Software	PlantPredict	NREL SAM



1. Year 1 levelized real cost for a project beginning in the given year
2. ITC normalized over useful life and steps down to 10% by 2023
3. PTC steps down to 40% by 2020 and expires thereafter

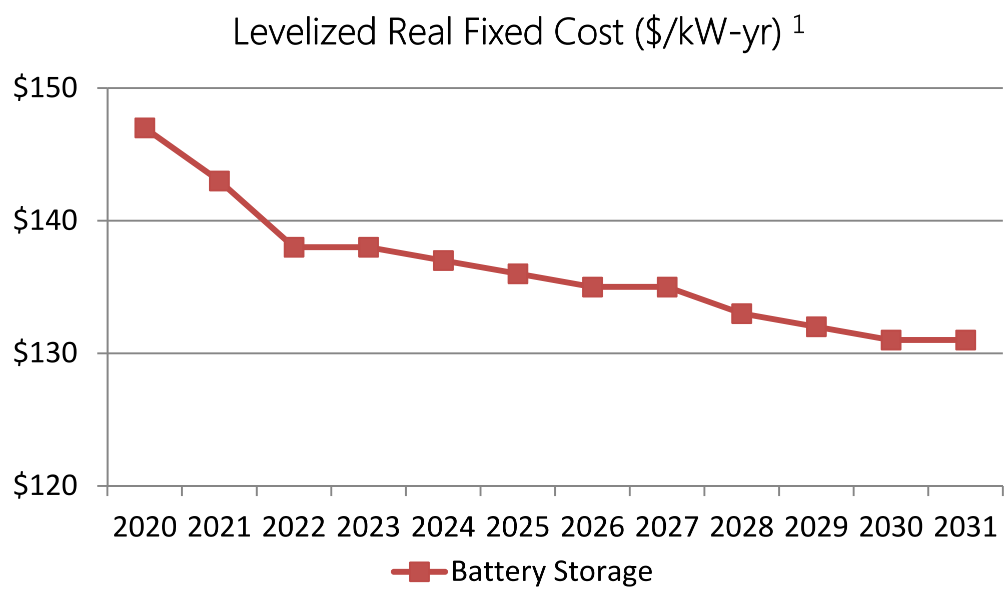
Battery Storage Assumptions

Levelized Real Fixed Cost ($/kW-yr) [1]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Battery Storage	$157	$152	$146	$146	$146	$144	$144	$143	$141	$140	$139	$139

Other Modeling Assumptions

	Battery Storage
Energy Capacity: Power [2]	4:1
Fixed O&M (2017$/kW-yr)	$9.00
Useful Life (yr) [3]	10
MACRS Depreciation (yr)	7
AC-AC efficiency	90%
Hourly Profile Modeling Software	AURORA



1. Year 1 levelized real cost for a project beginning in the given year
2. Current MISO Tariff requirement for capacity credit
3. Assumes daily cycling, no module replacement cost, full depth of discharge

2018 Integrated Resource Plan

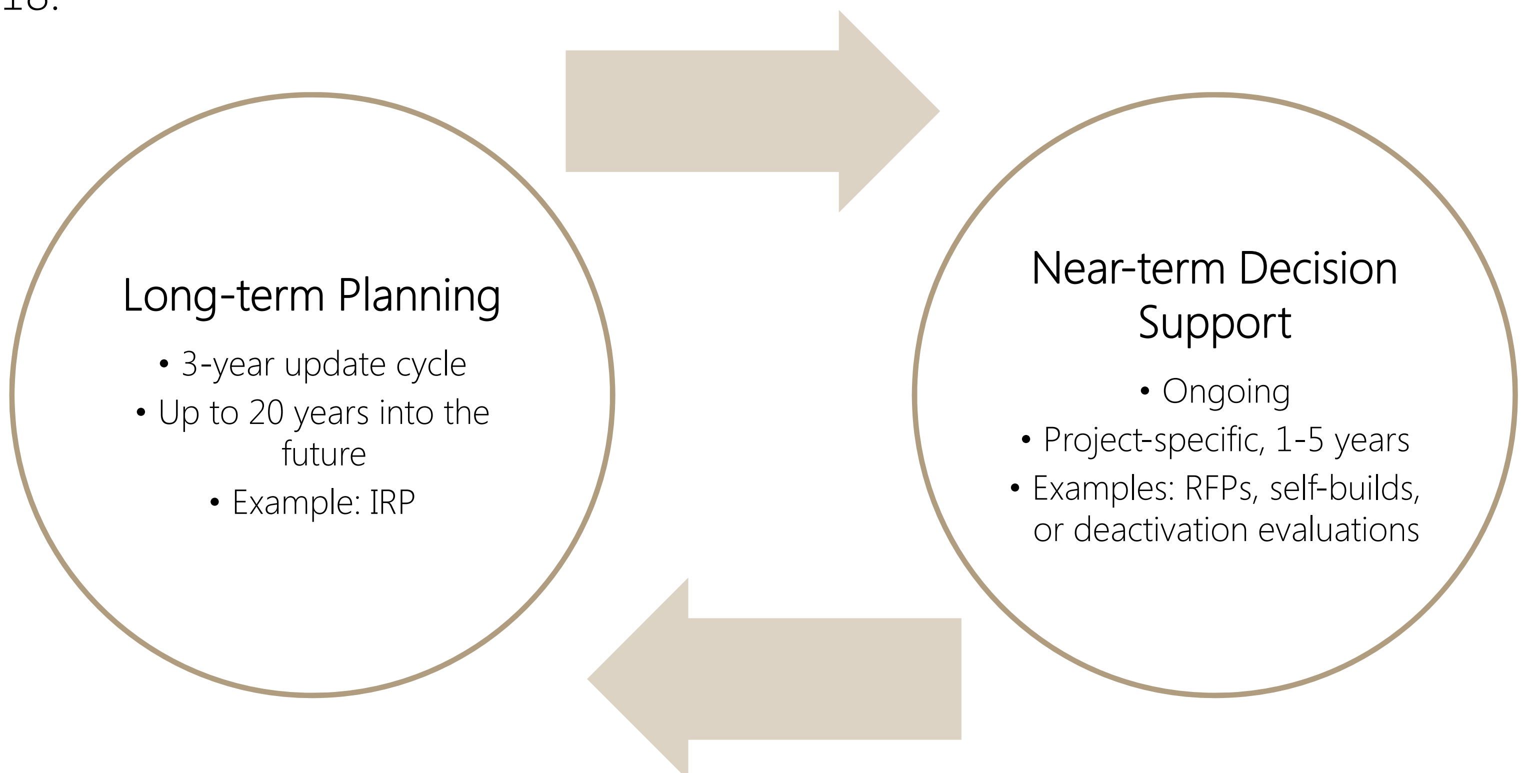
LUNCH – WILL RESUME AT [12:40]

2018 Integrated Resource Plan

IRP PROCESS OVERVIEW

Integrated Resource Planning

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 has begun 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, 2018.



2018 Integrated Resource Plan

- Evaluation period: 2020 through 2039.
- Employ a futures-based approach with additional sensitivity analysis to capture a broad range of uncertainty.
- Utilize the AURORA Energy Market Model to perform Long-term Capacity Expansion Modeling.

Integrated Resource Plan Development

Long-term Outlooks for the Industry/Region	•Generation technology costs •Electricity sales/economic indicators •Fuel and CO_2 Prices
Impact on the Overall Market	• How the long-term outlooks for the industry/region may influence resource additions in the region overall.
Impact on EAI	• How the long-term outlooks and resource additions in the region may influence resource additions for EAI.
IRP Action Plan	• Output of the IRP which provides directional guidance to EAI's planning activities until the next update to the IRP.

Modeling Process

- **Market Model**
  - Simplified model will be used to develop the market build scenarios for each future.
    - 2 Pool model: MISO, EAI
    - Build out MISO Pool to achieve target resource mix, not in excess of need
- **Initial Production Cost Simulation**
  - Simulate market in each future to generate market price curve (i.e. LMPs) for MISO, excluding EAI
- **Long-term Capacity Expansion Model**
  - Optimize supply and demand side alternatives to create a portfolio under each future
    - 12% Reserve Margin target
    - Unlimited transfer capability between MISO pool and EAI
    - Portfolio addition decisions based on maximizing value of supply additions
- **Final Production Cost Simulations**
  - Compute Variable Supply Costs for each future and its sensitivity's portfolio obtained through Capacity Expansion Model

2018 Integrated Resource Plan

FUTURES DEVELOPMENT

2018 IRP Analytical Framework

In an approach consistent with EAI's 2015 IRP, EAI Resource Planning has used a futures-based approach to the IRP analysis. This approach reasonably accounts for a broad range of uncertainty while focusing on an appropriate amount of meaningful, thoughtful modeling iterations.

