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CO_2 Capture & Storage -EPRI CoalFleet Program

PacifiCorp Energy - IGCC/Climate Change Working Group

Salt Lake City, January 25, 2007

Neville Holt – EPRI Technical Fellow Advanced Coal Generation Technology

EPRI CO_2 Capture and Storage Presentation Outline

- Overview
- PC Post Combustion Removal – Status, Studies, Chilled Ammonia pilot
- Oxyfuel – Status, SaskPower
- IGCC/PC Studies DOE, EPRI - New Plants with and without Capture
- Adding Capture to IGCC – Pre-Investment? Work in Progress
- IGCC/PC EPRI Study adding Capture to new plant designed without Capture – CPS San Antonio
- Effect of Capital Cost increases on COE, CO_2 cost, and Strategic selection of power generation technologies
- Conclusions

Options for CO_2 Response (The Stabilization Wedge & Slices)

- Conservation (Yes - but Rest of the World?)
- Renewables (Yes - but not enough)
- Nuclear (Ultimately Yes – but implies wide Proliferation)
- Adaptation (Probably Yes – we always do)
- Switch from Coal to Natural Gas (Maybe but not enough NG)
- CO_2 Capture & Sequestration (CCS) (Maybe but site specific & costly)

Notes :

US Coal Power Plants emit > 2 billion metric tons of CO_2/yr (~36% of US and 8% of World CO_2 emissions).

1 billion metric tons/yr = ~25 million bpd of supercritical CO_2

Effort Required for CCS Slice- World-wide build or replace 8 GW of Coal Power plants with CCS every year and maintain them until 2054

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Advanced Coal CO_2 Capture Options

- Post Combustion removal of CO_2 from flue gas by e.g. Amine (MEA) or other sorbent scrubbing for
  - Natural Gas Combined Cycle (NGCC) plants
  - Pulverized Coal (PC) plants
- Pulverized Coal Combustion with Oxygen and recycle CO_2 to give a concentrated CO_2 stream (Oxyfuel or Oxygen Combustion (OC))
- Coal Gasification with Shift reactor and removal of CO_2 from syngas prior to combustion of H_2 in combined cycle (IGCC)
- Coal Gasification and syngas combustion with Oxygen and recycle CO_2 to give a concentrated CO_2 stream (e.g. Clean Energy Systems etc)

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CO_2 Capture - Technology Options, Status, Costs, Issues

- IGCC and CO_2 removal are offered commercially but have not operated in a mature integrated manner
  - **Big issues IGCC Cost (Particularly with low rank coals), Integration, H_2 Turbines and CO_2 Storage**
- Advanced PC and CO_2 post combustion are each offered commercially but CO_2 removal has only operated at small scale and not integrated
  - **Big Issues CO_2 Capture Cost, Integration and CO_2 Storage**
- **Oxyfuel Combustion is not as advanced**
- **Many promising options are under development (DOE, EPRI, others)**

Gasification and Combustion Needed With CO_2 Options

EPRI Programs 2007ff

- P 66 CoalFleet for Tomorrow – Future Coal Options
  Focus on Deployment of New Plants, Designs for Capture Readiness and Capture

  - 66A Economic and Technical Overview (IGCC,PC,CFBC)

  - 66 B Gasification - IGCC and Co-production (Hydrogen,SNG,F-T etc)

  - 66 C Combustion - USC PC, Advanced materials, CFBC, OxyFuel

- P 103 CO_2 Capture & Storage

  Focus on Sequestration and Existing Plants

  - Participation in US Regional Partnerships, IEA GHG

  - Capture focus Existing Plants

  - Chilled Ammonia (ABS) 5 MW Pilot Plant

Economic Evaluations of SOA Coal Technologies with CO_2 Capture and Sequestration (CCS) - Current Summary

At the current State-of-the Art (SOA) there is no "Single Bullet" technology for CCS. Technology selection depends on the location, coal and application

- IGCC/Shift least cost for bituminous coals
- IGCC/Shift and PC plants with Amine scrubbing similar COE for high moisture Sub-bituminous Coals
- PC with Amine scrubbing least cost for Lignites
- CFBC can handle high ash coals and other low value fuels
- Oxyfuel (O_2/CO_2 Combustion), Chemical Looping are technologies at developmental stage

