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

DE-FE0007525

Project Review Meeting

August 9, 2016

Heat Integration with 25 MW KM-CDR at Plant Barry

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

Project Participants

Southern Company

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Jerrad Thomas

Mitsubishi Heavy Industries America, Inc.

Tim Thomas
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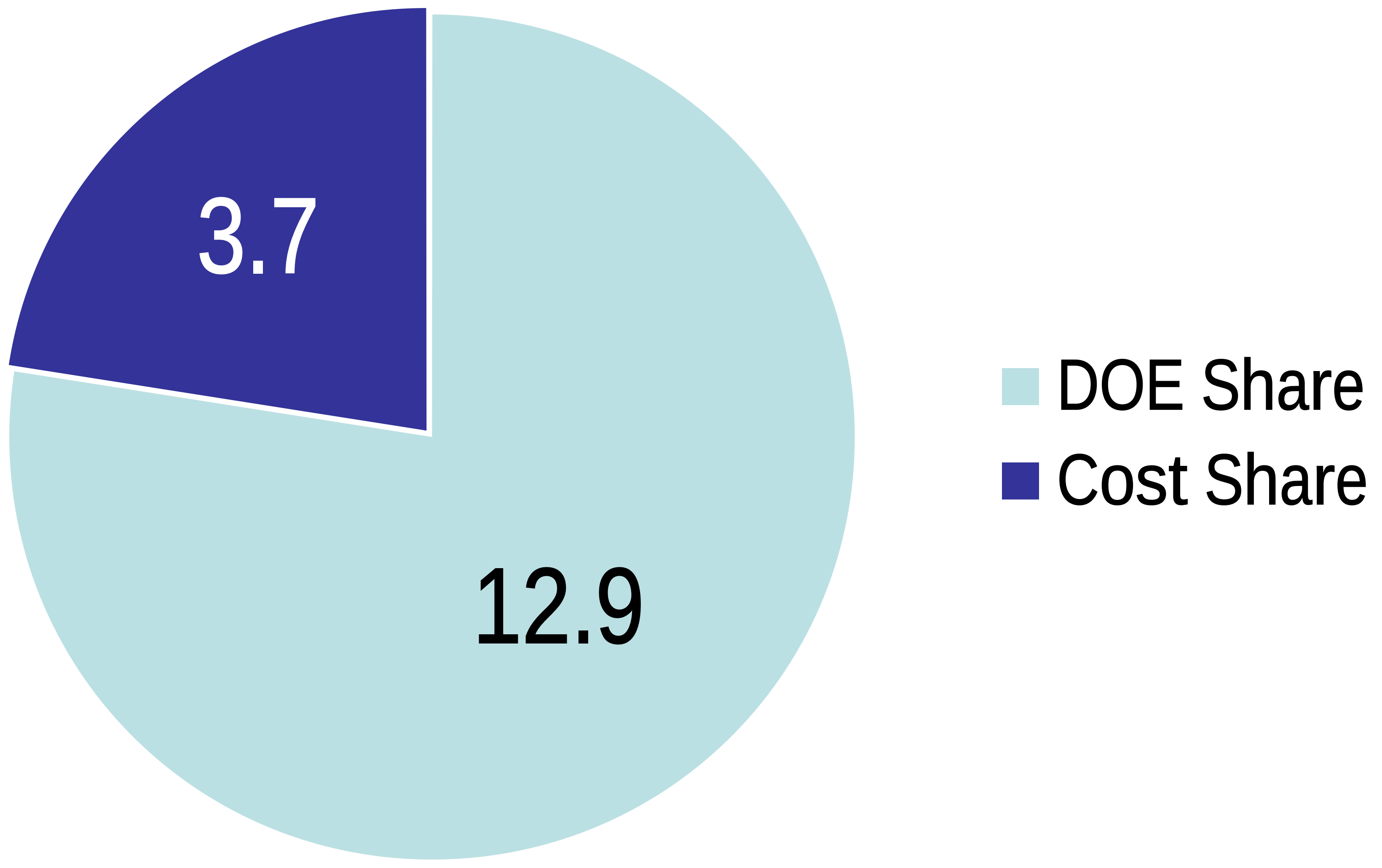
URS

