BUILDING A WORLD OF DIFFERENCE

11 March 2013

CITY OF AMES

ENERGY RESOURCE OPTIONS STUDY

BLACK & VEATCH

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AGENDA

Approach

Gap Analysis/Technology Screening

Technology Overview

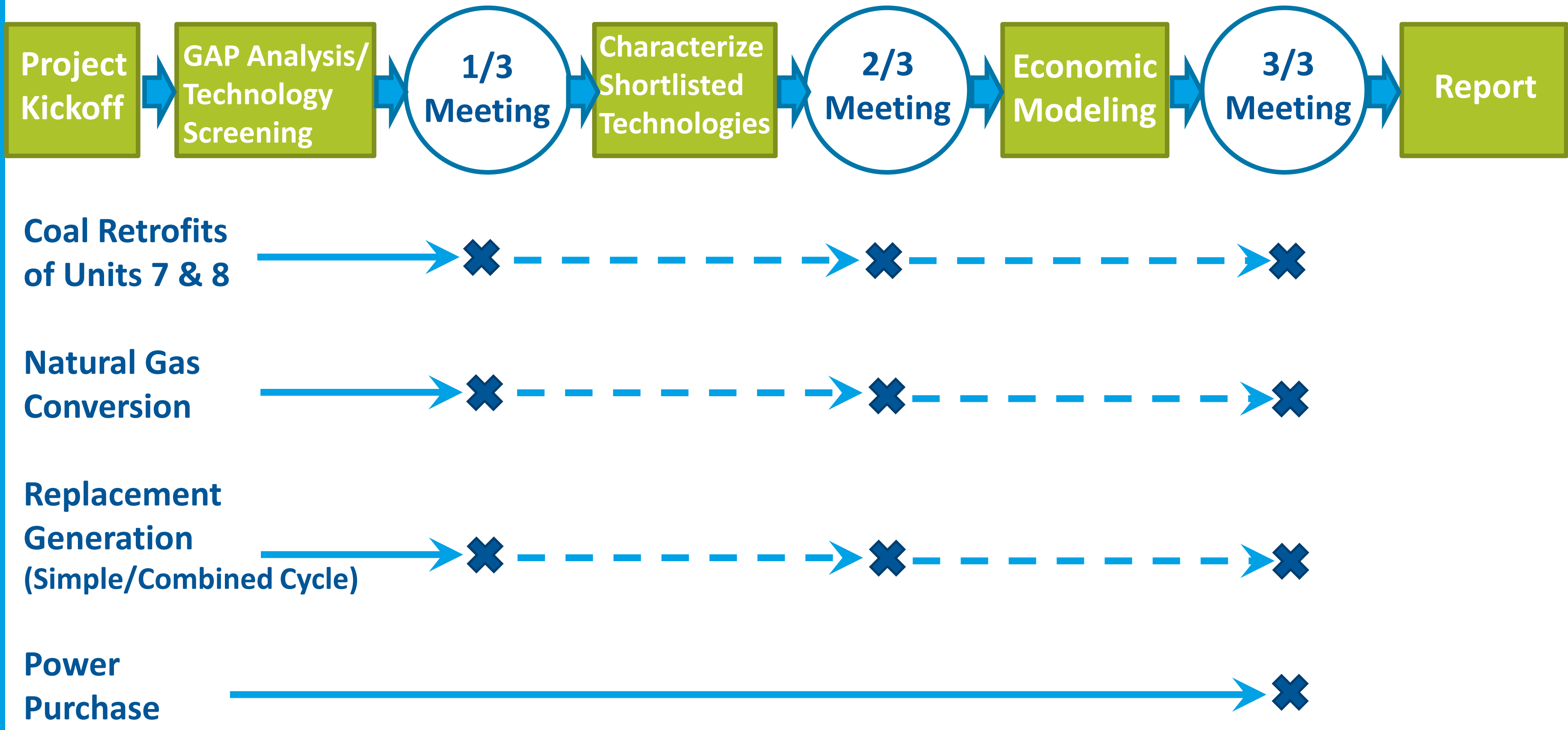
Option Screening

Strategist

APPROACH

BOB SLETTEHAUGH PROJECT MANAGER
ENERGY

STUDY WORKFLOW



GAP ANALYSIS/ TECHNOLOGY SCREENING

BOB SLETTEHAUGH PROJECT MANAGER
ENERGY

GAP ANALYSIS KEY FINDINGS

- **Study Design Basis:**

FINAL STUDY DESIGN BASIS AIR COMPLIANCE GAPS			
	Unit 7	Unit 8	Regulation
SO_2	34%	13%	2014 CSAPR
Annual NO_x	62%	64%	2014 CSAPR
Ozone Season NO_x	70%	60%	2014 CSAPR
Mercury	74%	74%	MATS *
HCl	55%	28%	MATS *
Filterable-PM	NO GAP	NO GAP	MATS *
* Not applicable if unit(s) converted to natural gas.			

Gap Analysis dictates likely technical solutions.

TECHNOLOGY SCREENING

- **Qualitative screening/ranking of potential technologies**
- **Driven by identified Gap analysis findings**
- **Areas of focus:**
  - NOx controls
  - Mercury controls
  - SO2 and acid gas (HCl) controls
  - PM controls
  - Boiler conversion to natural gas technologies

Used to set the stage for option screening.

TECHNOLOGY SCREENING KEY FINDINGS

- **Unit 7 Continued Coal Operation**
  - NOx – Low Nox Burners/Overfire Air with SNCR
  - Mercury – PAC injection with existing ESP
  - SO2 – DSI with existing ESP
  - PM – No existing Gap. ESP upgrade or new fabric filter possible.
- **Unit 8 Continued Coal Operation**
  - NOx – Low NOx Burners/Overfire Air with SNCR
  - Mercury – PAC with existing ESP converted to cold-side
  - SO2 – DSI with existing ESP converted to cold-side
  - PM – No existing Gap. ESP converted to cold-side or new fabric filter possible.

Highest scoring technologies considered in option screening.

TECHNOLOGY SCREENING KEY FINDINGS

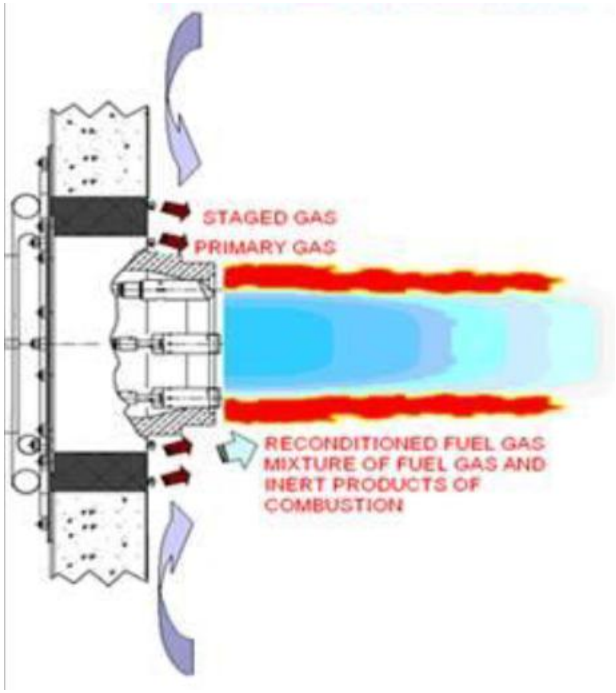
- **Either Unit 7 or Unit 8 Converted to Natural Gas**
  - Compatible with RDF co-firing
  - MATS compliance not applicable
  - LNB would reduce NOx
  - PM control required with continued RDF co-firing

Highest scoring technologies considered in option screening.

