Fifth Annual Conference on Carbon Capture & Sequestration

Steps Toward Deployment

CCS Economic Analyses

2006 Cost & Performance Comparison of Fossil Energy Power Plants

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May 8-11, 2006 • Hilton Alexandria Mark Center • Alexandria, Virginia

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Overview

- **<u>Purpose</u>: To compare near-term commercial offerings for IGCC, PC and NGCC cases both with and without current technology for CO_2 capture**
  - Developed with consistent design requirements and up-to-date performance and capital cost estimates
  - Considered technologies that could be built now and deployed by 2010
  - Provides baseline costs and performance for which to compare advancing technologies within the FE R&D Program
- **Public report available Summer 2006**

Study Matrix

Case	Plant Type	ST Cond. (psig/°F/°F)	GT	Gasifier/ Boiler	Acid Gas Removal/ CO_2 Separation / Sulfur Recovery	CO_2 Cap
1	IGCC	1800/1050/1050	F Class	GE	Selexol / - / Claus	
2					Selexol / Selexol / Claus	90%
3				CoP E-Gas	MDEA / - / Claus	
4					Selexol / Selexol / Claus	90%
5				Shell	Sulfinol-M / - / Claus	
6					Selexol / Selexol / Claus	90%
7	PC	2400/1050/1050		Subcritical	Wet FGD / - / Gypsum	
8					Wet FGD / Econamine / Gypsum	90%
9		3500/1100/1100		Supercritical	Wet FGD / - / Gypsum	
10					Wet FGD / Econamine / Gypsum	90%
11	NGCC	2400/1050/950	F Class	HRSG		
12					- / Econamine / -	90%

GEE – GE Energy
CoP – Conoco Phillips

Design Basis: Coal Type

Illinois #6 Coal Ultimate Analysis (weight %)

	As Rec'd	Dry
Moisture	11.12	0
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	**2.51**	2.82
Ash	9.70	10.91
Oxygen (by difference)	6.88	7.75
	100.0	100.0
HHV (Btu/lb)	11,666	13,126

Design Basis: Assumptions

Economic

Startup	**2010**
Plant Life (Years)	**20**
Capital Charge Factor (%)	**13.8**
Dollars (Constant)	**2006**
Coal ($/MM Btu)	**1.34**
Capacity Factor	**85**

Site

Greenfield, Midwestern USA, 0 ft Elevation

Rail and Highway Access

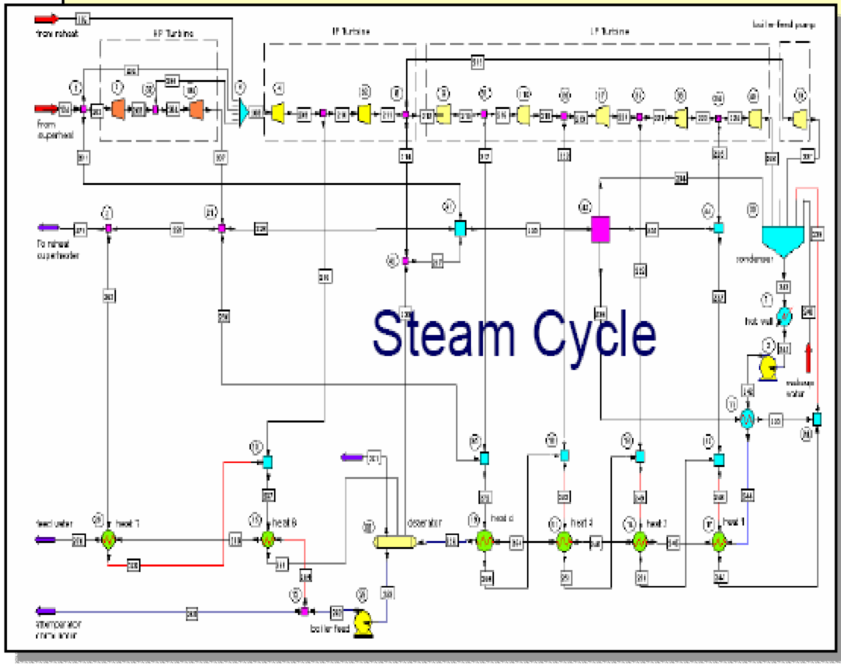
Municipal Water

300 Acres

Technical Approach

1. Extensive Process Simulation (ASPEN)

- All major chemical processes and equipment are simulated
- Detailed mass and energy balances
- Performance calculations (auxiliary power, gross/net power output)



2. Cost Estimation

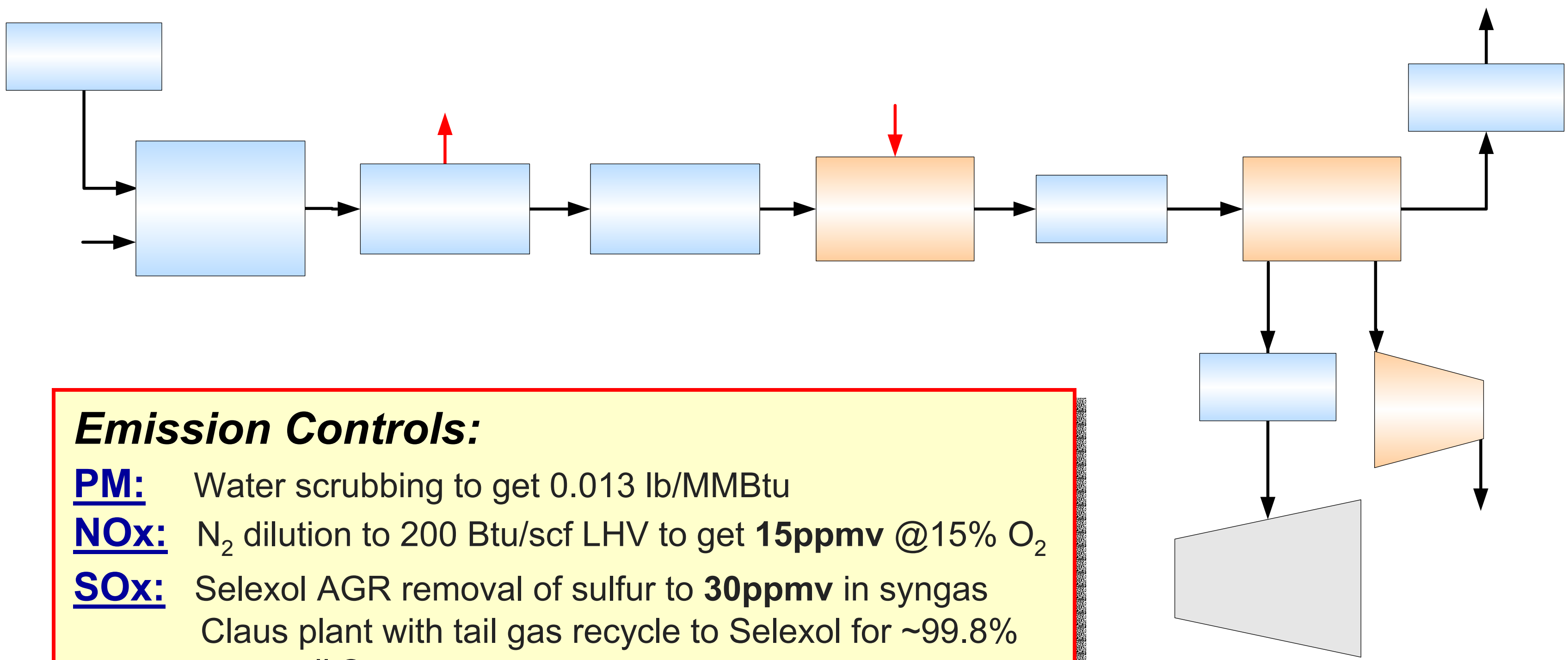
- **Inputs from process simulation** (Flow Rates/Gas Composition/Pressure Temp.)
- **Sources for cost estimation**
  - Parsons
  - Vendor sources where available
- **Follow DOE Analysis Guidelines**

IGCC Power Plant

Current State CO_2 Capture Using Selexol™

Pre-Combustion Current Technology

IGCC Power Plant with CO_2 Scrubbing



Emission Controls:

PM: Water scrubbing to get 0.013 lb/MMBtu

NOx: N_2 dilution to 200 Btu/scf LHV to get **15ppmv** @15% O_2

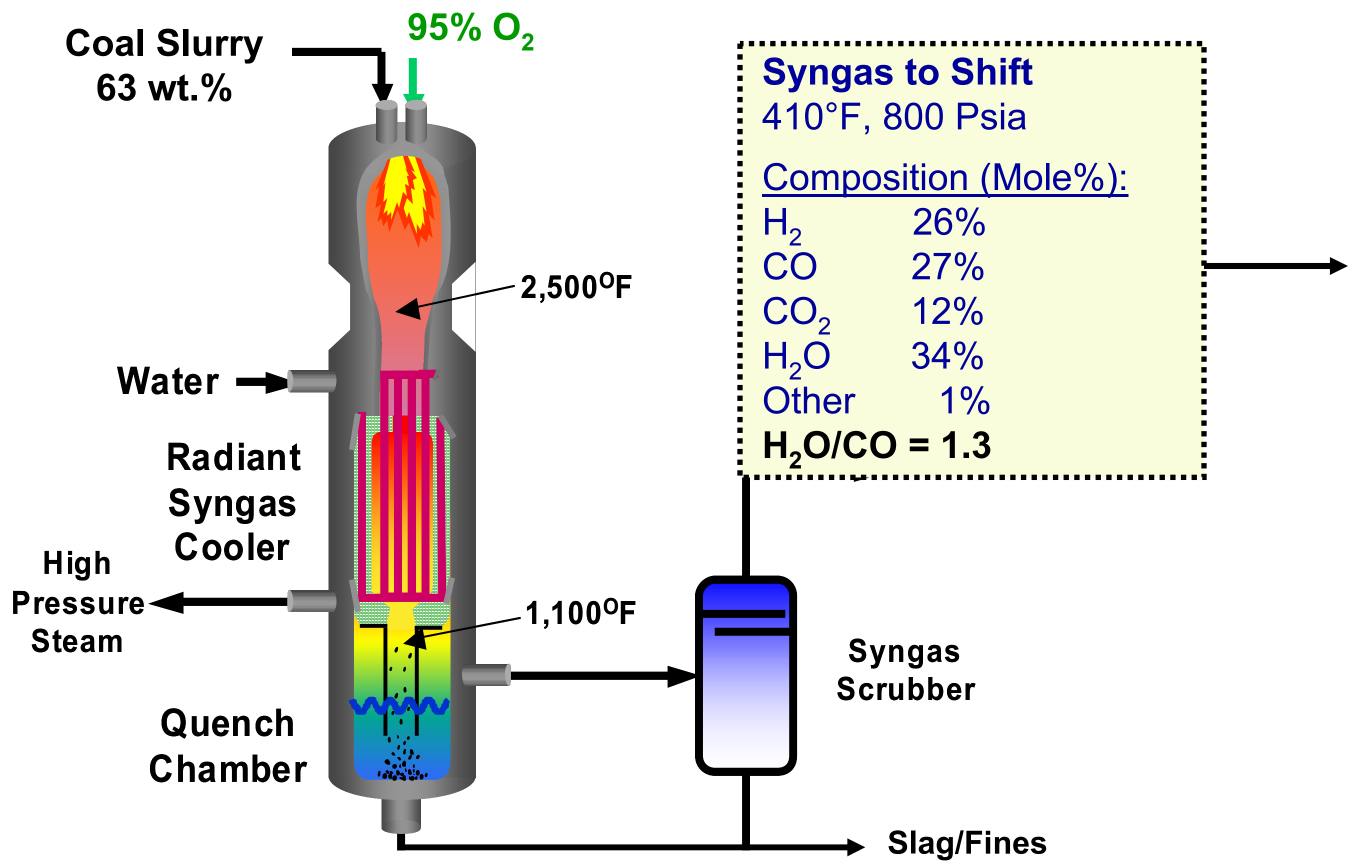
SOx: Selexol AGR removal of sulfur to **30ppmv** in syngas
Claus plant with tail gas recycle to Selexol for ~99.8% overall S recovery

Hg: Activated Carbon beds for ~90% removal

Advanced F-Class Turbine - 232MWe (42% LHV)

Steam Conditions - 1800psig/1050°F/1050°F

Cases 1 & 2: GE Energy Radiant



Syngas to Shift
410°F, 800 Psia

Composition (Mole%):

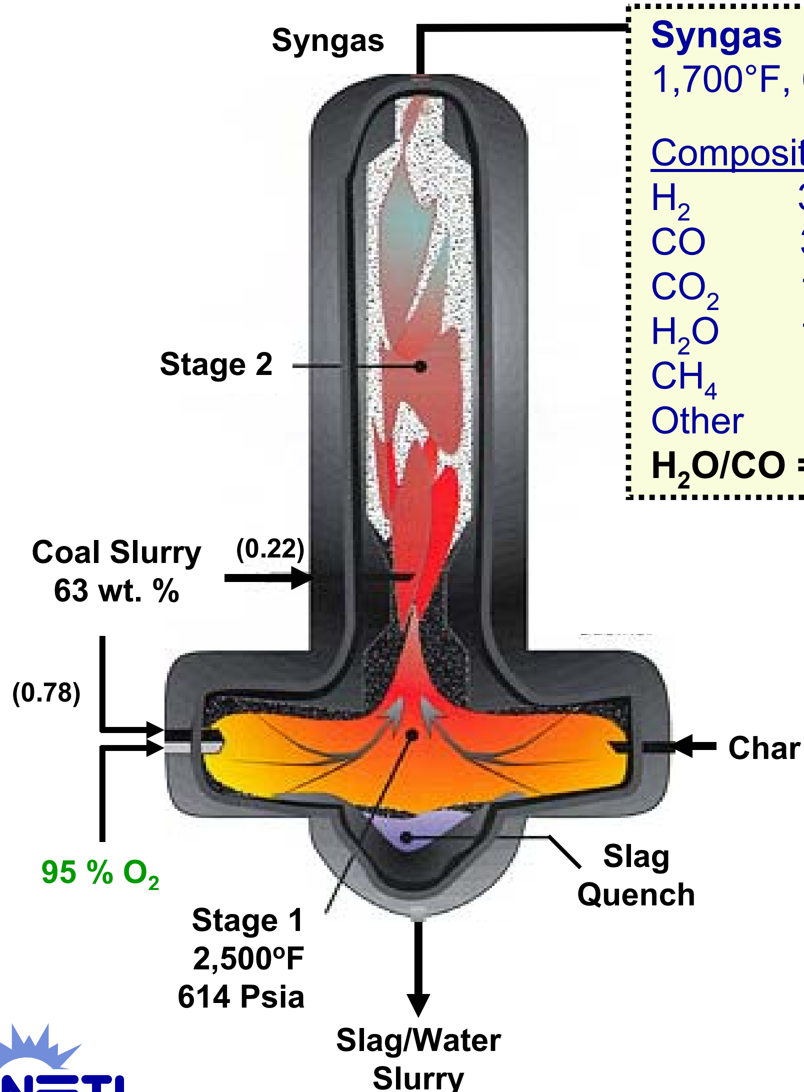
H_2	26%
CO	27%
CO_2	12%
H_2O	34%
Other	1%

H_2O/CO = 1.3

Design: Pressurized, single-stage, downward firing, entrained flow, slurry feed, oxygen blown, slagging, radiant and quench cooling

Note: All gasification performance data estimated by the project team to be representative of GE gasifier

Cases 3 & 4: ConocoPhillips E-Gas™



Syngas
1,700°F, 614 psia

Composition (Mole%):

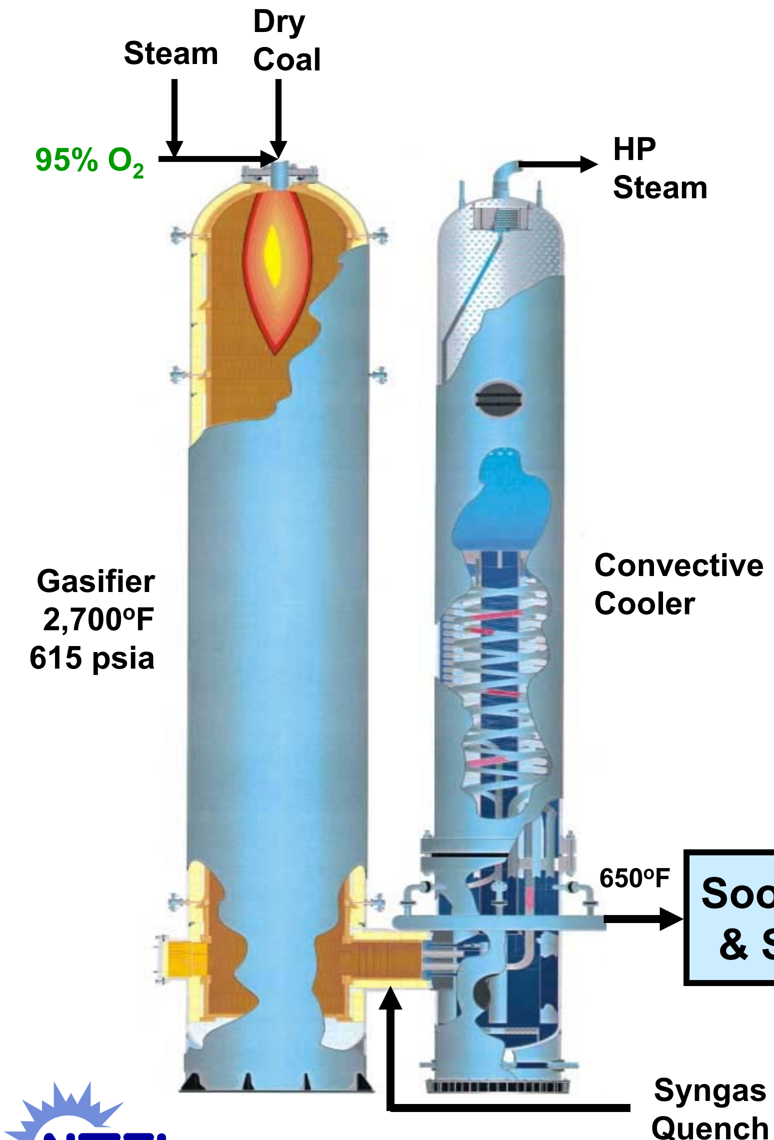
H_2	30%
CO	31%
CO_2	17%
H_2O	16%
CH_4	3%
Other	3%

$H_2O/CO = 0.4$

Design: Pressurized, two-stage, upward firing, entrained flow, slurry feed, oxygen blown, slagging, fire-tube boiling syngas cooling, syngas recycle

Note: All gasification performance data estimated by the project team to be representative of an E-Gas gasifier

Cases 5 & 6: Shell Gasification



Soot Quench & Scrubber

To Shift

Design: Pressurized, single-stage, downward firing, entrained flow, dry feed, oxygen blown, convective cooler

Note: All gasification performance data estimated by the project team to be representative of Shell gasifier