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
- Cost and performance of generation technologies
- Customer usage trends
- Commodity price trends

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

2018 IRP Futures

Low Growth

- Low peak load growth and natural gas prices tied to slumping demand.
- Accelerated deactivation assumption for non-EAI coal and legacy gas units in the market.

Reference

- Baseline for comparison to additional futures and sensitivities.
- Inputs expected case values for key inputs, including forecasted energy and load, natural gas, and CO_2.

High Growth

- Peak load growth and high natural gas prices tied to increasing demand.
- Slightly accelerated deactivation assumption for non-EAI coal and legacy gas units.
- 30% of Solar PV installations augmented with battery storage to stabilize LMPs.

Futures – Market Assumptions

	Reference Future	Low Future	High Future
Market Coal Deactivations	60 years	55 years	50 years
Market Legacy Gas Fleet Deactivations	60 years	55 years	50 years
Magnitude of Market Coal & Legacy Gas Deactivations	12% by 2028 54% by 2038	31% by 2028 88% by 2038	54% by 2028 91% by 2038
Incremental Market Resources (Renewables / Gas)	34% / 66%	25% / 75%	50% / 50%

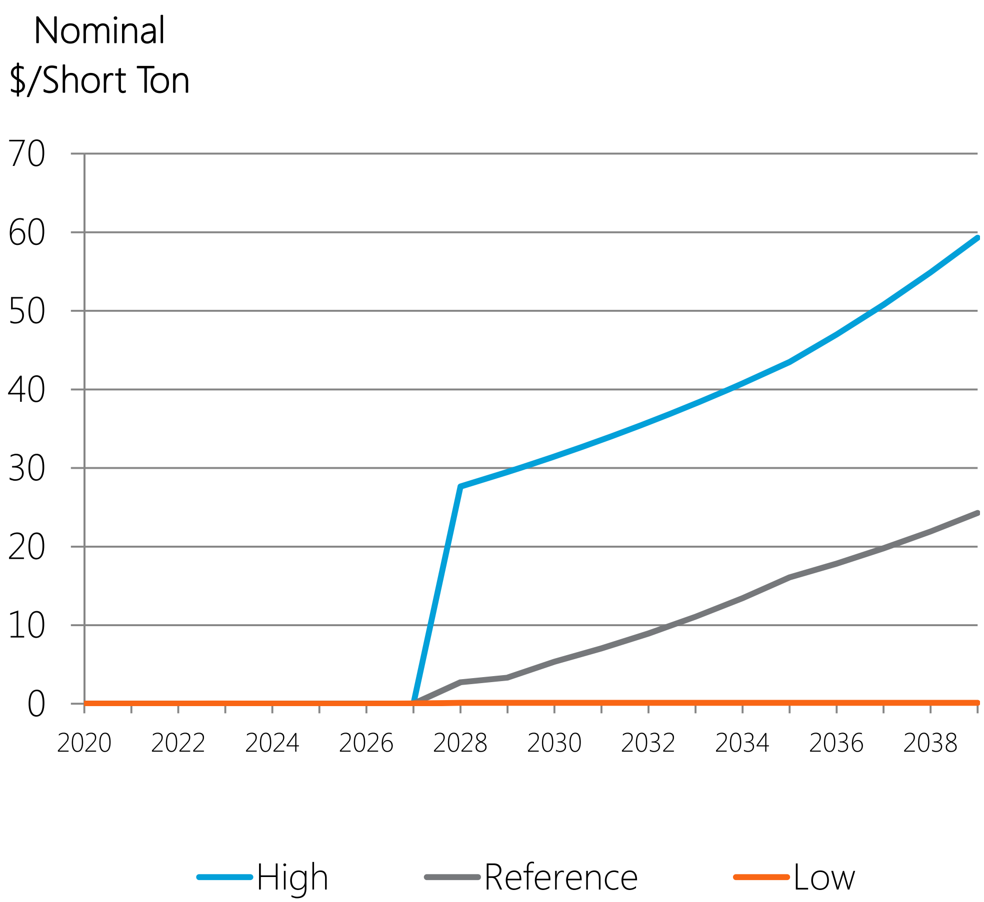
Notes:
1. *Renewables / gas percentages apply only to incremental generation in MISO South.*

Futures – Macro Assumptions

	Reference Future	Low Future	High Future
Peak & Energy Load Growth	Reference	Low	High
Natural Gas Prices	Reference ($5.01)	Low ($3.40)	High ($6.78)
CO_2 Price Forecast	Reference	Low	High

CO_2 Price Forecast Scenarios

EAI's POV is that natural carbon regulation for the power generation sector will occur, though the timing, design, and outcome remain uncertain.



- Low: represents a scenario where either no program exists or only program(s) that require on-site measures rather than a tradeable commodity.
- Reference: a mid-case scenario that represents a regional mass-based cap.
- High: assumes a national cap and trade program that begins in 2028 and targets an approximately 80% reduction from 2005 sector emissions by 2050.

Demand-side Evaluated with Supply-side

Through the Stakeholder Engagement Process that took place during the development of the 2015 IRP, EAI received feedback from Stakeholders on modeling of demand-side resource alternatives.

Customer Load & Energy Requirements

- Includes steady growth of EE portfolio
- Captures measure lives specific to EE portfolio
- Includes organic EE

Capabilities

- Existing and planned generation resources with assumed useful life
- Existing Load Modifying Resources
- New-build CT, CCGT, Renewables
- Additional Utility-sponsored DSM Programs NEW!

ICF's DSM As A Resource Methodology

- Engaged with ICF to develop potential, incremental Utility-sponsored DSM Programs to be evaluated as resources in AURORA's Capacity Expansion Model.

- Demand Response Portfolios (DR)
  - Low/Mid/High DR portfolios developed using five Direct Load Control (DLC) Programs and one Commercial TOU program.
  - Portfolio Targets:
    - Low: 25MW, Mid: 50MW, High: 100MW

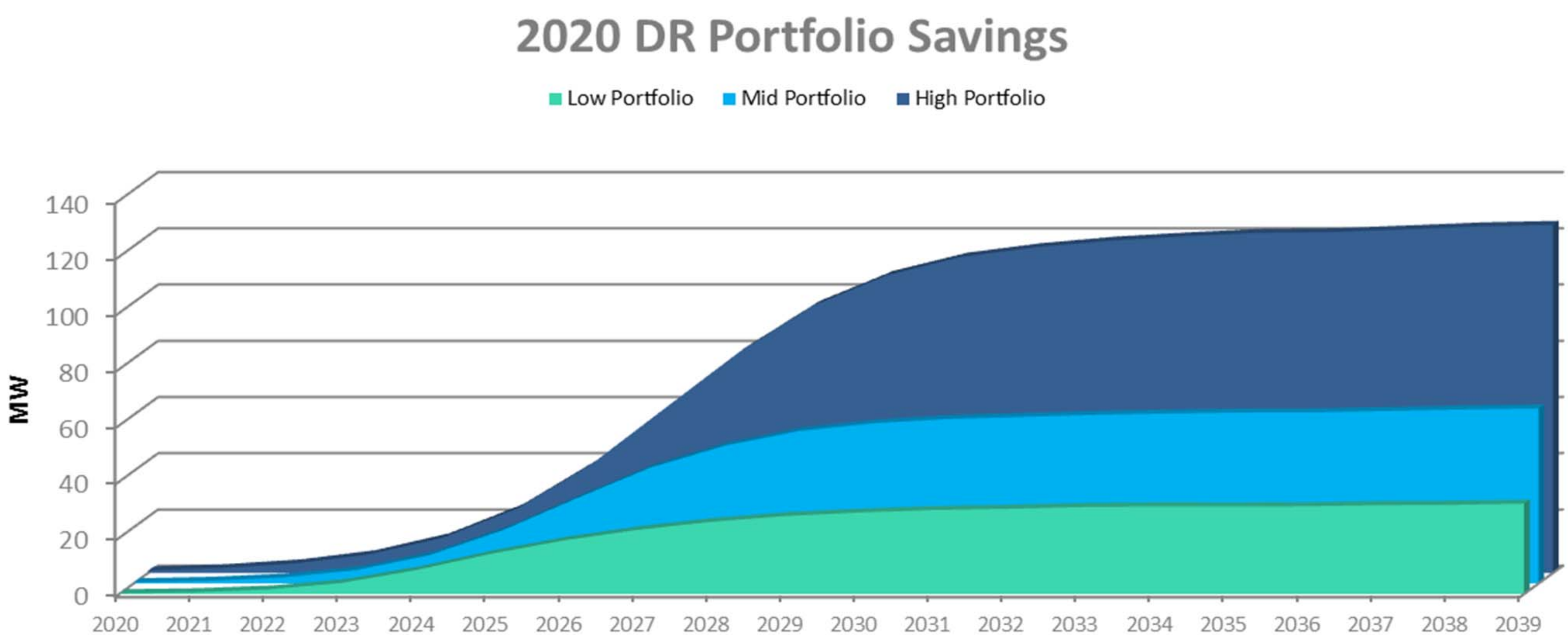
- Energy Efficiency Portfolios (EE)
  - Low/High EE portfolios developed for Industrial Self-Direct customers based on percentage of compliance with APSC EE goals.[1]
  - Portfolio Baselines:
    - 50% EE Compliance (Low), 25% EE Compliance (High)

