MOVE THE WORLD FORWARD MITSUBISHI HEAVY INDUSTRIES GROUP

Development and Demonstration of Waste Heat Integration with Solvent Process for More Efficient CO_2 Removal from Coal-Fired Flue Gas

DE-FE0007525

2017 NETL CO_2 Capture Technology Project Review Meeting

August 22nd, 2017

MITSUBISHI HEAVY INDUSTRIES AMERICA, INC.

Contents

1. Project Overview

Project Participants

Southern Company

Project Management
Funding
Host Site

MITSUBISHI HEAVY INDUSTRIES AMERICA, INC.

Technology Provider
Reporting

AECOM

Reporting
Detailed Design
Flue Gas Measurement

NETL

Project Management
Funding

Team-Members

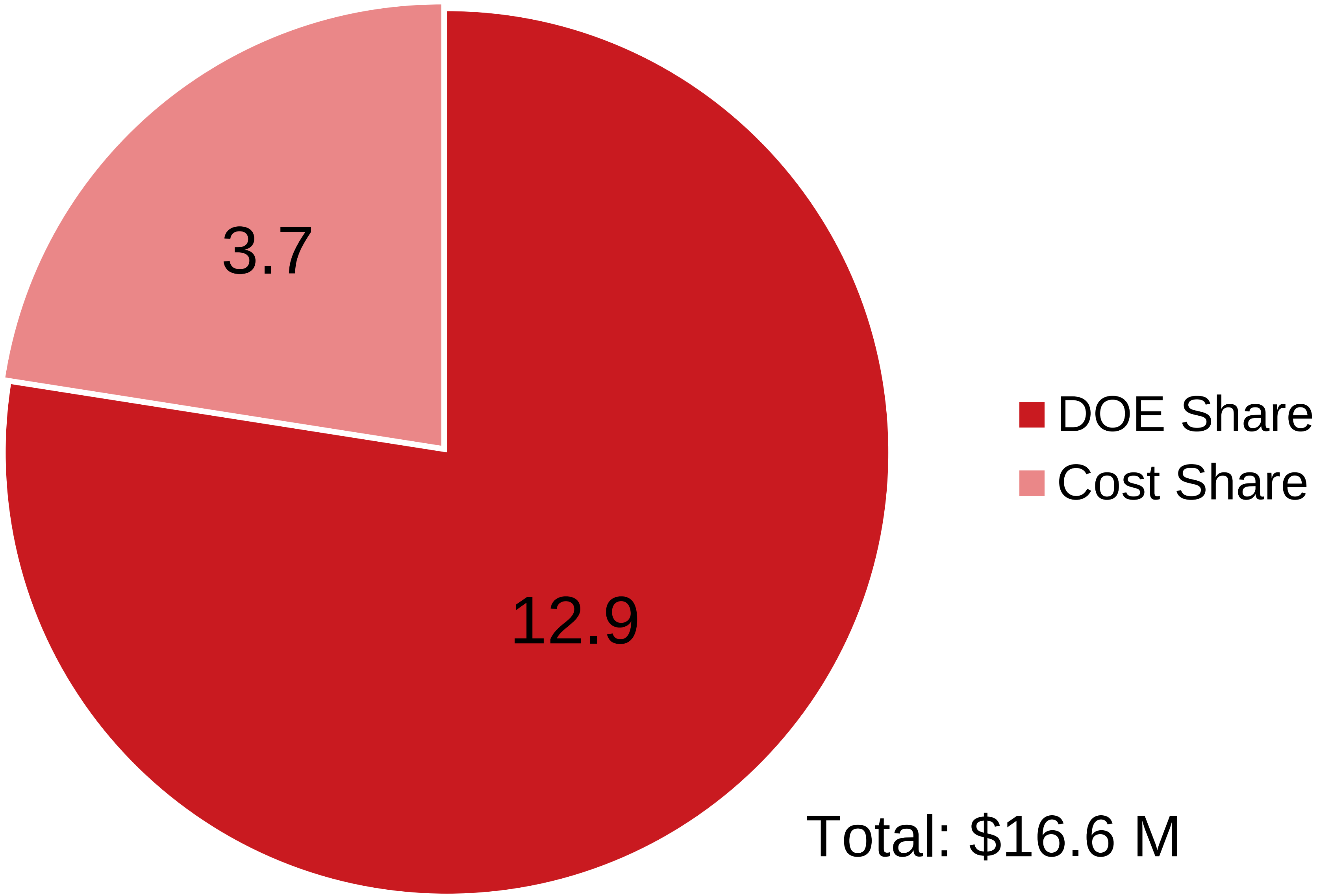
Nick Irvin (P.I.)
Joe Kowalczyk
Jerrad Thomas

Tim Thomas
Shintaro Honjo

Katherine Dombrowski
Max Bernau
Jack Cline

Bruce Lani

Total Project Budget ($MM)



Total: $16.6 M

Overall Project Objectives

- **The heat integration was chosen for its ability to provide:**
  - ✓ Increased plant efficiency,
  - ✓ Mitigation of parasitic losses from a CO_2 capture system (CCS),
  - ✓ Reduced water consumption and cooling water use, and
  - ✓ Improvement in air quality system performance
- **The heat integration included heat recovery for use in the coal EGU Rankine cycle. The heat was sourced from:**
  - ✓ A pilot CO_2 capture facility and
  - ✓ The coal EGU flue gas.

Objectives – to quantify the benefit of heat integration

- Quantify energy efficiency improvements
  - Unit heat rate improvement
  - Flue gas pressure drop
- Identify and/or resolve integration problems
  - Effect on water quality
  - Corrosion, erosion, or plugging
  - Issues with high-sulfur flue gas
- Quantify ancillary benefits
  - Better ESP performance
  - Increased SO_3, Hg, Se capture
  - Reduced water consumption and use