Syngas
350°F, 600 Psia

Composition (Mole%):

H_2	29%
CO	60%
CO_2	2%
H_2O	4%
Other	5%

H_2O/CO = 0.1

Source: "The Shell Gasification Process", Uhde, ThyssenKrupp Technologies

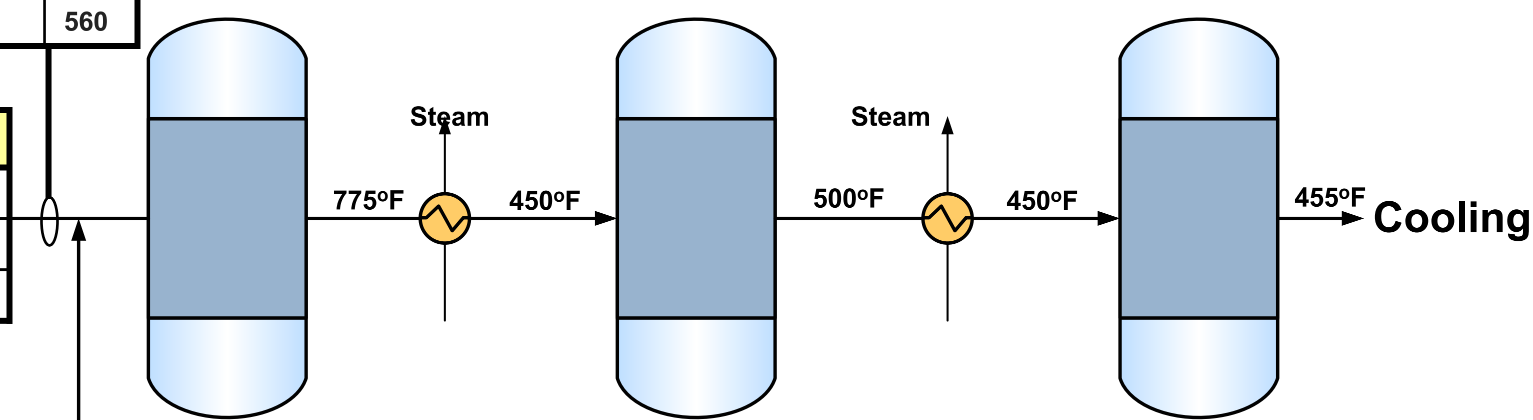
NETL

Water-Gas Shift Reactor System

Design:
- Haldor Topsoe SSK Sulfur Tolerant Catalyst
- Up to 99% CO Conversion
- H_2O/CO = 2.3 (Project Assumption)
- Overall ΔP = ~30 psia

Pressure (Psia)	
GE	800
E-Gas	560
Shell	560

H_2O/CO Ratio	
GE	1.3
E-Gas	0.4
Shell	0.1



	Relative HP* Steam Flow	Steam Turbine Output (MW)
GE	1.0	270
E-Gas	2.0	216
Shell	2.8	202

*High Pressure Steam

$$H_2O + CO \longleftrightarrow CO_2 + H_2$$

H_2O/CO has great effect on relative performance

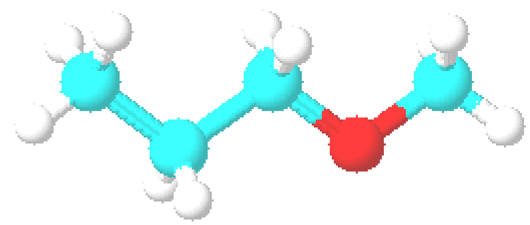
CO_2 Capture via Selexol Scrubbing

Advantages

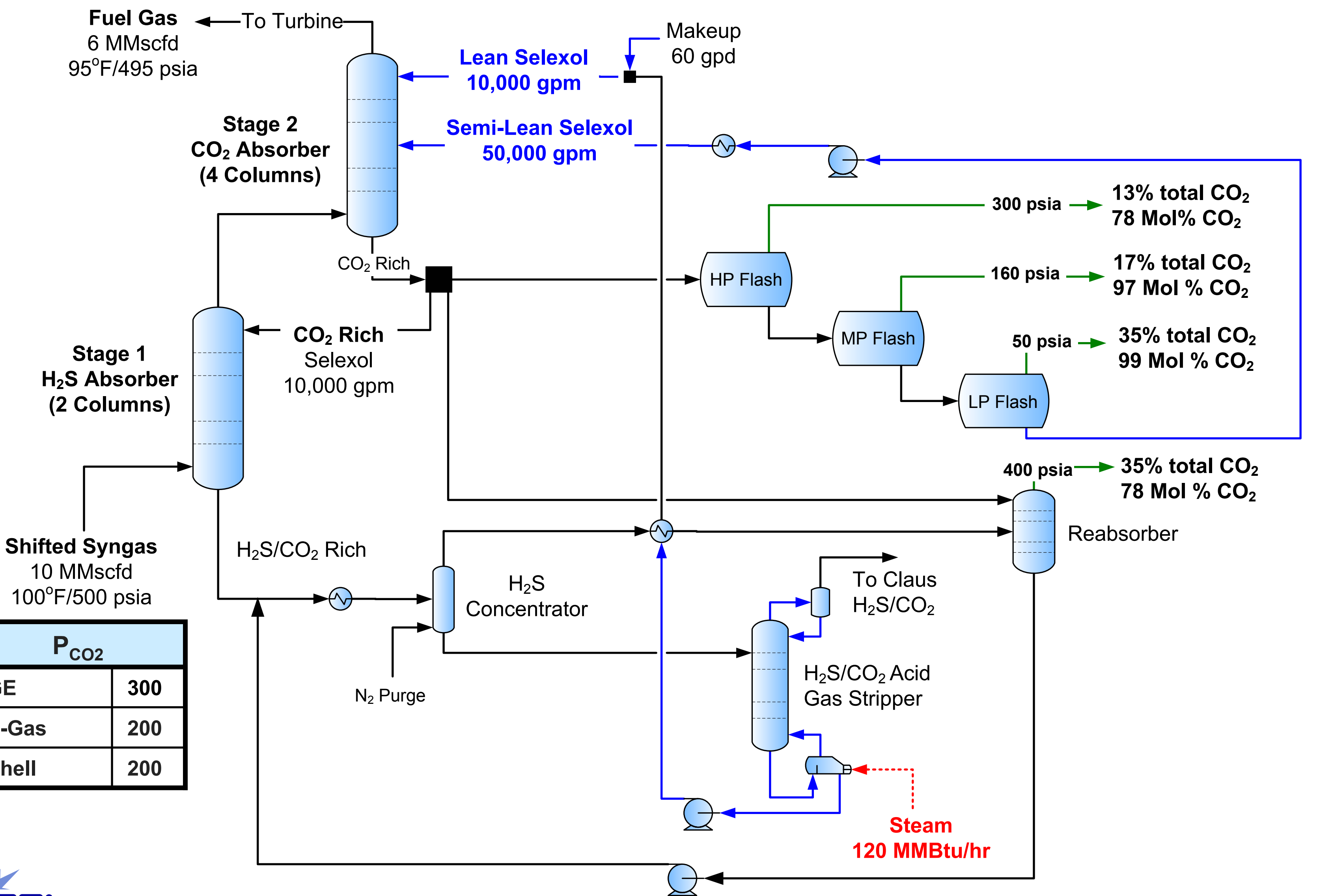
- Physical Liquid Sorbent → High loadings at high CO_2 partial pressure
- Highly selective for H_2S and CO_2 → No need for separate sulfur capture system
- No heat of reaction (ΔH_{rxn}), small heat of solution
- Chemically and thermally stable, low vapor pressure
- 30+ years of commercial operation (55 worldwide plants)

Disadvantages

- Requires Gas Cooling (to ~100^{o}F)
- CO_2 regeneration by flashing



Selexol™ Scrubbing



P_{CO2}	
GE	300
E-Gas	200
Shell	200

IGCC Power Plant

Results

Cases 1 & 2: GE Energy Radiant Performance

	Case 1 No Capture	Case 2 Capture
Coal Flow Rate (Ton/day)	5,846	6,063
CO_2 Captured (Ton/day)	-	13,120
Total Gross Power (MW)	769	741
Auxiliary Power (MW)		
Base Plant Load	26	26
Air Separation Unit	96	115
Gas Cleanup/CO_2 Capture	3	8
CO_2 Compression	-	29
Total Auxiliary Load (MW)	125	178
Net Power (MW)	644	563
Net Heat Rate (Btu/kWh)	8,832	10,463
Efficiency (% HHV)	38.6	32.6
Energy Penalty (%)[1]	-	16%

