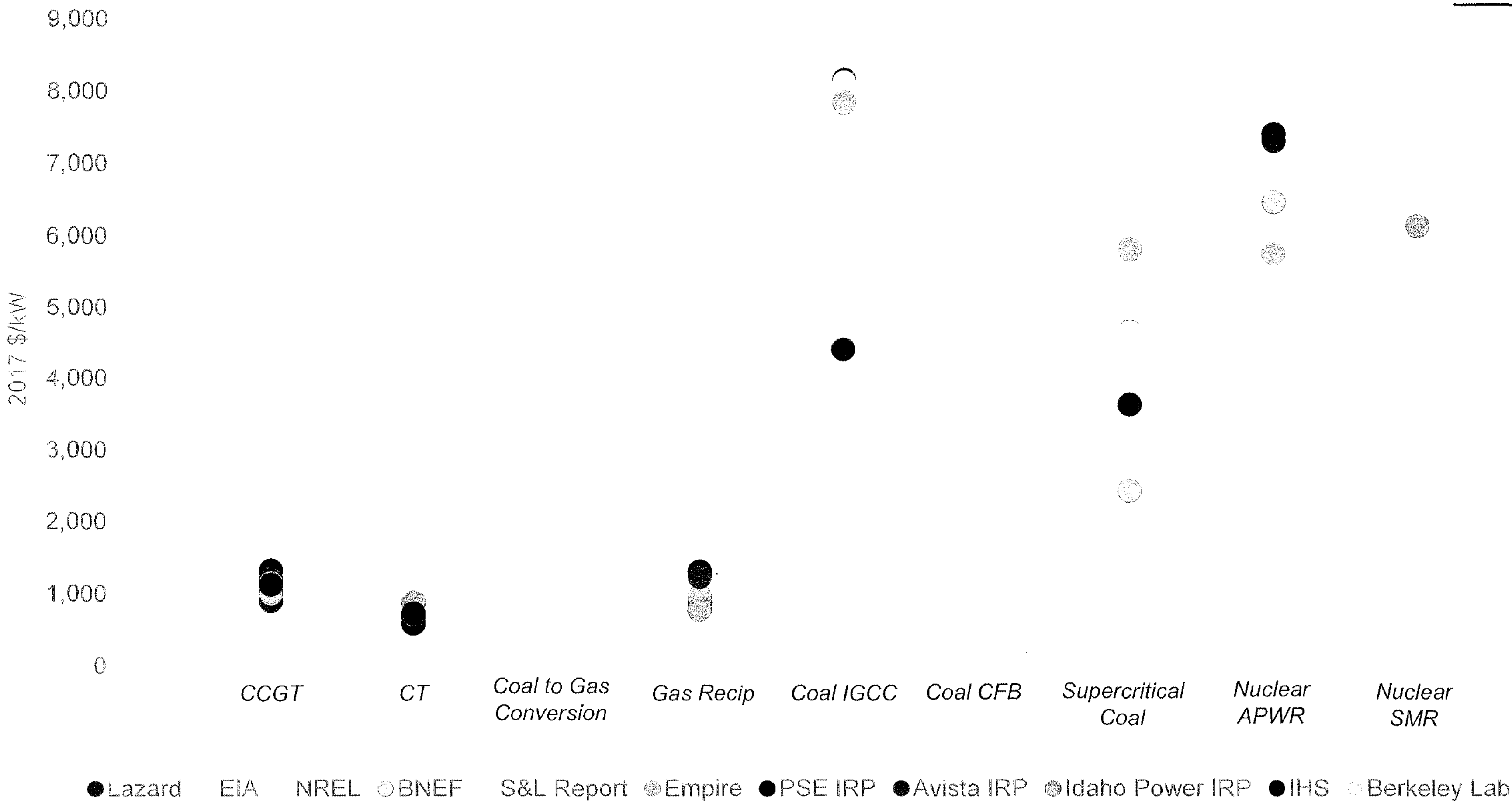
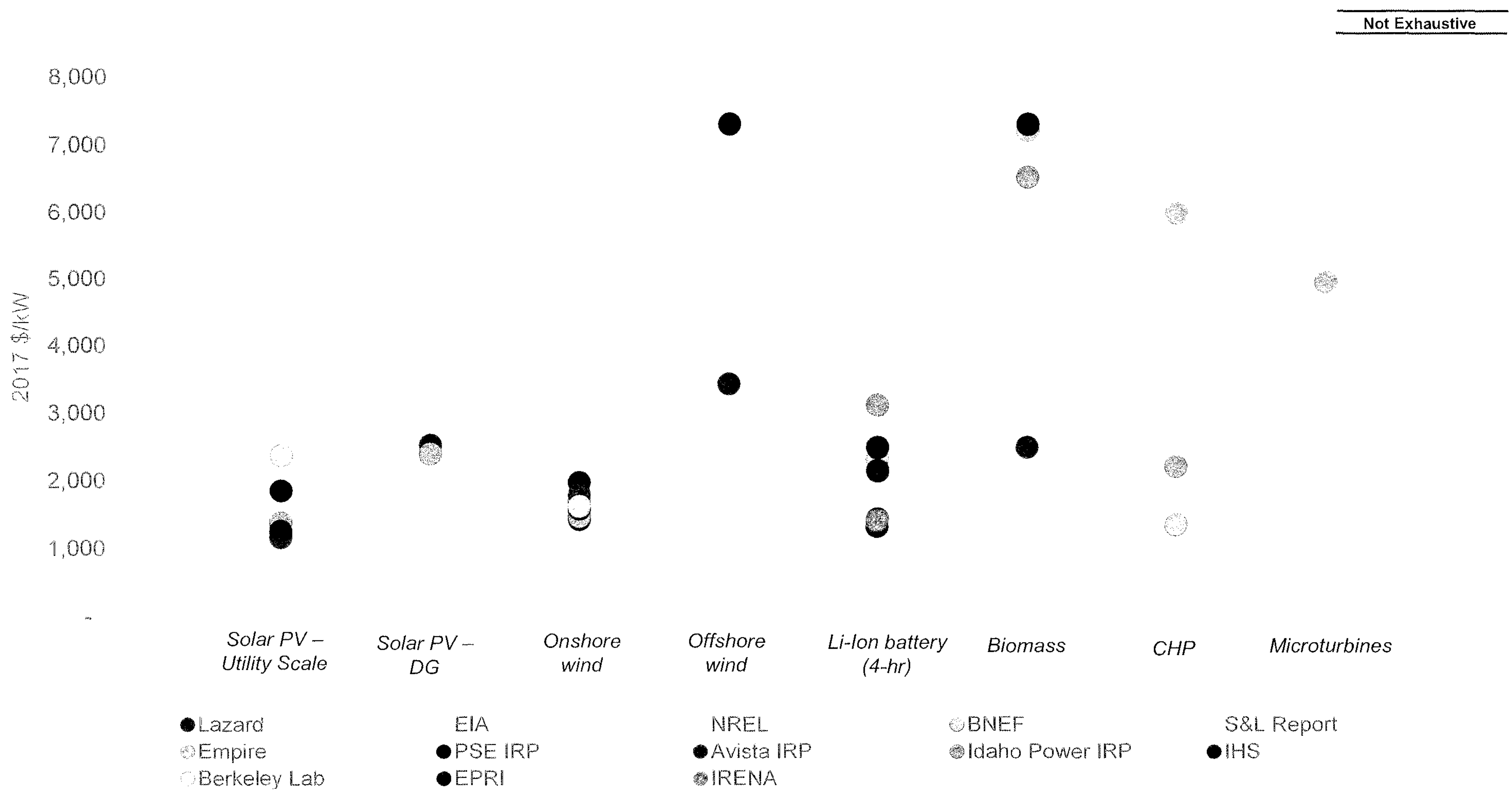
3rd Party Data Sources

Data Source	Description	Link
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)	N/A
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 AEO)	EIA Capital Cost Estimates
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)	Empire District Avista Puget Sound Energy Idaho Power
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)	Lazard LCOE V. 11.0
	Lazard Levelized Cost of Storage Version 3.0 (2017)	Lazard LCOS V.3.0
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook	IHSMarkit (subscription required)
	US Wind Capital Cost and Required Price Outlook	
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)	
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs	
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region	Bloomberg New Energy Finance (subscription required)
	Key cost input in LCOE Scenarios, 1H 2017	
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)	
National Renewable Energy Technology Laboratory	NREL Annual Technology Baseline 2017	NREL ATB 2017

Not Exhaustive

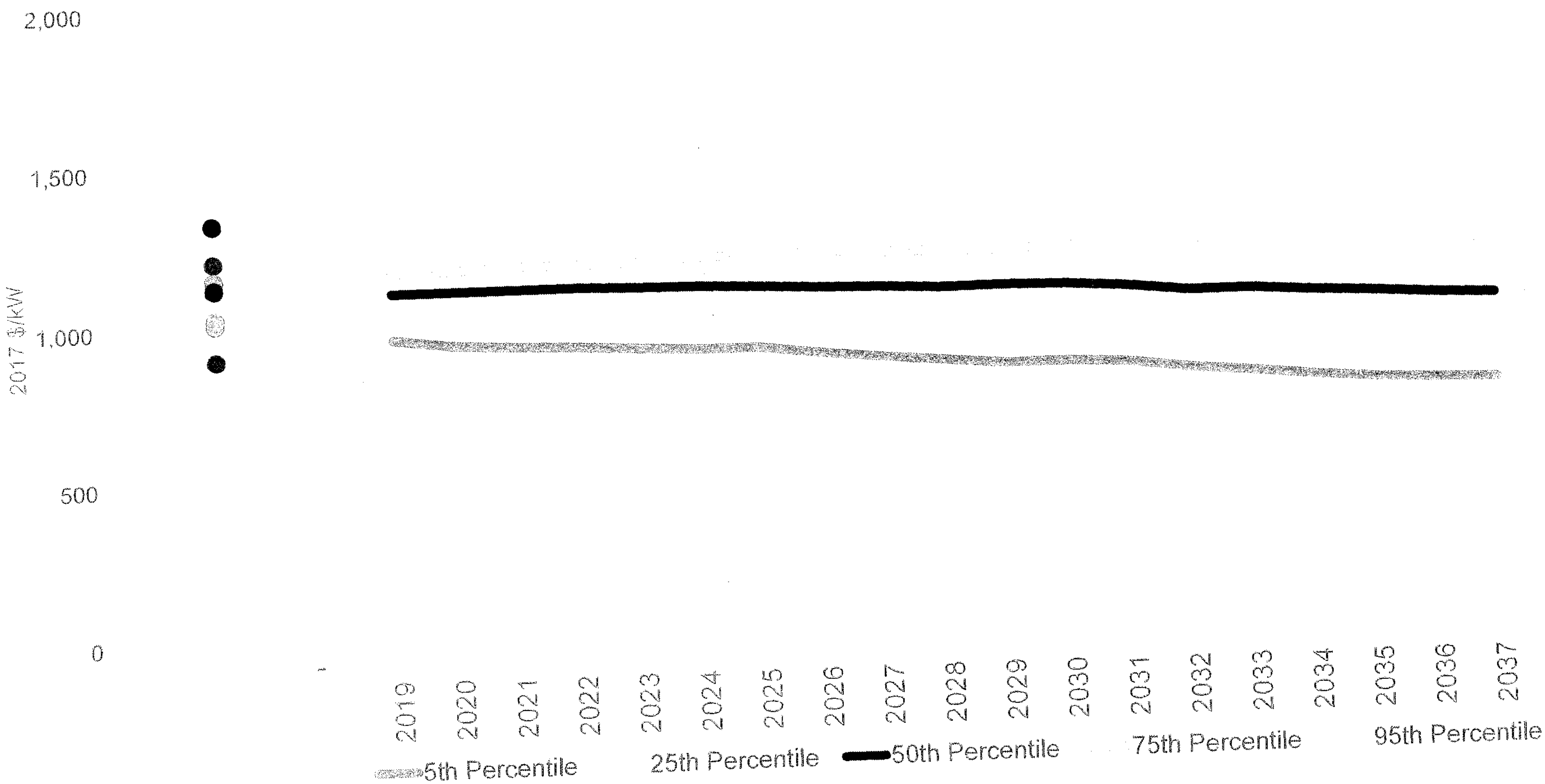


2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,276	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927



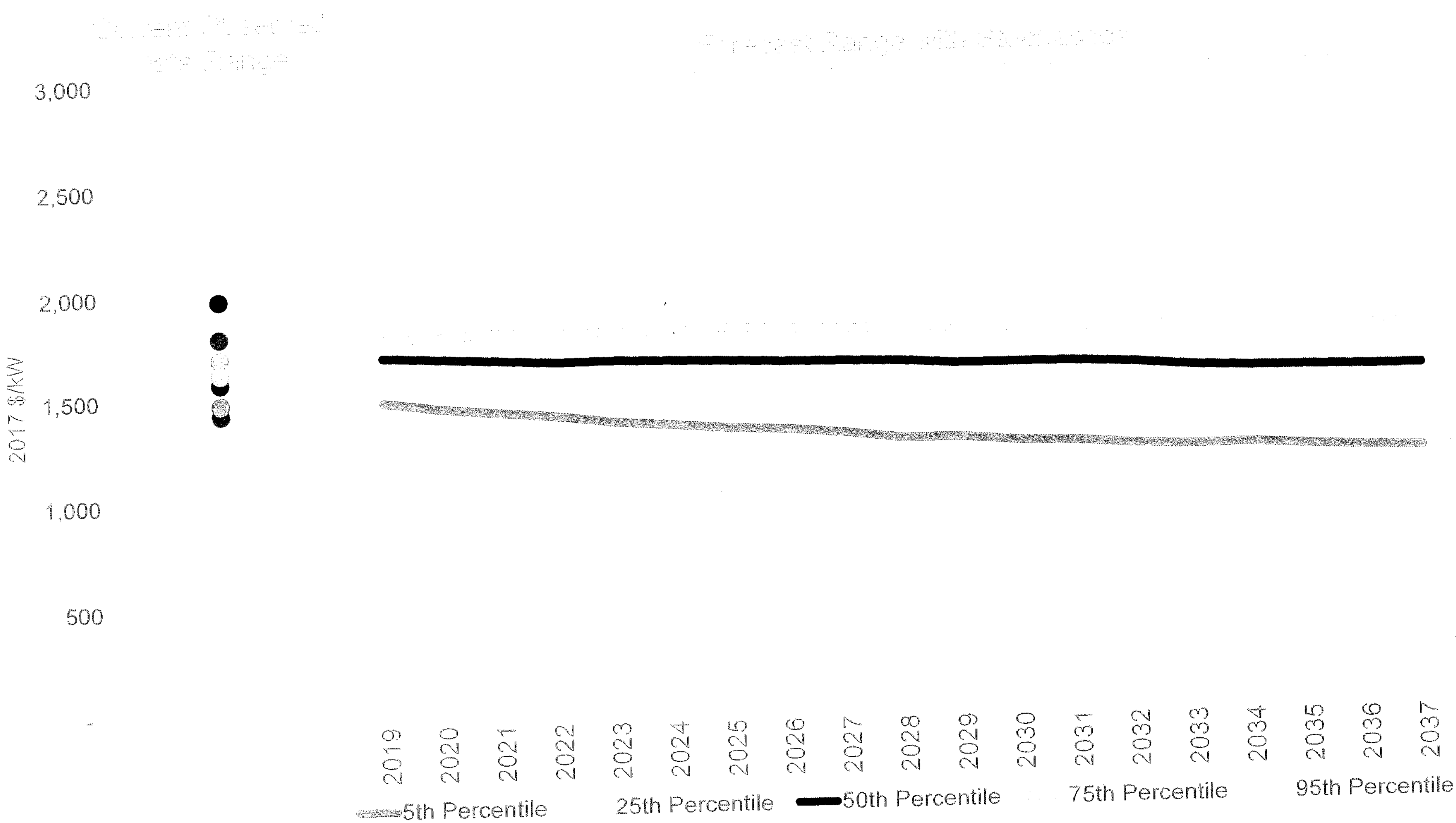
2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

- The team used the range of data sources to develop forecasts for capital costs over time that include uncertainty bands
- Methodology for developing forecasts for a given technology consisted of several steps:
  - Identify expected range of capital costs over time from data sources (starting point ranges and long-term forecasts, where they exist)
  - Using an interactive expert opinion approach based on the source data, elicit distributions for capital costs in three time periods (near-term, mid-term, and long-term)
  - Simulate 500 paths for capital costs based on random sampling from distributions



How to interpret the probability distributions and diagnostic statistics:

- 50th percentile is the middle value – half the observations are above this value and half are below
- Generally, percentiles represent thresholds below which a given percentage of observations is expected to fall (i.e., the 95th percentile indicates that 95% of the cost observations in that year are at or below this level)



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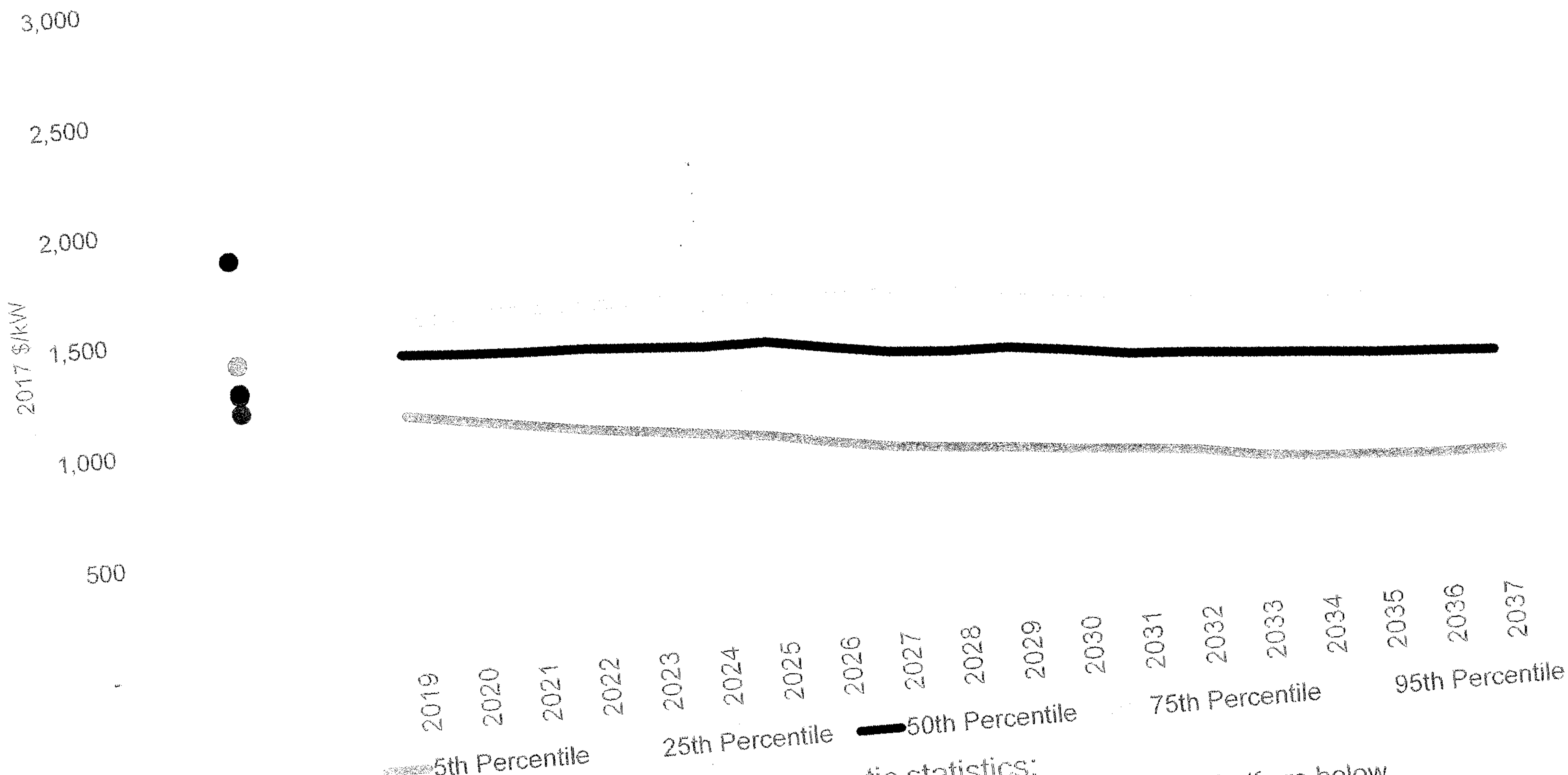

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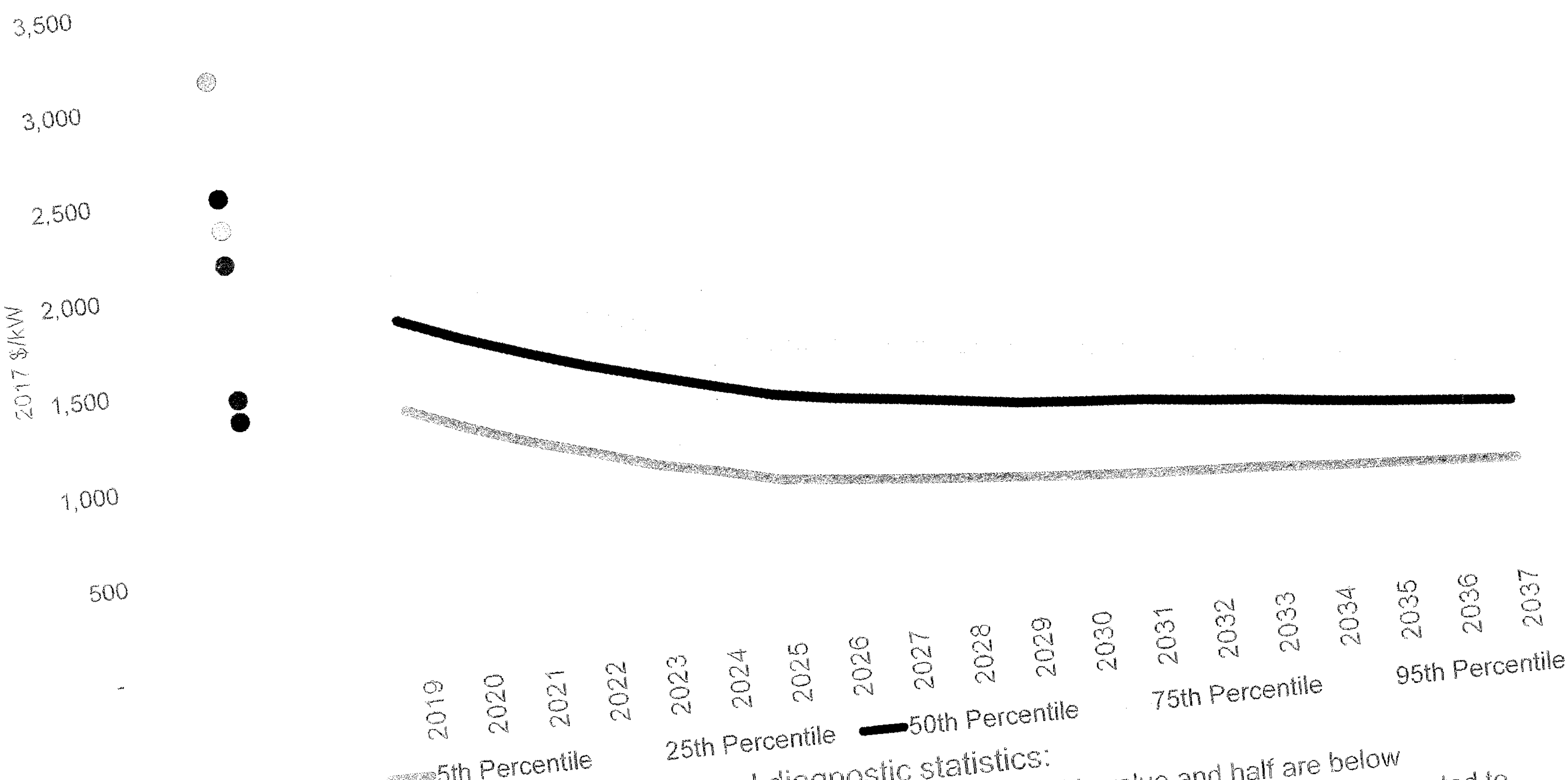

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Attachment 4-A

Attachment 4-A

2018 COMMODITY PRICE FORECASTING

NIPSCO IRP Stakeholder Meeting

NIPSCO

Robert Kaineg & Pat Augustine

March 23, 2018

CRA Charles River Associates

Outline

- Natural Gas
- Coal
- Power

CRA Natural Gas Outlook

Natural Gas Market Overview

- The industry has undergone a considerable transformation over the last decade
- Low cost shale gas has reduced domestic prices, and the Mid-Atlantic has transformed from a gas importer into a major production region, bottlenecked by existing midstream infrastructure

Trailing Trends

Regional Gas Supply Growth

Changing Pipeline Flows

- Northeast and Mid-Atlantic transformed from a major importer to a net supplier despite significant demand growth driven by coal switching
- Sizable gas infrastructure investments made in midstream to address flow issues
- Changing supply dynamics due to generation, industrial, and Mexico exports are starting to reverse flows of the major US gas transport backbone

Leading Trends

Supply & Pricing Dynamics

- Low cost North American supply still has significant growth upside (improved drilling economics and a large resource base)
- A sustained low gas price environment starting to incent additional power generation demand for gas (new capacity + further coal and nuke to gas substitution)
- Techniques developed in the Marcellus moving back into traditional regions (e.g. Haynesville) likely to improve productivity of these regions

Demand Growth Potential

- The electric sector increasingly relies on gas generation to meet energy needs, IRPs tend to rely on new gas and renewables meet growing load
- Short term LNG outlook firming ~10bcf/d of firm projects coming online in the next 2-4 years, another 8-10 bcf/d of potential in the following decade
- Sustained low gas prices driving interest in petrochemical investments

NGF Model – Natural Gas Price Forecasting

Gas Supply

- Total resource in place, proved and unproven
- Resource growth over time
- Wet / dry product distribution
- Historic wells drilled and ongoing production
- Conventional & associated production
- Existing tight and CBM
- Existing offshore production

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- First year initial production rate
- Changing drilling and production efficiencies
- Productivity decline curve
- Well lifetime
- Distribution of performance

Gas Demand

- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)

Other Market Drivers

- Value of NGL / condensates
- Natural gas storage

CRA continuously enhances NGF to reflect changes in key gas market drivers

Key Modeling Inputs and Drivers of CRA's Gas Price Forecast

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) 2016 "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2016 "Minimum" resource, and grows the resource base to achieved PGC 2016 "Most Likely" volumes by 2050
Well Productivity	• IP rates based on historic data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data for initial mode year, IP rates improve annually in line with EIA assumptions The "Poor Heavy" resource base is conservative, and reflects the fact that sampled data reflects only geology expected to be productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA based individual well productivity on available historic data, adopted EIA assumptions for cost improvements over time
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2017 Reference Case (with CPP)	The AURORA case assumes "base case" carbon pressure and AEO 2017 Reference assumes CPP, meaning demand estimates are consistent
LNG Exports	• Under-construction projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031	Current advanced-stage projects expected to come online and be highly utilized driving 2019 view Low domestic prices drive further international interest for US gas, but no other projects able to complete before 2021
Pipeline Exports	• Mexican export increase to ~8bcf/d by 2021, 10.5bcf/d by 2030	CRA expects pipeline export capacity to meet growing gas demand in Mexico will be ~60% utilized by 2021, and 75% utilized by 2031
NGL & Condensate Value	• Liquids valued at 70% of AEO 2017 Reference Oil Price	AEO17 for long-term oil price forecast; 70% value for NGLs is consistent with last 5 years of price history

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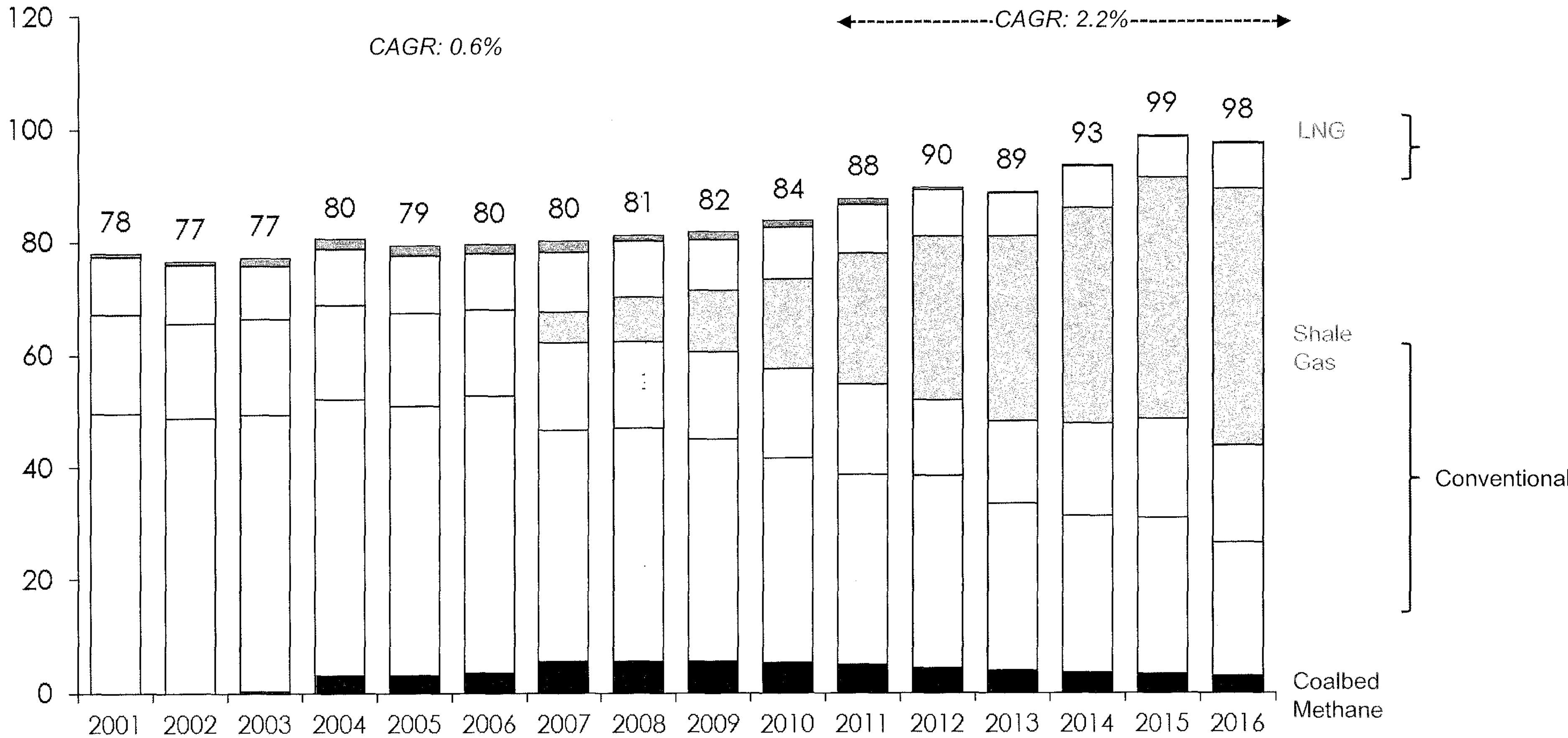
Key Natural Gas Market Trends – Shale Gas

- US Gas production was relatively flat from 2000-2010 until growth accelerated due to rapidly expanding shale gas production

Gas Withdrawals and Imports

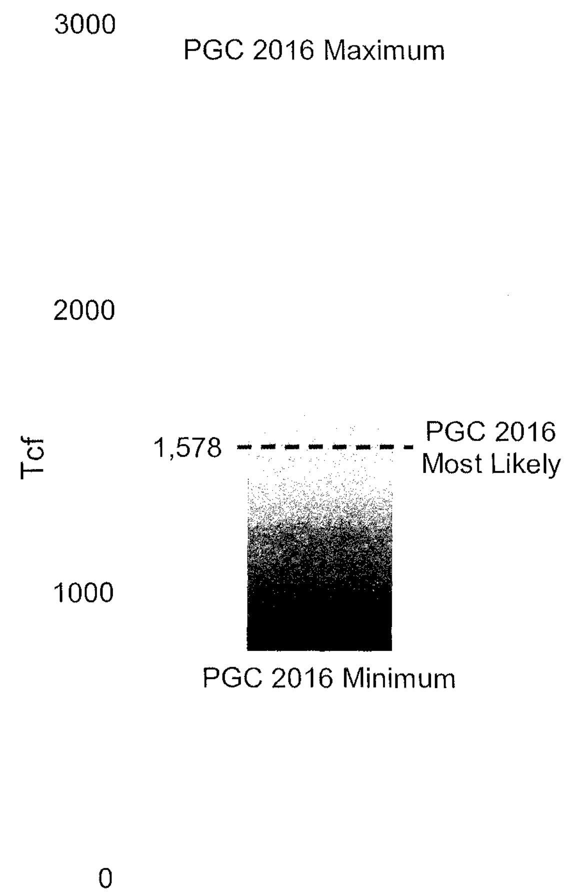


CRA relies on the PGC 2016 "Minimum" value as the starting value for recoverable shale reserves, resource grows at a steady rate until the PGC "Most Likely" value is reached in 2050

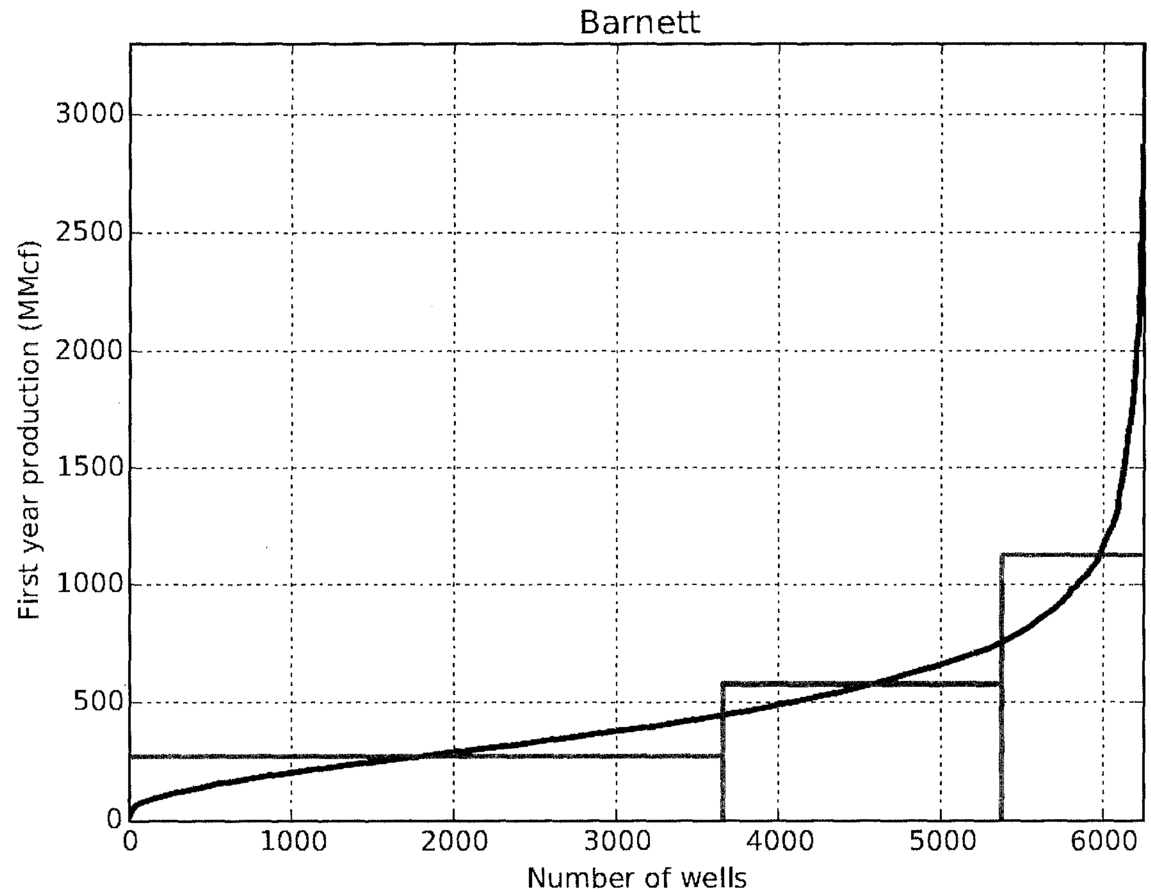
- **Probable** – gas associated with known fields
- **Possible** – gas outside of known fields, but within a productive formation in a productive province
- **Speculative** – gas in formations and provinces not yet proven productive