EPRI's CoalFleet for Tomorrow Program

- Build an industry-led program to accelerate the deployment of advanced coal-based power plants; use "lessons learned" to minimize risk: address "Capture Readiness"
- Employ "learning by doing" approach; generalize actual deployment projects (50 & 60 Hz) to create design guides
- Augment ongoing RD&D to speed market introduction of improved designs and materials; lead industry collaborative projects
- Deliver benefits of standardization to IGCC (integration gasification combined cycle), USC PC (ultra-supercritical pulverized coal), and SC CFBC (supercritical circulating fluidized-bed combustion)
  - Lower costs, especially with CO_2 capture
  - Higher reliability
  - Near-zero SO_X, NO_X, PM, and Hg emissions
  - Shorter project schedule

CoalFleet Participants Span 5 Continents

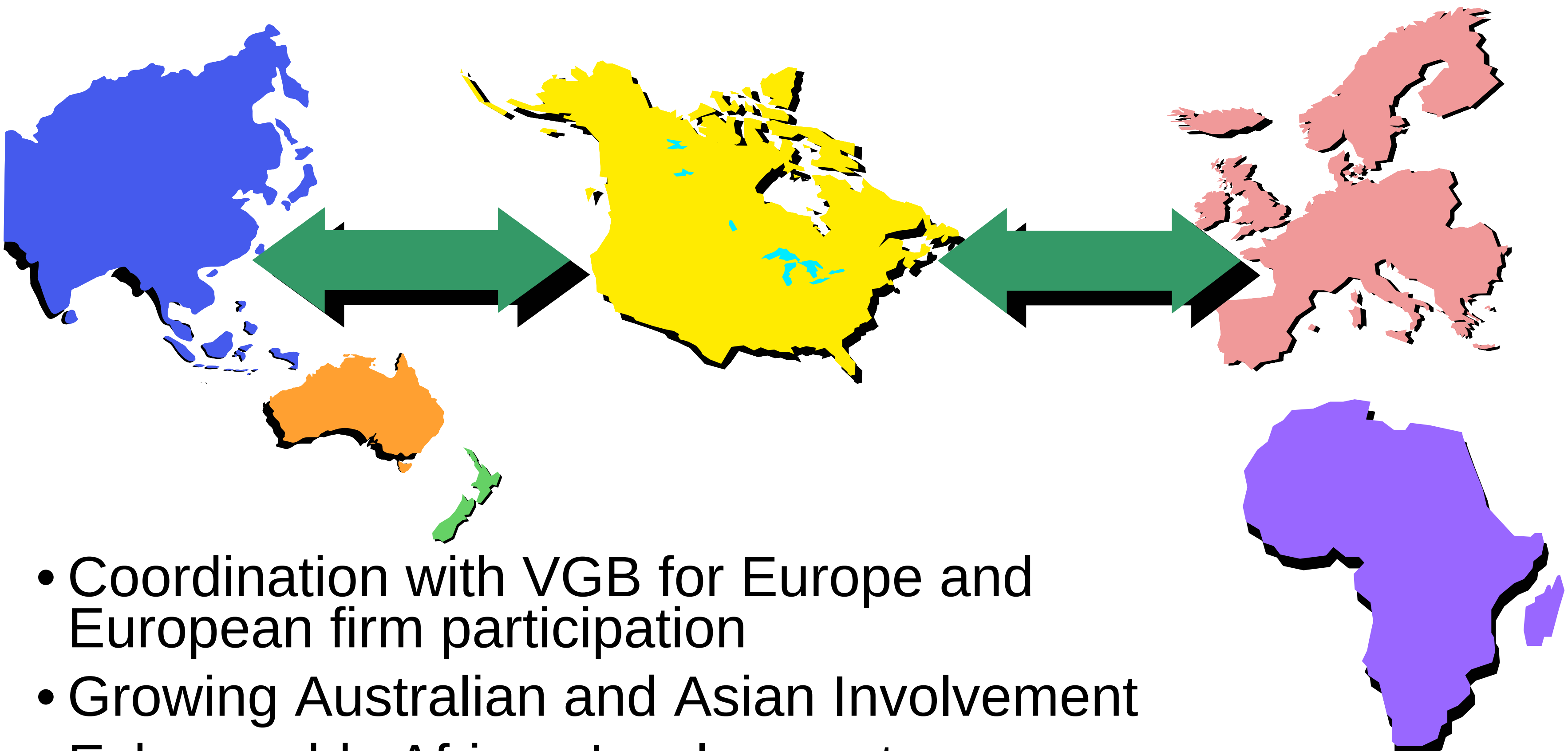
>60% of U.S. Coal-Based Generation, Large European Generators, Major OEMs (50 & 60 Hz) and EPCs, U.S. DOE