- Multiple start dates for each resource portfolio
  - 2020, 2025 and 2030 available for modeling

[1] *Compliance percentage denotes the assumed % of existing self-direct industrial customers at program start*

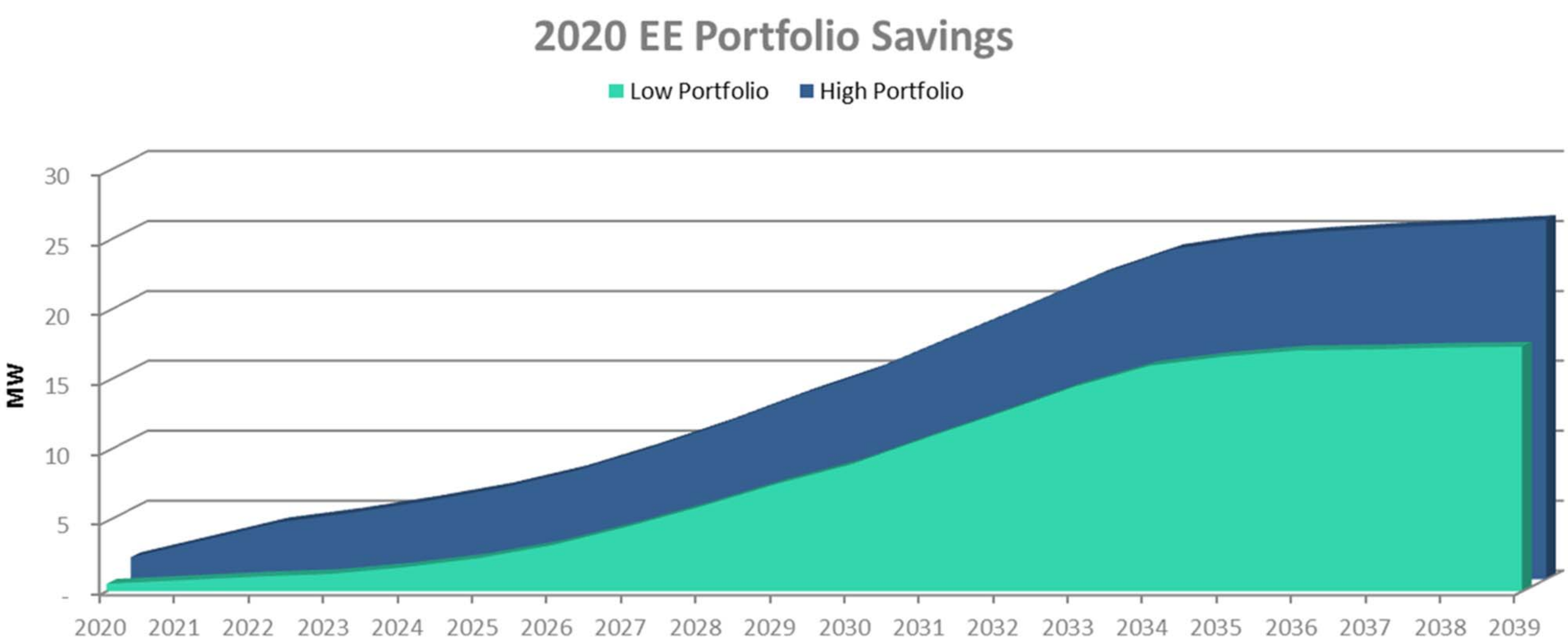
Demand Response Portfolios

- AURORA takes into account program start date options, assumed program life, hourly DR profiles, and annual program costs.
- DR Portfolios are mutually exclusive; AURORA cannot select more than one in the Capacity Expansion Model.
- Nine total portfolios available for modeling (3 Portfolios x 3 Start Dates)



Energy Efficiency Portfolios

- AURORA takes into account program start date options, assumed program life, hourly EE profiles, and annual program costs.
- EE Portfolios are mutually exclusive; AURORA cannot select more than one in the Capacity Expansion Model.
- Six total portfolios available for modeling (2 Portfolios x 3 Start Dates)

