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

DE-FE0007525

Project Closeout Meeting

May 23, 2017

SOUTHERN COMPANY

Project Participants

Southern Company

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Project Objectives and Overview

Team-Member Roles

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

In this project, advanced heat integration was demonstrated on a coal EGU

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.

Project objectives were chosen to quantify effects of heat integration on the coal EGU

SOUTHERN COMPANY

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

Heat integration system transfers heat into boiler using two heat exchangers

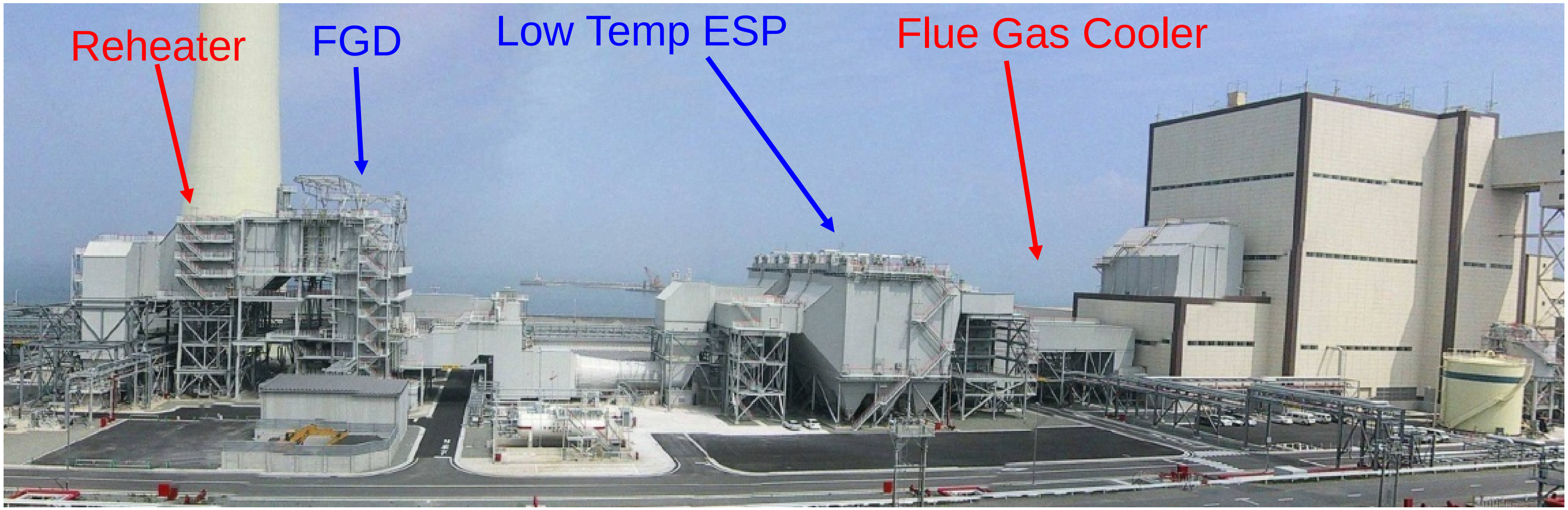
Together, the two heat exchangers and associated balance of plant are known as the High Efficiency System (HES):

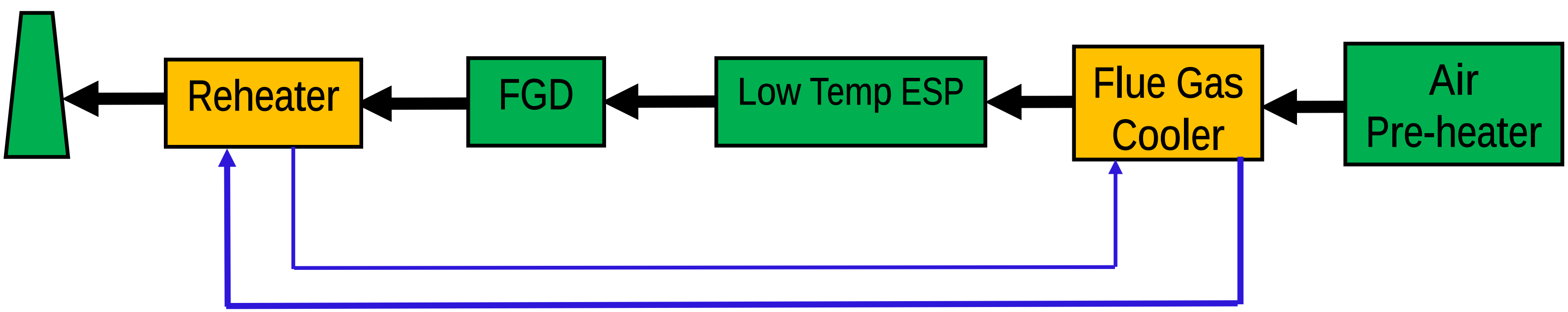
- CO$_2$ Cooler: Recovers heat from the outlet of the stripper in the CO$_2$ capture facility.
- Flue Gas Cooler: Recovers heat from the coal EGU flue gas downstream of the plant air heater.

A standard heat exchanger can be used for the CO$_2$ Cooler but the Flue Gas Cooler is based on a heat exchanger used to recover heat from flue gas in Japan.

The Flue Gas Cooler is based on a similar process used in Japan

Hirono P/S Japan - 600MW



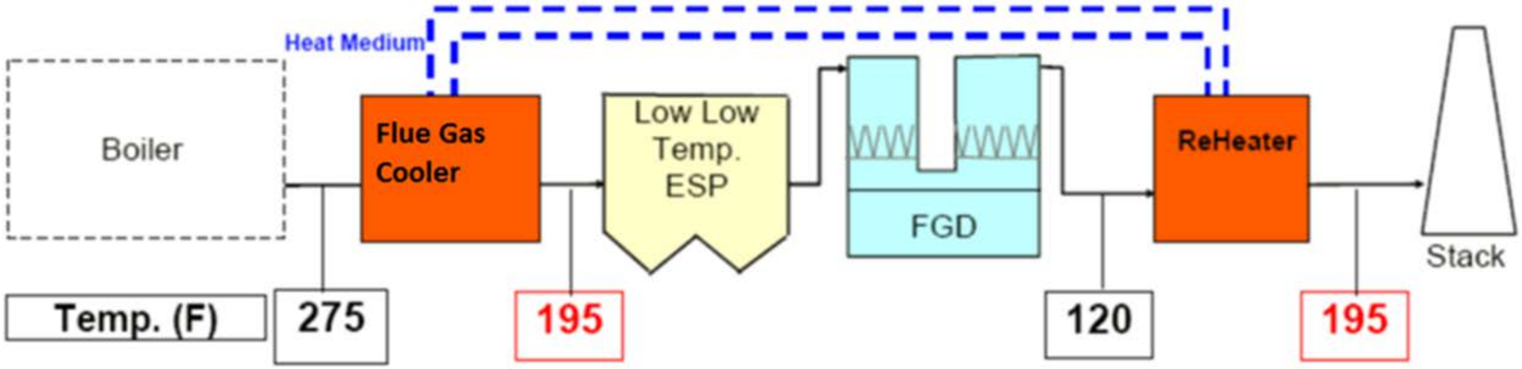


Water Loop

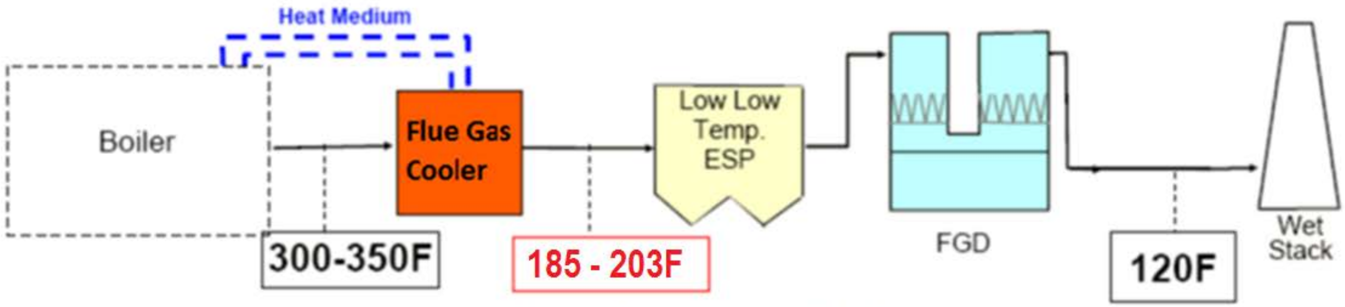
Flue Gas

Plume Abatement

Here, plume abatement may not be desirable; the heat can instead be used to improve heat rate



(a) Application for Europe and Japan



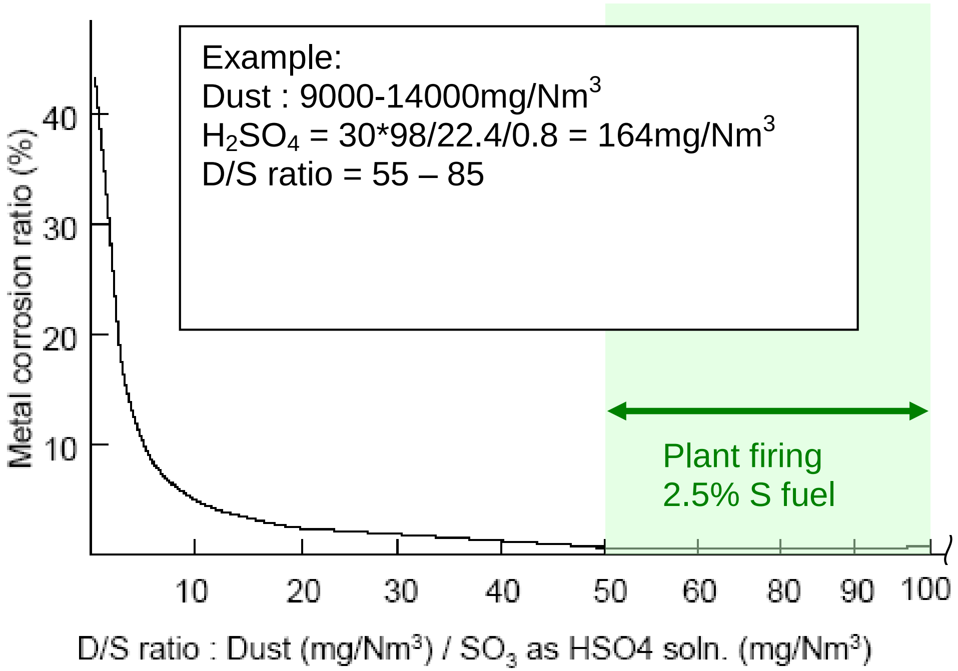
(b)Application for the U.S.