- AES
- Alliant
- Alstom Power
- Ameren
- American Electric Power
- Arkansas Electric Coop
- Austin Energy
- Babcock & Wilcox
- Bechtel Corp.
- BP
- California Energy Commission
- Calpine
- CPS Energy
- ConocoPhillips Technology
- CSX Corporation
- Dairyland Power Coop
- Doosan Heavy Industries
- Duke Energy Corp
- Dynegy
- East Kentucky Power Coop
- EdF
- Edison International
- E.ON
- ESKOM
- Exelon Corp.
- FirstEnergy Service
- GE Energy
- Great River Energy
- Golden Valley Electrical Association
- Hitachi

CoalFleet Participants Span 5 Continents (cont'd)

- Hoosier Energy
- Jacksonville Electric Authority
- Kansas City Power & Light
- Lincoln Electric
- MHI
- Minnesota Power
- Nebraska Public Power District
- New York Power Authority
- PacifiCorp
- Portland General Electric
- Pratt Whitney Rocketdyne
- Progress Energy
- Public Service Co. New Mexico
- Richmond Power & Light
- Rio Tinto
- Salt River Project
- Shell
- Siemens
- Southern Company
- Stanwell Corporation
- Tri-State G&T
- TVA
- TXU
- U.S. DOE
- We Energies
- Wisconsin Public Service

CoalFleet Continues to Expand Collaborative Relationship with International Organizations



- Coordination with VGB for Europe and European firm participation
- Growing Australian and Asian Involvement
- Eskom adds African Involvement
- Potential for Support from Asia-Pacific Partnership

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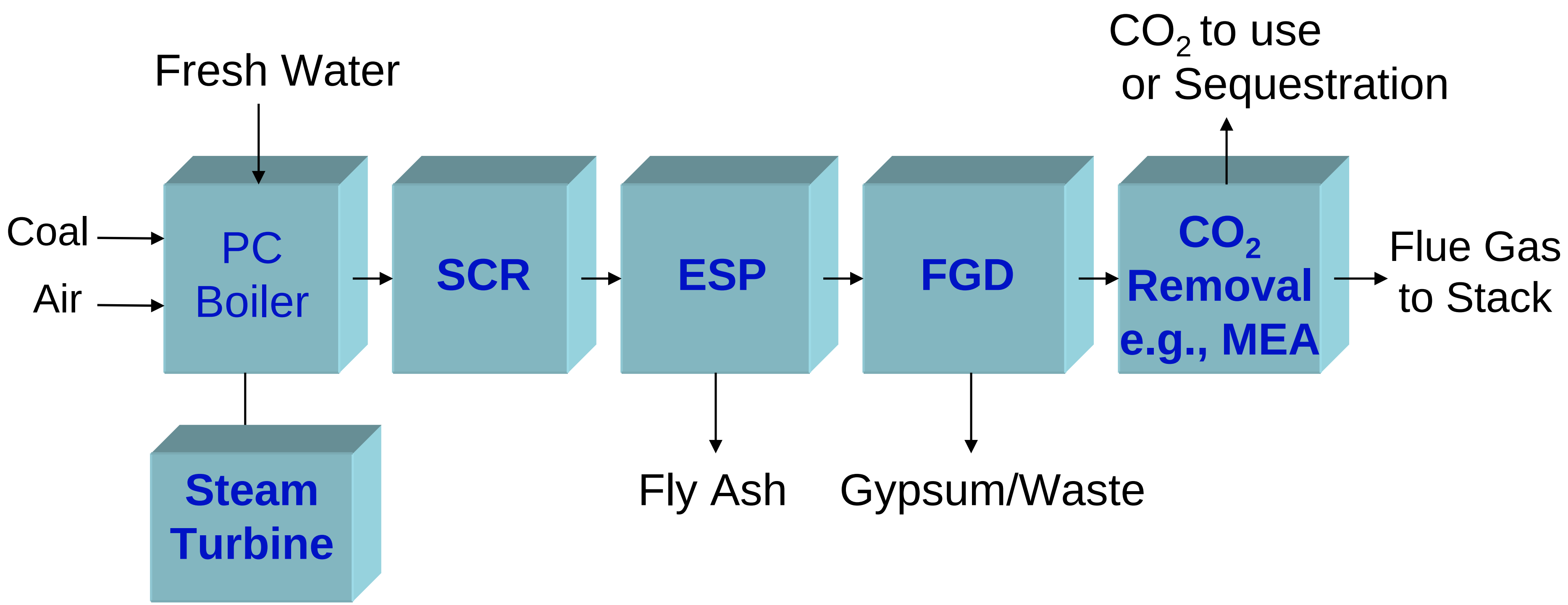
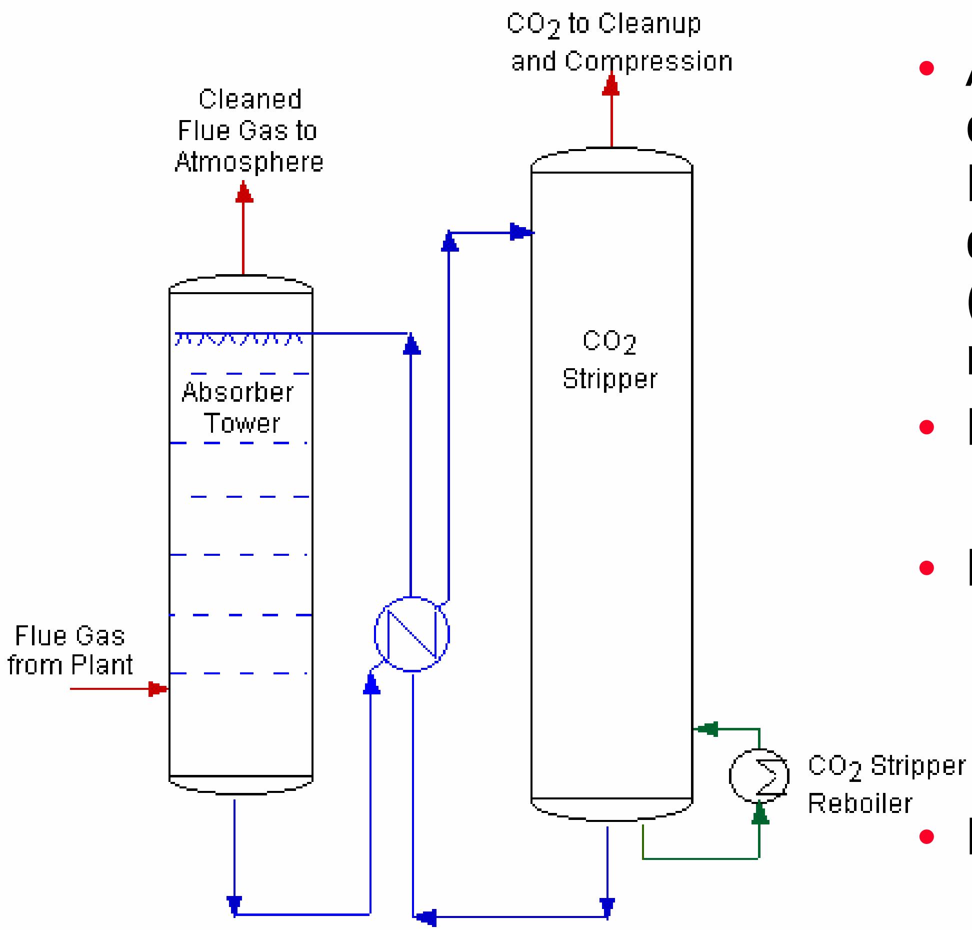
Pulverized Coal (PC) with CO_2 Removal