- **Minimum** – 100% probability that state resource is recoverable
- **Most Likely** – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions
- **Maximum** – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present

Uncertainty Range for Shale Resource in PGC 2016



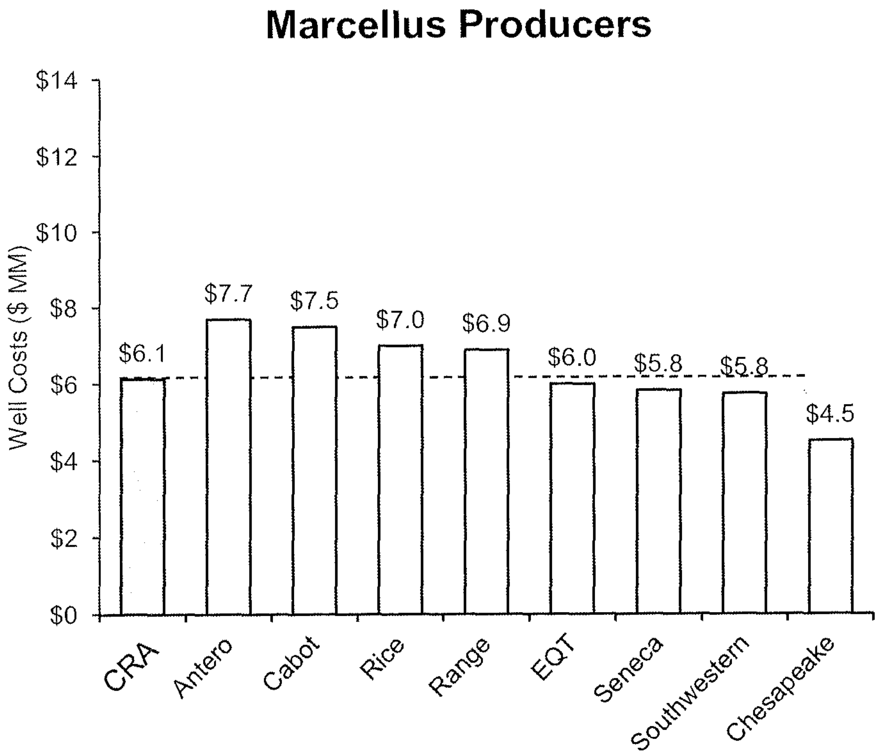
CRA assumed "Poor Heavy" productivity distribution (50% poor, 20% prime, 30% average) for future undiscovered resource

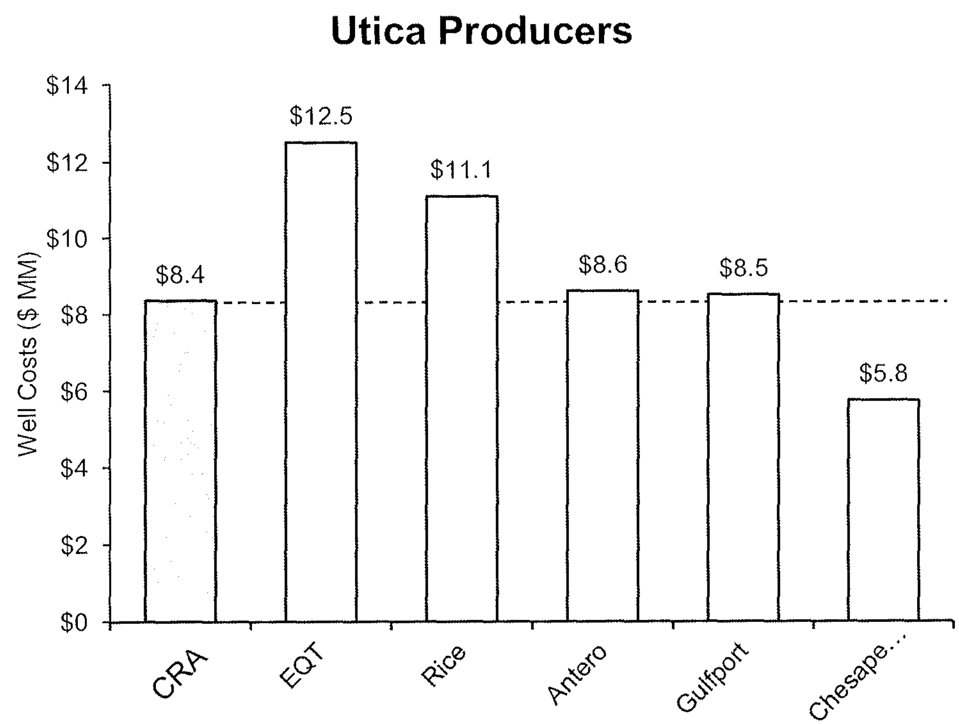


This productivity analysis was performed for all basins in CRA's model with sufficient recent drilling data

Gas Price Drivers – Drilling Costs

- CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region





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Well productivity & cost structure improves in CRA's base case consistent with EIA Tier 1 rate of EUR growth

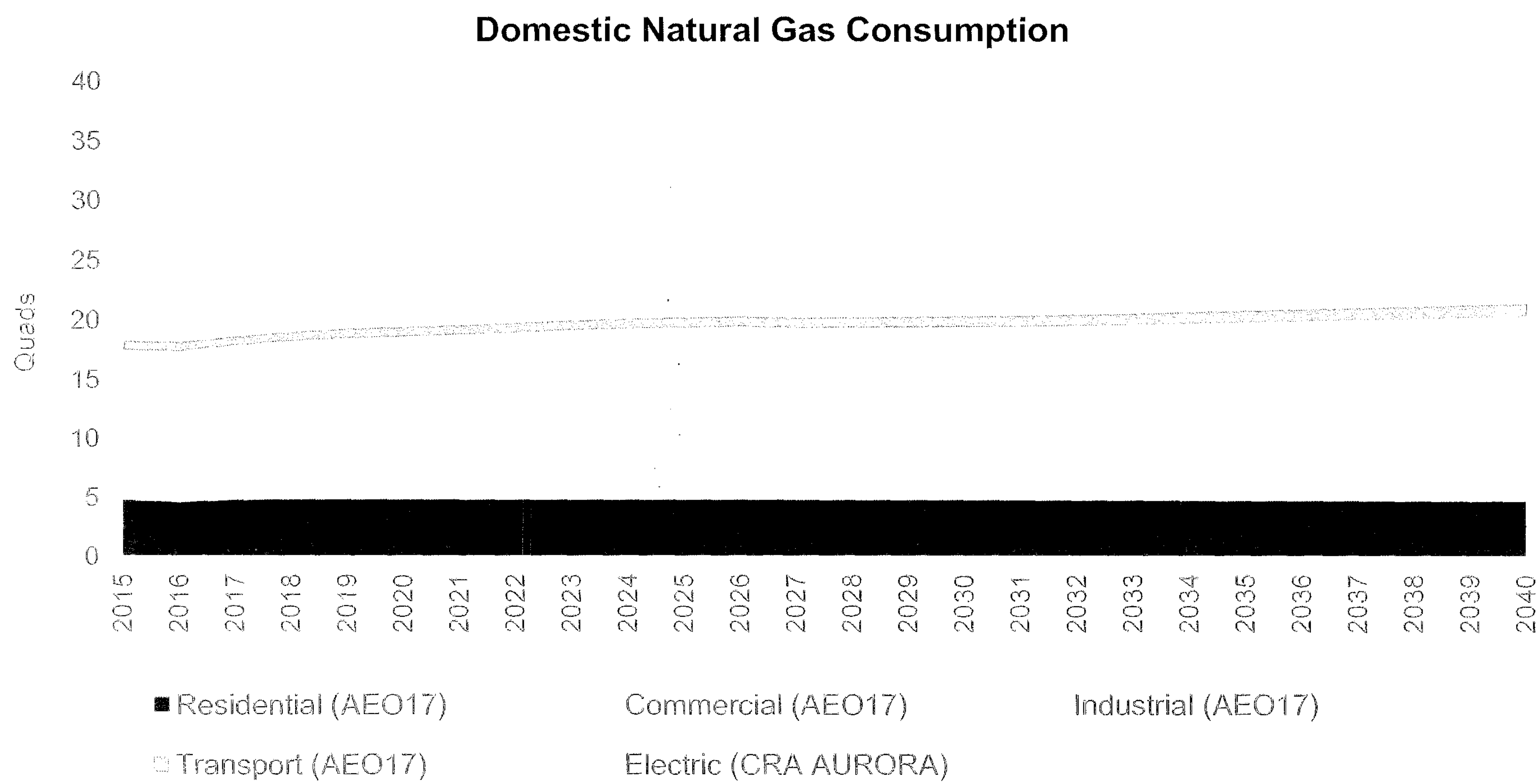
Table 9.6. Onshore lower 48 technology assumptions

Crude Oil and Natural Gas Resource Type	Drilling Cost	Lease Equipment & Operating Cost	EUR-Tier 1	EUR-Tier 2
Tight oil	-1.00%	-0.50%	1.00%	3.00%
Tight gas	-1.00%	-0.50%	1.00%	3.00%
Shale gas	-1.00%	-0.50%	1.00%	3.00%
All other	-0.25%	-0.25%	0.25%	0.25%

Source: U.S. Energy Information Administration, Office of Energy Analysis.

– Based values for IP rates and well costs are based on producer-reported values

CRA modeled electric gas demand in AURORA under base case CO2 assumptions, Residential, Commercial, Industrial and Transportation sector demand taken from AEO2017



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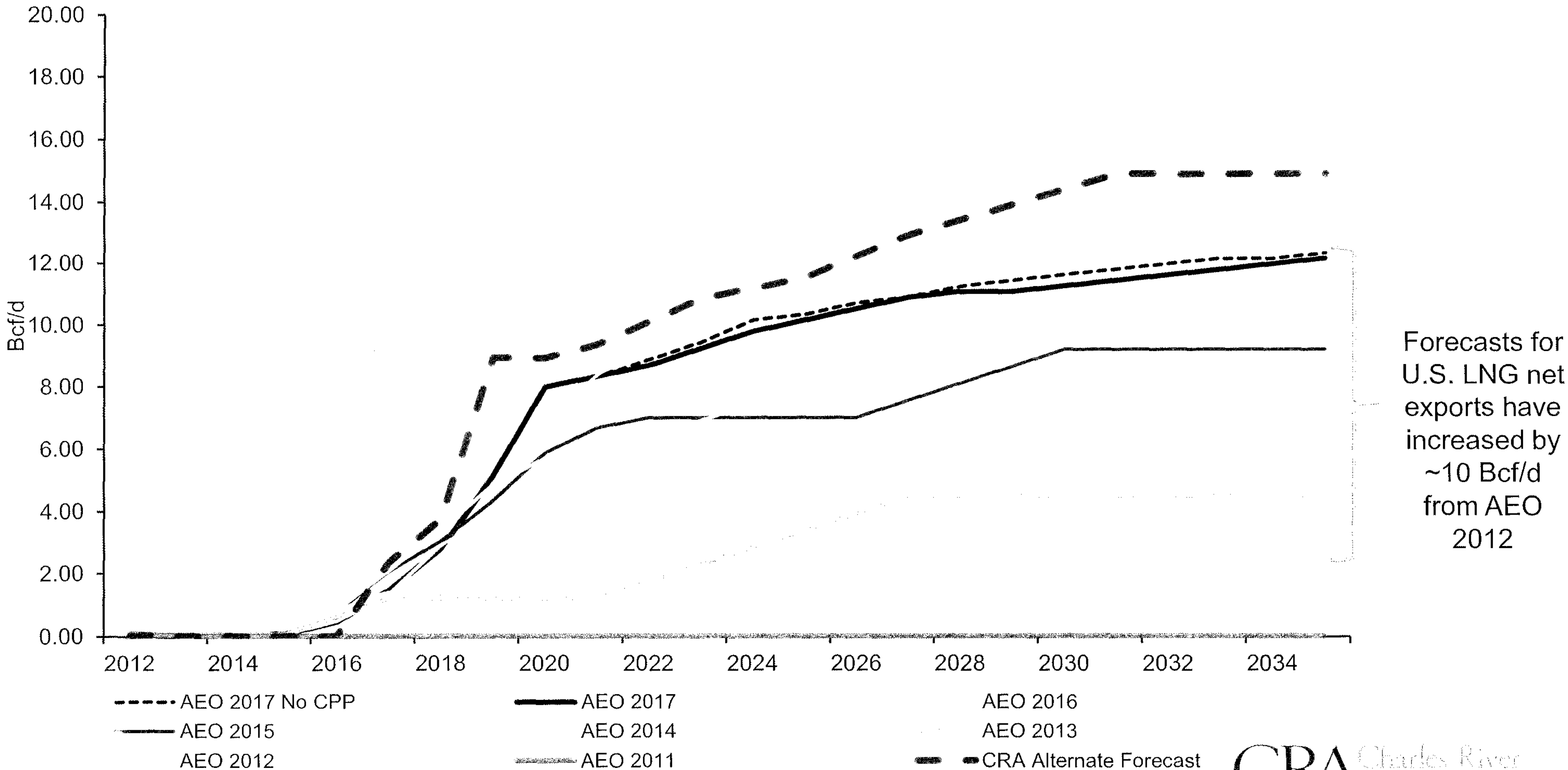
Gas Price Drivers – LNG

- Forecast of LNG Exports: AEO 2017 Reference Case LNG exports are between 25%-35% higher than AEO 2015, but lower than AEO 2016
- BP forecasts higher LNG exports than AEO, with ~15 Bcf/d of exports by 2030 and ~22 Bcf/d by 2035
- LNG exports could potentially be higher than AEO 2017 projects, given current planned builds



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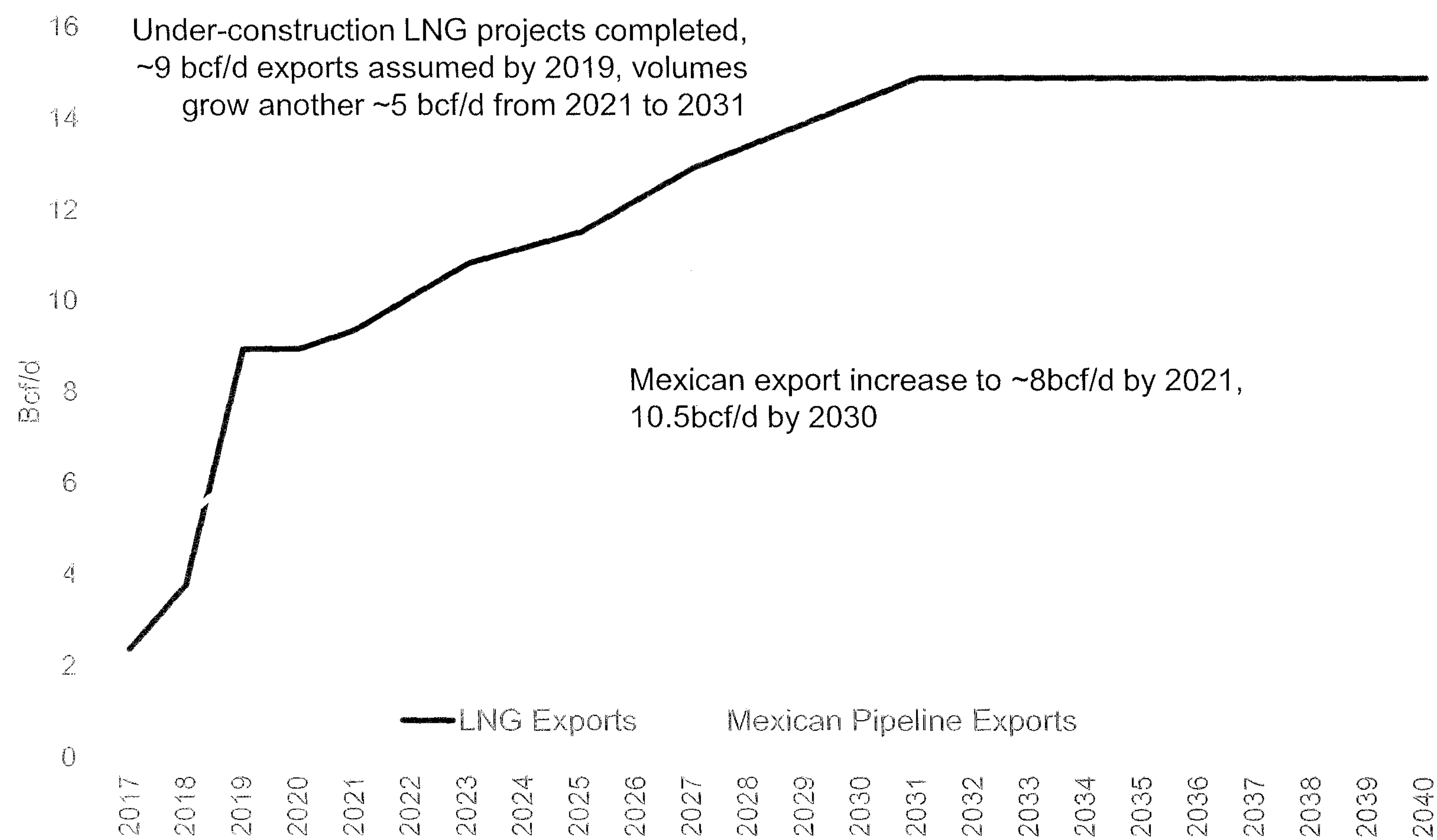
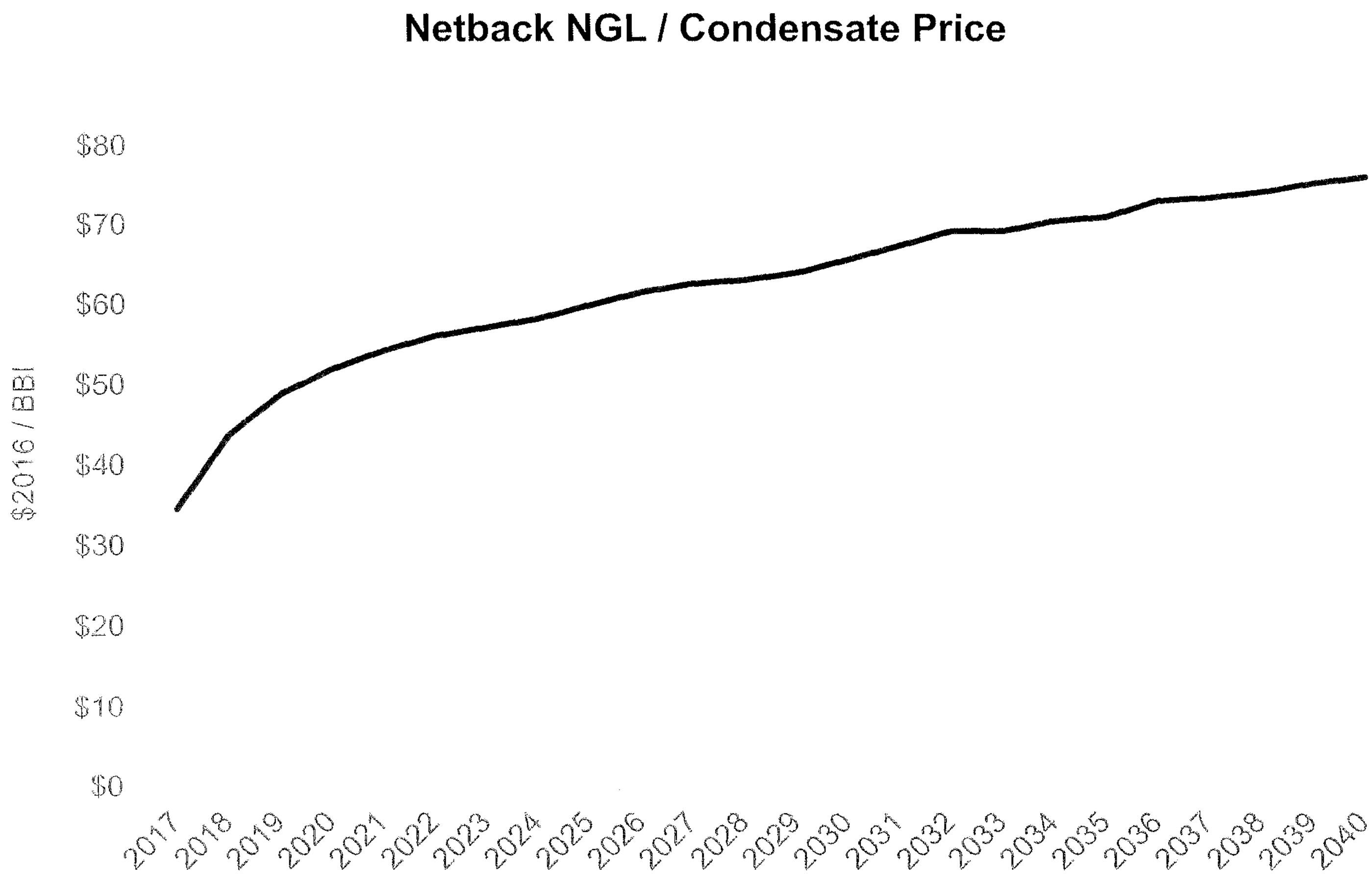
CRA assumes that LNG & Mexican gas exports grow through the 2030s



CRA assumes NGL & condensates valued at 70% of AEO reference case oil price forecast



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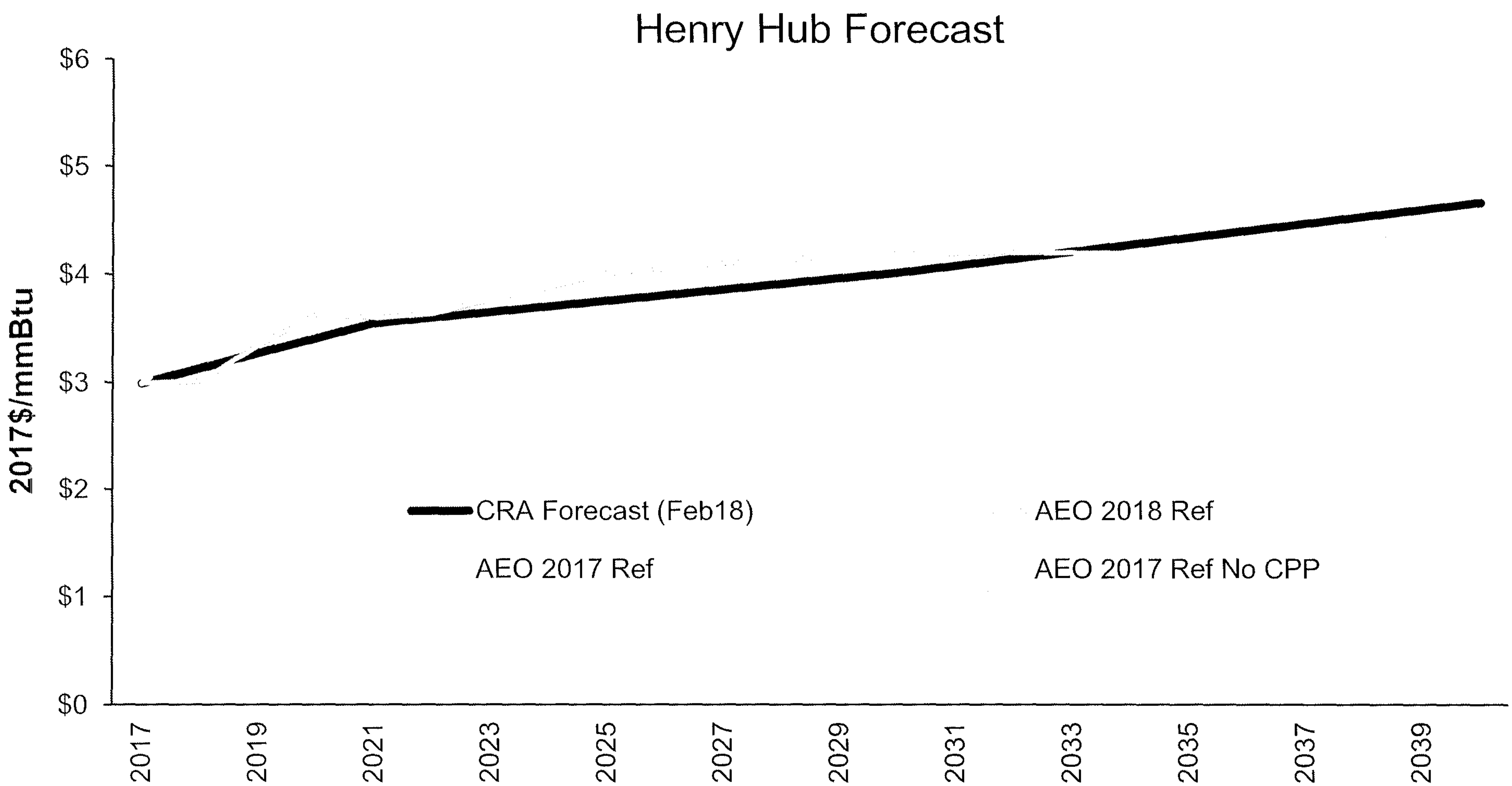
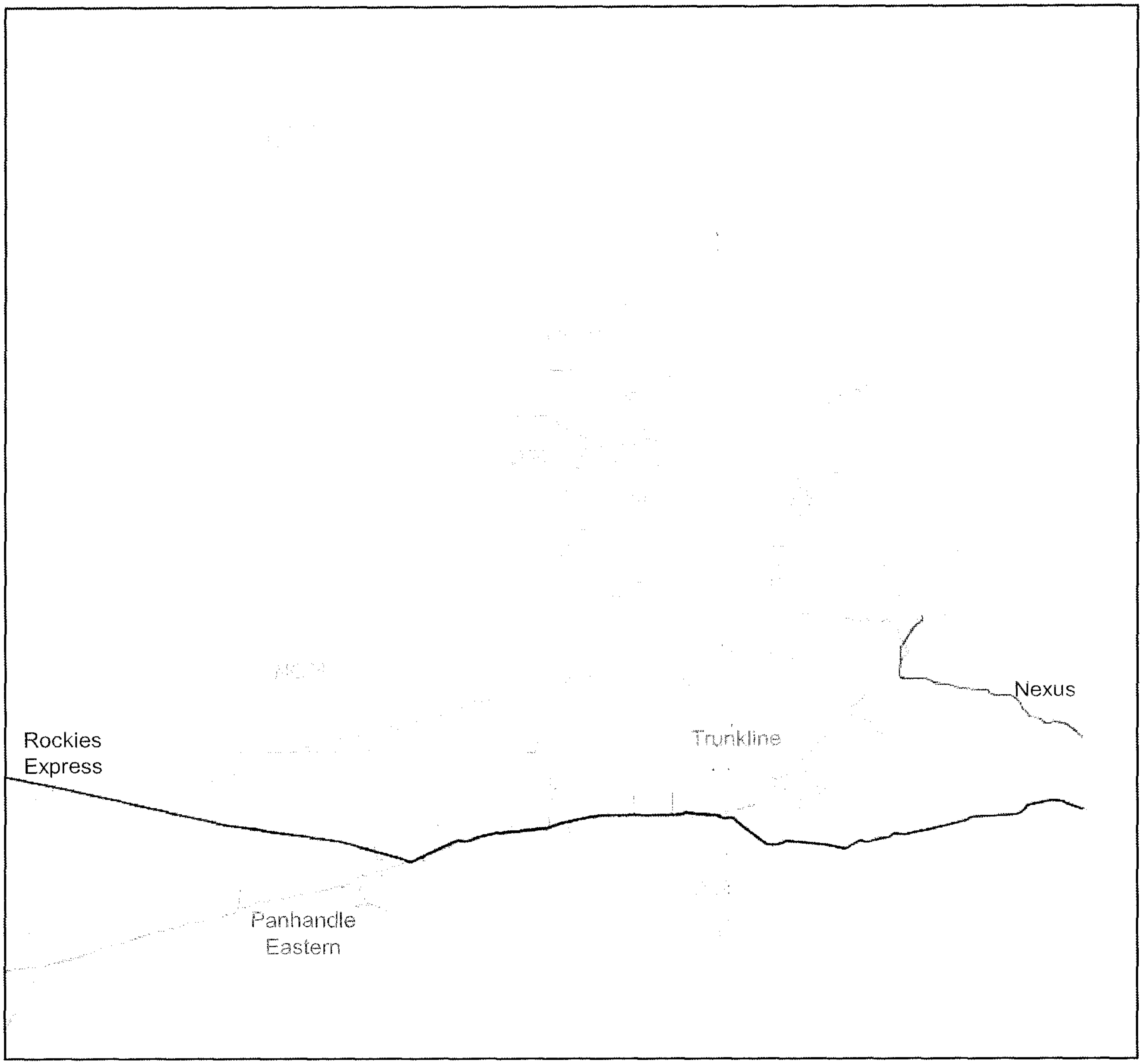
CRA Natural Gas Price View



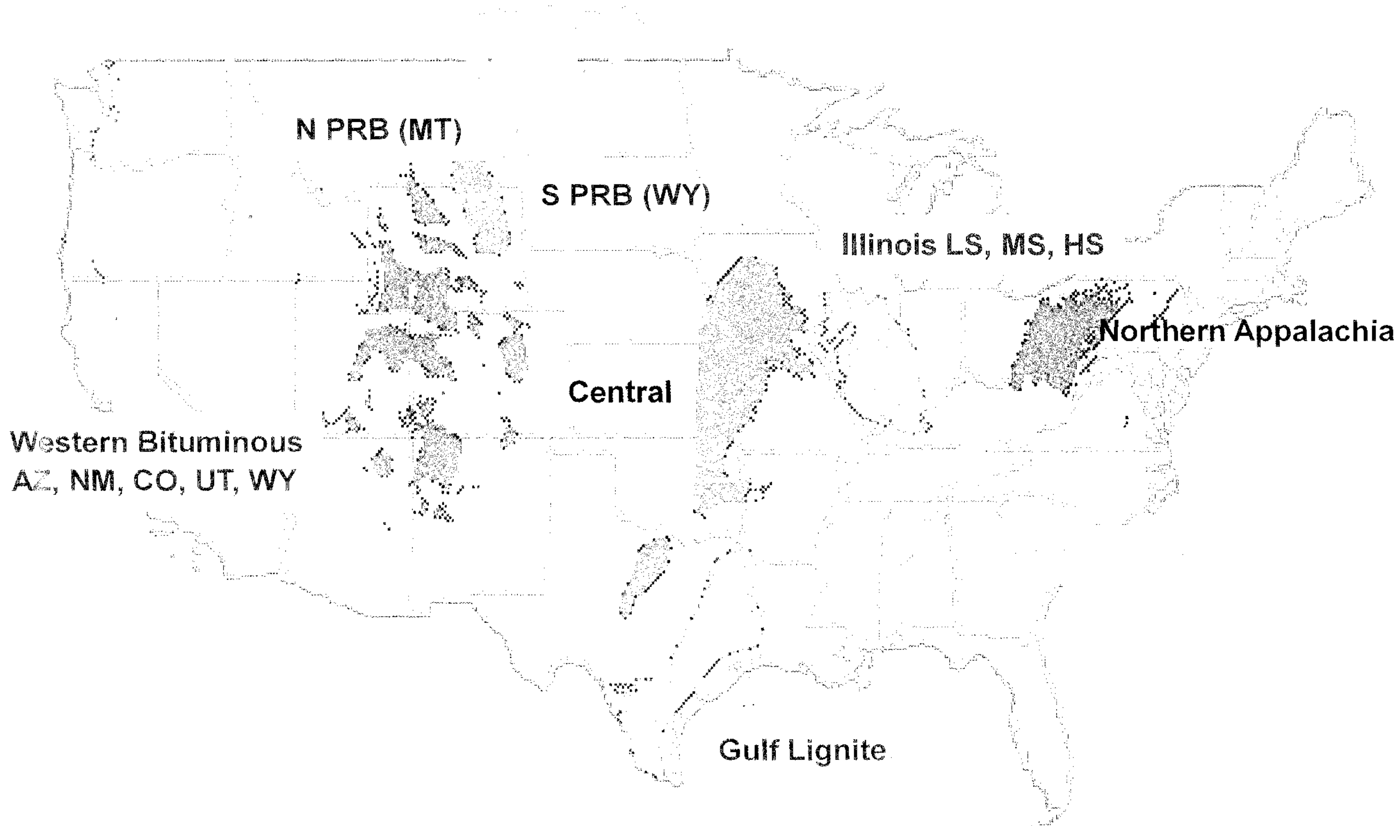
Local Gas Dynamics in MISO



Coal Market Outlook

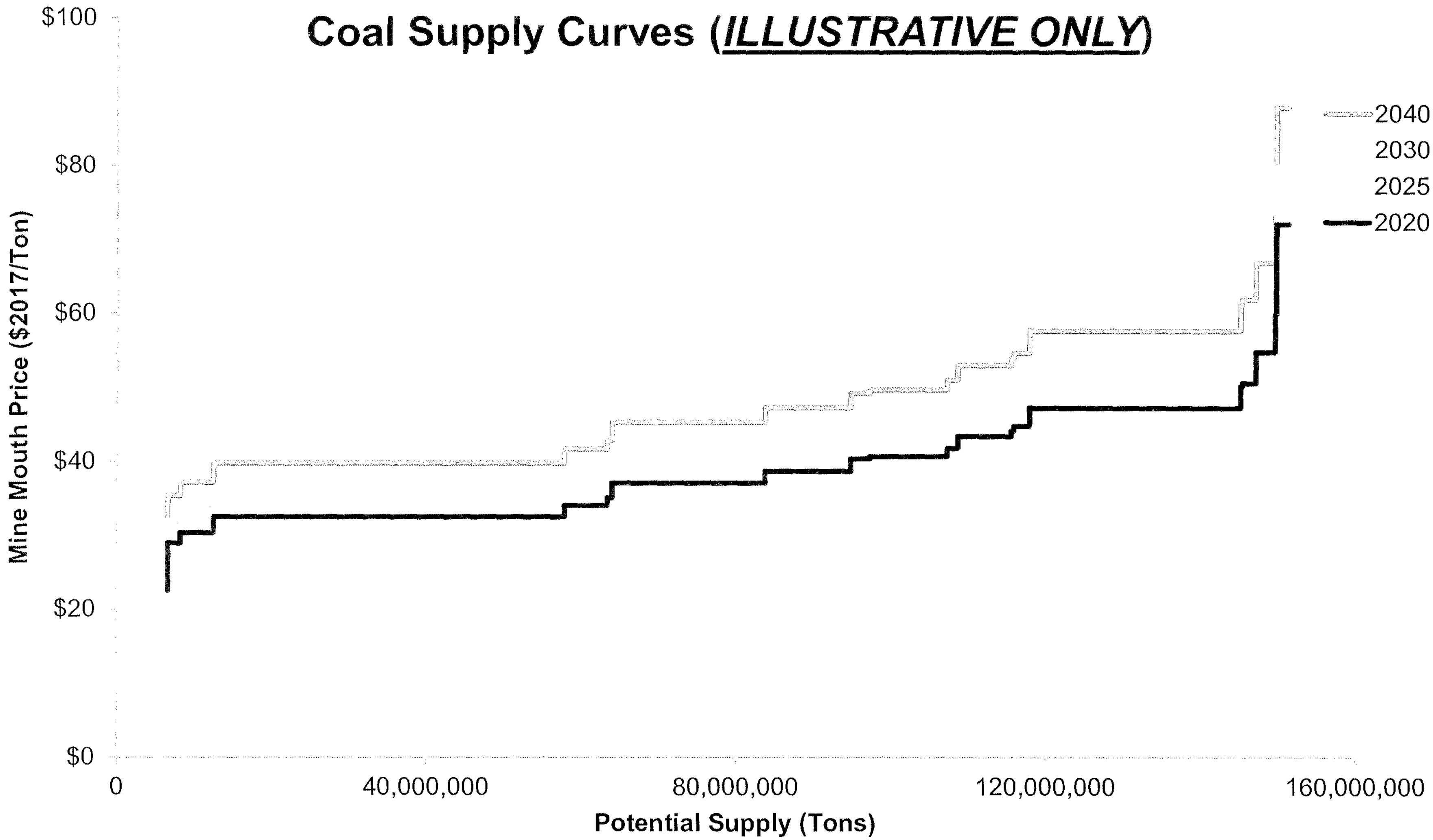
Coal

- Coal forecasting process assesses future supply/demand balance for the U.S. coal market:
  - Macroeconomic drivers, including domestic and international demand
  - Microeconomic drivers, including trends in mining costs and production trends
- The CRA NEEM model has coal supply curves, which are calibrated to reflect market analysis
- NEEM and AURORA are run in iterative fashion under various market views to develop coal price forecast