Katherine Dombrowski
Mandi Richardson
Jack Cline

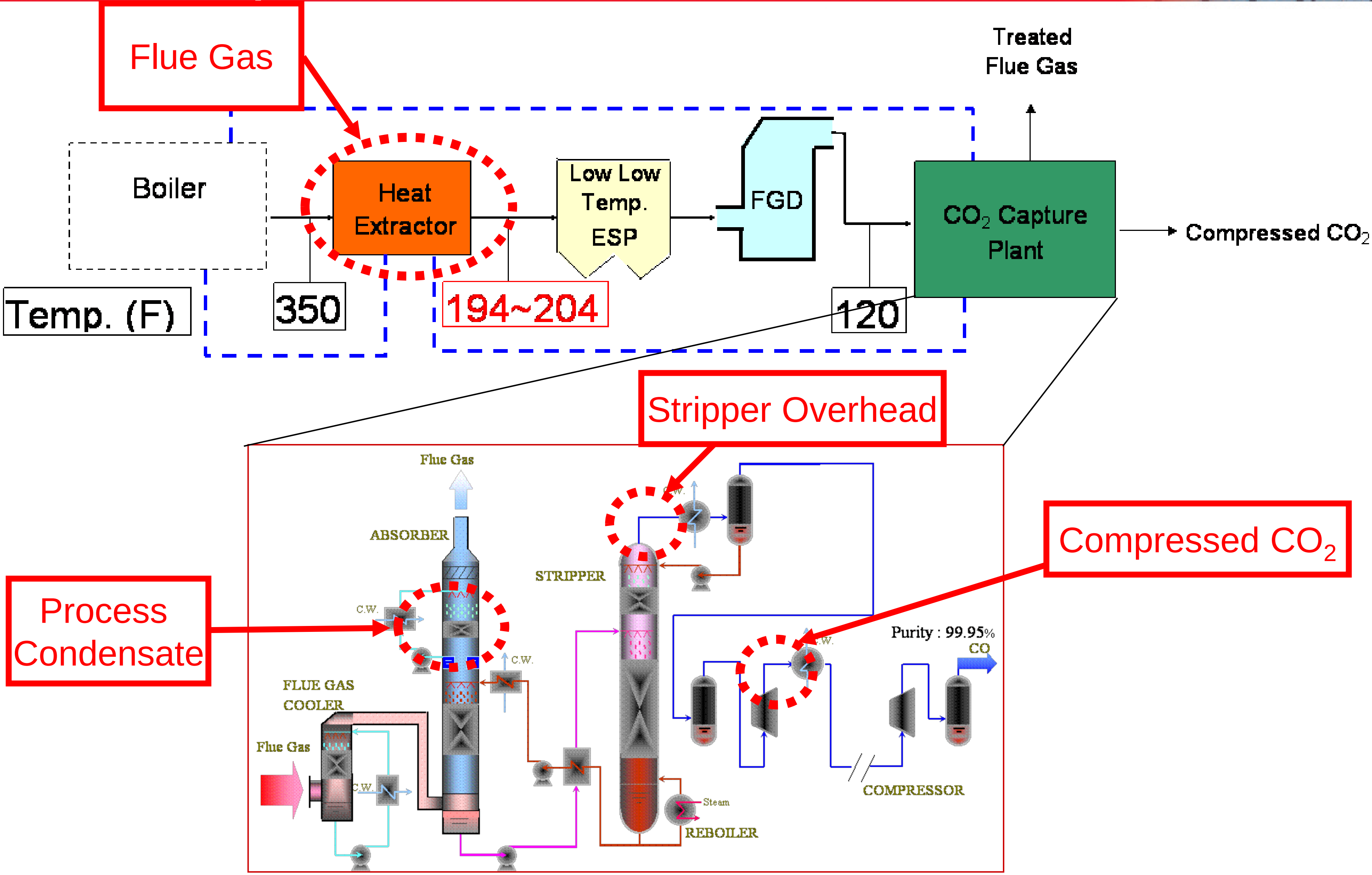
NETL

Bruce Lani

Total Project Budget ($MM)



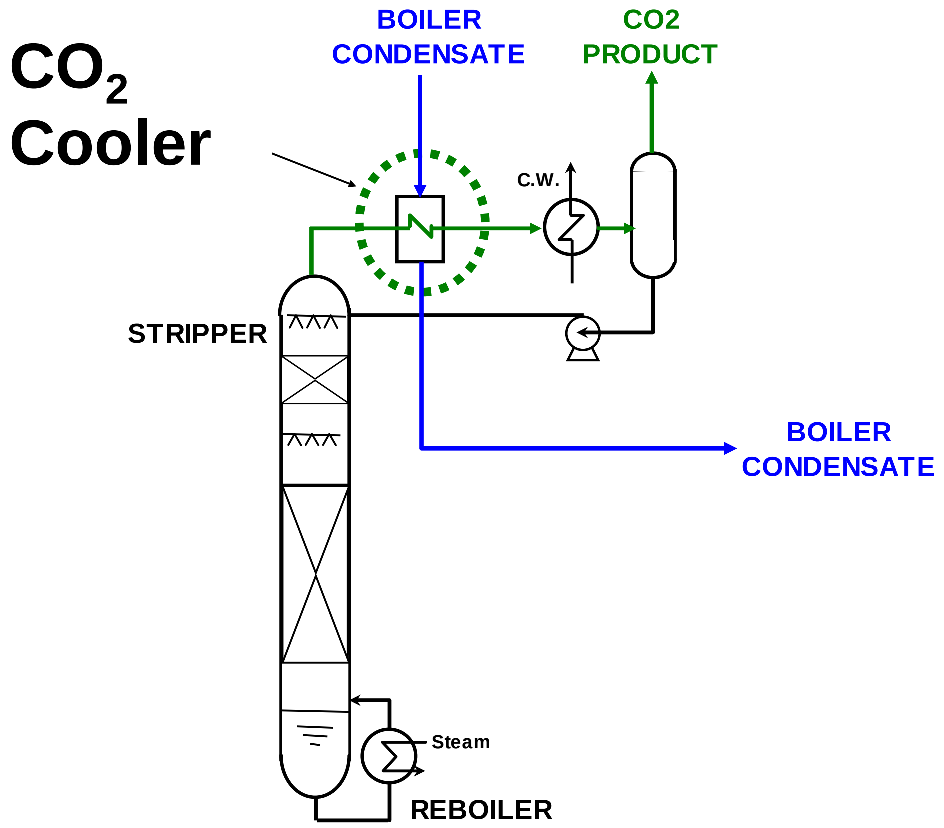
Waste heat sources include flue gas and CCS plant streams



Boiler feed water will be heated with CO_2 Cooler and Flue Gas Cooler

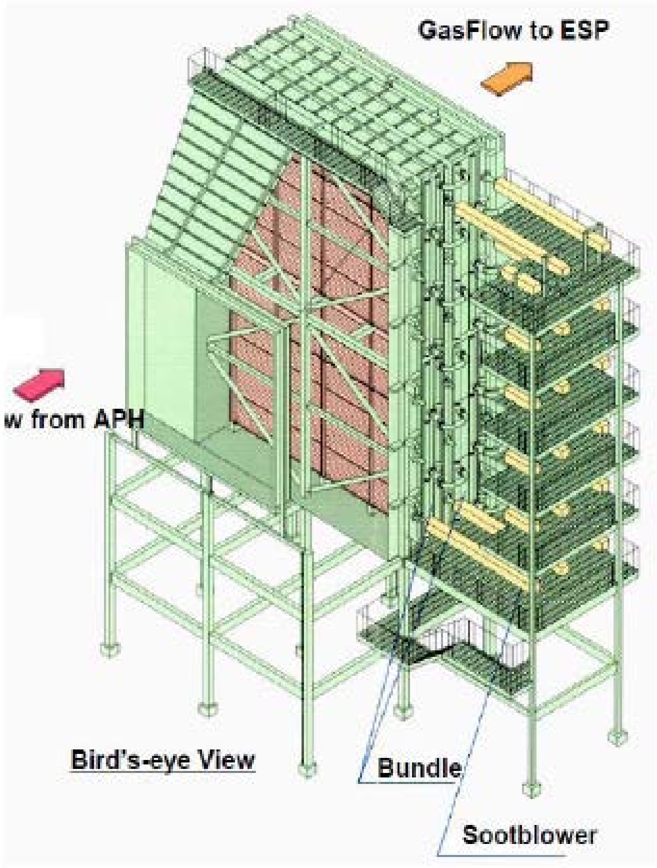
CO_2 Cooler

Standard heat exchanger



Flue Gas Cooler

MHI proprietary heat exchanger



Flue Gas Cooler proven on low S coals

Carbon steel tubes in good condition after 2 years operation at Japanese plant

What happens with higher sulfur coals (>1% S) fired in US?