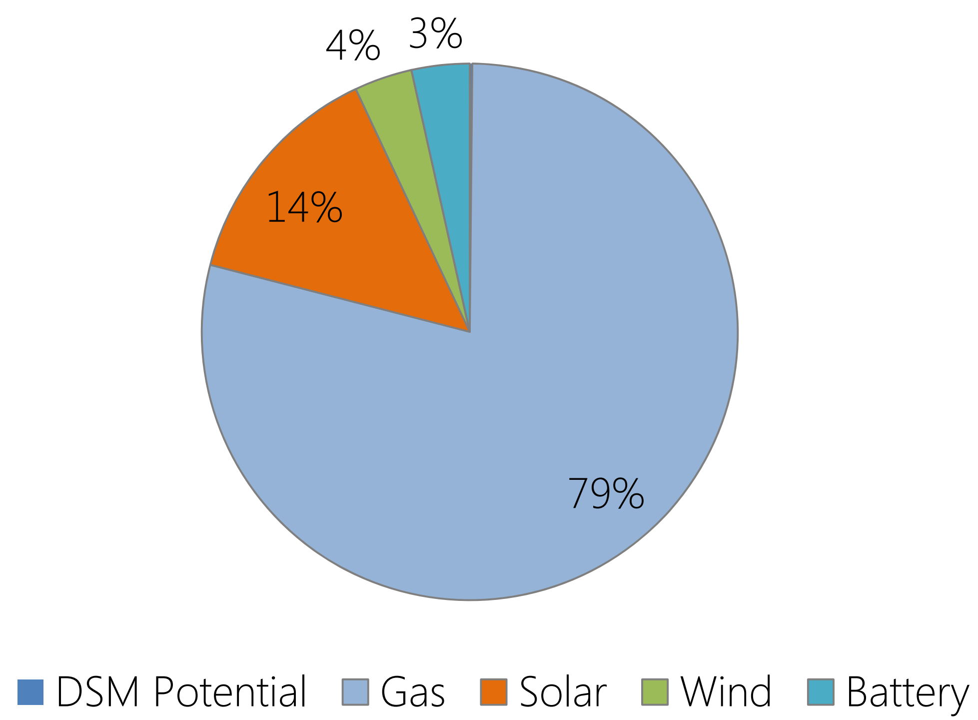


2018 Integrated Resource Plan

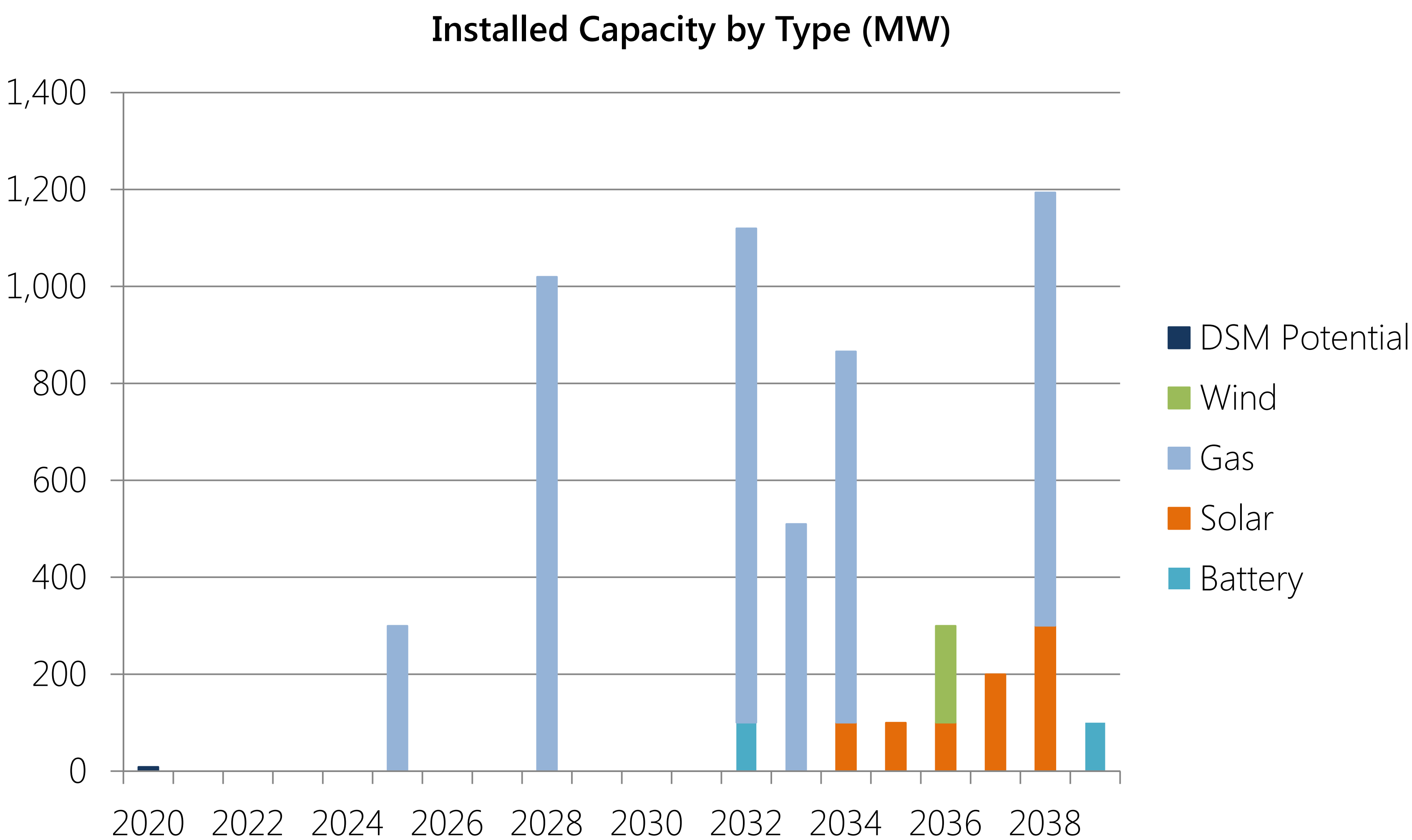
PRELIMINARY RESULTS

Reference Case Future Portfolio Mix

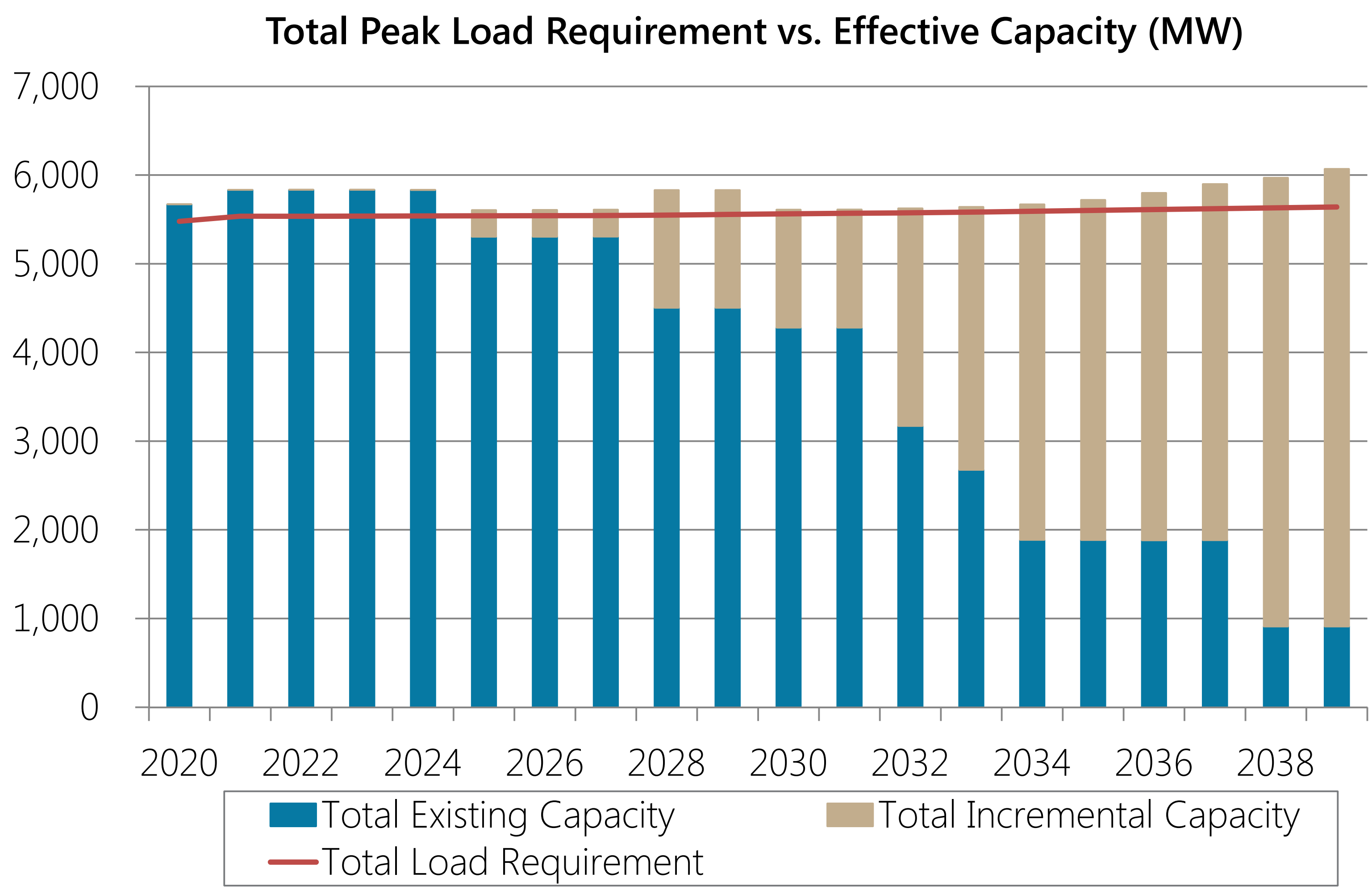
The Capacity Expansion Modeling for the Reference Case Future optimized a future portfolio that is largely comprised of natural gas-fired resources while the rest of the portfolio is a mix of renewables and battery storage. The incremental Energy Efficiency Portfolio at the low level was also selected (DSM Potential).