TECHNOLOGY OVERVIEW

BOB SLETTEHAUGH PROJECT MANAGER ENERGY

LNB/ OFA/ SNCR



Fuel Tech. September 20, 2012.

- Cost effective way to reduce NOx emissions (CSAPR cap and trading)
- LNB and OFA control and balance air and coal to minimize NOx formation
- SNCR reduces NO_x by using a chemical reagent to convert NO_x to elemental nitrogen

Minimize formation and maximize conversion of NOx to elemental nitrogen.

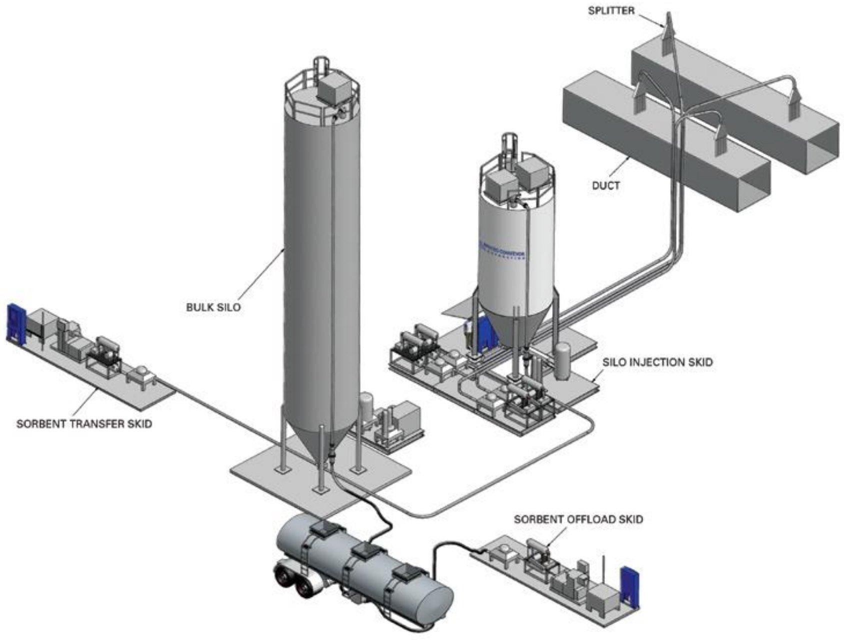
POWDERED ACTIVATED CARBON (PAC)

Innova Corporate. Web. 21 Jan. 2011.

- Cost effective way to reduce MATS regulated emissions of mercury
- PAC + mercury → Removed in PM control device
- Highly temperature dependent – requires cold-side PM control device
- Also commonly referred to as activated carbon injection (ACI)

Capture mercury with other particulates.

DRY SORBENT INJECTION (DSI)



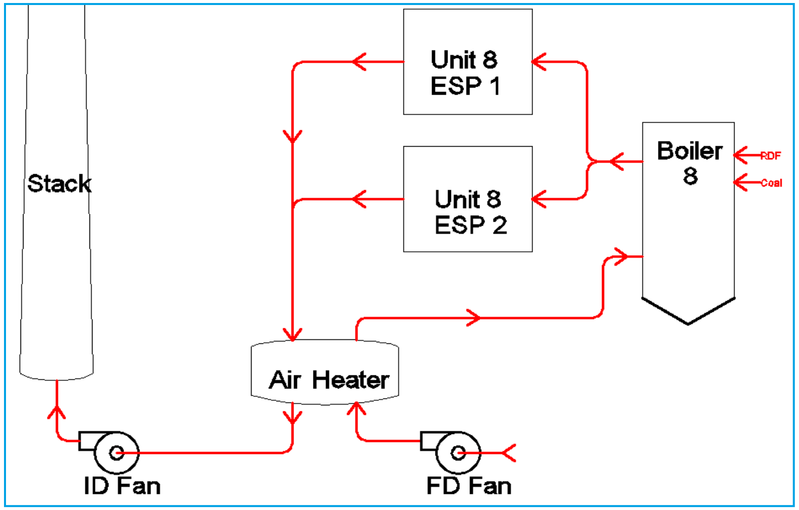
United Conveyor Corporation. 9 September 2012.

- Cost effective way to reduce MATS regulated emissions of acid gases (HCl) and SO_2
- Most common sorbent is Trona
- Trona + Acid Gas/SO_2 → Removed in PM control device
- Performs better at higher temperatures – above 275°F

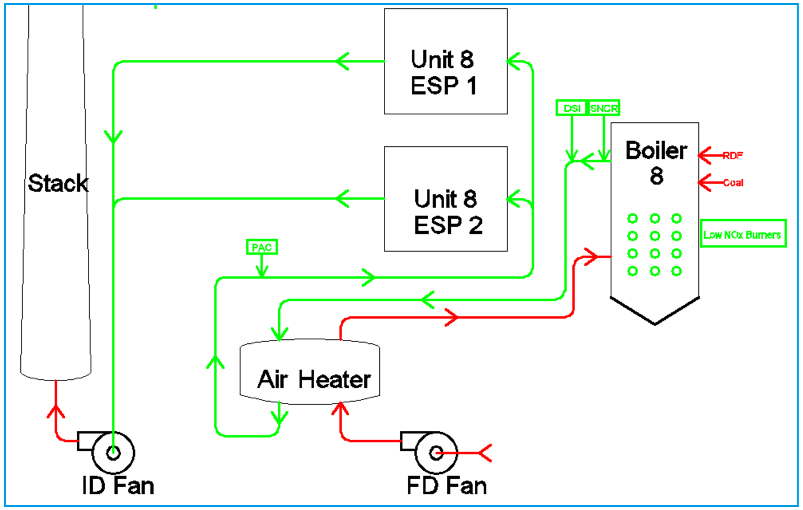
Capture acid gases and SO_2 with other particulates.