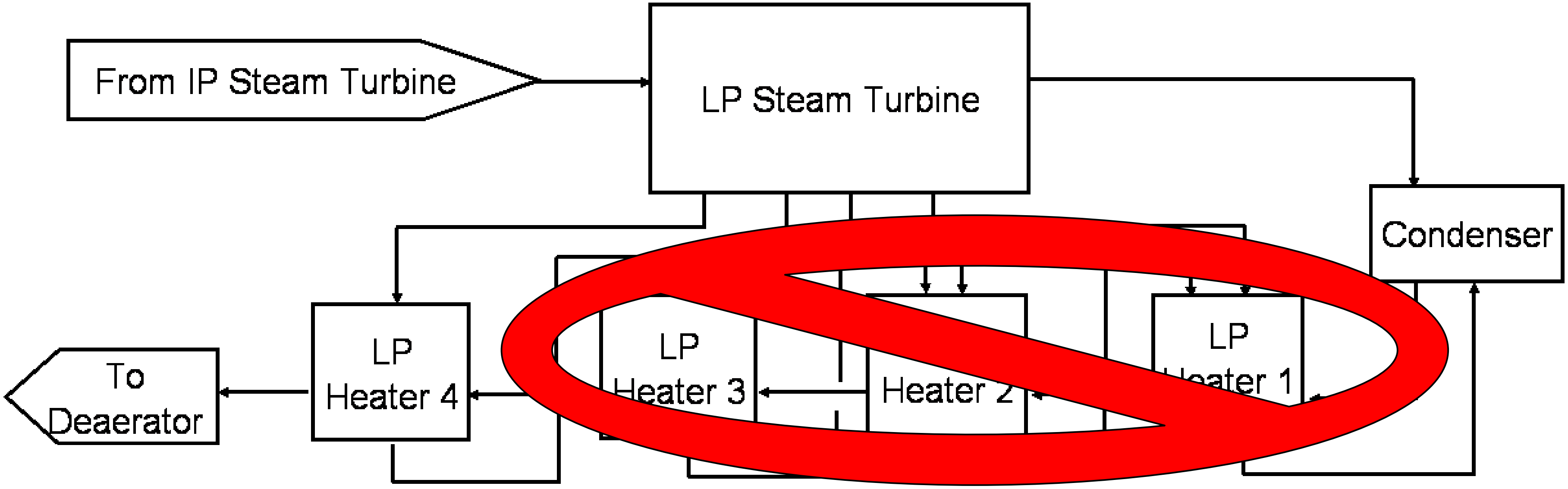
Flue Gas Cooler captures SO_3

- 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

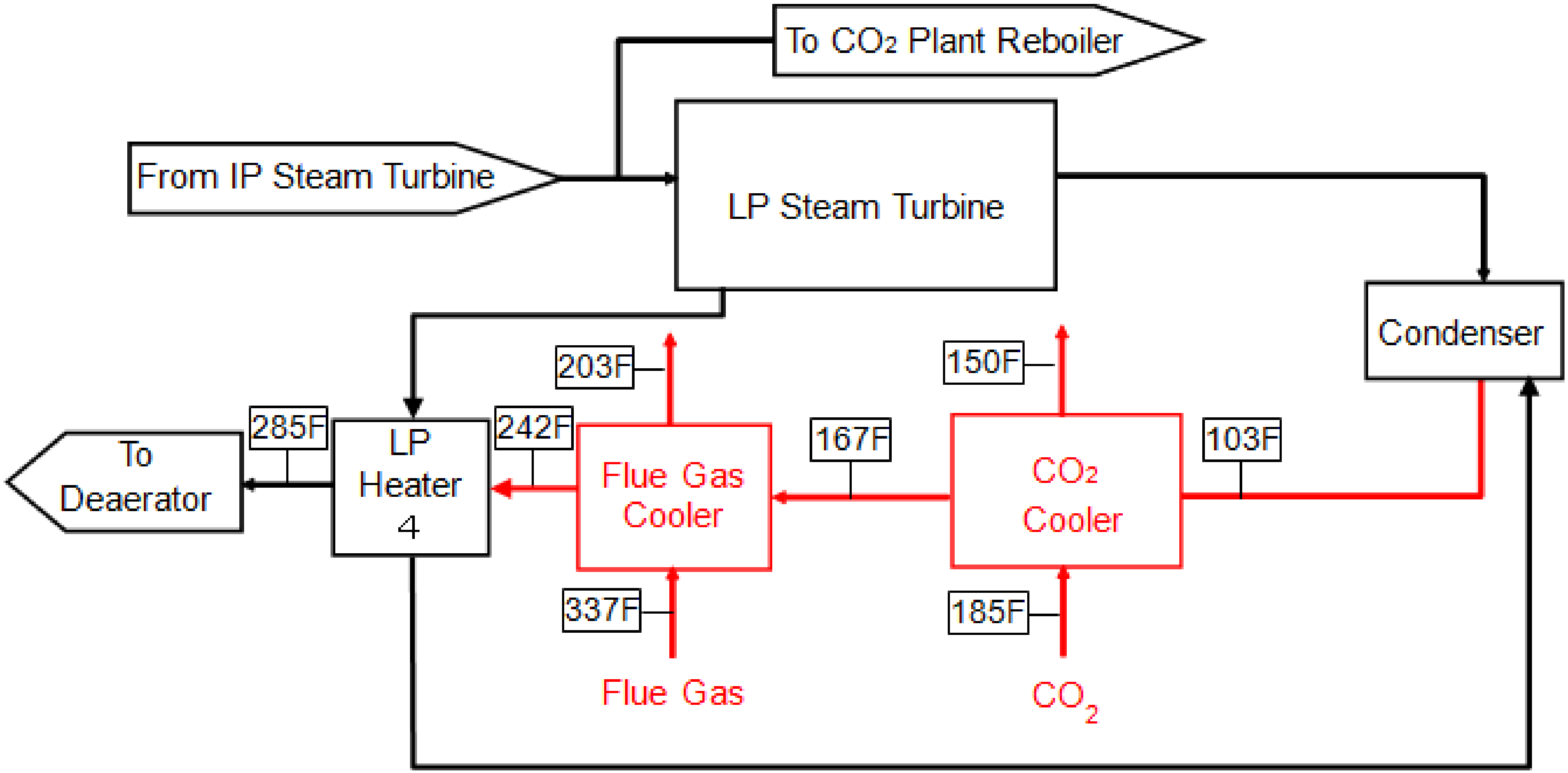
Other benefits of Flue Gas Cooler

- Improve removal of Hg, Se, SO_3 across the ESP
- Reduce AQCS cost
  - Improve ESP performance
  - Improve FGD performance
  - Improve CCS performance
- Potential to simplify boiler/steam turbine cycles
- Improve plant heat rate

