Pulverized Coal Oxycombustion Power Plants

Final Results

Revised:
November 1, 2007

Original Publication Date:
August 2007

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Goals and Objectives

Exploring feasibility of a non-gasification based system in a carbon constrained world

- **Determine cost and performance estimates of new pulverized coal oxycombustion power plants**
  - Technologies deployed in 2012 and 2020
- **Assess the technical and economic feasibility of co-sequestration with CO_2, SOx and NOx**
- **Assess the integration of developmental processes such as novel O_2 membrane technologies**

Study Matrix

Case	Plant Design	Steam Cycle	Oxidant	Pipeline Specification
1*	Air Fired No CO_2 Capture	SC	Air	N/A
2		USC		N/A
3	Air-Fired MEA CO_2 Capture	SC		UR Saline Formation
4		USC		UR Saline Formation
5	Oxyfuel Combustion	SC	95%	UR Saline Formation
5A			99%	UR Saline Formation
5B			95%	Match 5A
5C			95%	URSF and >95% CO_2
6		USC	95%	UR Saline Formation
6A			95%	URSF and >95% CO_2
7		SC	~100% ITM	UR Saline Formation
7A			~100% ITM	URSF and >95% CO_2

URSF: Unrestricted Saline Formation Specification

Steam Conditions

Supercritical (SC): 3,500 Psig/1,110°F/1,150°F
*Current state-of-the-art

Ultra-supercritical (USC): 4,000 Psig/1,350°F/1,400°F
*Advanced Materials Program Target (2015—2020)

Environmental Targets

Based on BACT analysis, exceeding new NSPS requirements

Pollutant	Emission Limits	Control Technology
SO_2	0.085 lb/MMBtu	Wet Limestone FGD
NOx	0.07 lb/MMBtu	LNB, OFA, SCR (Air) LNB, OFA, FGR (Oxy)
PM	<0.015 lb/MMBtu	Fabric Filter
Hg	90% Removal	Co-benefit Capture

BACT: Best Available Control Technology
NSPS: New Source Performance Standards
LNB: Low NOx Burners
OFA: Over-fired air
SCR: Selective Catalytic Reduction
FGR: Flue Gas Recycle (for oxyfuel cases)

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
Total	100.0	100.0
HHV (Btu/lb)	11,666	13,126

Cost = $1.80/MMBtu or $42/short ton

CO_2 Pipeline Specification

	Saline Formation O_2 Restricted	Saline Formation O_2 Unrestricted
Pressure (psia)	2200	2200
CO_2	not limited[1]	not limited[1]
Water	dehydration (0.015 vol%)	dehydration (0.015 vol%)
N_2	not limited[1]	not limited[1]
O_2	**<100 ppmv**	**Up to 3%**
Ar	not limited	not limited
NH_3	not limited	not limited
CO	not limited	not limited
Hydrocarbons	<5 vol%	<5 vol%
H_2S	<1.3 vol%	<1.3 vol%
CH_4	<0.8 vol%	<0.8 vol%
H_2	uncertain	uncertain
SO_2	<3 vol%	<3 vol%
NOx	uncertain	uncertain

"Low Cost" assumption used for this analysis

1: These are not limited, but their impacts on compression power and equipment cost need to be considered.

References:

1. "Impact of Impurities on CO2 Capture, Transportation, and Storage", IEA GHG Report Number Ph 4-32, August 2004
2. "Oxy Combustion Processes from Power Plant", IEA GHG Report Number 2005/9, July 2005
3. "Recommended Pipeline Specifications", NETL Carbon Sequestration Systems Analysis Technical Note #10, March 2007

Economic Assumptions

Startup	**2012 (SC)** **2020 (USC)**
Capital Charge Factor[1], %	
High Risk	
(All USC and CO_2 capture cases)	17.5
Low Risk	
(Supercritical without CO_2 capture)	16.4
Capacity Factor	**85**
CO_2 transportation (miles)	**50**
Storage[2]	**Saline Formation**
Monitoring (years)	**80**

[1]Complete financial structure and economic parameter assumptions shown in backup slides

[2]Saline formation characteristics shown in backup slides

Economic Assumptions

Financial Structure

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
Low Risk				
Debt	50	9%	4.5%	2.79%
Equity	50	12%	6%	6%
			11%	8.79%
High Risk				
Debt	45	11%	4.95%	3.07%
Equity	55	12%	6.6%	6.6%
			11.55%	9.67%

	High Risk	Low Risk
Capital Charge Factor	0.175	0.165
Coal Levilization Factor	1.2022	1.2089
Natural Gas Levelization Factor	1.1651	1.1705
General O&M Levelization Factor	1.1568	1.1618

Economic Assumptions

Parameter Assumptions

Parameter	Value
Income Tax Rate	38% Effective (34% Federal, 6% State less 1% Property and 1% Insurance
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Depreciation	20 years, 150% Declining Balance
Working Capital	Zero for all parameters
Plant Economic Life	30 years
Investment Tax Credit	0%
Tax Holiday	0 years
Start-up Costs (% EPC)	2%
All other additional costs ($)	0
EPC escalation	0%
Duration of Construction	3 years

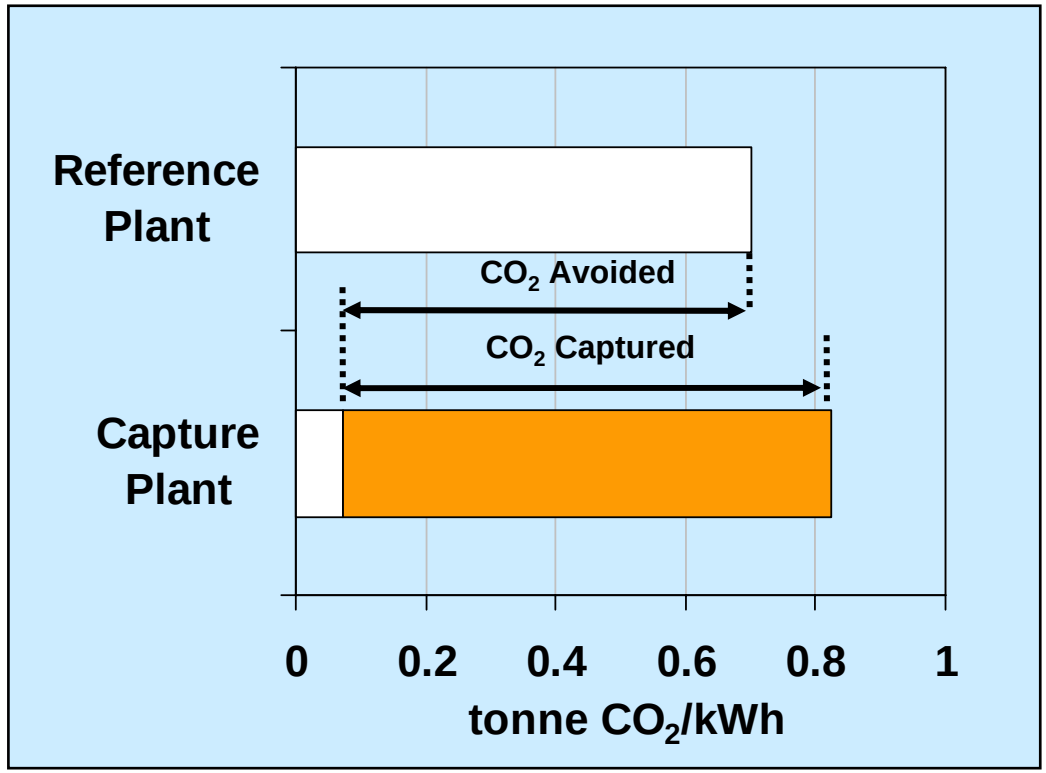
CO_2 Mitigation Costs

CO_2 Avoided

$$\frac{(COE_{capture} - COE_{base})}{(Emissions_{base} - Emissions_{capture})}$$

CO_2 Captured

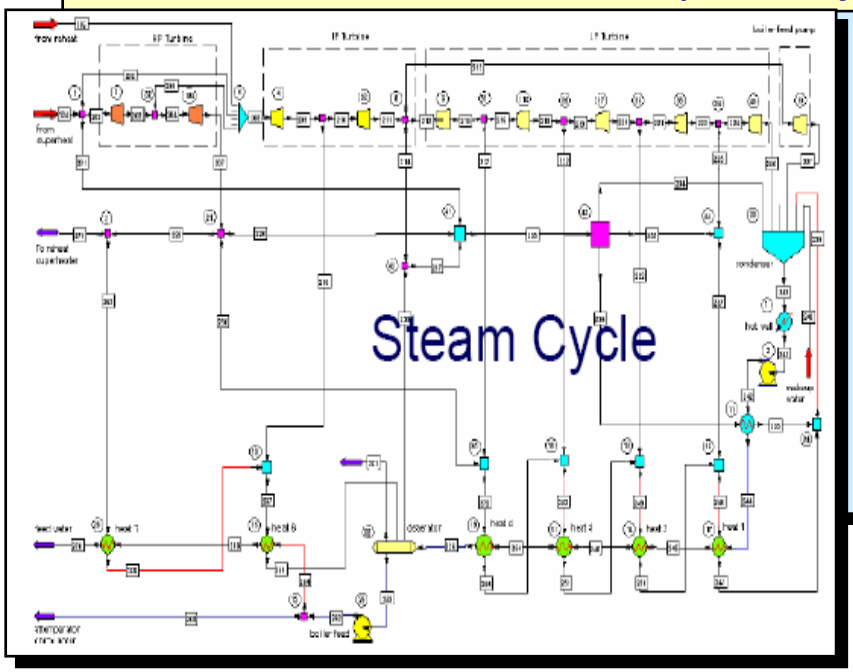
$$\frac{(COE_{capture} - COE_{base})}{(CO_2 \text{ Removed})}$$



Technical Approach

1. Engineering Studies and Extensive Process Simulation (ASPEN)

- All major chemical processes and equipment are vendor specified: AL/B&W
- 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**
  - ASU & CO_2 Trains: Air Liquide
  - Boiler & FGD: B&W
  - BOP: RDS (Parsons)
- **Follow DOE Analysis Guidelines**

Air-Fired Pulverized Coal

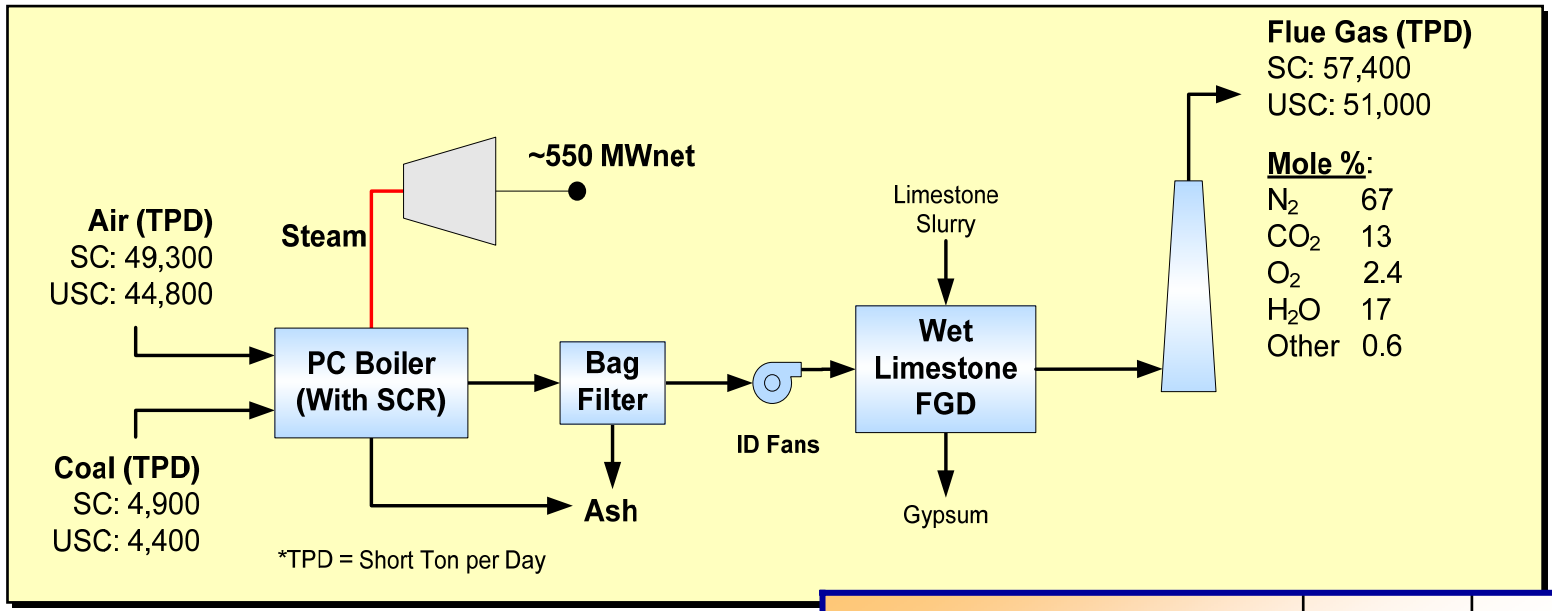
No CO_2 Capture

Case 1 — Supercritical

Case 2 — Ultra-supercritical

Case	Plant Design	Steam Cycle	Oxidant	Pipeline Specification
1*	Air Fired No CO_2 Capture	SC	Air	N/A
2		USC		N/A

Baseline No CO_2 Capture Cases



Consumables	Case 1	Case 2
Raw Water Usage (gpm)	5,400	4,700
Ammonia (lb/hr)	1,170	1,040
Limestone (lb/hr)	40,800	36,000

Emissions (85% CF)	Case 1	Case 2
Carbon Dioxide (tons/year)	3,625,750	3,219,700
SO_2 (tons/year)	1,511	1,343

Performance	Case 1 SC	Case 2 USC
Gross Power (MW)	**584**	**583**
Auxiliary Power (MW)		
Base Plant Load	18	16
Forced + Induced Draft Fans	9	8
Flue Gas Cleanup (SCR, Filter, FGD)	3	3
Total Aux. Power (MW)	**30**	**27**
Net Power (MW)	**554**	**556**
Net Efficiency (%HHV)	**40**	**45**

Baseline No CO_2 Capture Cases

Economic Results

	Supercritical	Ultrasupercritical
Report Number →	**1**	**2**
Plant Capital Cost ($/kWe)		
Base Plant (Inc. SCR)	1,335	1,437
PM and SOx Cleanup	228	204
CO_2 Capture	-	-
CO_2 Compression	-	-
Total Plant Capital Cost ($/kWe)	1,563	1,641
Total Plant Capital Cost (¢/kWh)	**3.44**	**3.86**
Total Production Cost (¢/kWh)[a]	**2.85**	**2.60**
Total Cost of Electricity	**6.29**	**6.45**