HOT TO COLD ESP CONVERSION (UNIT 8)

Before…



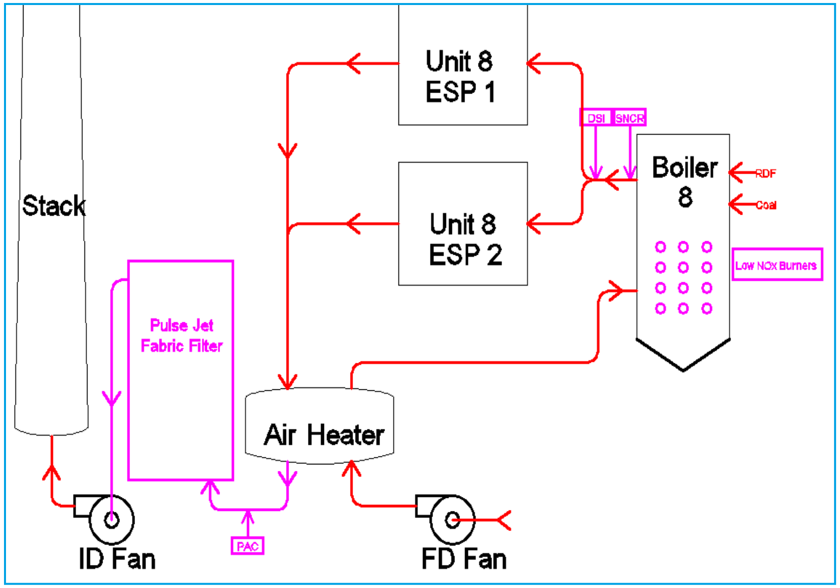
After…



- PAC requires cold-side PM control device
- Reroute Unit 8 flue gas ducts
- Reuse Unit 8 ESPs
- Different ESP operating conditions
- No derate
- Difficult to construct but achievable – independently reviewed

Reroute flue gas and reuse ESPs.

FABRIC FILTER



- Alternative to converting Unit 8 ESPs to cold-side
- Leave Unit 8 ESPs in place
- More certainty, lower reagent costs
- More expensive
- Derate without additional upgrades

Add a fabric filter behind Unit 8.

ESP VS. FABRIC FILTER

- **ESP**
  - Advantages:
    - Lower maintenance cost
    - Lower capital cost
    - No/minimal derate
  - Disadvantages:
    - Lower collection efficiency
    - Higher reagent cost
    - Concern with SSM

- **Fabric Filter**
  - Advantages:
    - High collection efficiency
    - Lower reagent cost
  - Disadvantages:
    - Higher capital cost
    - Derate unless additional upgrades are made

Many factors to consider.

BOILER CONVERSION TO NATURAL GAS

- **Natural gas supply pipeline**
- **Onsite:**
  - Metering and pressure regulation station
  - Gas supply heaters
  - Onsite supply and distribution
- **Inside the plant**
  - New Low NOx burners
  - Boiler piping & controls
  - Build to NFPA code

OPTION SCREENING

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ENERGY

ENERGY RESOURCE PLANS

City of Ames RFP

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Unit 7	CR	R	R	R	NG	NG	NG	NG	NG	R	R	R	R	R	R	R
Unit 8	CR	CR	CR	CR	CR	R	R	R	NG	NG	NG	NG	R	R	R	R
GT1	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO
GT2	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO	FO
Alternative Resources																
MISO		X				X				X			X			
PPA			X				X				X			X		
SCCT (33 MW)				X								X			X	
SCCT (65 MW)								X							X	
CCCT (98 MW)																X

Energy Resource Plan

	1	2	3	4	5	6	7
Unit 7	CR	R	NG	NG	NG	R	R
Unit 8	CR	CR	CR	R	NG	NG	R
GT1	FO	FO	FO	FO	FO	FO	FO
GT2	FO	FO	FO	FO	FO	FO	FO

16 plans narrowed down to seven unique Energy Resource Plans.

ADDITIONAL PLANS ADDED BY BLACK & VEATCH

Energy Resource Plan

	1	2	3	4	5	6	7
Unit 7	CR	R	NG	NG	NG	R	R
Unit 8	CR	CR	CR	R	NG	NG	R
GT1	FO	FO	FO	FO	FO	FO	FO
GT2	FO	FO	FO	FO	FO	FO	FO

Additional Combinations

		NEW	NEW		NEW				NEW		
	1*	2*	3*	4	5	6	7	8	9	10	11
Unit 7	CR	CR	CR	NG	CR	NG	R	R	CR	NG	R
Unit 8	CR	CR	CR	CR	NG	NG	CR	NG	R	R	R
New CTG Unit	No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes

* Considered Plans 1, 2, and 3 are differentiated by how 2014 CSAPR compliance is achieved between the two units.

Four plans added for thoroughness

OPTION BREAKDOWN

- **Unit 7:**

	OPTION 7A	OPTION 7B	OPTION 7C
Considered Plans	1, 5	2, 3, 9	4, 6, 10
Fuel	Coal	Coal	Natural gas
NO_x Controls	LNB, OFA, SNCR	LNB, OFA, SNCR	LNB
SO_2 Controls	None*	DSI	None
Mercury Controls	PAC	PAC	None
PM Controls	Existing Cold-side ESP	Existing Cold-side ESP**	Existing Cold-side ESP***

*Possible use of allowances or sharing of credits from Unit 7. Installation of DSI on Unit 8 as a fallback position.

**Plan 2, in which Unit 7 compensates for Unit 8 to comply with CSAPR SO_2 limits, would require a fabric filter.

***Assumes continued co-firing of RDF for Unit 7.

- Option 7A does not have DSI.
- Characteristics of Option 7A can be derived from Option 7B.
- Elimination of Option 7A agreed upon.

OPTION BREAKDOWN

- **Unit 8:**

	OPTION 8A	OPTION 8B	OPTION 8C
Considered Plans	1, 3, 7	2, 4	5, 6, 8
Fuel	Coal	Coal	Natural gas
NO_x Controls	LNB, OFA, SNCR	LNB, OFA, SNCR	LNB
SO_2 Controls	DSI	None*	None
Mercury Controls	PAC	PAC	None
PM Controls	Conversion to cold-side ESP	Conversion to cold-side ESP	Existing hot-side ESP**

*Possible use of allowances or sharing of credits from Unit 7. Installation of DSI on Unit 8 as a fallback position.