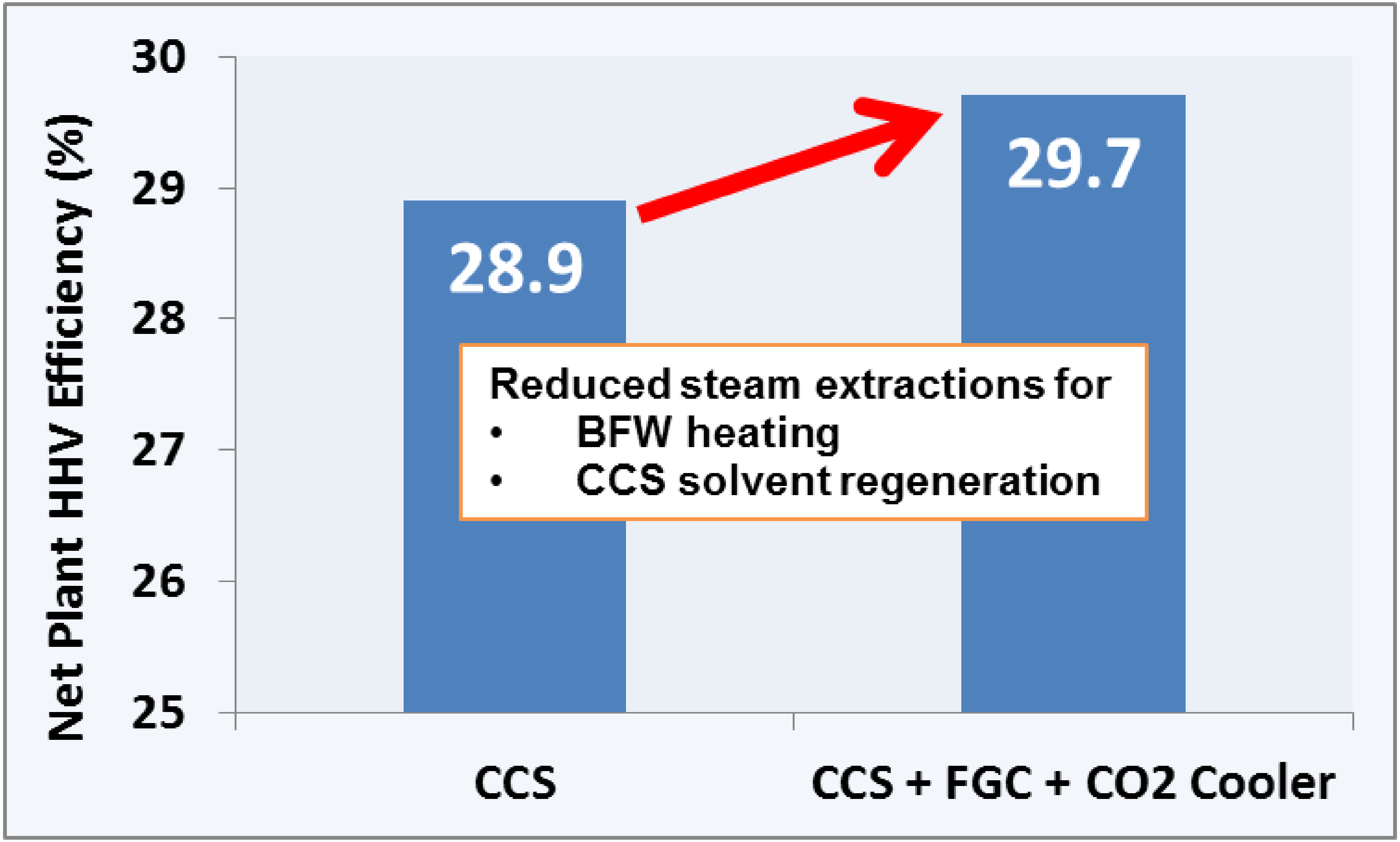
Heat integration eliminates LP heaters 1-3



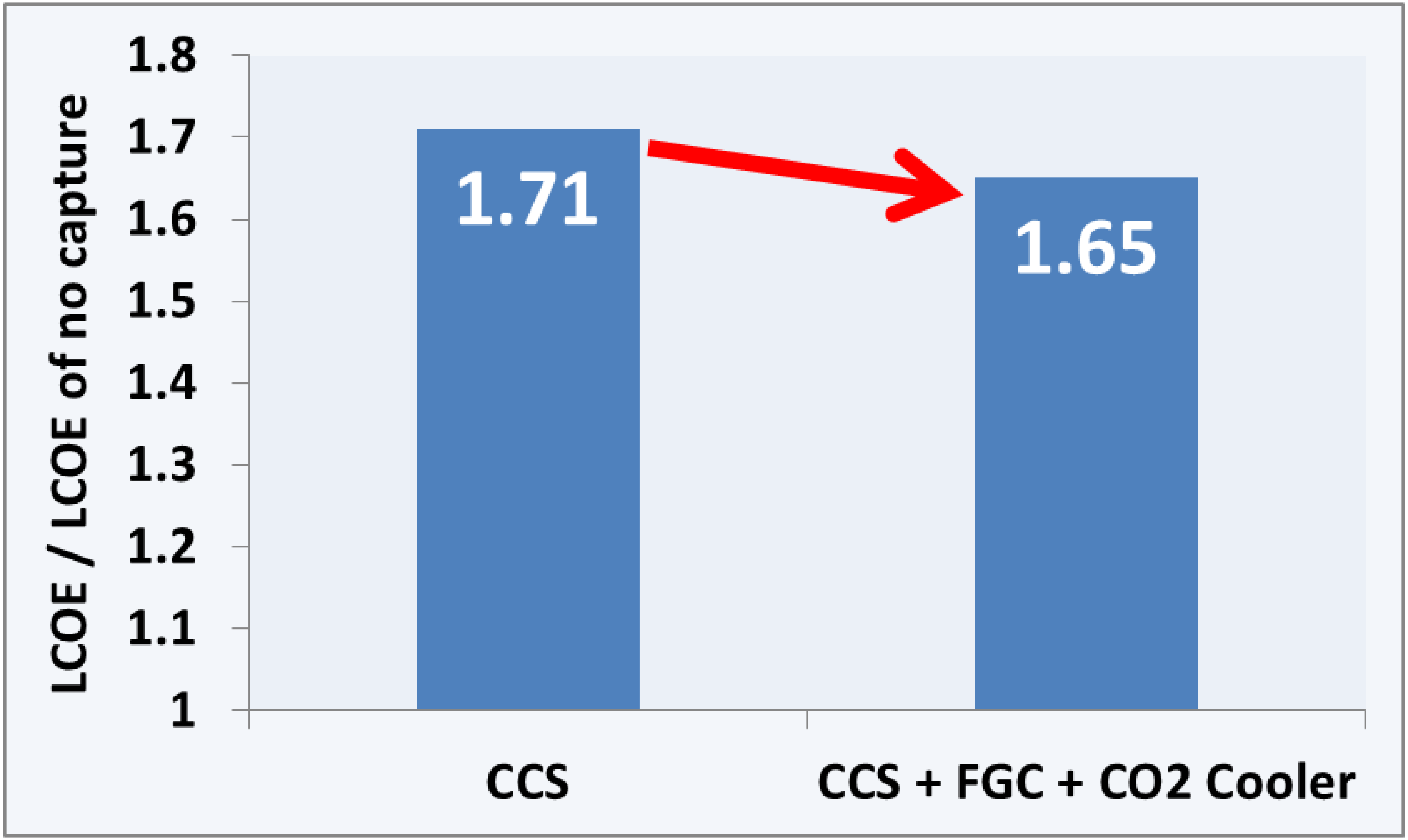
Heat integration eliminates LP heaters 1-3



Heat integration increases plant efficiency



Heat integration decreases cost of CCS



Analysis per 2010 DOE Cost and Performance Baseline

Heat Integration Challenges

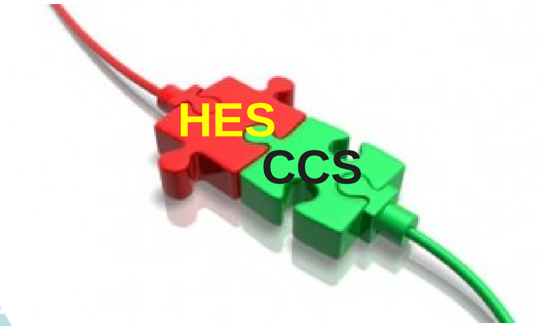
- Highly integrated systems incorporating waste heat recovery have yet to be demonstrated at any scale in the U.S.
- Overcome skepticism in U.S. by proving system reliability
- Process control during transients/perturbations, which are typical in power plant operations
- Removal performance of specific impurities not yet quantified for varying operating conditions
- Uncertainty around the reliability of the system with higher sulfur fuels (> 1% S)