[redacted]

Each basin in NEEM is represented by a set of annual supply curves, which change over time to reflect cost developments & depletion (if applicable)



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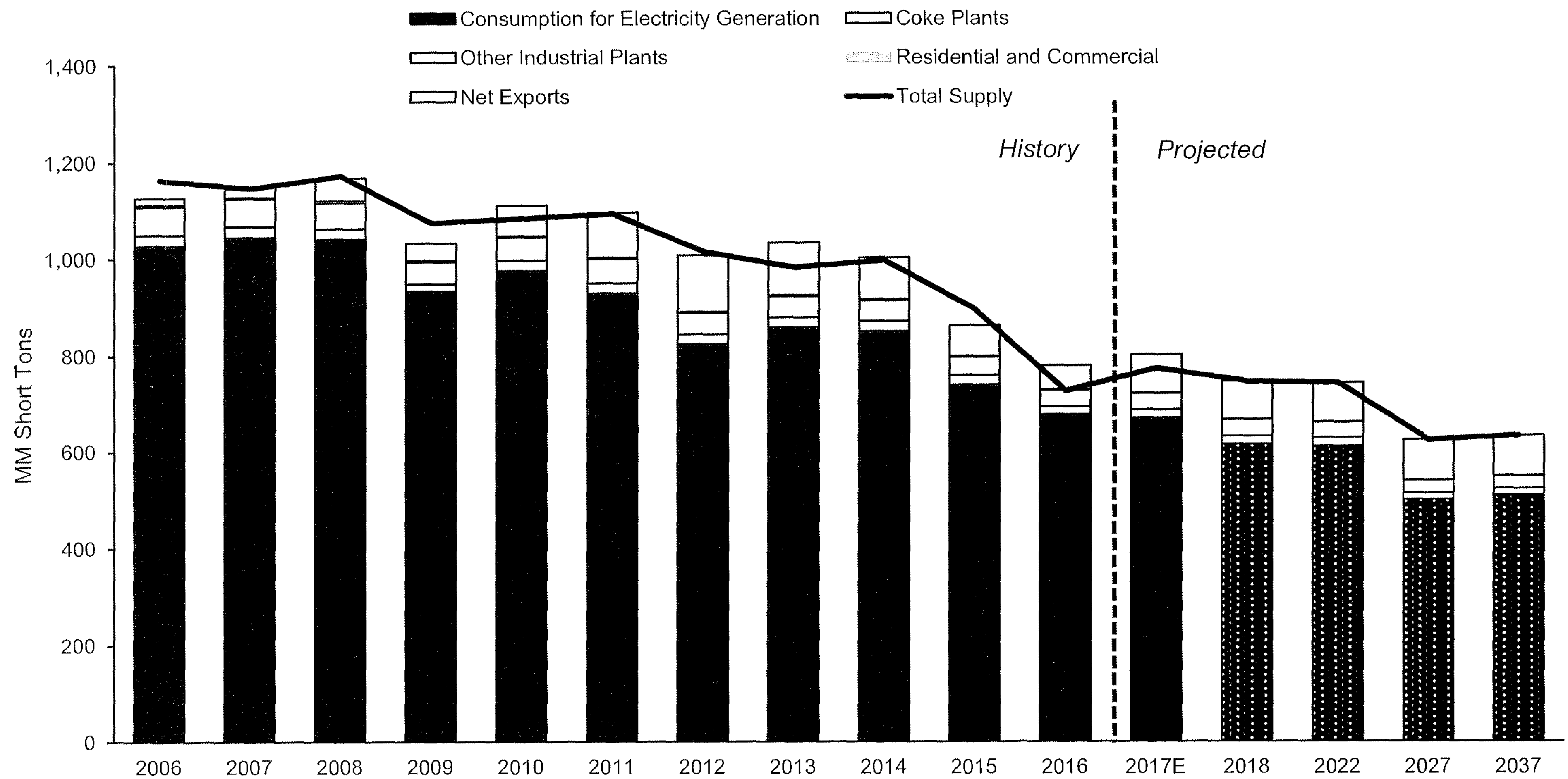
U.S. Coal Prices expected to be mostly flat over the study period

- This indicates that many market participants expect relatively weak coal demand during 2018-2021, with little appreciation or decline in real dollar pricing from current levels

- Initial results show a net decline in coal-fired demand over the study period
- CRA expects U.S. steam coal demand to fall significantly (~25%) over the next decade
- Increased renewable generation and the retirement of about 33 GW of coal-fired capacity is expected in the first 5 years of the forecast

Supply Demand Balance for U.S. Coal - 2006-2037



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Trends in Regional U.S. Coal Production

Coal Type	Current to 2027 Production Forecast (% decline)	Comments
CAPP	-21%	High cost drives decline in electric sector demand; met coal demand sustained
NAPP	-13%	Increased int'l demand and some replacement of CAPP demand
ILB	-9%	Increased int'l demand and some replacement of CAPP demand
PRB	-22%	Domestic steam coal demand declines, especially after CO_2 pressure

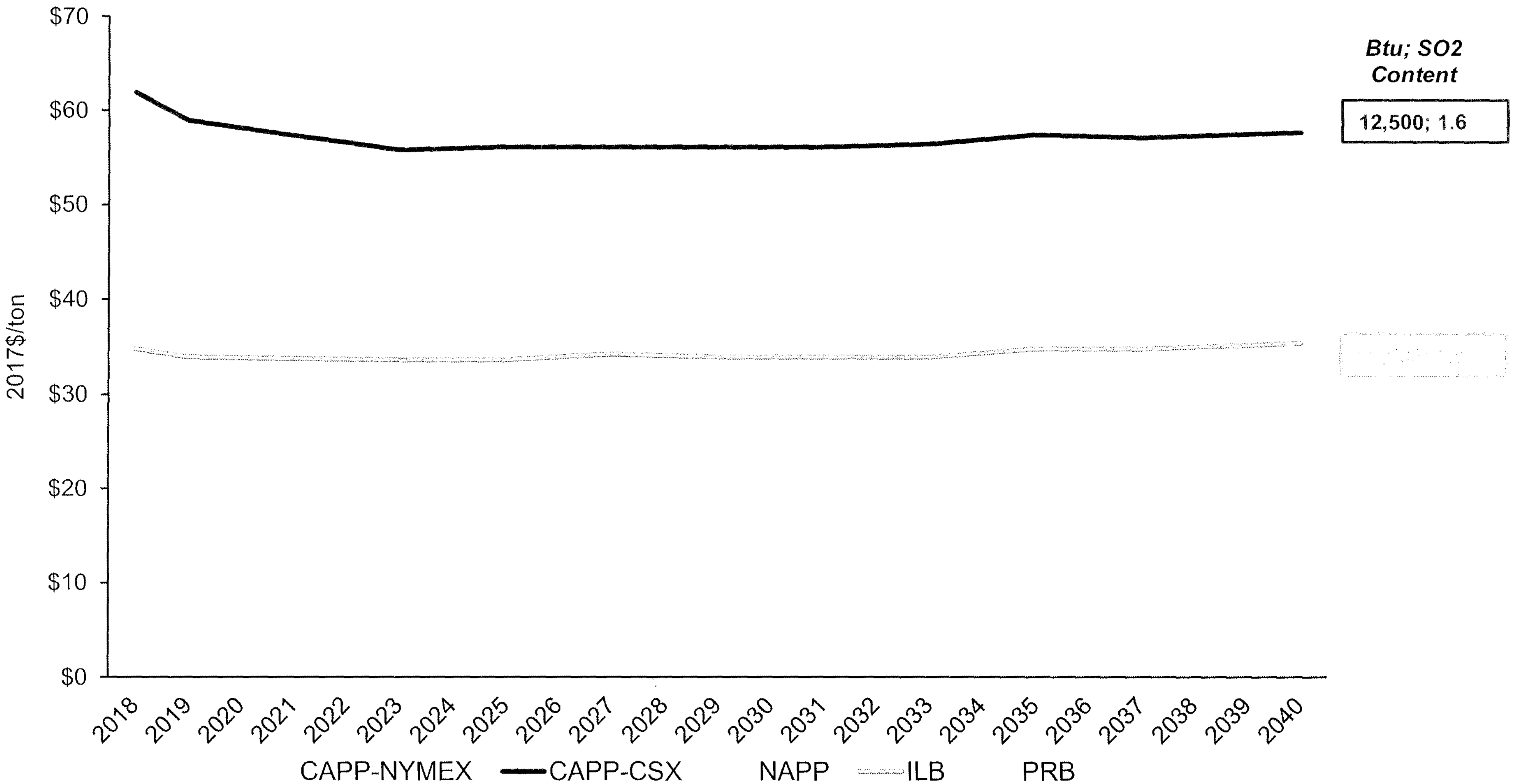
Summary of Price Trends by Coal

Coal	Market Trend
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton) for Appalachian coal through the early-to-mid-2020s • Thereafter, reserve depletion expected to drive modest increase in real coal price for Appalachian coals
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia • NAPP's lower cost profile, due to larger longwall mines, allows highly efficient mining of large-block coal reserves
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth
PRB	• PRB prices increase modestly (in real dollars per ton) at an average rate of 0.8%/year through the forecast period • Price growth over time driven by higher production costs due to downward-sloping coal seams/reserve depletion.

[redacted]

Forecast of Commodity Prices for Key U.S. Coal Types

Over the long-term, coal price projections are generally flat in real terms



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Carbon Price Outlook

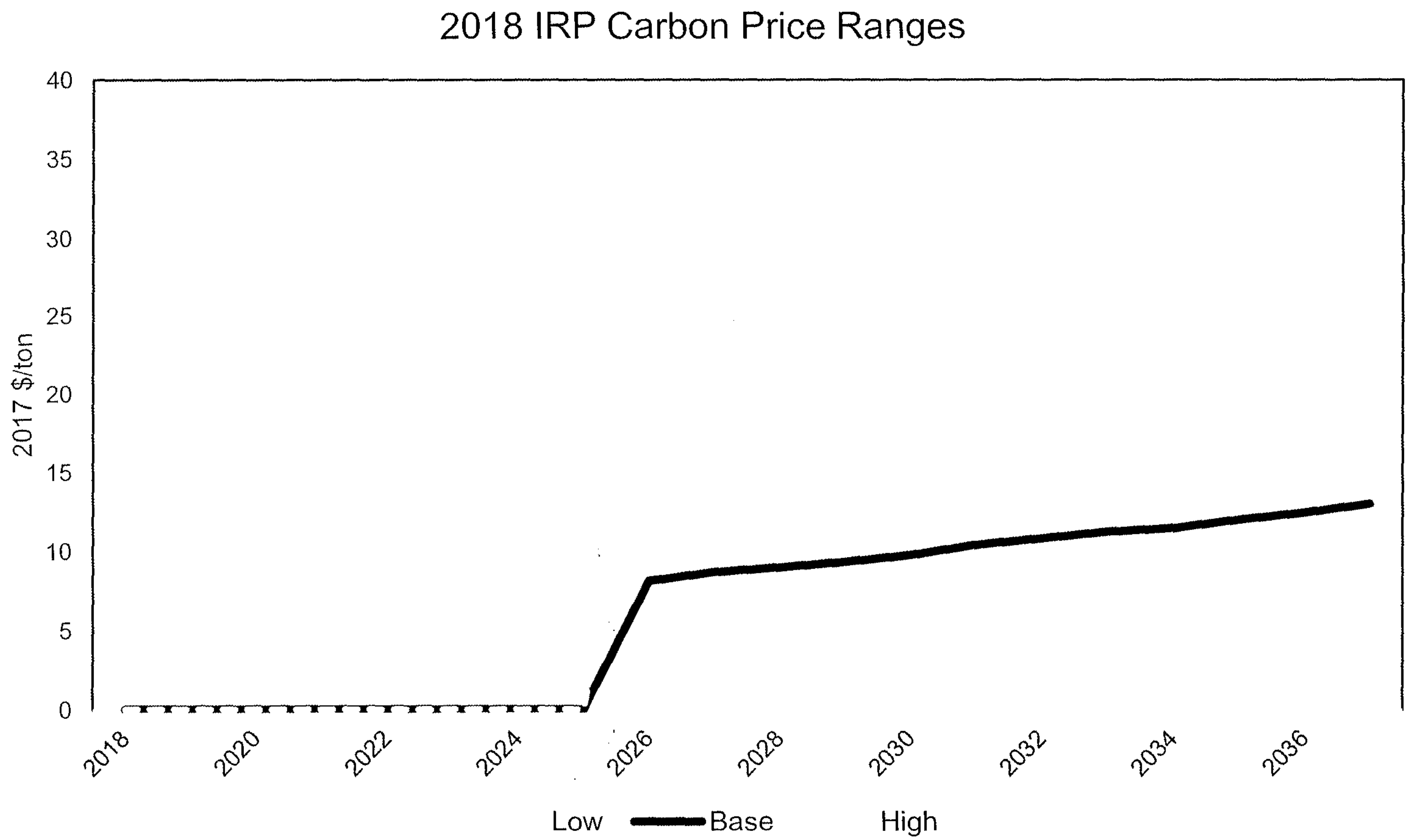
Carbon Policy and Emission Pricing

- Assumes a new federal rule or legislative action coming into force by the mid-2020s. Analysis suggests a ~20% reduction in U.S. coal demand post-2026 vs. a $0 carbon price scenario.
- Rationale
  - Timing: New administration post-2020 would need to re-develop rule through EPA or pursue a legislative fix with a newly constructed Congress. Earliest likely implementation around 2026.
  - Stringency: In line with CPP-type stringency (ie, 30-40% reductions in emissions vs. historical baseline)

- Assumes a modified EPA plan to control carbon, with focus on "Building Block 1" coal plant heat rate efficiency improvements. No specific tax or emission cap requirement would be present under such regulations.
- Rationale
  - Trump Administration has withdrawn CPP with a focus on modest replacement to meet requirements of the endangerment finding. Thus, the base case would follow current rule revision expectations, with long-term potential of a continued divided Congress/Executive Branch and/or prolonged legal challenges for any future EPA regulation.

- Assumes a stricter new federal rule or legislative action coming into force by the mid-2020s. Price levels are generally consistent with a 50-60% reduction in electric sector CO_2 emissions relative to 2005 by the 2030s.
- Rationale
  - Timing: Same as Base Case
  - Stringency: Would represent an initial pathway towards aggressive carbon reduction goals (ie, 80% by 2050 target under the "2 degree" scenario). *Note that economy-wide reduction scenario has not been evaluated to date.*

Carbon Policy and Emission Pricing



**Note that high case represents a potential initial pathway for an 80% power sector CO2 emission reduction by 2050. An additional scenario with broader economic impacts may be assessed at a later time as a separate scenario.*

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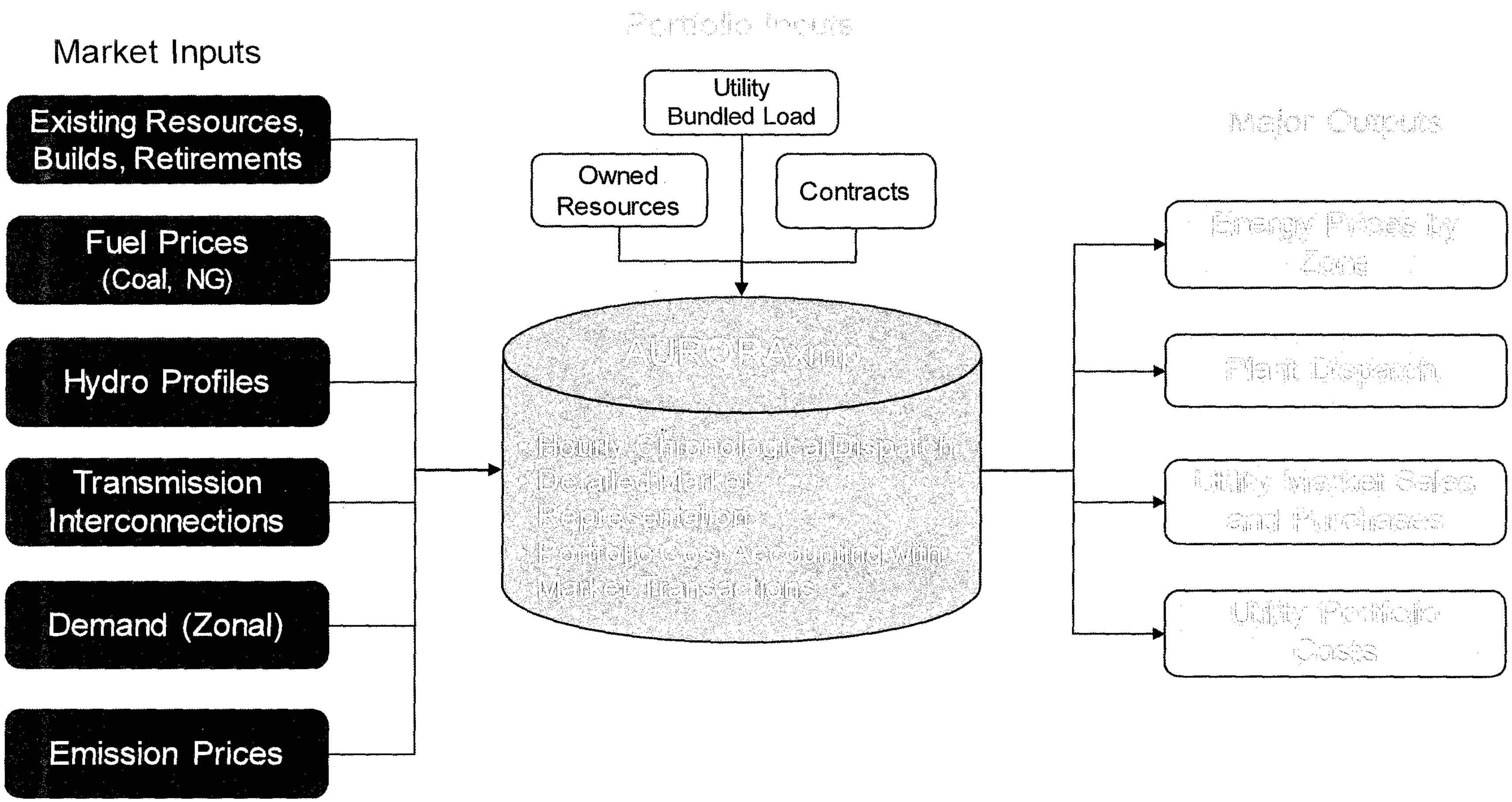
MISO Power Market Outlook

MISO Power Market

Attachment 4-A

AURORA – Power Price Forecasting



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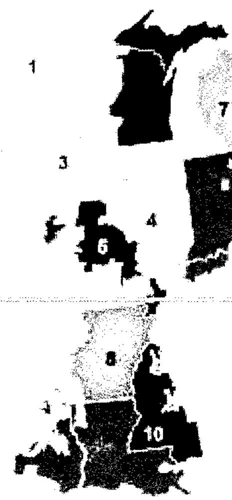
MISO Power Market

Attachment 4-A

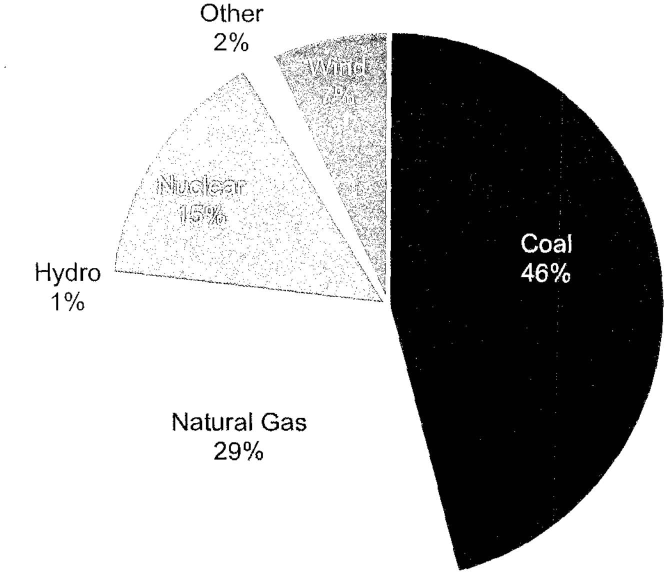
MISO – Overview

MISO North



Local Resource Zone	
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

MISO Historical Generation by Fuel Type
Total: 686 GWh



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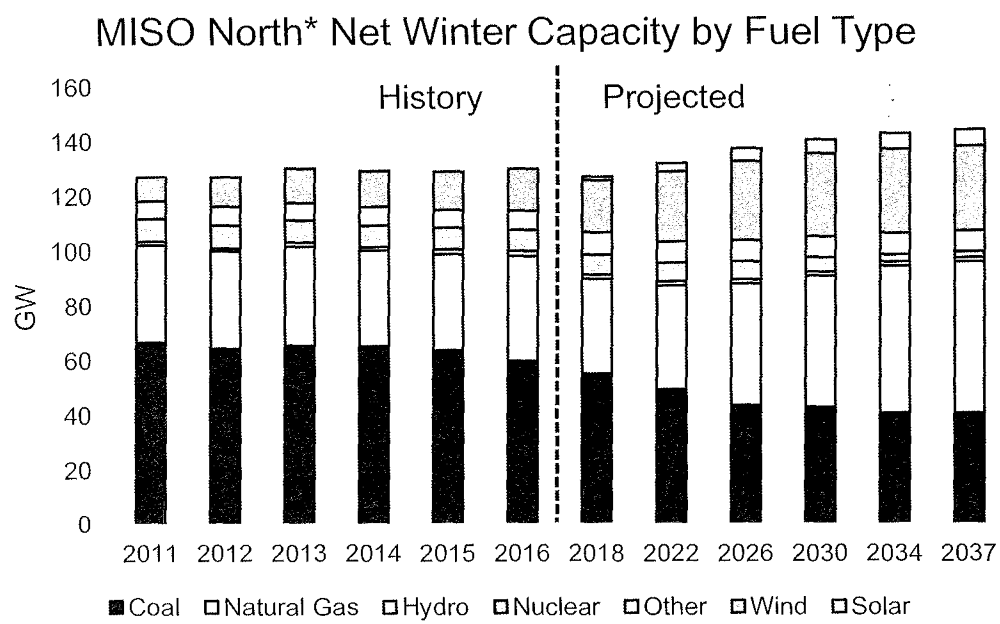
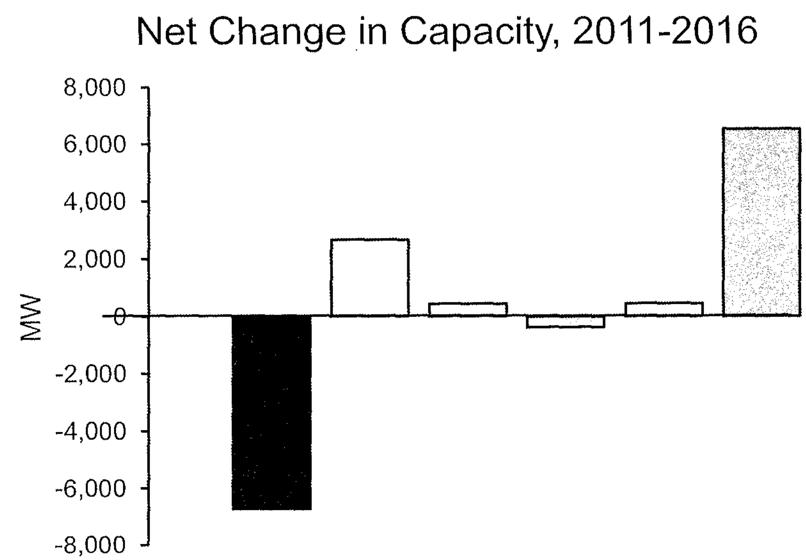
Expected continued shift from coal to gas and renewables in MISO

- 6.3 GW decline in net coal capacity; no new coal plants since 2013
- Indiana Zone: Bailly 7 and 8, Schahfer 17 and 18, and Vectren AB Brown plant



*MISO North includes LRZ 1-7



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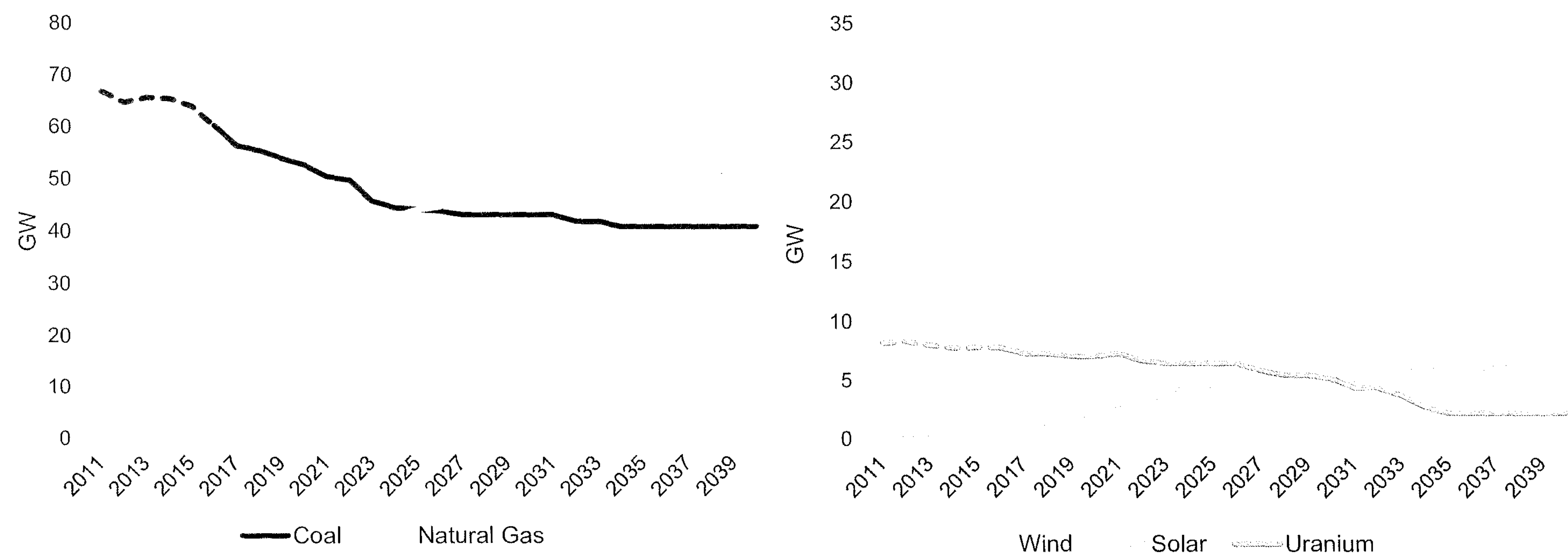
CRA expects broad trends to continue across MISO

- Coal comprised 46% of total energy produced in MISO-North in 2016, compared with 61% of energy in 2011
- Retiring coal and nuclear capacity is expected to be replaced by a mix of gas and renewables

MISO North Capacity by Fuel Type



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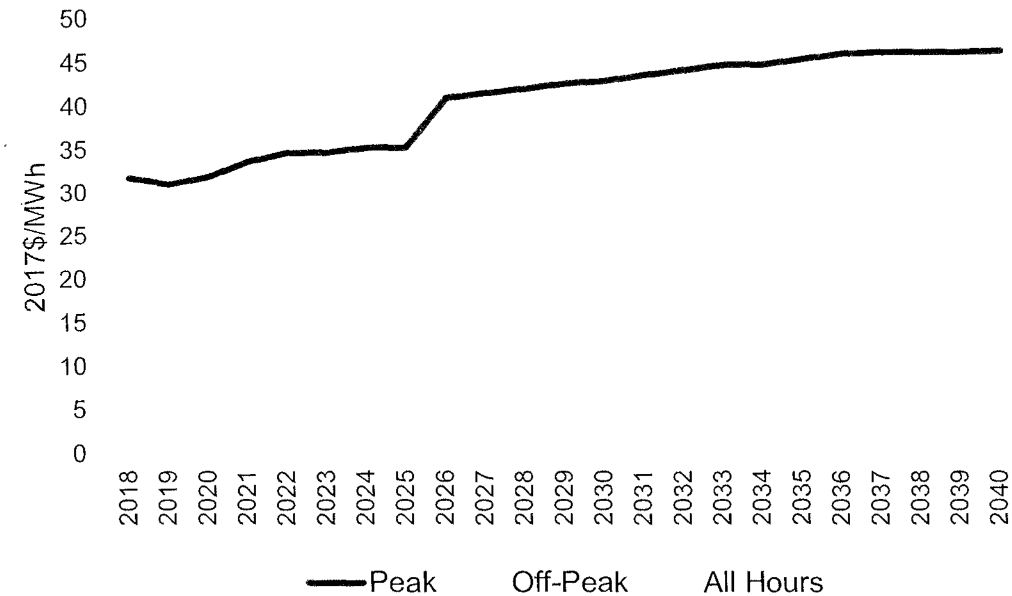
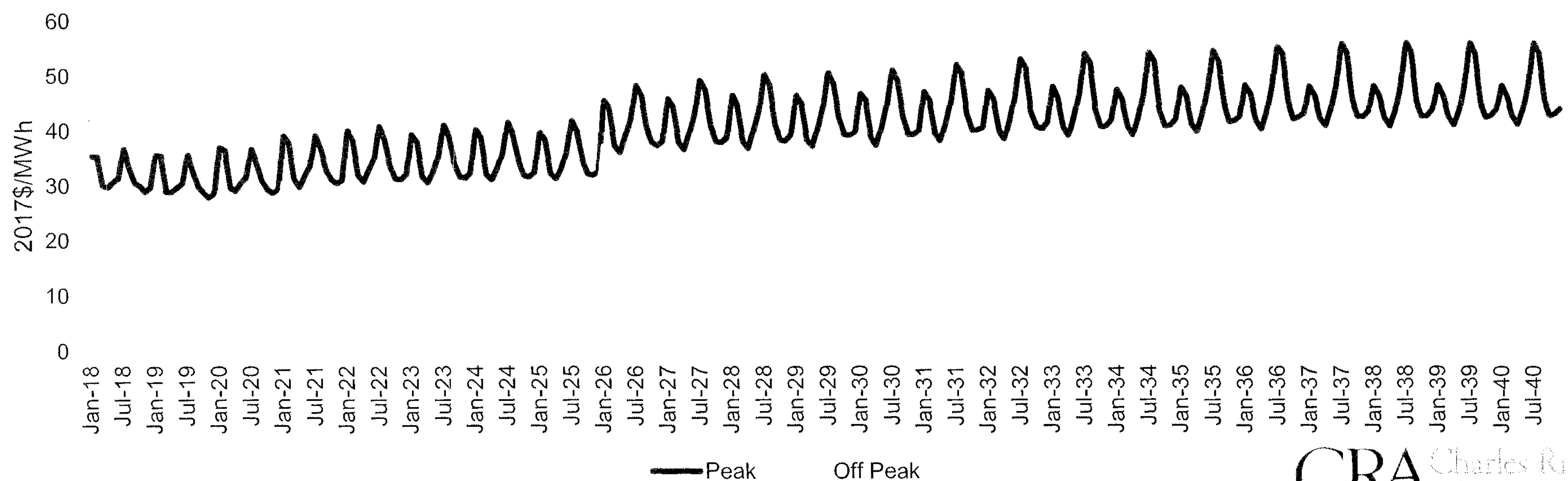
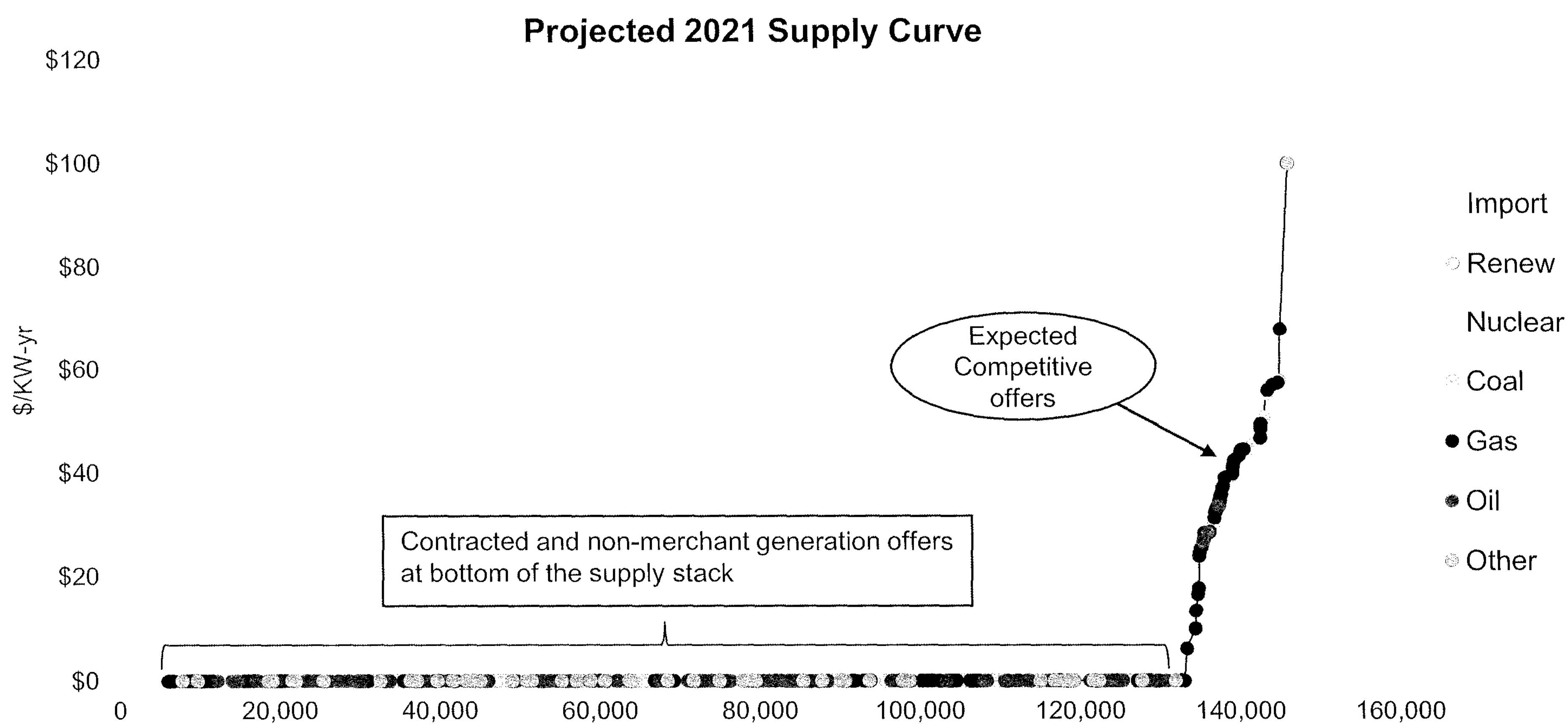
CRA Power Price Forecast – MISO Zone 6