**Assumes continued co-firing of RDF for Unit 8.

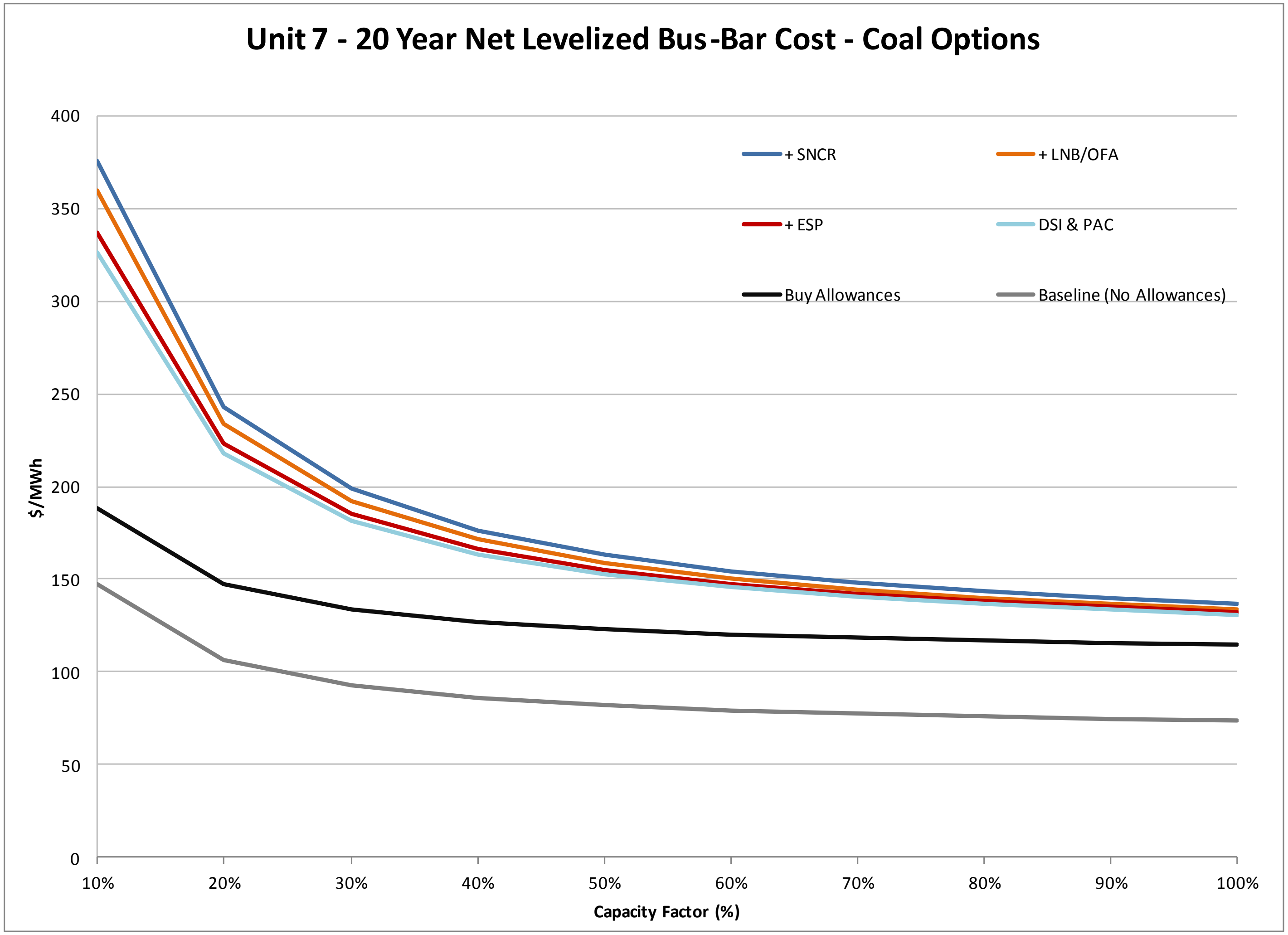
- Option 8B does not have DSI.
- Plans with Option 8B involve relying on over-control from Unit 7. High risk and violates plan guidelines.
- Elimination of Option 8B agreed upon.

INITIAL OPTIONS CHARACTERIZED

	OPTION A	OPTION B	OPTION C	OPTION D
Unit	7	7	8	8
Previous Number	7B	7C	8A	8C
Considered Plans	2, 9	4, 6, 10	1, 4, 7	5, 6, 8
Fuel	Coal	Natural gas	Coal	Natural gas
NO_x Controls	LNB, OFA, SNCR	LNB	LNB, OFA, SNCR	LNB
SO_2 Controls	DSI	None	DSI	None
Mercury Controls	PAC	None	PAC	None
PM Controls	Existing cold-side ESP	Existing cold-side ESP*	Conversion to cold-side ESP	Existing hot-side ESP*
* Assumes continued co-firing of RDF.				

Four options, 1 coal & 1 gas for each unit

LEVELIZED COST – UNIT 7 ON COAL



Red line represents minimum requirement.

LEAST-COST OPTIONS FOR UNITS 7 AND 8

		UNIT 7 COAL [a]	MIN UNIT 7 COAL [a]	UNIT 7 GAS [a]	UNIT 7 GAS [b]	UNIT 8 COAL [c]	UNIT 8 GAS [c]
Primary Fuel		Coal	Coal	Gas	Gas	Coal	Gas
NO_x Controls - SNCR		No	No	No	No	No	No
NO_x Controls - LNB/OFA		No	No	Yes	Yes	No	Yes
SO_2/HCl Controls - DSI		Yes	Yes [d]	No	No	Yes	No
Mercury Controls - PAC		Yes	Yes [d]	No	No	Yes	No
PM Controls - Upgraded ESP		Yes	Yes	No	No	Yes	No
PM Controls - Hot-to-Cold ESP		NA	NA	NA	NA	Yes	No
COST ESTIMATES (2012$)							
Total Evaluated Overnight Capital Cost	$1,000	$15,054[e]	$7,820	$37,920[e]	$16,540[e] [f]	$22,049	$34,990
Fixed O&M Cost	$/kW-yr	$54.03	$54.03	$32.17	$32.17	$68.70	$52.79
Variable O&M Cost	$/MWh	$6.23	$6.23	$3.56	$3.56	$7.40	$2.69
PERFORMANCE							
Net Unit Output	MW	30.3	30.3	30.7	30.7	59.4	61.0
Net Unit Heat Rate (HHV)	Btu/kWh	13,129	13,129	13,293	13,293	12,466	12,462
RDF Co-Firing	%	10	0	8.7	8.7	10	8.7
PROJECT SCHEDULES							
Project Duration	Months	31	31	30	30	31	30
Outage Duration	Months	2	2	1	1	2	1

[a] Unit 7 costs are the incremental costs to operate Unit 7 when Unit 8 is operating on coal.
[b] Unit 7 costs are the incremental costs to operate Unit 7 when Unit 8 is operating on natural gas.
[c] Unit 8 costs are presented on a stand-alone basis.
[d] Reagent storage capacity is sized on the basis of Unit 7 rarely operating, and AQC equipment dedicated to Unit 7 would have limited redundancy.
[e] $6 million Unit 7 refurbishment cost required if continued co-firing of RDF or if operating hours were more than required to meet peak demand.
[f] Natural gas pipeline capital cost is included with Unit 8 capital cost.