Project Objectives

Quantify tangential benefits

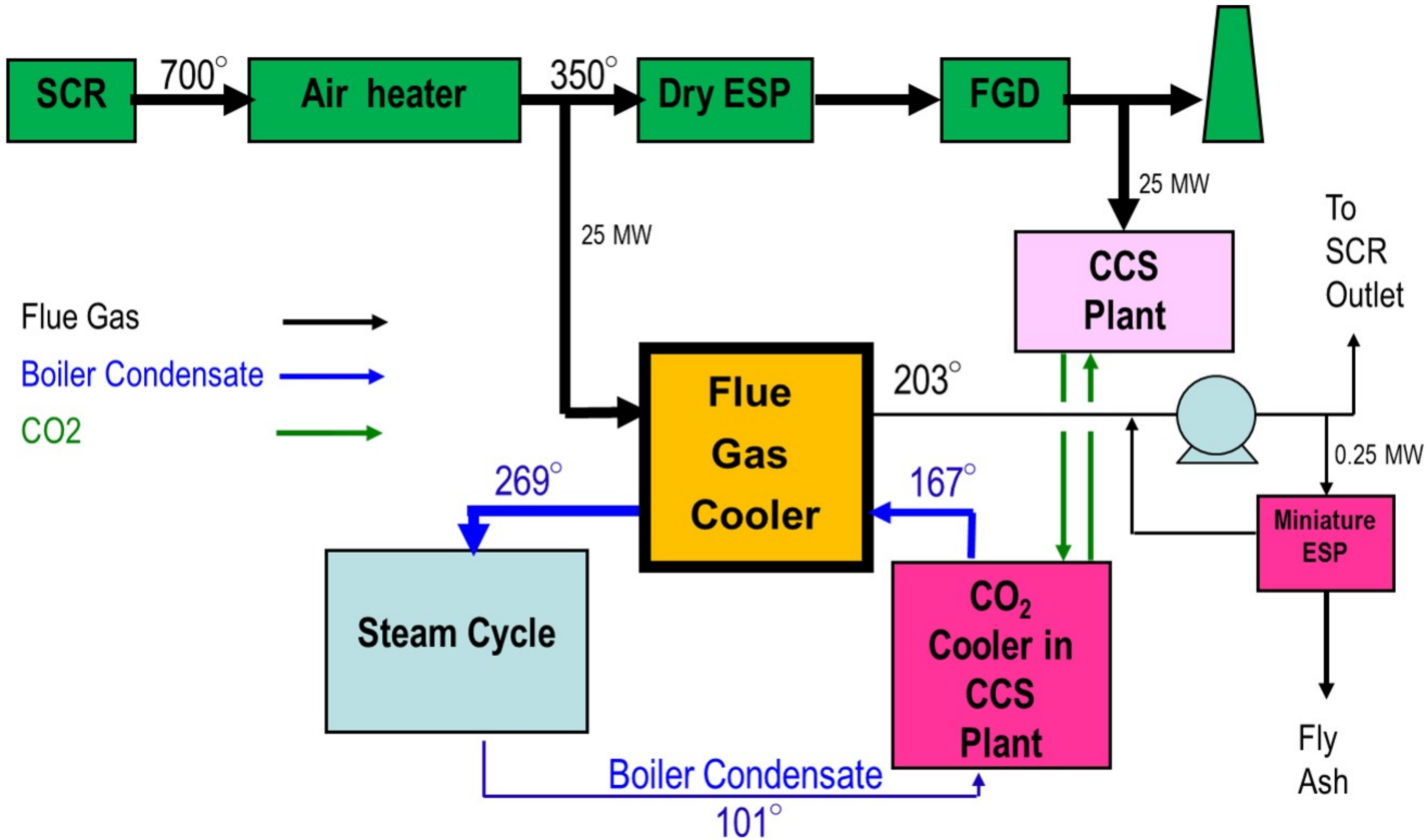
- Better ESP performance
- Increase SO_3, Hg, Se capture
- Reduce CCS solvent consumption
- Reduce FGD H_2O consumption