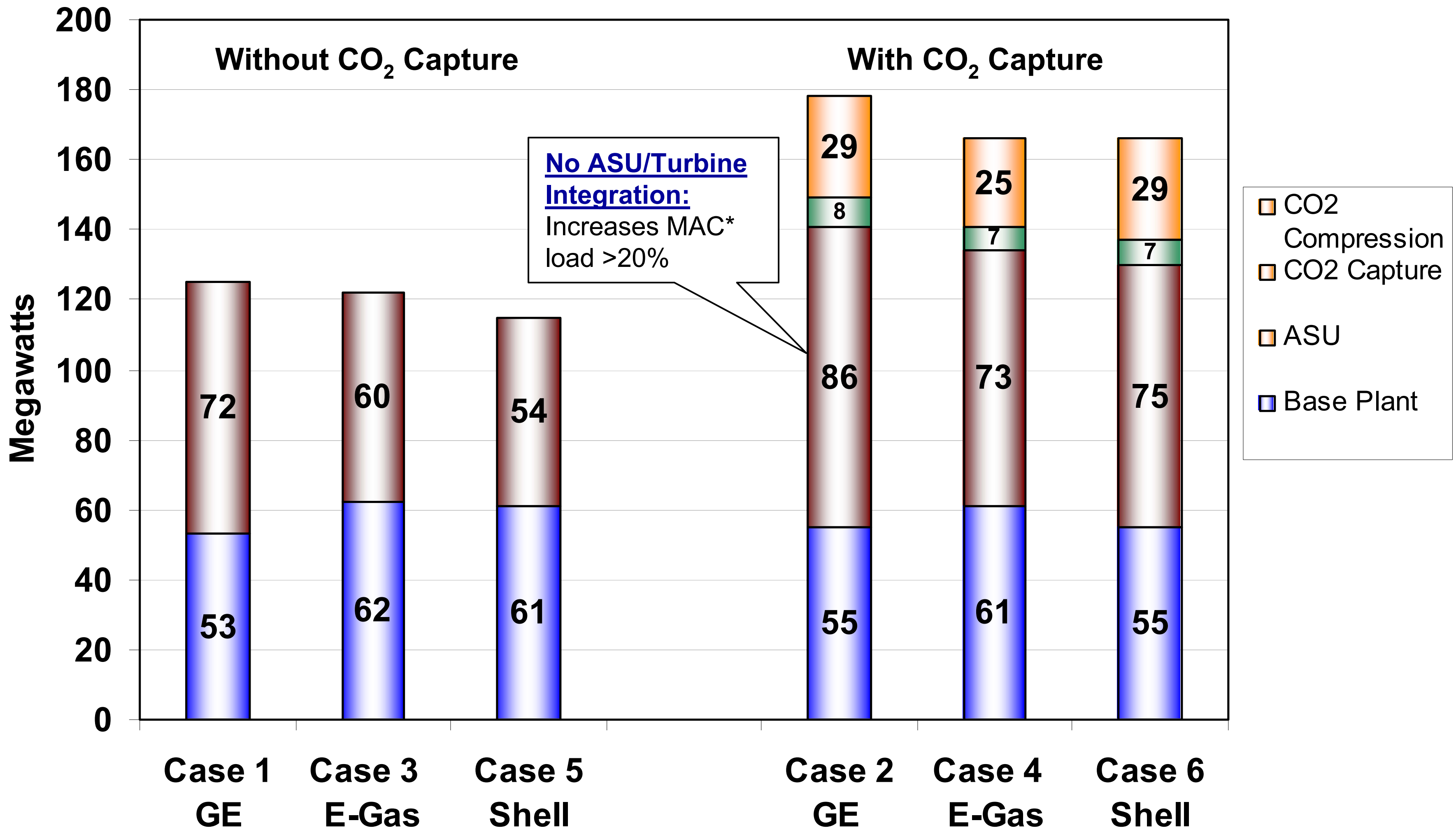
Steam for Capture

- Additional O_2
- ↑ in ASU air comp. load w/o CT integ.

Includes H_2S/COS Removal in Selexol Solvent

[1] CO_2 Capture Energy Penalty = Percent decrease in net power plant efficiency due to CO_2 Capture

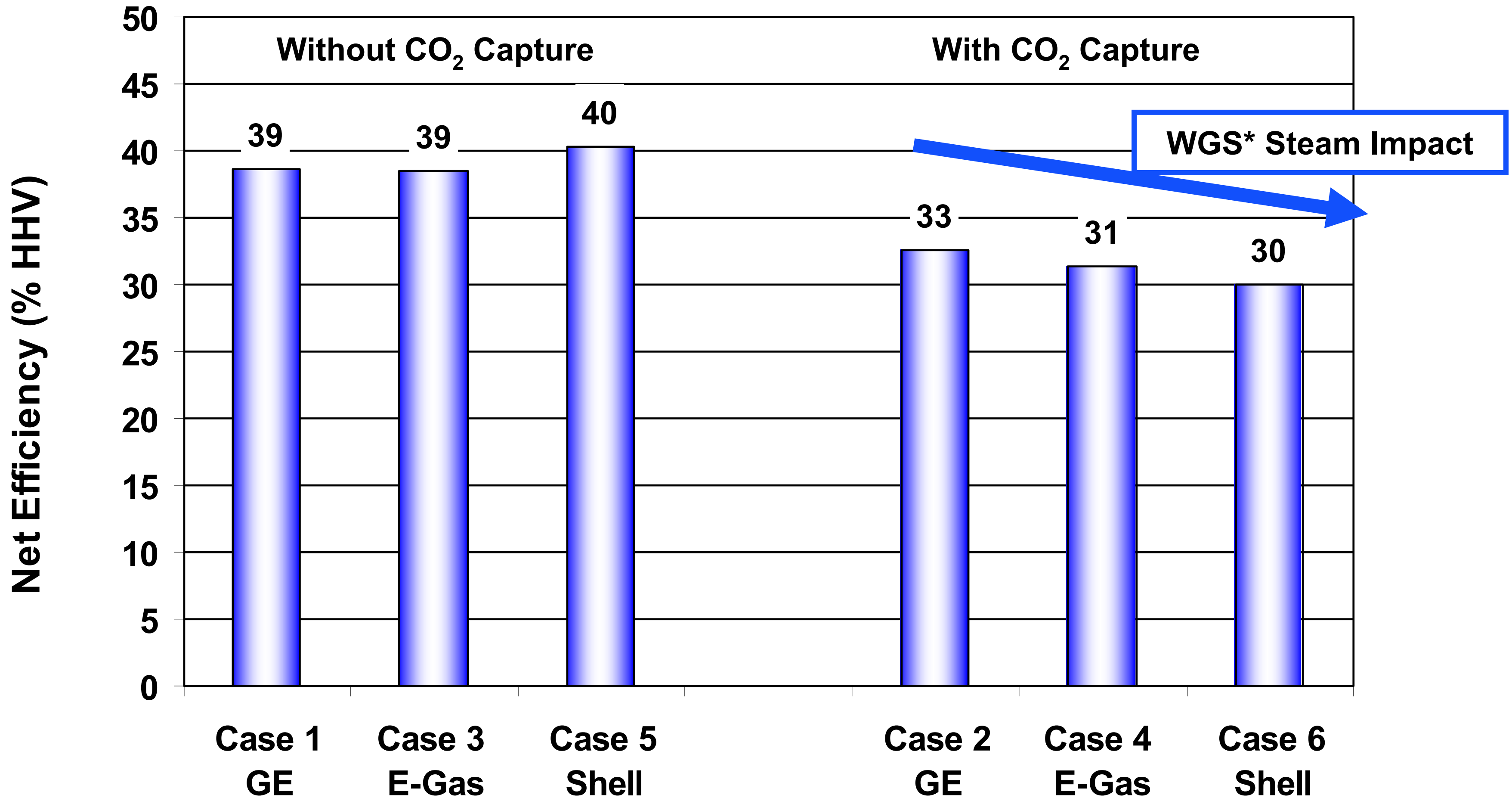
IGCC Auxiliary Load Summary



*main air compressor

IGCC Thermal Efficiency Summary

CO_2 Capture decreases net efficiency by 6-10 percentage points



*Water Gas Shift

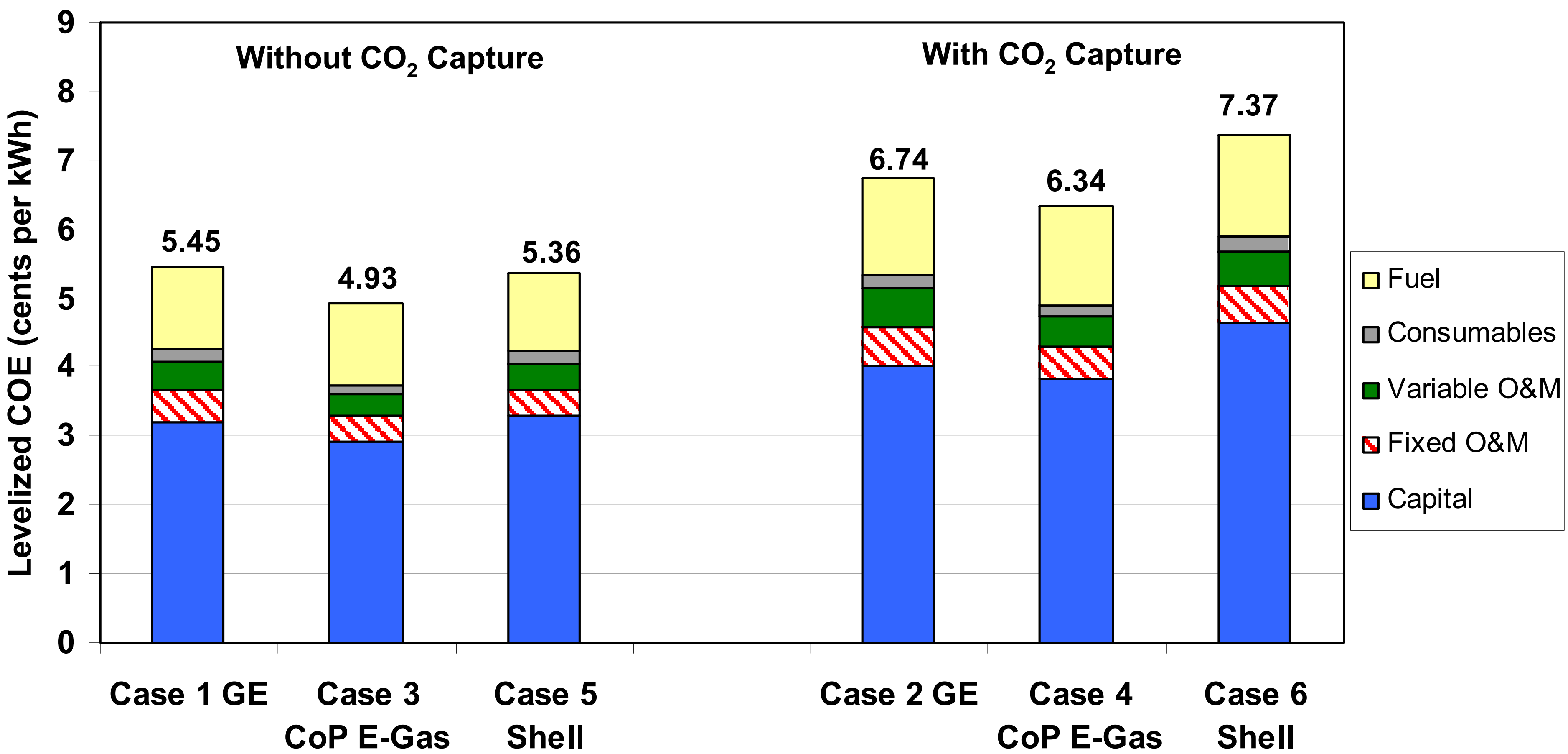
Cases 1 & 2: GE Energy Radiant Economics