STRATEGIST

NATALIE ROLPH

ECONOMIST
MANAGEMENT CONSULTING

ECONOMIC ANALYSIS GOALS

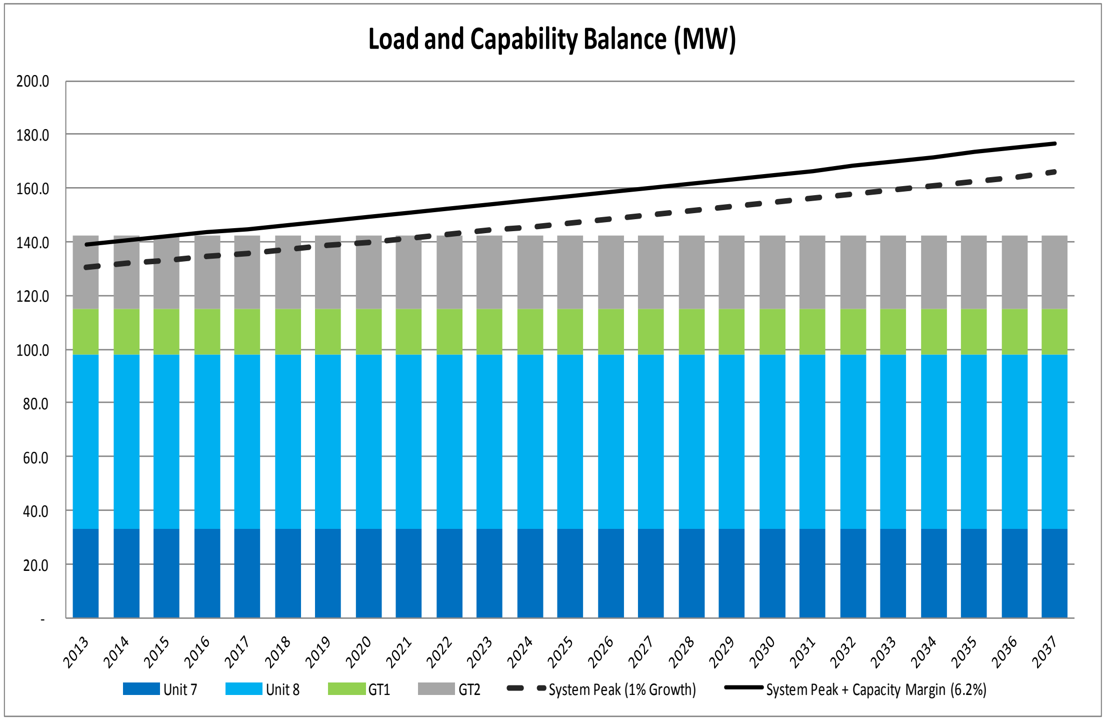
- Identify COA's least-cost environmental compliance plan
  - With and without the continued use of RDF
  - Under a range of future economic and market conditions
- Estimate the impact of continued RDF use
  - On least-cost plan selection

ECONOMIC ANALYSIS APPROACH

- Characterize assumptions and economic/market inputs
- Identify key compliance options
- Identify key system constraints
- Use an Optimum Generation Expansion model to test combinations of compliance and growth options and find least-cost plans
    - With continued RDF use
    - W/O continued RDF use
- Check the robustness of selected plans

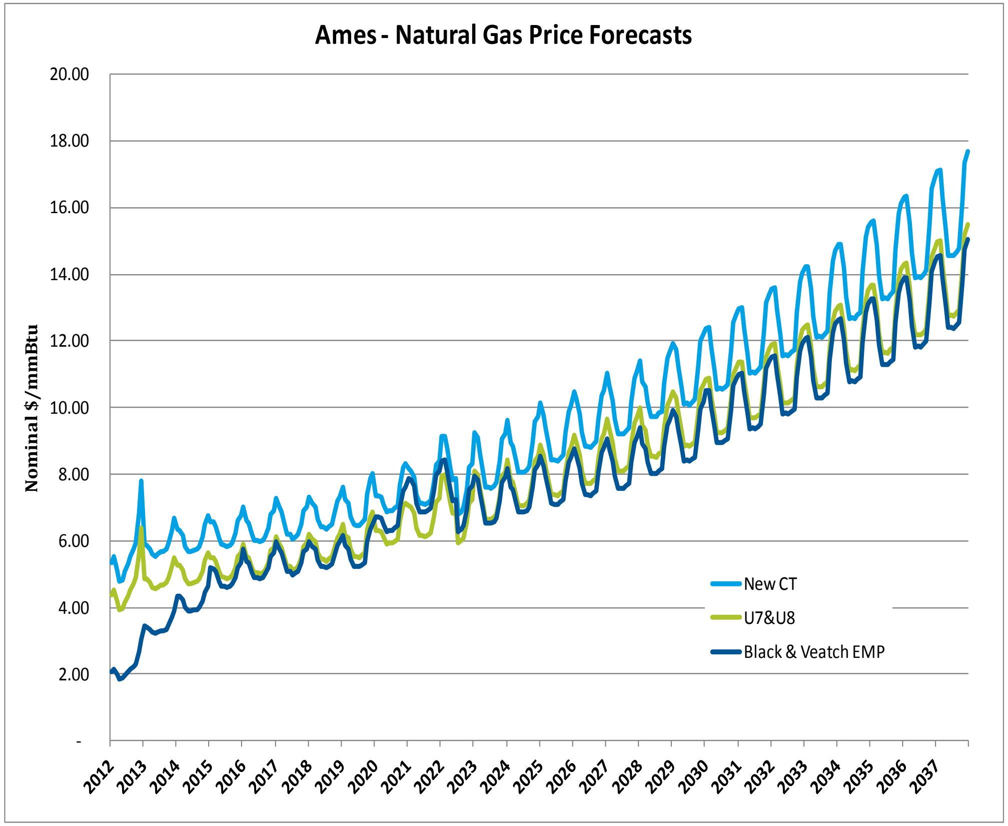
CITY OF AMES – FORECAST CAPACITY BALANCE

- Assumes 1% load growth and 6.2% reserve margin
- Produces a 34 MW need by 2037
- Initial deficits handled through short-term capacity purchases



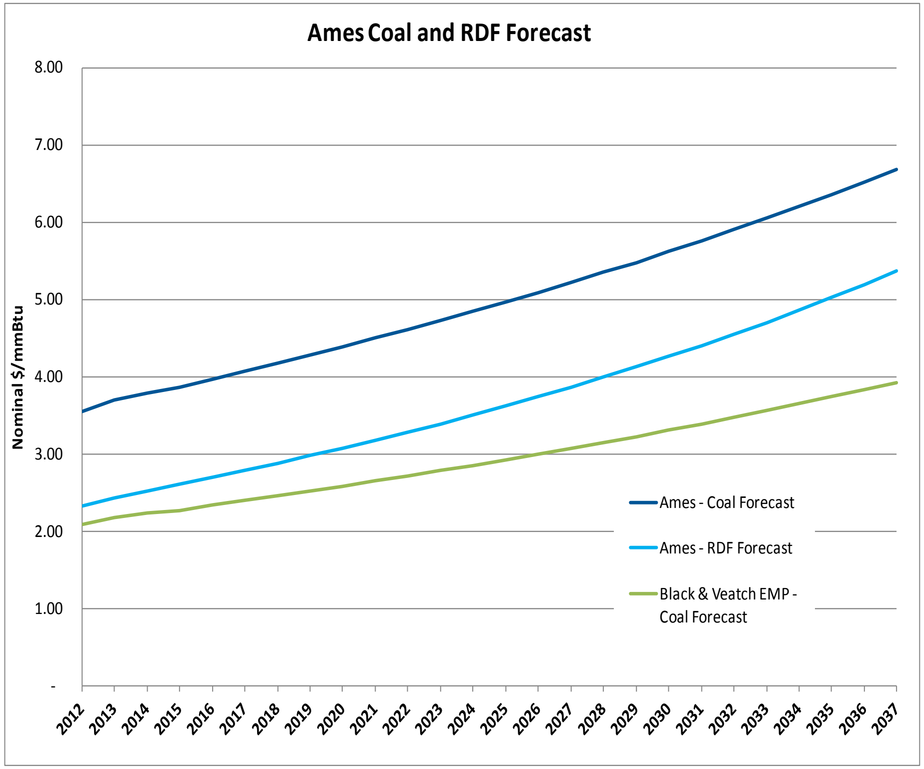
NATURAL GAS PRICE FORECAST (NOMINAL DOLLARS)