- Power prices are relatively flat in the near-term, due to flat gas and coal prices and relatively modest load growth
- Some upward pressure expected into the 2020s as a result of higher natural gas prices, although growing renewables lower the market heat rate over time
- National carbon price, starting in 2026, drives price increase





Capacity prices are influenced by market design



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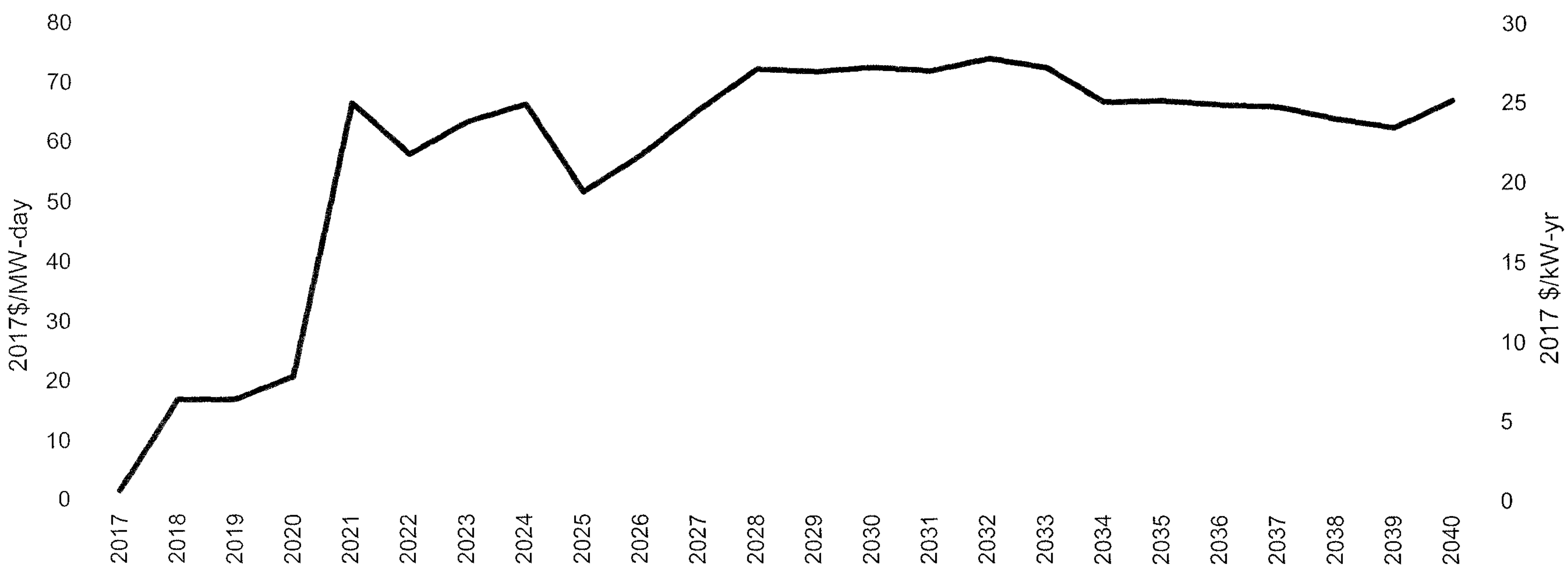
CRA MISO Capacity Price Forecast

- Flat load and increases in renewable, behind-the-meter, and DR/EE supply
- Tariff revisions impacted offer thresholds on the low end
- Import constraints between North and South relaxed



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Attachment 4-A

Demand Side Management Update

Alison Becker
Manager Regulatory Policy

Richard Spellman
GDS Associates (GDS)

2018 Electric DSM Savings Update

- The Electric DSM Savings Update report will focus on a 20-year time horizon (2019-2038).
- For years 2019-2021, data will be gathered from NIPSCO's recent filing in Cause No. 45011 pending before the Indiana Utility Regulatory Commission ("IURC").
- GDS will update measure costs, kWh and kW savings, useful lives, saturation data, etc.

2018 Electric DSM Savings update (continued)

- The savings update will consider new sources of secondary data that are now available.
- The final Electric DSM Savings Update report will be completed by June 1, 2018
  - GDS will present draft results to the Oversight Board during the April meeting

2018 Electric DSM Savings Update Report Contents

- Recommended cost-effective DSM savings measures and programs.
- Information on innovative programs and technologies.
- Budgets for each program.
- A cost-effectiveness ranking for all technologies (measures) reviewed.
- Cost-effectiveness evaluations for each proposed program.
- GDS will calculate the Total Resource Cost ("TRC") test, the Utility Cost test, the Participant test and the Rate Impact Measure ("RIM") test.
- The TRC test will be used to determine measure, program and portfolio cost effectiveness.

Technical Approach for Electric Baseline Development

Development of DSM Assumptions

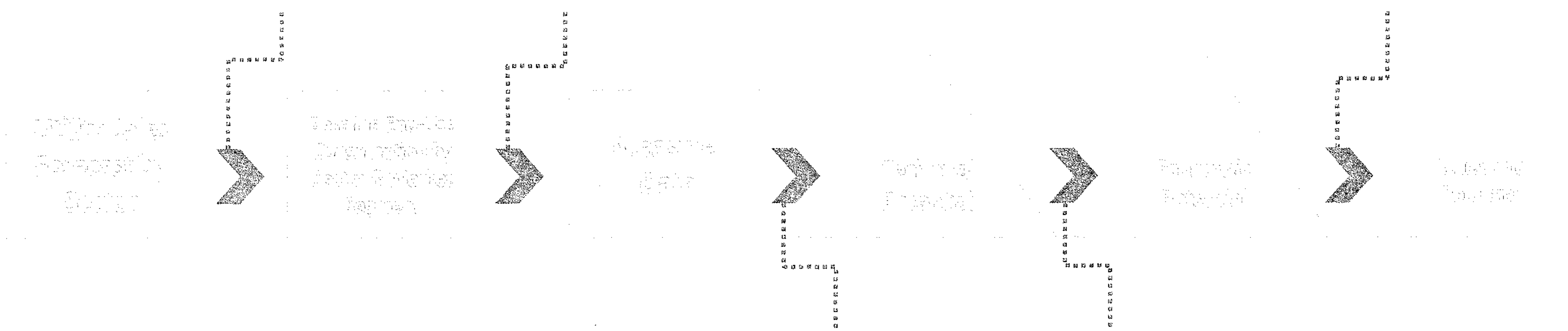
- GDS will develop appropriate base case and energy efficient case assumptions at the measure level to inform the measure characterization.
- Updates will include:
  - Measure costs
  - Measure kWh and kW savings
  - Measure lives
  - Measure and equipment saturation data

Technical Approach-Measure Assumptions

- **Develop measure database with detailed sourcing**
- **Account for codes and standards**
- **Coordinate with NIPSCO/OSB on critical methodological decisions**
  - Future potential of currently installed efficient technologies
  - Applicable replacement strategies (e.g. Replace on burnout, retrofit, early replacement)
  - Achievable potential scenario development
- **Develop appropriate funding levels and market adoption rates**
- **Quality control of model inputs/outputs**

- **Review of existing market data (Subtask 1.1)**
- **Primary market research (Subtask 1.2); surveys, interviews, on-site inspections**
- **Indiana Technical Resource Manual version 2.2 for measure data**
- **NIPSCO program planning and evaluation data, other industry sources**
- **Energy modeling software**

Assessment of Potential Savings



Development of Funding Levels

GDS will recommend the appropriate and necessary funding levels that will support achieving specific levels of program penetration and delivery over various time periods.

Attachment 4-A

Paul Kelly

Director of Federal Regulatory Policy

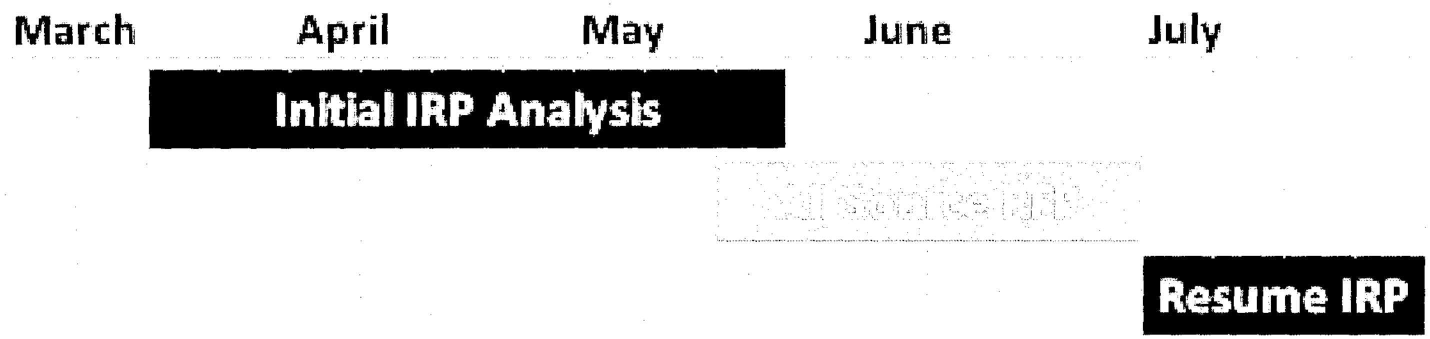
Goal Identify every viable resource in the market that can best meet our customers' needs

- Expert Assistance
  - Retained Charles River Associates (CRA) to develop and administer RFP
  - Utilizing a separate division within CRA to ensure independence from the IRP process
- Stakeholder Input
  - Seeking feedback on approach/design to ensure a robust, transparent process and result
- Resource Evaluation Criteria

  Complementary to the IRP portfolio analysis:
  - Cost to our customers
  - Reliability
  - Deliverability
  - Duration
  - Environmental impact
  - Employee and operational impact
  - Local community impact

- Technology
  - Requesting all solutions regardless of technology, including demand-side options and storage
- Size
  - Defining a minimum total need of 600 MW for the portfolio but without a cap
  - Allows smaller resources <600 MW to offer their solution as a piece of the total need
  - Also encourages larger resources >600 MW to offer their solution for consideration
- Acceptable Arrangements
  - Seeking bids for asset purchases and purchase power agreements for new and existing resources
- Duration
  - First year of need begins June 1, 2023
  - Minimum contractual term and/or estimated useful life of 5 years
- Deliverability
  - Solutions must have firm transmission delivery to MISO Local Resource Zone 6
- Participants & Pre-Qualification
  - Intending to leverage CRA's network of contacts and recommendations from stakeholders
  - Requiring utility-grade counterparties to ensure credit quality and ability to fulfill resource obligation

Timeline for the RFP



Date	Event
March 23rd	Overview RFP design with stakeholders
April 6th	RFP Design Summary document shared with stakeholders to request feedback
April 20th	Stakeholder feedback on Design Summary due back to NIPSCO
May 14th	**RFP initiated**
May 28th	Notice of Intent and Pre-qualifications due from potential bidders
June 29th	**RFP closes**
July 24th	Summary of RFP bids presented at Public Advisory Meeting webinar; IRP resumes analysis incorporating results of RFP

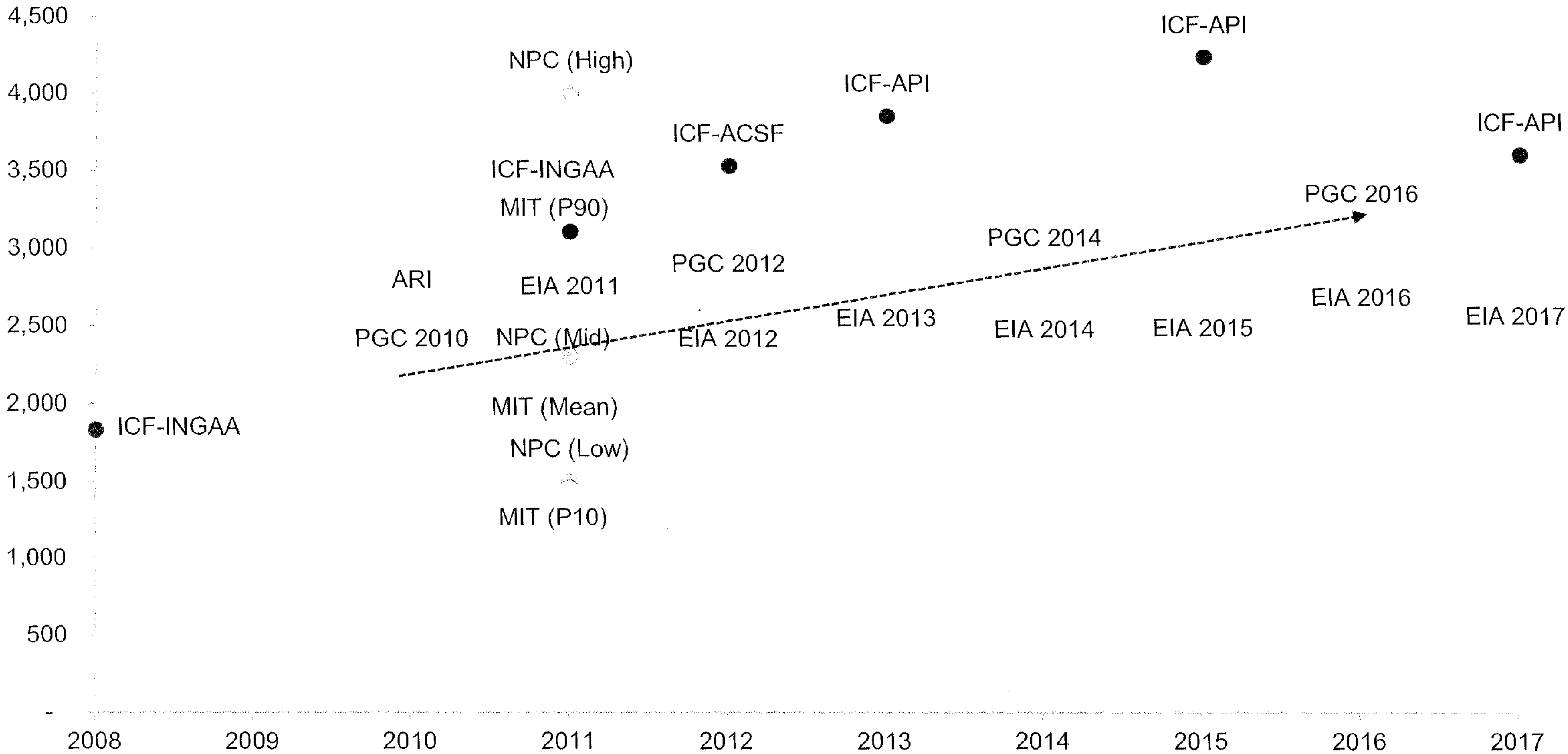
Similar to the 2016 IRP, NIPSCO plans to conduct a robust stakeholder engagement process for the 2018 IRP, including five formal stakeholder engagement meetings and one on one meetings with interested parties

	Meeting 1 – March 23- Avalon Manor	Meeting 2 – May 11 Avalon Manor	Meeting 3 – July 24 Webinar, SouthLake	Meeting 4 – September 19 Fair Oaks Farms	Meeting 5 – October 18 Fair Oaks Farms
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source RFP Solicitation?	- What are the preliminary findings from the modeling ?	- What is NIPSCO's preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP - Common understanding of DSM modeling methodology - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Stakeholder feedback and shared understanding of the modeling and preliminary results - Review stakeholder modeling and analysis requests	- Communicate NIPSCO's preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

Attachment 4-A

Gas Price Drivers – Resource Size

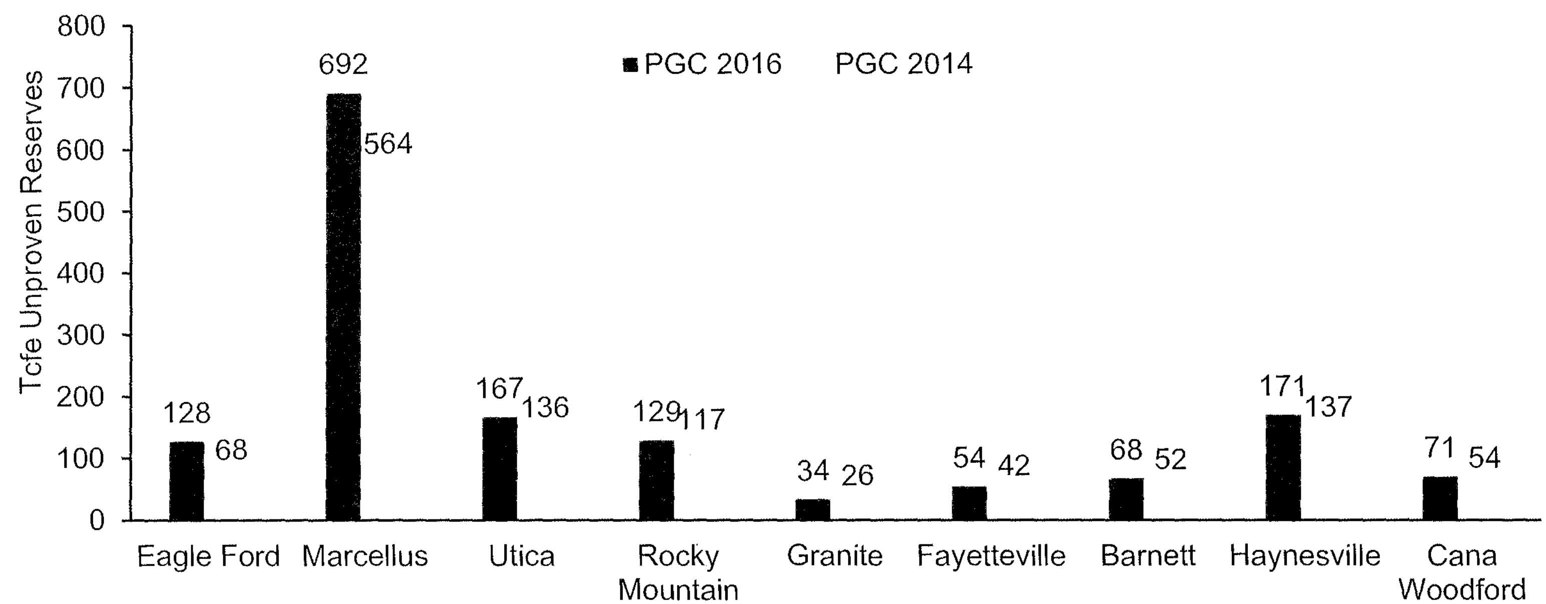
Estimates of resource in place have grown steadily as additional gas and oil continue to be discovered and extraction technology improves



* Note that CRA relies on the Potential Gas Committee (PGC) biennial report as the basis for our NGF resource estimate

Gas Price Drivers – Resource Size

- Shale resource drives the increase in total U.S. gas resource estimates in the PGC 2016 Natural Gas Supply Study
  - PGC 2016, released in July of 2017, estimates a "Traditional" unproved gas resource of 2,658 Tcf, a 12% increase from PGC 2014
  - The increase in total resource growth is driven primarily by shale gas resource, PGC 2016 estimates a total of 1,578 Tcf of shale resource, up from 1,253 Tcf in PGC 2014
- This is PGC's fifth consecutive publication showing an increase in resource estimates



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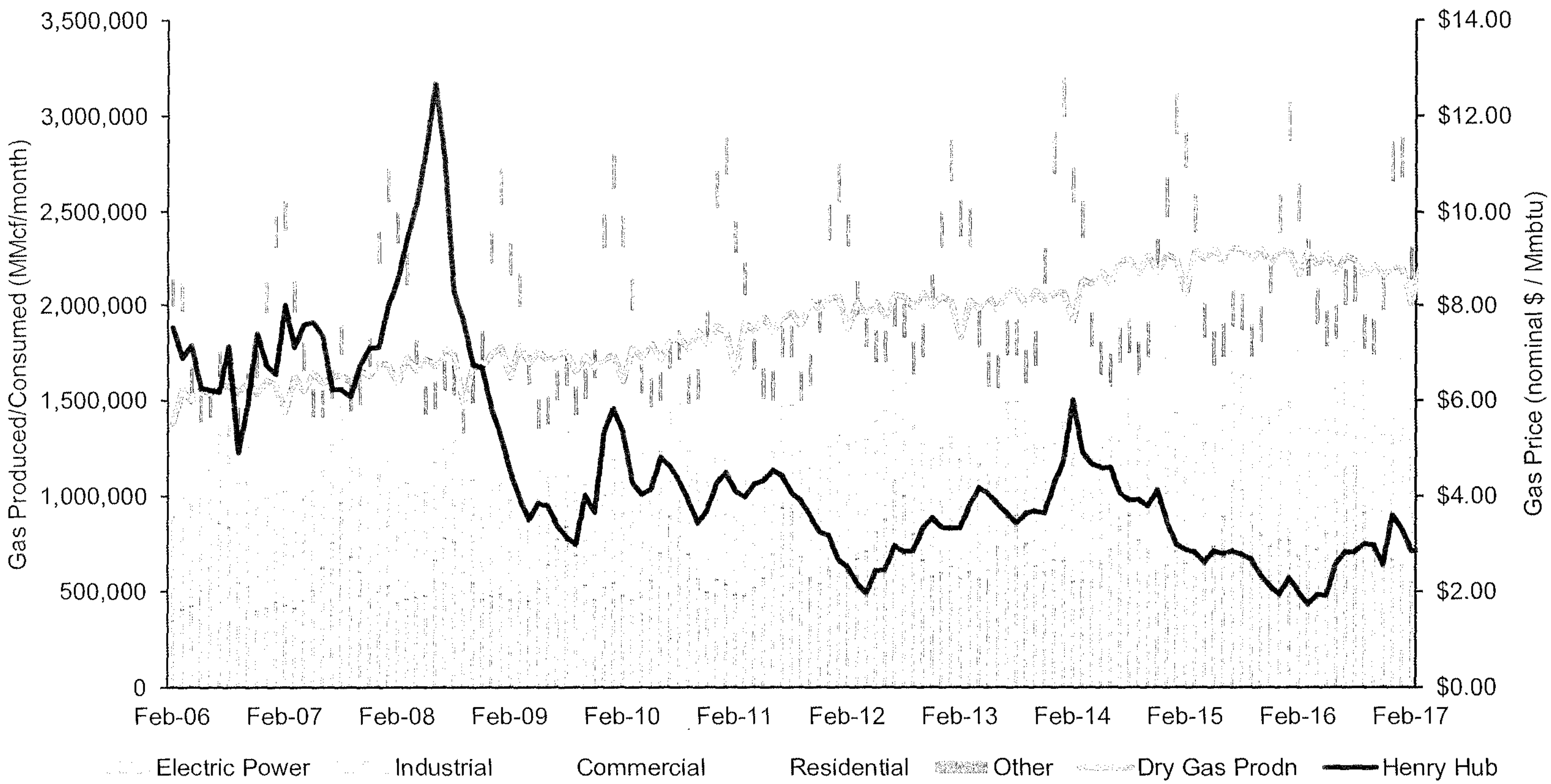
Gas Price Drivers – Well Productivity

Natural Gas Dry Production and Consumption



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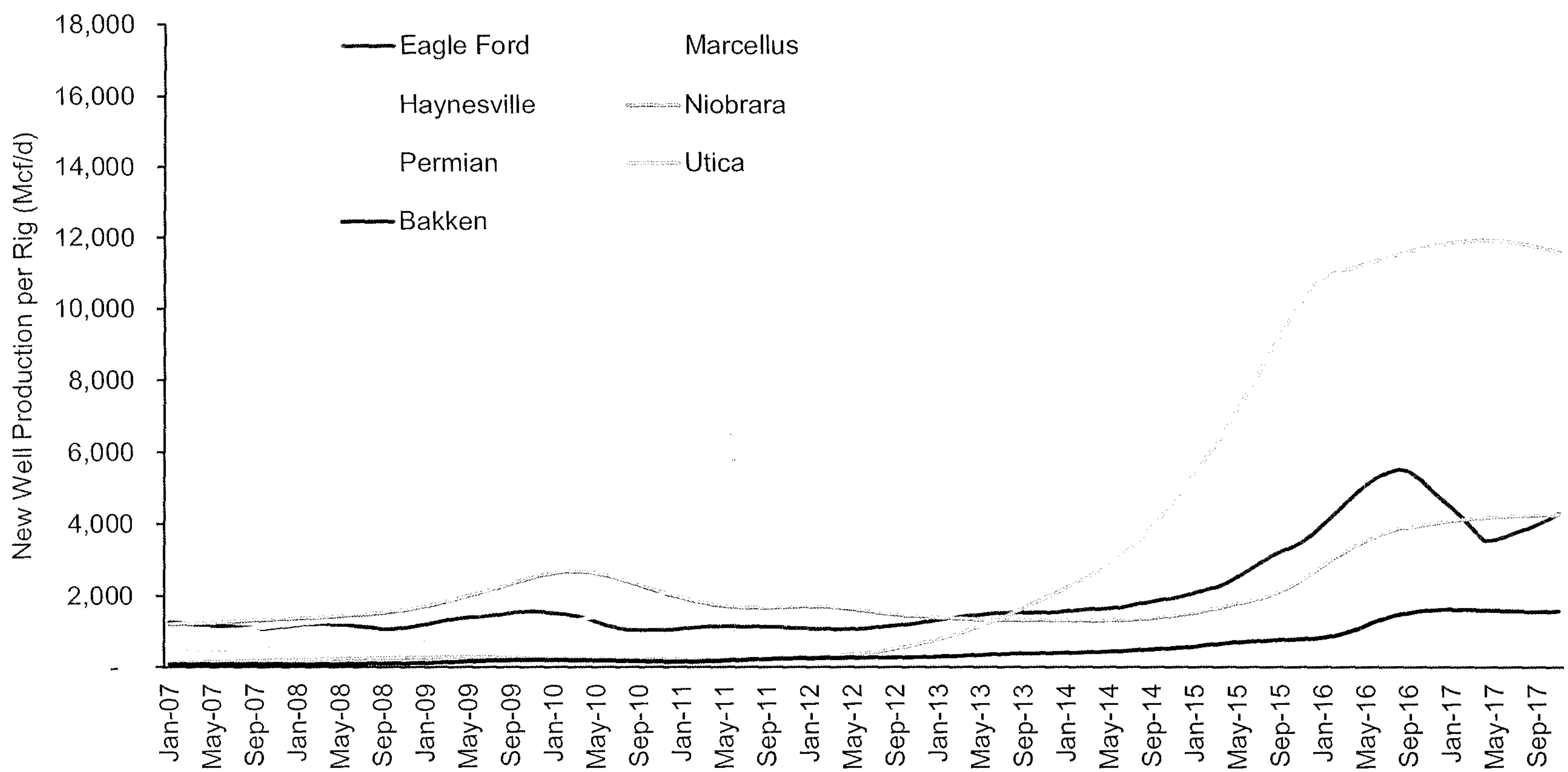
Attachment 4-A

Gas Price Drivers – Productivity Trends

Drilling Productivity in Select Gas Basins



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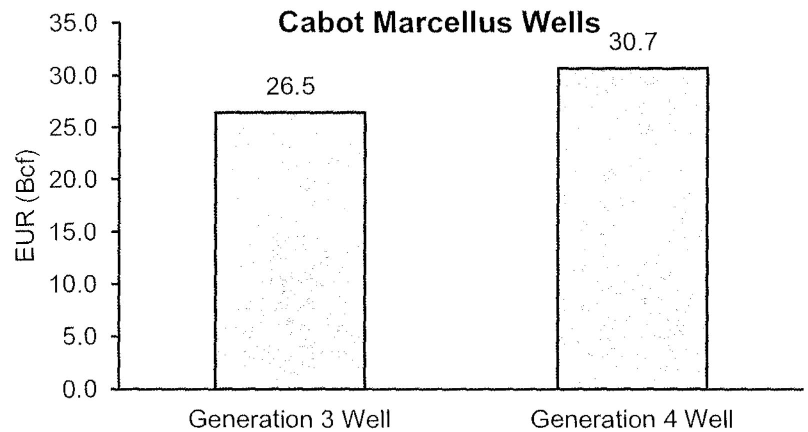
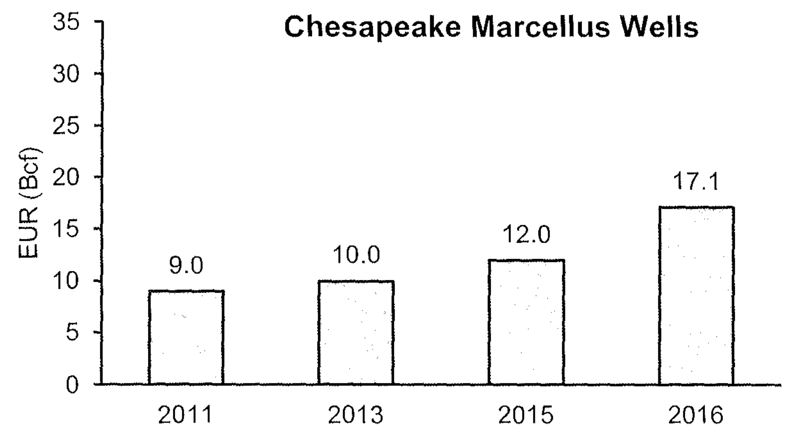
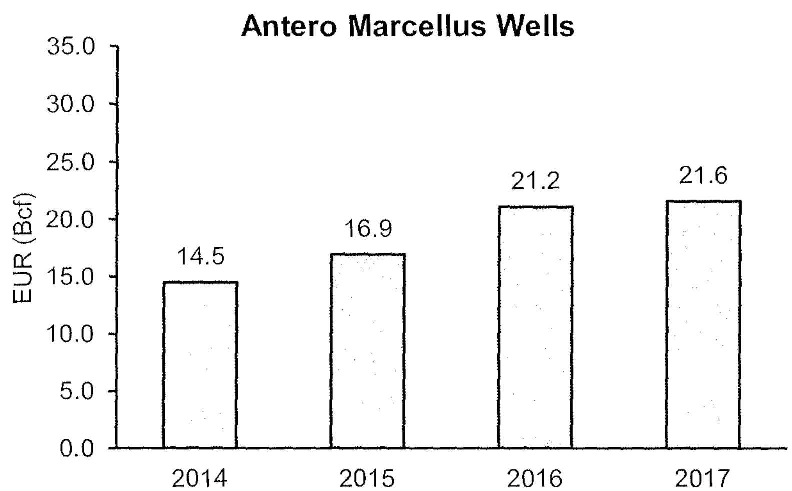
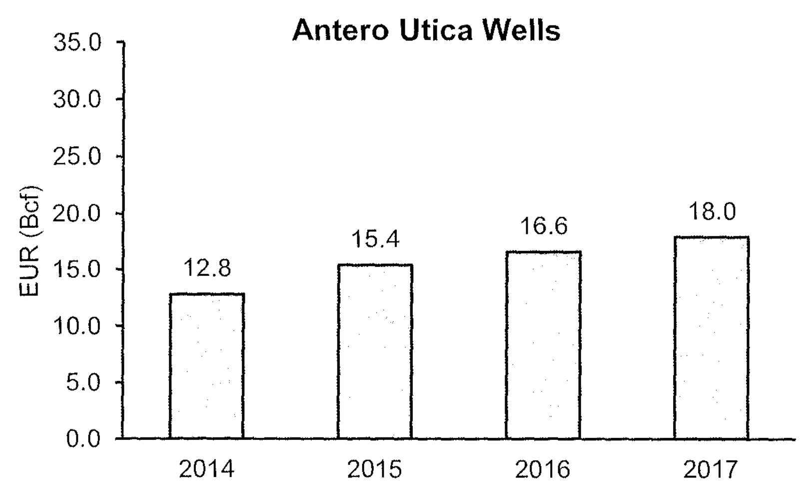
Well productivity on a per well basis has been consistently improving, even as longer laterals and multi pad drilling improve per rig performance