	Case 1 No Capture	Case 2 Capture	Difference
Plant Cost ($/kWe)[1]			
Base Plant	1,311	1,457	146
Air Separation Unit	100	165	65
Gas Cleanup/CO_2 Capture	146	262	116
CO_2 Compression	-	66	66
Total Plant Cost ($/kWe)	1,557	1,950	393
Capital COE (Cents/kWh)	3.21	4.02	0.81
Variable COE (Cents/kWh)	2.24	2.72	0.48
Total COE (Cents/kWh)[2]	5.45	6.74	1.29
Increase in COE (%)	-	24	
$/tonne CO_2 Avoided	-	18	

[1]Total Plant Capital Cost (Includes contingencies and engineering fees)

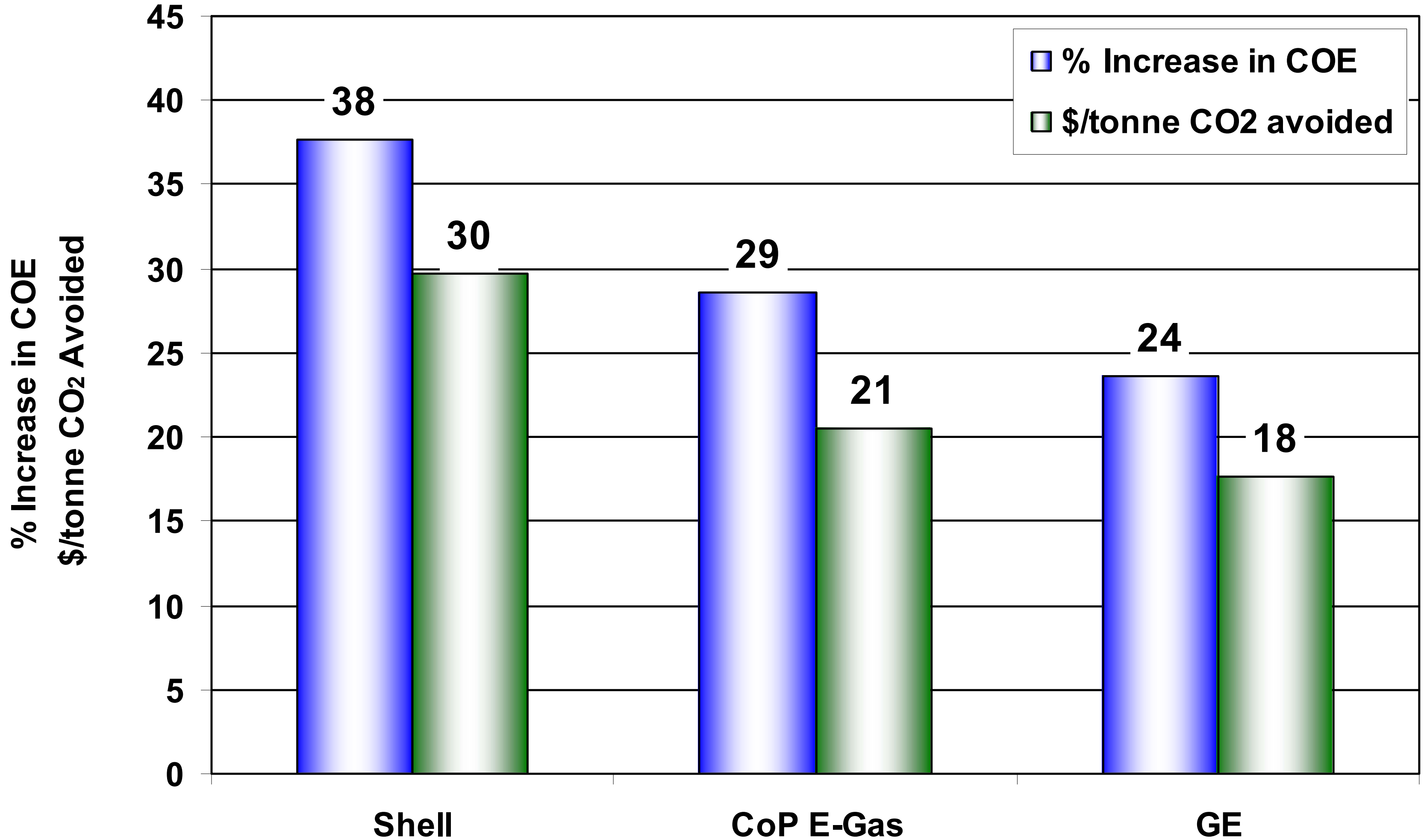
[2]January 2006 Dollars, 85% Capacity Factor, 13.8% Levelization Factor, Coal cost $1.34/10^6$Btu

IGCC Economic Results Summary



Average COE (cents/kWh) = 5.3 and 6.8 (w/ Capture)
Average increase in COE for CO_2 Capture = 30%

IGCC CO_2 Capture Mitigation Cost Summary



IGCC CO_2 Capture Key Points

1. No ASU integration with CO_2 Capture cases, this increases ASU MAC* power load and overall ASU capital costs
2. Syngas H_2O/CO ratio has large influence on water-gas shift steam requirement, steam turbine output and net plant efficiency
3. CoP/E-Gas has high methane content, with Selexol at 95% capture, can only get 89% carbon capture

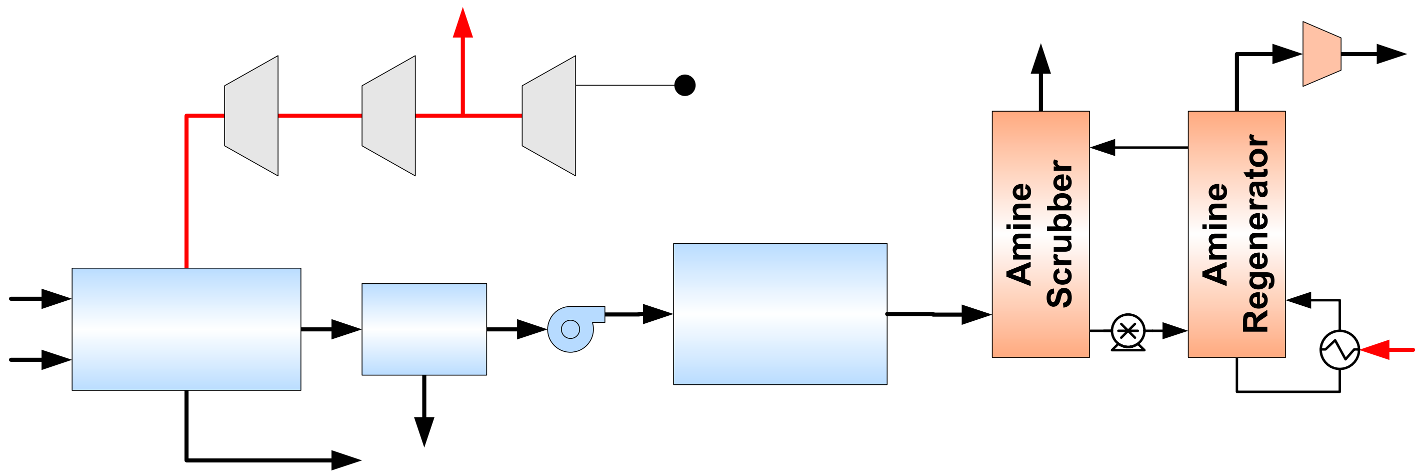
*Main Air Compressor

Pulverized Coal Power Plant

Current State CO_2 Capture Using Advanced Amines

Post-Combustion Current Technology

Pulverized Coal Power Plant with CO_2 Scrubbing



PM Control: Bag House to get 0.015 lb/MMBtu (99.8% removal)

SOx Control: FGD to get 0.086 lb/MMBtu (98.5% removal)

NOx Control: LNB + OFA + SCR to maintain 0.7 lb/MMBtu

Mercury Control: Activated Carbon beds for ~90% removal

Steam Conditions (Subcritical) - 2400psig/1050°F/1050°F

Steam Conditions (Supercritical) - 3500psig/1100°F/1100°F

Amine Scrubbing Advantages/Disadvantages

Amine Advantages

1. **Proven Technology → Remove CO_2 and H_2S from NG**
2. **Chemical solvent → *High* loadings at *low* CO_2 partial pressure**
3. **Relatively Cheap**