[a]Fixed and Variable O&M, Consumables and Fuel Cost

Air-Fired Pulverized Coal

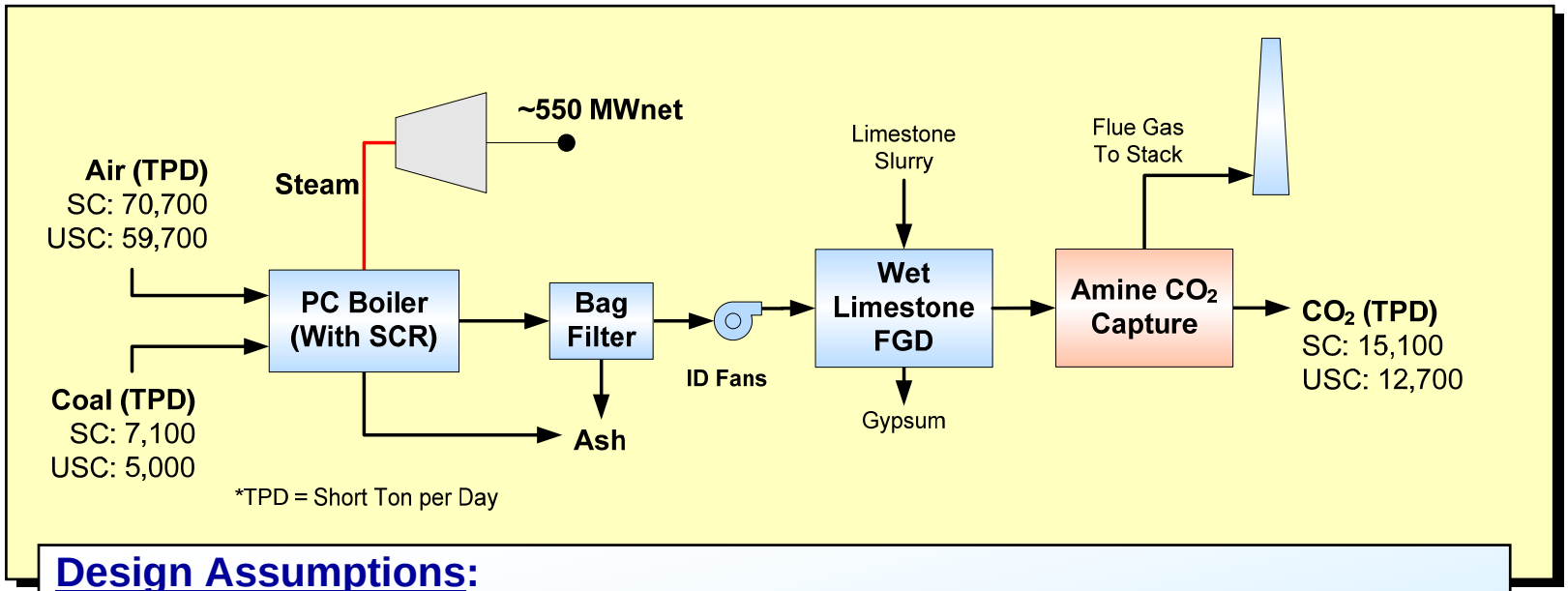
Econamine FG Plus^{SM} CO_2 Capture

Case 3 — Supercritical

Case 4 — Ultra-supercritcal

Case	Plant Design	Steam Cycle	Oxidant	Pipeline Specification
3	Air-Fired MEA CO_2 Capture	SC	Air	UR Saline Formation
4		USC		UR Saline Formation

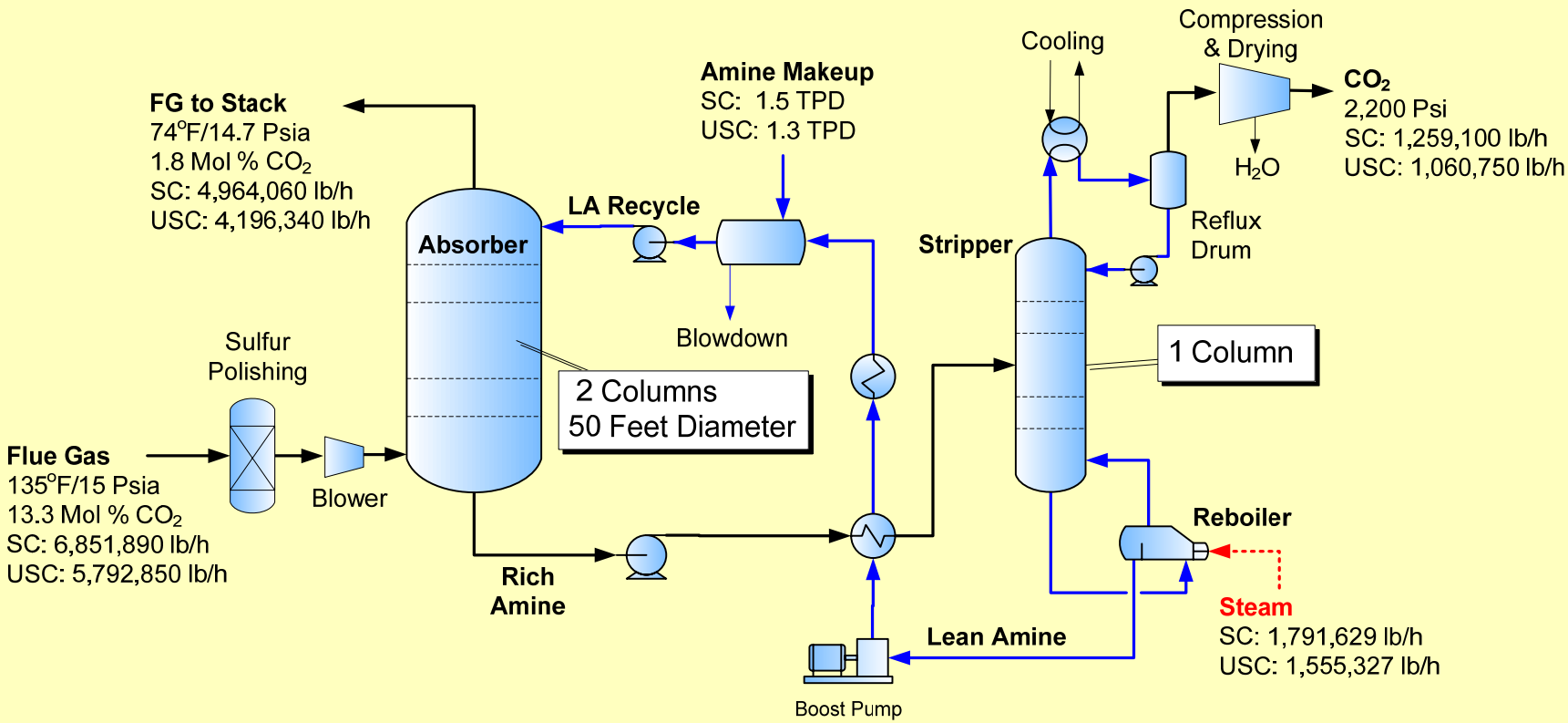
Amine Scrubbing CO_2 Capture Cases



Design Assumptions:

1. 90% CO_2 Capture
2. Sulfur polishing step to maintain <10 ppm SO_2 into absorber
3. MEA regeneration steam is extracted from the IP/LP crossover pipe

Fluor Econamine FG Plus^{SM} Scrubbing

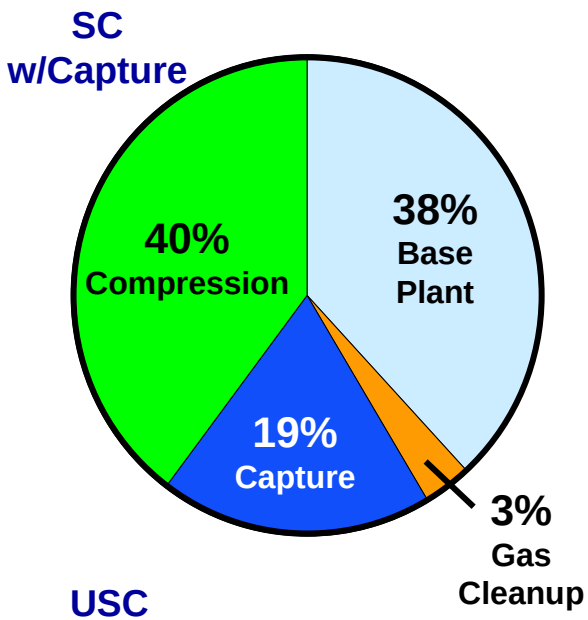


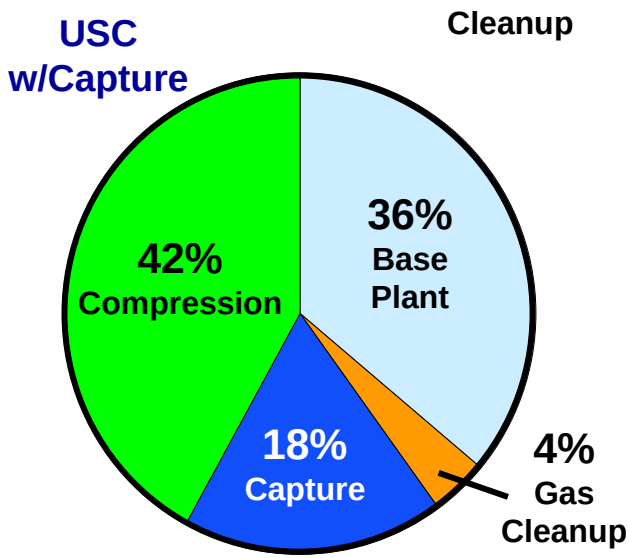
Absorption (°F)	100's	Reboiler Heat Duty (Btu/lb CO_2)	1,550
Regeneration (°F)	250's	Auxiliary Power (MW)	19-22

Amine Scrubbing Performance Results

	Supercritical		Ultrasupercritical	
CO_2 Capture	No	MEA	No	MEA
Report Number →	1	3	2	4
Total Gross Power (MW)	584	667	583	650
CO_2 Stream (Ton/day)	-	15,100	-	12,700
Auxiliary Power (MW)				
Base Plant Load	27	45	24	38
Flue Gas Cleanup	3	4	3	4
CO_2 Capture	-	22	-	19
CO_2 Compression	-	47	-	44
Total Auxiliary (MW)	30	118	27	105
Net Power (MW)	554	549	556	545
Coal Flow Rate (Ton/day)	4,900	7,100	4,400	6,000
Efficiency (% HHV)	39.5	27.2	45	32.1
Energy Penalty[a]	-	12.2	-	7.4

[a]CO_2 Capture Energy Penalty = Percent points decrease in net power plant efficiency due to CO_2 capture compared to Case 1—Supercritical PC w/o CO_2 capture