CO_2 Capture = $, Space, Ultra Low SO_2, and Lots of Energy

CO_2 Capture by Chemical Absorption



- Amine processes are commercially available -Fluor, Kerr McGee, MHI and have been demonstrated at 300 mt/day CO_2 (500 MW PC produces ~10,000 mt/day CO_2)
- Requires extensive pretreatment
  - » Essentially no NO_x or SO_2
- Large reboiler steam requirement
  - » Large net output reduction
  - » Make-up power source for Retrofit of existing plant?
- Looking at split-flow options
  - » Reduced steam consumption

Potential Improvements for Post Combustion CO_2 Capture

- Alternative equipment arrangements and designs - membrane absorbers (Kvaerner, TNO), membrane regenerator (Kvaerner)
- Alternative solvents – Hindered Amine (MHI- KS-1), Piperazine addition (promoter) to K_2CO_3, Other amines (PTRC at U.Regina)
- Ammonium Carbonate with CO_2 and water forms Ammonium Bicarbonate (EPRI, Nexant) . Can be regenerated at pressure. Potential energy savings in regeneration and compression
- Adsorption technologies – Amine enriched solids, K, Na and Ca carbonates, Lithium oxide
- Cryogenic cooling of flue gas
- Recycle flue gas to increase CO_2 concentration (perhaps viable for NGCC – need to consider effect of lower oxygen)

Chilled Ammonia Process Performance Prediction (Early Data Only)