Flue Gas Cooler condenses SO_3 onto the fly ash

- 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 in the Flue Gas Cooler can be mitigated by fly ash in the flue gas

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

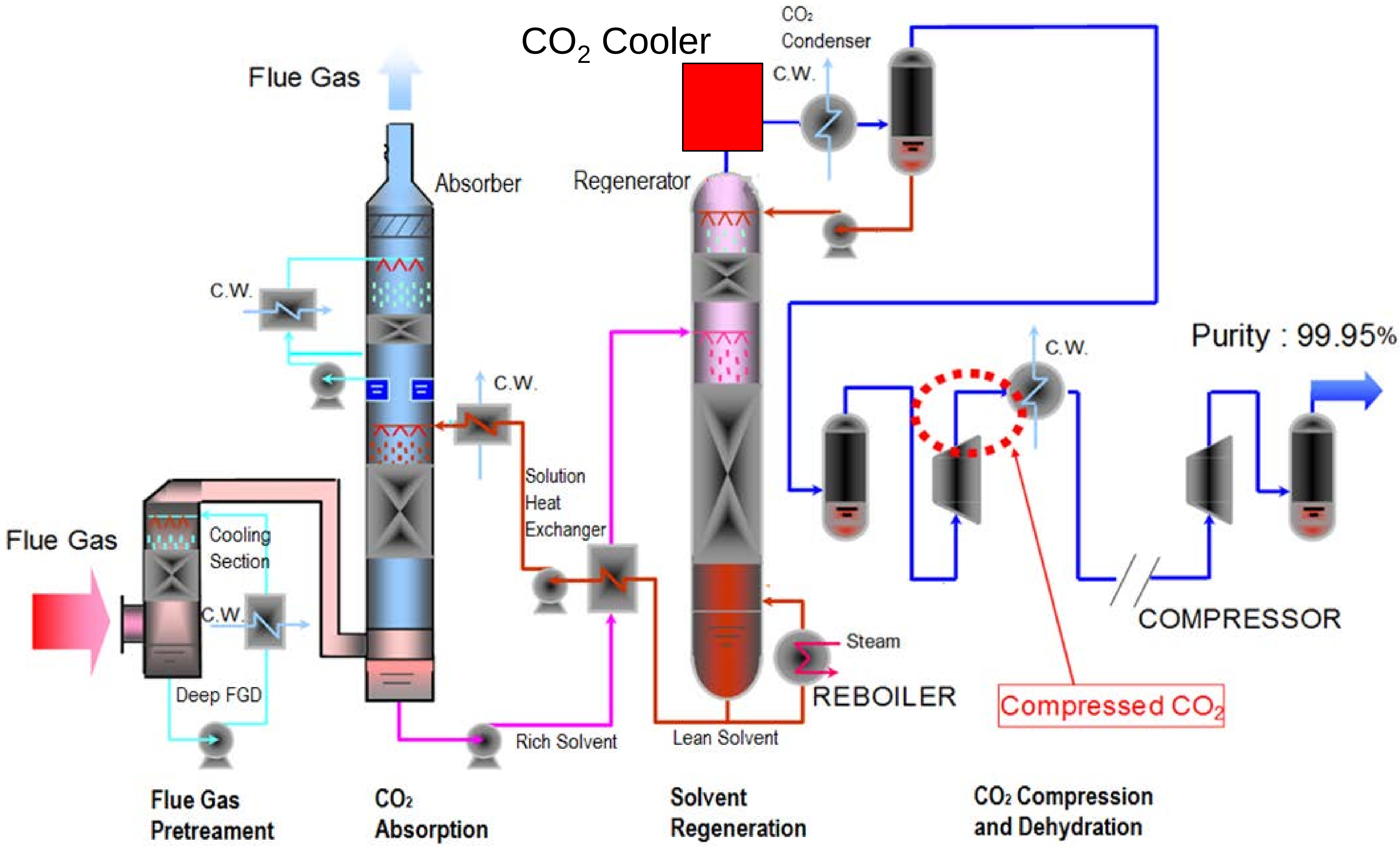


Ratio of fly ash or dust in the flue gas can be used to determine corrosion rate.

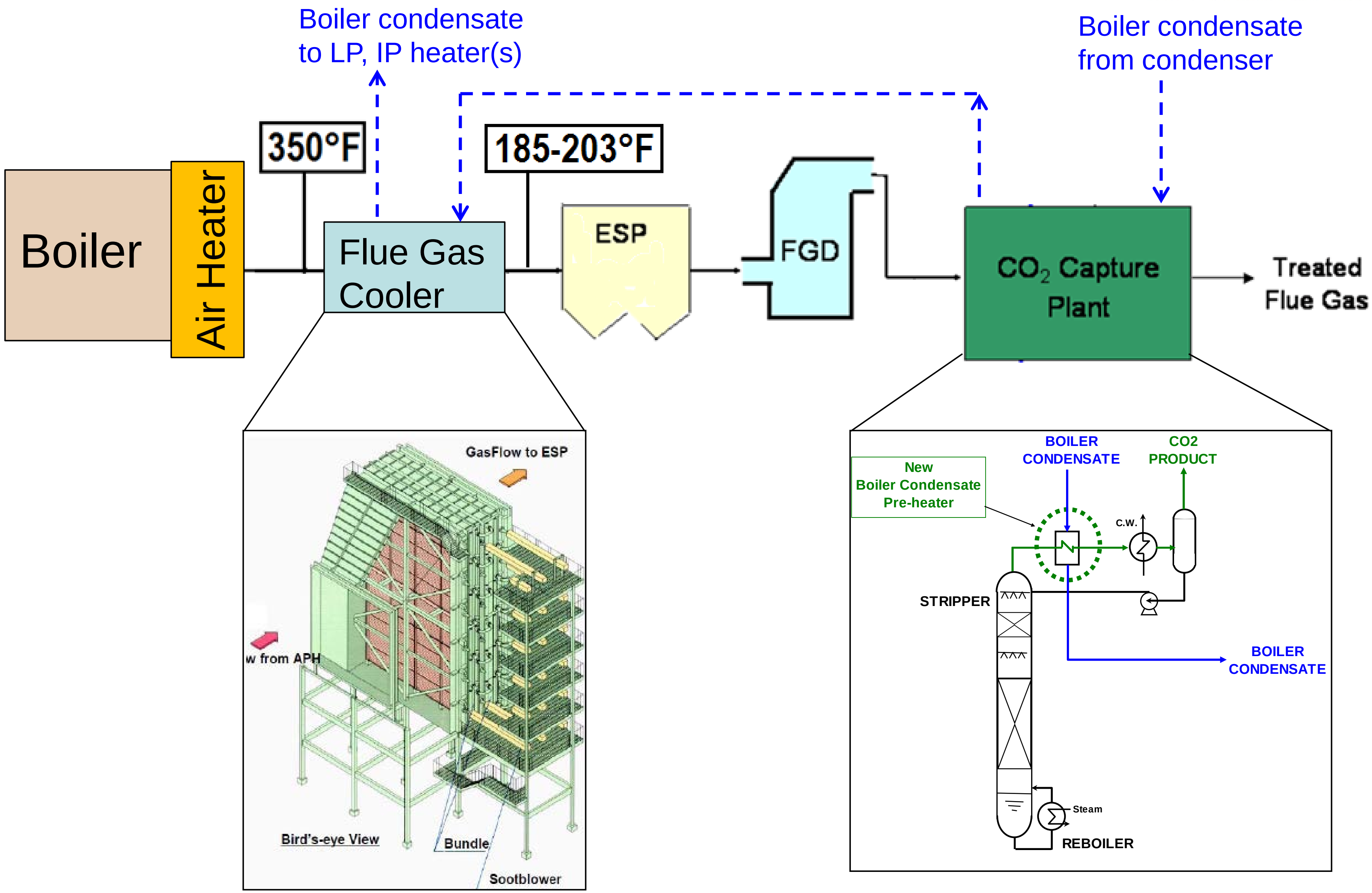
The Flue Gas Cooler can also provide environmental benefits including:

- Reduced water consumption in the FGD and cooling water use in the CCS facility due to reduction in gas temperature;
- Better SO_3 capture through condensation of the SO_3 on the fly ash;
- Better particulate control device performance through both reduced gas volume and lower ash resistivity due to reduced temperature and moisture adsorption to fly ash; and
- Increased capture of Hazardous Air Pollutants (mercury, other toxic metals, etc.) due to reduced flue gas temperatures and SO_3 concentrations as well as improved particulate capture performance.