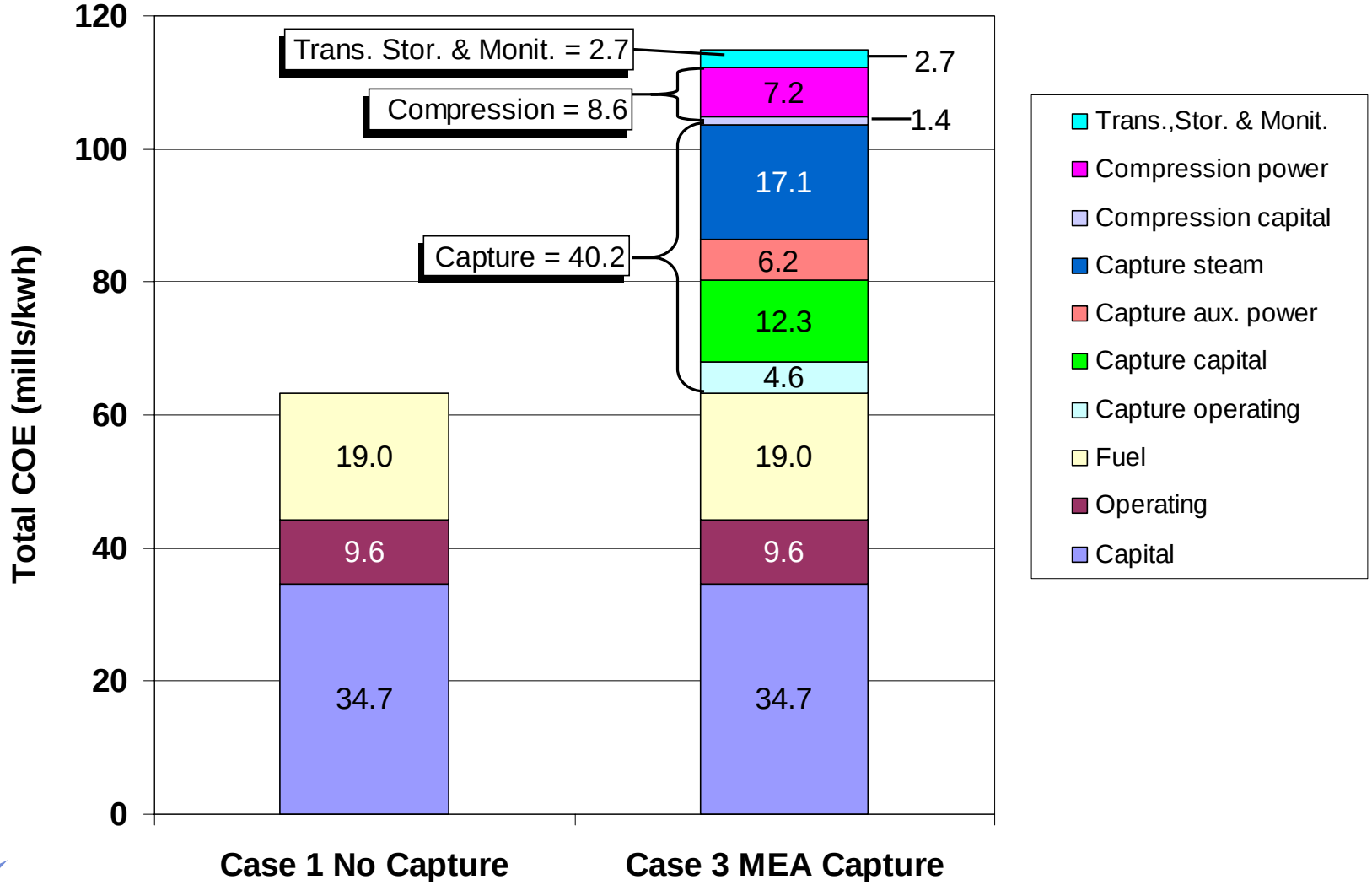


Amine Scrubbing CO_2 Capture Costs

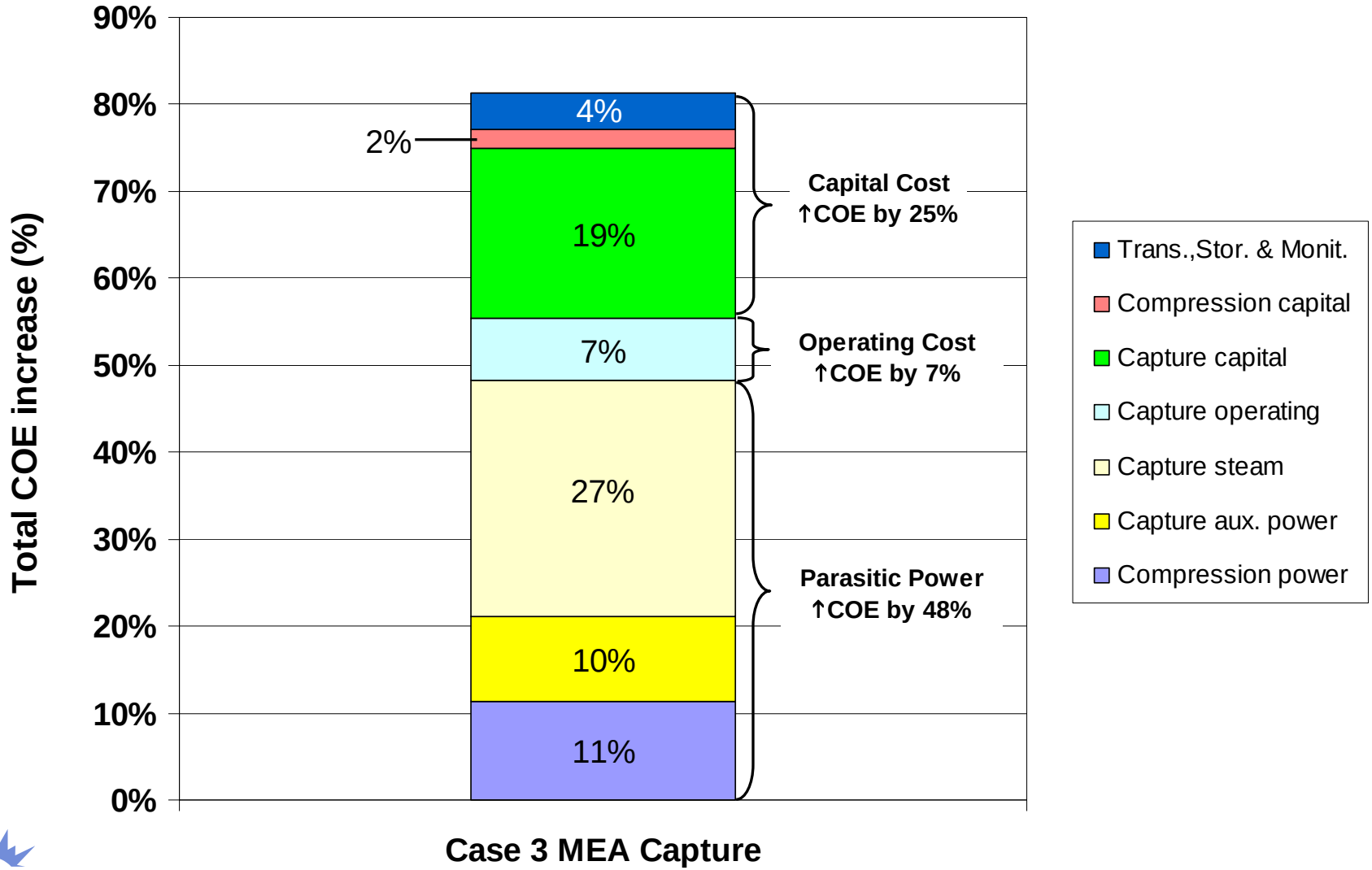
		Supercritical		Ultrasupercritical	
	CO_2 Capture	No	MEA	No	MEA
	Report Case Number →	1	3	2	4
Capital ($/kW)	Base Plant	1,335	1,724	1,437	1,845
	Flue Gas Cleanup	228	300	204	273
	CO_2 Capture	-	749	-	673
	CO_2 Compression	-	84	-	76
	Total Capital ($/kW)	1,563	2,857	1,641	2,867
	Capital COE (¢/kWh)	3.44	6.71	3.86	6.74
	Production COE (¢/kWh)	2.85	4.33	2.60	3.86
	Total Plant COE (¢/kWh)	6.29	11.04	6.46	10.60
Including Transportation and Storage					
	Total COE (¢/kWh)	6.29	11.44	6.46	10.98
	Incremental COE (¢/kWh)	-	5.15	-	4.69
	Increase in COE (%)[a]	-	82	-	75
	$/ton CO_2 Avoided[a]	-	68	-	61

[a]Compared to Case 1—Supercritical PC w/o CO_2 capture where COE = 6.29 (¢/kWh)

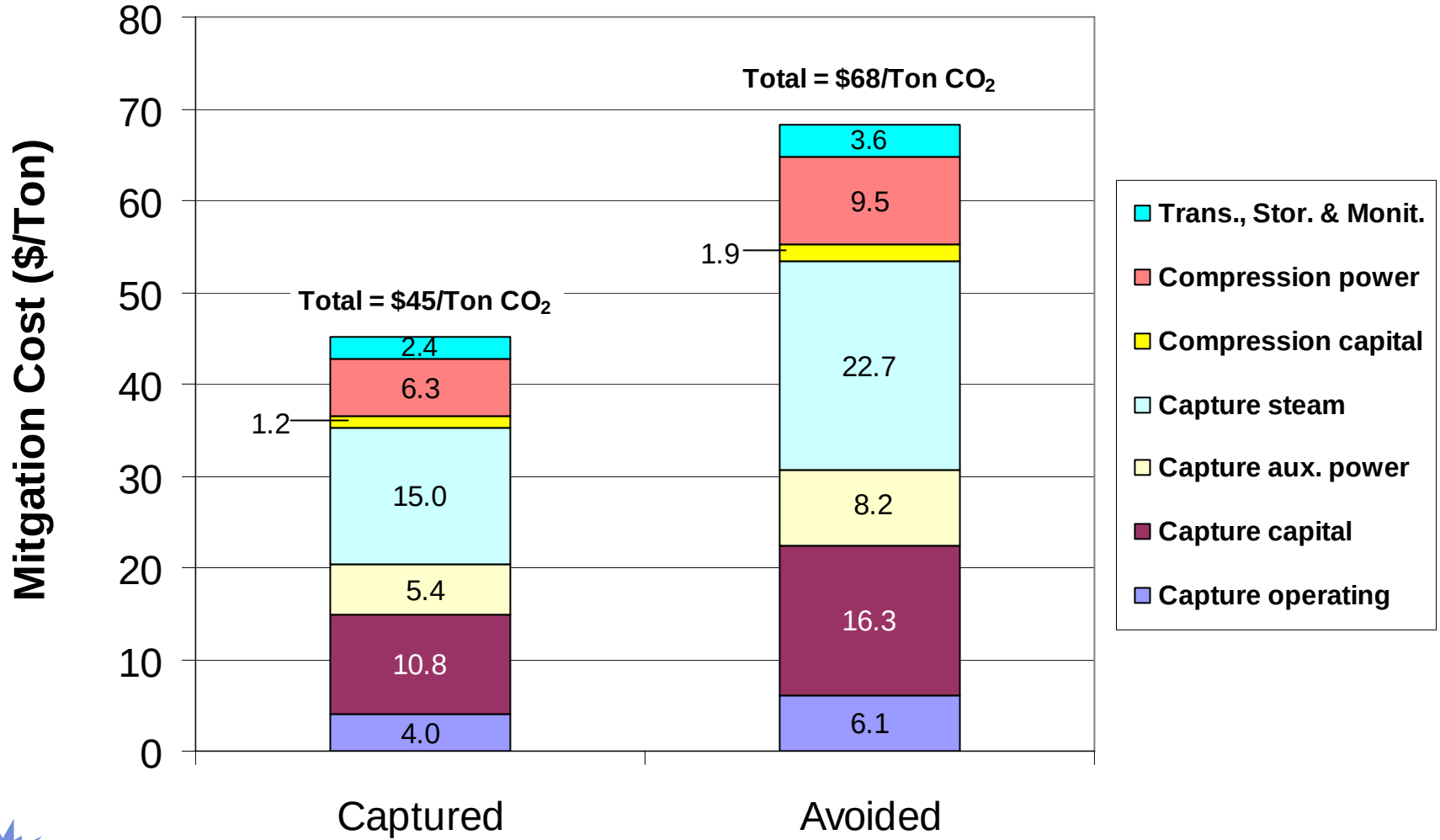
Amine Scrubbing Incremental COE Distribution



Amine Scrubbing COE Increase Distribution



Amine Scrubbing Mitigation Cost Distribution



Amine Scrubbing CO_2 Capture
Key Points

1. **Potential to obtain near 100% CO_2 purity**

2. **Capable of removing 90+% flue gas CO_2**

3. **Post-combustion amine-based CO_2 capture technology comes with significant energy penalties**
   - Steam for MEA regeneration increases COE by 27%
   - CO_2 capture auxiliary power increases COE by 10%
   - CO_2 compression auxiliary power increases COE by 11%

4. **CO_2 compression, transport, storage and monitoring <u>capital costs</u> are relatively low**
   - Increases COE by only 6%

5. **Ultra-supercritical steam cycle**
   - For every 1% increase in net efficiency, 100,000 tons per year **<u>less</u>** CO_2 is generated

Oxygen-Fired Pulverized Coal
Cryogenic Air Separation Unit
Case 5 — Supercritcal

Case	Plant Design	Steam Cycle	Oxidant	Pipeline Specification
5	Oxyfuel Combustion	SC	95%	UR Saline Formation
5A			99%	UR Saline Formation
5B			95%	Match 5A
5C			95%	URSF and >95% CO_2

Oxy-combustion in Pulverized Coal Boilers for CO_2 Capture

- **Principle**: O_2 is provided by ASU, N_2 is replaced by re-circulated CO_2

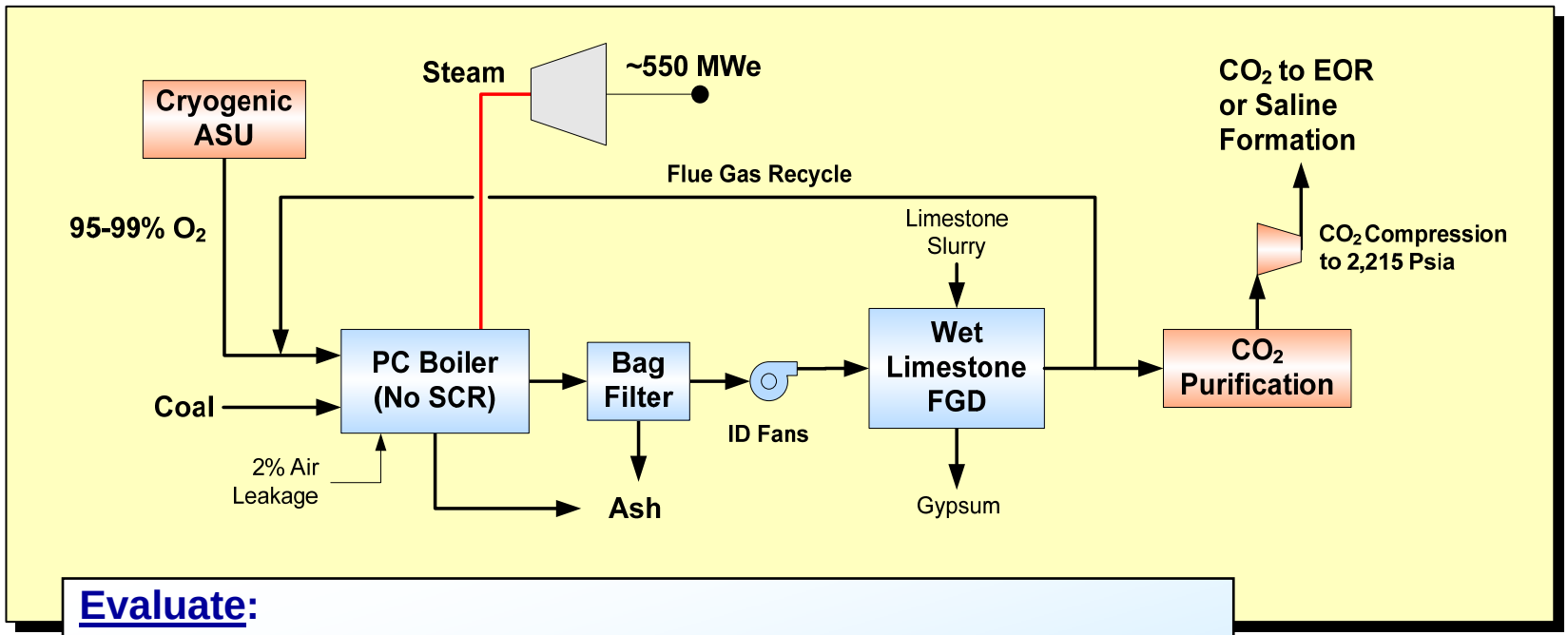
$$\text{Coal} + O_2 \longrightarrow CO_2 + H_2O$$

  - O_2 is diluted with recycled flue gas **for temperature control**
  - Can be applied to new or existing PC plants

- **Advantages**
  - Flue Gas CO_2 Content: From 13% (air fired) to 70+% in oxy-combustion
  - NOx Emission: Reduced by 60 to 70% in Boiler
    - Combustion controls meet environmental requirements—No SCR required!
  - Mercury Ionization: Increased oxidized/elemental mercury ratio obtained during testing on PRB coal. Enhances removal in the ESP and FGD
  - Potential for new compact boiler design: Reduction in FG recycle equipment

Reference:
1. Advanced Low/Zero Emission Boiler Design Operation, Techno-Economic Study, Air Liquide, Countryside, IL, Department of Energy-NETL, November 2004

Cryogenic ASU Oxyfuel Combustion



Evaluate:

1. Impact 95 versus 99% oxygen purity has on the CO_2 purification/compression process
2. Minimum CO_2 recycle rate
3. Co-sequestration (CO_2/NOx/SOx) feasibility

Supercritical Oxyfuel Performance Results

	Supercritical			
Report Case Number →	5	5A	5B	5C
Oxygen Purity (%)	95	99	95	95
CO_2 Stream (Ton/day)	18,200	17,600	17,100	15,500
CO_2 Purity (Vol %)	83	87	88	96
Auxiliary Power (MW)				
Base Plant Load	33	33	33	33
Air Separation Unit	130	131	130	130
Flue Gas Cleanup	4	4	4	4
CO_2 Capture/Compression	79	75	79	81
Total Auxiliary Load (MW)	246	243	246	248
Efficiency (% HHV)	28.3	28.5	28.2	28.1

Note:

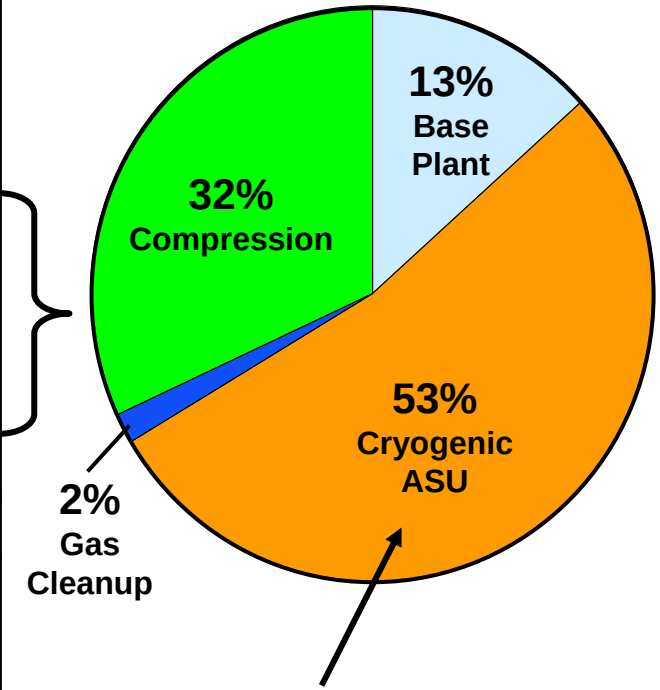
All cases have nominal 550 MWnet output

Supercritical Oxyfuel Performance Results

	Supercritical	
CO_2 Capture	No	Oxyfuel
Report Case Number →	1	5
Total Gross Power (MW)	584	793
CO_2 Stream (Ton/day)	-	18,200
Auxiliary Power (MW)		
Base Plant Load	27	33
Air Separation Unit	-	130
Flue Gas Cleanup	3	4
CO_2 Capture/Compression	-	79
Total Auxiliary Load (MW)	30	246
Net Power (MW)	554	547
Coal Flow Rate (Ton/day)	4,900	6,800
Efficiency (% HHV)	39.5	28.3
Energy Penalty[a]	-	11.2