Used Parsons Study for basis	Supercritical PC Without CO_2 Removal	Supercritical PC With MEA CO_2 Removal	Supercritical PC With NH_3 CO_2 Removal
LP Steam extraction, lb/hr	0	1,220,000	270,000
Power Loss, KWe	0	90,000	20,000
GROSS POWER, KWE	491,000	402,000	471,300
AUXILIARY LOAD, KWE			
Induced Draft Fan	5,000	19,900	10,000
Pumping CO_2 system,	0	1,900	5,000
Chillers	0	0	8,900
CO_2 compressor	0	30,000	9,500
NET POWER OUTPUT	462,000	330,000	415,000
% POWER REDUCTION		29	10

Source: Nexant

5 MW Chilled Ammonia CO_2 Capture Pilot

- Jointly Funded by Alstom and EPRI
- Site Selection Complete
  - WE Energies Pleasant Prairie Power Plant
- $11 million for construction, operation for one year, data collection and evaluation
  - Alstom will design, construct and operate
  - EPRI will collect data and provide evaluation
- 24 firms have agreed to fund EPRI testing with more being added
- Operations beginning in the 3rd Quarter of 2007

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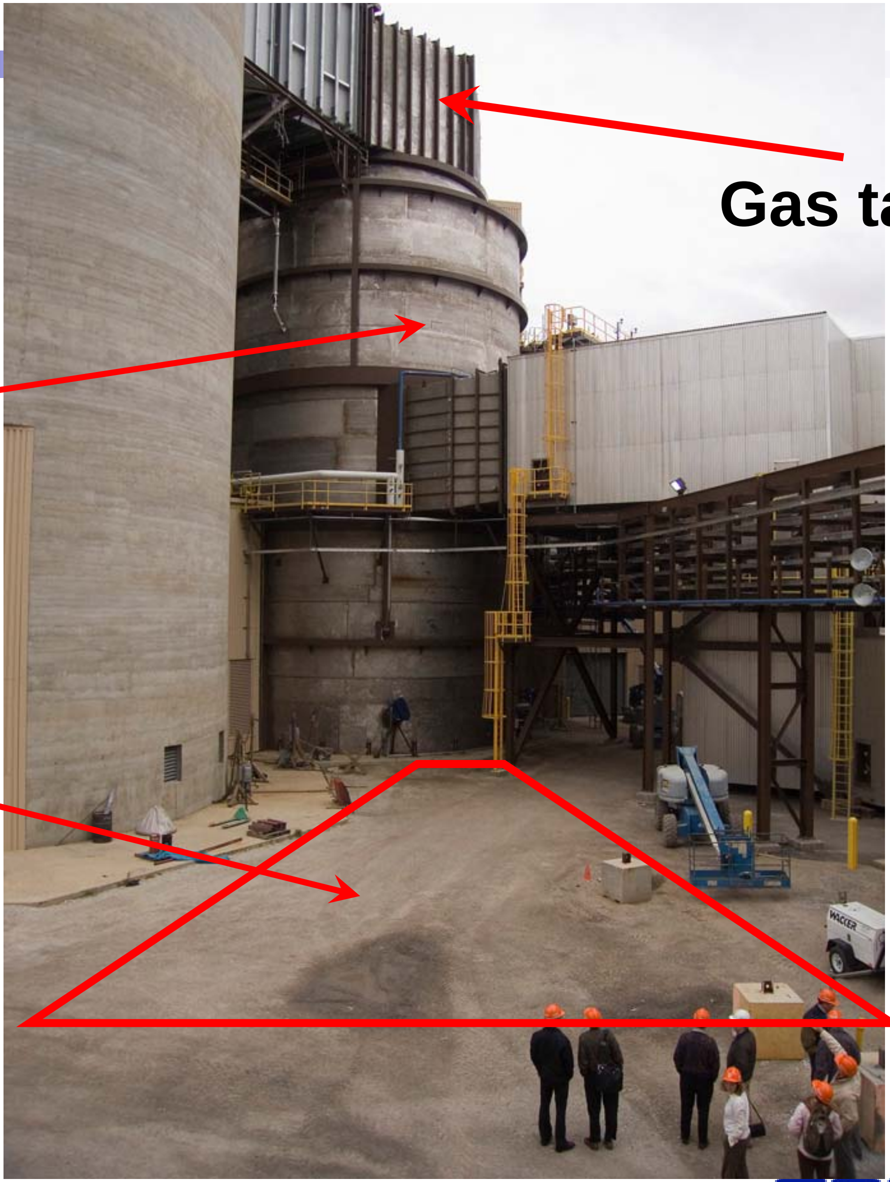
5 MW Chilled Ammonia CO_2 Pilot Capture Pilot