- Initial natural gas commodity and demand prices thru 2022 provided by COA
- Subsequent escalation from B&V EMP
- COA prices slightly higher than general market prices
- Winter prices run approximately 20 % higher than summer prices



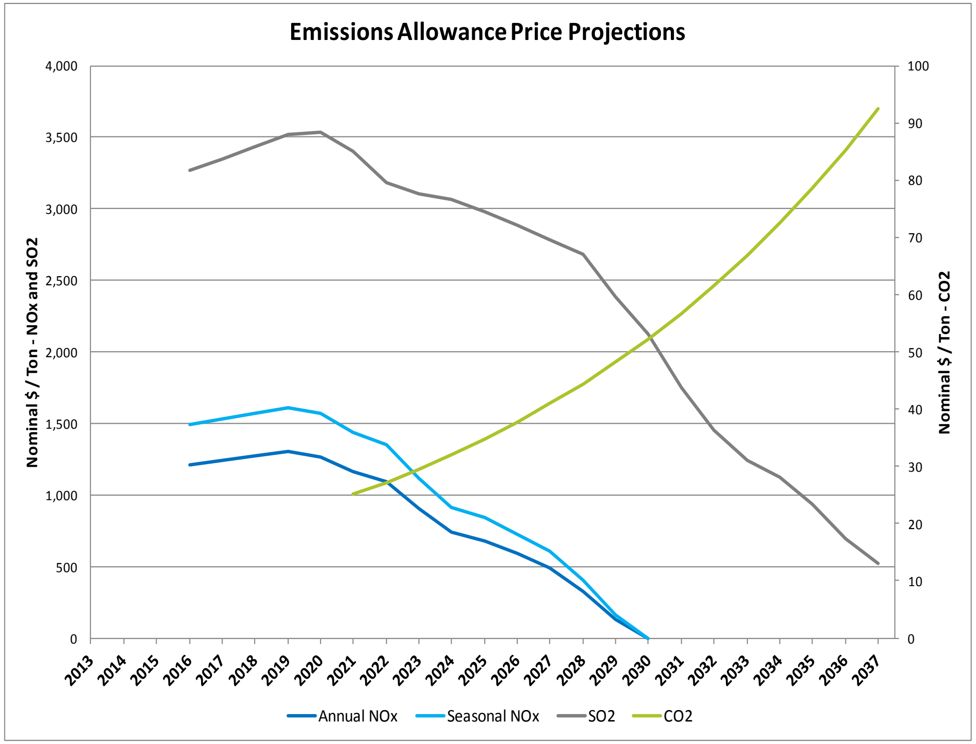
DELIVERED COAL AND RDF PRICE FORECAST (NOMINAL DOLLARS)

- Delivered coal prices provided by COA for 2013
- B&V EMP escalation rates used thereafter
- RDF prices set at 2/3 of delivered coal prices per RDF contract

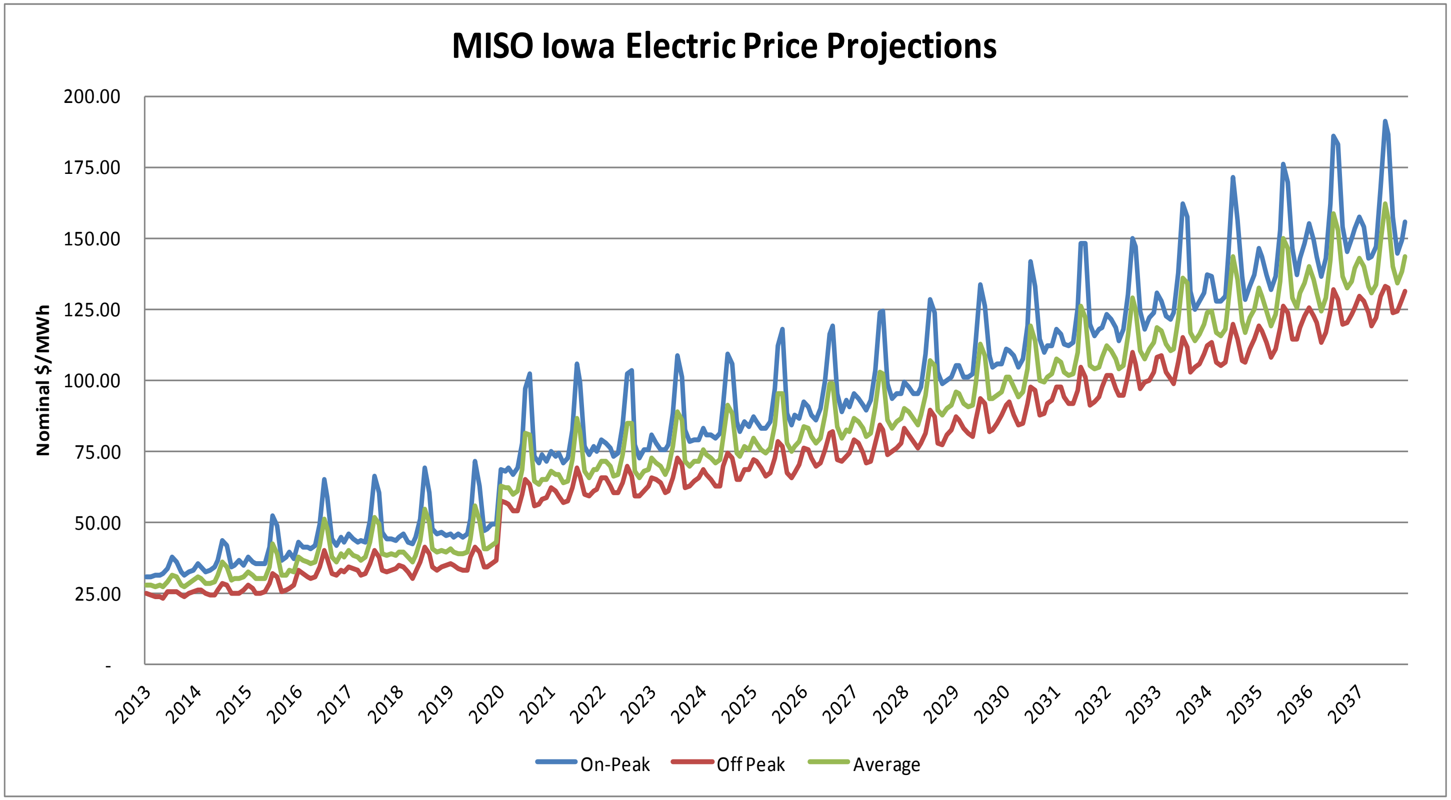


EMISSION ALLOWANCE PRICE FORECAST (NOMINAL DOLLARS)

- Forecast from B&V EMP
- Based on projected supply and demand for allowances under CSAPR
- CSAPR prices over shadowed by CO_2 prices in early 20's



MONTHLY ELECTRIC MARKET PRICES (NOMINAL DOLLARS)



Post 2019, increases reflect effect of CO_2 price forecast.