Amine Disadvantages

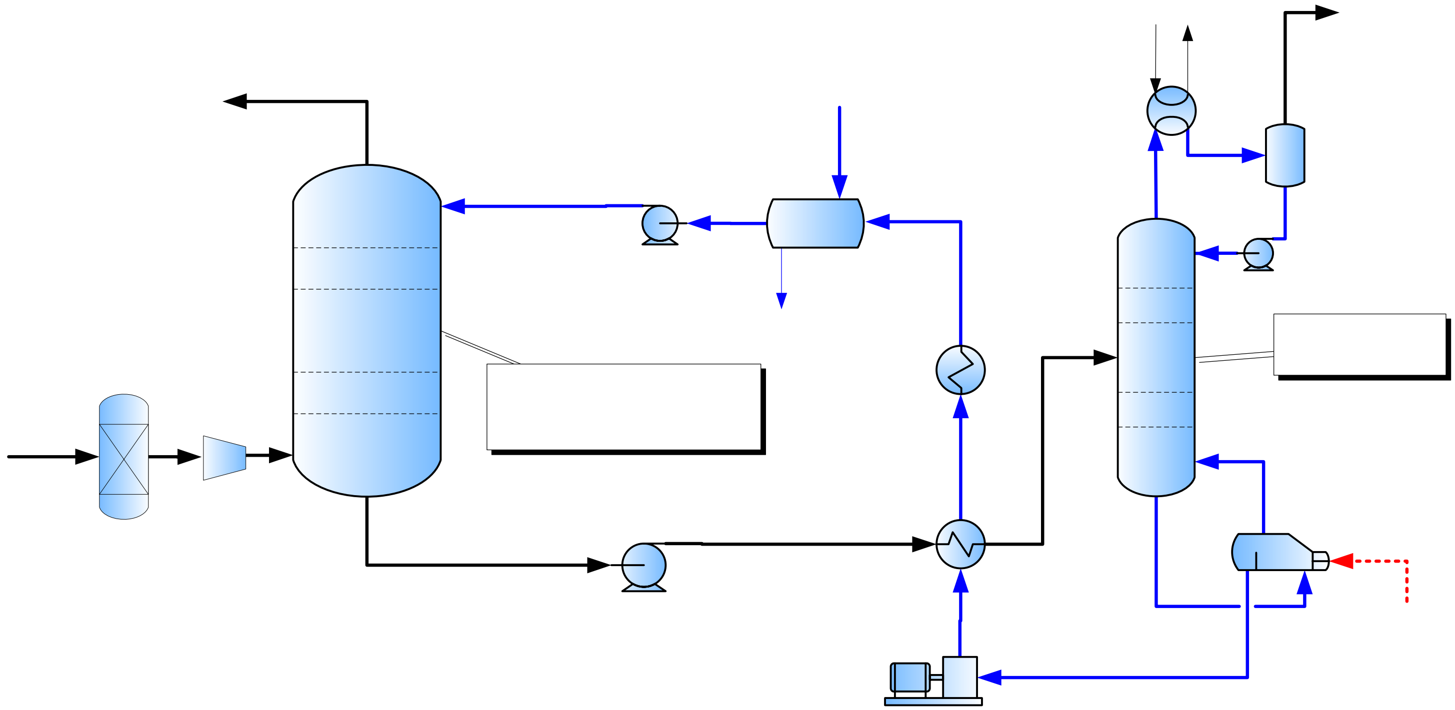
1. **High heat of reaction → high regeneration energy required**
   - 1,500 to 3,500 Btu/lb CO_2 removed
2. **Degradation and Corrosion**
   - Requires 10 ppm sulfur or less

Amine Scrubbing Improvements

Amine CO_2 scrubbing technology leaders are Fluor (Econamine FG Plus^{SM}) and Mitsubishi (KS)

Improvements	Benefits	Outcome
1. New Solvent Formulation	↑ Reaction Rates	↓ Packing volume, ↓ Absorber size ↓ Absorber cost
	↑ CO_2 Capacity	↓ Solvent circulation, ↓ Reboiler Duty
2. Heat Integration	↑ Reaction Rates	↓ Packing volume, ↓ Absorber size ↓ Absorber cost
	↑ CO_2 Capacity	↓ Solvent circulation, ↓ Reboiler Duty
3. Split Flow	↓ Reboiler Duty	↑ Power plant efficiency
4. Condensate Flash Steam Stripping	↓ Semi-Lean Loading	↓ Reboiler Duty
5. Integrated Steam Generation	↓ Reboiler Duty	↑ Power plant efficiency
6. Larger Diameter Vessels	60 foot diameter	Accommodate power plants
7. Non-Thermal Reclaimer	↓ Solvent Losses	↓ Solvent make-up costs, eliminate any solid hazardous waste

Fluor Econamine FG Plus^{SM} Scrubbing



Reboiler Heat Duty (Btu/lb CO_2)	1,5[illegible]0	Regeneration (ºF)	250's
MEA Circulation Rate (GPM)	35,000	Auxiliary Power (MW)	22-25
Absorption (ºF)	100's	Induced Draft Fan (MW)	13-15

FG to Stack

100ºF/14.7 Psia

5,325,560 lb/h

1,255,160 ACFM

Pulverized Coal Power Plant

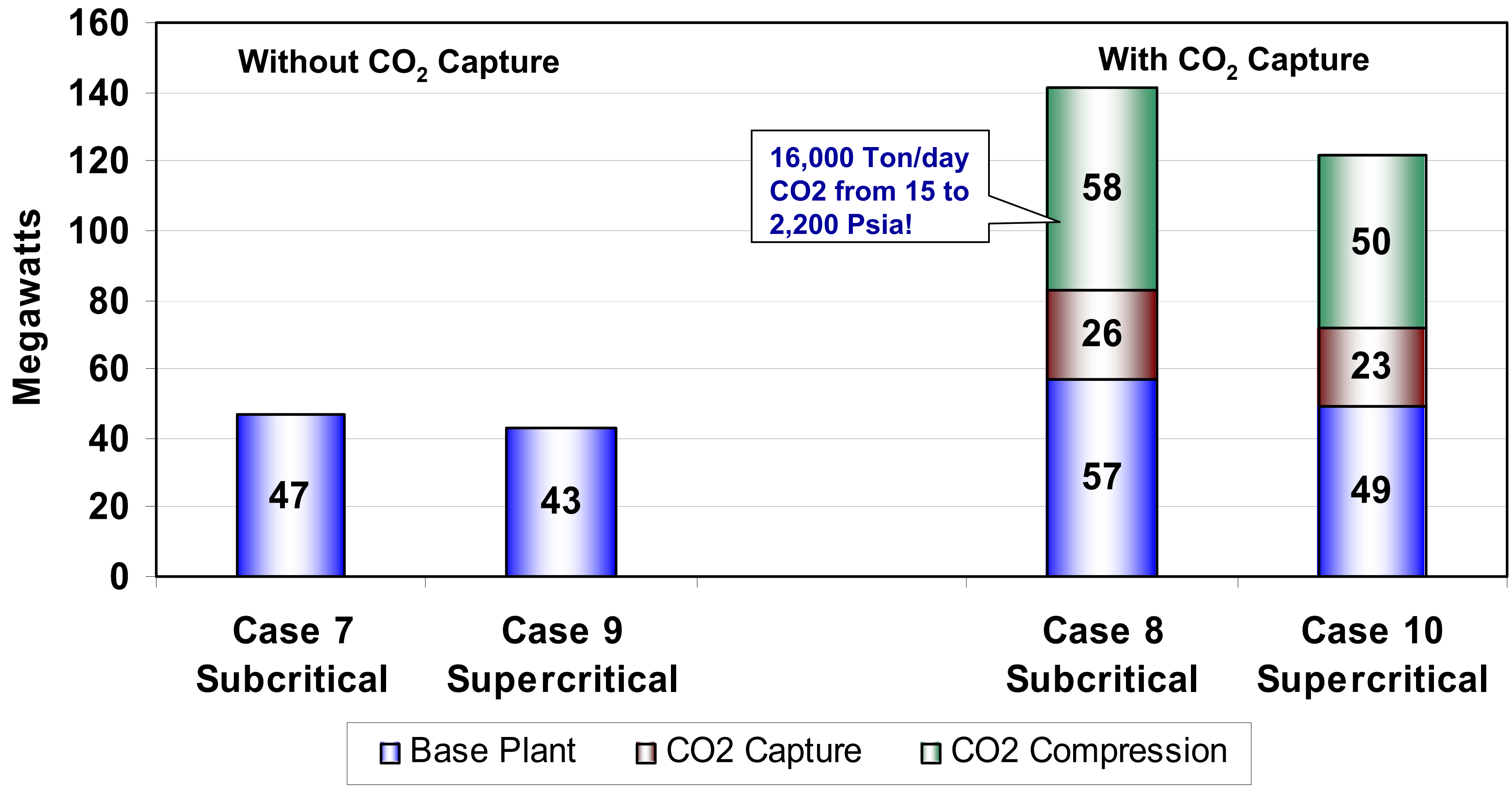
Results

Pulverized Coal Combustion Performance

	Subcritical		Supercritical	
	No Capture	Capture	No Capture	Capture
Coal Flow Rate (Ton/day)	5,310	8,069	5,013	7,091
CO_2 Captured (Ton/day)	-	15,880	-	14,620
Total Gross Power (MW)	597	690	593	672
Auxiliary Power (MW)				
Base Plant Load	27	31	24	27
Forced + Induced Draft Fans	13	19	12	17
CO_2 Capture	-	25		22
CO_2 Compression	-	58	-	49
Flue Gas Cleanup	7	7	7	7
Total Auxiliary Load (MW)	47	140	43	122
Net Power (MW)	550	550	550	550
Net Heat Rate (Btu/kWh)	9,389	14,274	8,857	12,517
Efficiency (% HHV)	36	24	39	27
CO_2 Energy Penalty (%)[1]	-	33	-	31