Gas takeoff

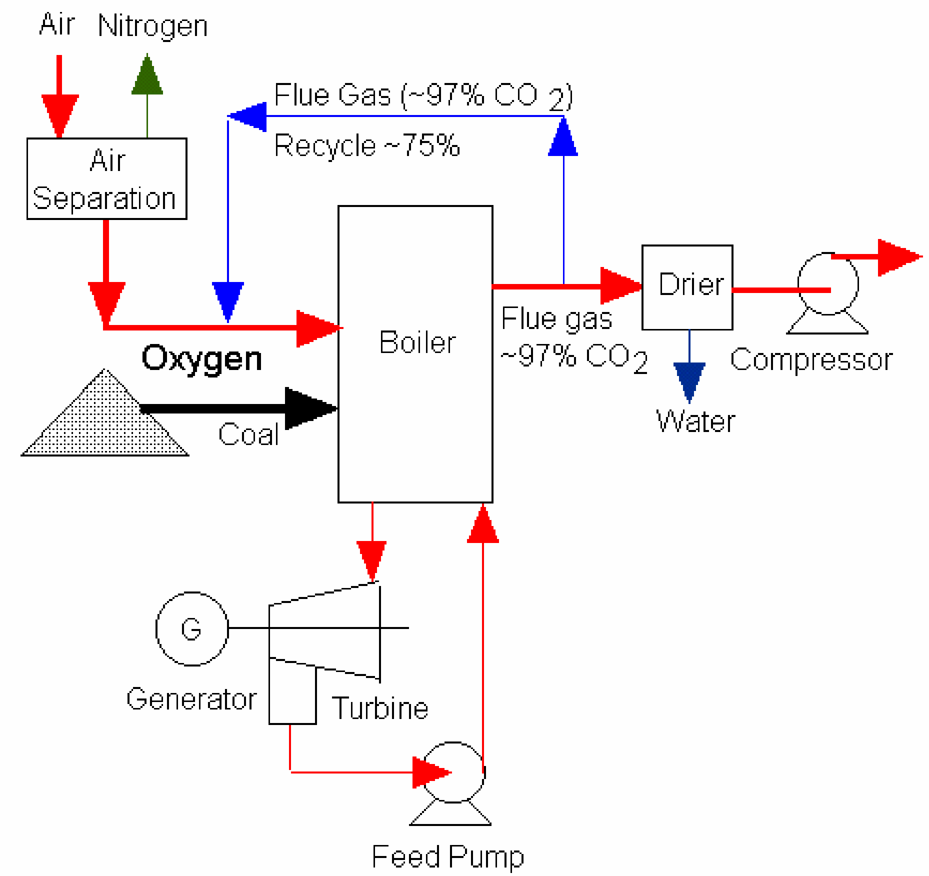
Scrubber Module

CO_2 pilot location

5 MW Chilled Ammonia CO_2 Capture Pilot Participants

AEP	Great River Energy	SRP
Ameren	Hoosier	Southern Co
CPS Energy	KCPL	Tri-State
Dairyland	MidAmerican	TXU
DTE Energy	NPPD	TVA
Dynegy	Oglethorpe	We Energies
E.ON U.S.	Pacificorp	
Exelon	PNM	
First Energy	Sierra Pacific	

CO_2 Capture by O_2/CO_2 Combustion



O_2/CO_2 Combustion

- Small test facilities at Canmet, B&W, Alstom
- Potential reuse of existing boiler equipment
  - » Pulverizers, air heaters, etc.
  - » Potential “retrofit kit”
- CO_2 recycled for temp. control
- SO_2 removed from purge stream
  - » If higher purity CO_2 required
- Requires large oxygen plant
- Large auxiliary power requirement
  - » Large net output reduction
  - » Make-up power source for Retrofit of existing plant?