Overall Project Schedule

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BP1 — Nov 2011 – Mar 2013

- FEED and Target Cost Estimate
- Permitting

BP2 — Apr 2013 – Apr 2015

- Engineering, Procurement, Construction

BP3 — May 2015 – May 2017

- Operations
- Field Testing Analysis

2. Background Technologies

Post-Combustion Carbon Capture System

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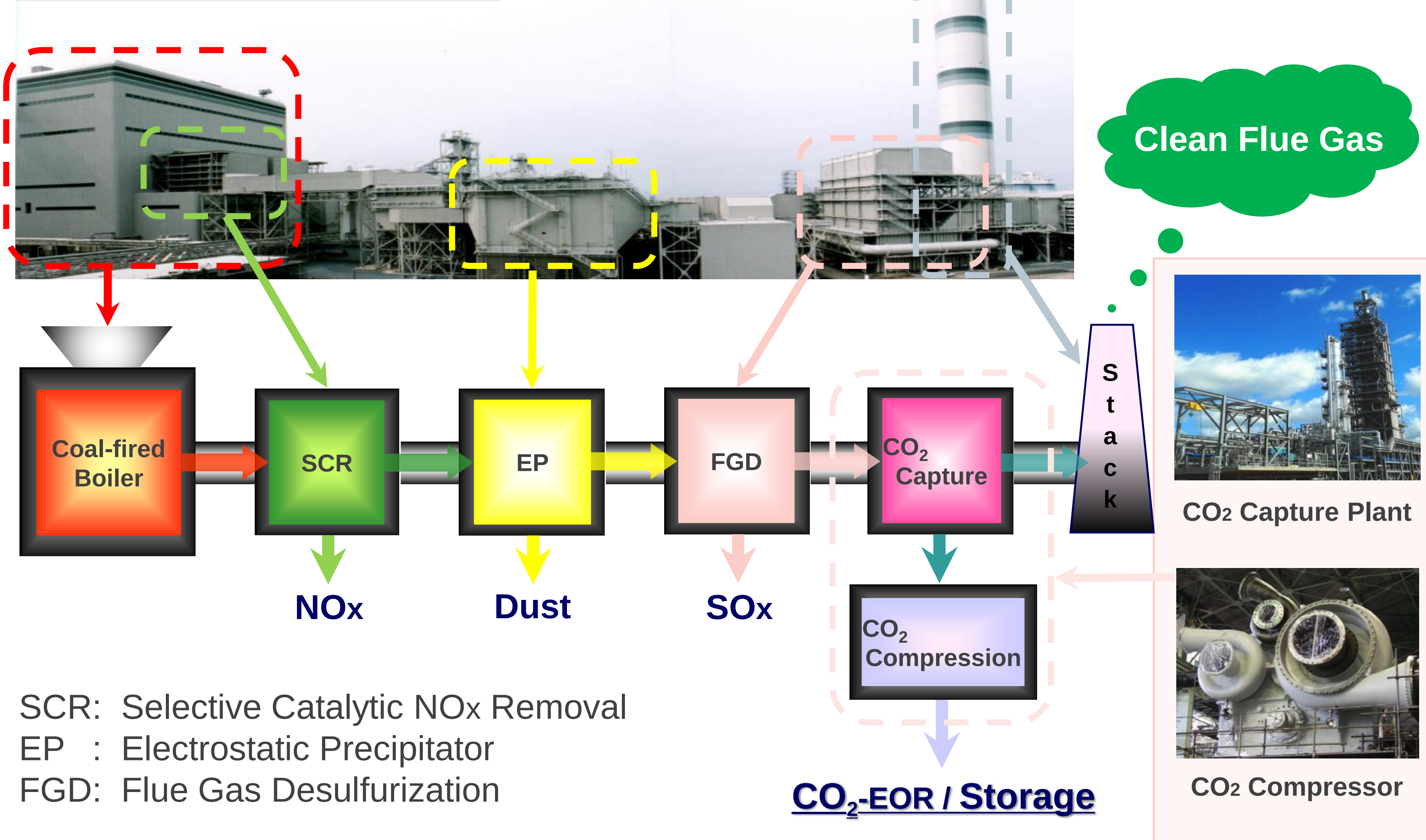
Coal-fired Power Station



SCR: Selective Catalytic NOx Removal

EP : Electrostatic Precipitator

FGD: Flue Gas Desulfurization

KM CDR Process®

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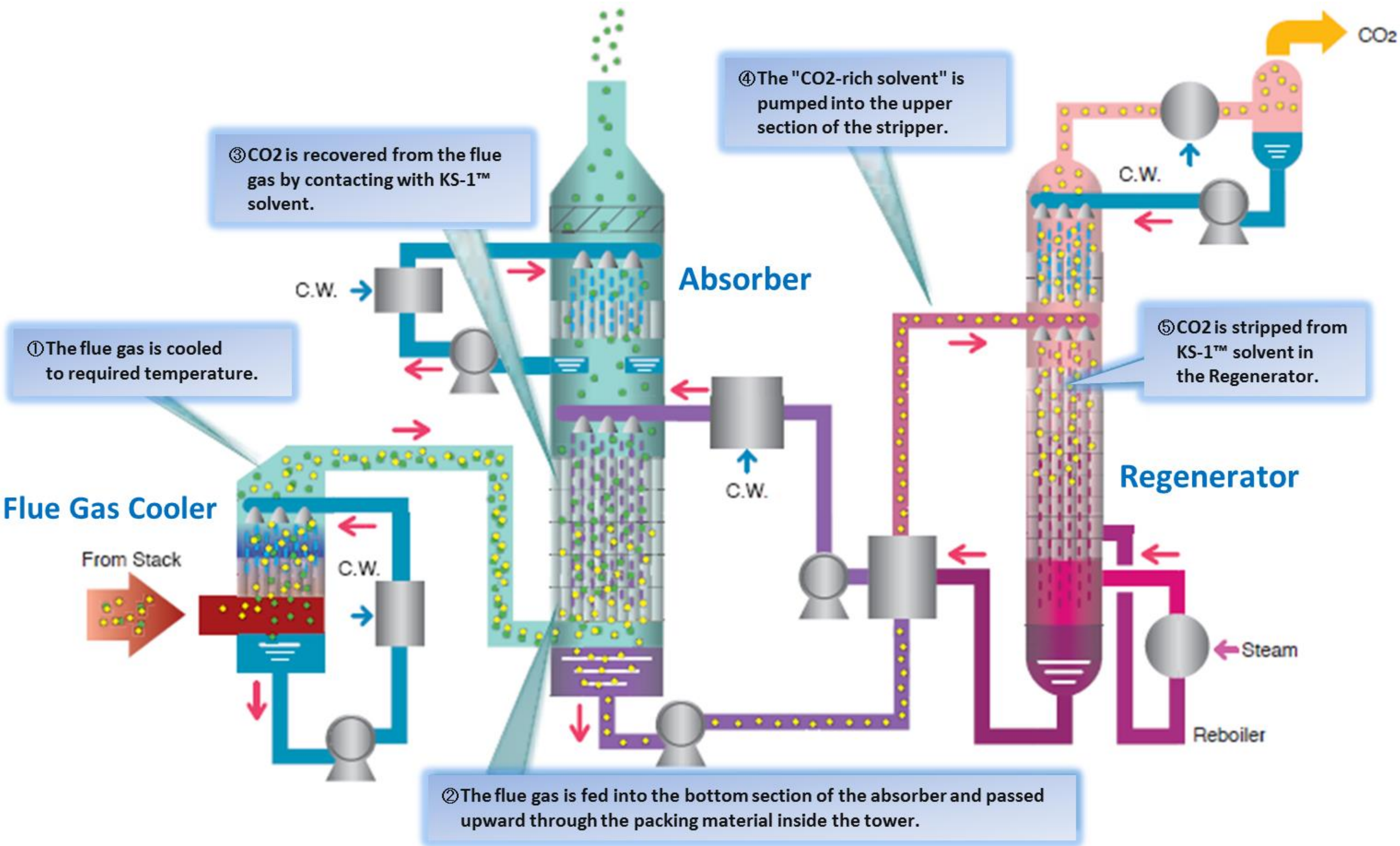