[a]CO_2 Capture Energy Penalty = Percent points decrease in net power plant efficiency due to CO_2 capture compared to Case 1—Supercritical PC w/o CO_2 capture

Case 5
Auxiliary Power Loss



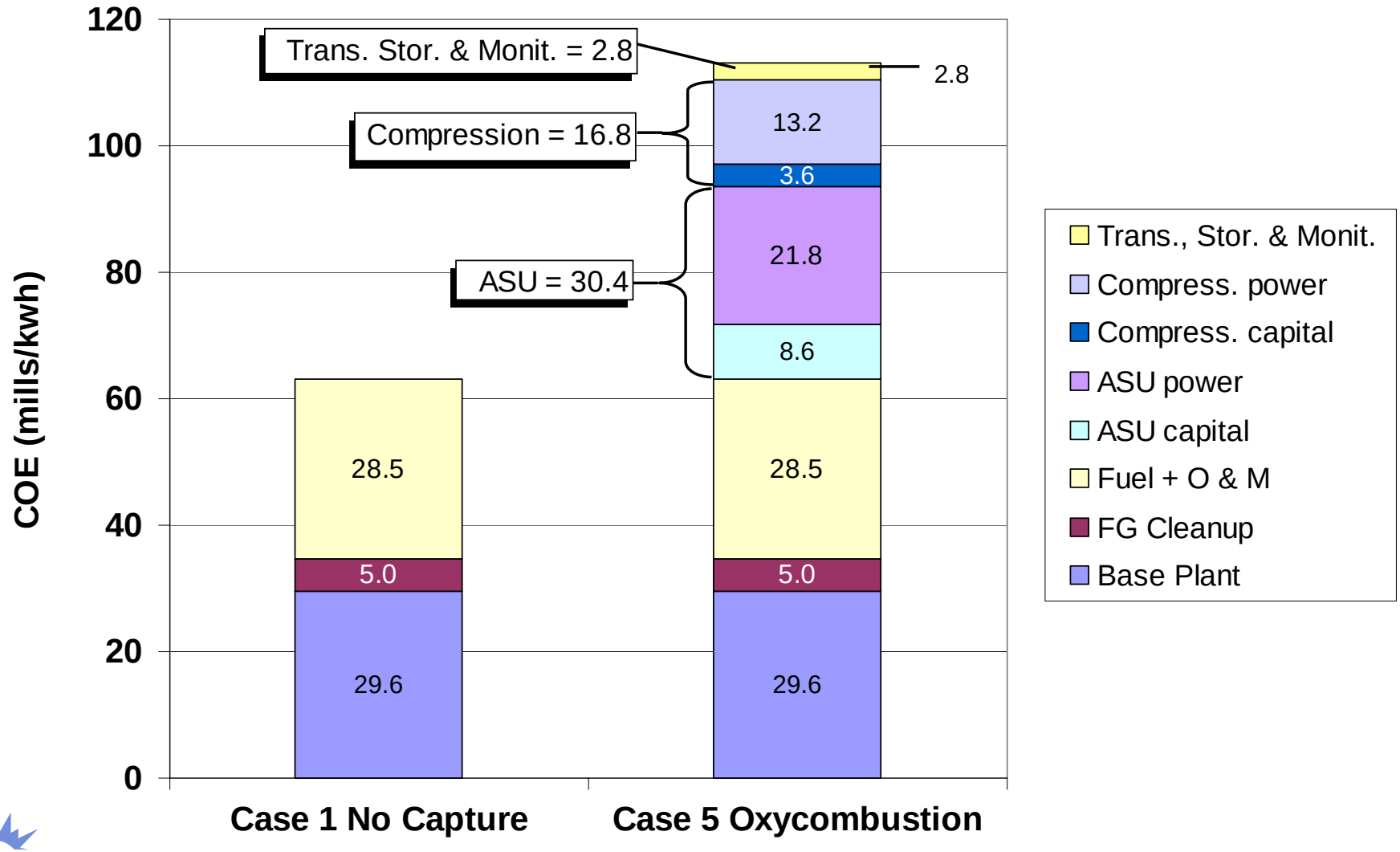
Continued R&D necessary to lower oxygen production power requirements

Supercritical Oxyfuel Economic Results

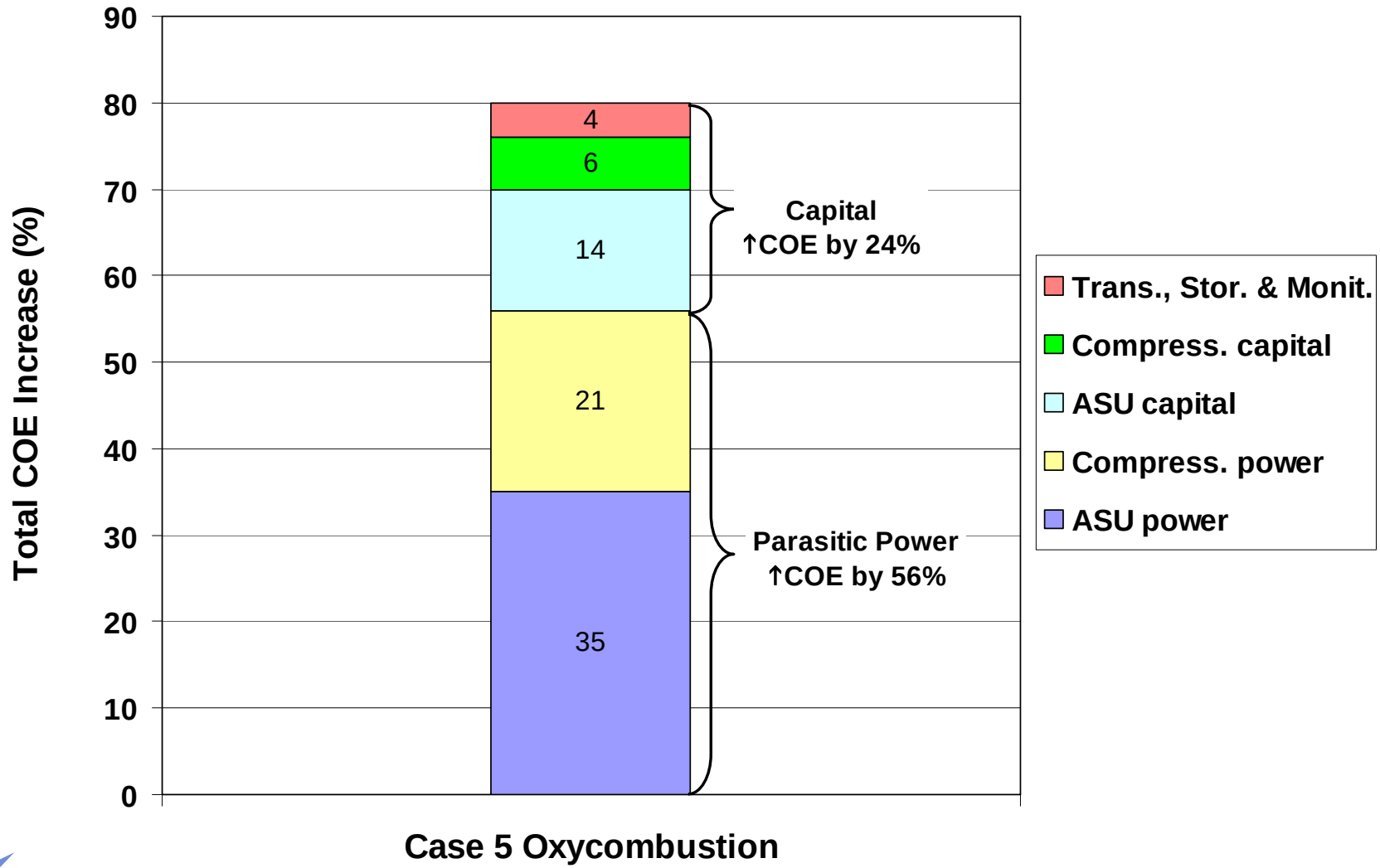
		Supercritical		
	CO_2 Capture	No	95% Oxyfuel	99% Oxyfuel
	Report Case Number →	1	5	5C
Capital ($/kW)	Base Plant	1,335	1,893	1,912
	Air Separation Unit	-	509	511
	Flue Gas Cleanup	228	318	319
	CO_2 Capture/Comp.	-	210	282
	Power Plant Capital ($/kW)	1,563	2,930	3,024
	Capital COE (¢/kWh)	3.44	6.89	7.11
	Production COE (¢/kWh)	2.85	4.01	4.06
	Total Plant COE (¢/kWh)	6.29	10.90	11.16
Including Transportation and Storage				
	Total COE (¢/kWh)	6.29	11.30	11.54
	Incremental COE (¢/kWh)[a]	-	5.01	5.28
	Increase in COE (%)[a]	-	80	83
	$/ton CO_2 Avoided[a]	-	57	60

[a]Compared to Case 1—Supercritical PC w/o CO_2 capture

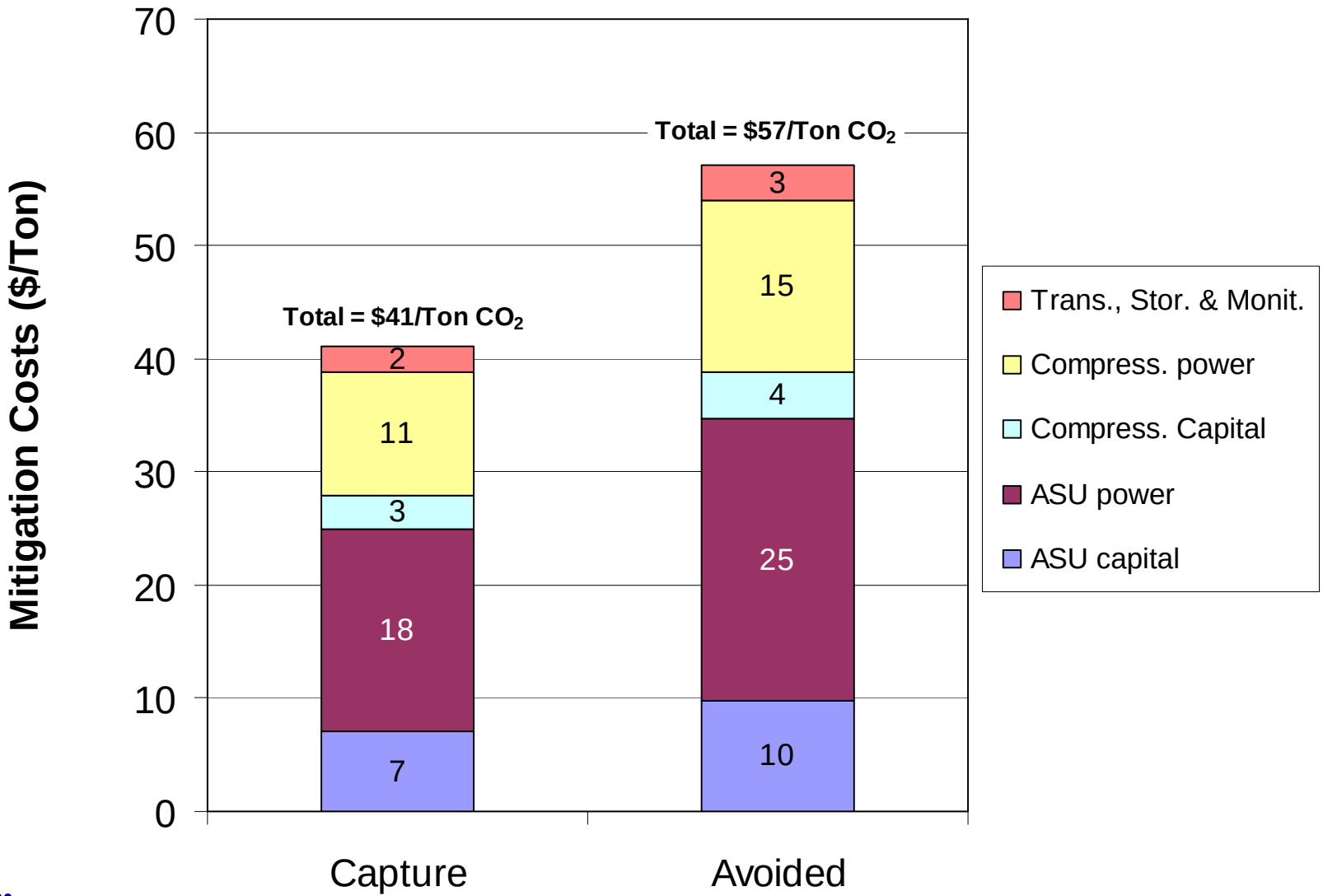
Oxyfuel Incremental COE Distribution



Oxyfuel COE Increase Distribution



Oxyfuel Mitigation Cost Distribution



Supercritical Oxyfuel Combustion
Key Points

1. **Potential to obtain near 100% CO_2 recovery**

2. **Current PC oxyfuel technology comes with significant energy penalties**
   - Increase in auxiliary power from 30 MW to > 240 MW
   - Decrease power plant efficiency by 30% (~12 net efficiency points!)

3. **72% flue gas CO_2 recycle rate required to maintain adiabatic boiler flame temperatures**
   - Increases flue gas constituent concentrations by a factor of **3.5**
   - Recycle rate makes the flue gas corresponding to a coal with 2.5% sulfur content equivalent to a flue gas from a coal with a **8.75%** sulfur
   - Exceeds current boiler material design limits ability to handle more than 3.5% sulfur coal. Therefore, desulfurization unit required!
   - For a coal with a sulfur content 1% or lower and using current boiler materials, removal of the FGD unit is technically feasible if co-sequestration (CO_2/SOx) is possible

Supercritical Oxyfuel Combustion
Key Points

4. Going from 95% to 99% O_2 purity results in:

- Less than 0.5% <u>increase</u> in ASU auxiliary load (130.5 MW to 131 MW)
- A 9% <u>increase</u> in ASU capital cost ($509/kWe to $555/kWe)
- A 4 Megawatt <u>decrease</u> in CO_2 compression and purification auxiliary power (78.5 to 74.5 MW) → Results in a slightly higher net power plant efficiency.