Resolve operational problems of integration

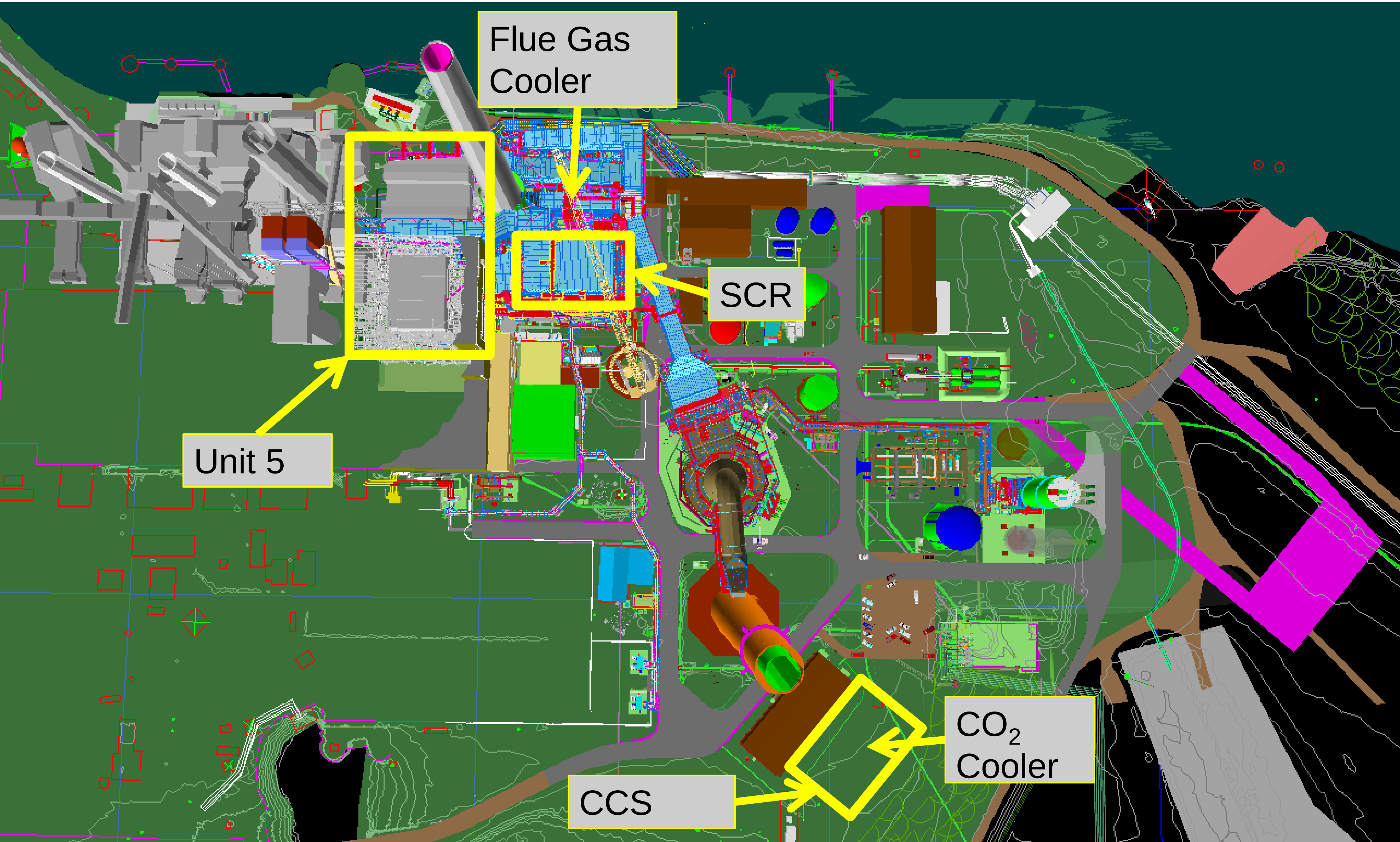


Quantify energy efficiency improvements

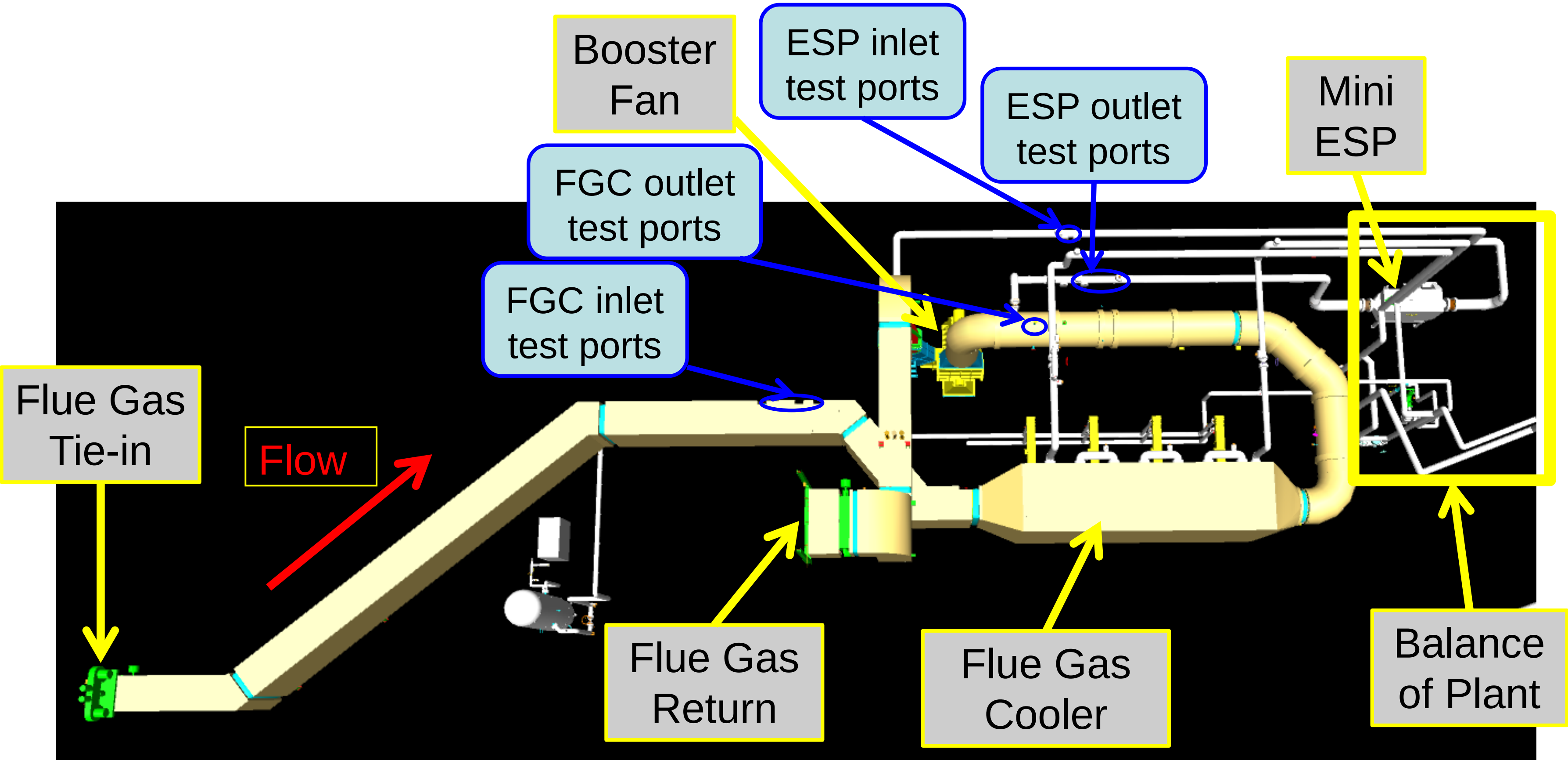
PROJECT = Boiler feed water will be heated with CO_2 Cooler and Flue Gas Cooler