Current OxyFuel Development Status

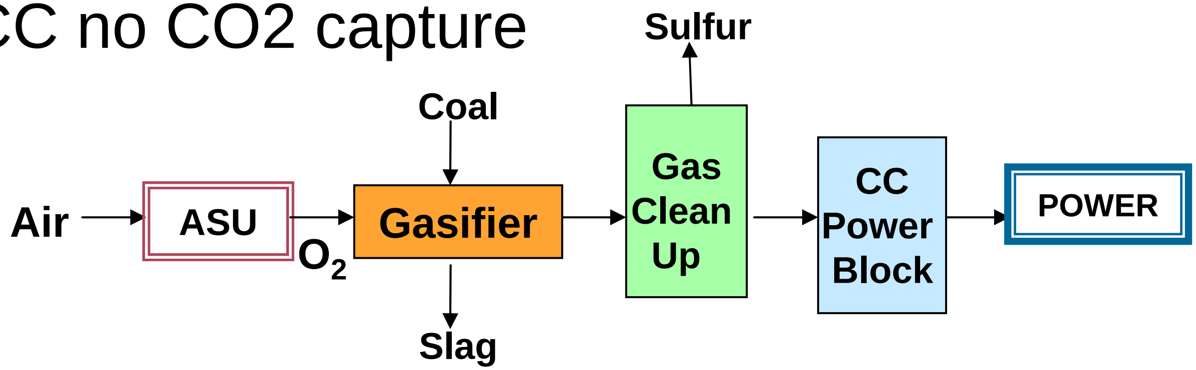
- Engineering design studies for commercial scale plants (Air Products, Air Liquide, Alstom, B&W etc)
- Operation of several pilot scale boilers
  - CANMET (~ 1 MM/Btu/hr)
  - Babcock and Wilcox (~5 MMBtu/hr). Larger unit planned
  - Alstom CFB (2.6-7.4 MMBtu/hr)
- A key issue is the removal of other gases (SO_2, O_2, NOx, HCl, Hg etc). Is FGD required, at least for high sulfur coals, on either recycle or CO_2 product streams? To date there has been no testing of downstream non-condensable gas recovery system
- To date no boiler testing at supercritical steam conditions
- Vattenfall announced plans for 30 MWth Oxyfuel demo near Schwarze Pumpe, Germany
- SaskPower plans 300 MW net with B&W, Air Liquide

IGCC with Capture

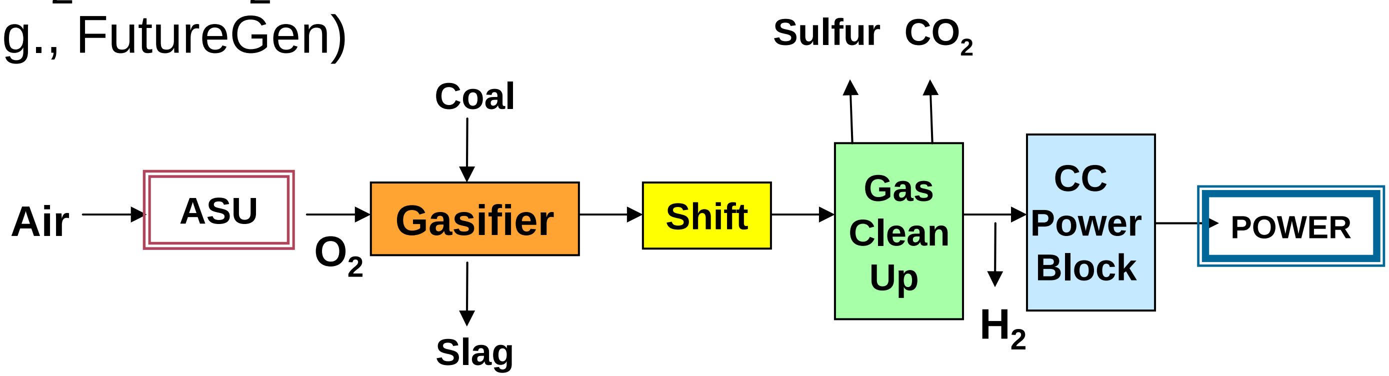
- DOE/NETL and EPRI studies for IGCC plants designed with Capture from the start
- Additional Costs of Capture for Different Gasification Technologies
- IGCC/Gasification Improvements Needed for more Cost-effective Capture
- IGCC Design Options for Degree(%) of Capture
- IGCC Pre-Investment Options for later addition of CO_2 Capture
- CPS San Antonio Study adding capture to IGCC/PC plants designed without pre investment for Capture
- CPS Results converted to IOU financing

IGCC with and without CO_2 Removal

IGCC no CO2 capture



H_2 & CO_2
(e.g., FutureGen)



CO_2 Capture = $, Space, Shift, H_2 Firing, CO_2 Removal, Energy

CO_2 Capture from Gasification-based coal power plants - US

- No coal gasification-based power plant (IGCC) currently recovers CO_2 from the process
- Three non-power facilities in the US and many plants in China recover CO_2
- The recovered CO_2 from the Great Plains plant is used for enhanced oil recovery 2.7 MTY~ 300 MWe if it were an IGCC