Bottom Line: The CO_2 compression and purification auxiliary power savings—due to the use of a higher purity oxidant—is offset by a 9% increase in ASU capital cost resulting in a <u>negligible</u> advantage in going from 95 to 99% oxygen purity.

5. Flue gas purification to get 96% CO_2 purity adds $72/kWe to compression/purification process

Oxygen-Fired Pulverized Coal
Cryogenic Air Separation Unit
Case 6 — Ultra-Supercritcal

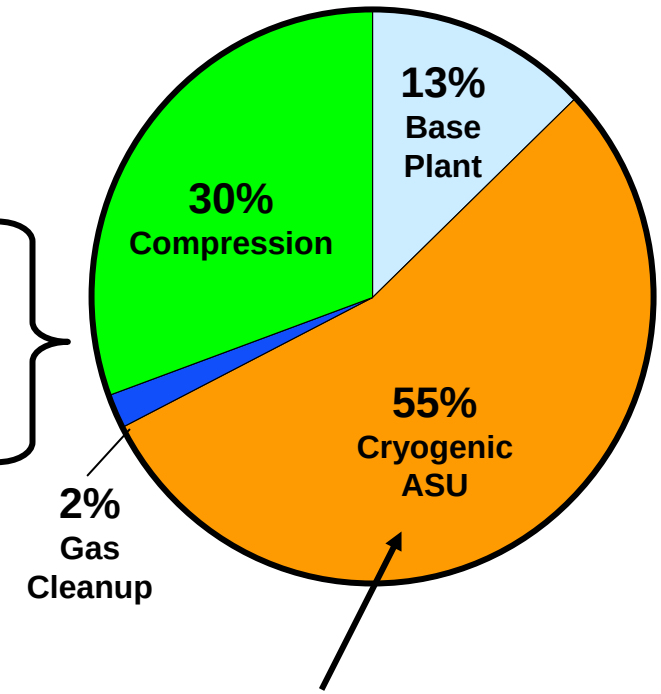
Case	Plant Design	Steam Cycle	Oxidant	Pipeline Specification
6	Oxyfuel Combustion	USC	95%	UR Saline Formation
6A			95%	URSF and >95% CO_2

Ultra-Supercritical Oxyfuel Performance Results

	Supercritical	Ultrasupercritical	
CO_2 Capture	No	No	Oxyfuel
Report Number →	1	2	6
Total Gross Power (MW)	584	583	773
CO_2 Stream (Ton/day)	-	-	13,500
Auxiliary Power (MW)			
Base Plant Load	27	24	28
Air Separation Unit	-	-	120
Flue Gas Cleanup	3	3	4
CO_2 Capture/Compression	-	-	67
Total Auxiliary (MW)	30	27	219
Net Power (MW)	554	556	553
Coal Flow Rate (Ton/day)	4,900	4,400	5,900
Efficiency (% HHV)	39.5	44.6	33
Energy Penalty	-	-	6.4[a]

[a]CO_2 Capture Energy Penalty = Percent points decrease in net power plant efficiency due to CO_2 capture relative to Case 1—Supercritical PC w/o CO_2 capture

Case 6
Auxiliary Power Loss



Continued R&D necessary to lower oxygen production power requirements

Ultra-Supercritical Oxyfuel Economic Results

		Supercritical	Ultrasupercritical	
	CO_2 Capture	No	No	Oxyfuel
	Report Case Number →	1	2	6
Capital ($/kW)	Base Plant	1,335	1,437	1,937
	Air Separation Unit	-	-	472
	Flue Gas Cleanup	228	204	292
	CO_2 Capture/Comp.	-	-	197
	Total Capital ($/kW)	1,563	1,641	2,898
	Capital COE (¢/kWh)	3.44	3.86	6.81
	Production COE (¢/kWh)	2.85	2.60	3.56
	Total Plant COE (¢/kWh)	6.29	6.46	10.37
Including Transportation and Storage				
	Total COE (¢/kWh)	6.29	6.46	10.73
	Incremental COE (¢/kWh)[a]	-	-	4.44
	Increase in COE (%)[a]	-	-	71
	$/ton CO_2 Avoided[a]	-	-	50

[a]Relative to Case 1 ("Base Case") where COE = 6.29 (¢/kWh)

Ultra-Supercritical Oxyfuel Combustion

Key Points

1. **High efficiency cycle improves CO_2 capture energy penalty**
   - Reduces ASU auxiliary load by 10 MW (from 130 MW to 120 MW)
   - USC net efficiency with capture 33% (versus 28% with supercritical)

2. **High efficiency cycle improves COE and CO_2 Emissions**
   - Every 1 percentage point increase in HHV efficiency improvement reduces CO_2 emissions by about 100,000 short-tons per year!
   - Savings of about $10/ton CO_2 avoided from SC to USC

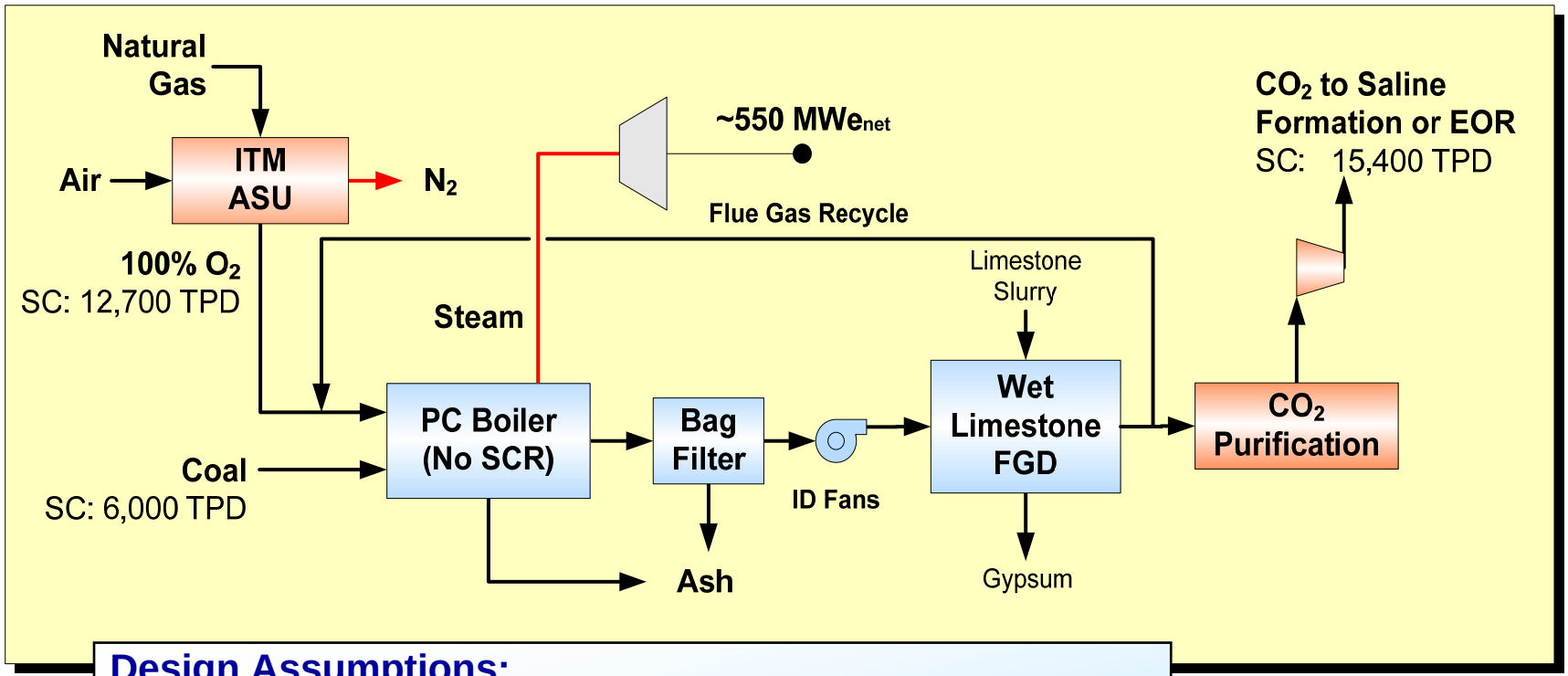
Oxygen-Fired Pulverized Coal

Membrane Air Separation Unit

Case 7—Supercritical

Case	Plant Design	Steam Cycle	Oxidant	Pipeline Specification
7	Oxyfuel Combustion	SC	~100% ITM	UR Saline Formation
7A			~100% ITM	URSF and >95% CO_2

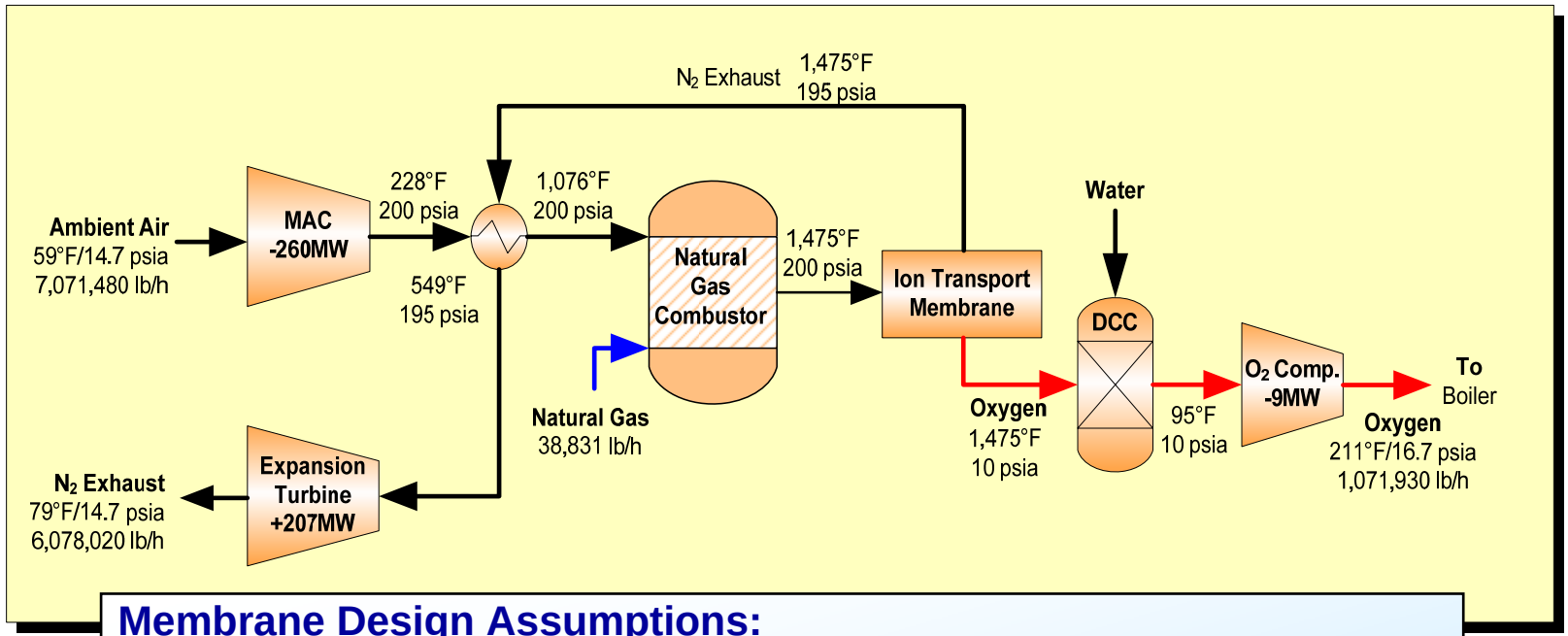
Membrane ASU Oxyfuel Combustion



Design Assumptions:

1. Supercritical Steam Cycle
   - Results compared to Case 5—supercritical with cryogenic ASU
2. Natural gas used for O_2 membrane air heating

Membrane ASU Oxyfuel Combustion



Membrane Design Assumptions:

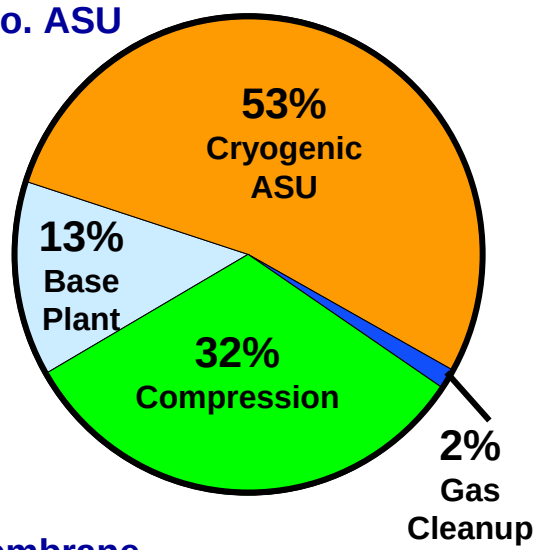
1. Membrane requires 200 Psia/1,475°F air
2. 70% O_2 recovery
3. 100% pure O_2 product recovered at sub-atmospheric pressure
4. Direct-fired natural gas furnace used for remaining air heating
5. Natural gas price = $6.75/MM Btu
6. Bare Erected Capital Cost estimated to be 30% lower than cryogenic ASU

Membrane PC Oxyfuel Performance Results

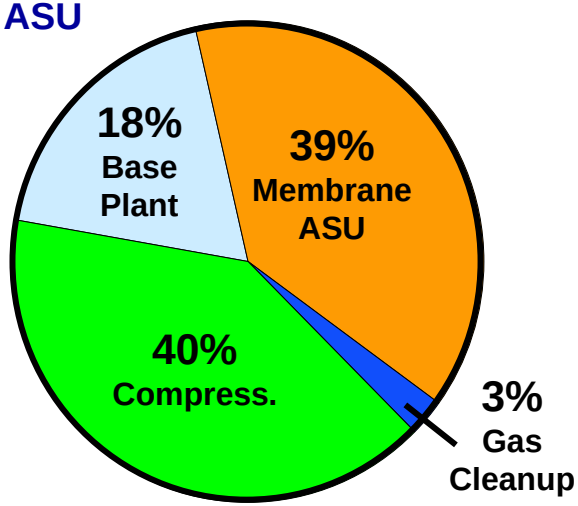
	Supercritical		
CO_2 Capture	No	Cryo. Oxyfuel	Memb. Oxyfuel
Report Number →	1	5	7
Total Gross Power (MW)	584	793	714
CO_2 Stream (Ton/day)	-	18,200	15,400
Auxiliary Power (MW)			
Base Plant Load	27	33	30
Air Separation Unit Net	3	130	62
Flue Gas Cleanup	-	4	4
CO_2 Capture/Compression	-	79	65
Total Auxiliary (MW)	30	246	161
Net Power (MW)	554	547	553
Coal Thermal Input (MWth)	1,404	1,933	1,710
Nat. Gas Thermal (MWth)	-	-	260
Efficiency (% HHV)	39.5	28.3	28.1
Energy Penalty[a]	-	11.2	11.4

[a]CO_2 Capture Energy Penalty = Percent points decrease in net power plant efficiency due to CO_2 capture compared to Case 1—Supercritical PC w/o CO_2 capture