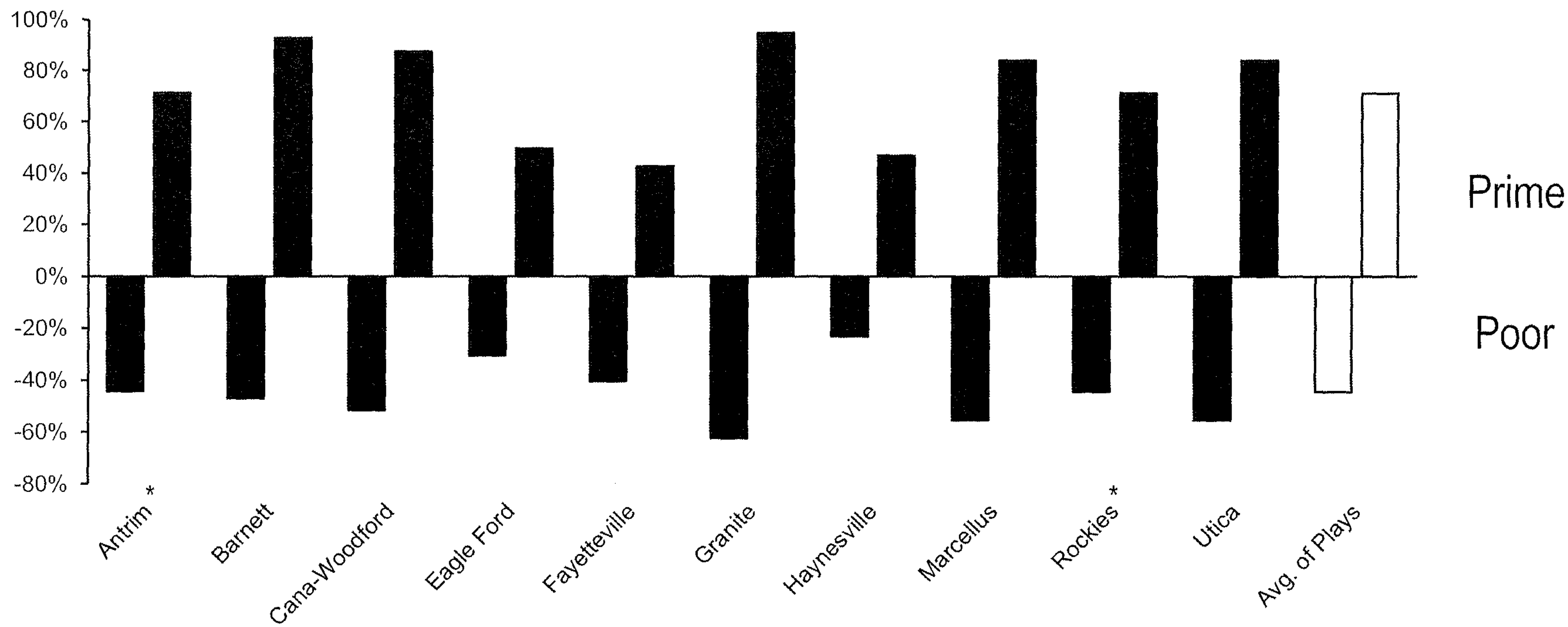






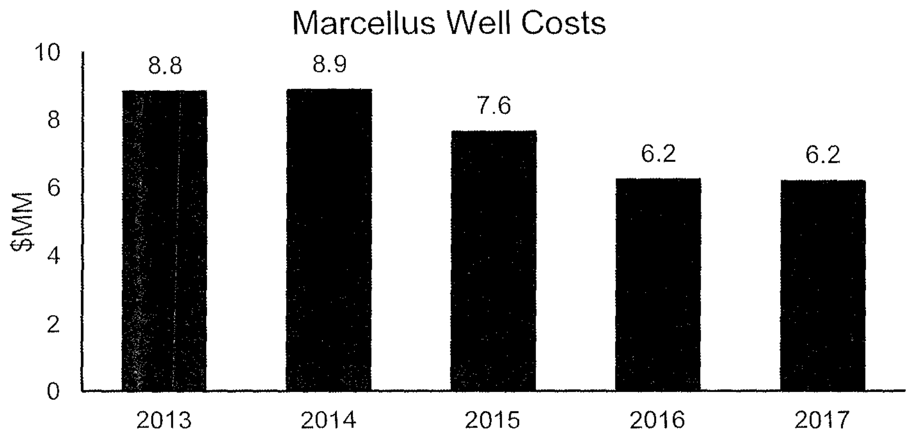
Productivity Distribution by Major Shale Basin

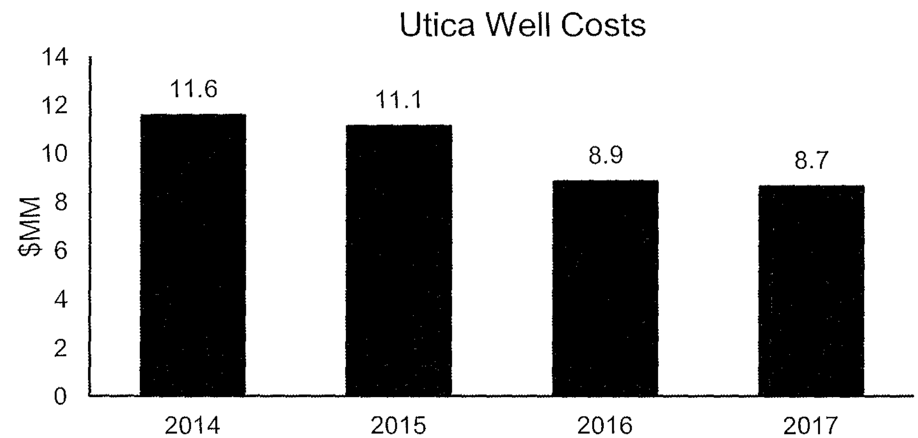
Poor and Prime Productivity by Region Relative to Play Average

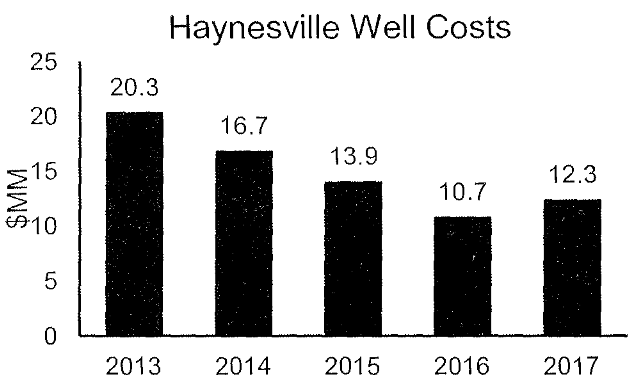


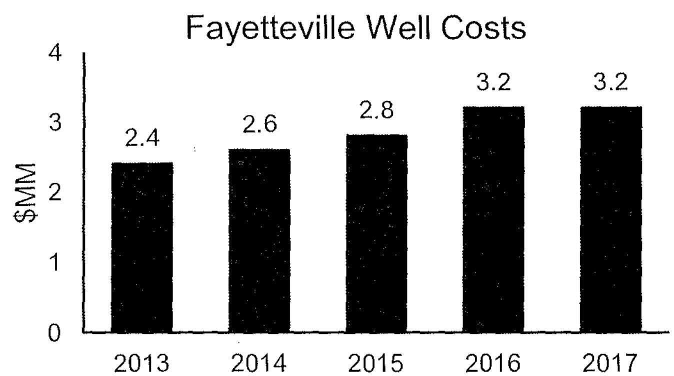
Attachment 4-A

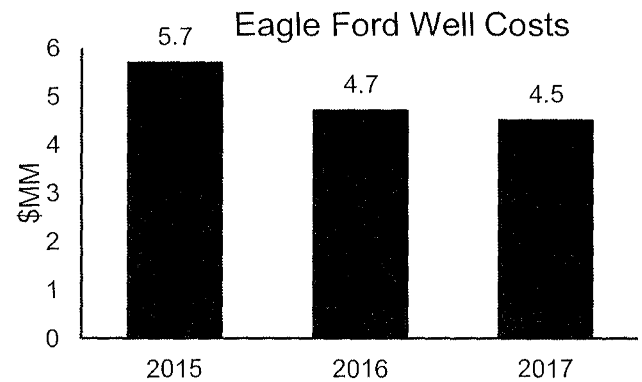
Gas Price Drivers – Drilling Costs





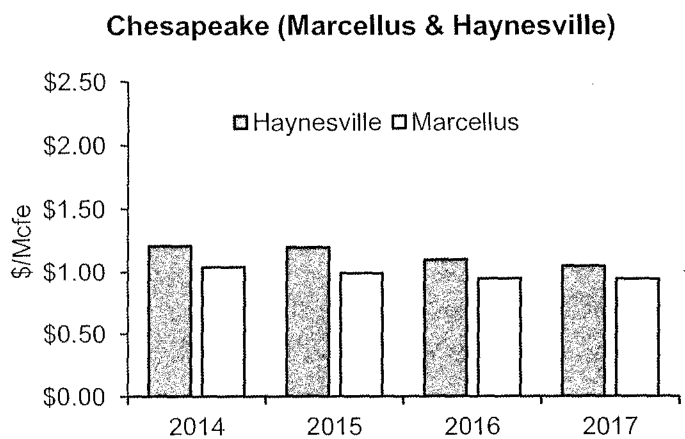


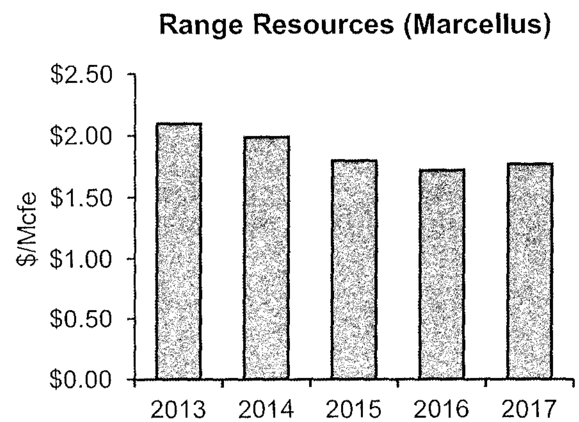


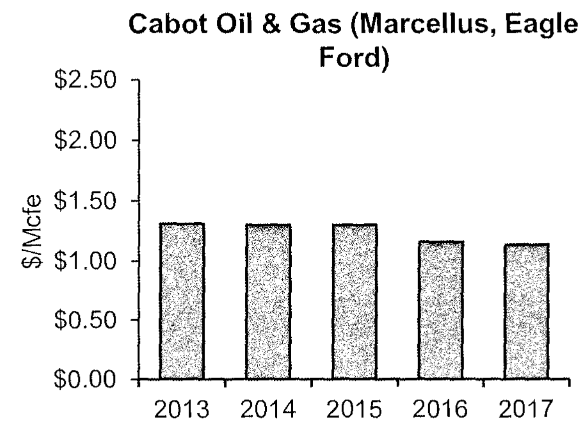


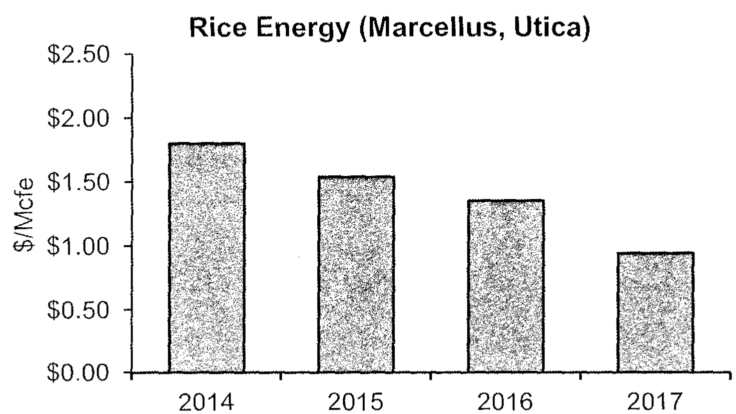
Gas Price Drivers – O&M Costs

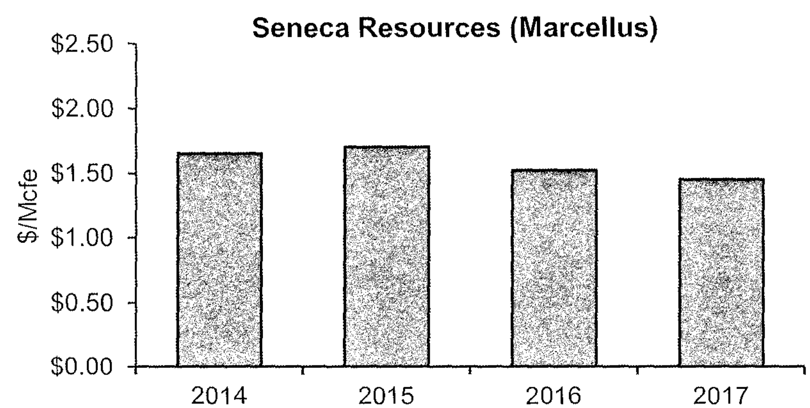
O&M Cost by Producer







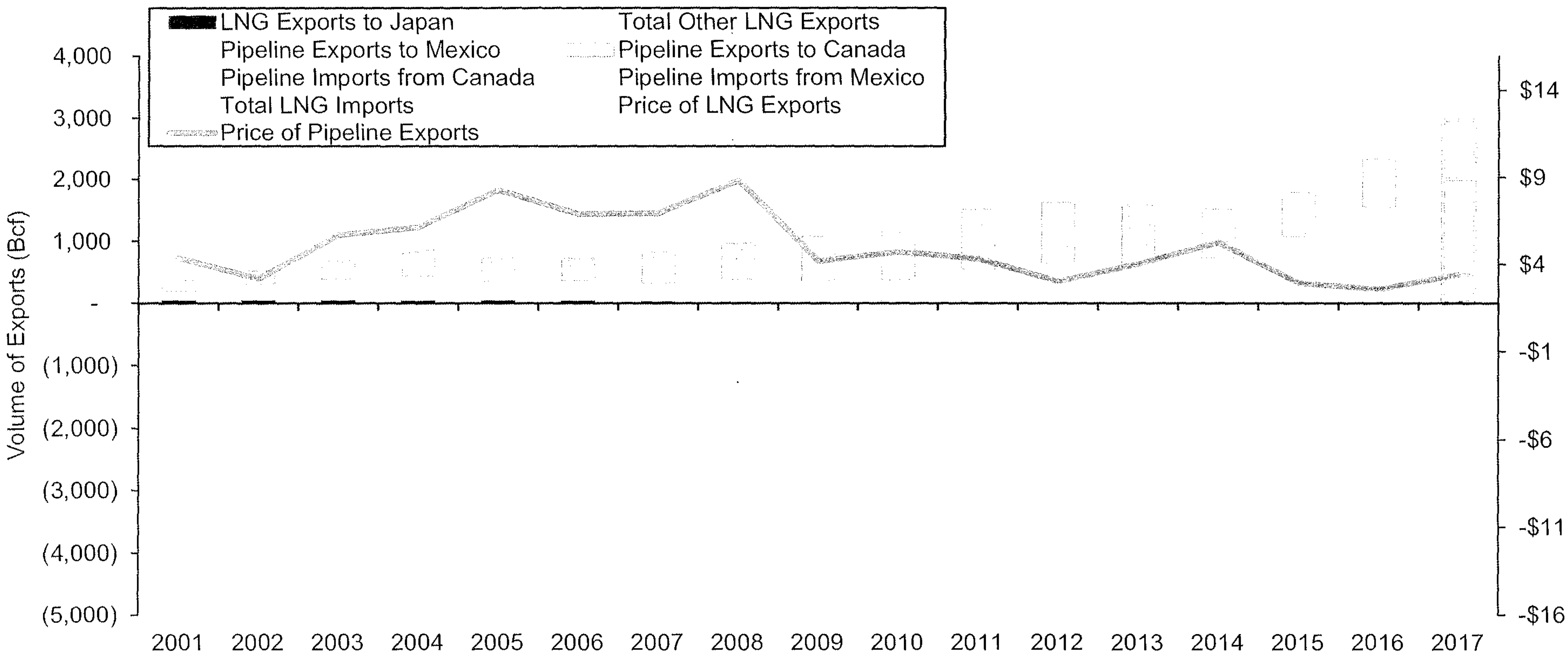




Gas Price Drivers – LNG

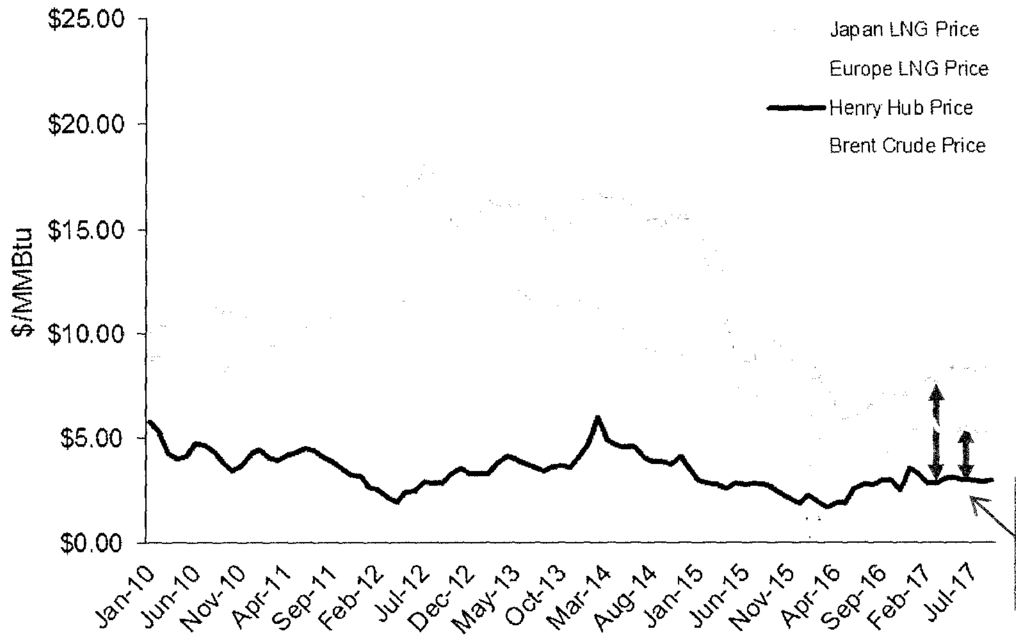
- US gas exports continue to grow, driven by export capacity additions and stabilized international market prices

U.S. Exports (LNG and Pipeline: 2001-2017 (Projected))

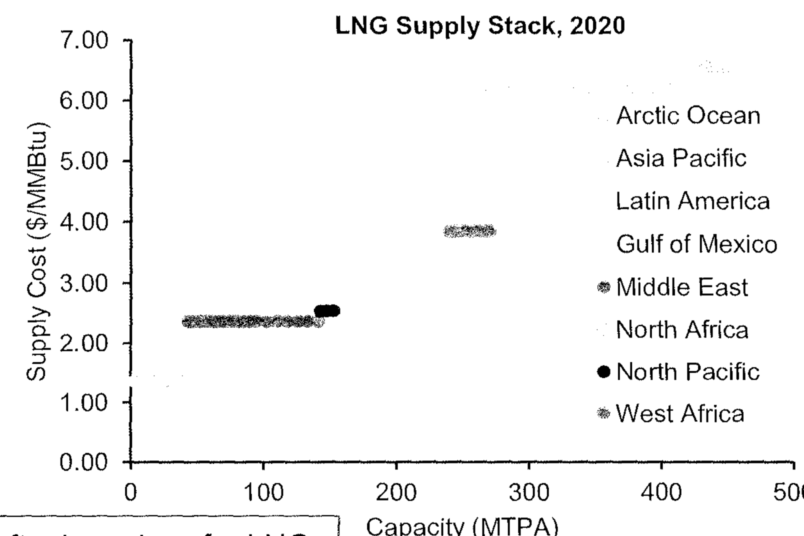


* 2017 data includes monthly average pricing data up to September 2017 and annualized projected volumes based on daily averages up to September

Gas Price Drivers – LNG



Softening prices for LNG exports threatens many potential projects



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Gas Price Drivers – LNG

US LNG terminal forecast largely unchanged in the past year, approximately 10 Bcf/d is now under construction or already completed

	Project	Status	FTA / Non FTA	Expected In Service	Capacity (Bcf/d)
In Service / Under Construction	Sabine (T1-T3)	Operating	Non-FTA		1.8 Bcf/d
	Sabine (T4)	Commissioning	Non-FTA	2018	0.6 Bcf/d
	Cove Point (Full Terminal)	Commissioning	Non-FTA	2017	0.82 Bcf/d
	Sempra Cameron (T1-T3)	Under Const.	Non-FTA	2019	1.8 Bcf/d
	Elba/Southern LNG (T1-T5)	Under Const.	Non-FTA	2018	0.36 Bcf/d
	Freeport (T1-T3)	Under Const.	Non-FTA	2018-19	1.8 Bcf/d
	Sabine (T5)	Under Const.	Non-FTA	2018	0.6 Bcf/d
	Corpus Christi (T1-T2)	Under Const.	Non-FTA	2018-19	2.14 Bcf/d
	Sub-total				**9.92 Bcf/d**
Awaiting FID	Sabine (T6)	Approved	Non-FTA	2021 +	0.6 Bcf/d
	Lake Charles (T1-T3)	Approved	Non-FTA	2021 +	2.1 Bcf/d
	Magnolia (T1-T4)	Approved	FTA	2021 +	1.0 Bcf/d
	Golden Pass	Approved	Non-FTA	2021 +	2.0 Bcf/d
	Sempra-Cameron (T4-T5)	Approved	Non-FTA	2021 +	1.4 Bcf/d
	Corpus Christi (T3)	Approved	Non-FTA	2021 +	1.4 Bcf/d
	Sub-total				**8.5 Bcf/d**
	[redacted]				
	Terminals (Pre-Filing)				**4.75 Bcf/d**
	Grand Total				**42.17 Bcf/d**

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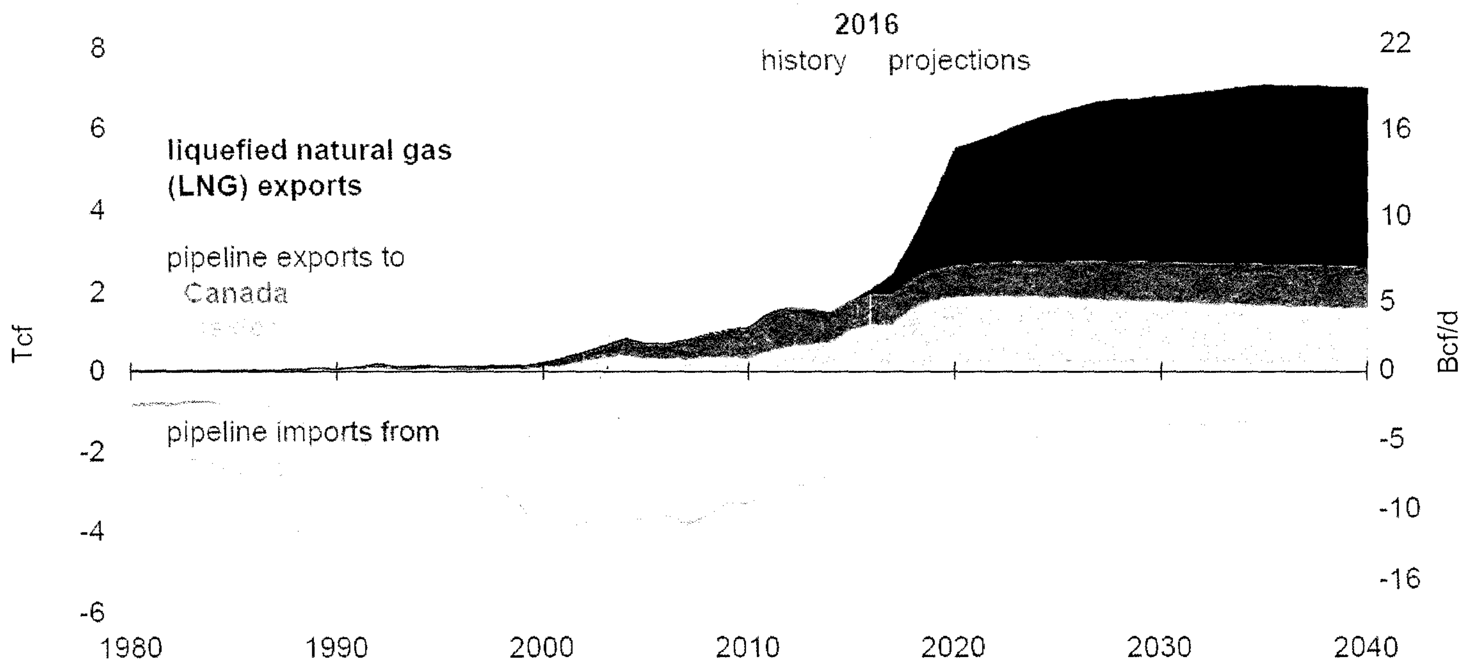
Gas Price Drivers – Net Pipeline Exports

- EIA projects that US transitions to net exporter of natural gas by 2020

Net Exports from USA (AEO 2017)



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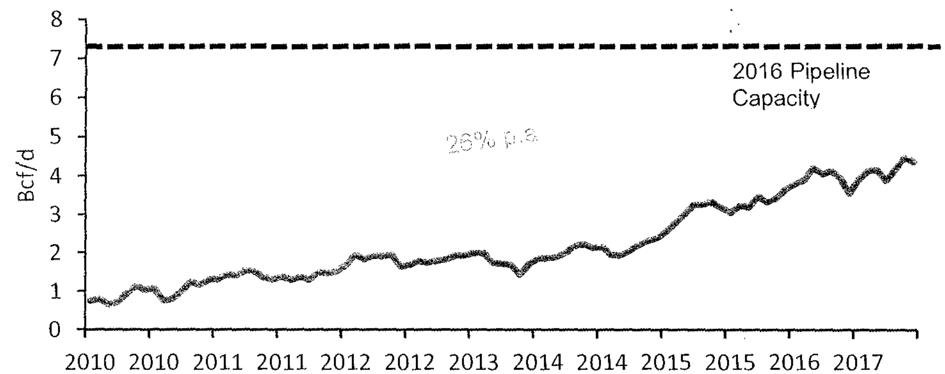
Attachment 4-A

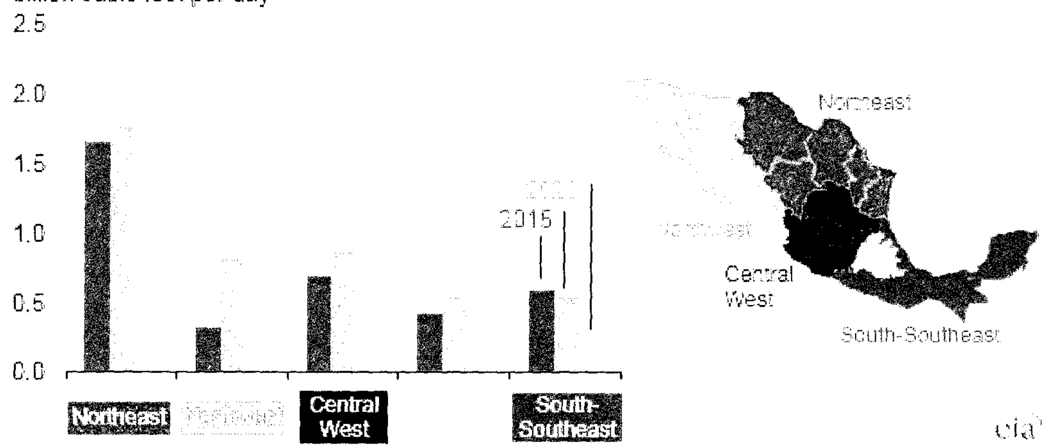
Gas Price Drivers – Net Pipeline Exports

Mexican exports have steadily risen over the last five years, and are expected to rise as electric sector demand grows while domestic production remains flat/declines

Net Exports to Mexico (2009 – 2017)



Mexico projected natural gas consumption in the electric generation sector, 2015-29
billion cubic feet per day



Pipeline	Online Year	Capacity (Bcf/d)
Tula - Villa de Reyes	2017	0.6
Sur de Texas - Tuxpan	2018	2.6
Tuxpan - Tula	2017	0.7
San Isidros - Samalayuca	2017	1.13
Comanche Trail Pipeline	2017	1.1
Trans-Pecos Pipeline	2017	1.3
Samalayuca - Sásabe	2018	0.5
La Laguna – Aguascalientes	2018	1.1
Nueces – Brownsville	2018	2.6

- Mexico's 2015-2019 gas development plan includes 12 new gas infrastructure projects, totaling over 3,200 miles of pipeline and 9 Bcf/d – as of July, 7 of the 12 projects have been awarded contracts
- Pipeline export capacity to Mexico is expected to double from current levels, to 14 Bcf/d, by 2018

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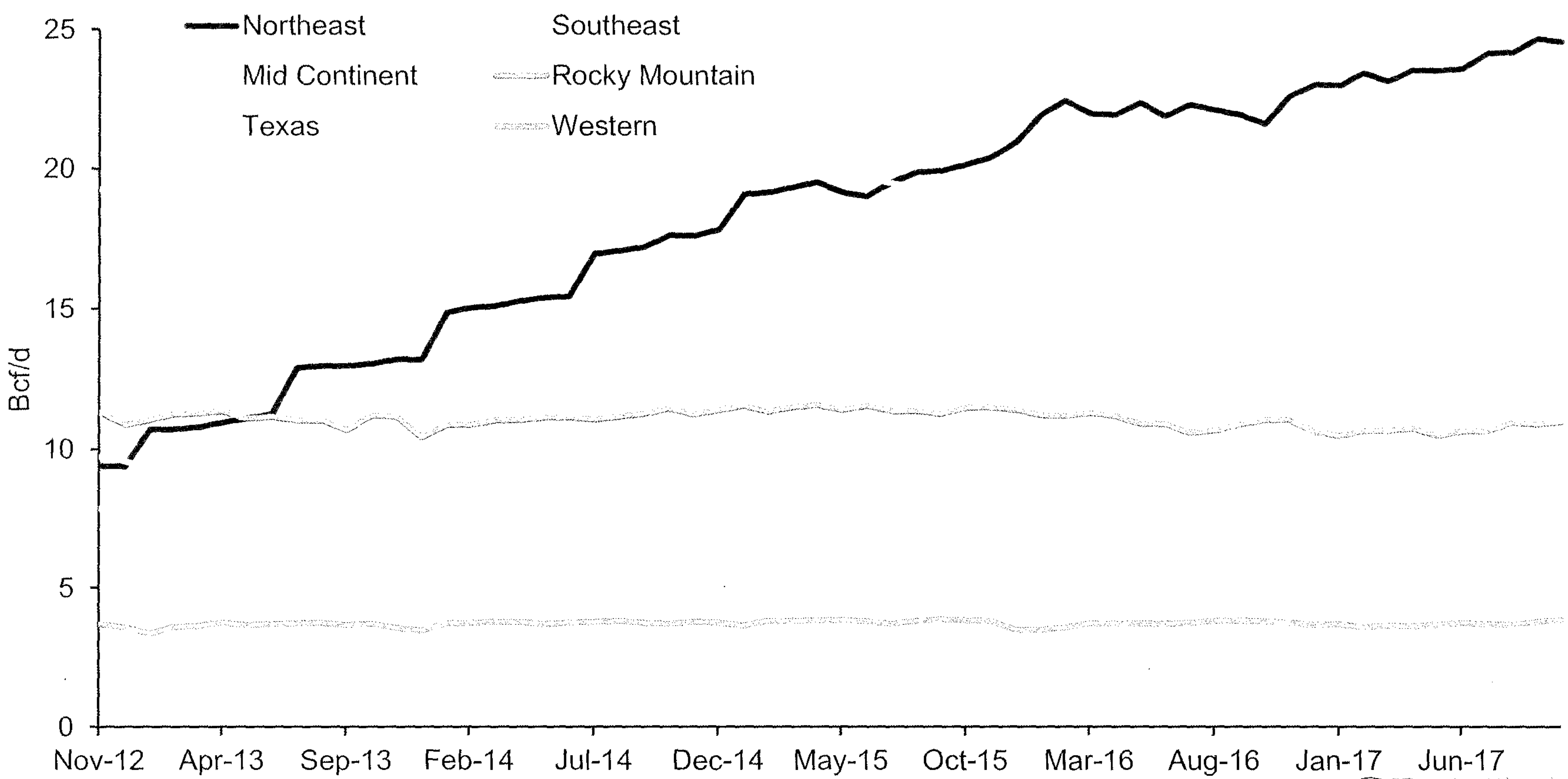
Key Natural Gas Market Trends – Changes in Flows

- The Northeast region has shifted from a net importer to a net exporter of natural gas, impacting regional prices and direction of gas flow across major pipelines
- These trends should continue as new large pipeline projects (Rover, Nexus, MVP and ACP) will provide long term export capacity for Marcellus/Utica production



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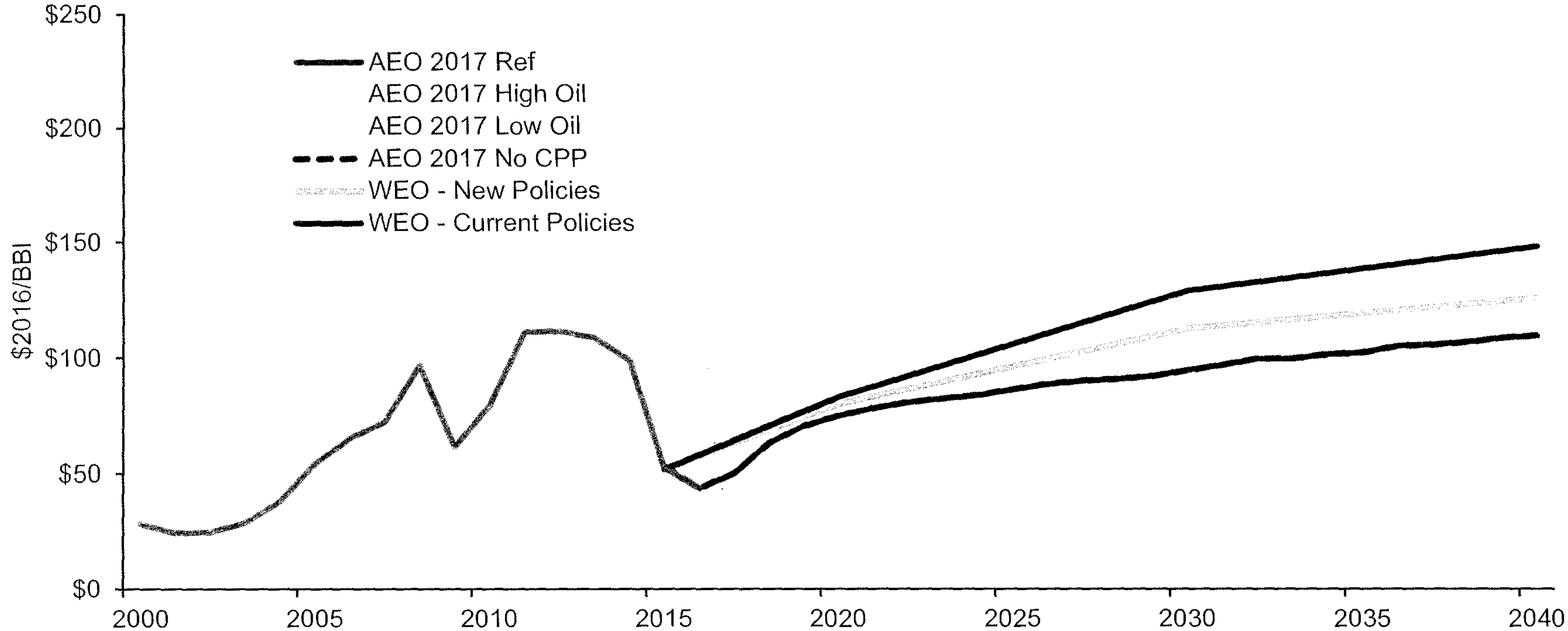
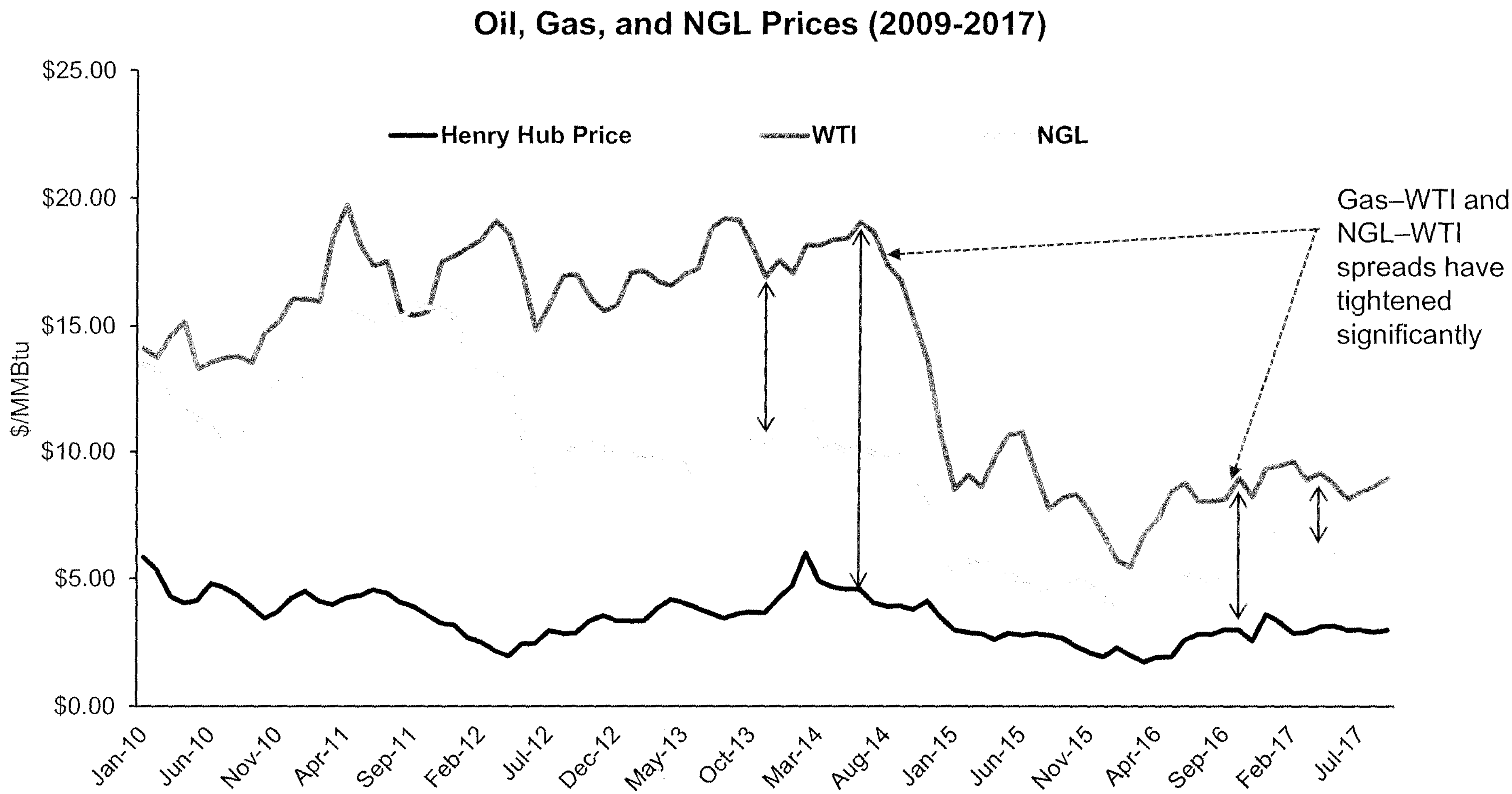
Gas Price Drivers – Oil / NGL Prices