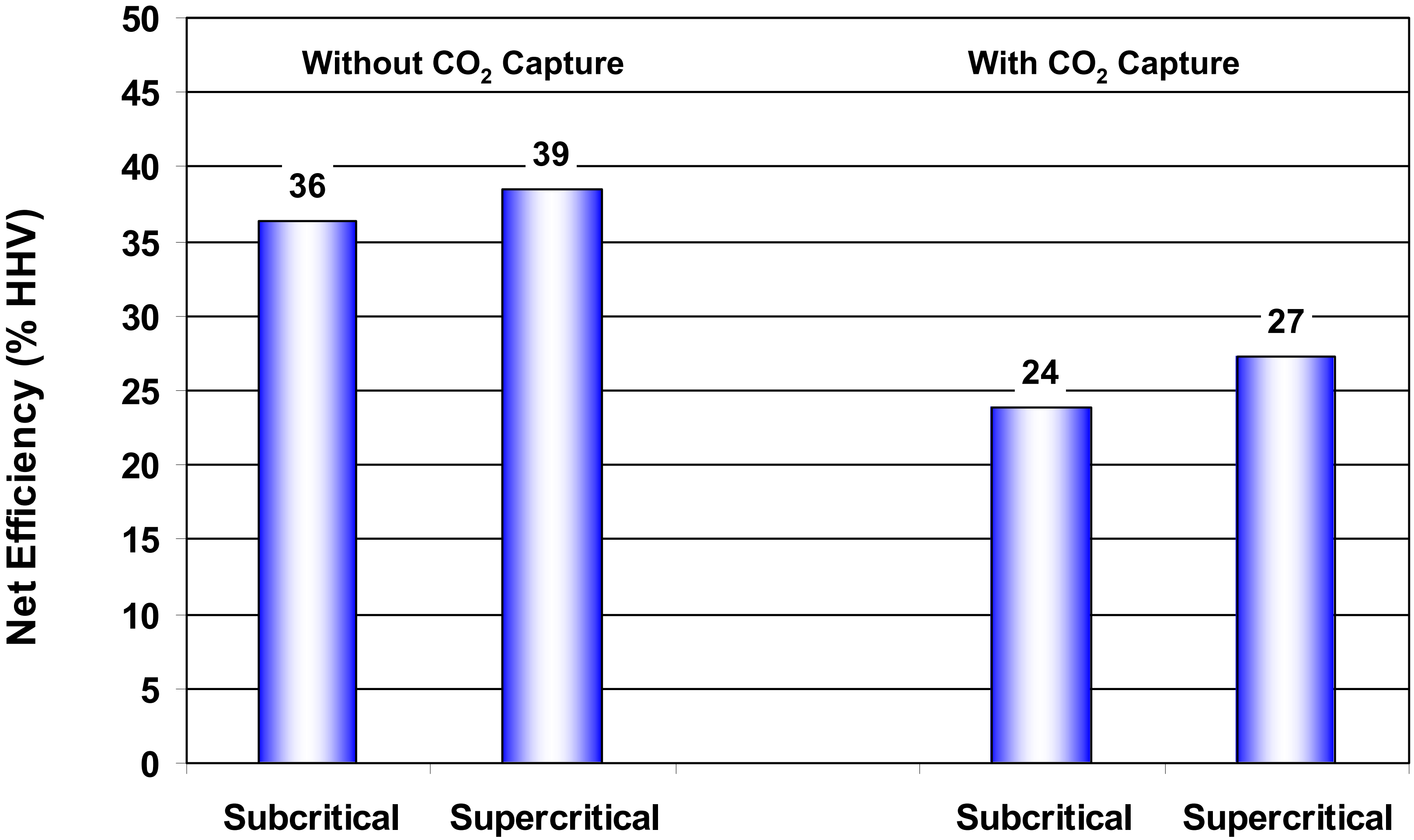
[1] CO_2 Capture Energy Penalty = Percent decrease in net power plant efficiency due to CO_2 Capture

Pulverized Coal Auxiliary Load Summary



Pulverized Coal Thermal Efficiency Summary

CO_2 Capture decreases net efficiency by 12 percentage points



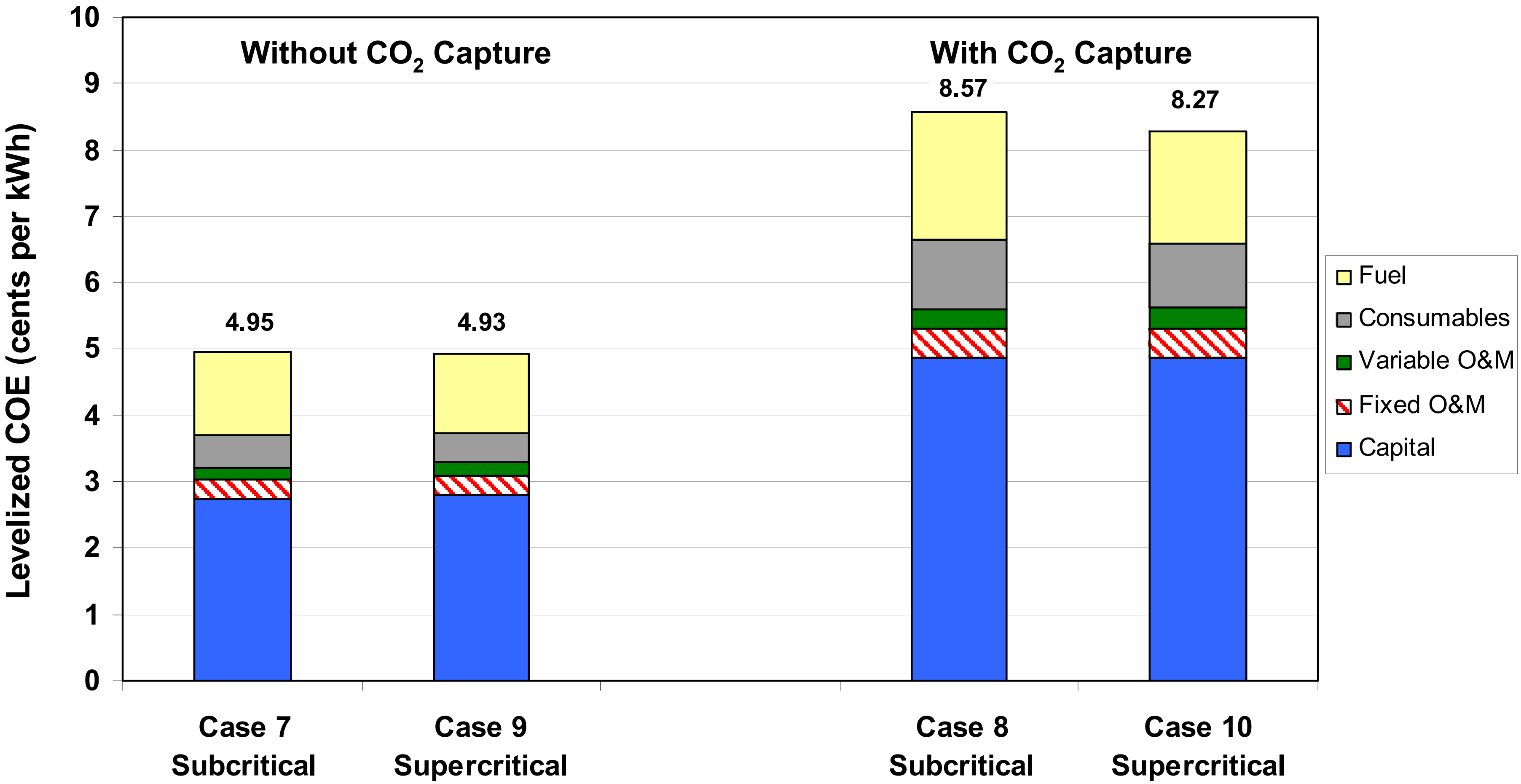
Pulverized Coal Combustion Economics

	Subcritical		Supercritical	
	No Capture	Capture	No Capture	Capture
Plant Cost ($/kWe)[1]				
Base Plant	1,117	1,367	1,159	1,661
CO_2 Capture	-	624	-	622
CO_2 Compression	-	82	-	82
SOx and NOx Cleanup	206	285	196	257
Total Plant Cost ($/kWe)	1,323	2,358	1,355	2,365
Capital COE (Cents/kWh)	2.73	4.87	2.79	4.87
Variable COE (Cents/kWh)	2.22	3.70	2.14	3.39
Total COE (Cents/kWh)[2]	4.95	8.57	4.94	8.27
Increase in COE (%)	-	73	-	67
$/tonne CO_2 Avoided	-	49	-	48

[1]Installed Plant Capital Cost (Includes contingencies and engineering fees)