Cryo. ASU



Membrane ASU



Membrane PC Oxyfuel Economic Results

	Supercritical		
CO_2 Capture	No	Cryogenic Oxyfuel	Membrane Oxyfuel
Report Number →	1	5	7
Base Plant ($/kWh)	1,335	1,893	1,828
Air Separation Unit ($/kWh)	-	509	352
Flue Gas Cleanup ($/kWh)	228	318	276
CO_2 Capture/Comp. ($/kWh)	-	210	183
Power Plant Capital ($/kWh)	1,563	2,930	2,639
Capital COE (¢/kWh)	3.44	6.89	6.20
Production COE (¢/kWh)	2.85	4.01	4.87
Total Plant COE (¢/kWh)	6.29	10.90	11.07
Including Transportation and Storage			
Total COE (¢/kWh)	-	11.30	11.43
Incremental COE (¢/kWh)[a]	-	5.01	5.14
Increase in COE (%)[a]	-	80	82
$/ton CO_2 Avoided[a]	-	57	66

[a]Compared to Case 1—Supercritical PC w/o CO_2 capture where COE = 6.29 (¢/kWh)

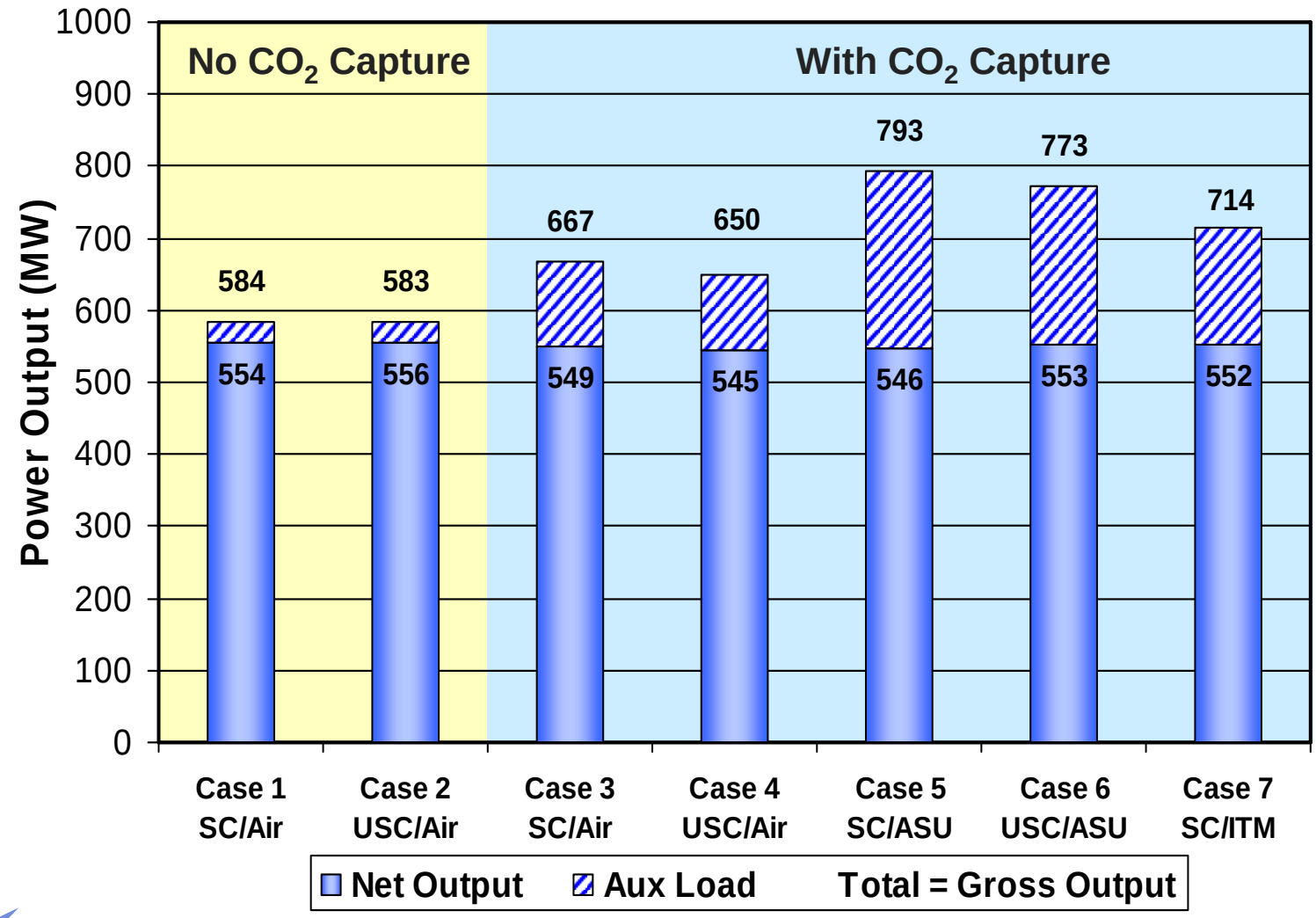
Membrane PC Oxyfuel Combustion

Key Points

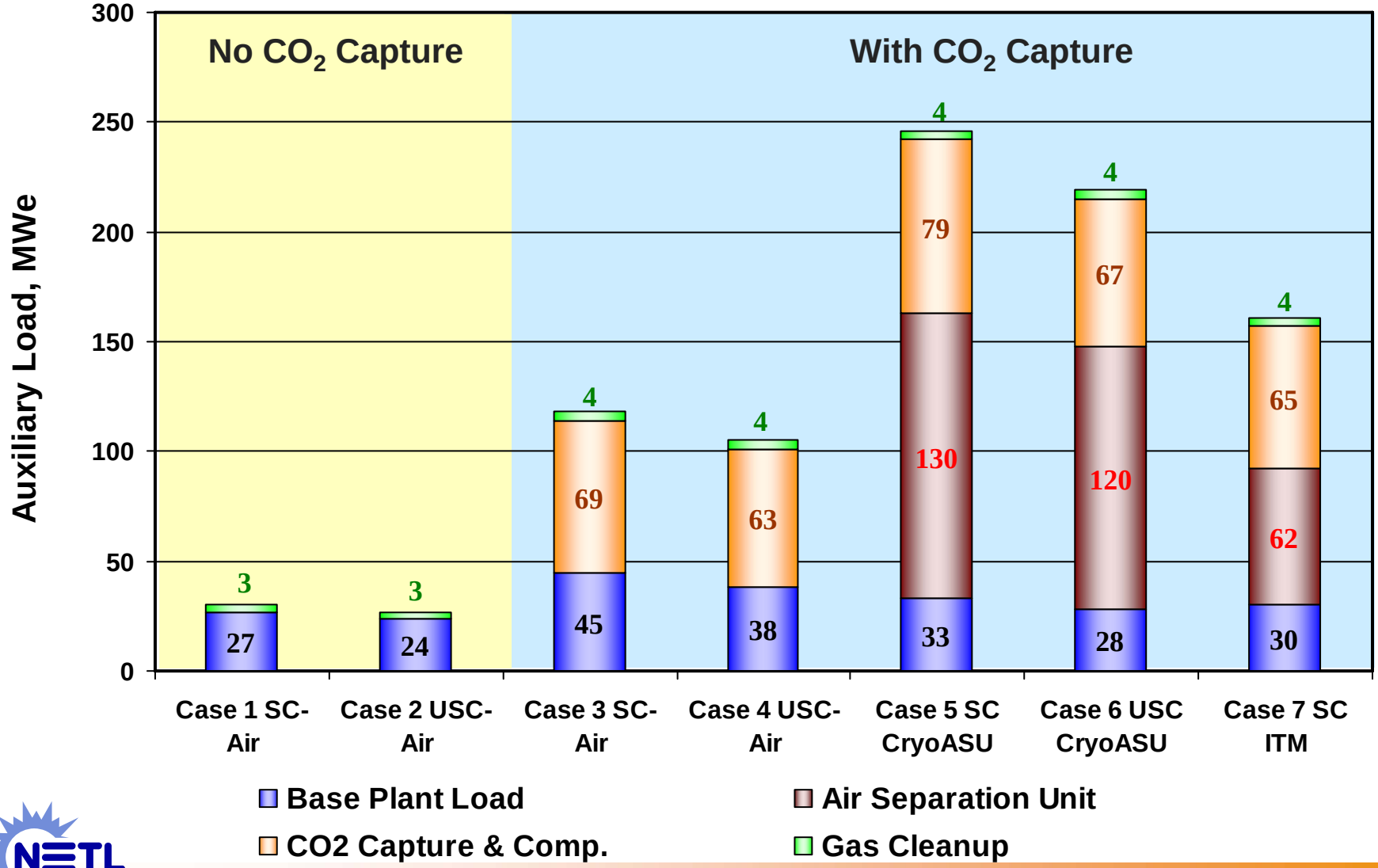
1. **Need for better boiler/O_2 membrane integration**
   - ~39,000 lb/hr natural gas used = $44MM+ annual operating expense
   - Adds 260MW_{th} (13%) input to overall power system
   - Adds to power plant carbon footprint = +1,300 ton CO_2/day