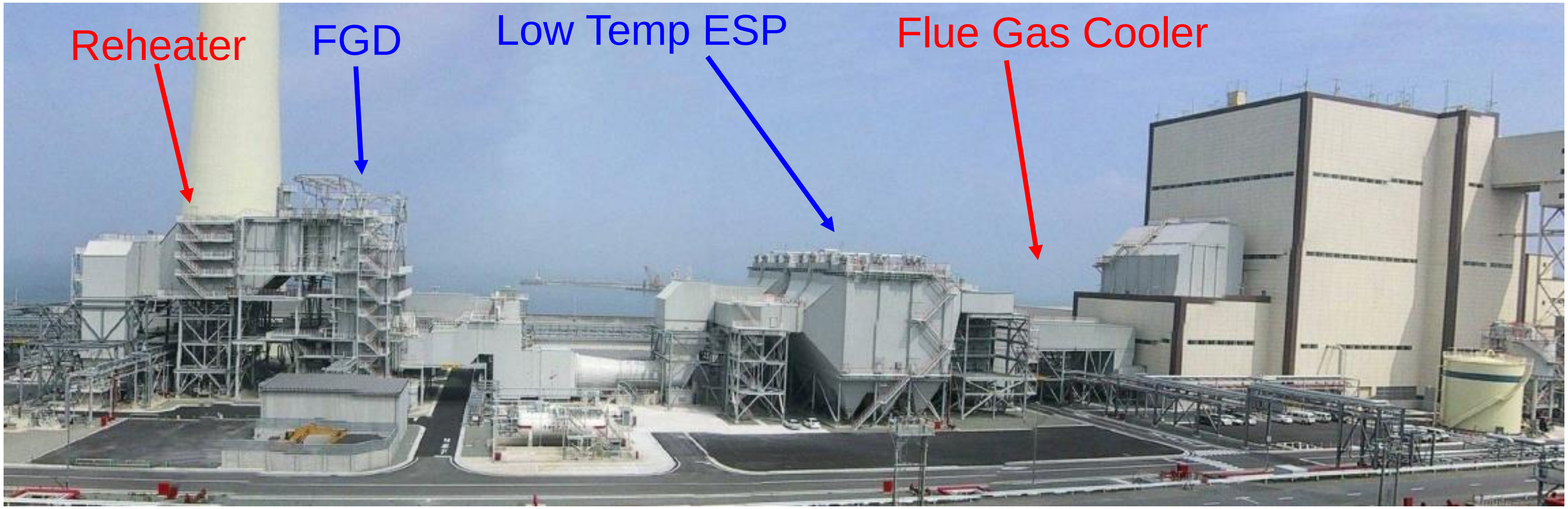
Petra Nova Project Overview

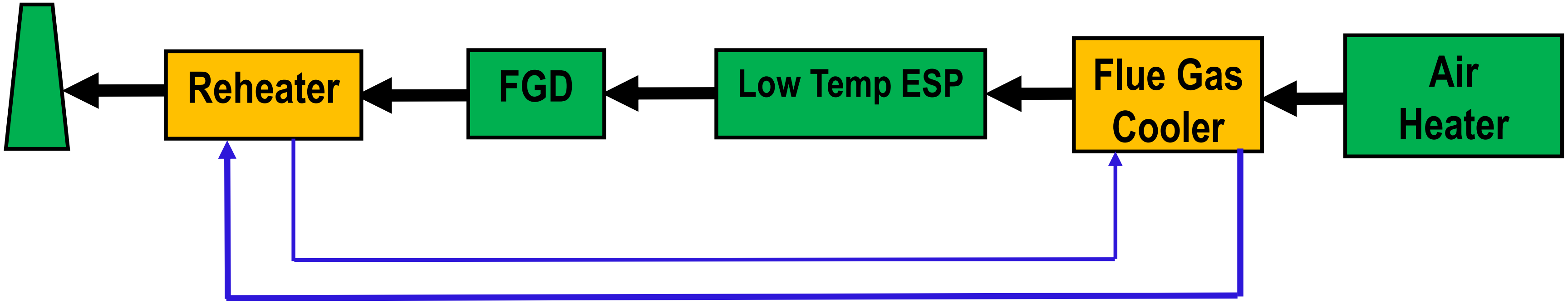
- "NRG Energy, JX Nippon complete world's largest post-combustion carbon capture facility on-budget and on-schedule"

NRG press release: http://investors.nrg.com/phoenix.zhtml?c=121544&p=irol-newsArticle&ID=2236424

Conventional High Efficiency System

Hirono P/S Japan - 600MW





Water Loop

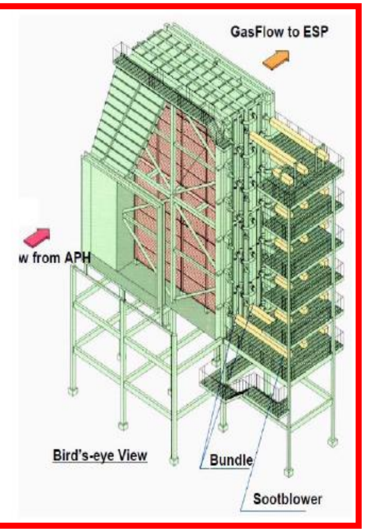
Flue Gas

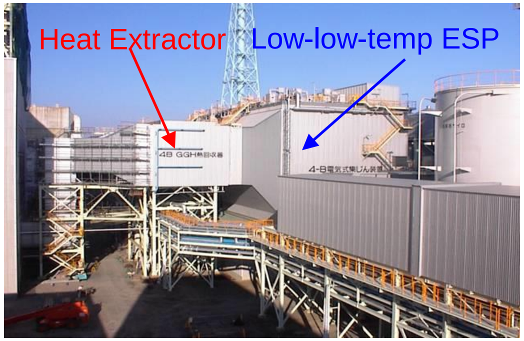
Plume Abatement

High Efficiency System (HES)

- Commercially proven technology
  - Installed & operated at ten coal-fired units in Japan since 1997
  - MHPS's proprietary heat exchanger

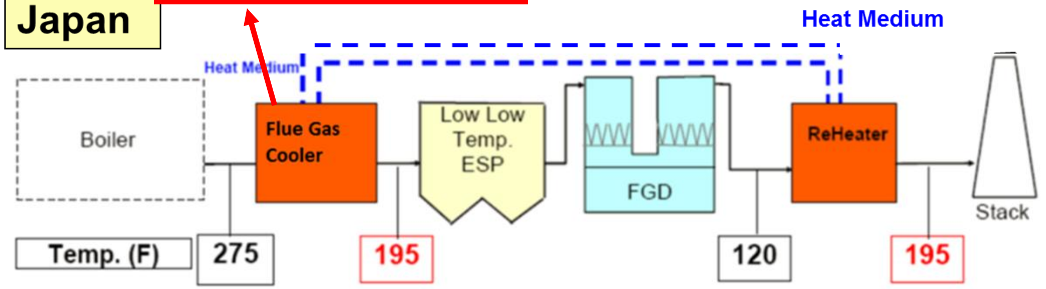
- Benefits of HES
  - Removal improvement of hazardous air toxics (PM, SO_3, Hg, Se, etc.) across the ESP
  - Reduction of makeup & cooling water
  - AQCS (ESP, FGD & CCS) cost reduction
  - Reduction of total energy penalty of CCS plant
  - Potential to simplify boiler/steam turbine cycles