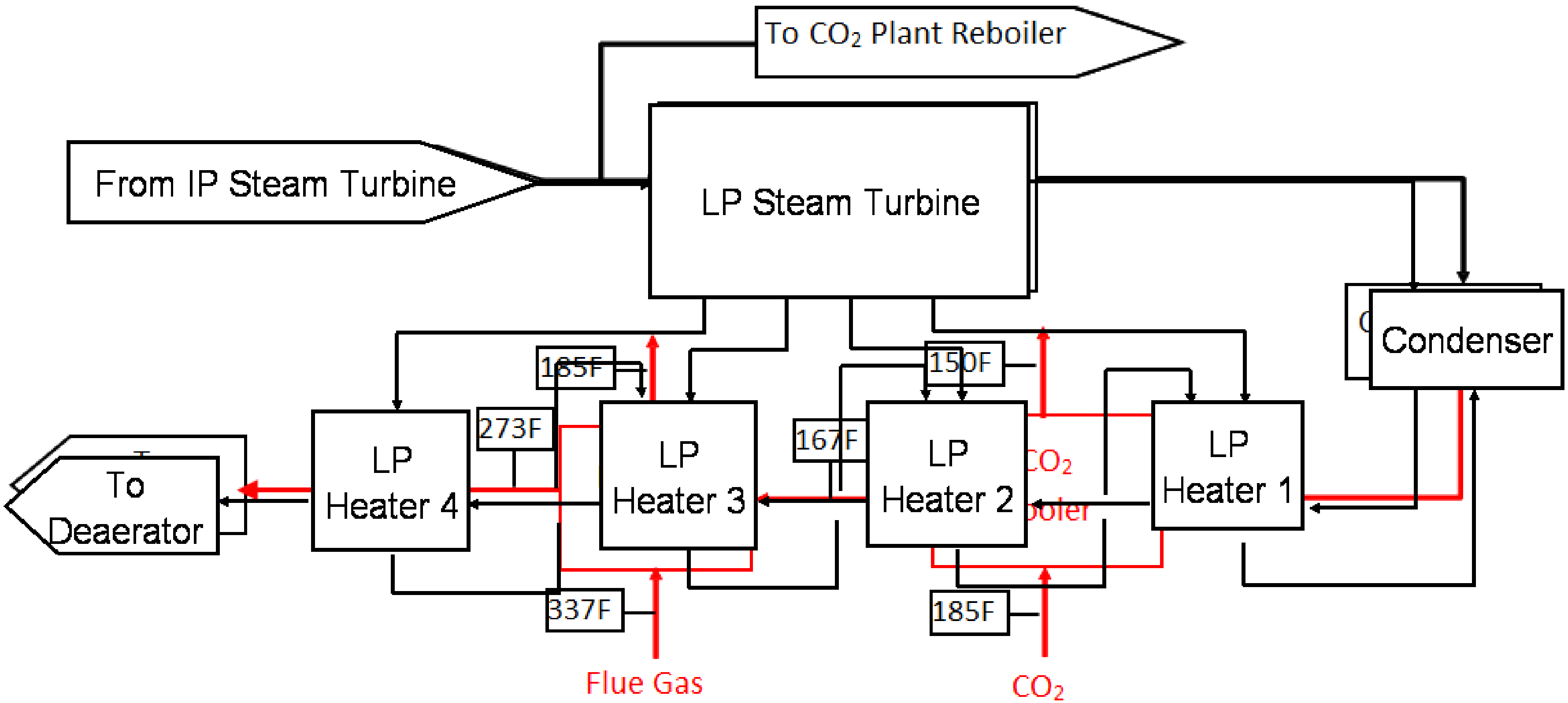
In the HES, heat is also recovered from the CO_2 capture system



In the HES, boiler condensate is first heated in the CO_2 Cooler and then the Flue Gas Cooler



Heat integration can eliminate the need for low pressure heaters



A pilot HES was tested to quantify benefits, drawbacks, or obstacles

- Pilot included a CO_2 capture system to provide heat for the CO_2 Cooler
- Pilot used a slipstream of plant flue gas to provide heat for the Flue Gas Cooler
- Various measurements were taken in the flue gas and boiler condensate around each heat exchanger
- Pilot integrated balance of plant and control equipment with the host site

Pilot Unit at Plant Barry

To demonstrate the HES, a 25-MW pilot was built at Plant Barry

BP1
- FEED and Target Cost Estimate
- Permitting

BP2
- Engineering, Procurement, Construction

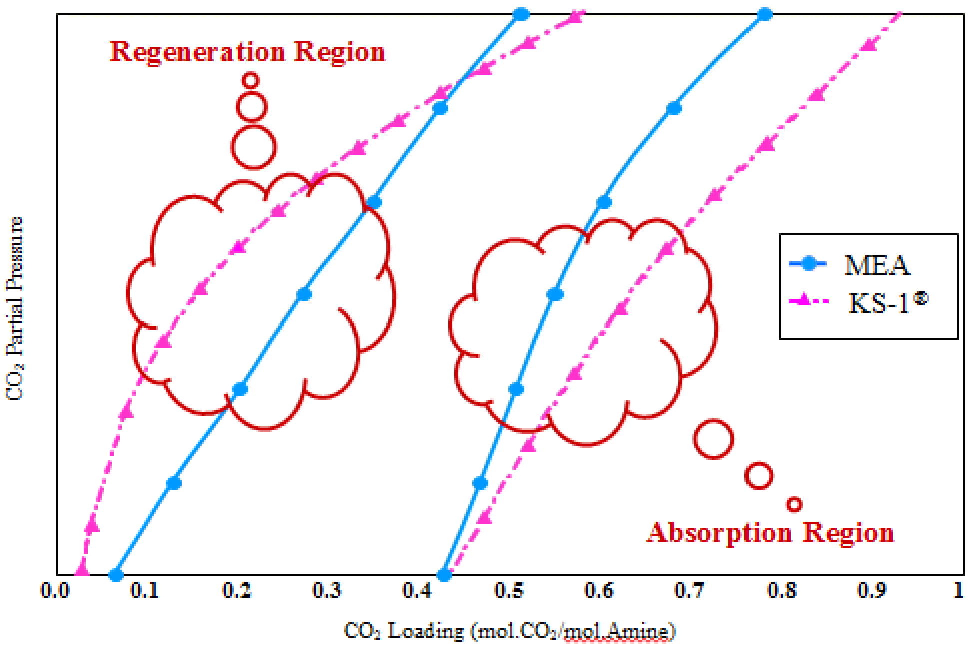
BP3
- Operations
- Field Testing Analysis

Plant Barry was chosen for the 25-MW CCS plant already in place

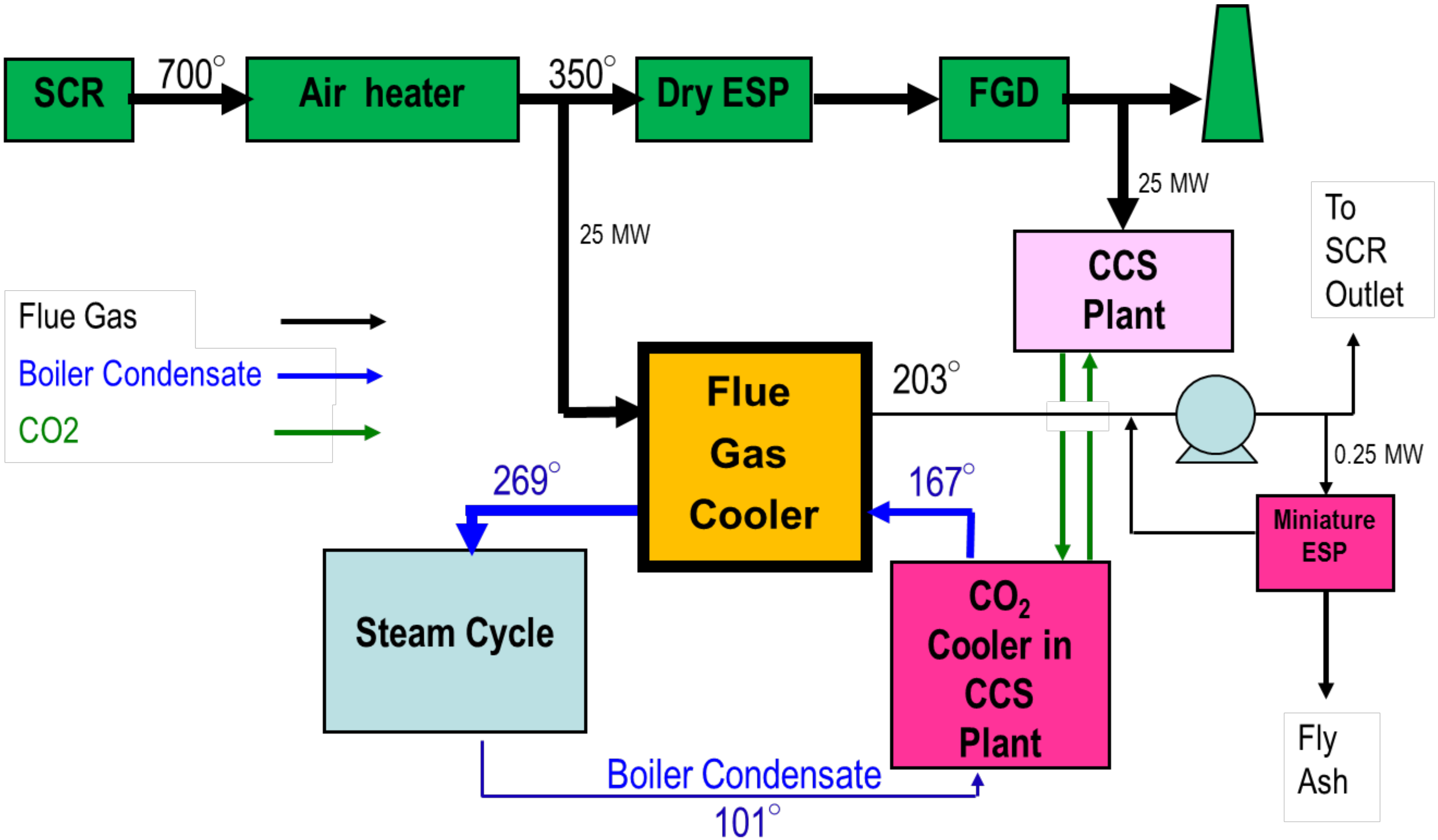
- **Funded by industry consortium**
- **Fully integrated CO_2 capture/compression**
- **Storage in Citronelle Dome**
- **Capacity: 500 metric tons CO_2/day**