Reference Case Future Capacity Expansion Results



Reference Case Future Load & Capability



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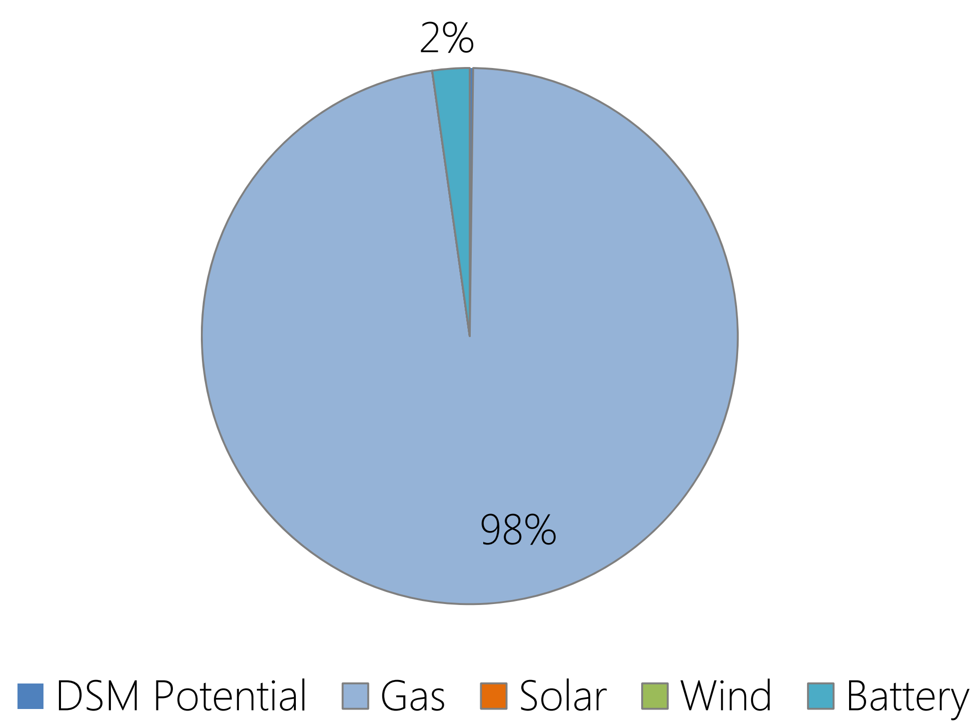
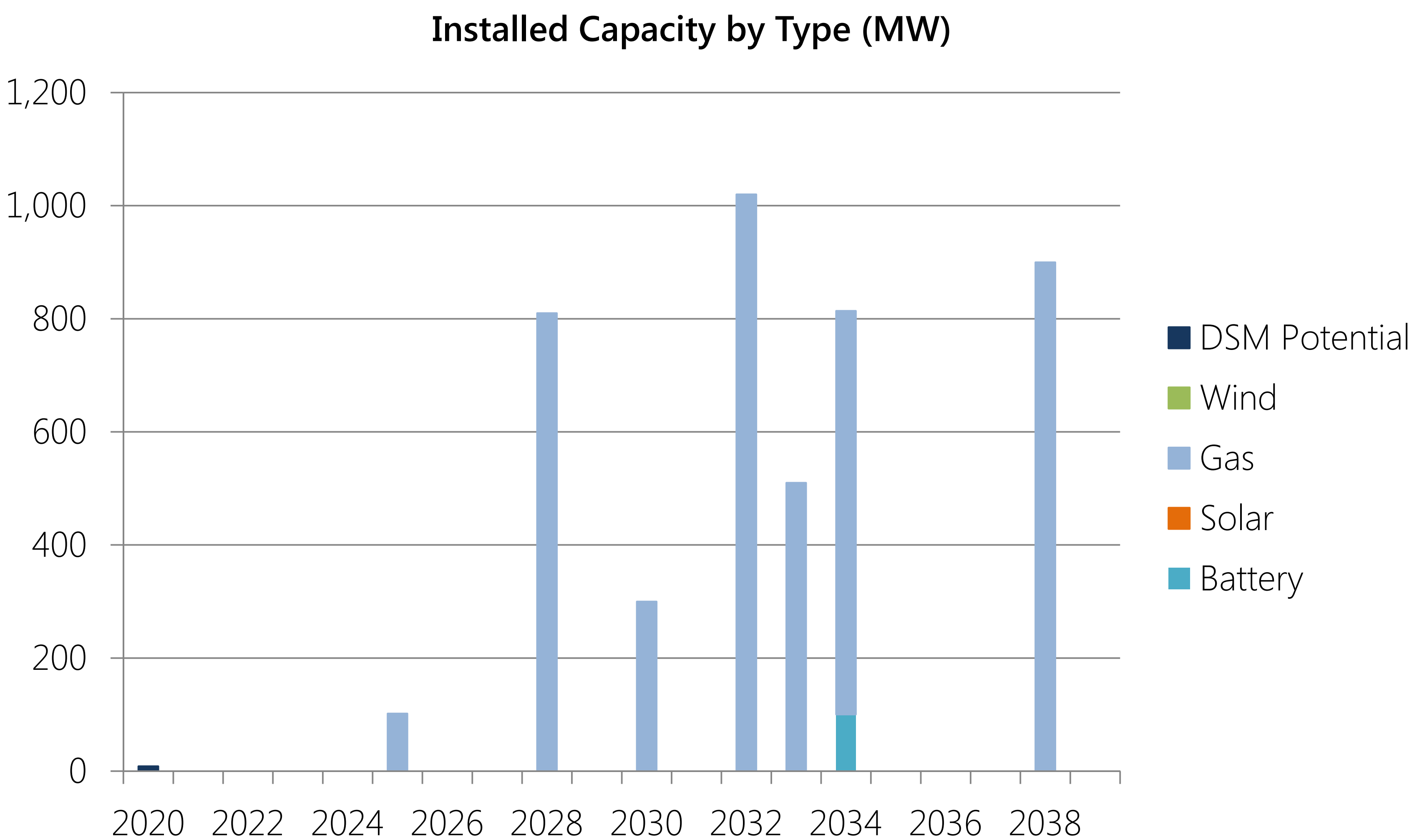
Lower Growth Future Portfolio Mix

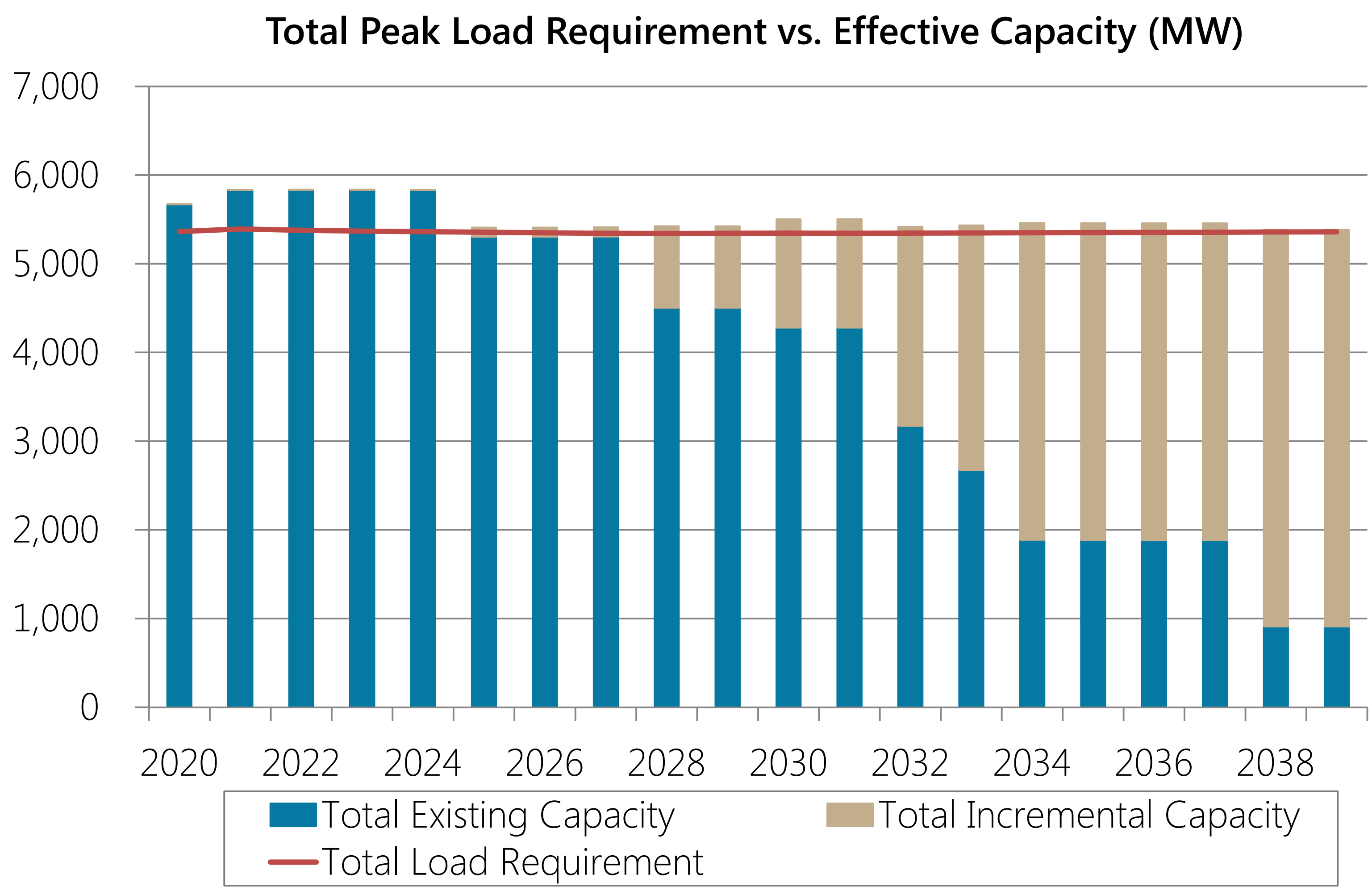
The Capacity Expansion Modeling for the Lower Growth Future optimized a future portfolio that is primarily fueled by natural gas. One battery energy storage resource and the incremental Energy Efficiency Portfolio at the low level were also selected.