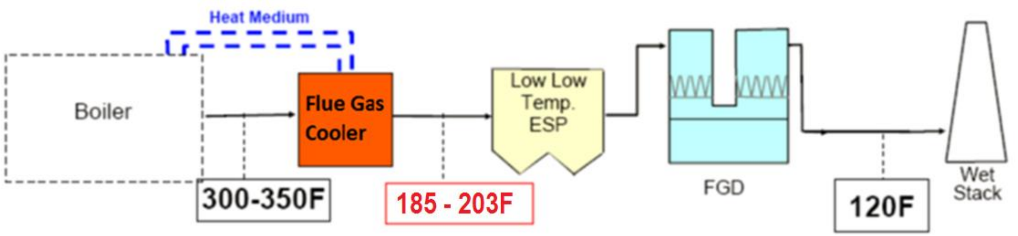


Tomato P/S Japan - 700MW

Japan

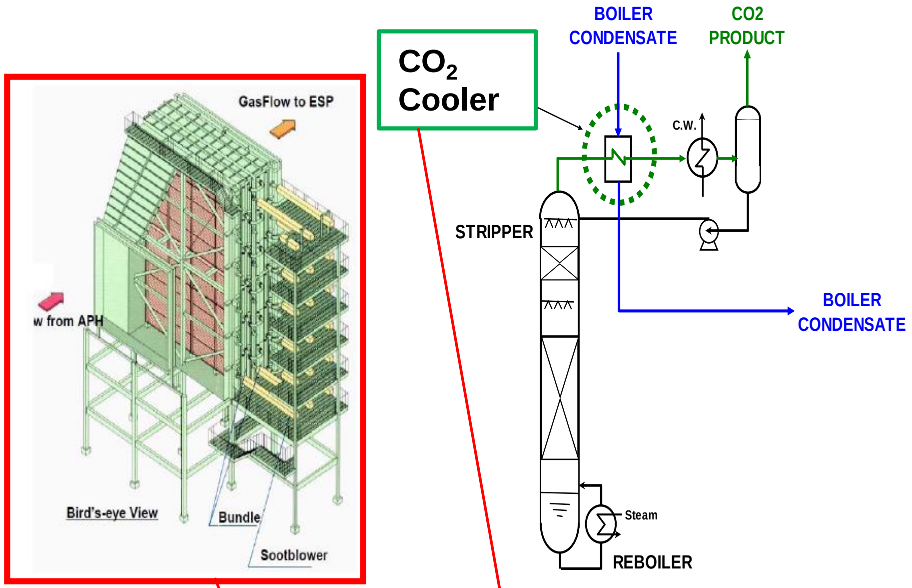


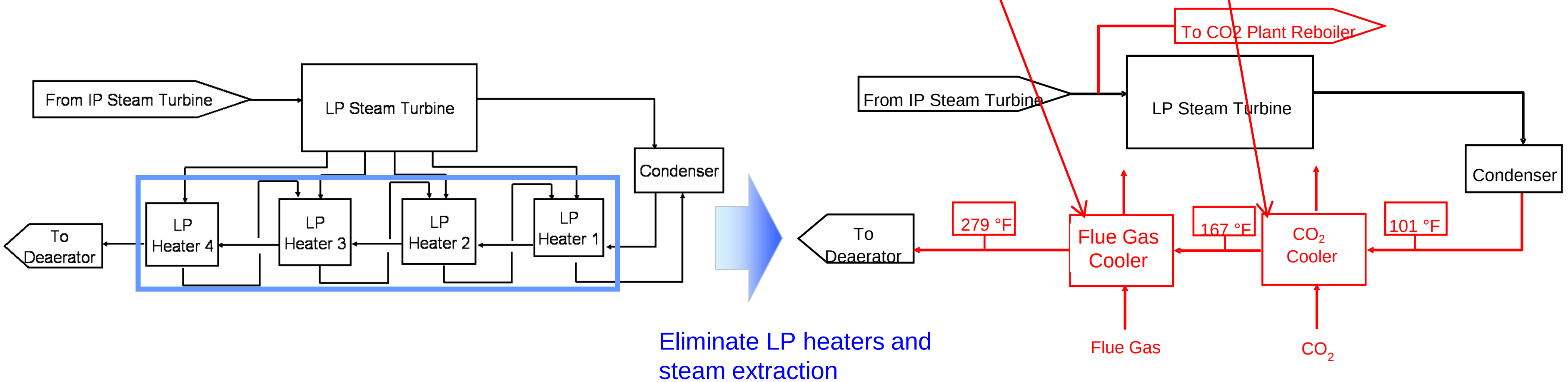
U.S. Power station



Commercial application of HES

- Heat Integration System with HES
  - HES recovers waste heat from the flue gas by incorporating a heat extractor downstream of the air heater
  - Recovered heat can be applied to the boiler feed water, thereby reducing the energy penalty of CCS plant





Application to boiler/steam turbine cycles

SO_3 Removal

Operates downstream of the APH

Mechanism for removal of SO_3 from flue gas

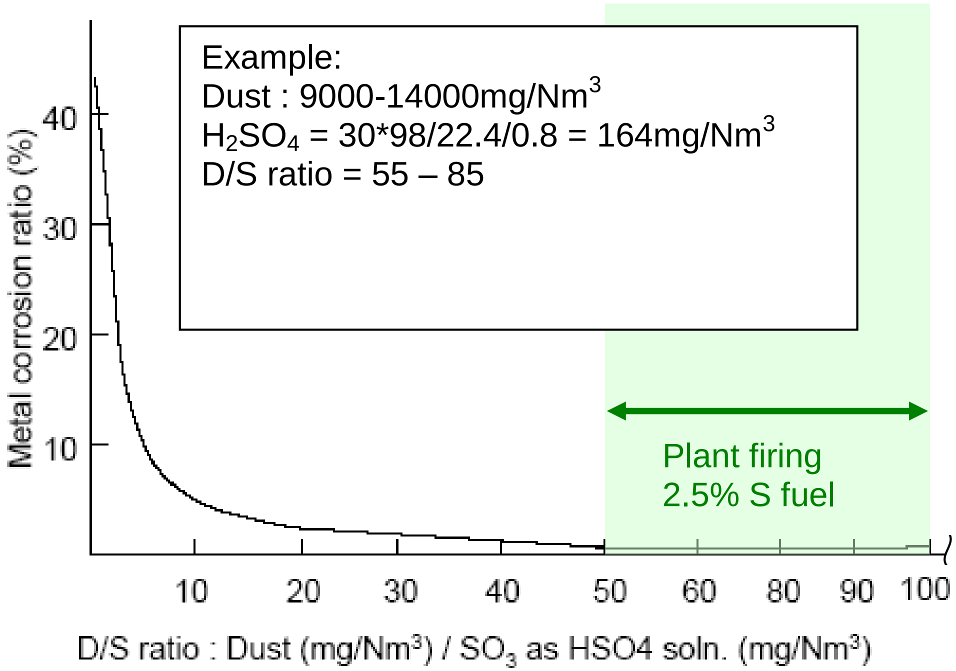
- SO_3 (g) + H_2O (g) --> H_2SO_4 (g)
- H_2SO_4 (g) --> H_2SO_4 (l)
- H_2SO_4 (l) condenses on fly ash in flue gas and a protective layer of ash on tube bundles

Flue Gas Cooler tube skin temperature < SO_3 dewpoint

- Alkaline species in fly ash (Ca, Na) neutralize H_2SO_4
- Silicates, etc. physically adsorb H_2SO_4

Corrosion Mitigation Mechanism

Carbon steel tubes in good condition after 2 years of operation in Japan.