CCS plant at Barry uses Kansai Mitsubishi Carbon Dioxide Recovery Process (KM CDR)®

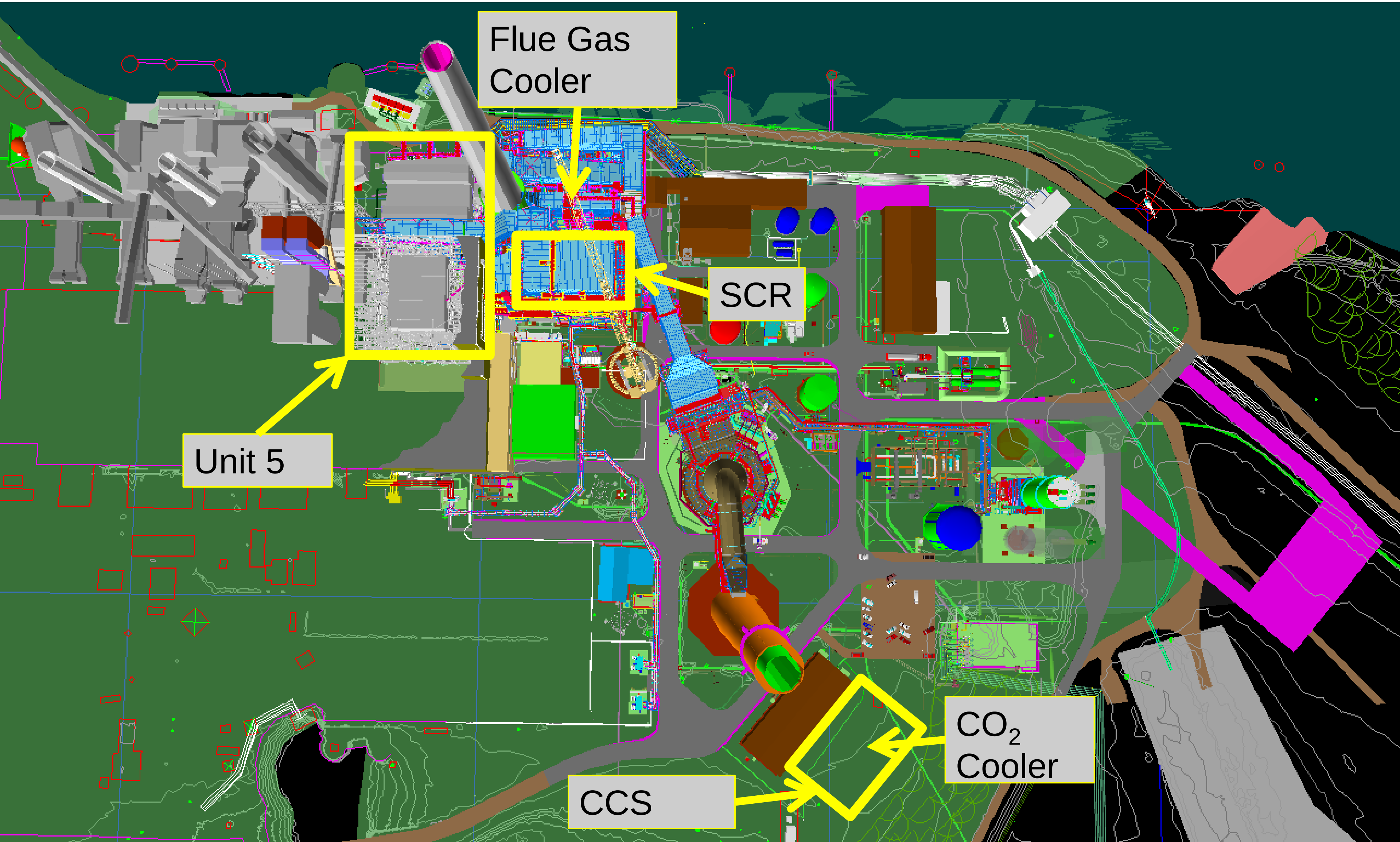
- KM CDR uses a proprietary solvent, KS-1, as the absorbent media for CO_2
- Dominant reaction of KS-1 requires a lower molar ratio than that of MEA
- KS-1 has been shown to degrade (via formation of heat stable salts) more slowly than MEA
- KS-1 is more efficient at adsorbing and desorbing CO_2



The CO_2 and Flue Gas Coolers were integrated as shown; a mini-ESP was also included



The CO_2 Cooler was located near the CCS plant; The FGC was located downstream of the air heater



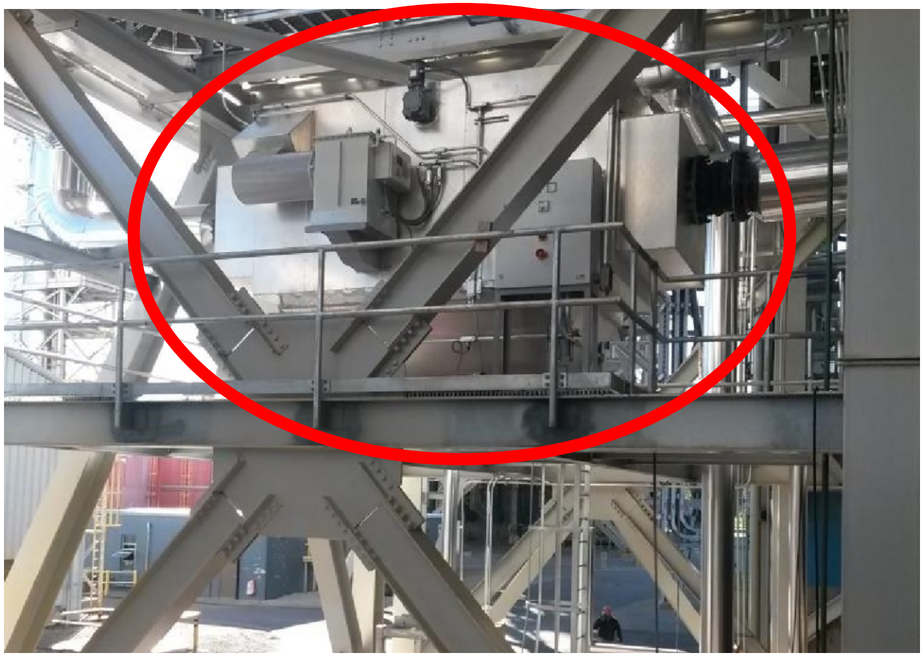
Both the Flue Gas Cooler and CO_2 Cooler were sized for a 25-MW coal EGU

CO_2 Cooler

Flue Gas Cooler

A blower was used to pull the slipstream of flue gas through the Flue Gas Cooler and ESP

Flue Gas Blower



Pilot ESP (0.25 MW)

Several deviations from the intended design and operation occurred but are believed to be minor

- Initially the team proposed heating CCS process condensate as well as boiler condensate; a techno-economic study found this to not be advantageous
- In the CO_2 Cooler, steam, rather than product CO_2 was often used to heat the boiler condensate due to scheduling conflicts with operating the CCS plant
- A condition to test the effect of $CaBr_2$ injection on the Flue Gas Cooler was initially planned but not carried out.
- Only 900 hours of operation were achieved due to scheduling conflicts with the host unit and issues with the flue gas blower

Erosion of the flue gas blower caused significant delays and limited runtime

- Fly ash caused erosion of critical components of the flue gas blower.
- This equipment was only necessary for the pilot to pull the slipstream of flue gas through the Flue Gas Cooler; it would not be used in a full-scale HES.
- Erosion was stopped by applying a thick coating; however, the coating began to chip off due to thermal expansion/contraction of the coated elements.