Brent Crude Prices – Forecast



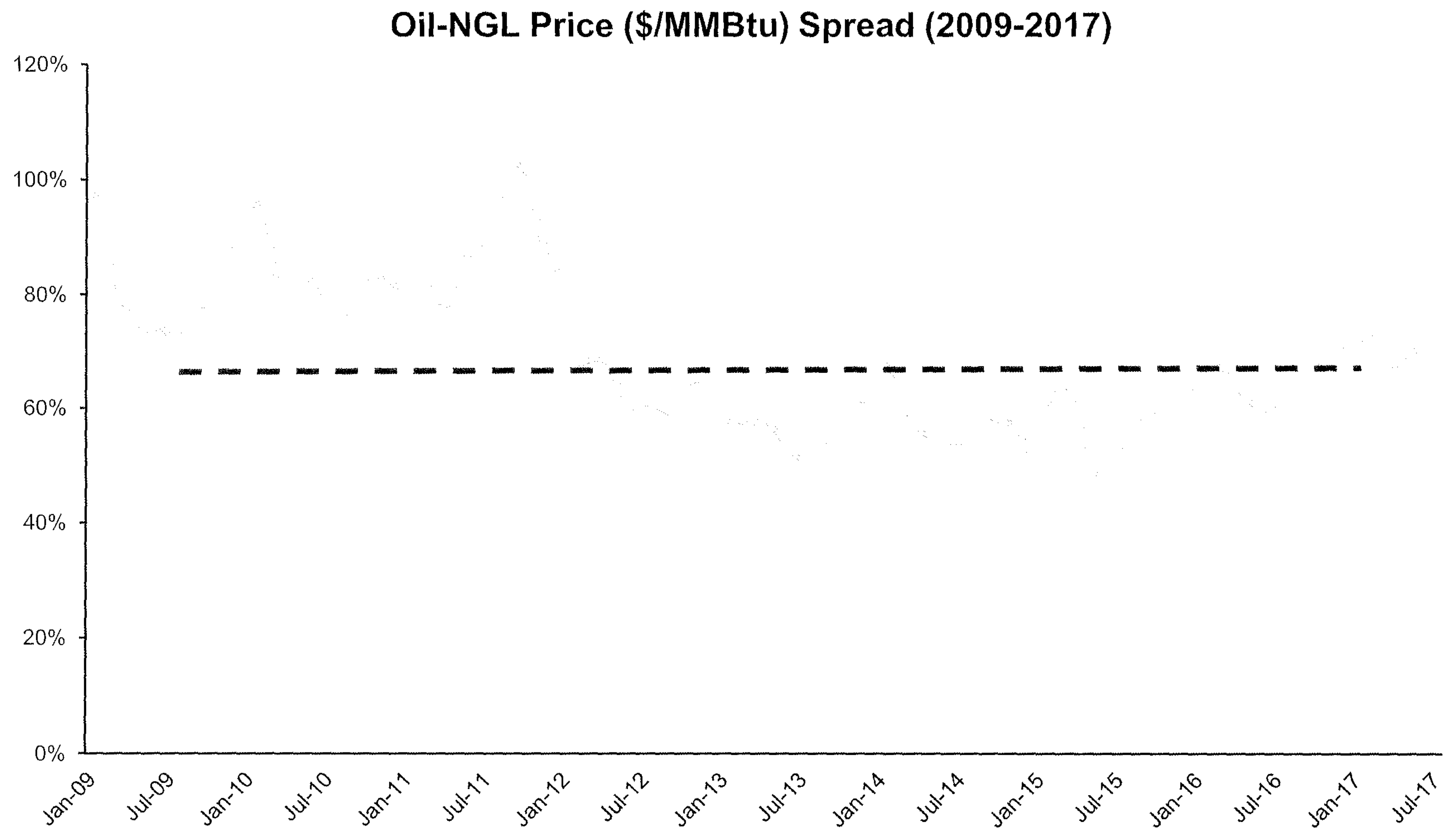
Gas Price Drivers – Oil / NGL Prices



Note: NGL Composite price encompasses NGL spot prices at Mont Belvieu with monthly volumes used to calculate weight.

Attachment 4-A

Gas Price Drivers – Oil / NGL Prices



Source: EIA

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Methodology for Forecasting U.S. Steam Coal Prices

- Macroeconomic drivers:
  - U.S. market: Electric demand growth expected to be met through natural gas generation under expected gas prices and environmental requirements
  - International market: International demand for exports of steam and metallurgical coals from the U.S. grow modestly
- Microeconomic drivers:
  - Trends in coal mining costs for key supply regions
  - Production trends for key coal supply regions, incl. mine expansions and closures

Coal units in the model see a delivered coal price that incorporates commodity and transport costs

Delivered Unit Fuel Cost ($/ton) = Transportation Cost ($/ton) + Solved Mine Mouth Price ($/ton)

- CRA calibrates these inputs to reflect market developments that affect coal supply and transport costs

Coal Outlook Overview

- The price downturn from 2011-2016 reflects the 27% decline in U.S. coal production from 2014-2016

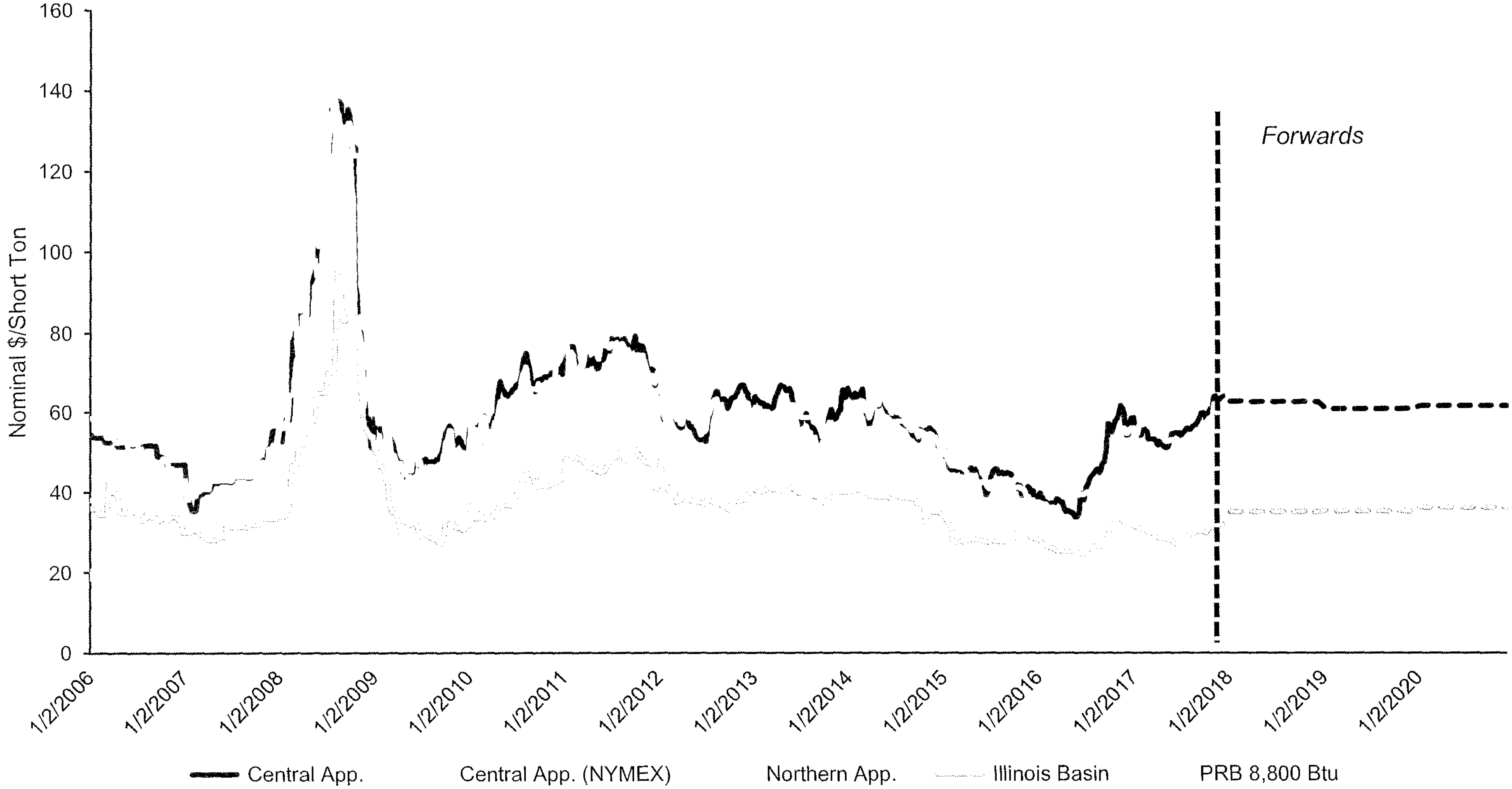
- Price increase caused by increased demand for U.S. coals exports, and a reduction in U.S. coal stockpiles

- 8-10% decline from 2017 levels by 2022, and a 25% decline by 2027, driven by CO_2 pricing from 2026

- In real terms, CRA projects prices to generally remain near current levels over the 2020-2040 period

- Due to high mining costs, Central Appalachian coal production is primarily targeted at the metallurgical coal market, and less than 30 million tons/year of this coal is currently used for electric generation within the U.S.

Historical Coal Prices vs. Forwards



Source: Coaldesk LLC broker sheet, 12/8/2017. Price for NAPP 3.5# coal is estimated based on published Coaldesk data.

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The U.S. electric sector makes up the bulk of domestic demand, and is expected to decrease its reliance on coal over the forecast period

- Coal's share of 2017 U.S. electric generation was about 32%
- Carbon pressure and sustained low gas prices are likely to drive a decline in coal's market share
- CRA's base case shows that coal generation accounts for approximately 24% of total generation from 2027-2035

- Low gas prices and growing renewable generation are expected to drive 30+ GW of coal-fired retirements over the 2018-2022 period
- After 2022, tightening environmental targets and new, highly efficient NGCC entry continue this trend; CRA expects 23-24% of electric demand to be met by coal-fired units by the late 2030s

International demand for U.S. coal expected to grow modestly, driven by emerging Asian economies and decommissioning of EU nuclear units

- CRA projects 52 million tons of metallurgical coal and 40 million tons of steam coal in 2017

- Europe is the primary market for U.S. exports of both metallurgical and steam coal. However, Asia is an important secondary market, especially for metallurgical coal.
- The global scarcity of metallurgical coal reserves may allow the U.S. to maintain its 2017-2018 production levels for these coals, despite being a relatively high-cost producer.

- Several coal terminals have been proposed in the Pacific Northwest, Millennium Bulk Terminal (MBT), the last currently active project of this type, was denied its water quality certification in September 2017
- CRA's preliminary case assumes that the MBT is not completed

Attachment 4-A

U.S. Mining Costs by Coal Supply Region, 2015-2017

– Smaller average size of the coal mines and greater reserve depletion in CAPP leads to an increase in expected production costs, relative to other major U.S. coal supply regions

Cash Operating Costs Per Ton of Coal

(averages for 1Q-3Q of each year unless otherwise noted)

	YTD 2015	YTD 2016	YTD 2017	Nominal % Change 2015-2017
Central App				
Arch Coal (CAPP)	$54.25	$51.30	$61.11	**NM[2]**
Contura Energy (East)[1]	$66.45	N/A	$72.35	**NM[2]**
Northern App				
Consol Coal Resources	$34.47	$30.03	$29.57	**-14.2%**
Illinois Basin				
Alliance Resource Partners (ILB EBITDA expense)	$31.67	$30.03	$25.67	**-18.9%**
Peabody Energy (Midwestern U.S.)	$33.46	$30.96	$32.23	**-3.7%**
Powder River Basin ("PRB")				
Arch Coal (PRB)	$10.69	$10.95	$10.45	**-2.2%**
Cloud Peak Energy	$9.81	$10.07	$9.68	**-1.3%**
Contura Energy (PRB)[1]	$10.38	N/A	$10.02	**-3.5%**
Peabody Energy (PRB)	$9.97	$9.80	$9.57	**-4.0%**

Source: Company financial reports.

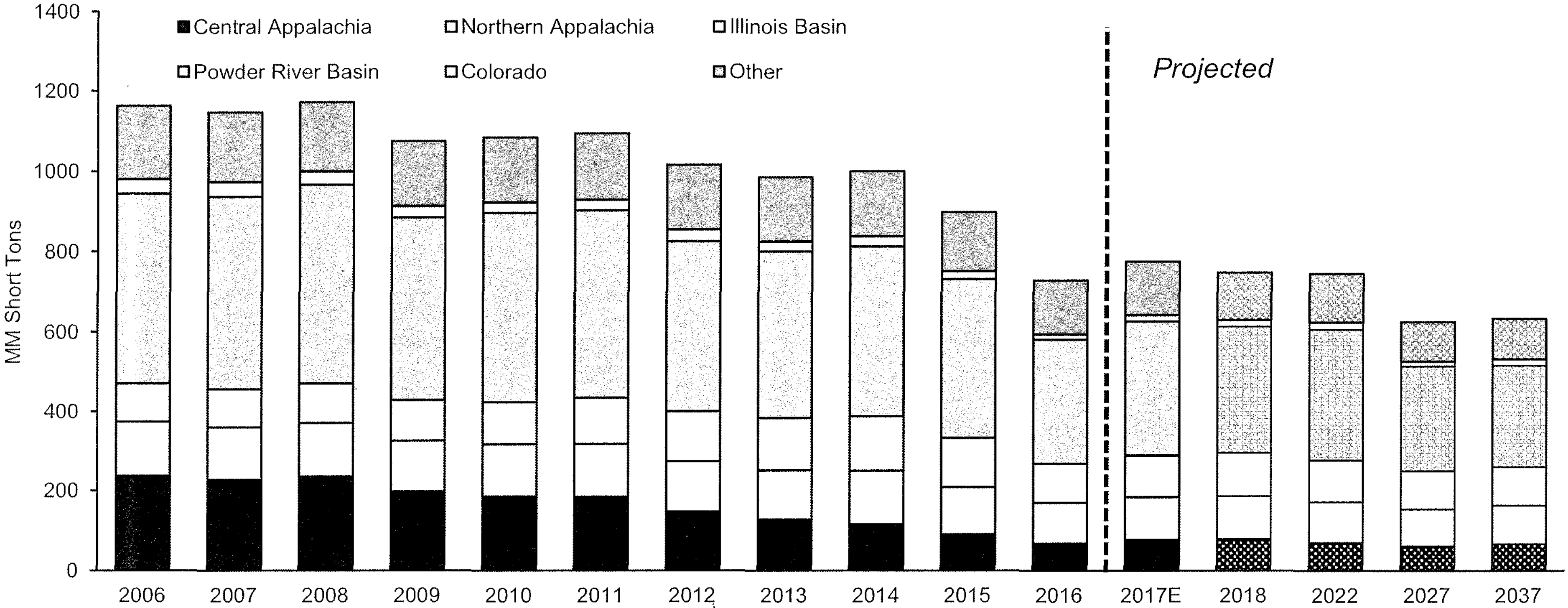
Notes:

1. 2015 data is 1Q2015 only.

2. 2015-2017 mining cost comparisons for Central Appalachia are not meaningful due to increasing concentration on metallurgical coal production during this period.

Attachment 4-A

U.S. Coal Production by Supply Region - 2006-2037



Net Change in Coal Production (MM Tons)	2006-2017	2017-2022	2022-2037
Central Appalachia	(159)	(8)	(3)
Northern Appalachia	(32)	(4)	(5)
Illinois Basin	8	0	(9)
Powder River Basin	(135)	(8)	(73)
Colorado	(20)	1	(1)
Other	(50)	(11)	(20)
Total	**(388)**	**(30)**	**(112)**

Sources: 2006-2016 data from U.S. Mine Safety and Health Administration (MSHA) and Energy Information Administration (EIA). 2017 and later data is estimated.

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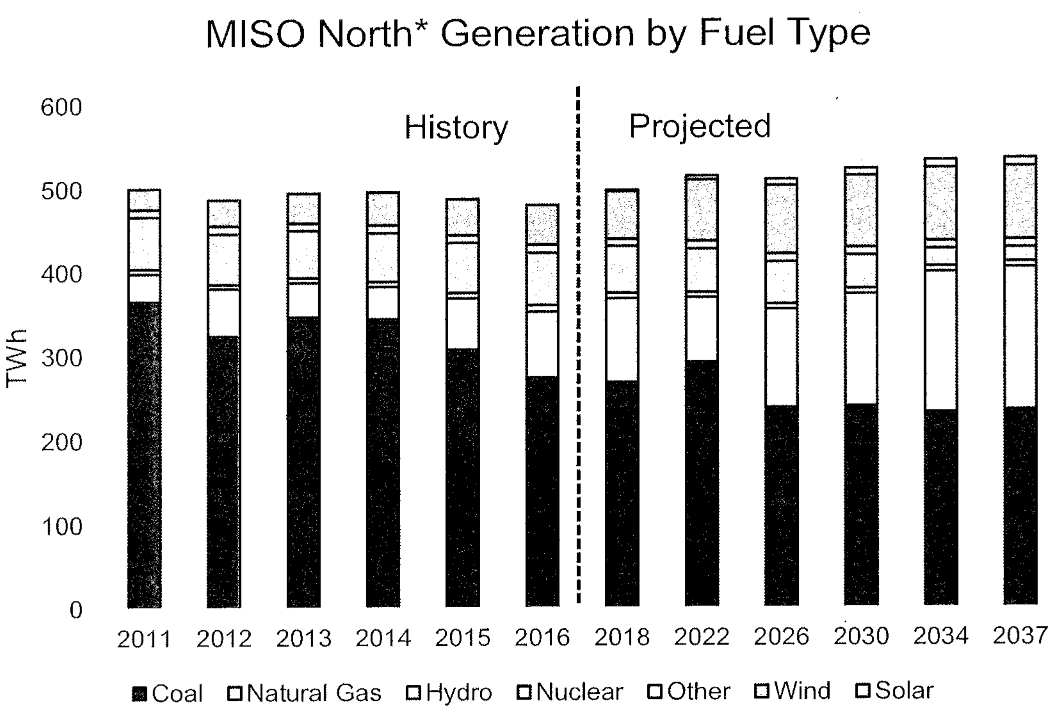
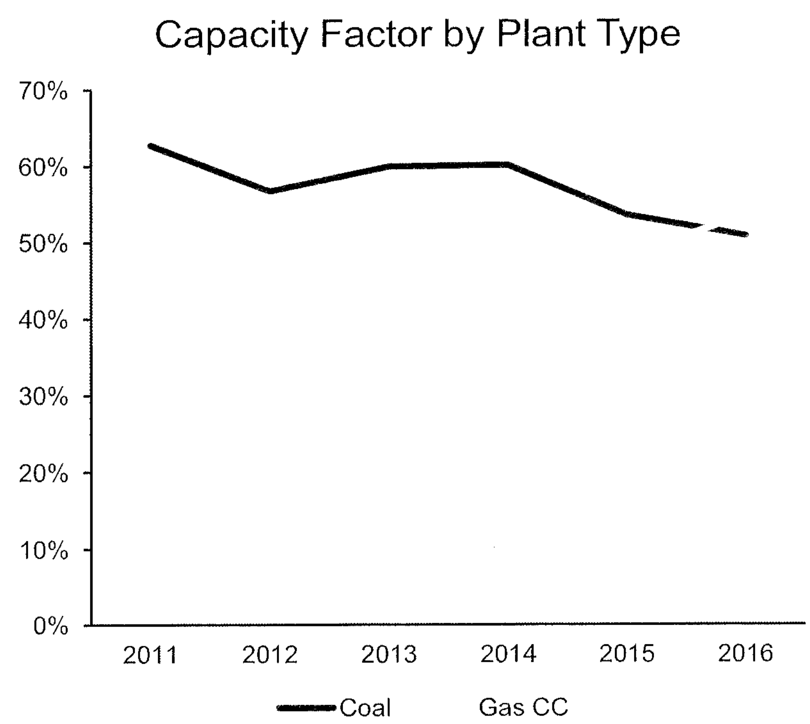
Generation has shifted from coal to gas and wind in recent years

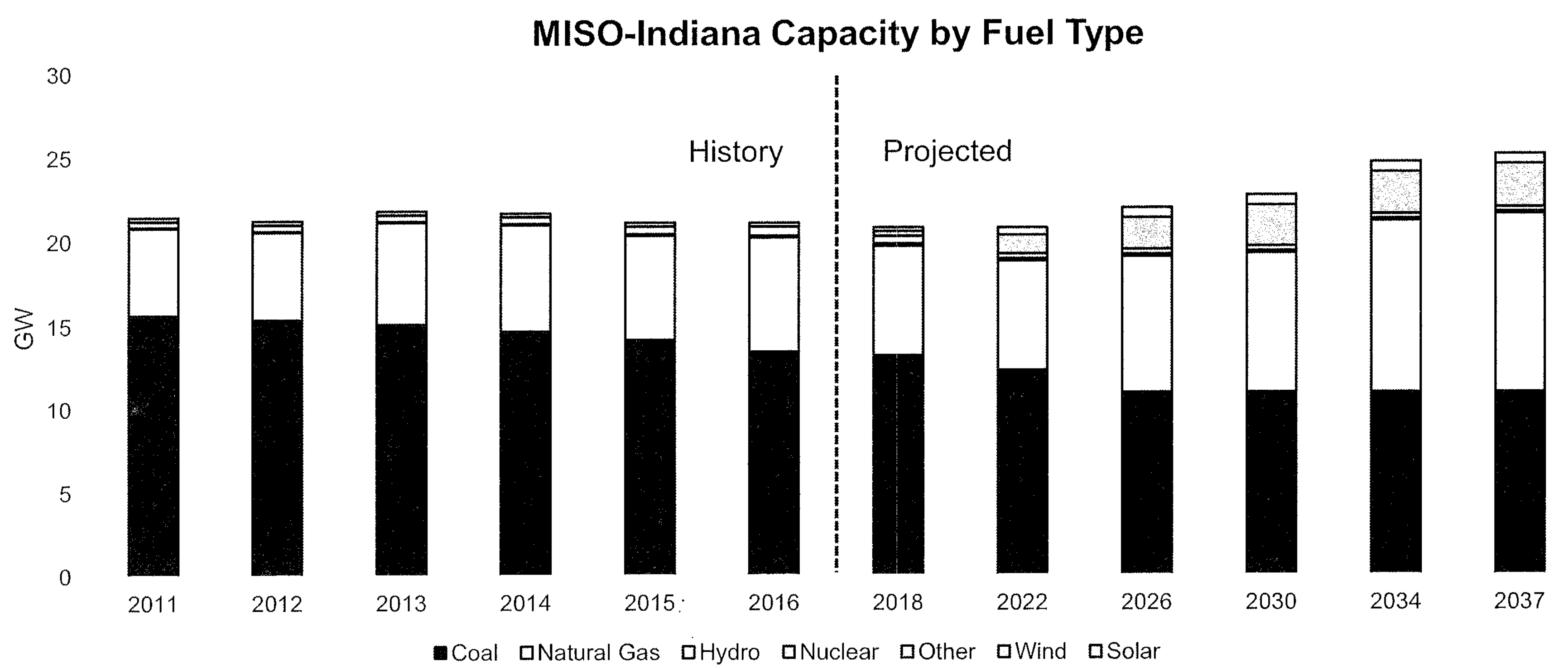


*MISO North includes LRZ 1-7

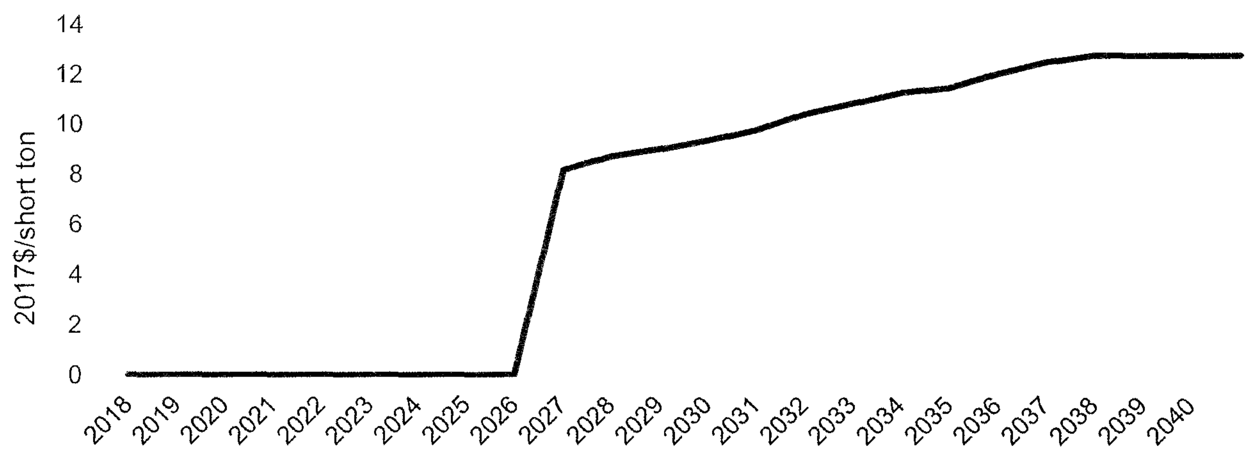


MISO-Indiana Zone

– For example: IPL Eagle Valley gas CC expected online in June 2018



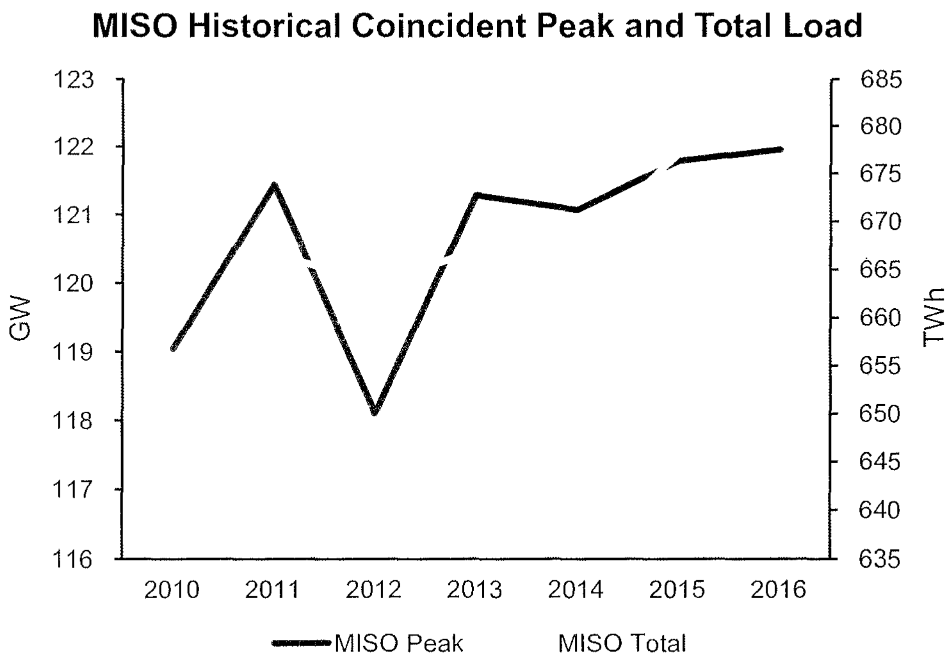
Environmental policy drivers influence shift in generation mix and power price forecast

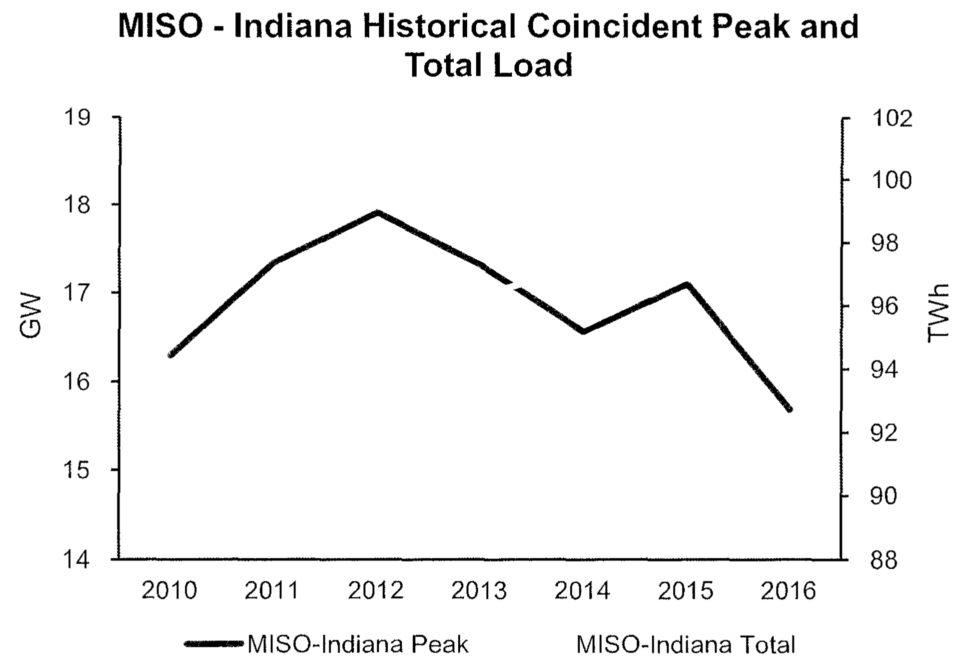


MISO RPS Targets

25% (IL, MN), 15% (MI, MO), 10% (IN, ND, WI), *None* (AR, MS, LA, IA)