Higher fly ash or dust loading in the flue gas can mitigate corrosion rate.

3. 25-MW Pilot Demonstration at Plant Barry

Plant Barry 25-MW CCS Demonstration Plant

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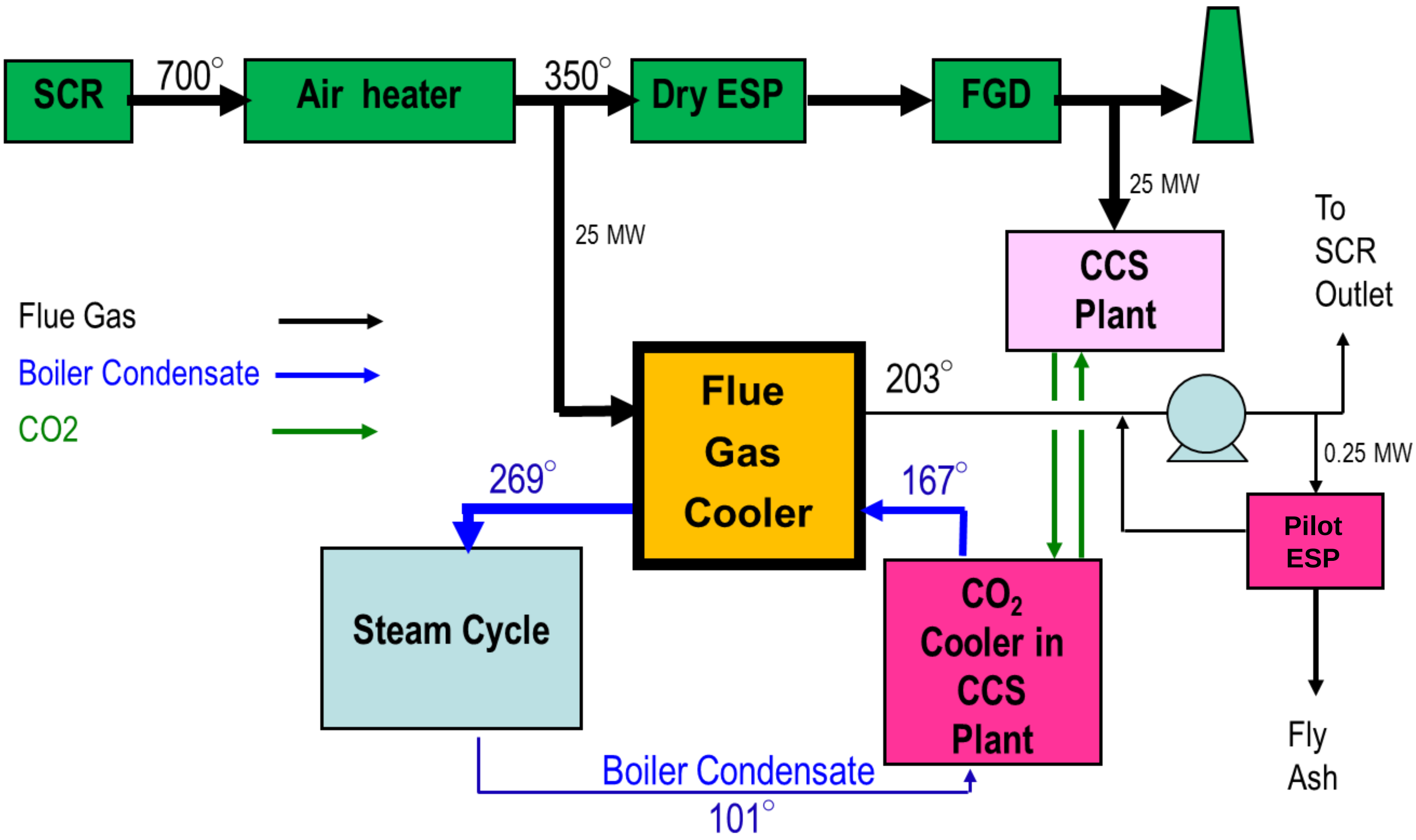
- **Funded by industry consortium**
- **Fully integrated CO_2 capture/compression**
- **Storage in Citronelle Dome**
- **Capacity: 500 metric tons CO_2/day**