REPLACEMENT UNIT CHARACTERISTICS

CHARACTERISTIC	
Size (MW)	35 or 65
Capital Cost ($/kW)	1,250
Fixed O&M ($/kW-yr)	13
Variable O&M ($/MWh)	4.5
Heat Rate (Btu/kWh)	9,700
CO_2 Emissions Rate (lb/mmBtu)	115
SO_2 Emissions Rate (lb/mmBtu)	0.07
NO_x Emissions Rate (lb/mmBtu)	0.01

Characteristics represent a broad range of available units.
Specific generator models not simulated to avoid biasing environmental evaluation with specific turbine price and performance assumptions which may change during a competitive bidding process.

OTHER ASSUMPTIONS AND CONSTRAINTS – FINANCIAL COSTS

- 4% long-term cost of debt
- 20 year cash finance up to $30.5 million for Units 7 and/or 8 (1)
- Insurance
- 5.5% annual carrying charge rate for most options
- 7.7 % annual carrying charge rate for new combustion turbine projects
- 4% discount rate

(1) $24.5 million if Unit 7 is not retired.

OTHER ASSUMPTIONS AND CONSTRAINTS

- **Transmission Assumptions**
  - With completion of new transmission, market purchases are not limited
  - As long as all retirements are replaced with in-City capacity, no additional transmission expenditures are needed
- **Minimum Load Levels**
  - To use RDF and avoid disposal costs, Unit 8 must run at 36 MW minimum load
  - To use RDF and avoid disposal costs, Unit 7 must run at 28 MW minimum load
- **Estimated Units 7 and 8 Retirement Cost - $20Million**

OTHER ASSUMPTIONS AND CONSTRAINTS

- **Gas Pipeline Assumptions**
  - The first time gas is brought to Ames for electric generation, gas pipeline costs of $13.9 million will be incurred.
  - An additional $3.2 million is required to access Units 7 and 8
  - An additional $1.3 million is required to access the new CT site
- **Electric Interconnection Assumptions**
  - Installation of the first new combustion turbine at the new CT site will entail $5.5 million in electric interconnection costs

COMPARATIVE ECONOMIC CRITERIA AND MODEL

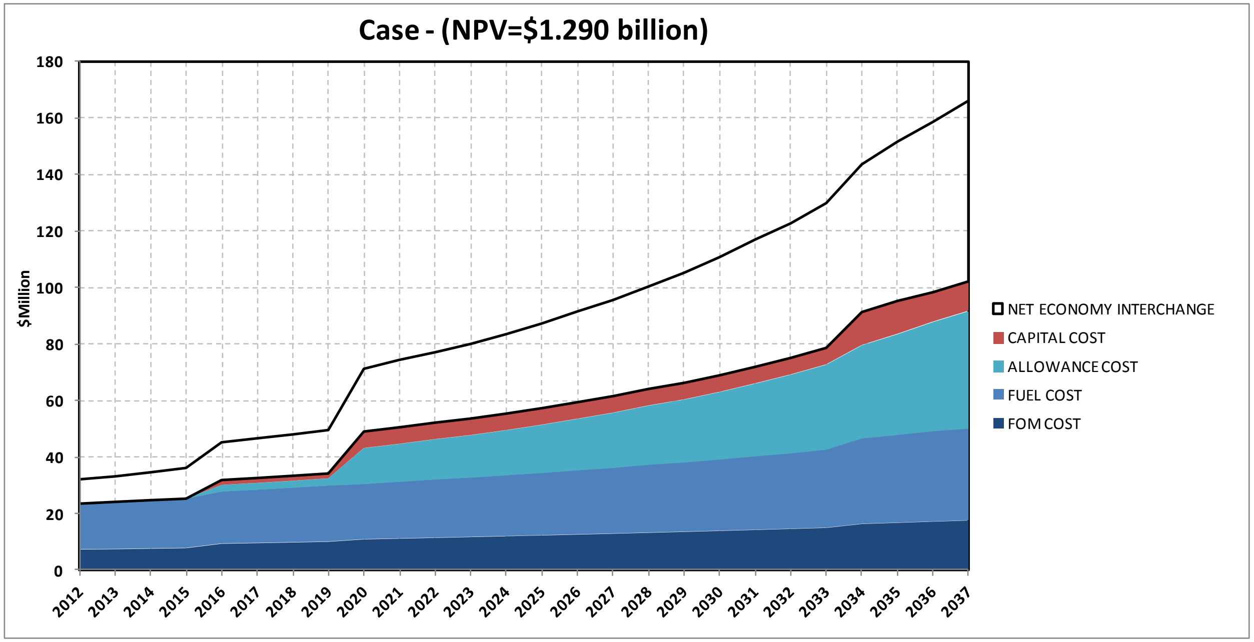
- **Net Present Value (NPV) of comparative electric costs including**
  - System-wide generation fuel costs
  - Existing and new generator fixed & variable O&M
  - Emission allowance costs
  - Net purchased power costs
  - Annual carrying charges on new plant (generation, pipeline and transmission)
- **Optimum Generation Expansion Model, Strategist, considers all possible combinations of existing generator compliance options and new CT capacity to identify the least cost plans through 2037 on a NPV basis**