Results Summary

Power Output Summary

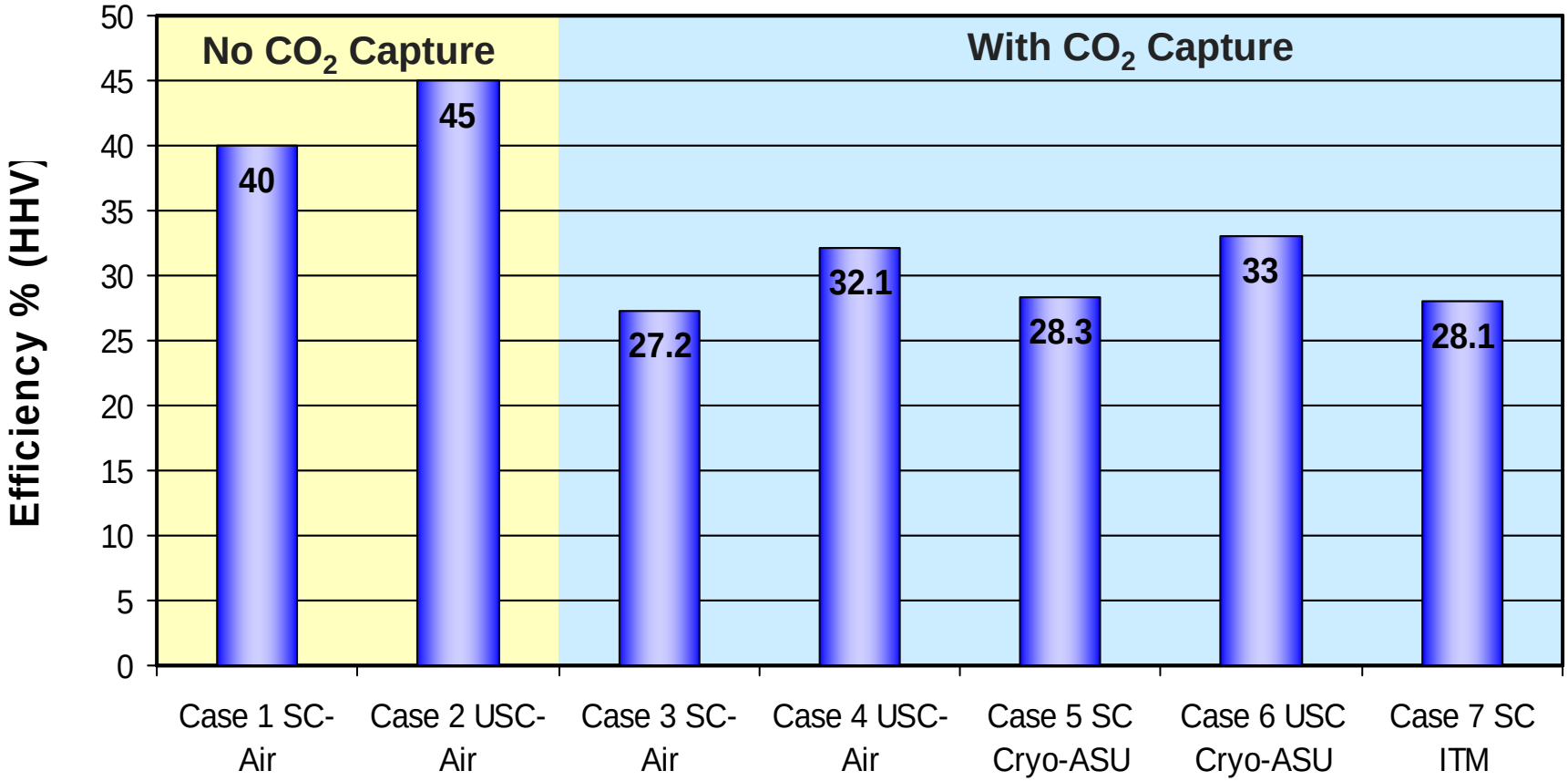


Auxiliary Load Summary

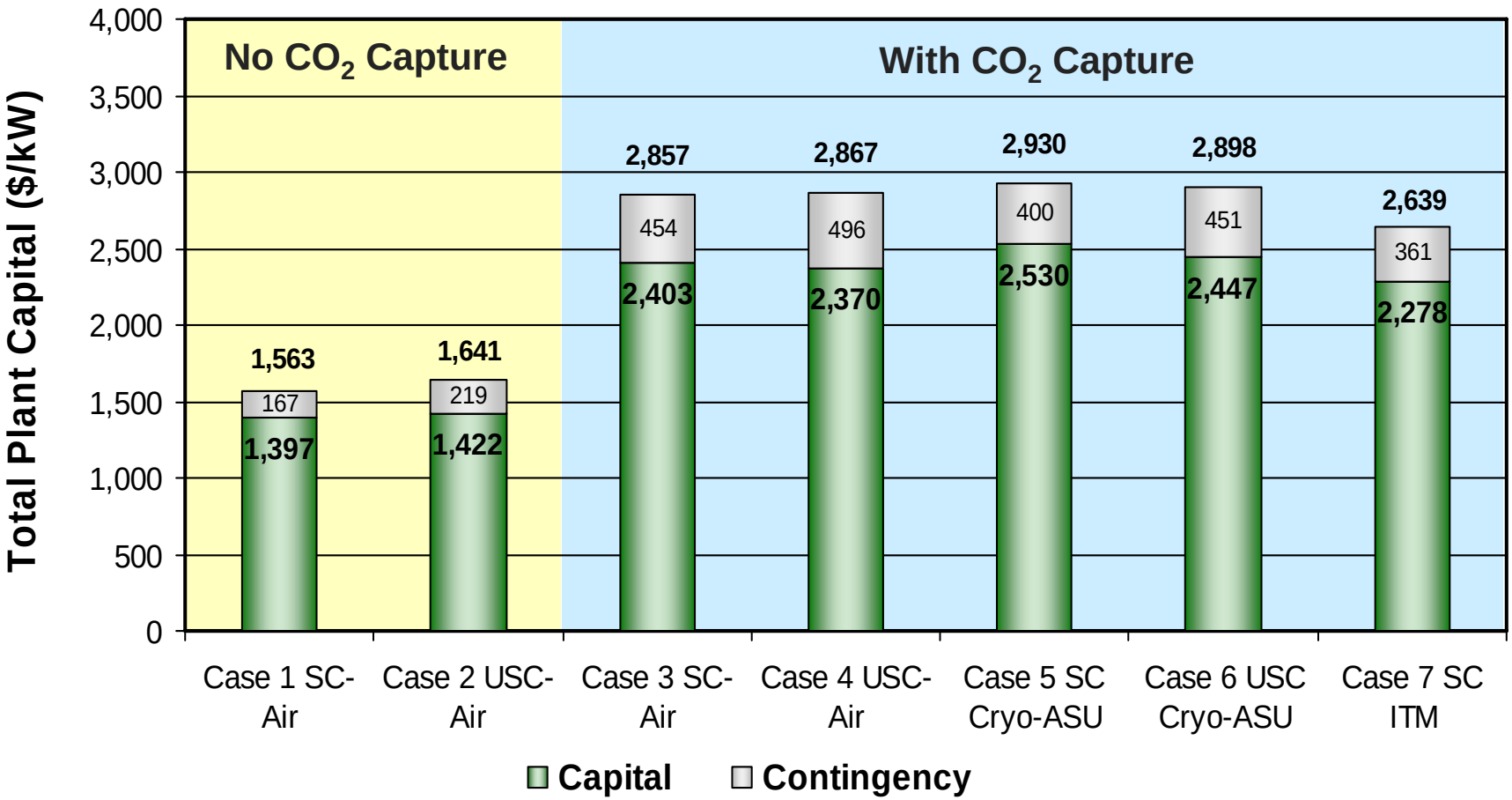


Thermal Efficiency Summary

CO_2 Capture decreases net efficiency by ~13 percentage points

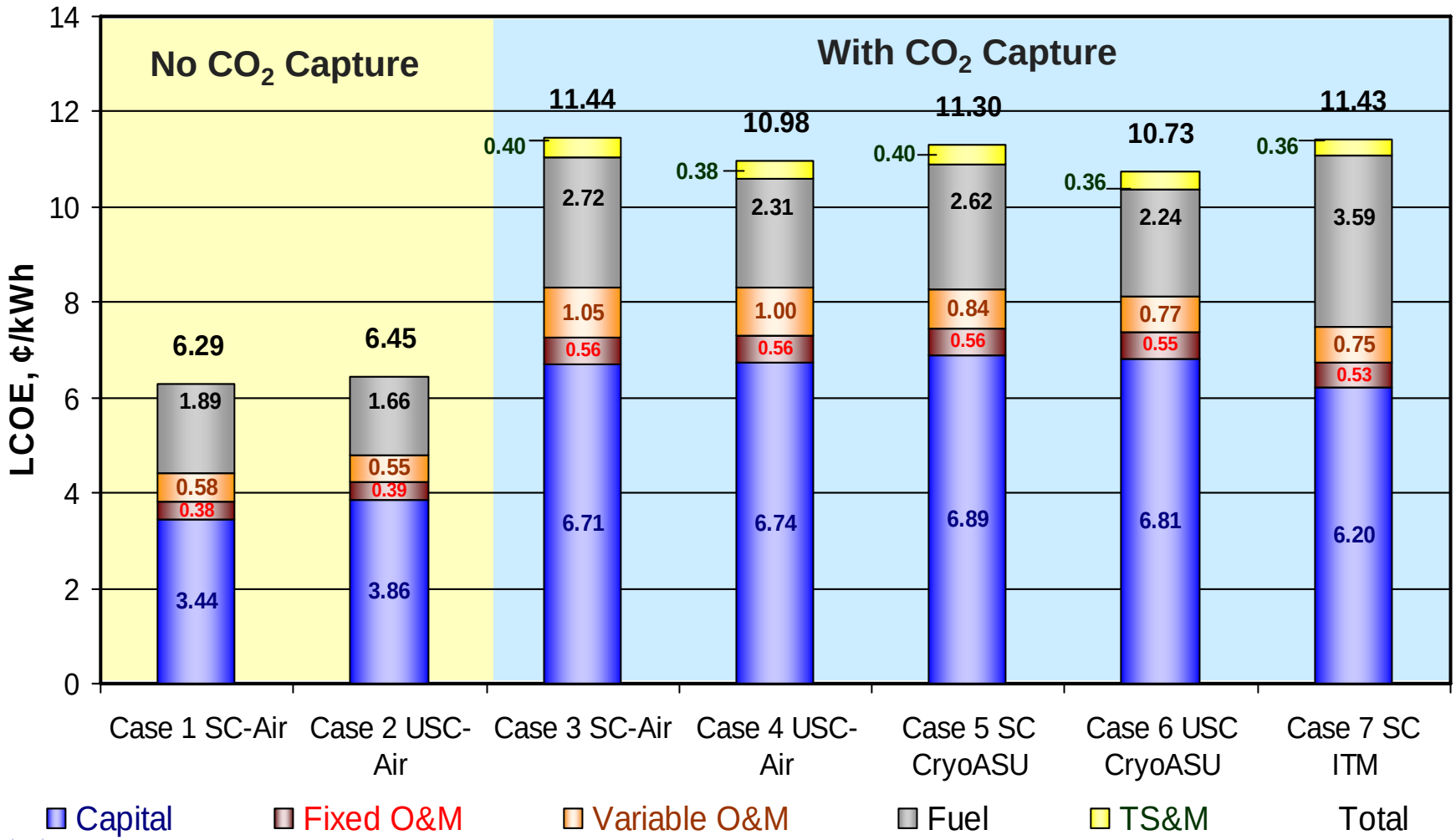


Total Plant Capital Cost Summary

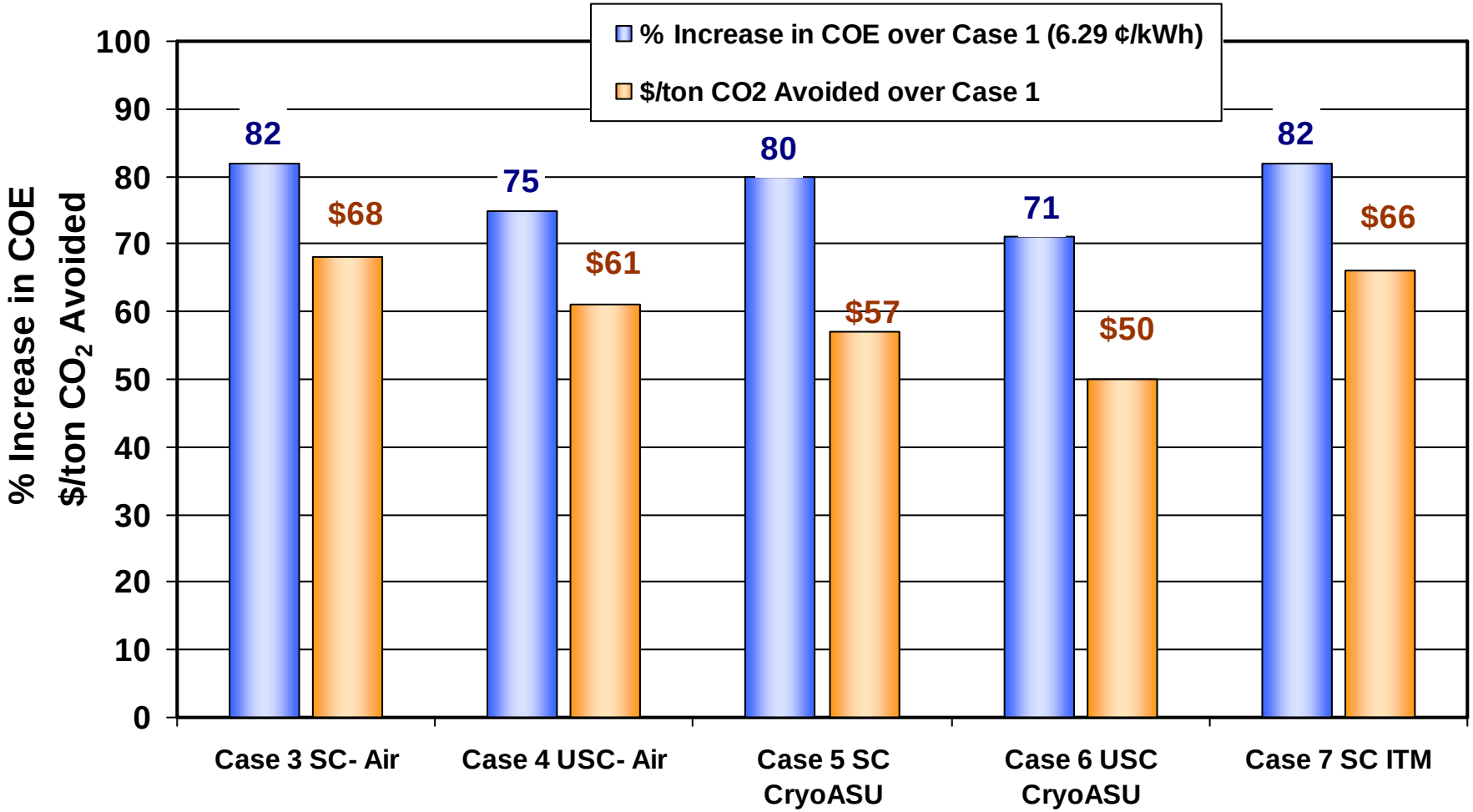


CO_2 Capture increases Total Plant Cost by 73-87%

Levelized Cost of Electricity



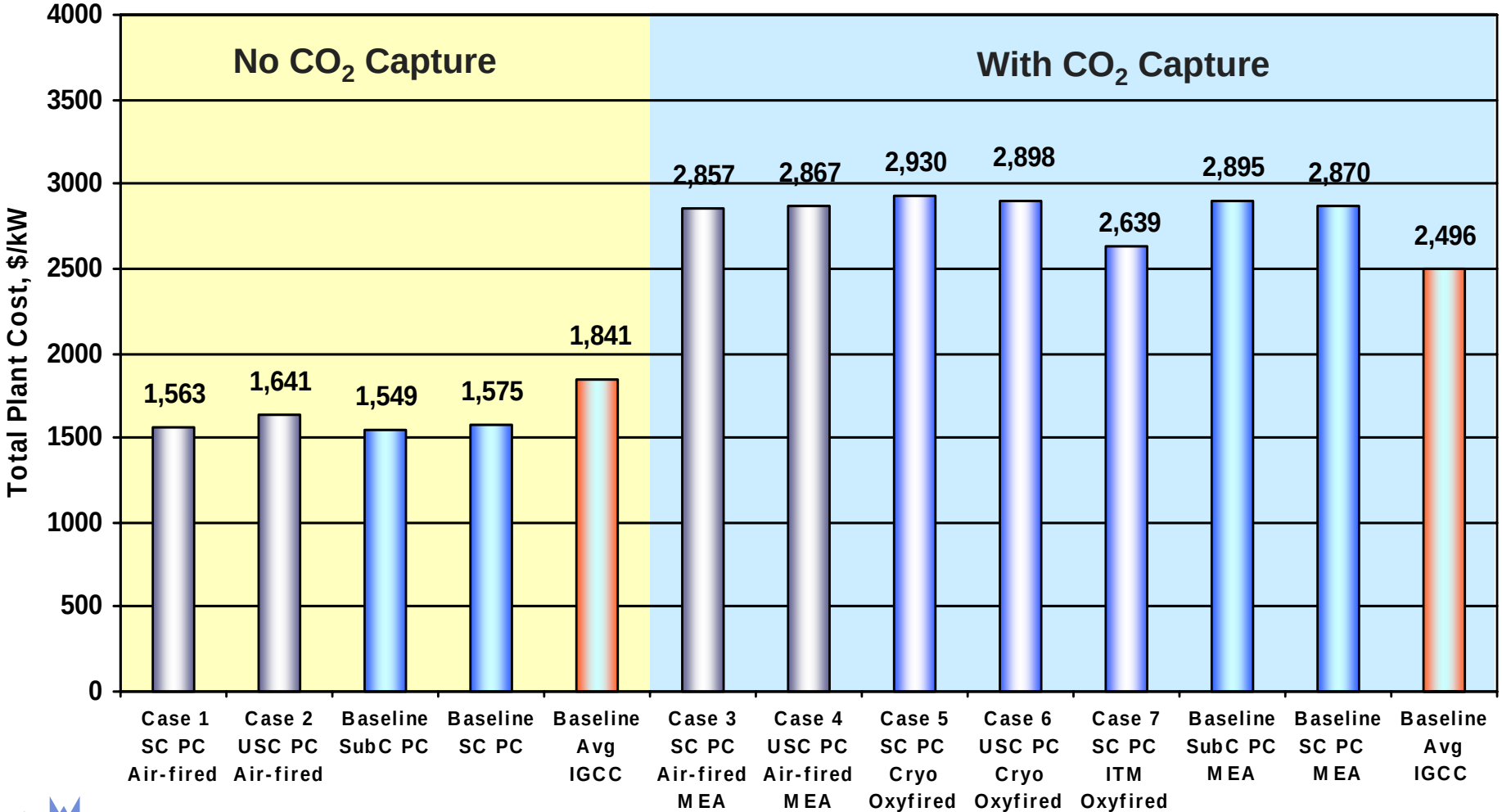
CO_2 Capture Mitigation Costs



*Including CO_2 transport, storage and monitoring costs

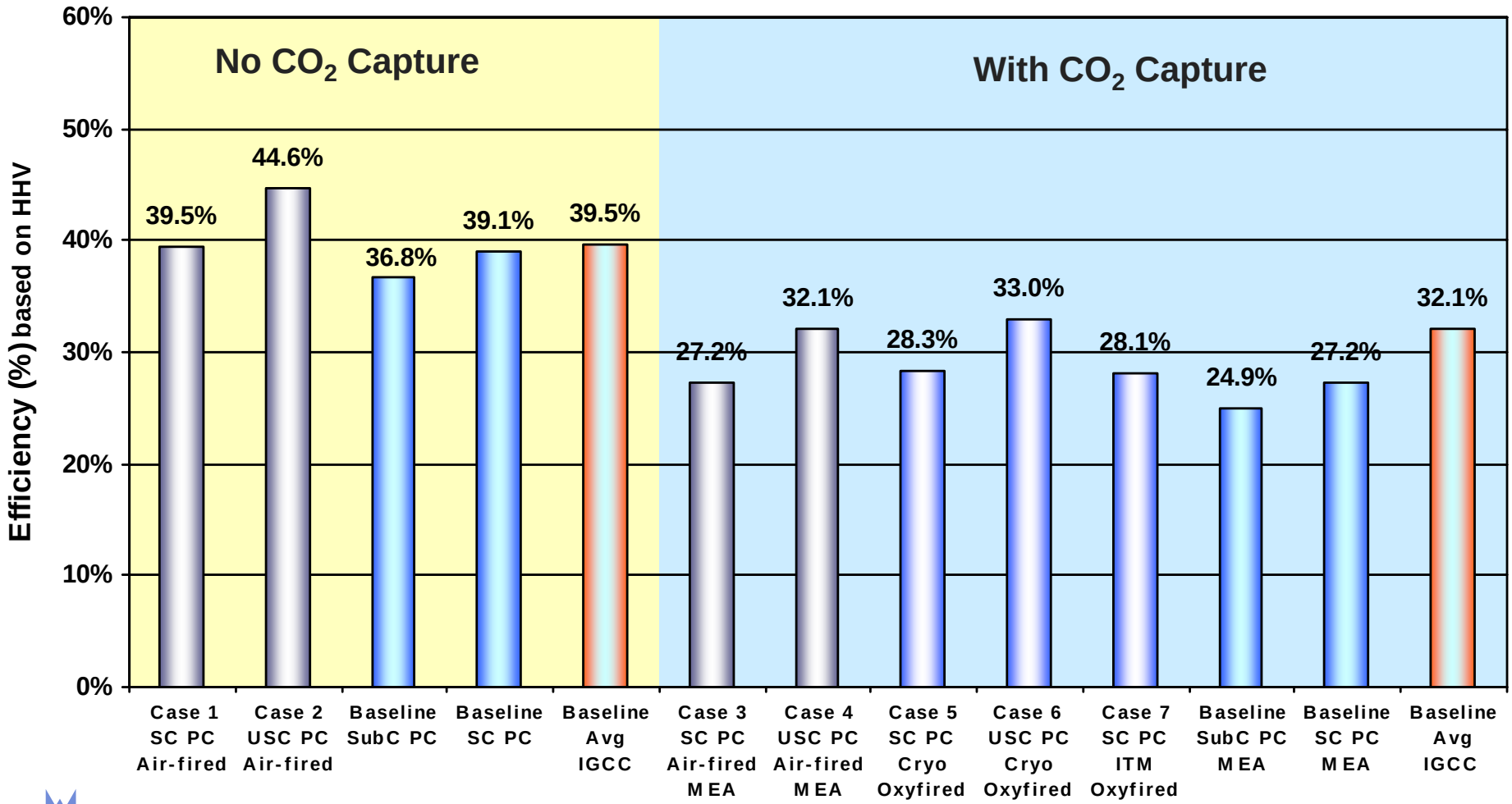
Comparisons to NETL Bituminous Baseline Study