Process Flow of 25-MW Pilot Demonstration Plant



Aerial View of Plant Barry Demonstration Plant

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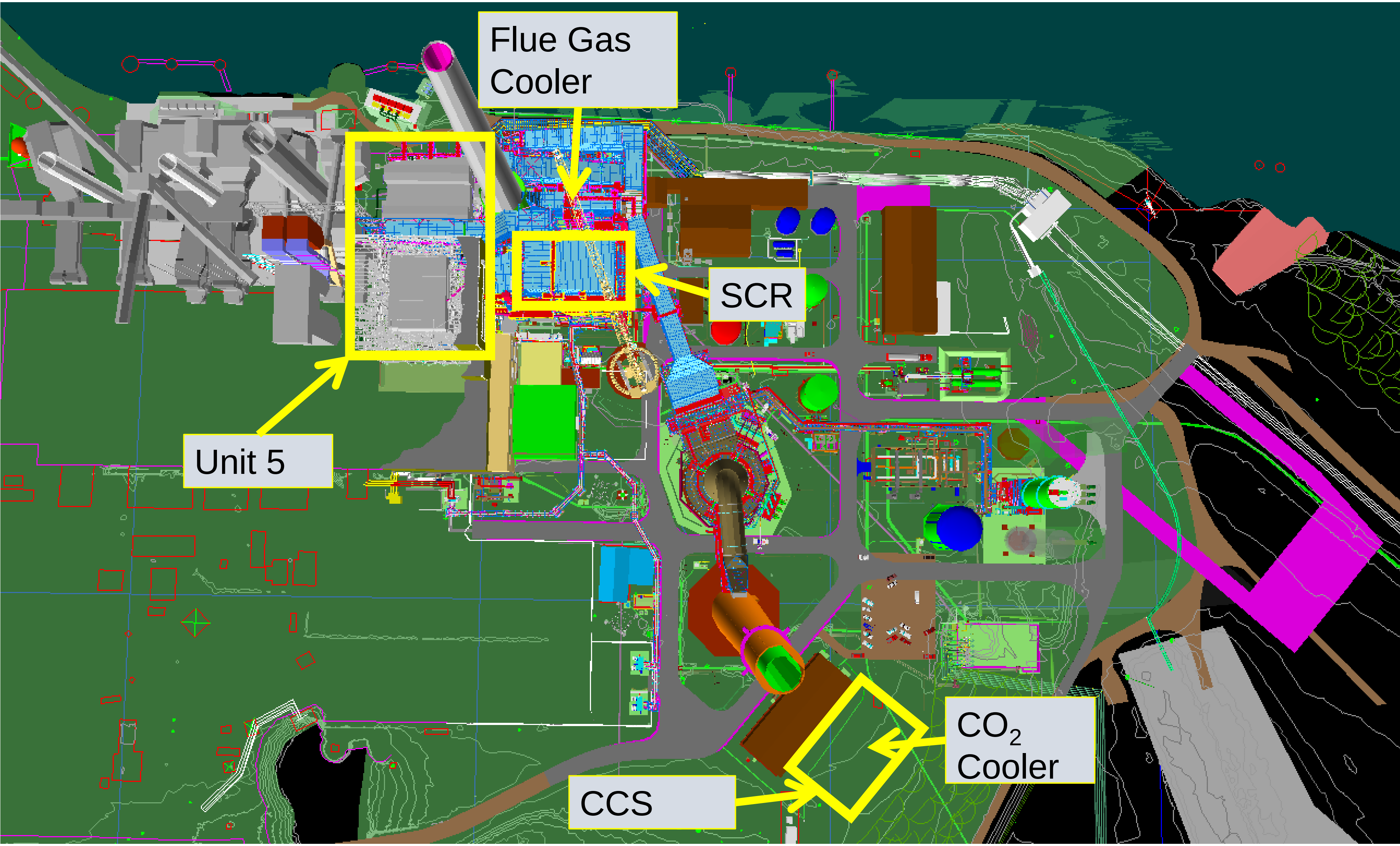
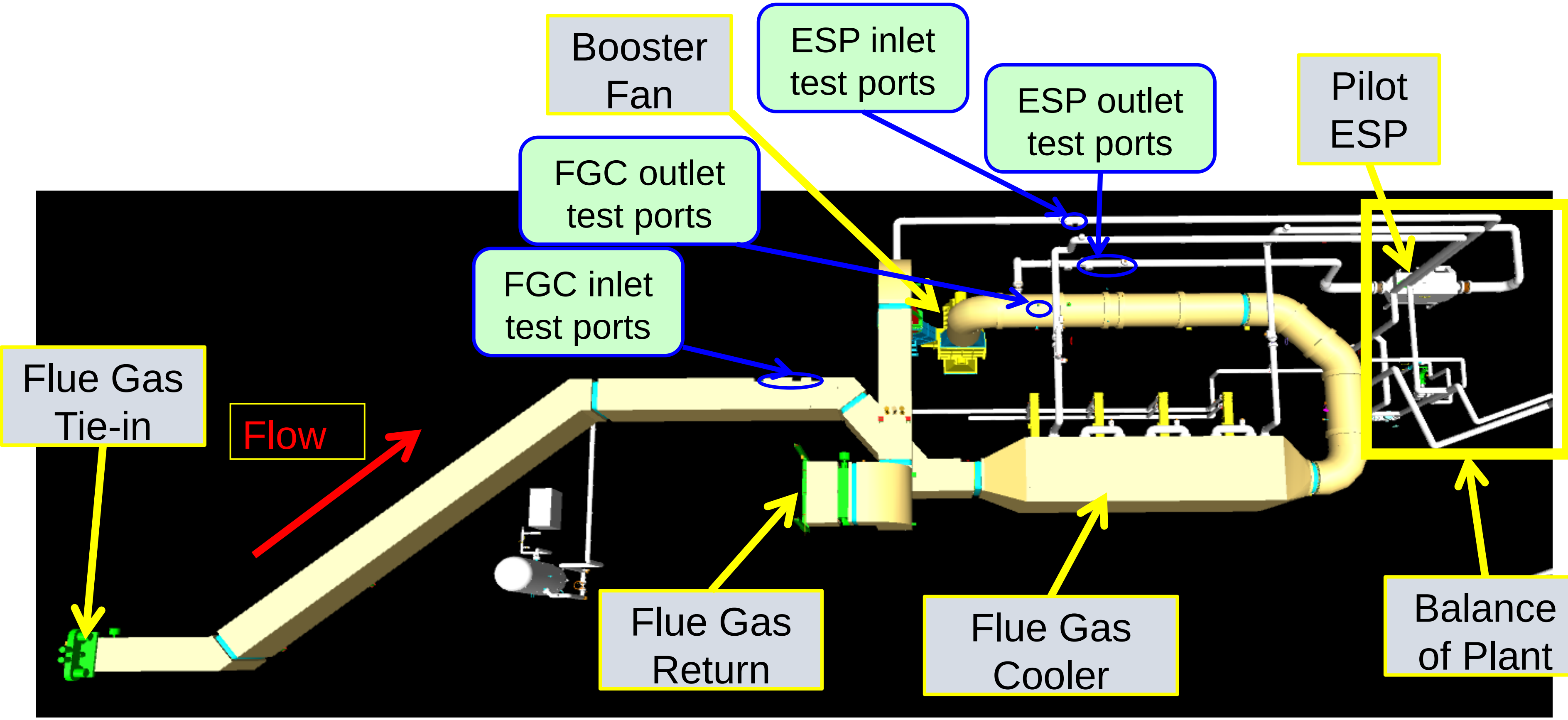


3D Model of Plant Barry Demonstration Plant



Flue Gas Cooler and CO_2 Cooler

CO_2 Cooler

Flue Gas Cooler

Flue Gas Blower and Pilot ESP

Flue Gas Blower

Pilot ESP (0.25 MW)

4. Test Results

Baseline Performance

- Confirmed heat integration performance
  – 240-300 MMBTU/hr heat recovery for 550 MW base plant (Case 9)

Source	Data collected	Units	w/o HES heat integration	w/ HES heat integration	w/ HES heat integration
			12/16/2015	9/9/2015	9/1/2015
FGC	Flue gas flow rate	scfm	49,998	60,640	60,631
	Flue gas temp FGC inlet	degF	288	323	314
	Flue gas temp FGC outlet	degF	NA	200	186
	Recovered heat	MMBtu/h	NA**	8.66	9.09
CO_2	Flue gas flow rate*	scfm	73,800	73,800	73,800
	CO_2 removal performance*	%	> 90	> 90	> 90
	BC flow rate	stph	0	38	50
	BC temp CO_2 cooler inlet	degF	NA	128	123
	BC temp CO_2 cooler outlet	degF	NA	167	167
	Recovered heat	MMBtu/h	NA	2.9	4.4
Plant	Boiler Load net	MW	721	783	680
	BC flow rate	stph	0	38	50
	BC feed temp	degF	NA	128	123
	BC return temp	degF	NA	280	264
	Recovered heat	MMBtu/h	NA	11.1	13.6
	Recovered heat for 550 MW base plant	MMBtu/h	NA	244	300