Lower Growth Future Capacity Expansion Results

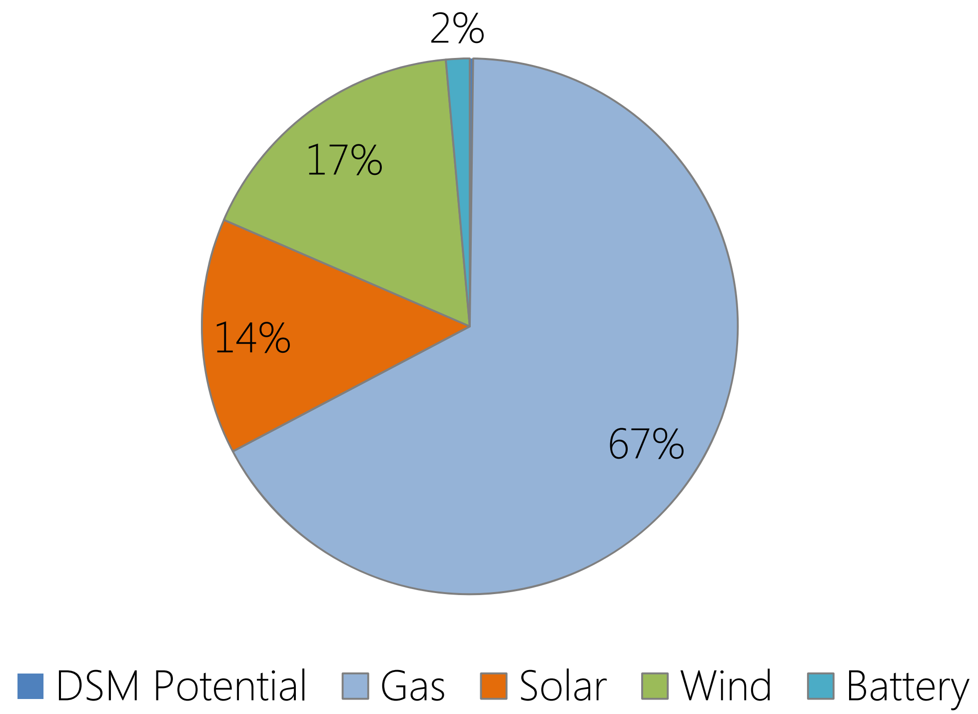


Lower Growth Future Load & Capability

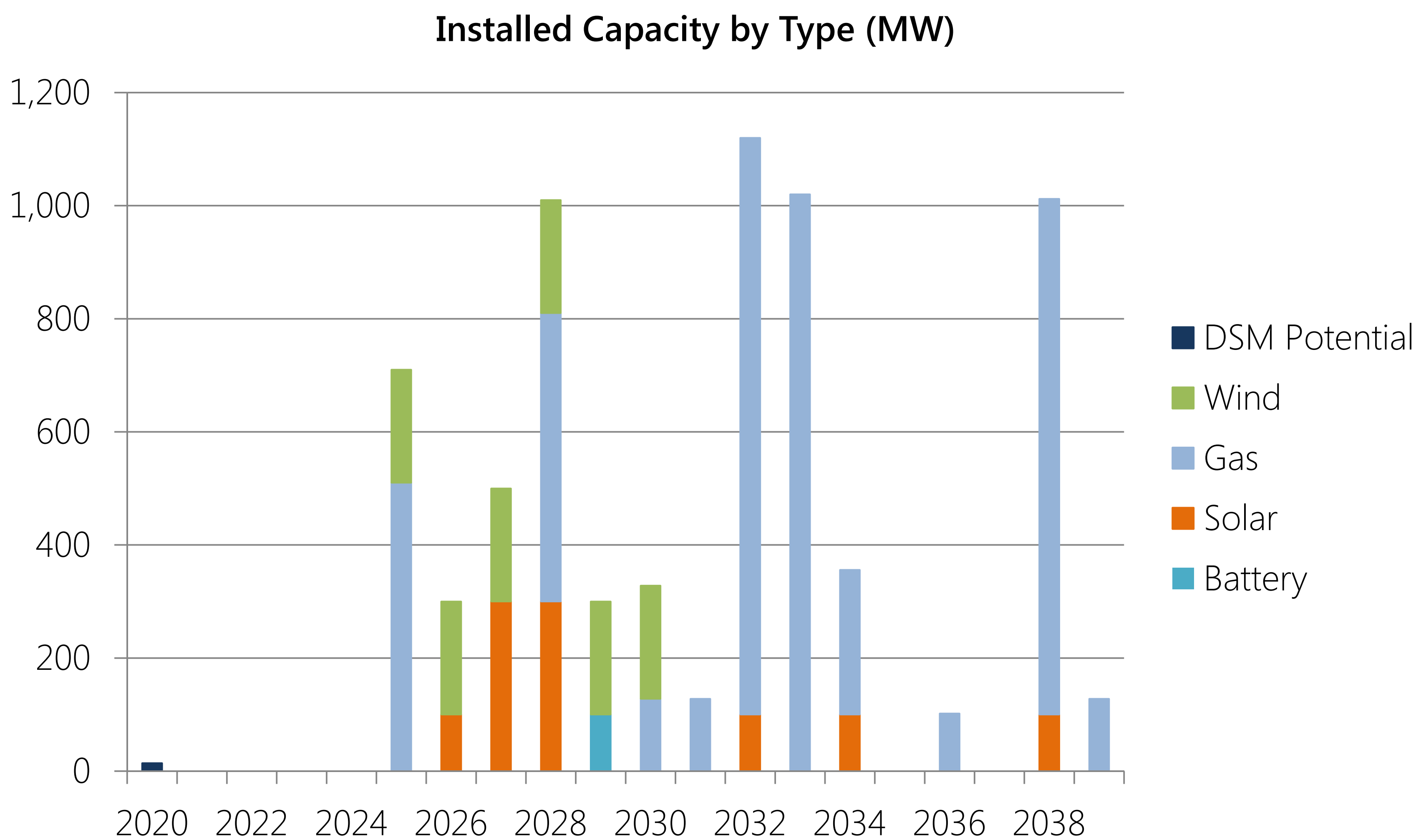


Higher Growth Future Portfolio Mix

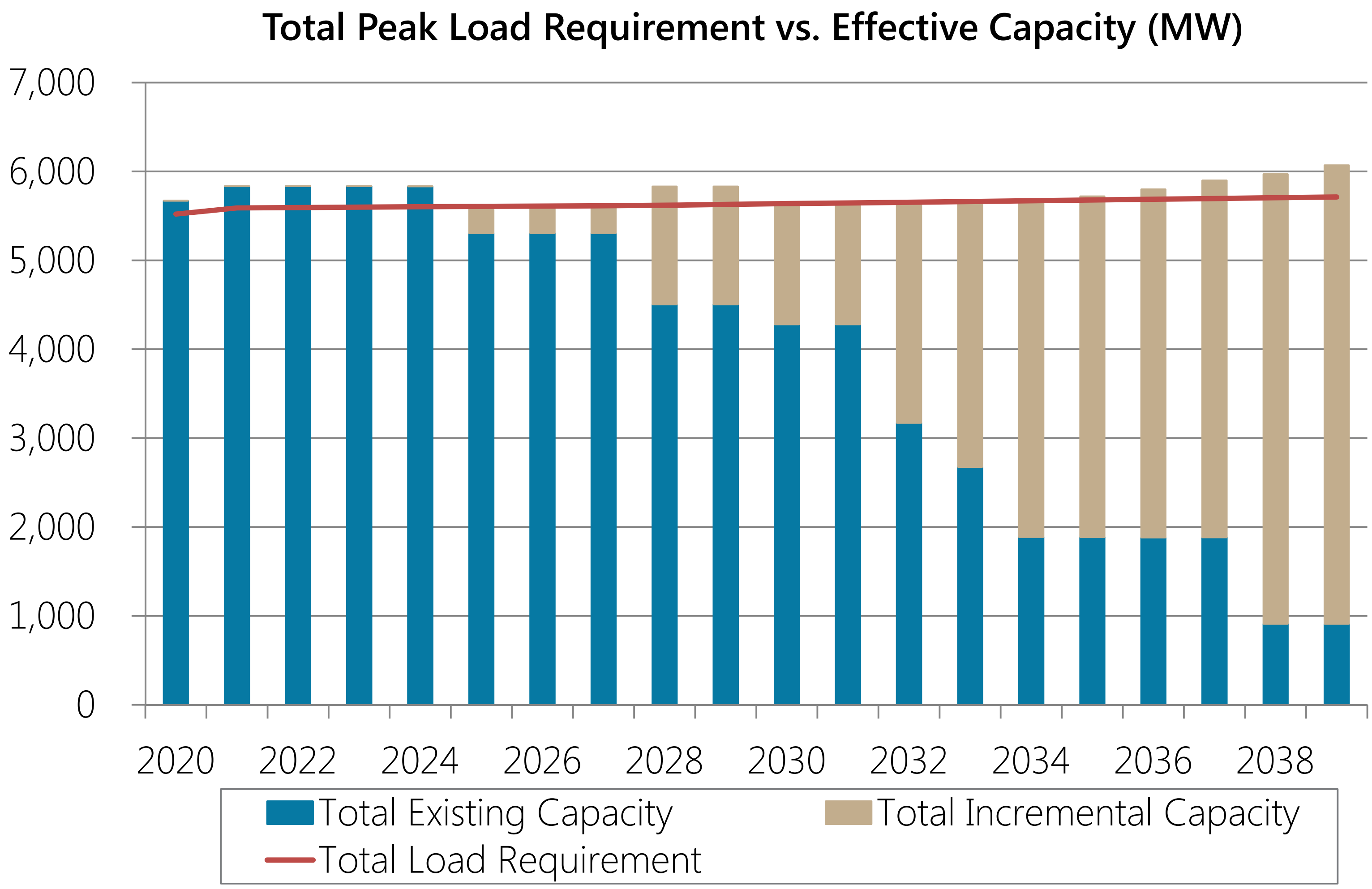
The Capacity Expansion Modeling for the Higher Growth Future optimized a future portfolio that is comprised of approximately two-thirds natural gas-fired resources while the rest of the portfolio is a mix of renewables and battery storage. The incremental Energy Efficiency Portfolio at the high level was also selected.