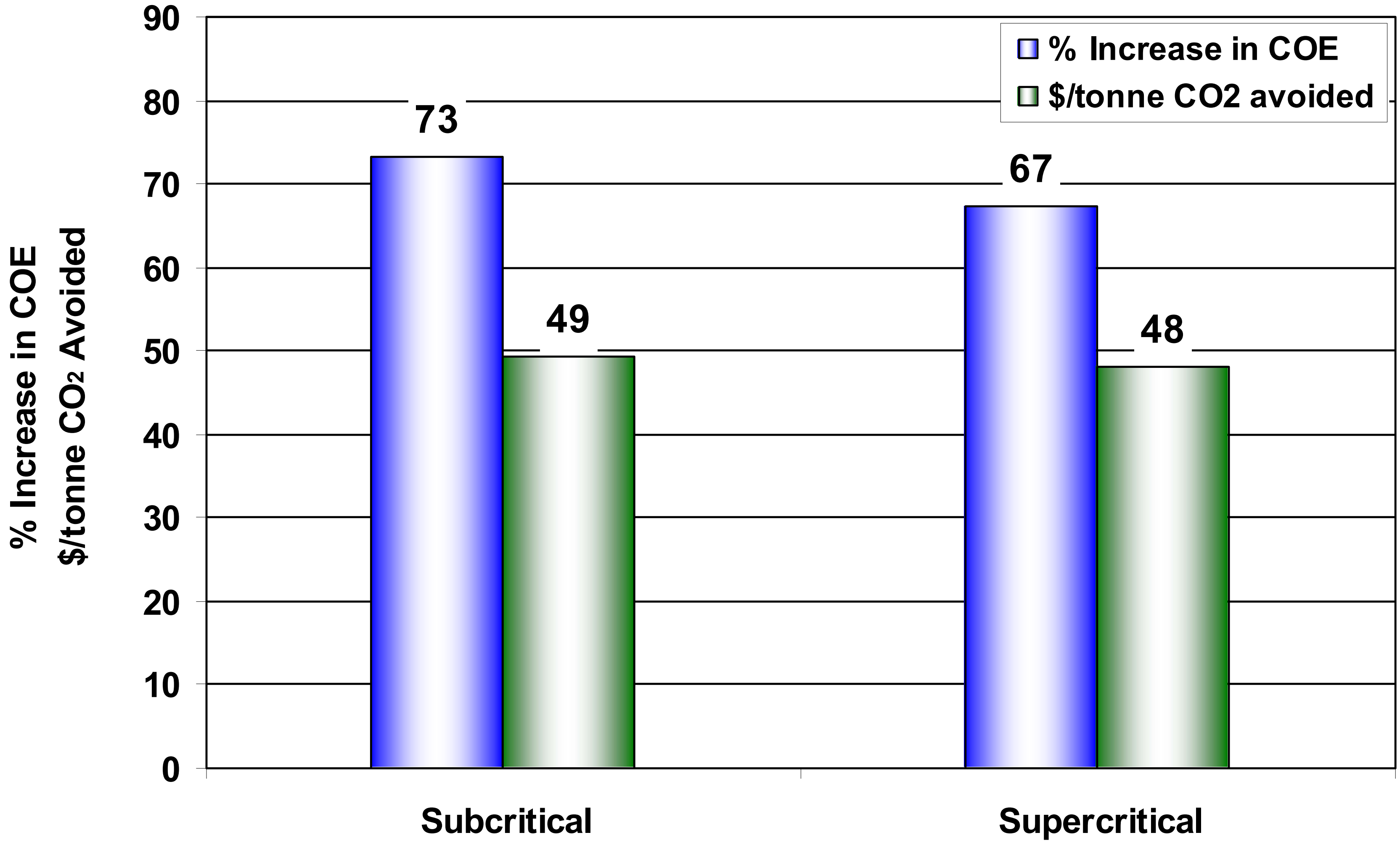
[2]January 2006 Dollars, 85% Capacity Factor, 13.8% Levelization Factor, Coal cost $1.34/10^{6}Btu

Pulverized Coal Summary Results



PC CO_2 capture average increase in COE = 70%

Pulverized Coal CO_2 Capture Mitigation Costs



Pulverized Coal CO_2 Capture Key Points

1. **Advanced amine scrubbing technology for 90% CO_2 capture continues to be very energy intensive and costly**
   - Definite need for performance and cost improvements
   - Good opportunity for R&D

2. **"Post-combustion CO_2 capture processes can be regarded as *current technology*, but some demonstration of these technologies at large scale coal fired power plants is needed before they can be widely adopted with an acceptable level of commercial risk." (IEA 2004)**

Acknowledgements

- **NETL Team**
  - Juli Klara – Subtask Manager
  - Jared Ciferno – Technical Monitor
  - Mike Reed – Technical Monitor
- **RDS Team**
  - Ron Schoff (Parsons Corporation) – Technical
  - Pam Capicotto (Parsons Corporation) – Performance
  - Mike Rutkowski (Parsons Corporation) - Technical
  - Vlad Vaysman (WorleyParsons) - Technical
  - Tom Buchanan (WorleyParsons) – Cost
  - Massood Ramezan (SAIC) – Subtask Manager

Thank You!

Cases 3 & 4: ConocoPhillips E-Gas™ Performance

	Case 3 No Capture	Case 4 Capture
Coal Flow Rate (Ton/day)	5,583	5,768
CO_2 Captured (Ton/day)	-	11,870
Total Gross Power (MW)	734	680
Auxiliary Power (MW)		
Base Plant Load	29	29
Air Separation Unit	91	103
Gas Cleanup/CO_2 Capture	2	7
CO_2 Compression	-	27
Total Auxiliary Load (MW)	122	166
Net Power (MW)	612	515
Net Heat Rate (Btu/kWh)	8,870	10,895
Efficiency (% HHV)	38.5	31.3
CO_2 Energy Penalty (%)[1]	-	19

[1]CO_2 Capture Energy Penalty = Percent decrease in net power plant efficiency due to CO_2 Capture

Cases 3 & 4: ConocoPhillips E-Gas™ Economics

	Case 3 No Capture	Case 4 Capture	Difference
Plant Cost ($/kWe)[1]			
Base Plant	1,173	1,399	226
Air Separation Unit	133	158	25
Gas Cleanup/CO_2 Capture	111	237	126
CO_2 Compression	-	67	67
Total Plant Cost ($/kWe)	1,417	1,861	444
Capital COE (Cents/kWh)	2.92	3.83	0.91
Variable COE (Cents/kWh)	2.01	2.51	0.50
Total COE (Cents/kWh)[2]	4.93	6.34	1.41
Increase in COE (%)	-	29	
$/tonne CO_2 Avoided		21	

[1]Total Plant Capital Cost (Includes contingencies and engineering fees)

[2]January 2006 Dollars, 85% Capacity Factor, 13.8% Levelization Factor, Coal cost $1.34/10^6$Btu

Cases 5 & 6: Shell Gasification Performance

	Case 5 No Capture	Case 6 Capture
Coal Flow Rate (Ton/day)	5,401	5,743
CO_2 Captured (Ton/day)	-	12,430
Total Gross Power (MW)	736	667
Auxiliary Power (MW)		
Base Plant Load	25	23
Air Separation Unit	90	107
Gas Cleanup/CO_2 Capture	1	7
CO_2 Compression	-	29
Total Auxiliary Load (MW)	115	166
Net Power (MW)	621	501
Net Heat Rate (Btu/kWh)	8,468	11,156
Efficiency (% HHV)	40.3	30.6
CO_2 Energy Penalty (%)[1]	-	25

[1]CO_2 Capture Energy Penalty = Percent decrease in net power plant efficiency due to CO_2 Capture

Cases 5 & 6: Shell Gasification Economics

	Case 5 No Capture	Case 6 Capture	Difference
Plant Cost ($/kWe)[1]			
Base Plant	**1,354**	**1,726**	**372**
Air Separation Unit	**124**	**154**	**30**
Gas Cleanup/CO_2 Capture	**115**	**302**	**187**
CO_2 Compression	**-**	**70**	**70**
Total Plant Cost ($/kWe)	**1,593**	**2,252**	**659**
Capital COE (Cents/kWh)	**3.28**	**4.63**	**1.35**
Variable COE (Cents/kWh)	**2.08**	**2.74**	**0.66**
Total COE (Cents/kWh)[2]	**5.36**	**7.38**	**2.02**
Increase in COE (%)	**-**	**38**	
$/tonne CO_2 Avoided		**30**	

[1]Total Plant Capital Cost (Includes contingencies and engineering fees)

[2]January 2006 Dollars, 85% Capacity Factor, 13.8% Levelization Factor, Coal cost $1.34/10^6$Btu

NETL

Capillary Pressure Induced CO_2 Retention

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Schlumberger-Doll Research
Ridgefield, CT 06877

Geological sequestration involves injection of CO_2 into depleted oil and gas fields, saline aquifers, subsea sediments and deep coal beds. Among these, injection into saline aquifers appears to have the maximum storage potential. Various mechanisms that enhance long term storage include geological trapping, dissolution and mineralization.

In addition to the above mentioned four mechanisms, large volume of CO_2 may be immobilized, although the injected fluid may remain largely connected. This retention mechanism is driven by capillary pressure hysteresis. This is different from residual CO_2 trapping that arises though disconnections caused by fluid imbibition.

1 Introduction

A significant increase in atmospheric CO_2 concentration has been observed since the onset of the last century. The present level of CO_2 concentration in the atmosphere is reported to be 381 ppm, the highest ever seen in last 400 thousand years [1][2]. Several studies have shown that the change in CO_2 concentration and other greenhouse gases cause a warming effect necessitating technologies that mitigate CO_2 accumulation [1]. One of the technologies is geological carbon sequestration.

Geological sequestration involves injecting captured CO_2 directly into depleted oil-gas reservoirs, saline aquifers, and unminable coal beds. While saline aquifer sequestration has no tangible benefits, it has by far the largest storage potential. CO_2 injected into saline aquifers is expected to migrate slowly updip until containment by impermeable boundaries. In the absence of barriers, the time scale for migration should be kept sufficiently large to allow dissolution into saline water, eventually trapping CO_2 (permanently). Other trapping mechanisms that have been suggested are mineralization and residual CO_2 rich phase via counter imbibition [3][4].