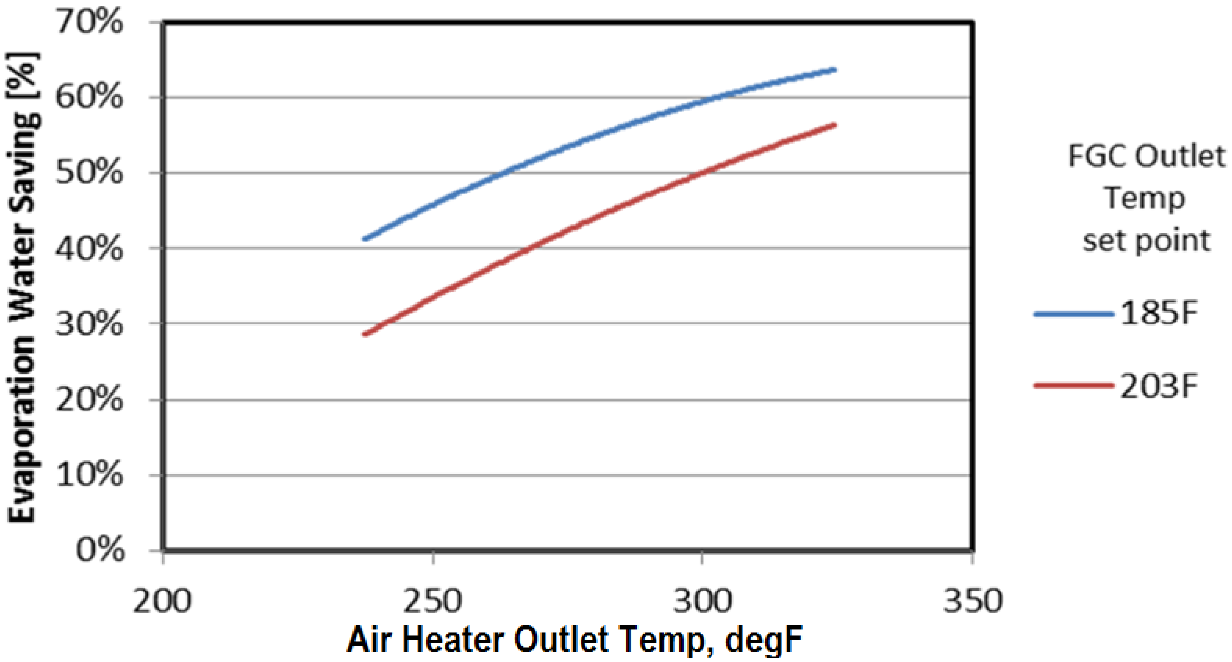
Evaluation Results of Heat Integration

- Calculated heat integration benefit by Aspen model
  - 18.3 MW was gained from the DOE Case 10 plant (subcritical PC EGU with CCS)
  - 0.9% of plant efficiency was increased

	Original Case 10 Value	Gain or Loss (-) Due to HES
Total LP feedwater heater and deaerator steam extraction	421,000 lb/hr	-366,000 lb/hr
Turbine generation	673 MW	18.7 MW
Cooling fan and water pumps power consumption increase	-	1.6 MW
Induced draft fan power consumption	12.1 MW	-1.3 MW
Total Power Gain	-	18.3 MW
Plant Thermal Efficiency	26.2%	0.9% points

Water Consumption Reduction

- By cooling the flue gas, FGD makeup water can be reduced
- Percentage of water saved was calculated, not measured
- Up to 65% of the FGD makeup water can be saved
  - 502 gpm for a 550-MW plant
- 50-60% reduction of cooling water use in the CCS system
  - 45,000 gpm for a 550 MW plant



Impurities Removal Test

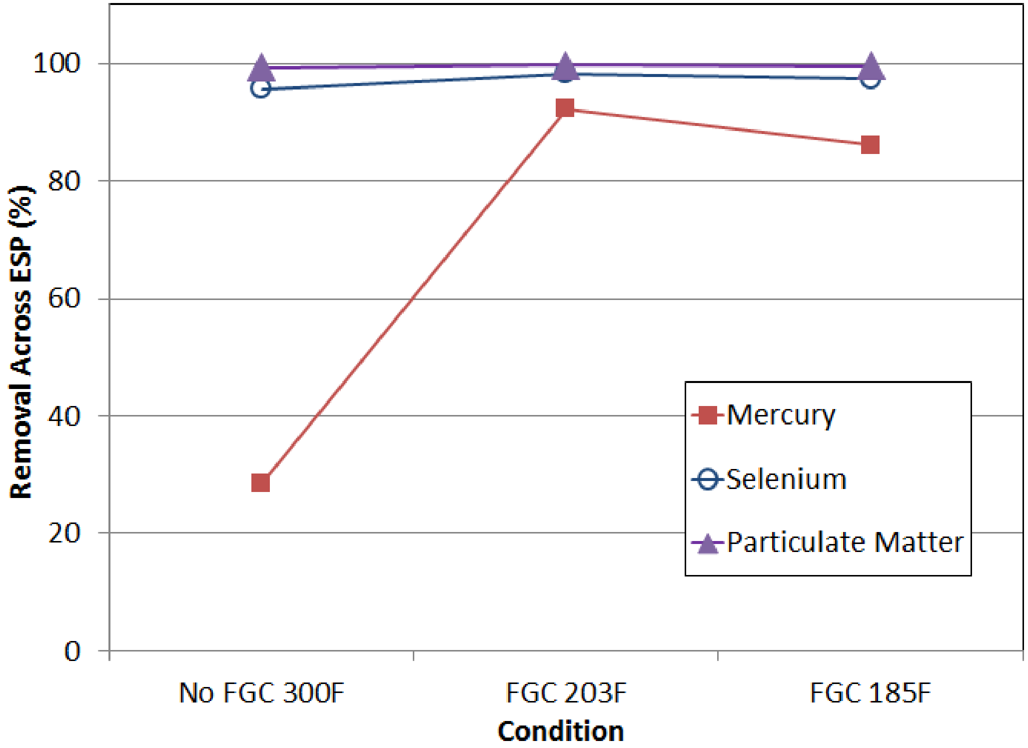
- Test Conditions
  - No FGC 300F: No water flowed through the FGC, the flue gas was not cooled
  - FGC 203F + SO_3: The flue gas was cooled to 203F and SO_3 was injected
  - FGC 203F: The flue gas at the FGC outlet was cooled to 203F
  - FGC 185F: The flue gas was further cooled down to 185F

- Test Methods and Locations

Location	Analyte(s)
FGC Inlet	Particulate Matter, Metals (total and gas-phase), SO_2, SO_3
FGC Outlet	Flowrate only
ESP Inlet	Particulate Matter only
ESP Outlet	Particulate Matter, Metals (total and gas-phase), SO_2, SO_3