Higher Growth Future Capacity Expansion Results



Higher Growth Future Load & Capability



Modeling Results Observations

- **Reference Case Future:** the proportion of renewables as part of the future portfolio is smaller than in the 2015 IRP Capacity Expansion Modeling (Future 1) even though the technology cost assumptions are lower.
    - Several factors are contributing to this result, but the biggest impact is coming from recently added AURORA dynamic modeling enhancements which are discussed in the following slides.
- **Lower Growth Future:** as expected, and as seen in the 2015 IRP, low gas prices, no adder for CO_2 emissions, and low load forecast scenario create a future world that favors gas-fired resources.
- **Higher Growth Future:** the high gas prices combined with a high-priced CO_2 adder disadvantages gas-fired resources enough to increase the proportion of renewable resource additions.

Impact of Increased Intermittent Resources

The increased proportion of non-dispatchable or intermittent resources in the generation portfolio, particularly solar resources, is causing a shift in the way utility resource planners analyze future portfolios.

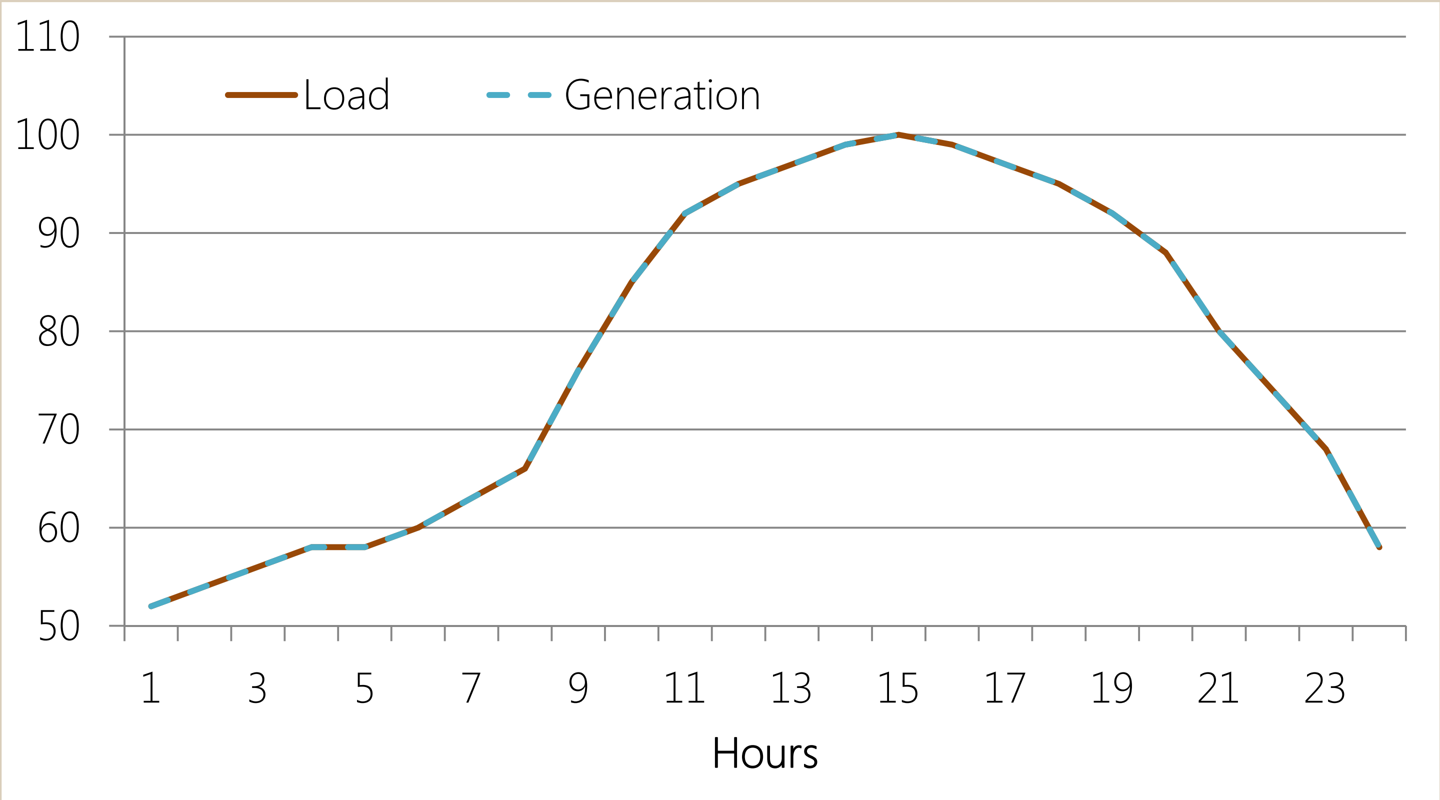
In addition to ensuring adequate capacity and reserves at the maximum hour of customer load, the focus must also now include the first few afternoon hours when solar generation is decreasing but customer loads are still elevated.

Recently, the AURORA model has added functionality to take this dual-focus into account and the portfolio optimized under the Reference Case Future is evidence of this function.

The following slides use an illustrative example to demonstrate this effect on a typical summer peak day for a hypothetical utility with 100 MW of customer load and 110 MW of capacity.