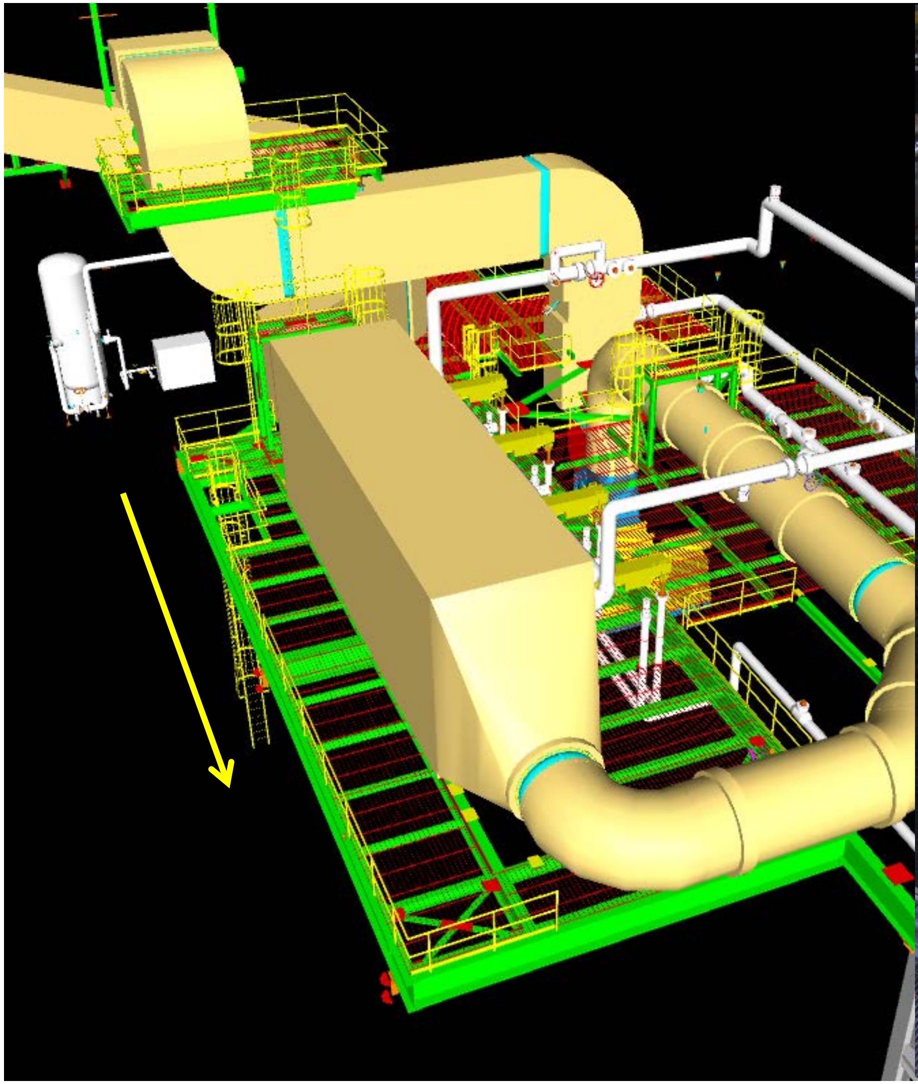
General Layout



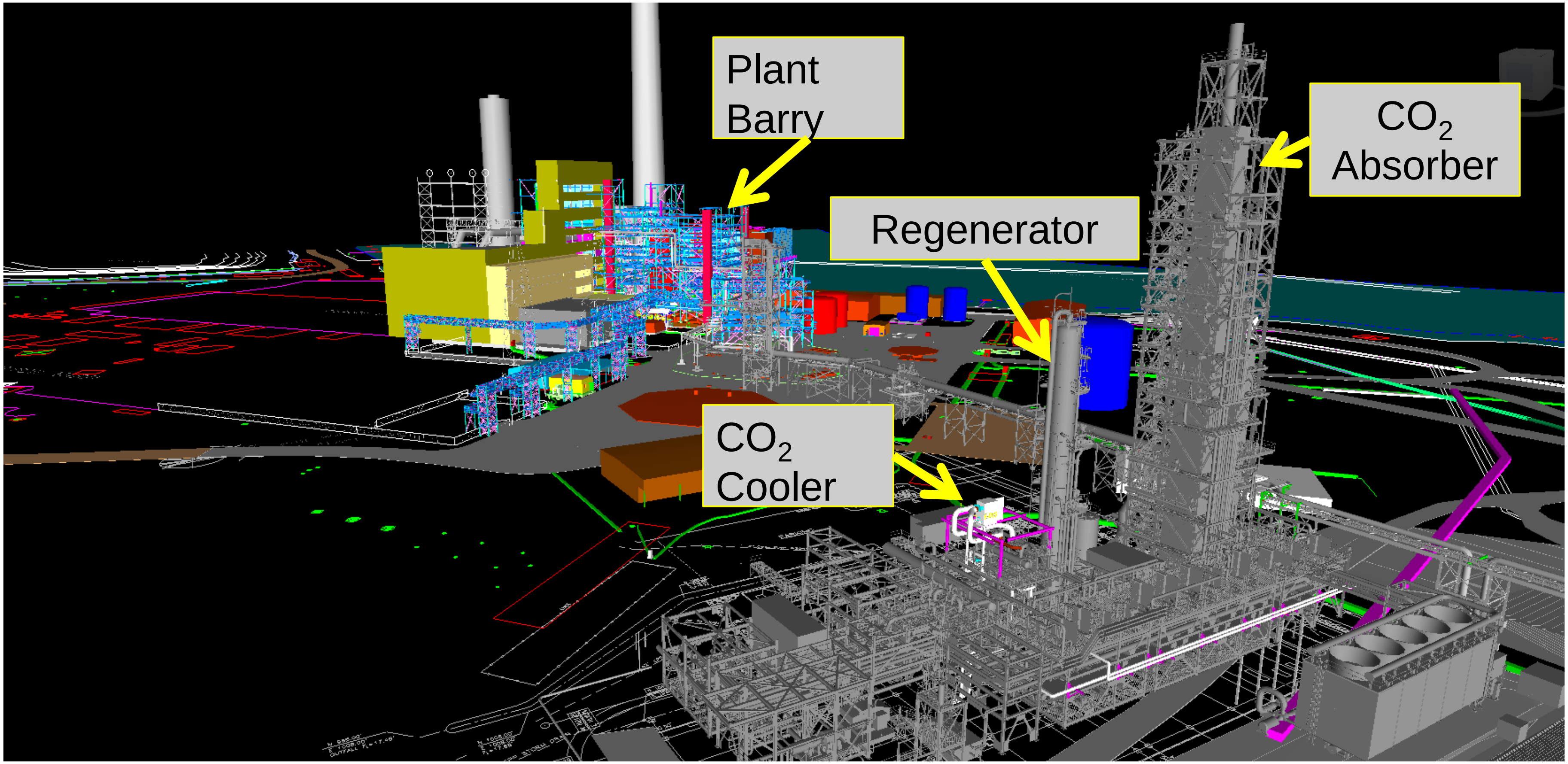
Flue Gas Cooler Area – Plan View



Flue Gas Cooler Installed



CO_2 Cooler General Arrangement



CO_2 Cooler Installed

Baseline Performance

- Confirmed heat integration performance
  - 240-300 MMBTU/hr heat recovery for 550 MW base plant (Case 9)
  - Up to 65% reduction of FGD makeup water