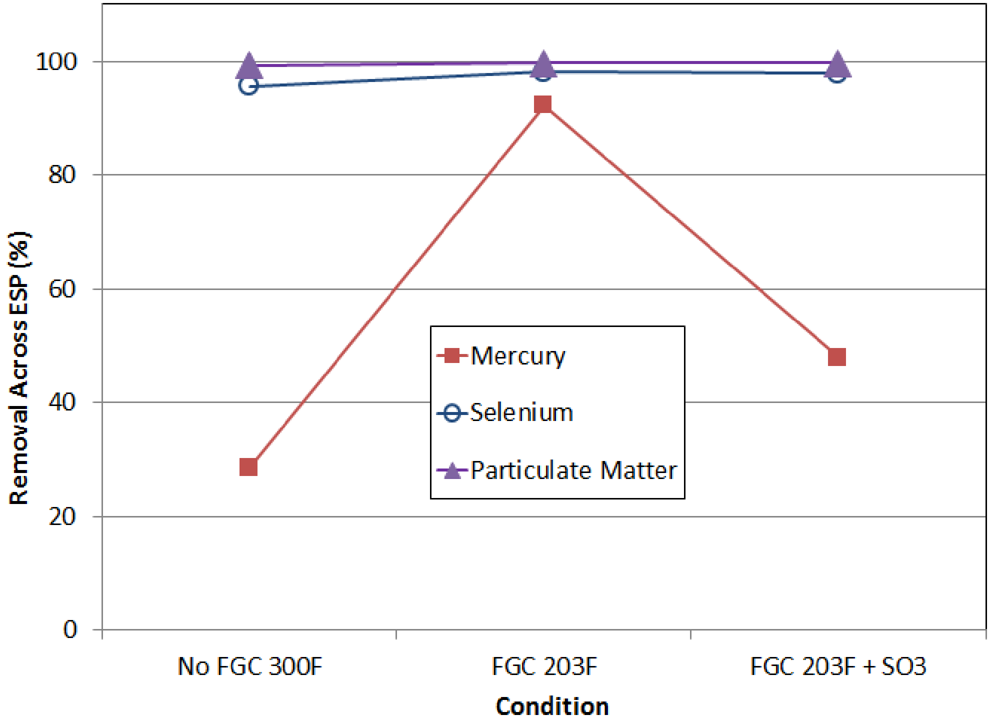
Impurities Removal Test Results – Temp Effect

- Impurities removal is enhanced by the Flue Gas Cooler operation due to operation of the FGC:
  - Native mercury removal by fly ash increased significantly from 28 to >86% due to the Flue Gas Cooler
  - Selenium removal increased from 96 to 98%
  - No discernable effect due to temperature decrease from 203 to 185°F on either metal or particulate matter
  - SO_3 removal not calculated due to low concentrations



Impurities Removal Test Results – SO_3 Effect

- SO_3 injection inhibits Mercury capture, no effect on Selenium or Particulate Matter due to SO_3 injection:
  - Mercury removal decreased from >92 to 40%
  - Mercury removal still higher during SO_3 injection than without FGC operation
  - Selenium removal unchanged
  - Particulate matter removal unchanged
  - SO_3 removal not calculated due to low concentrations



Impurities Removal Test Results – Summary

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- Confirmed Impurities Removal performance
  - PM removal: > 99.5%
  - SO_3 removal: less than 0.05 ppm at ESP outlet
  - Hg removal: > 86% w/o SO_3 injection, ~40% w/ SO_3 injection
  - Se removal: > 98%

Condition, Day	Run Number, Day	SO_3 con. at ESP outlet	Percent Removal Across FGC/ESP		
		ppmd at 3% O_2	PM	Hg	Se
NO FGC 300F	R3-0 (12/15-16, 2015)	0.03	99.3%	28%	96%
FGC 203F+ SO_3	R3-2 (12/18-19, 2015)	0.04	99.7%*	40%	98%
FGC 203F	R3-1-1 (09/23-24, 2015)	0.04	99.7%*	>92%	98%
FGC 185F	R3-1-2 (09/25-26, 2015)	0.02	99.6%	86%	98%

* Calculated from the estimated inlet concentrations

Long-Term Durability Test Results (913 hours)

- Flue Gas Cooler internal surfaces were visually inspected before, during and after operation
- No mechanical damage to tubes found via visual inspection (see pictures below)
- No damage to soot blowers found via visual inspection
- No ash deposition or accumulation on tube walls

(a) Before operation

(b) October, 2015

(c) January, 2016*

*The remaining fly ash can be easily removed by soot-blowers.

Material Evaluation Test Results

- The sample with the most uniform corrosion provided a rate of 40 mils/year which has never seen in commercial plants
- Flue gas was not purged from the duct after operation like would be done in a full-scale plant

Tested Tube Samples

5. Techno-Economic Analysis Results

TEA Cases

- **Case 9**
  - DOE/NETL case for a 550-MW subcritical coal EGU without CCS, burning bituminous coal;
- **Case 10**
  - DOE/NETL case for a 550-MW subcritical bituminous coal EGU using the monoethanolamine (MEA) solvent, Econamine, CCS system
- **Case 10b**
  - 550-MW subcritical bituminous coal EGU using the KM CDR Process for the CCS system, also has SO_3 control
- **Case 10c**
  - 550-MW subcritical bituminous coal EGU using the KM CDR Process for the CCS system, also has SO_3 control and High Efficiency System

Summary of TEA Results

Case		9	10	10b	10c
Plant Configuration		Subcritical PC w/out CCS	Subcritical PC w MEA CCS	Subcritical PC w KM CDR® CCS	Subcritical PC w KM CDR® CCS w heat integration
Avoided Cost	$/ton		70.6	58.5	51.4
Total Overnight Cost	MM$	1,098	1,985	1,800	1,741
Cost of Electricity	mils/kWh	59.4	109.6	101.5	96.5
Percent Increase in COE from Case 9		-	98%	71%	62%
Percent Decrease in COE from Case 10		-	-	13.7%	18.0%

6. Summary

Summary – Energy Improvements

- Quantify energy efficiency improvements
  - Unit heat rate improvement
  - Flue gas pressure drop

- Use of the HES can increase the generation of a 550-MW plant with CCS by 18.3 MW.
- Thermal efficiency can be increased by 0.9 percentage points (i.e. from 26.2 to 27.1%), alternately heat rate could decrease from 13,050 to 12,630 Btu/kWh.
- Pressure drop across the Flue Gas Cooler was measured to be 2-4 inWc.

Summary – Integration Challenges

Identify and/or resolve integration problems

- Effect on water quality
- Corrosion, erosion, or plugging
- Issues with high-sulfur flue gas

- Boiler condensate water quality was found to be unaffected by the HES.
- Corrosion was found on the Flue Gas Cooler tubes. Corrosion may have been increased due to the lack of a flue gas purge.
- No plugging was found in the Flue Gas Cooler.
- Little to no SO_3 was measured in the flue gas, even during injection of SO_3.

Summary – Ancillary Benefits

- Quantify ancillary benefits
  - Better ESP performance
  - Increased SO_3, Hg, Se capture
  - Reduced water consumption and use

Via the reduced flue gas temperature:

- ESP outlet flue gas particulate matter concentration decreased by 36%,
- ESP outlet flue gas mercury concentration decreased by 80%,
- ESP outlet flue gas selenium concentration decreased by 33-56%,
- Up to 65% of FGD makeup water can be saved, and
- 50-60% of CCS cooling water can be saved.

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