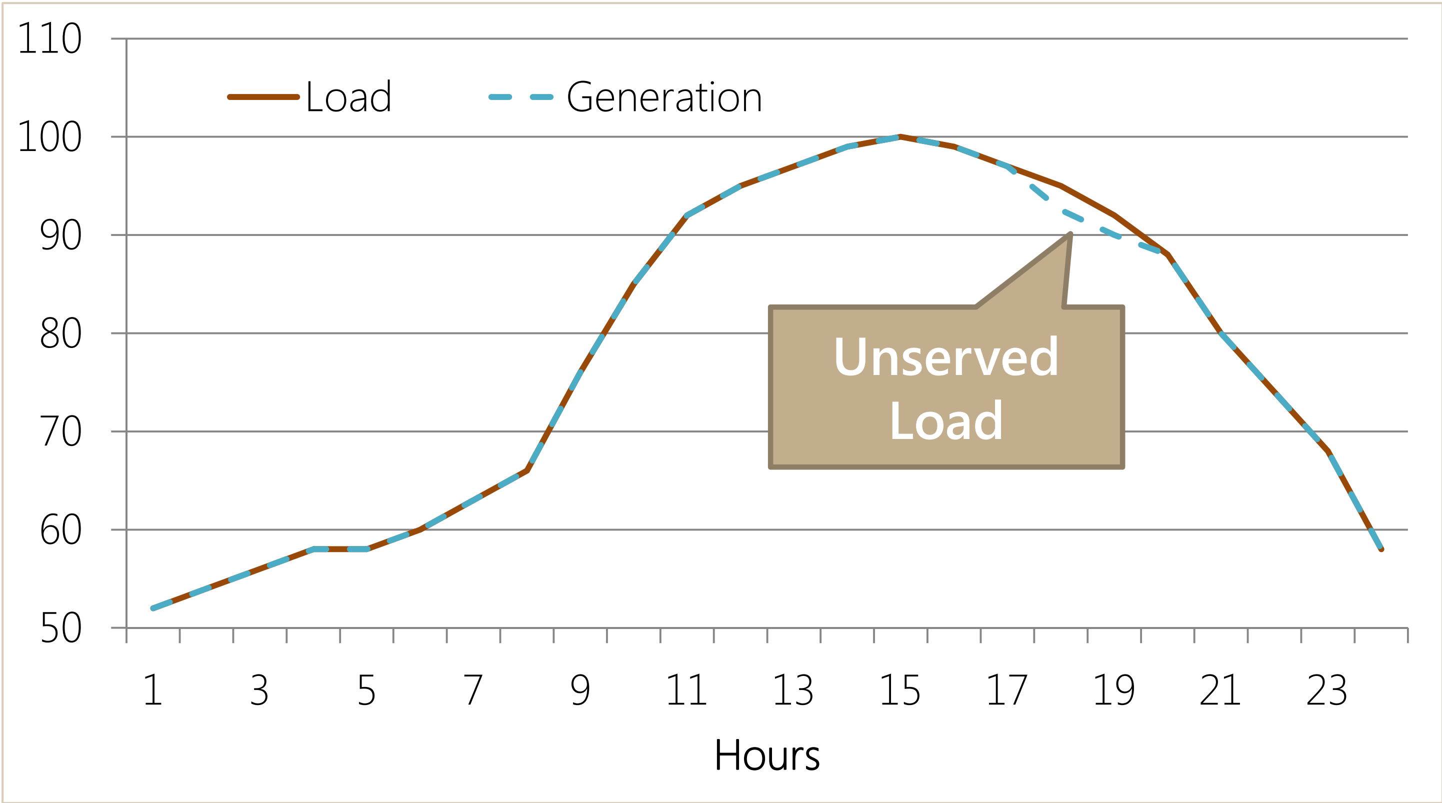
Scenario 1 Example – 100% Dispatchable Portfolio

Load	100 MW
Dispatchable Capacity	100 MW
Solar Capacity	0 MW



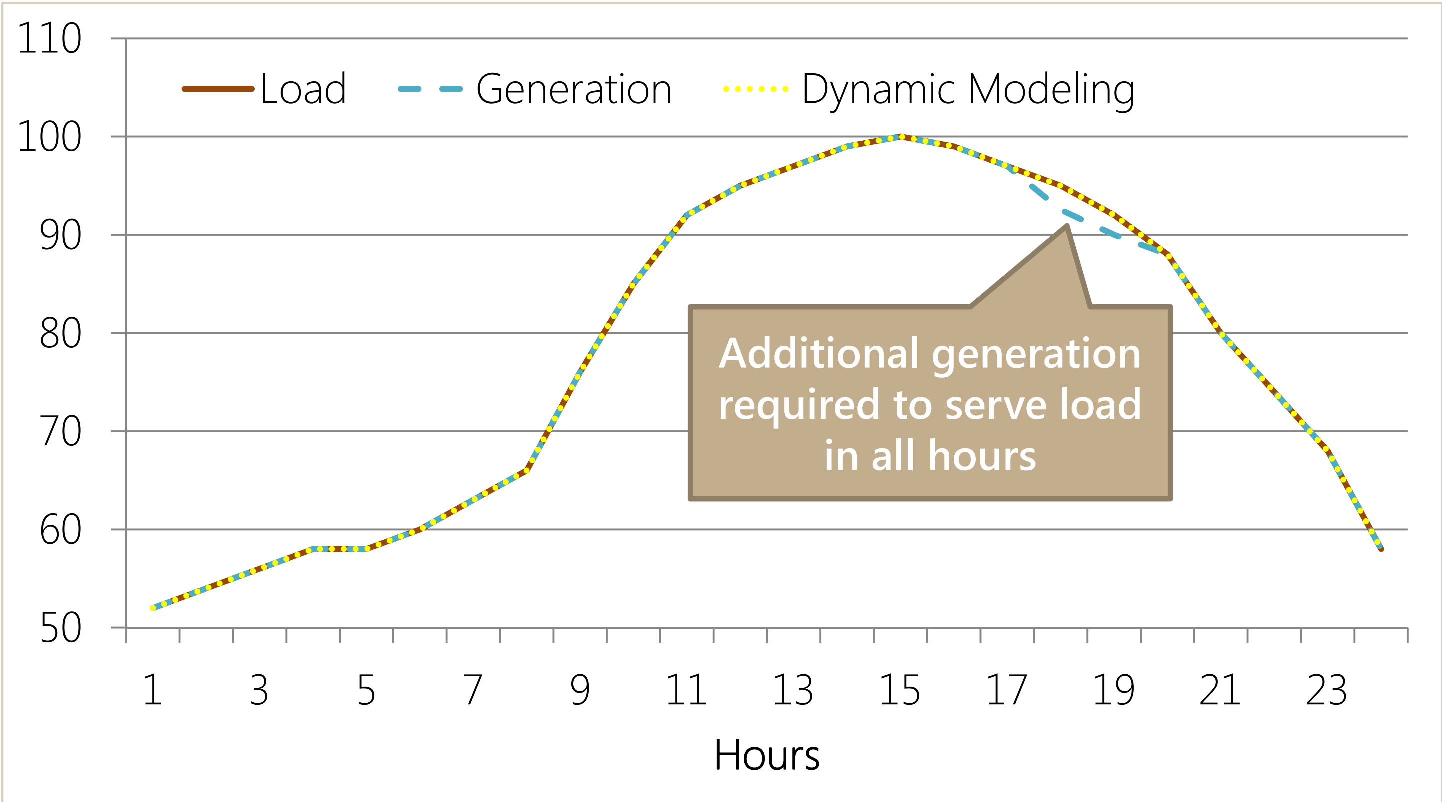
Scenario 2 Example – Adding Solar

Load	100 MW
Dispatchable Capacity	90 MW
Solar Capacity	20 MW



Scenario 3 Example – Dynamic Modeling

Load	100 MW
Dispatchable Capacity	90+5 MW
Solar Capacity	20 MW



Gas and Solar in the 2018 IRP Futures

Based on the initial evaluation of results from the 2018 IRP modeling, it appears that AURORA is seeing the capacity shortage in the afternoon/evening as demonstrated in the example on the previous slides. The model seems to be addressing this shortage by building gas technologies rather than renewables, even if its first preference is renewables.

Influencing factors are:

- increase in Solar PV generation in the market as well as in EAI's portfolio
- decrease in coal and gas-fired generation in the market as well as in EAI's portfolio
- timing and size of EAI's capacity needs

Preliminary Conclusions

- **The first supply-side resource addition in each of the three futures occurs in 2025.**
  - All three futures indicate that EAI will need to replace at least a portion of the capacity that is currently provided by Lake Catherine Unit 4 when it reaches the end of its useful life, which is assumed to be 5/31/2025 for the purposes of the IRP.
- **An incremental EE portfolio is selected in all three futures in 2020, though the level varies. No DR portfolios were selected.**
  - The economic benefit of the DR Portfolios is challenged by the assumed low price for capacity in MISO.
  - Based on the approach and assumptions used by ICF to develop the EE Portfolios, they show cost-effectiveness potential at some level in all three futures.

Next Steps: Additional Analysis

For each future, EAI is performing additional Capacity Expansion Modeling to test the sensitivity of the resource selections to certain assumptions.

Reference Future →	What if EAI's load growth is lower than expected and existing resources remain viable longer?
Low Growth Future →	What if EAI's customers use more electricity and existing resources remain viable longer?
High Growth Future →	What if EAI's customers change how they use electricity?

2018 Integrated Resource Plan

STAKEHOLDER SESSION

Stakeholder Process Timeline

ACTIVITY	DATE
Stakeholder meeting	June 6
Stakeholder / EAI interaction (as needed)	June 6 – October 1
Stakeholders finalize Stakeholder Report and provide to EAI	October 17
EAI finalizes IRP and files written report with the APSC including Stakeholder Report	October 31

2018 Integrated Resource Plan

WRAP-UP AND NEXT STEPS