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

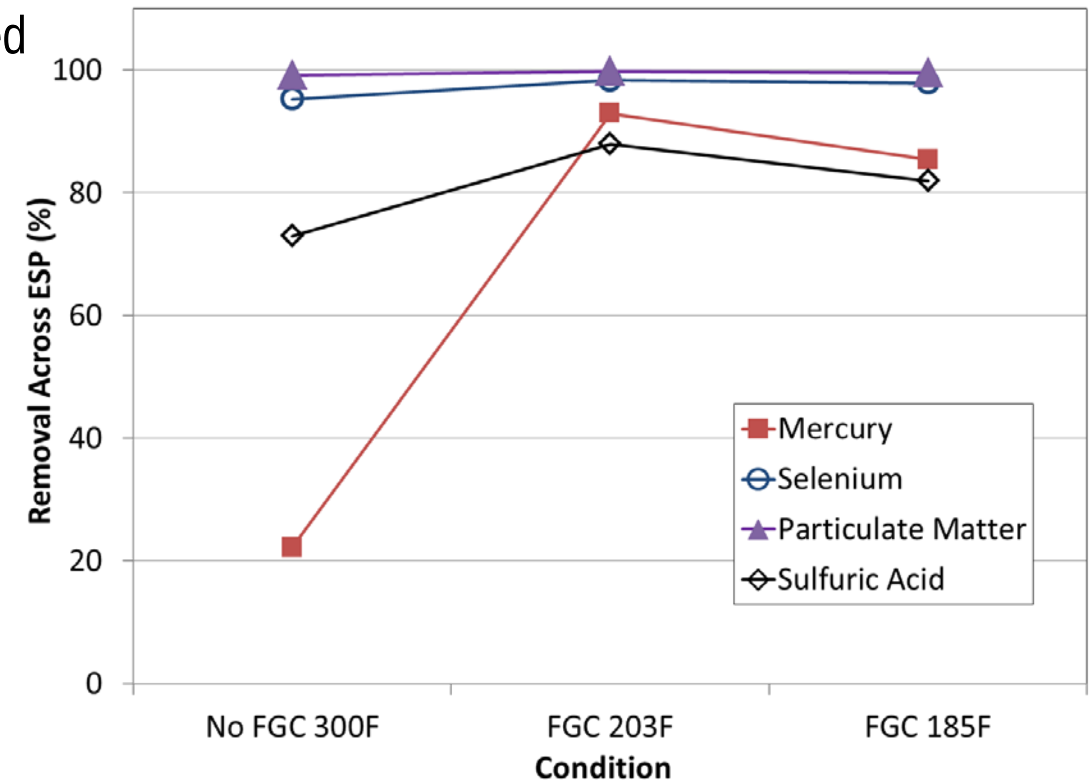
Impurities Removal Test

- 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

Sampling Location	Sampling Method Analyte
FGC Inlet	US EPA Method 17/Method 29 Particulate Matter and Metals (total)
	IGS/Method 29 Metals (gas-phase)
ESP Inlet	US EPA Method 5 Particulate Matter
ESP Outlet	US EPA Method 5/Method 29 Particulate Matter and Metals (total)
	IGS/Method 29 Metals (gas-phase)

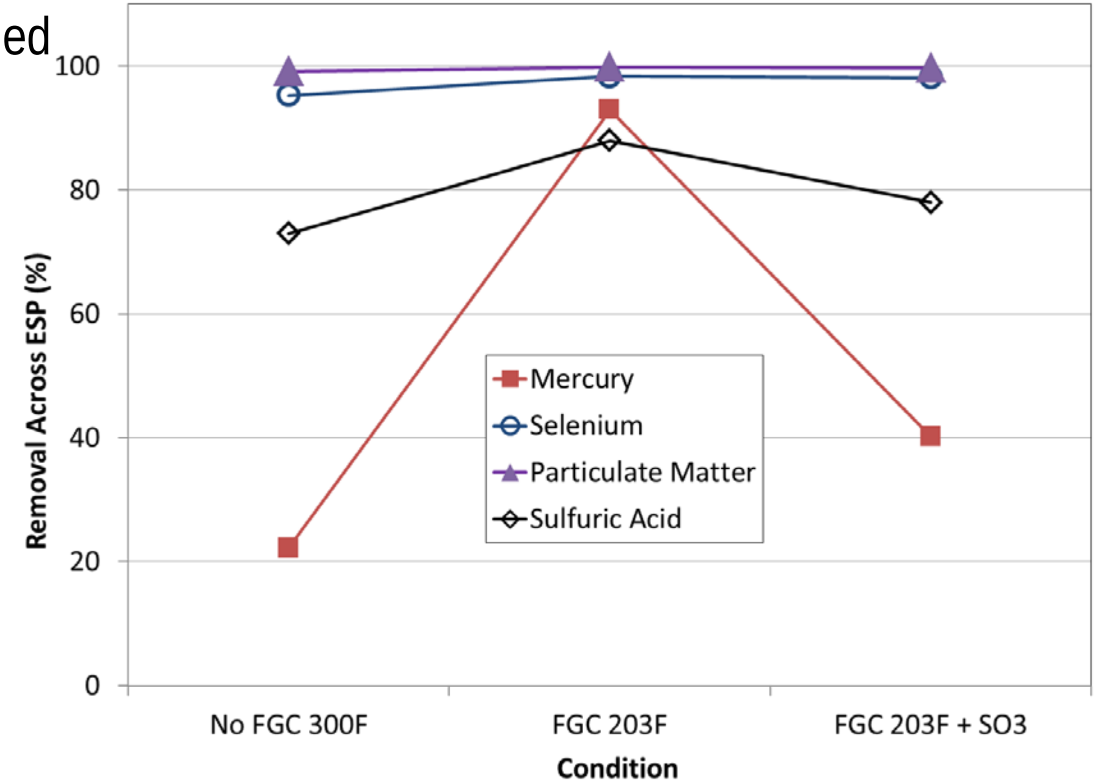
Impurities Removal Test Results

- 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 22 to >85%
  - ESP Outlet SO_3 decreased by 40%
  - Selenium removal increased from 95 to 98%
  - No discernable effect due to temperature decrease from 203 to 185F



Impurities Removal Test Results

- SO_3 Injection Inhibits Mercury Capture, No Effect on Selenium or Particulate Matter Due to SO_3 Injection:
  - Mercury removal decreased from 93 to 40%
  - But removal still higher than without FGC operation
  - Selenium removal unchanged
  - Particulate matter removal unchanged



Impurities Removal Summary

- Confirmed ESP performance improvement
  - PM removal: > 99.5%
  - SO_3 removal: less than 0.05 ppm at ESP outlet
  - Hg removal: > 85% 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 Day 2 (12/16/15)	0.03	99.2%	22%	95%
FGC 203F+ SO3	R3-2 Day 1 (12/18/15)	0.04	NM	40%	98%
FGC 203F	R3-1-1 Day 2 (09/24/15)	0.02	NM	>92%	98%
FGC 185F	R3-1-2 Day 2 (09/26/15)	0.02	99.6%	85%	98%

Durability Test (Preliminary)

- No significant corrosion on tube bundles
  - 4 wks w/o SO_3 injection, 3 wks w/ SO_3 injection
  - Detailed analysis is in progress

(a) Before operation

(b) October, 2015

(c) January, 2016*

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

Techno-Economic Analysis

Case		11	12	12a	12b
Plant Configuration		Supercritical PC w/out CCS	Supercritical PC w MEA CCS	Supercritical PC w KM CDR® CCS	Supercritical PC w KM CDR® CCS w heat integration
Avoided Cost	$/ton		95.9	78.5	75.0
CO_2 Captured Cost	$/ton		66.4	59.9	58.8
Cost of Electricity	mils/kWh	80.95	147.27	135.94	133.73
Percent Decrease in COE from Case 12		-	-	7.7%	9.2%

BP3 completes by December 2016

BP1
- FEED and Target Cost Estimate
- Permitting

✓

BP2
- Engineering, Procurement, Construction

✓

BP3
- Operations ✓
- Field Testing Analysis

WORK IN PROGRESS

Remaining project work

Commission — June 2015

Operations and Testing — Dec 2015

Data Analysis, Reporting & Decommission — Jan 2016 – Dec 2016

- Data analysis
- Estimate reduction of power penalty
- Detailed measurement of tubes corrosion & erosion
- Reporting

Summary

- Completed operation & testing
- Confirmed heat integration performance
  - 240-300 MMBTU/hr heat recovery for 550 MW base plant (Case 9)
  - Up to 65% reduction of FGD makeup water
- Confirmed ESP performance improvement
  - PM removal: > 99.5%
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  - Detailed analysis is in progress
- Data analysis & reporting will be completed by December 2016

Questions?