LEAST COST PLAN DEVELOPMENT - BASE CASE ASSUMPTIONS AND FORECASTS

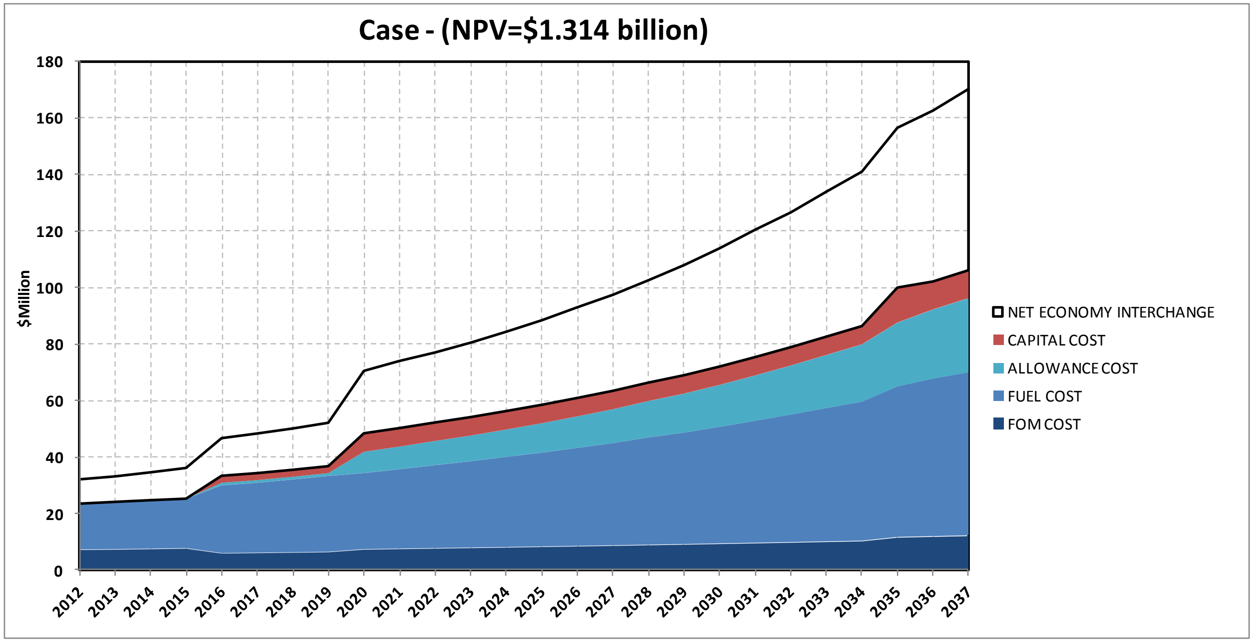
	DESCRIPTION	NPV ($ BILLIONS)
RDF Co-firing	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal[a]	1.290
	Select Unit 8 on Coal Select Unit 7 on Natural Gas	1.308
	Select Unit 8 on Natural Gas Select Unit 7 on Natural Gas	1.309
	Select Unit 8 on Coal Select Unit 7 on Coal	1.302
No RDF	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal	1.077
	Select Unit 8 on Coal Unit 7 on Natural Gas	1.077
	Select Unit 8 on Natural Gas Unit 7 on Natural Gas	1.049
	Select CTs and Retire Unit 7 and Unit 8	1.104

[a] Minimum cost Unit 7 on coal would not co-fire RDF when Unit 8 is unavailable. Neither unit co-fires RDF for the “No RDF” cases.

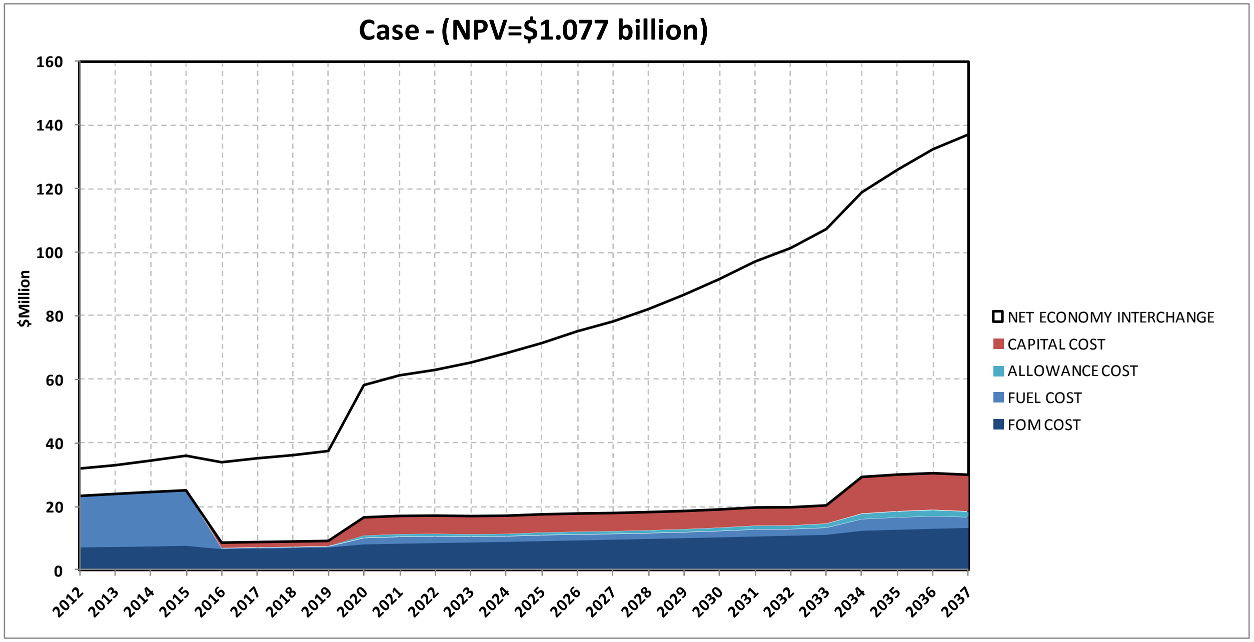
FORECAST COMPARATIVE REVENUE REQUIREMENTS – BASE CASE WITH RDF – U8 ON COAL, MINIMUM COST U7 ON COAL



FORECAST COMPARATIVE REVENUE REQUIREMENTS - BASE CASE WITH RDF – U8 ON GAS, U7 ON GAS



FORECAST COMPARATIVE REVENUE REQUIREMENTS - BASE CASE NO RDF – U8 ON COAL, MINIMUM COST UNIT 7 ON COAL



LEAST COST PLAN DEVELOPMENT – NO CO_2 CAPS

	DESCRIPTION	NPV ($ BILLIONS)
RDF Co-firing	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal[a]	0.949
	Select Unit 8 on Natural Gas Unit 7 on Natural Gas	1.055
No RDF	Select Unit 8 on Coal Unit 7 on Natural Gas	0.838
	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal	0.837
	Select Unit 8 on Natural Gas Unit 7 on Natural Gas	0.813

[a] Minimum cost Unit 7 on coal would not co-fire RDF when Unit 8 is unavailable. Neither unit co-fires RDF for the “No RDF” cases.

LEAST COST PLAN DEVELOPMENT – HIGHER FINANCE COSTS

	DESCRIPTION	NPV ($ BILLIONS)
RDF Co-firing	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal[a]	1.298
	Select Unit 8 on Natural Gas Unit 7 on Natural Gas	1.321
No RDF	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal	1.086
	Select Unit 8 on Natural Gas Unit 7 on Natural Gas	1.061

[a] Minimum cost Unit 7 on coal would not co-fire RDF when Unit 8 is unavailable. Neither unit co-fires RDF for the "No RDF" cases.

Assumes a 7.7 % annual carrying charge rate applies to all compliance options.

LEAST COST PLAN DEVELOPMENT – 20% HIGHER GAS PRICES

	DESCRIPTION	NPV ($ BILLIONS)
RDF Co-firing	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal[a]	1.295
	Select Unit 8 on Natural Gas Unit 7 on Natural Gas	1.390
No RDF	Select Unit 8 on Coal Unit 7 on Natural Gas	1.079
	Select Unit 8 on Coal Minimum Cost Unit 7 on Coal	1.079
	Select Unit 8 on Natural Gas Unit 7 on Natural Gas	1.051

[a] Minimum cost Unit 7 on coal would not co-fire RDF when Unit 8 is unavailable. Neither unit co-fires RDF for the “No RDF” cases.

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Together

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