Test Program and Results

The test program was organized into five tests to satisfy the project objectives

Performance Test - Evaluate the CO_2 Cooler and Flue Gas Cooler performances and verify controllability of the temperature control valves.

Turndown Load Operation Test - Evaluate the Flue Gas Cooler performance under reduced flue gas flow conditions.

Impurities Removal Test - Evaluate the effect of cooling the flue gas via the Flue Gas Cooler on the pilot ESP performance for particulate matter, sulfur oxides, and trace metals.

Long-Term Durability Test - Evaluate the system data and physical condition of the Flue Gas Cooler, such as vibration and mechanical damage

Material Evaluation Test – Evaluate any corrosion, erosion or boiler condensate leakage in the Flue Gas Cooler.

Performance Test

Purpose: Evaluate the CO_2 Cooler and Flue Gas Cooler performances and verify controllability of the temperature control valves.

Items evaluated:

- Heat recovery performance of CO_2 Cooler and Flue Gas Cooler and effect on plant generation (via modeling)
- Flue gas pressure drop across the Flue Gas Cooler
- Water consumption reduction for the existing FGD system and cooling water use reduction in the CO_2 capture system via calculations

Several heat recovery modes were investigated in the Performance Test

Recovered heat was calculated by measuring the boiler condensate temperatures at the inlet and outlet of the CO_2 Cooler and Flue Gas Cooler.

Test Condition	R1-1	R1-2	R1-3	R1-4	R1-5
CO2 Cooler heat recovery mode	Normal	Normal	Increased	Increased	Reduced
Flue Gas Cooler heat recovery mode	Normal	Increased	Normal	Increased	Normal
Flue gas flowrate scfm	60,000	60,000	60,000	60,000	60,000
Flue Gas Cooler flue gas outlet temperature set point	203F	185F	203F	185F	203F
Flue Gas Cooler heat transfer coefficient (Btu/ft^2hrF)	2.7	4.3	2.4	3.9	2.1
Total Heat Recovered (MMBtu/hr)	11.5	13.6	11.1	13.5	10.1
Percentage recovered by the CO_2 Cooler	42%	32%	54%	44%	32%
Total heat recovered for a 550-MW coal EGU (MMBtu/hr)	253	300	244	297	222

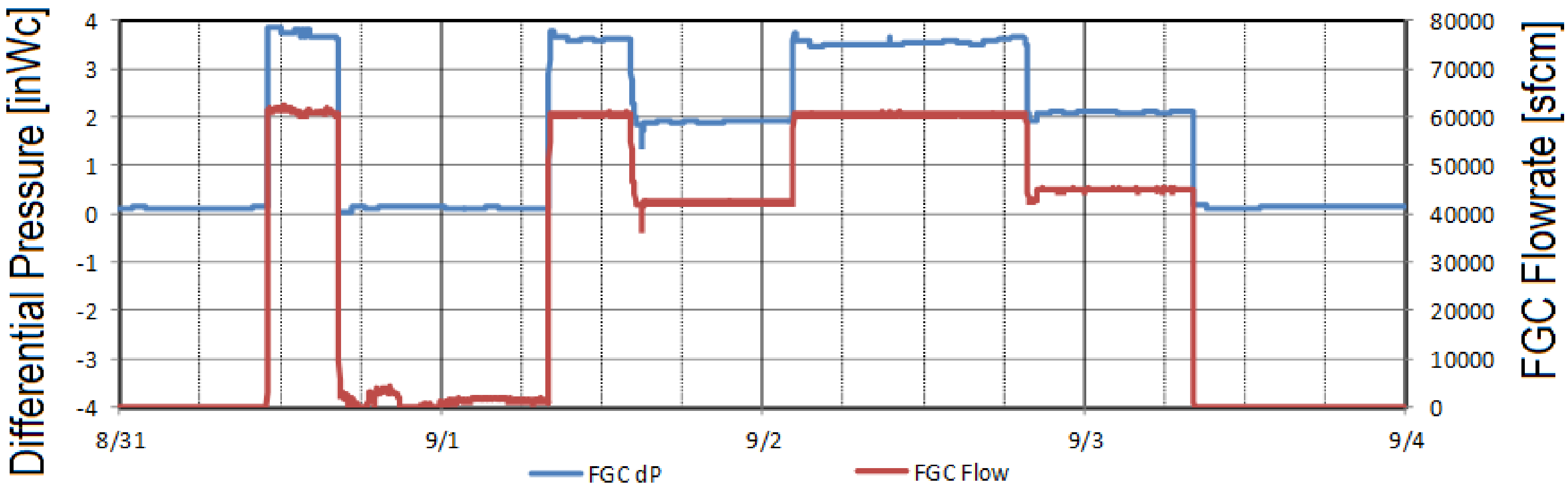
Aspen Plus® was used to model the effect of the recovered heat on generation

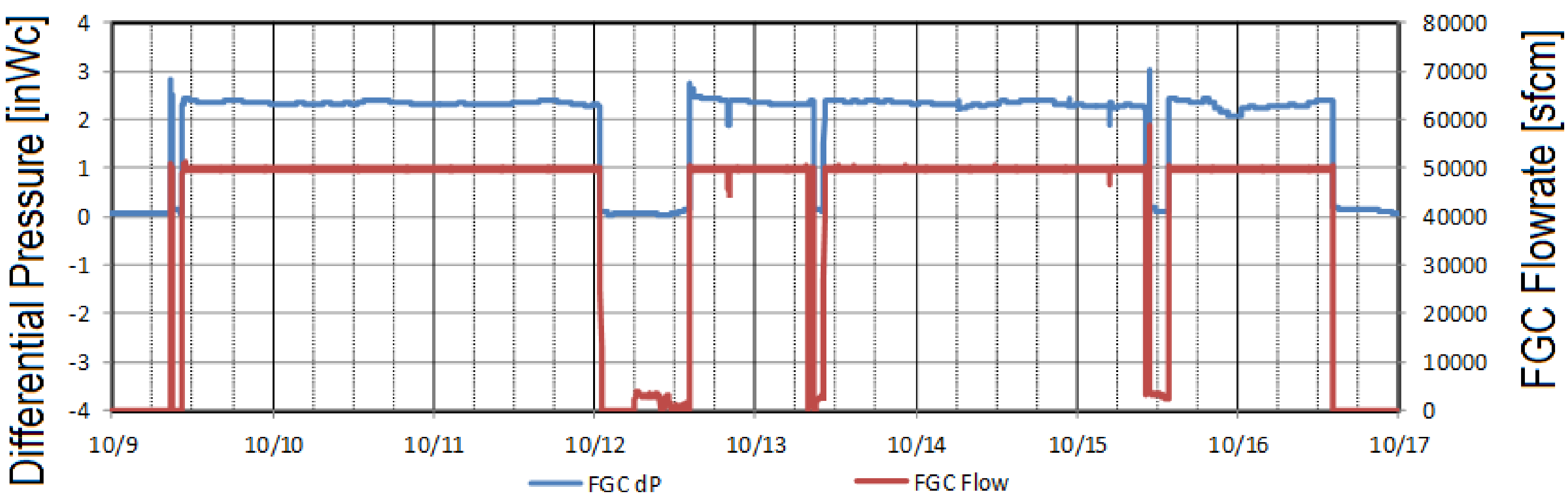
The DOE Case 10 plant (subcritical PC EGU with CCS) was used as the basis for the model.

	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

Flue gas pressure drop across the Flue Gas Cooler was monitored throughout testing

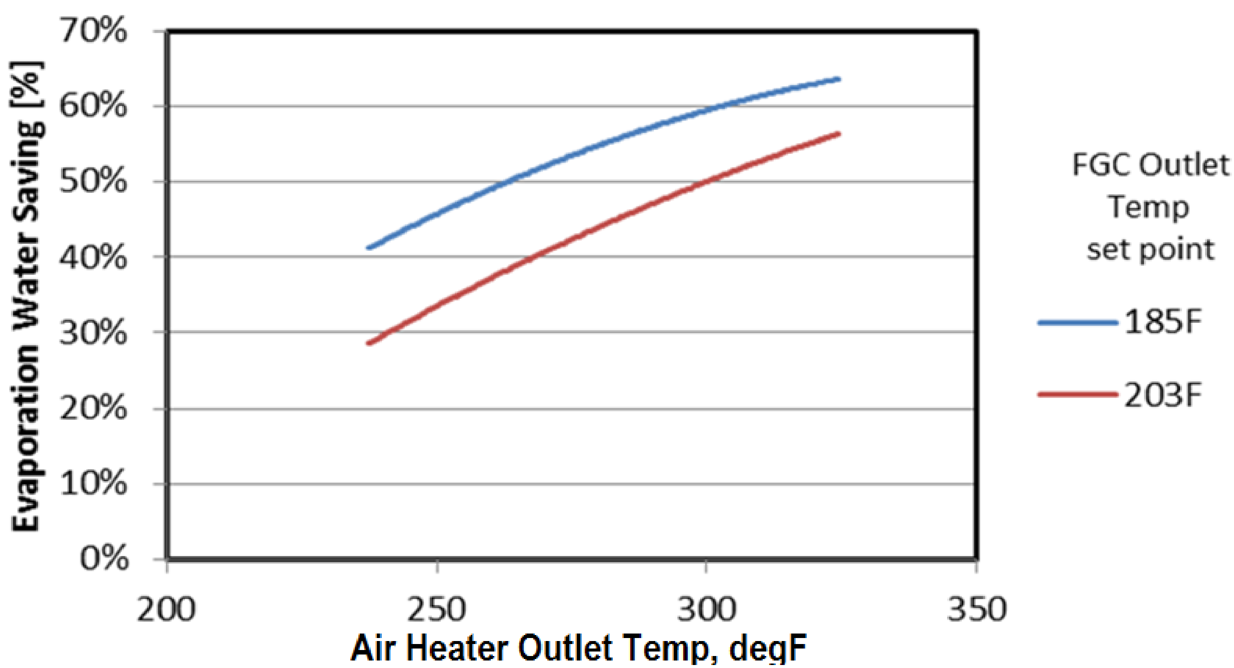
- Pressure drop across Flue Gas Cooler ranged from 2-4” H_20





The Flue Gas Cooler can reduce evaporative water consumption in the FGD

- By cooling the flue gas, FGD makeup water can be reduced.
- Percentage of water saved was calculated, not measured.
- For coal EGUs with an air heater outlet temperature of 300ºF, up to 60% of the FGD makeup water can be saved.
- For a 550-MW plant, 400 gpm of FGD makeup water would be saved.