Total Plant Cost Comparison
with NETL Bituminous Baseline Report Results



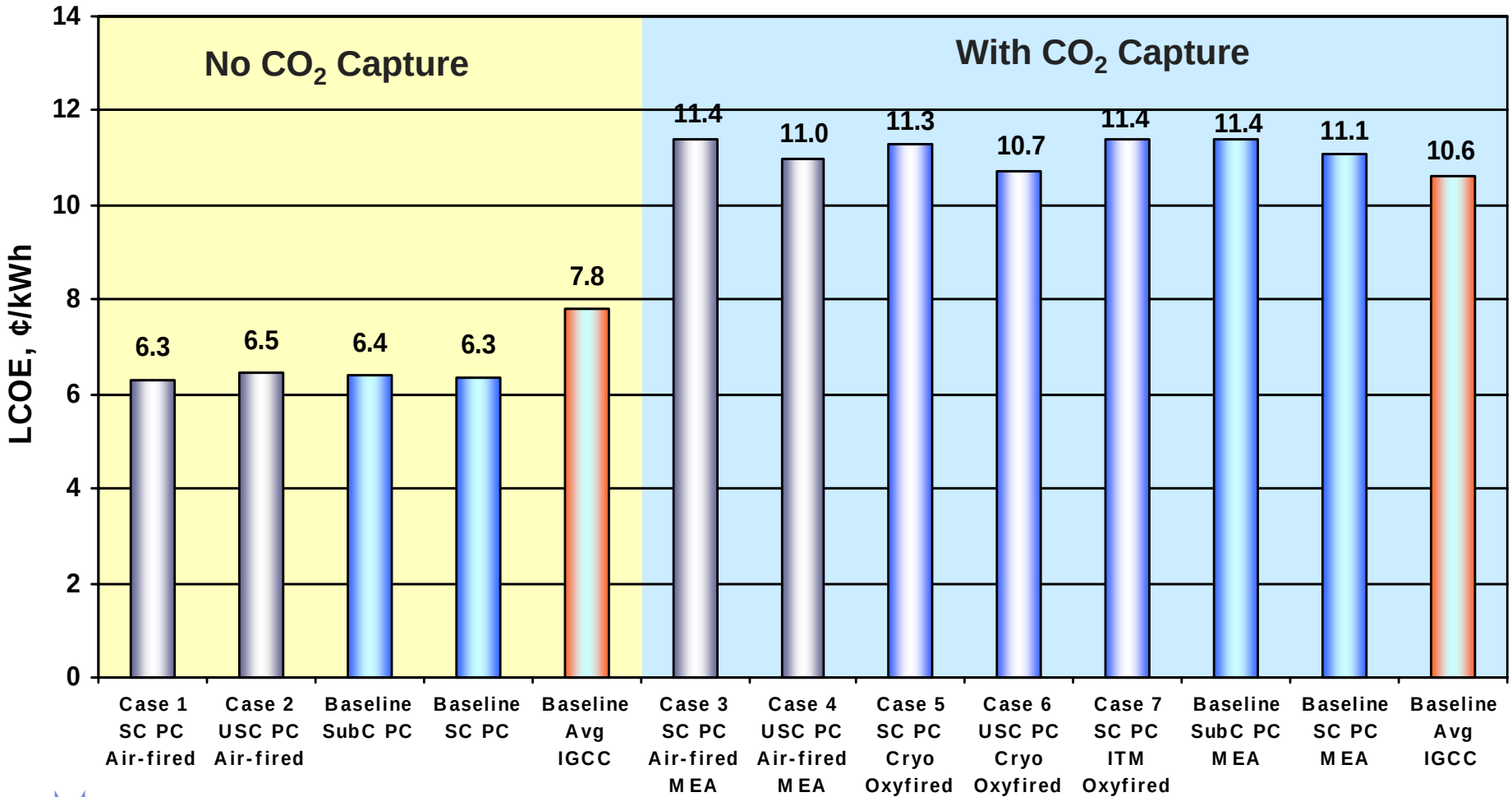
Total Plant Capital Cost includes contingencies and engineering fees

Efficiency Comparison
with NETL Bituminous Baseline Report Results



Levelized Cost of Electricity Comparison

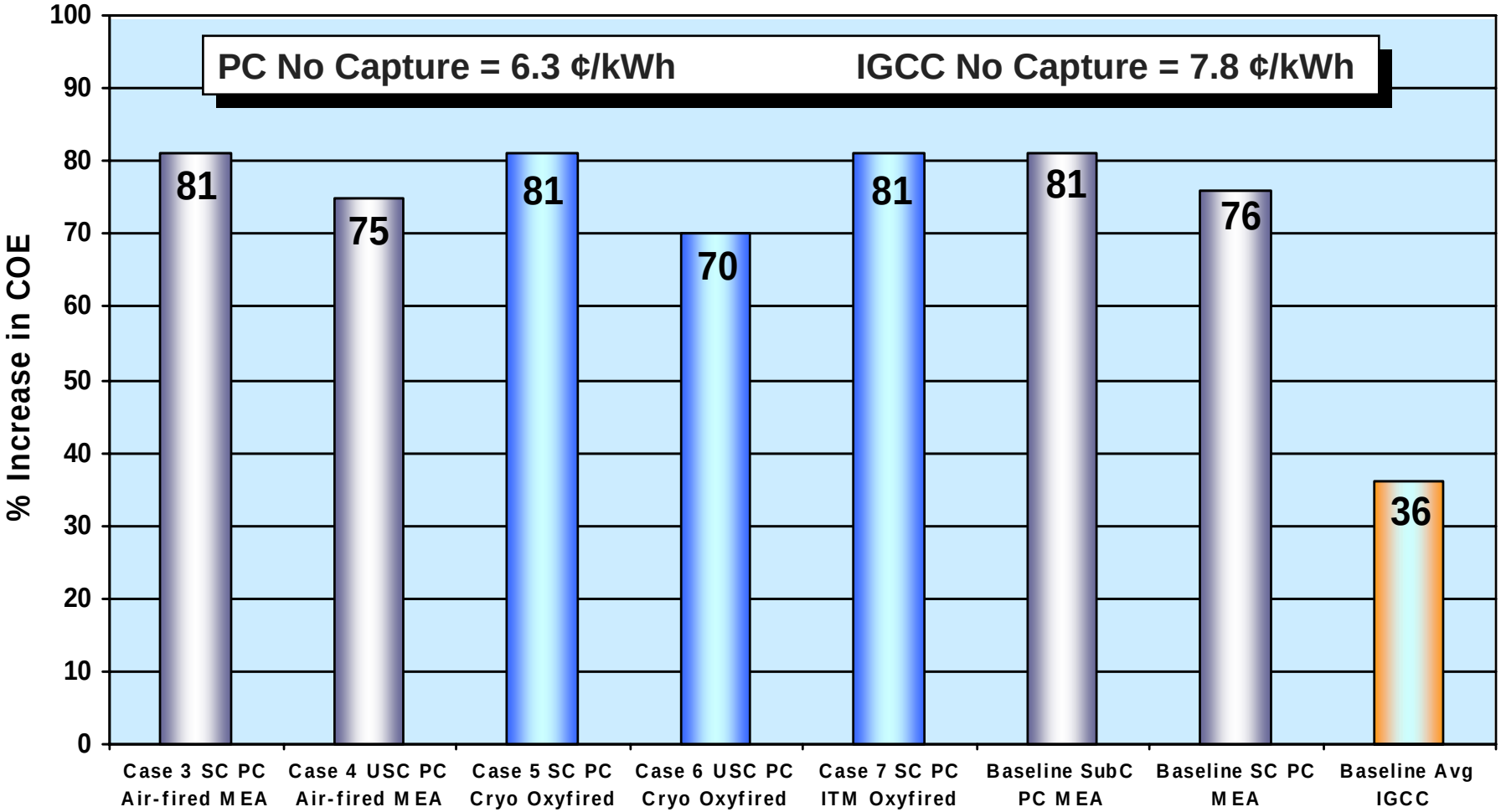
with NETL Bituminous Baseline Report Results



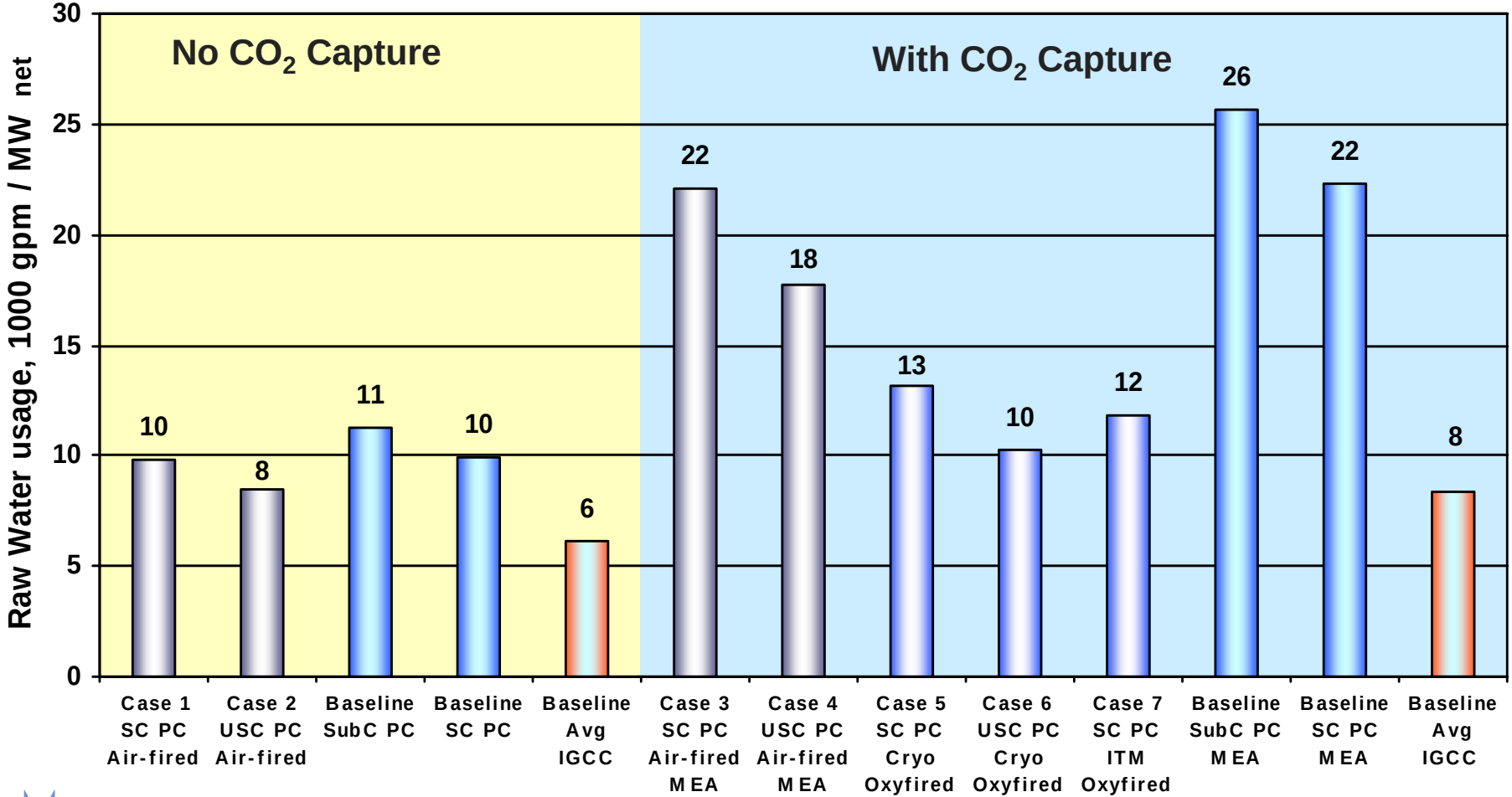
Includes costs for CO_2 Transport, Storage, & Monitoring

Levelized Cost of Electricity Comparison

with NETL Bituminous Baseline Report Results



Raw Water Usage per MW_{net} Comparison
with NETL Bituminous Baseline Report Results



Highlights

NETL Viewpoint

- **Most up-to-date performance and costs for PC oxyfuel combustion available in public literature to date**
- **Establishes baseline performance and cost estimates for current state of PC oxyfuel combustion technology**
- **Fossil Energy RD&D aimed at improving performance and cost of clean coal power systems including development of new approaches to capture and sequester greenhouse gases**

Result Highlights: Efficiency & Capital Cost

- **Coal-based plants using today's technology are efficient and clean**
  - IGCC & PC: 39%, HHV (without capture on bituminous coal)
  - Meet or exceed current environmental requirements
  - Today's capture technology can remove 90% of CO_2, but at significant increase in COE

- **Total Plant Cost: IGCC ~20% higher than PC capex**
  - PC: $1,600/kW (average)
  - IGCC: $1,900/kW (average)

- **Total Plant Cost with Capture: PC > IGCC capex**
  - IGCC: $2,500/kW (average)
  - PC (Amine): $2,900/kW (average)
  - PC (Oxyfuel): $2,900/kW

Results Highlights: COE

- **20 year levelized COE: PC lowest cost option**
  - PC: 64 mills/kWh (average)
  - IGCC: 78 mills/kWh (average)

- **With CCS: IGCC lowest cost option**
  - IGCC: 106 mills/kWh (average)
  - PC (Amine): 114 mills/kWh (average)
  - PC (Oxyfuel): 113 mills/kWh