Electricity demand growth in MISO has been relatively modest

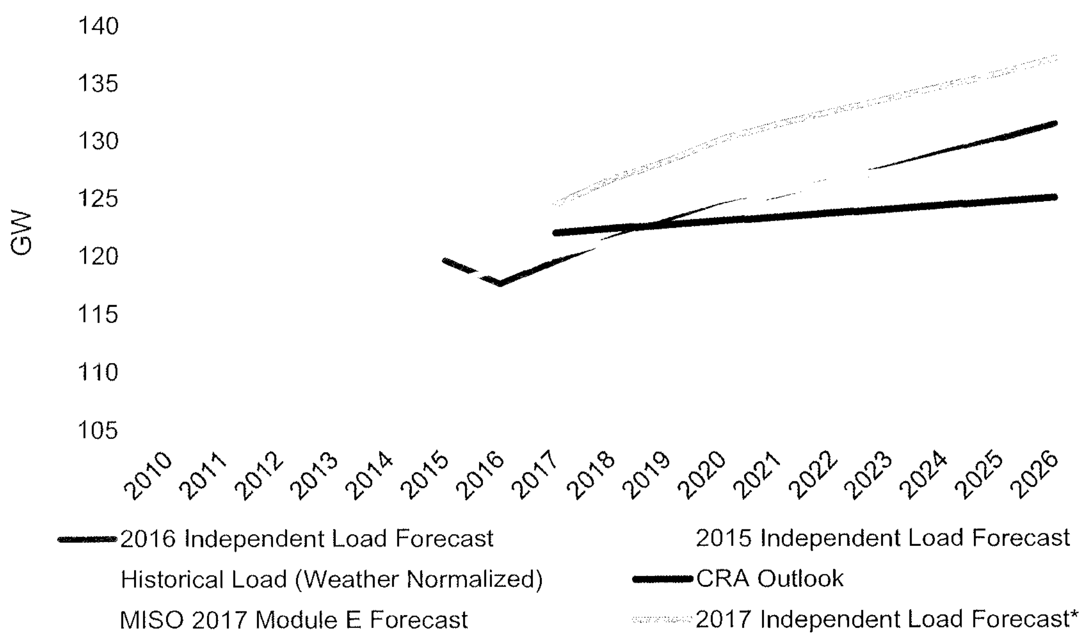




Attachment 4-A

CRA expects modest growth in annual, peak demand

MISO Peak Demand Projections with Historical Load



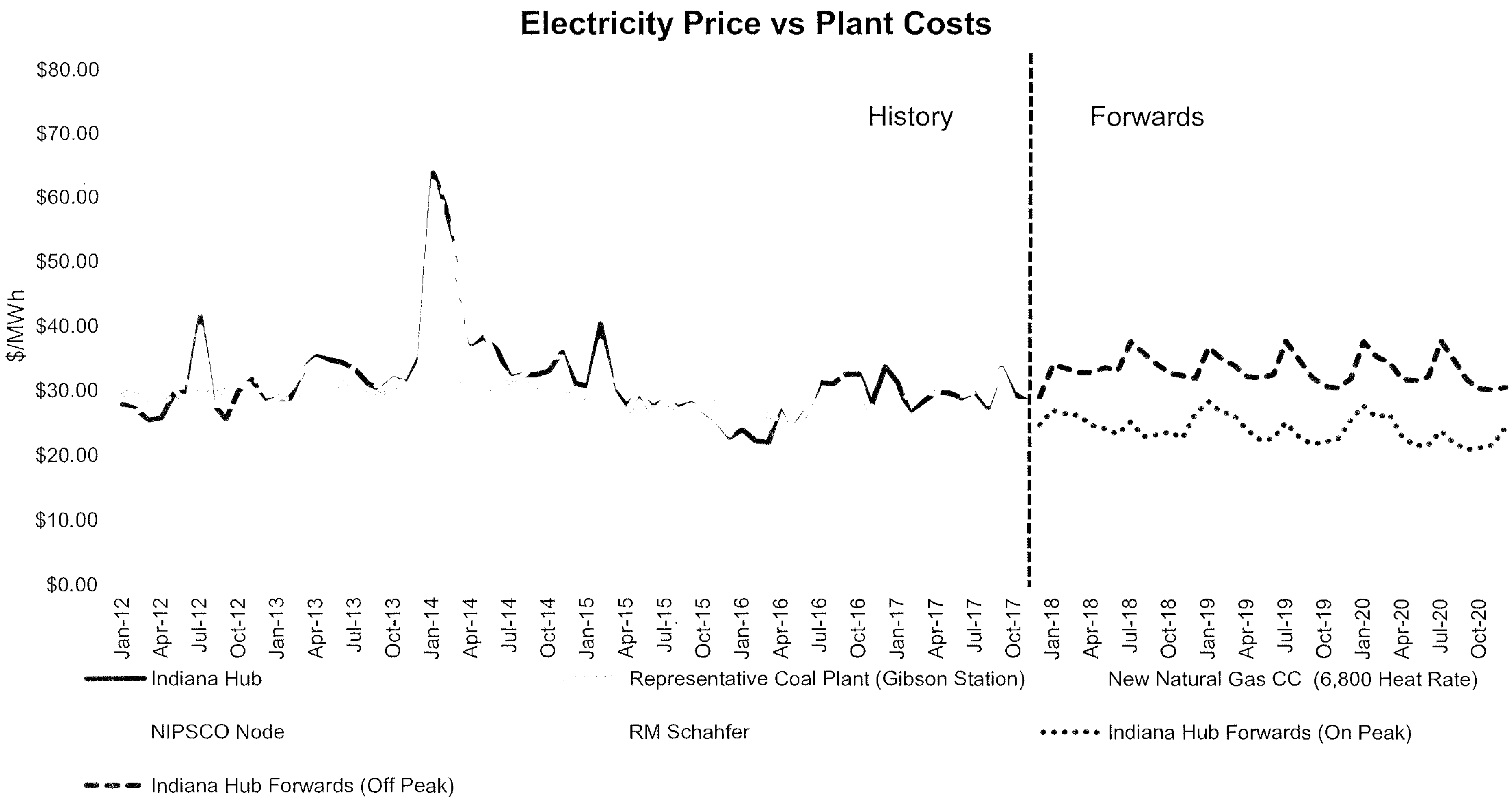
*Note 2017 ILF Forecast does not include impact of DR and DG

Peak Load Forecast	10-Year Summer Peak CAGR
2010-2016 Weather-Normalized	*0.40%*
2015 Independent Load Forecast	0.98%
2016 Independent Load Forecast	1.12%
2017 MISO Module E	0.27%
CRA Outlook	**0.24%**

CRA Charles River Associates

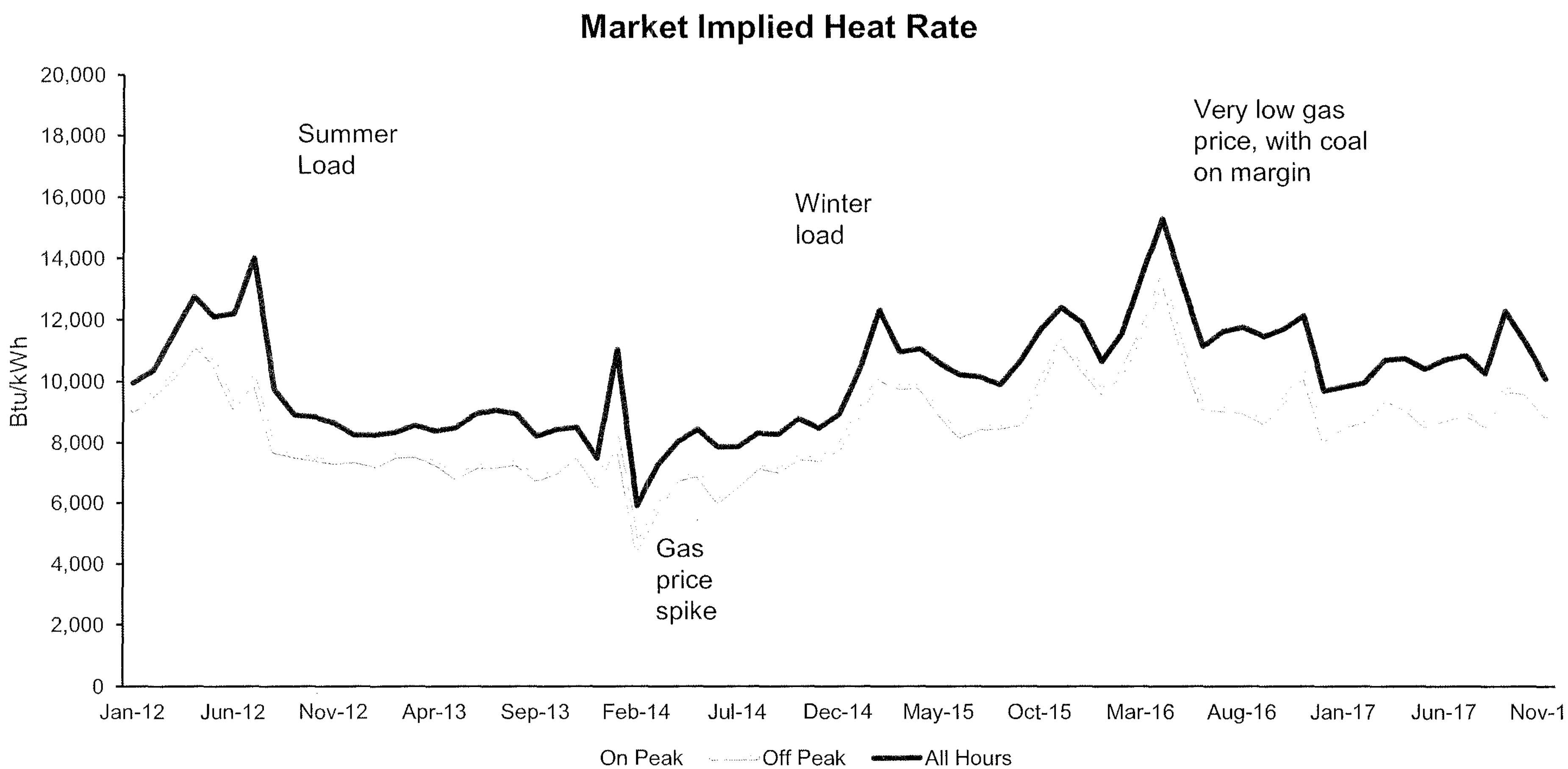
Attachment 4-A

MISO Energy Market Dynamics



CRA Charles River Associates

Market heat rate is seasonal, with increases in recent years

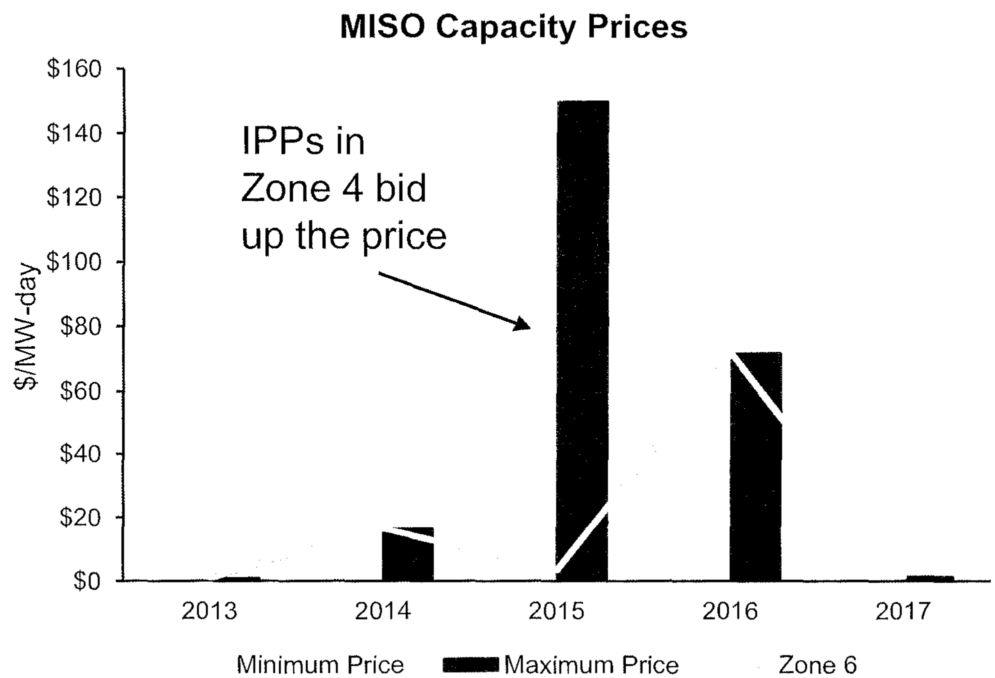


*Using Indiana Hub and RexEast Gas Price Index

Attachment 4-A

MISO Resource Adequacy and Capacity Market

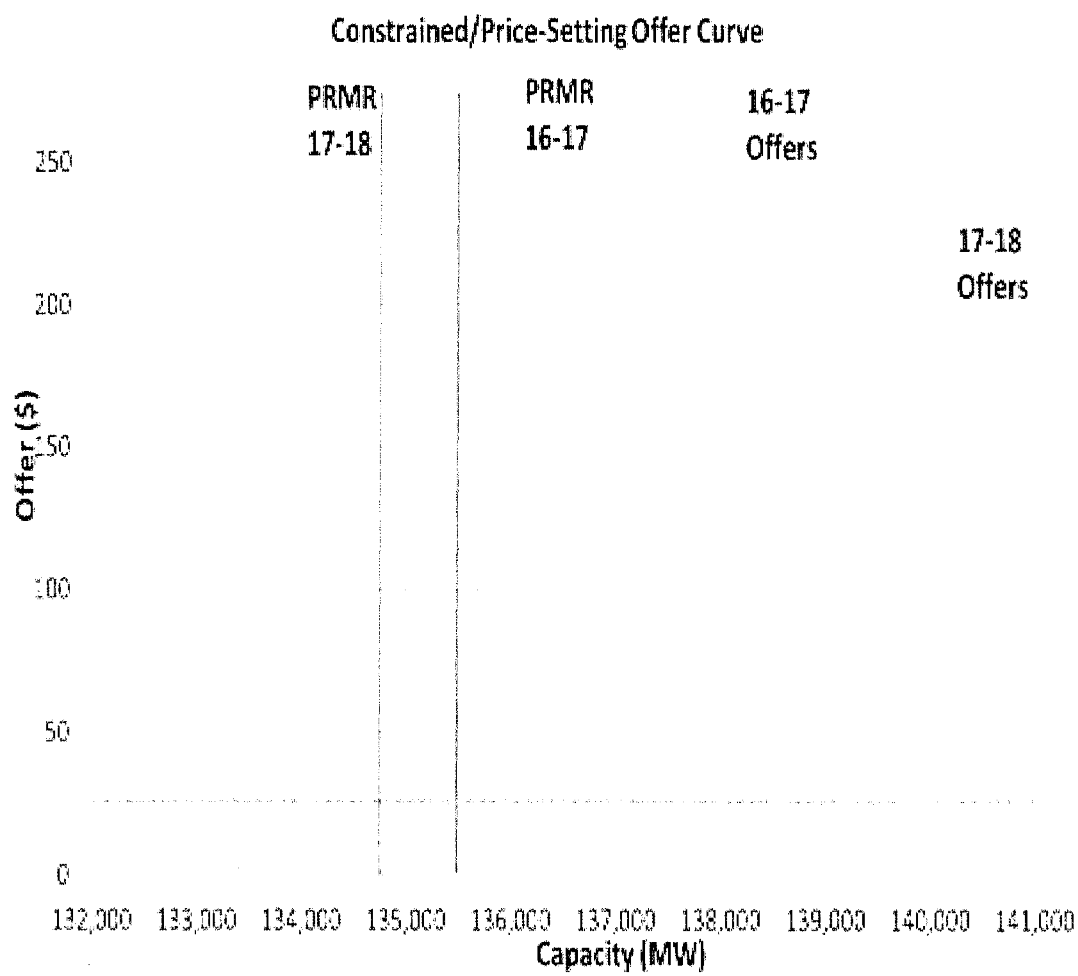
- Vertical demand curve
- Prompt, rather than forward, market



CRA Charles River Associates

Explaining the downward trend between 2016/17 and 2017/18 auctions

- More renewables
- More behind-the-meter
- More DR/EE



Source: MISO

Acronym	Definition
CRA	Charles River Associates (IRP Consultant)
NEEM	North American Electricity and Environment Model
NGF	Natural gas sector market model
ELG	Effluent Limitation Guidelines
CCR	Coal Combustion Residuals
NPVRR	Net Present Value of Revenue Requirement
LNG	Liquefied Natural Gas
MISO	Midcontinent Independent System Operator
CONE	Cost of New Entry
EIA	Energy Information Administration
AEO	Annual Energy Outlook (from EIA)

NIPSCO

INTEGRATED RESOURCE PLANNING

ACRONYMS

ACRONYMS

A

AC	Alternating Current
ACEEE	American Council for an Energy Efficient Economy
ACESA	American Clean Energy and Security Act of 2009
ACI	Activated Carbon Injection
ACLM	Air Conditioning Load Management
	Annual Energy Outlook (from EIA)
AFUDC	Allowance for Funds used During Construction
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ARRA	American Recovery and Reinvestment Act of 2009
ASM	Ancillary Services Market
ATC	Available Transfer Capability or Capacity

B

BA	Balancing Authority or Balancing Area
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BESS	Battery Energy Storage System

C

C&I	Commercial and Industrial
CAA	Clean Air Act – EPA issued initial rules in 1970
CAAA	Clean Air Act Amendments – 1990
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCT	Clean Coal Technology
CDD	Cooling Degree Days
CFL	Compact Fluorescent Lighting
CHP	Combined Heat & Power
CIP	Critical Infrastructure Protection
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity

CPP	Clean Power Plan
CPW	Cumulative Present Worth
CRA	Charles River Associates (IRP Consultant)
CVR	Conservation Voltage Reduction
CSPAR	Cross State Air Pollution Rule – EPA issued rules July 2011
CT	Combustion Turbine

D

DA	Distribution Automation, or Day Ahead Scheduling
DG	Distributed Generation
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand-Side Management

E

ECS	Energy Control System
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFORd	Equivalent Forced Outage Rate demand
EIA	Energy Information Administration of the U.S. Department of Energy
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicles

F

FAC	Fuel Adjustment Clause
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

G

GDP	Gross Domestic Product
GHG	Green House Gas

H

HAP	Hazardous Air Pollutant
HDD	Heating Degree Days

Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning

I

ICAP	Installed Capacity
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gas Combined Cycle
IMM	Independent Market Monitor
IRP	Integrated Resource Planning
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission

K

kWh	Kilowatt hour

J

JCSP	Joint Coordinated System Planning

L

LAER	Lowest Achievable Emission Rate
LMR	Load Modifying Resource
LMP	Locational Marginal Pricing
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load Serving Entity

M

MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MFDI	Multi Family Direct Install
MISO	Midcontinent Independent System Operator
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	Midcontinent ISO Transmission Expansion Planning
MVA	Mega Volt Ampere, Mega Volt Amplifier, or Multivariate Analysis
MVP	Multi-Value Projects (transmission for both reliability and economic benefits)

MW	Megawatt

N

NAAQS	National Ambient Air Quality Standard – EPA issued rules January 2013
NEEM	North American Electricity and Environmental Model
NERC	North American Electric Reliability Corporation (formerly Council)
NG	Natural Gas
NGF	Natural Gas Sector Market Model
NID	Net Internal Demand
NIST	National Institute of Standards and Technology
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value of Revenue Requirements
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance

P

PC	Pulverized Coal
PCT	Participant Cost Test (see EM&V)
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM LLC (Regional Transmission Organization)
$PM_{2.5}$	Particulate Matter that is 2.5 micrometers in diameter or smaller
PPA	Purchase Power Agreement
PRMucap	Planning Reserve Margin on UCAP (Unforced Capacity)
PV	Photovoltaic
PVRR	Present Value Revenue Requirement

R

RCRA	Resource Conservation and Recovery Act (coal ash disposal regulations)
REC	Renewable Energy Credit
REP	Renewable Energy Production
RES	Renewable Energy Standards
RFC	Reliability First Corporation
RFP	Request for Proposals
RIM	Rate Payer Impact Measure (see EM&V)

RRaR	Revenue Requirement at Risk
RTO	Regional Transmission Organization (Independent System Operator)

S

SAIFI	System Average Interruption Frequency Index (Reliability-see also SAIDI and CAIDI)
SCADA	Supervisory Control and Data Acquisition
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction (pollution control)
SIP	State Implementation Plan (environmental)
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SREC	Solar Renewable Energy Credit

T

TBEL	Technology Based Effluent Limits
TOU	Time of Use
TRC	Total Resource Cost Test (see EM&V)
TW	Terawatt

U

UCAP	Unforced Capacity (the amount of Installed Capacity that is actually available)
UCT	Utility Cost Test (see EM&V)
Ultra SCPC	Ultra Super Critical Pulverized Coal

V

VAR	Volt Ampere Reactive, Variance, or Value at Risk

W

WQBEL	Water Quality Based Effluent Limits

NIPSCO

Northern Indiana Public Service Company
2018 Integrated Resource Planning
Public Advisory Meeting #1
SUMMARY

March 23, 2018

Welcome and Introductions

Alison Becker opened the meeting by asking participants in the room and on the telephone to introduce themselves. She then introduced Violet Sistovaris.

Overview of Public Advisory Process
Violet Sistovaris, Executive Vice President, NiSource and President, NIPSCO

Ms. Sistovaris began by welcoming participants and explaining NIPSCO's decision to update its Integrated Resource Plan ("IRP") and the importance of stakeholders to that process. She continued with a safety message about severe weather preparedness and discussed the purposes of the meeting and reviewed the agenda. Ms. Sistovaris then provided an overview of NiSource and NIPSCO and a roadmap for the Stakeholder Engagement process and an overview of the public advisory process. She noted that NIPSCO will have a total of five public advisory meetings, with four of them being in person and the fifth as a webinar.

Why a 2018 IRP Update and Improvements from 2016
Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained the need for an update to NIPSCO's 2016 IRP, noting that the 2016 IRP Preferred Plan created a need for additional capacity. He provided an overview of the 2016 Preferred Plan and discussed the drivers and rationale for the 2018 update. Specifically, NIPSCO is doing the update now to preserve its ability to fully consider all resource options to address the capacity need. For example, a combined cycle gas turbine ("CCGT") takes several years to build. In order to have it online by the time the capacity is required in 2023, NIPSCO needs to make decisions this year. The IRP update is crucial to that process.

After providing information on why the 2018 update is required, Mr. Douglas reviewed the lessons learned from the 2016 IRP process. He provided information on NIPSCO's improvement plan in several areas, including commodity price forecasts, scenarios and sensitivities, risk modeling, capital costs assumptions, demand side management ("DSM") modeling and the Preferred Plan and scorecard.

Participants had the following questions and comments, with answers provided after:

- What do you think of recent tariffs that will affect solar equipment coming from other countries?
    - Solar costs have been volatile and are difficult to plan for. We have tried to take into account all known factors including tax incentives, expert cost forecasts and supply and demand forecasts.
- There are a number of concerns related to the resource(s) that may be selected as well as the short notice related to this update. It will be important to have access to the modeling early in the process. Generally, there is a concern with the timing of the update.
    - NIPSCO recognizes the extra work the update creates for stakeholders and apologizes for that. However, the Company finds it to be the right thing for the customers. Mr. Douglas also noted that it was encouraging to see so many stakeholders in attendance and that NIPSCO is pleased with the level of engagement in the process. Finally, he noted that NIPSCO has started the Public Advisory process earlier than in 2016 and will continue to look for ways to engage stakeholders.
- There was discussion about the request for proposal ("RFP") process that will be upcoming related to the additional capacity. There was a question about if the process would be opened up for stakeholder input. In addition, there was a question about the formal process related to the IRP. When will NIPSCO submit, when will comments be due, etc.?
    - The intention is to facilitate the processes for stakeholder input, both formal and informal. There was discussion on how this process would fit with a filing related to a certificate of public convenience and necessity ("CPCN") if a CCGT were selected and Mr. Douglas noted that a CCGT is an example of a technology that has the longest lead time. There is no bias for any specific technology and the data in the IRP (and received from the RFP) will be the driver of the decision making.
- Expression of appreciation for five meetings, but request for other ways to solicit feedback. This could include online comments, etc.
    - NIPSCO is happy to discuss alternative ways of soliciting feedback.
- The evaluation will be on a unit-by-unit basis?
    - Yes. NIPSCO is grouping Units 14 and 15 and Units 17 and 18 together.
- Sounds as though NIPSCO is committing to reevaluating the retirement of Units 17 and 18?
    - Yes.
- How will the metrics gathered be used and weighted? If they are not weighted, are they not all treated as equal?
    - It will be important to have a discussion around metrics, but it is difficult to make those determinations without the data. It is important to look at environmental attributes, costs to customers, etc. Ultimately, NIPSCO

owns the Preferred Plan decision and will base that decision on stakeholder feedback and the scorecard criteria, not a formulaic answer given by weightings of the criteria. Once the decision has been made, NIPSCO understands the need to discuss it with stakeholders.

- At a high level, the IRP should inform the RFP, which should then inform a CPCN. It would be good to understand this process.
  - NIPSCO recognizes this process is unique, but given the need for capacity, NIPSCO's IRP will be enhanced by the real data that comes from an RFP. The decision was made to go through an RFP as quickly as possible and use those cost results to inform the IRP. Once again, although the timing is built on the long lead-time for a CCGT, no decisions have been made.
- The Xcel Energy RFP was renewable focused. Need to have sufficient time to discuss the RFP.
  - Today's discussion is meant to introduce the RFP and NIPSCO's planned process. However, there will be additional time for input as part of that process. The goal of the RFP is to make sure it is broad enough to capture a variety of resources without being overly complex. NIPSCO is open to ideas for how to make sure it is an "all source" RFP.

Modeling Approach
Jim McMahon and Pat Augustine, Charles River Associates ("CRA")

Messrs. McMahon and Augustine provided information related to NIPSCO's modeling approach for the IRP. The discussion started by reviewing the key areas where CRA is providing support for the 2018 IRP Update: fundamental commodity price forecasting and integrated resource planning. Mr. McMahon then reviewed the resource planning approach and models and tools to be used in the 2018 IRP Update. Regarding forecasting, CRA noted it has a Natural Gas Price Fundamentals Model ("NGF Model") and provided an overview of that as well as a discussion related to macro-level market analysis using CRA's North American Electricity and Environment Market ("NEEM") Model. There was also discussion around the use of Aurora to provide regional power market and portfolio analysis and how the PERFORM model will be utilized to perform net present value revenue requirement ("NPVRR") calculations. Charles River Associates discussed the modeling of uncertainty and also how it identifies risks and uncertainties.

NIPSCO is using the same "scenarios" for the 2018 IRP Update: Base, Aggressive Environmental Regulation, Challenged Economy, and Booming Economy & Abundant Natural Gas. In addition to discussing the scenario framework, CRA provided a table detailing the key input variables for each of the scenarios. As the next step, CRA explained how stochastics will be used in the analysis and how the use of stochastics provides improved coverage of uncertainty. Mr. Augustine finished with a discussion on the distribution of outcomes and how portfolios can be compared on a cost and risk basis.

Participants had the following questions and comments, with answers provided after:

- DSM is included on Slide 15, but not on Slide 16. What will be the basis of the DSM screening?
  - The basic information will come from GDS Associates, the company selected by NIPSCO to perform the update to the projected DSM savings. Slide 16 shows how CRA will incorporate that projected savings, as DSM is an input to the Aurora model.
- The extraction of natural gas produces more greenhouse gas. Does the model capture that?
  - The model does not explicitly capture greenhouse gas emissions from natural gas extraction. A final greenhouse gas emission number associated with gas consumption can be determined through reverse engineering, but it is not an input into the IRP modeling.
- Does the model incorporate the idea of an option value in terms of uncertain technologies?
  - Yes, it is represented explicitly in the modeling and that will become clearer when the results are released.
- Do you have a technique to determine historical accuracy?
  - There are ways. CRA did a validation process against the 2016 IRP, but it is not truly back-casting. There is a regular exercise in the Aurora model for back-casting capacity factors, market prices, and generation by fuel type, which is based on history. Stochastics also assist with incorporating the randomness inherent in the market.
- Will stakeholders be able to suggest scenarios?
  - Yes, it is encouraged. Stakeholder scenarios will help NIPSCO fine tune its analysis.
- Extraction emissions will not be included, correct?
  - That is correct. It may be something NIPSCO and CRA could have together by the September meeting. Right now, NIPSCO only looks at things as the United States Environmental Protection Agency does. In other words, emissions on the customer-side are included, but nothing is accounted for prior to its use by NIPSCO.
- Who determines the base case?
  - NIPSCO noted there would be additional discussion in the afternoon and that NIPSCO is looking at CRA for input as well as from the stakeholders. However, the ultimate decision is NIPSCO's.
- Is NIPSCO continuing to assume an effluent limitation guidelines ("ELG") requirement?
  - Yes, one of the scenarios will consider a less stringent ELG requirement, but the Base Case will be with the ELG requirement as it stands today.
- There does not appear to be a Base Case run with different fuel price scenarios?
  - This is an example of how the use of stochastics provides a wide range of information. NIPSCO is willing to discuss scenarios more in-depth to ensure thoughts are being captured.

- The point is that scenarios are a set of integrated and interrelated assumptions. How do you tease out and get at low and high gas prices? Can you get at that through the stochastic modeling process?
    - Scenarios establish potential states-of-the-world for high and low gas prices based on fundamental factors. In addition, stochastic modeling incorporates a broader range of potential outcomes, but it is still difficult to tease out the underlying reasons for specific price movements in certain variables such as gas prices. The scenario process is looking to capture themes NIPSCO finds to be reasonable, while the stochastics add a broader range of uncertainty.
- Regarding Base Case question in carbon pricing, there is a concern of the definition of the scenario. Want to have a discussion before locked in.
    - NIPSCO welcomes the feedback.
- One of your options is purchasing capacity for a period of time. Will you get into the level of detail of considering what you see with other Midwest generating units?
    - Yes. (It was noted NIPSCO hoped to address that more in depth in the afternoon session.)

Long-Term Energy and Demand Forecast
Mahamadou Bikienga, Lead Forecasting Analyst

Mr. Bikienga provided an overview of the load forecasting process noting that it was much the same as the 2016 process. The forecast is updated annually and the models are updated annually, or as needed. The forecast provides a 23 year outlook. There is a residential, commercial, and industrial process. In addition, for "other energy" (public authority, railroad, company use and street lighting), NIPSCO has a specific process. Mr. Bikienga outlined the peak demand forecast process and then provided NIPSCO's Total Energy and Peak Demand projections for the period of 2018-2039. The compound annual growth rate ("CAGR") for the period is 0.33% for NIPSCO total energy; 0.41% for NIPSCO System Peak; and 0.44% for Midcontinent Independent System Operator ("MISO") Coincident Peak.

Participants had the following questions and comments, with answers provided after:

- What is the relationship between income and the customer forecast? Is the assumption that the higher the income, the higher the usage?
    - A higher income level may mean more appliances, more usage in the household, and less sensitivity to the thermostat setting. The core assumption is higher income, higher usage.
- Total energy use per customer is declining, but the charts indicate load growth is increasing?
    - Overall, it is a very small difference. There is slow growth, with rates similar to the last IRP. Industrial growth is actually projected to be flat. This data is available, and, with the appropriate non-disclosure agreement in place, this information can be shared.

- Should there be scenarios for the load forecast? How can electric vehicles be incorporated into the forecast?
    - NIPSCO has considered electric vehicles in the past, but they have very little impact. To the extent the IRP team needs additional information for scenarios, Load Forecasting can supply that.
- Do the models take into account the increase in solar usage? For example, Arcelor might go to all solar. Do you have contractual agreements with companies to make sure they will do what they say they will do?
    - When forecasting for industrial usage, information is provided by the largest customers and that assists with the forecasting process.
    - NIPSCO considers the loss of industrial load as part of the IRP process. The Company is taking into account scenarios of high and low industrial energy usages in forecasting the industrial energy volumes.

Capital Costs Assumptions for Future Resources
Fred Gomos, Manager, Corporate Strategy and Pat Augustine, CRA

Mr. Gomos provided an overview of NIPSCO's approach for capital costs assumptions in the 2018 IRP. He cited 3 important aspects of developing capital costs in the 2018 IRP, namely, moving away from proprietary, single point estimates, and utilizing publicly available data sources and using data from the RFP to collapse the uncertainty in developing capital cost estimates. Mr. Gomos noted that step one is the development of initial portfolios; step two is the evaluation of those portfolios across scenarios and stochastics; and the final step is integrating the portfolios into the IRP. He then provided an update on the data sources to be used in the 2018 update, which are based on more publicly available data than in previous IRP processes. The current capital costs estimates for gas, coal, and nuclear technologies and for renewables, storage, and other technologies were reviewed, with a note that these would continue to be refined.

The capital cost projections for CCGT, wind, solar photovoltaics, and storage (lithium-ion 4 hour) were reviewed, with the forecast range with stochastics discussed. It was noted that the team used a range of data sources to develop the forecasts and went through several steps: identifying the range of capital costs over time, using interactive expert opinion approach based on the source data, and simulating 500 paths for capital costs based on random sampling from distributions.

Participants had the following questions and comments, with answers provided after:

- Are you considering retrofits of any of the existing plants?
    - A range of compliance cost options are included, including ELG compliance costs.
- When there is only one input, how does that impact the modeling?
    - There will be an initial process to evaluate the expected costs and then, from that, a shorter list of feasible technologies will be developed. For the

feasible technologies, NIPSCO will have more data to allow for a full range of options to be considered.

- Regarding the solar and battery graphs, it seems the common understanding is that battery costs are going down. But, based on the graph, surprised at the high band in a short amount of time when prices are expected to go down.
    - There is a great deal of uncertainty where the price really is. NIPSCO expects the RFP to give better price information. However, the current slide is based on existing data, which incorporates a wide band of uncertainty, but a generally declining cost trajectory over time.
- Will the Xcel Energy information from its latest RFP be utilized among the data sources?
    - No, as they did not publish capital costs.
- Looking at the solar and storage information, do you combine it?
    - For purposes of the capital cost assumptions, no. That will be considered as part of another process.
- How do you anticipate including other third party studies for solar, wind and storage?
    - Slide 56 refers to the various studies that have been utilized.
- Will NIPSCO consider other forecasts, and, if so, what is the timeframe for providing that information?
    - NIPSCO will ultimately place more emphasis on the information contained in the responses to the RFP, but is interested in other forecasts as well, which are hopefully within the bands of the current projections. The goal is to get data from third party developers, as that is the best idea of what is executable in the market.
- How will the RFP data be integrated?
    - The data on the slides in this section will be updated with information from the RFP. NIPSCO will continue to discuss how best to do this.

2018 Commodity Price Forecasting
Robert Kaineg and Pat Augustine, CRA

Charles River Associates provided information regarding how commodity prices would be forecasted as part of the 2018 IRP. Robert Kaineg started by providing CRA's natural gas outlook, which included an overview of the market, price forecasting, key modeling inputs, market trends, and price drivers. He then provided information regarding the local gas dynamics in MISO. Next, he provided the same type of overview for the coal market, including a discussion of trends in regional coal production in the United States and a summary of the price trends by coal. Pat Augustine provided information on carbon dioxide ("CO_2") pricing, with information on the base case, low case and high case. He then gave an update on the MISO market outlook. He started by providing an overview of how AURORA does power price forecasting and provided information regarding the MISO footprint. Mr. Augustine noted that it is expected that there will be a continued shift from coal to gas and renewables and provided CRA's Power Price Forecast for MISO Zone 6. He then provided information regarding capacity prices and how they are influenced by market design and ended by providing CRA's MISO capacity forecast.

Participants had the following questions and comments, with answers provided after:

- Is the price reflective of the cost of capacity (what capacity in the market is going to cost)? The prices look low.
    - The model is not anchored to the cost of new entry. Instead, given the structure of the MISO capacity market, there will be entities that will build to native load, meaning that the existing units are going to set prices closer to the cost to stay in the market. In the Base Case, the assumptions will not necessarily reflect new cost because of the design and participation of the region.
- Would appreciate the ability to have as much information regarding what you have come up with so far in advance of the May meeting.
    - NIPSCO will work to provide that.

Demand Side Management Update
Alison Becker, Manager, Regulatory Policy
Richard Spellman, GDS Associates, Inc.

Ms. Becker provided a brief overview regarding how NIPSCO is updating its DSM forecast for the 2018 IRP. She explained that while NIPSCO is working with its Oversight Board ("OSB") on a full market potential study ("MPS"), the timing of the 2018 IRP update did not make completing that practical in order to have the data in time for the modeling in the IRP. Therefore, NIPSCO has elected to do a 2018 Electric DSM Savings Update, with a full MPS being completed after that process is complete. She then introduced Mr. Spellman, who is the president of GDS Associates, the firm selected by NIPSCO and the OSB to perform this work, to provide an overview of the Savings Update process. Mr. Spellman explained the types of information that will be included in the Savings Update and noted that it will cover the same years included in the IRP Update (2019 to 2038). He noted this will be completed by June 1, 2018 and that GDS will work with NIPSCO and the OSB on finalizing the data.

Mr. Spellman reviewed the report contents and stated that, while the intention was to use the Total Resource Cost test as the main screening of cost effectiveness, stakeholders had requested NIPSCO to use the Utility Cost Test and that was being considered by NIPSCO. He explained that for the DSM Savings Update Report due on June 1, GDS will update assumptions relating to measure costs, kilowatt hour ("kWh") and kilowatt savings and useful lives. Mr. Spellman then reviewed the technical approach for baseline development that will be completed for the development of the full energy efficiency potential study to be completed in 2019. Finally, he went through the process related to the assessment of potential savings for the full potential study to be completed in 2019 and discussed how GDS will recommend appropriate funding levels based on the projected savings.