The High Efficiency System can reduce cooling water use in the carbon capture system

- For coal EGUs with an air heater outlet temperature of 300ºF, up to 36% of the CCS cooling water use can be reduced.
  - For a 550-MW plant, 27,000 gpm of CCS cooling water use would be reduced by the Flue Gas Cooler.
- An additional 20% reduction in cooling water use can be realized by using the CO_2 Cooler to cool the product CO_2
  - For a 550-MW plant, 18,000 gpm of CCS cooling water use would be reduced by the CO_2 Cooler.

Turndown Load Operation Test

Purpose: Evaluate the CO_2 Cooler and Flue Gas Cooler performances at reduced flue gas flowrate.

Items evaluated:

- Heat recovery performance of CO_2 Cooler and Flue Gas Cooler
- Flue gas pressure drop across the Flue Gas Cooler
- Water quality of BC at the outlet of the Flue Gas Cooler

Heat recovery with a reduced flue gas flow was investigated in the Turndown Load Operation Test

Flue gas flowrate was reduced to 70-75% of the design value. Only issue encountered was vibrations from the Flue Gas Blower at low flowrates.

Test Condition	R2-1	R2-2	R2-3	R2-4
CO_2 Cooler heat recovery mode	Normal	Normal	Reduced	Reduced
Flue Gas Cooler heat recovery mode	Normal	Increased	Normal	Increased
Flue gas flowrate scfm	42,000	42,000	45,000	45,000
Flue Gas Cooler flue gas outlet temperature set point	203F	185F	203F	185F
Flue Gas Cooler heat transfer coefficient (Btu/ft^{2}hrF)	1.8	1.3	2.9	3.2
Total Heat Recovered (MMBtu/hr)	8.1	9.1	6.2	9.0
Total heat recovered for a 550-MW coal EGU (MMBtu/hr)	178	201	136	198

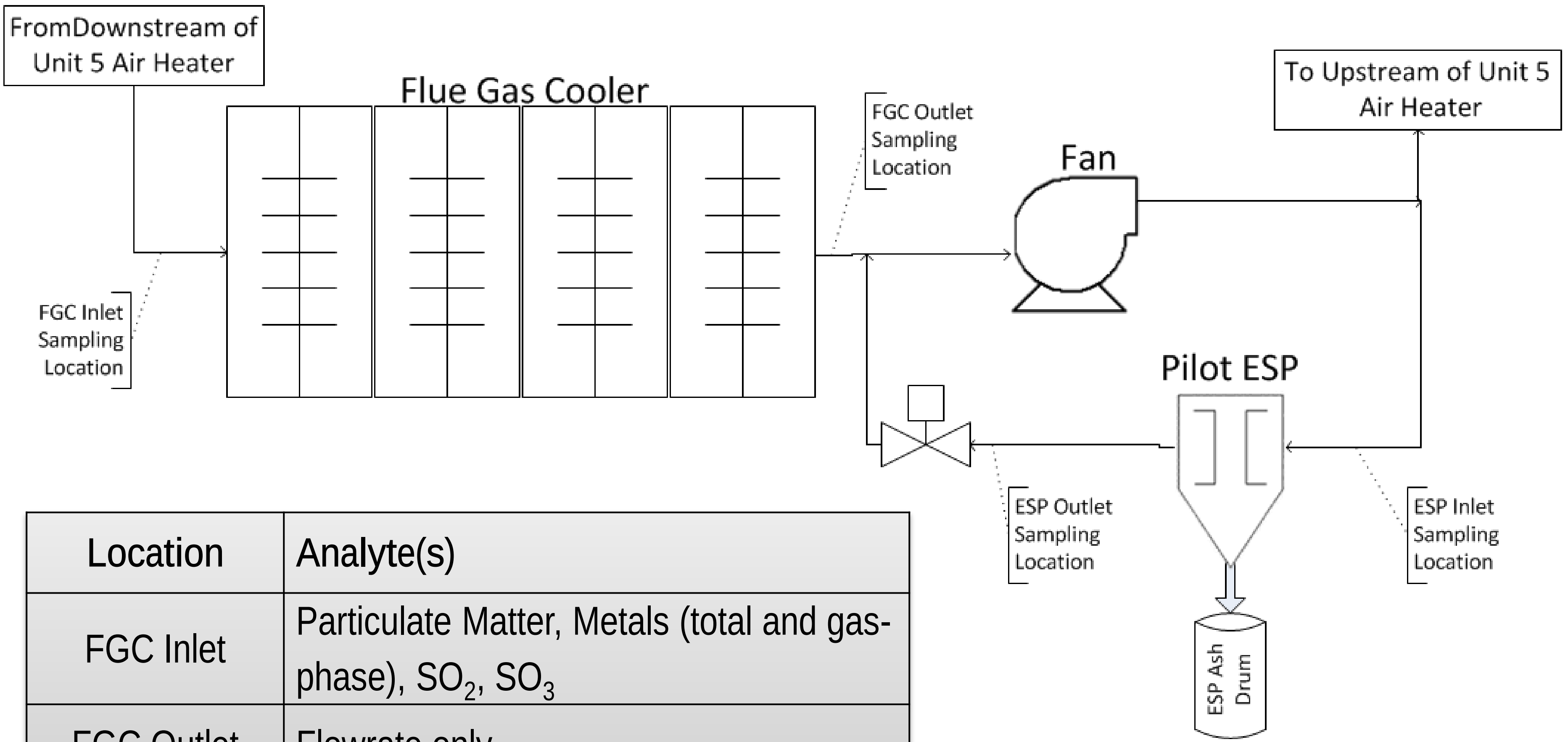
Impurities Removal Test

Purpose: Evaluate the effect of cooling the flue gas via the FGC on the pilot ESP performance for particulate matter, sulfur oxides, and trace metals.

Items evaluated:

- ESP SO_3, particulate matter, and trace metals removal performance
- Characteristics of ash collected at the ESP

Flue gas was sampled for particulate, metals, and sulfur oxides in the Impurities Removal Test



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

Test conditions were chosen to evaluate the effect of the Flue Gas Cooler and SO_3 concentration

Test Conditions included:

- No FGC 300F: No boiler condensate flowed through the FGC, the flue gas was not cooled by the Flue Gas Cooler.
- FGC 203F: The flue gas at the FGC outlet was cooled to 203°F by the Flue Gas Cooler.
- FGC 185F: The flue gas was further cooled down to 185°F by the Flue Gas Cooler.
- FGC 203F + SO_3: The flue gas was cooled to 203°F by the Flue Gas Cooler and SO_3 was injected. Although, no significant increase in flue gas SO_3 was measured due to injection.

Despite injection of SO_3 into the flue gas, very low concentrations were measured

- For condition FGC 203F + SO3, an 8ppm equivalent of SO_3 was injected into the flue gas via Plant Barry's ESP SO_3 conditioning system.

- Very little SO_3 was measured at either the FGC inlet or ESP outlet.