Participants had the following questions and comments, with answers provided after:

- Assuming the load forecast essentially incorporates the continuation of DSM programs as they have been in the past, how does this analysis impact that? Can past levels be accommodated or increased in the future?
    - A NIPSCO representative explained that the impacts of NIPSCO's existing DSM programs are captured in the consumption piece of load forecasting. .GDS will work closely with NIPSCO to remove the impacts of NIPSCO's existing energy efficiency programs from the NIPSCO load forecast. Typically, a calculation is performed to determine the percentage of forecast annual kWh sales that are expected to be saved in the future with energy efficiency programs, which is based on the impacts of DSM programs being removed from NIPSCO's load forecast.

RFP for Capacity
Paul Kelly, Director of Federal Regulatory Policy

Mr. Kelly provided an overview of NIPSCO's "all-source" RFP, which was still in the development at the time of the meeting. He noted that a different division of CRA had been retained to assist in the development and administration of the RFP process and that NIPSCO would be seeking stakeholder feedback on the approach/design to ensure a robust, transparent process and result. He also provided an outline of the resource evaluation criteria being considered. Mr. Kelly gave detail around the key design elements of the all-source RFP, noting that all solutions, regardless of technology would be considered. NIPSCO is open to asset purchases and purchase power agreements for new and existing resources. He then explained the timeline for the IRP, indicating a Design Summary would be shared with stakeholders on April 6 to request feedback. Ultimately, the RFP is scheduled to be initiated May 14, with a close date of June 29. At the July 24 IRP Public Advisory Meeting, a summary of the results will be presented.

Participants had the following questions and comments, with answers provided after:

- The schedule only allows 14 days for feedback, which is overly ambitious. Would request the opportunity to sign a non-disclosure agreement to have an opportunity to view the entire RFP.
    - That is something NIPSCO is happy to work through.
- Demand response is not typically contracted for more than one year. That should be considered in the design elements.
    - Great example of helpful feedback. This is something NIPSCO will take into account.
- How much of the IRP will already be completed when the proposals are received? How do you take the information from the RFP and weave it into the IRP?
    - The intent is to summarize by technology, size, range, etc. and put information into IRP for those technologies. The portfolio design can then be run on those numbers and replace the forecast information that was used.
- What are you looking for with the RFP? Actually contracting with vendors?

  - NIPSCO wants to understand the price of a resource instead of relying on a forecast. It is important to know what is real and available within the MISO footprint and deliverable to NIPSCO's customer load. The RFP will be binding and, once the Preferred Plan is in place, the Company can begin the process of contracting with individual bidders based on the solutions selected within the Preferred Plan.
- Glad all resources are included. There are parties interested in participating and hope the RFP will allow for those bidders.
  - That is something NIPSCO wants as well.
- Will you piece together resources to get to the 600 MW or must it all be in one proposal?
  - The intent is to get whatever size resources bidders want to propose and then NIPSCO can solve for meeting the 600 MW needed by combining bidder(s) as needed.
- Is there flexibility on the length of the contract? Must it only be for five years?
  - Five years is defined as the minimum term.
- The capacity need not be within NIPSCO's service territory, just within the MISO footprint?
  - Correct. NIPSCO is required to meet its planning reserve obligation in MISO with Zonal Resource Credits for its Local Resource Zone 6. Therefore, all resources considered will need to have firm delivery to Zone 6 in order to qualify for the required capacity accreditation.
- Is the MISO region the same as the Zone?
  - No. MISO covers 15 states and a portion of Canada. While transmission from the far western part of MISO could be expensive, it is possible that a resource that is electrically distant from NIPSCO's load could bid into this RFP if it can establish the firm transmission delivery to Zone 6.
- How is the local community impact being considered? Are you considering the health and environmental impacts (for example, Michigan City with 28% of the population below the poverty level)?
  - NIPSCO plans to evaluate environmental impact as an evaluation criteria in the RFP in a way that is similar to the IRP's coal retirement analysis The Company is open to considering additional ideas and perspectives from its stakeholders on how to further assess environmental/emissions impact as well as the local community impact.
- Does NIPSCO intend to have a carbon price as part of the RFP?
  - NIPSCO is simply requesting a price for the capacity, not something specifically for carbon. The Company expects it will be an integrated price to evaluate on the cost component. Would be interested in perspectives from stakeholders on how to consider carbon in the evaluation.
- Will NIPSCO be considering self-build options in the RFP?
  - No, NIPSCO is not evaluating a self-bid option in the RFP. While NIPSCO has continued to evaluate the CCGT solution that was identified at the time of the 2016 IRP, the focus of this RFP is looking more broadly at all viable solutions to address its needs.
- When do you expect to see the execution of contracts?

  - NIPSCO does not look to transact any earlier than the close of the IRP process. Once NIPSCO is through the stakeholder process and has developed its Preferred Plan, the Company will consider negotiating definitive agreement(s) in the fourth quarter of 2018.

Stakeholder Presentations

David Repp from Jet provided a presentation "Technology Introduction and Adaptability to Indiana Power Facilities," which provided information on an alternative to existing desulfurization technology. He walked through an overview of the technology, the technical features, and the benefits that could be provided.

Participants had the following questions and comments, with answers provided after:

- The Indiana Coal Council favors this technology. With what type of coal can this technology be utilized?
  - Can adapt on a wide range of low and high sulfur coals. You need to look at the economics-the higher the sulfur, the more economical the process is. That is the type of coal in Indiana.
- Is this a replacement of a scrubber?
  - That is a site-specific answer. The absorber is similar to what you would expect for a limestone absorber. You can retrofit a limestone scrubber into this technology and it will not cost much in capital.
- Have you qualified for any Department of Energy funding for this?
  - In discussions. The concept is ammonia based and not new. The Department of Energy has paid for new absorbers with this technology and a cost-share to retrofit, both were successful. In total, 300 units have been installed.

2018 Public Advisory Process and Closing

Ms. Becker outlined the remainder of the Public Advisory Process, with the following meetings scheduled:

Date	Location	Main Topic(s)
May 11, 2018	Avalon Manor, Merrillville, IN	• Existing Generation • Environmental Considerations • Retirements Update • DSM in the IRP
July 24, 2018	Webinar	• Preliminary Results from the RFP
September 19, 2018	Fair Oaks Farms, Fair Oaks, IN	• Preliminary Findings from the Modeling
October 18, 2018	Fair Oaks Farms, Fair Oaks, IN	• NIPSCO's Preferred Plan • Short Term Action Plan

Timothy Caister, Vice President, Regulatory Policy closed the meeting by thanking the attendees for their attendance and active participation.

JET

Jiangnan Environmental Technology

Technology Introduction and Adaptability to Indiana Power Facilities

Prepared Personally For:

NIPSCO®

March 23rd, 2018

An Alternative to Existing Desulfurization Technology

Provide Additional Revenue Stream to Plant

Reduce Plant's Operating Cost

Create Jobs and a product needed by Customers

Reduce Plant's Emissions and Solid/Liquid Waste

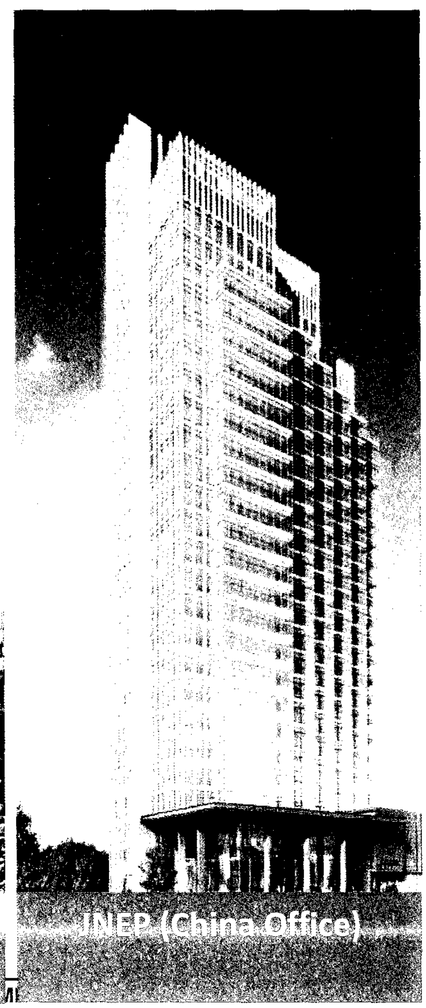
Efficient Use of Capital

Help Keep Plants Viable

About JET

JET provides customized solutions in Engineering, Construction and Operations Services for Power Plant Desulfurization. In 1998 JET established the first ammonia desulfurization technology research institute in China, and launched the first recovery type ammonia desulfurization unit in 2004. With a global vision, and a strong organizational culture heavily focused on R&D, JET is dedicated towards providing cost effective solutions towards eliminating air pollution, improving living conditions, and helping our customers meet increasingly stringent emission standards.

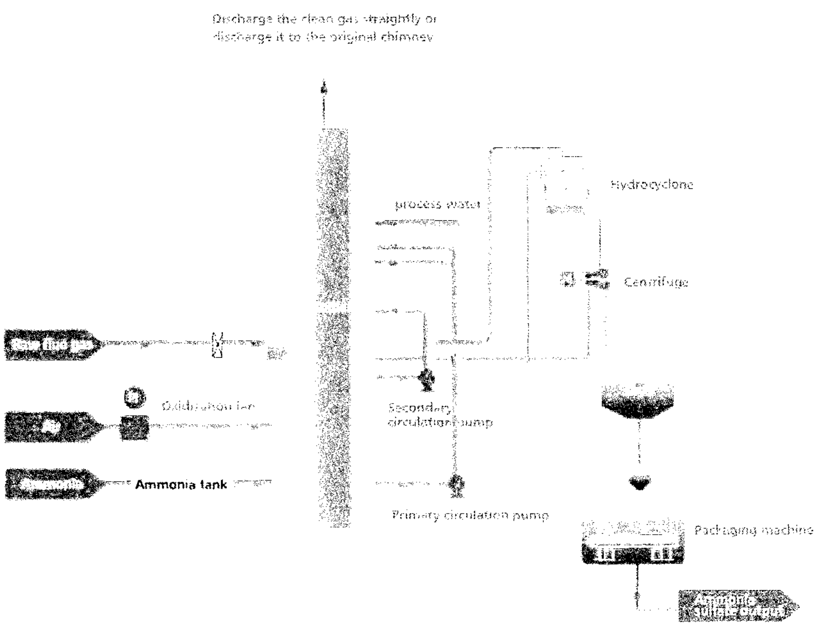
- Global leader with 80% market share in Ammonia-Based Desulfurization
- 65 patents and patent applications
- 150+ projects with more than 300 installed units
- 20+ installations with capacity bigger than 700,000 SCFM

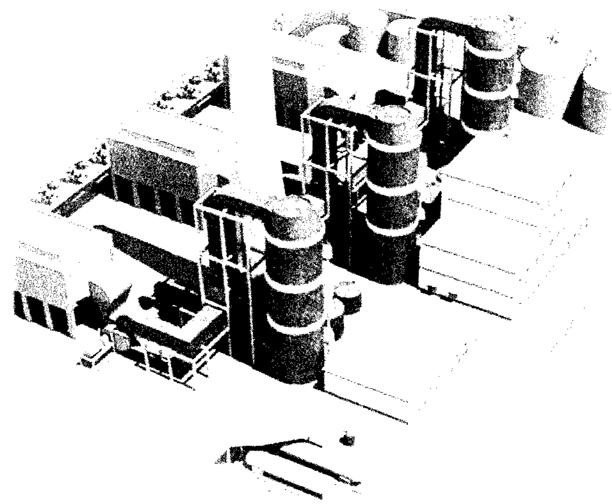


INEP (China Office)

JET Global Headquarters (Ridgefield Park, NJ)

Technology





	Year	Features	NH_3 recovery	SO_2 emission ppm	[illegible]	Performance
1st Gen	1998	Basic NH_3 based deSOx	not controlled	~ 70		Meets SO_2 emission limit
2nd Gen	2010	NH_3 based deSOx with NH_3 recovery control	≥ 97%	< 35		Meets HG2001-2010 standard
3rd Gen	2013	Fine PM control	≥ 98%	< 17.5	≤ 4.72	Meets GB13223-2011 special emission limit
4th Gen	**2015**	**Ultrasound-enhanced deSOx and PM-removal integration**	**≥ 99%**	**< 12**	**≤ 1.18**	**Meets ultra-low emission limit***

Technical Features

	[illegible]	[illegible]
Process	Turn waste (SO_2) to high value fertilizer	Consume 1.6 ton limestone & generate 0.7 ton CO_2 per ton SO_2 removed
Capital Cost	0.8 Base	Base
Operating Cost	100% Base or even make profit	Base
SO_2 Removal Efficiency	99.5%	97%
SO_2 Emission	12 PPM	35 to 70 PPM
Waste Water Generation	No	Yes
Solid Waste Generation	No	Yes
Synergy with Carbon Capture System	Yes	No

1 Low Operating Cost

The liquid-to-gas ratio of the ammonia process is only 1/6 to 1/3 of the limestone-gypsum process. Therefore, the power consumption of the ammonia-based process is about 50% less than that of the limestone-gypsum process.

The byproduct of the ammonia-based process is ammonium sulfate, which can be sold as fertilizer. The sales revenue from ammonium sulfate can offset the total cost of ammonia, and lower the overall operating cost.

2 No Secondary Pollution and High-value Byproduct

The EADS technology is environmentally friendly. Unlike other FGD processes such as limestone-gypsum process, it recovers SO_2 efficiently without generating any waste water, solid waste, or CO_2.

The byproduct of the ammonia-based process is saleable fertilizer, whereas the by-product of the limestone-gypsum process is gypsum and its sales value is significantly lower than that of ammonium sulfate. In some cases, the gypsum need to be disposed of as solid waste

3 High SO2 Removal Efficiency

Ammonia is a substance with much higher alkalinity and reactivity with SO_2, making it a more efficient absorbent than limestone. Therefore, the absorption of ammonia-based absorbent is faster than the limestone slurry. As a result, SO_2 removal up to 99% and SO_2 emission as low as 12 ppmv can be achieved by the ammonia-based process.

4 Excellent Adaptability and System Reliability

EADS technology can be applied to coal with sulfur content from 0.2% to 8% and flue gas with SO_2 content from 100 to 10,000 ppmv or higher.

5 Proven Technology

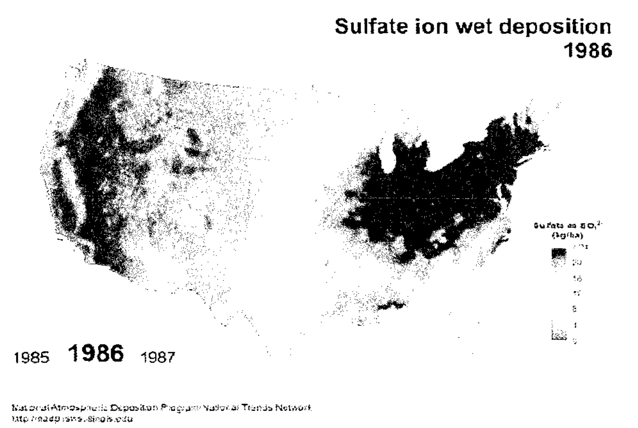
The technology proposed in this proposal is reliable and commercially proven. To date, more than 150 EADS projects have been put into operation or under construction.

Ammonia/Ammonium Sulfate

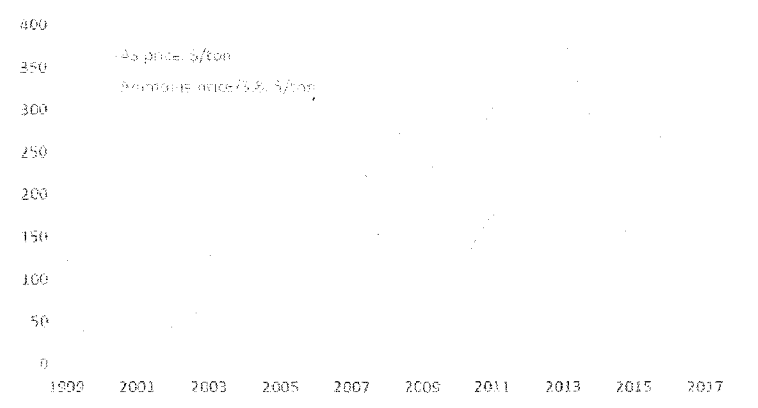
The EADS technology uses "ammonia" as the desulfurization absorbent, and anhydrous ammonia, aqueous ammonia, or gaseous ammonia can be used as the desulfurization agent. We are currently in talks with the following ammonia suppliers. Ammonia can also be synthesized from coal or natural gas.

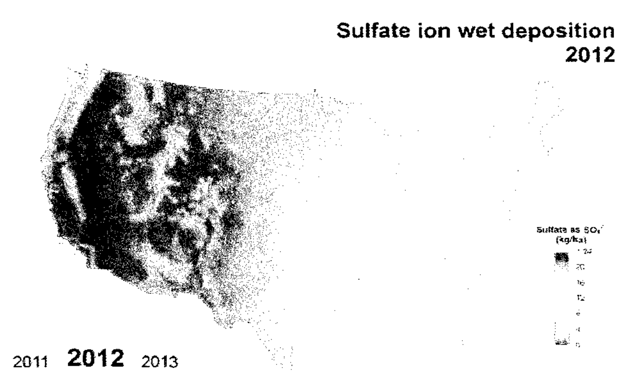
CF KOCH

Ammonium sulfate product will be sold to fertilizer produces as a feedstock for producing compound fertilizers or directly sold to fertilizer retailers. Ammonium sulfate is widely used in the US and Latin America, where about 70% of the fertilizers is imported. Nitrogen based Fertilizer is a growing market with a 2016 demand of 121 Million Tons!



Ammonia and Ammonium sulfate price





Comments from our Clients

WANHUA

"The newly-built ammonia-based FGD project, Tower #5, has been successfully completed and no malfunction occurs since the operation. We want to thank you for the remarkable contribution to our project..." -------- Wanhua Chemical Group Co.,Ltd

中国石化 SINOPEC

"The retrofit project for our Boiler #1 within 3 months meets the emission regulations as planned, while the cost and power consumption are much lower. We much appreciate your efforts in overcoming difficulties during the retrofit, such as the limited space of the site..." -------- Sinopec Qilu Petrochemical Company

中国神华
CHINA SHENHUA

"We sincerely thank JET's efforts and contributions in our coal-to-olefin retrofit project. The project is a highly difficult and challenging project, where the sites are small and the construction and operation run at the same time. Despite the difficulties, JET has successfully completed the construction, and the flue gas is much cleaner than before when the Limestone-gypsum process was applied..." -------- Shenhua Ningxia Coal Industry Group Co., Ltd.

Flexible Business Models – Low/No capital investment required from plant

Thank you for your interests in our technologies

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JET
Jiangnan Environmental Technology

All Source Request for Proposals – Interim Summary

Introduction and Request for Proposal Overview

Northern Indiana Public Service Company ("NIPSCO") does business in the State of Indiana as a regulated public utility. NIPSCO generates, transmits and distributes electricity for sale in Indiana and the broader Midcontinent Independent System Operator, Inc. ("MISO") regional electricity market.

NIPSCO is committed to meeting the energy needs of its customers today and in the future. Through the Integrated Resource Planning ("IRP") process, NIPSCO identifies its long term capacity needs and charts a path on how best to meet those needs. The IRP process seeks to identify preferred resource portfolios that are reliable, compliant, flexible, diverse and affordable, all of which are guiding principles of NIPSCO. Long term resource planning requires addressing risks and uncertainties created by a number of factors including the costs associated with new resources.

In its 2016 IRP, NIPSCO identified a minimum capacity need of 600 megawatts ("MW") by 2023. To address that projected resource need, NIPSCO has concluded that it is in the best interest of its customers to seek to acquire, construct or contract for additional generating capacity located within the MISO market. NIPSCO is releasing an "all source" Request for Proposals ("RFP") for supply and demand side capacity ("DSM") resources. An RFP solicitation is the best opportunity to mitigate the uncertainty associated with the cost of new resources. The purpose of the RFP is to identify the most viable resource(s) available to NIPSCO in the marketplace to meet the needs of its customers. NIPSCO is currently in the initial phases of the RFP process designed to both inform the IRP and identify specific assets, resources, projects or contractual options that best meet the Company's resource requirements.

A key aspect of NIPSCO's proposed process is the integration of the IRP and RFP processes which will be conducted in parallel. The parallel design is intended to ensure that the resource requirements identified through the IRP process were informed by the most current and accurate market information and that the RFP asset selection is consistent with the NIPSCO IRP. NIPSCO will first identify its preferred resource portfolio by aggregating data from the RFP responses and inputting such data into its IRP modeling. The RFP bid evaluation and selection process will be based upon the specific resource needs identified through this IRP modeling as well as the bid evaluation criteria.

NIPSCO is committed to a collaborative process considering the needs of all stakeholders throughout the design of the RFP. **The following memorandum represents a current outline of the proposed process and is seeking stakeholder feedback and comments by Friday, April 20th, 2018 to *nipsco_irp@nisource.com.*** NIPSCO will take stakeholder comments under advisement and reserves the right to update the process documents, timeline, bidding requirements or evaluation criteria prior to the official launch of the RFP.

The NIPSCO RFP is being designed to consider all sources of capacity and the company has no stated or unstated preference for the fuel source or deal structure related to the potential resource options available through the market. Consistent with that, the RFP will be issued as an all source procurement process that will consider a range of existing and in-development fossil and non-fossil fuel sources, purchase power agreements (including capacity-purchase agreements) ("PPA"), and DSM proposals in order to identify the mix of resources that best serves customer needs.

NIPSCO has retained Charles River Associates ("CRA") to support the IRP, RFP and stakeholder processes. CRA has a long track record of executing structured procurement processes on behalf of its utility clients and will support NIPSCO throughout the RFP design and execution.

Requesting Stakeholder Feedback – Design Subject to Change

NIPSCO is providing this interim summary of the All Source RFP to stakeholders to request their feedback on the proposed design. As such, it is currently in a "draft" state and will not be finalized until NIPSCO has considered all feedback received from our stakeholders and completed additional internal review.

Information and Schedule

The RFP is scheduled to launch on May 14th, 2018. At or before the 14th of May, CRA will initiate a marketing process in association with the launch. The marketing process will include the release of a public Information Website; one or more bidder information sessions; advertising in trade publications and direct outreach to potential process participants. The goal of the marketing process is to create bidder interest in the process and to educate potential bidders about the objectives of the integrated IRP and RFP work streams. Tentative key dates for the RFP include the following:

- May 14, 2018: RFP Issued
- May 16, 2018: Bidder Information Session
- May 28, 2018: Bidder Notice of Intent and Prequalification Due
- June 4, 2018: Prequalification Notices Sent to Approved Bidders
- June 29, 2018: Bidder Proposals Due
- July 2, 2018: Start of Bid Evaluation Period
- September 15, 2018: Bid Evaluation Completed
- Quarter 4 2018: Definitive Agreements Signed with Winning Bidders

It is anticipated that any asset purchase agreements, DSM agreements or PPA that may arise as a result of the RFP process would go into effect at or around 2023. However, the timing of any individual agreement may be an element of the proposal details submitted in response to the RFP. As such, NIPSCO is willing to entertain proposals with delivery prior to 2023 in the event such agreement is advantageous for NIPSCO's customers.

Certain information will be made available to bidders in advance of the proposal due date. The public Information Website will be the central source of information for the process. All bidders will have equal access to information to ensure a fair, equitable and non-discriminatory RFP.

Capacity Assets Considered in the RFP

As noted above, NIPSCO intends to issue an all-source RFP and will consider a wide range of options to meet customer needs. NIPSCO is anticipating the receipt of bids from any of the following categories of capacity assets:

- Asset purchases for new or existing resources including dispatchable, intermittent / renewables, stand-alone storage or resources paired with storage (semi-dispatchable)
- PPA
- DSM options

While the draft RFP makes specific reference to the above categories, NIPSCO will consider bids from non-traditional resource options outside the above set to the extent that they meet the basic bid requirements for the RFP. Additionally, there is no minimum offer or offer cap associated with this RFP. NIPSCO will consider bids from resources smaller or larger than the 600 MW need identified.

Key Qualification Requirements

NIPSCO is considering all sources to meet their resource requirements, however, there will be certain minimum qualification requirements associated with participation in the RFP process and certain threshold requirements on assets supporting the bids evaluated. These requirements fall into four general categories:

1. **Counterparty credit requirements**: NIPSCO will require that PPA counterparties and developers meet certain minimum credit and financial standing requirements. Potential counterparties that do not meet the minimum requirements may need to post additional performance collateral or be supported by parental guarantees.

2. **Asset reliability and deliverability requirements**: NIPSCO requires operational control of any physical asset bid into the RFP. Physical assets must also be interconnected at the transmission voltage (under MISO's functional control). Physical assets bid or that support a PPA bid into the RFP must have firm delivery capability into MISO Load Resource Zone 6 ("LRZ6"). In addition, bidders must demonstrate that resources currently meet MISO's (n-1) contingency criteria and either demonstrate that they meet (n-1-1) transmission criteria or provide cost estimates for the upgrades required to do so.

3. **Key development milestones:** New or planned generation facilities or PPA supported by new or planned generation facilities that have a development timeline greater than {*X*} months must have executed a pro-forma MISO Interconnection Service Agreement, Interconnection Construction Services Agreement and completed a MISO System Impact Study for the project for the proposed delivery point. New or planned generation facilities or PPA supported by new or planned generation facilities that have a development timeline less than or equal to {*X*} months must provide a timeline showing ability to complete key development milestone prior to June 1, 2023 including the above referenced items for the MISO generator interconnection queue.

4. **Remaining useful life:** Assets bid into the RFP must have an expected remaining useful life of at least five (5) years. NIPSCO will also not consider PPA with contract terms of less than five (5) years unless for DSM which NIPSCO will allow a minimum term of one (1) year.

Proposals supported by assets that do not meet the threshold criteria will not be evaluated further and will not be selected as a winning bidder through this process. Facilities not meeting the threshold criteria could be considered outside this process on a case by case basis or as NIPSCO needs dictate.

Proposal Content Requirements

As part of this RFP, NIPSCO will request information from bidders in order to inform the IRP process and to evaluate the bids received. Certain required information is commercially sensitive and proprietary. As a result, access to information will be restricted consistent with the terms and conditions of the non-disclosure agreement associated with the RFP. The information requested from bidders in association with the RFP process include the following:

- Counterparty corporate and financial information
- Experience of the facility operator or the project developer
- Facility name, location, interconnection points and commercial operating node
- Facility capacity availability and deliverability information
- Generation technology including dispatch and emissions characteristics
- Facility revenues and operating costs
- Generation facility operating data
- Generation facility operating and maintenance plan including information on long term service agreements ("LTSA")
- Detailed fuel supply information including fuel supply contract information
- Emissions and waste disposal compliance information
- Water supply and permitting information
- Capital expenditure plan including the cost of compliance with certain pending or proposed environmental restrictions or action
- Pending legal action or material contingencies
- Development milestones, interconnection and permitting information
- Offer price including any transferred liabilities
- Asset purchase agreement ("APA") and/or PPA markups

Because NIPSCO is conducting this RFP as part of its IRP public advisory process, NIPSCO will summarize bids by size and technology for presentation to stakeholders unless fewer than 3 bids are received for any given category. Bidder names will also be shared in the form of an aggregate list. The individual bids will be considered highly confidential.

Modeling Scenarios and Key Assumptions

NIPSCO's IRP team is tasked with analyzing near and long-term power market performance under a range of commodity, demand and environmental scenarios. Modeling conducted in support of the IRP includes a Base Case set of parameters reflecting NIPSCO's outlook for key drivers of power market performance and operations. The IRP process will also perform scenario analysis on certain parameters including natural gas prices, coal prices, carbon prices, power prices, NIPSCO load and costs of new resources.

In association with the 2018 IRP, NIPSCO is also developing a stochastic analysis to analyze the cost and risk-related tradeoffs between different resource and retirement combinations for the NIPSCO portfolio. The preliminary stochastic analysis relies on replacement cost estimates of different types of generating capacity. These estimates will be updated consistent with information derived from the all source RFP.

IRP modeling will be used to generate an optimal acquisition portfolio for NIPSCO reflecting the Base Case, scenarios, the stochastic analysis and supported by the updated resource costs generated through the RFP process. The optimal portfolio will be used in the RFP process to determine the amount of capacity from each resource category to select as winning bidders.

RFP Evaluation Criteria

The RFP team will begin the evaluation of RFP bids concurrent with the IRP scenario modeling and stochastic analysis.

Certain bids may be disqualified from consideration to the extent that they do not meet the threshold requirements for the RFP or if the bids are otherwise non-conforming.

Bids that survive the initial screening will be subject to further analysis and ranking. RFP bids will be grouped consistent with the asset categories used for the IRP and will be reviewed using a multi-dimensional evaluation framework. The framework considers reliability and deliverability, cost, asset-specific environmental considerations, development risk and asset specific risk factors. NIPSCO intends to weight evaluation criteria as part of the framework.

1. **Facility Reliability and Deliverability**: Bidders will be requested to provide power flow analyses under the MISO (*n-1*) reliability guidelines. Bidders will also be required to provide power flow analysis under NIPSCO's (*n-1-1*) reliability criteria or the cost to mitigate the difference between (*n-1*) and (*n-1-1*). Bidders will also be required to provide operating history and projected facility loadings over recent and near-term planning years. Assets that can demonstrate they currently meet NIPSCO reliability guidelines will receive full credit under the reliability category.

2. **Facility Cost**: NIPSCO will perform an evaluation of the cash cost of each bid. The cost analysis will examine the asset bid price, asset specific estimates of fixed and operating costs, capital expenditures, taxes, congestion costs and other cash considerations. Results will be adjusted for offsetting market revenues and presented on a net $/MW-day basis.

3. **Environmental Considerations:** NIPSCO will consider the specific environmental profile of individual assets. The evaluation will consider both criteria pollutants and asset carbon intensity in order to evaluate the asset specific exposure to scenarios or regulations not explicitly considered in the IRP modeling and to differentiate among the bids for assets within a given category.

4. **Development Risk:** Existing resources will receive full credit under this evaluation category. Plants in development will be awarded points based on the developer experience in MISO and development milestones achieved. Proposals will receive points based on the

demonstrated ability of the bidder to meet the key milestones in the development timeline as measured by the MW placed into service in MISO to date by the developer. Points will also be awarded in pro-rata fashion based on the development progress of the proposed project itself. In all cases, development projects must provide development collateral in support of meeting the target commercial operation date.

5. **Asset Specific Risk Factors:** Considerations may include, but not be limited to, fuel supply security and reliability, pending litigation or material contingencies associated with the facility or operator, and uncertainty related to transmission infrastructure or upgrades that may affect the facility operations. Proposals with no additional risks, or with risks for which the Respondent has described full mitigation measures, will receive the full credit.

Post RFP Timeline

Bidder proposals are due to NIPSCO by 5:00 PM EDT Central Prevailing Time on June 29th, 2018. The bid evaluation process will begin immediately upon receipt of the bids. It is expected that the bid evaluation will be completed by mid-September 2018 and a list of finalists will be submitted to NIPSCO by CRA for modeling within the IRP. Once the Preferred Plan is determined, it is expected that NIPSCO will enter into final negotiation with selected finalists and work towards definitive agreement(s) to be executed during the fourth quarter of 2018.

During the final negotiation period, NIPSCO will conduct site visits, if applicable, and execute a detailed engineering review of each asset in consideration of a definitive agreement. In addition, NIPSCO may perform additional dispatch modeling of each finalist as part of a broader due diligence effort designed to ensure that all stakeholder interests are protected and the selected asset(s) meet(s) NIPSCO's reliability and deliverability requirements.

All definitive agreement(s) would be subject to the granting of a Certificate of Public Convenience and Necessity ("CPCN") by the Indiana Utility Regulatory Commission. Agreements may require approval in other jurisdictions or at the Federal Energy Regulatory Commission, depending on the nature of the agreement or the asset(s) selected. Any regulatory filing(s) would begin after the conclusion of NIPSCO's due diligence and the execution of definitive agreements. As such, any definitive agreements are subject to regulatory approval.

NIPSCO Public Advisory Meeting 1 Registered Participants		
First Name:	**Last Name:**	**Company:**
Lauren	Aguilar	OUCC
Linda	Anguiano	Progressive Democrats of America - Calumet Region
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Russ	Atkins	NIPSCO
Pat	Augustine	Charles River Associates
Greg	Baacke	NIPSCO
Lisa	Beck	
Vernon	Beck	NIPSCO
Alison	Becker	NIPSCO
Anne	Becker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Marc	Blanchard	BP
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Tim	Caister	NIPSCO
Andy	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Mary	Chambers	NIPSCO
Daniel	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Claudia	Earls	NiSource
Amy	Efland	NiSource/NIPSCO
Greg	Ehrendreich	MEEA
Steve	Francis	Sierra Club - Hoosier Chapter
Thomas	Frank	Commuity Strategy Group
Fred	Gomos	NiSource
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Corey	Hagelberg	Beyond Coal
Barry	Halgrimson	Retired
John	Halstead	350 IN-Calumet
Rina	Harris	Vectren
John	Henderson	Stoll Keenon Ogden PLLC
David	Hicks	Indeck Energy Services, Inc.
Stephen	Holcomb	NIPSCO
Shelby	Houston	IPL/AES
Jim	Huston	Indiana Utility Regulatory Commission
Robert	Kaineg	Charles River Associates
Pauline	Katsouros	NIPSCO
Paul	Kelly	NIPSCO
Bryan	Little	NIPSCO
Jonathan	Mack	NIPSCO
Debi	McCall	NIPSCO
Jim	McMahon	CRA

NIPSCO Public Advisory Meeting 1 Registered Participants		
First Name:	**Last Name:**	**Company:**
Emily	Medine	EVA
Tony	Mendoza	Sierra Club
Nancy	Moldenhauer	none
Richard	Nelson	Praxair, Inc.
Adam	Newcomer	NIPSCO
Elizabeth	Palacio	Ms.
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Jodi	Perras	Sierra Club
Carmen	Pippenger	IURC
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
David	Repp	JET Inc
Matt	Rice	Vectren
Joe	Rompala	Lewis Kappes
Edward	Rutter	Indiana Office of Consumer Counselor
Anthony	Salcedo	Sal-tec Service
Cliff	Scott	NIPSCO
Brent	Selvidge	IPL
Robert	Seren	NIPSCO
Frank	Shambo	NIPSCO
Violet	Sistovaris	NIPSCO
Matt	Smith	Carmeuse Lime and Stone
Joan	Soller	MISO
Dick	Spellman	GDS Associates, Inc.
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Kathleen	Szot	NIPSCO
Maureen	Turman	NiSource
Bob	Veneck	Indiana Utility Regulatory Commission
Victoria	Vrab	NIPSCO
Jennifer	Washburn	CAC
Michael	Whitmore	NIPSCO
Ashley	Williams	Sierra Club
Fang	Wu	SUFG
James	Zucal	NIPSCO