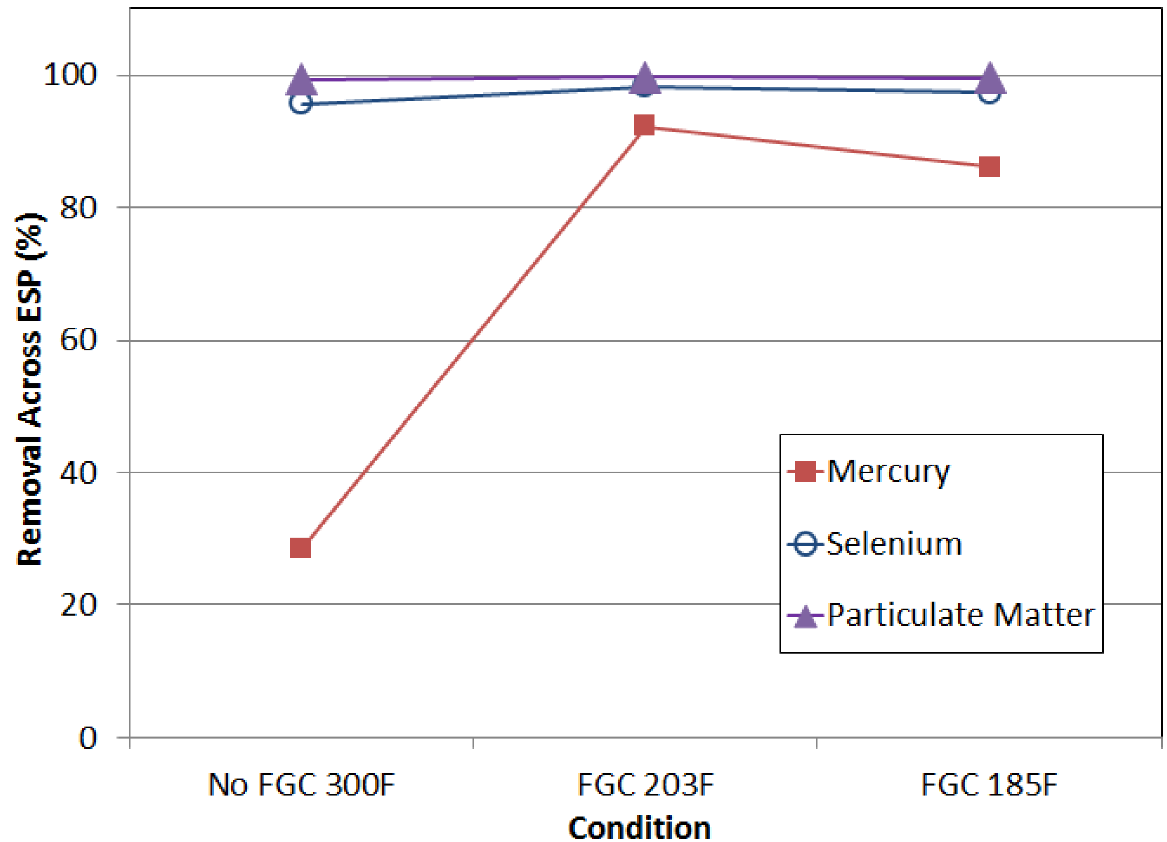
- The injected SO_3 removed by the alkaline fly ash.

- However, an appreciable effect was measured on mercury removal due to SO_3 injection.

Condition	FGC Inlet	ESP outlet
	(ppmd SO_3 at 3% O_2)	
NO FGC 300F	0.11	0.03
FGC 203F+ SO3	0.18	0.04
FGC 203F	0.17	0.04
FGC 185F	0.11	0.02

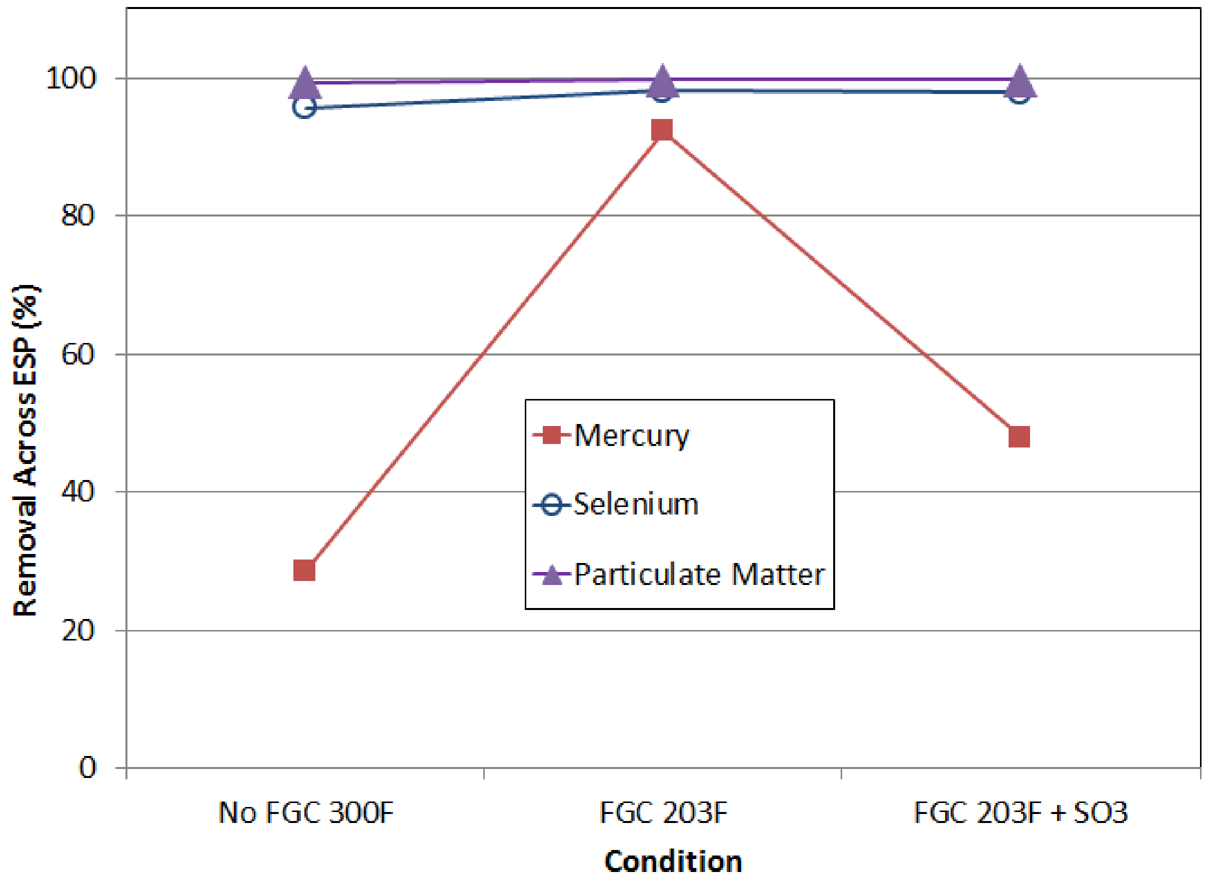
Impurities removal was enhanced by Flue Gas Cooler operation

- 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



SO_3 injection inhibited mercury capture, no effect on selenium or particulate matter

- 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



Long-Term Durability Test

Purpose: Evaluate the system data and physical conditions, including vibration, mechanical damage, etc.

Items evaluated:

- Flue Gas Cooler internal surfaces via visual inspection
- Flue Gas Cooler internal equipment such as soot blowers via visual inspection

The HES was operated for 913 hours for the Long-Term Durability Test

- 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

Purpose: Evaluate any corrosion, erosion or plugging in the Flue Gas Cooler.

Items evaluated:

- Flue Gas Cooler tubes wall loss via corrosion
- Boiler condensate leakage via flowmeters at the inlet and outlet of the Flue Gas Cooler
- Water quality of boiler condensate at the outlet of the Flue Gas Cooler

Heat transfer tubes from the Flue Gas Cooler were analyzed upon project completion

- Tubes were cut from the FGC and sent to Det Norske Veritas (DNV GL) for analysis. Control samples of tubing not exposed to flue gas used for comparison.
- The fins were removed and scale and deposits scrubbed off.
- Wall loss measurements were taken via a three-dimensional optical microscope.

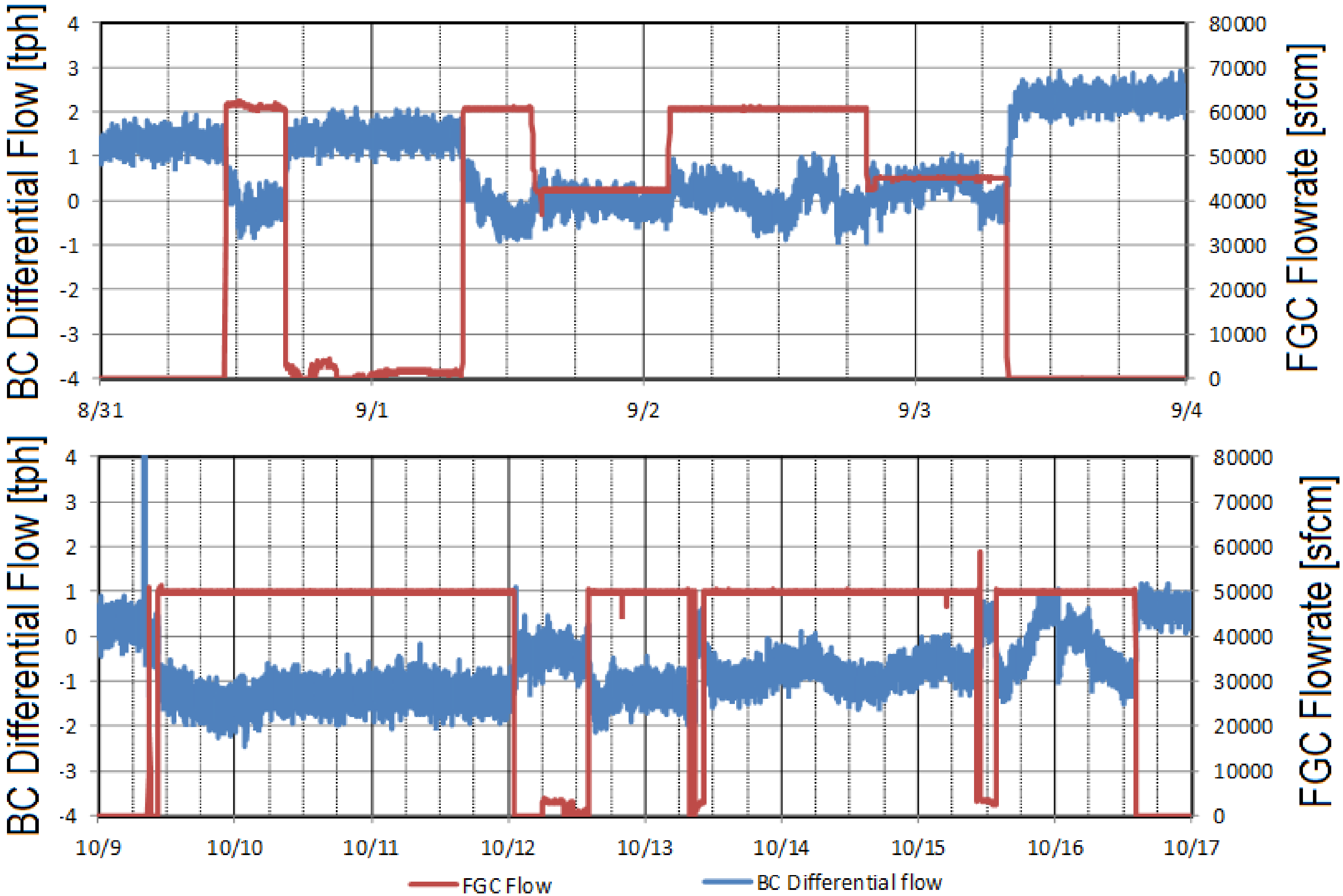
General corrosion was found on all tubes, likely due to presence of moisture

- The highest localized corrosion rate was estimated to be 174 mils per year.
- This sample was located near a duct wall.
- The sample with the most uniform corrosion provided a rate of 40 mils/year
- Flue gas was not purged from the duct after operation like would be done in a full-scale plant.

Tube Bundle	Inlet or Outlet	Row, 1 is lowest out of 32	Scale Present	Corrosion Present	Calculated Corrosion Rate (mils/year)
1	Inlet	1	Yes	Yes, localized	20
1	Inlet	8	Yes	Yes, localized	18
1	Outlet	4	Yes	Yes, localized	144
1	Outlet	15	Yes	Yes, localized	18
2	Inlet	15	Yes	Yes, localized	36
2	Outlet	2	Yes	Yes, localized	27
3	Inlet	1	Yes	Yes, localized	34
3	Inlet	4	Yes	Yes, localized	31
3	Outlet	1	Yes	Yes, localized	173
4	Inlet	13	Yes	Yes, localized	134
4	Outlet	1	Yes	Yes, prevalent	40
Not used	Not used	Not used	-	Flash rust only	-
Not used	Not used	Not used	-	Flash rust only	-
Not used	Not used	Not used	-	Flash rust only	-
Not used	Not used	Not used	-	Flash rust only	-
Not used	Not used	Not used	-	Flash rust only	-

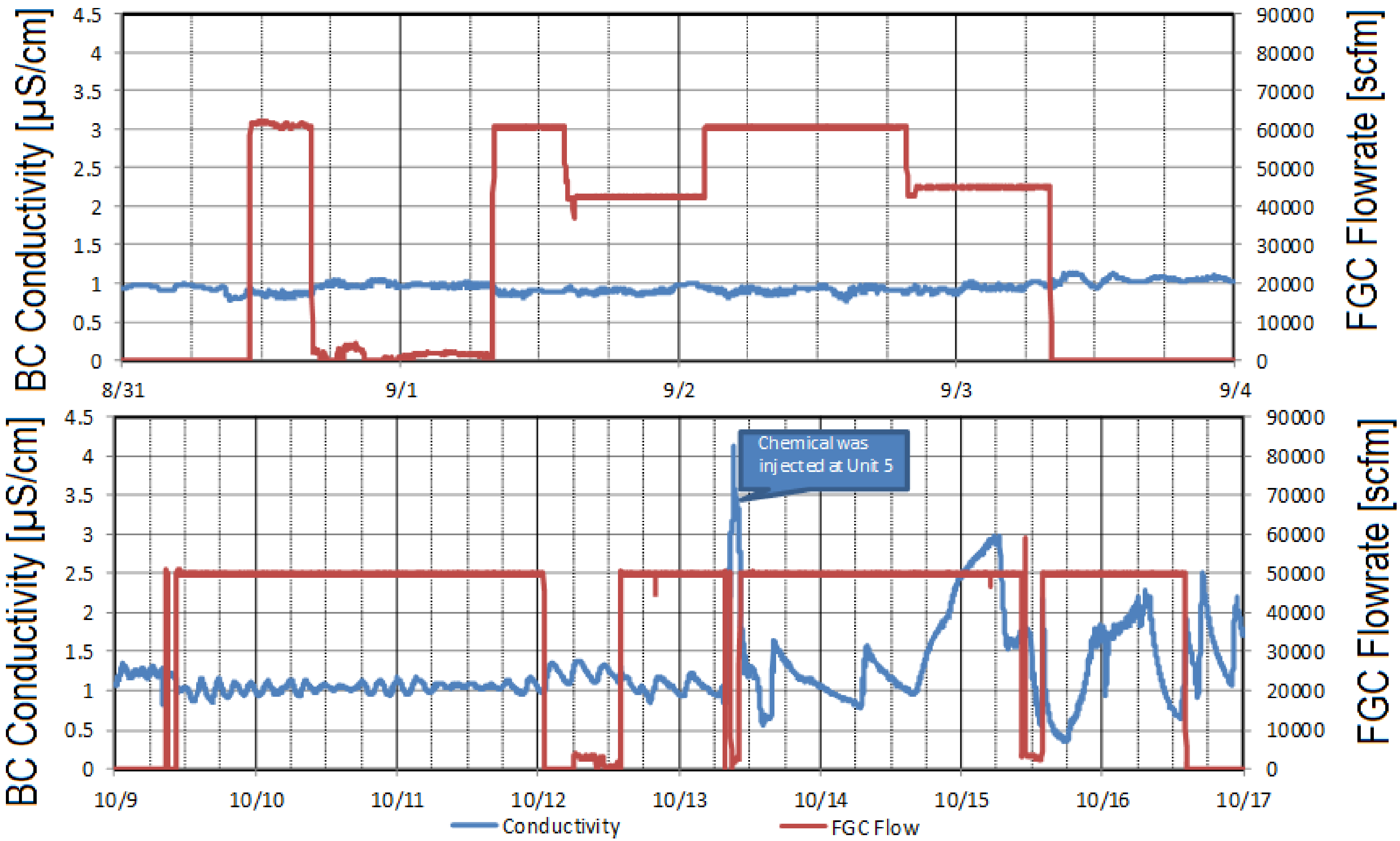
Boiler condensate differential flow varied throughout the demonstration.

Differential flowrate was measured via flow meters in the boiler condensate at the inlet and outlet of the Flue Gas Cooler



No significant impact or trend with boiler water quality detected

Water quality was measured via conductivity meter in the boiler condensate at the outlet of the Flue Gas Cooler



Techno-Economic Assessment

Several cases were compared in the Techno-Economic Assessment

- 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

Techno-Economic Assessment

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%

Environment, Health, and Safety Assessment

Six streams in a 550-MW plant with CCS were analyzed in the EH&S Assessment

Streams affected by the HES included:

1. Fly ash capture via particulate control device
2. FGD and polishing-scrubber wastewater
3. FGD gypsum or other solids
4. CO_2 capture system reclaimed waste
5. Product CO_2
6. Treated flue gas exiting via the stack

Cooling the flue gas caused an increase in uptake of metals on the fly ash

- Analysis of the fly ash captured by the pilot ESP showed increases of mercury and selenium.
- For fly ash to be reused in concrete manufacturing, mercury limits should be examined on a site-specific basis.

Analyte	Concentration in Ash ($\mu g/g_{ash}$)		
	No FGC 300F	FGC Operation	FGC 203F SO_3
Mercury	0.69	1.67	0.87
Selenium	67.5	134	103

Increased concentrations of metals were also measured in leachate from the fly ash

- Ash captured by the pilot ESP was subjected to the Toxicity Characteristics Leaching Procedure (TCLP).
- The concentrations of selenium, mercury, and arsenic increased due to FGC operation.
- All concentrations were far below the RCRA levels.

Analyte	Concentration in Ash Leachate (µg/l)			**Regulatory Limits** (µg/l)	
	No FGC 300F	FGC Operation	FGC 203F SO3	RCRA	Maximum Contaminant Limits
Mercury	0.00	0.18	0.04	200	2.0
Selenium	72.8	166	138	1,000	50
Arsenic	7.76	15.2	10.7	5,000	10

Metals and other contaminants are expected to be reduced in other streams due to the HES

- FGD and polishing scrubber wastewater and other byproducts would have reduced metals due to increased uptake by the fly ash.
- Less CO_2 capture solvent reclaimed waste would be created due to the reduction of SO_3 entering the CCS system that creates sulfur-based heat-stable salts.
- Fugitive amine emissions would also be reduced as this is also a byproduct of SO_3 entering the CCS system.
- Treated flue gas exiting the plant’s stack would have reduced metals and other contaminants due to increased uptake by the fly ash.

Conclusions

Summary of Project Objectives

- 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

Energy improvements were quantified

- 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.
- Use of the HES, can reduce the cost of electricity 4-5% from that of the DOE Case 10 plant with MEA CCS.
- Pressure drop across the Flue Gas Cooler was measured to be 2-4 inWc.

Potential integration challenges were measured but high sulfur flue gas was not tested

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.

Ancillary benefits of the HES were shown to be significant

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 60% of FGD makeup water can be saved, and
- Up to 50% of CCS cooling water can be saved.

Questions?