The Great Plains Synfuels Plant
http://www.dakotagas.com/Companyinfo/index.html

Weyburn pipeline
http://www.ptrc.ca/access/DesktopDefault.aspx

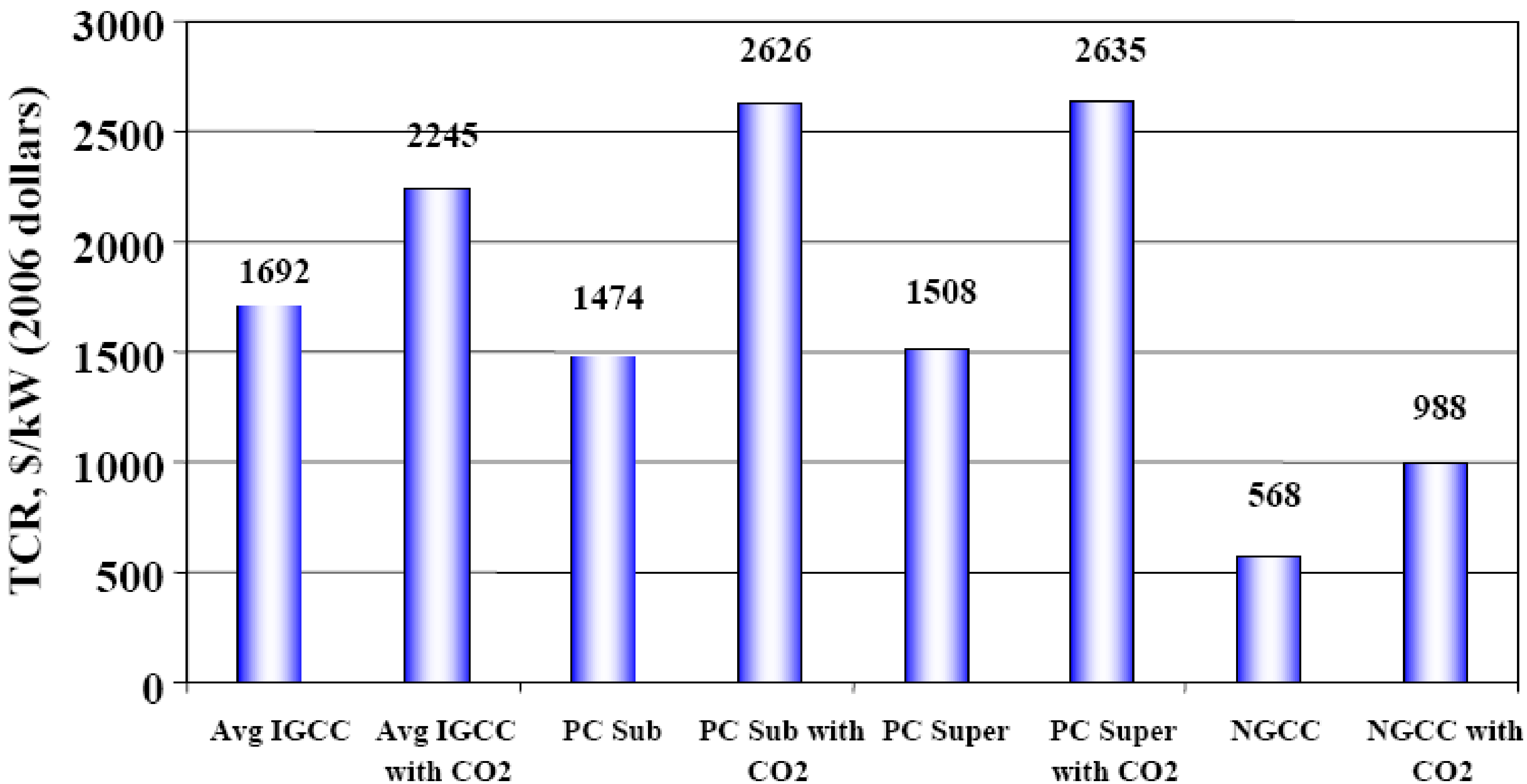
DOE NETL Draft Report "Cost & Performance Comparison of Fossil Energy Power Plants"

- IGCC, PC and NGCC designs evaluated a) without capture and b) with Capture. Illinois#6 coal $1.34/MBtu NG 7.46$/MBtu HHV.

- GE Radiant Quench, COP E-Gas Full Slurry Quench, Shell Gas Recycle Quench . All based on 2 x GE 7 FB GTs. Designs with capture have additional coal gasification etc to fully load the GTs when firing Hydrogen. Lower net output with capture. NETL presented results for IGCC as an average of the three technologies

- PC sub critical (2400/1050/1050) and Supercritical (3500/1100/1100). Designs with post combustion amine scrubbing capture are much larger so that net output is same as designs without capture
- NGCC without capture and with post combustion amine scrubbing

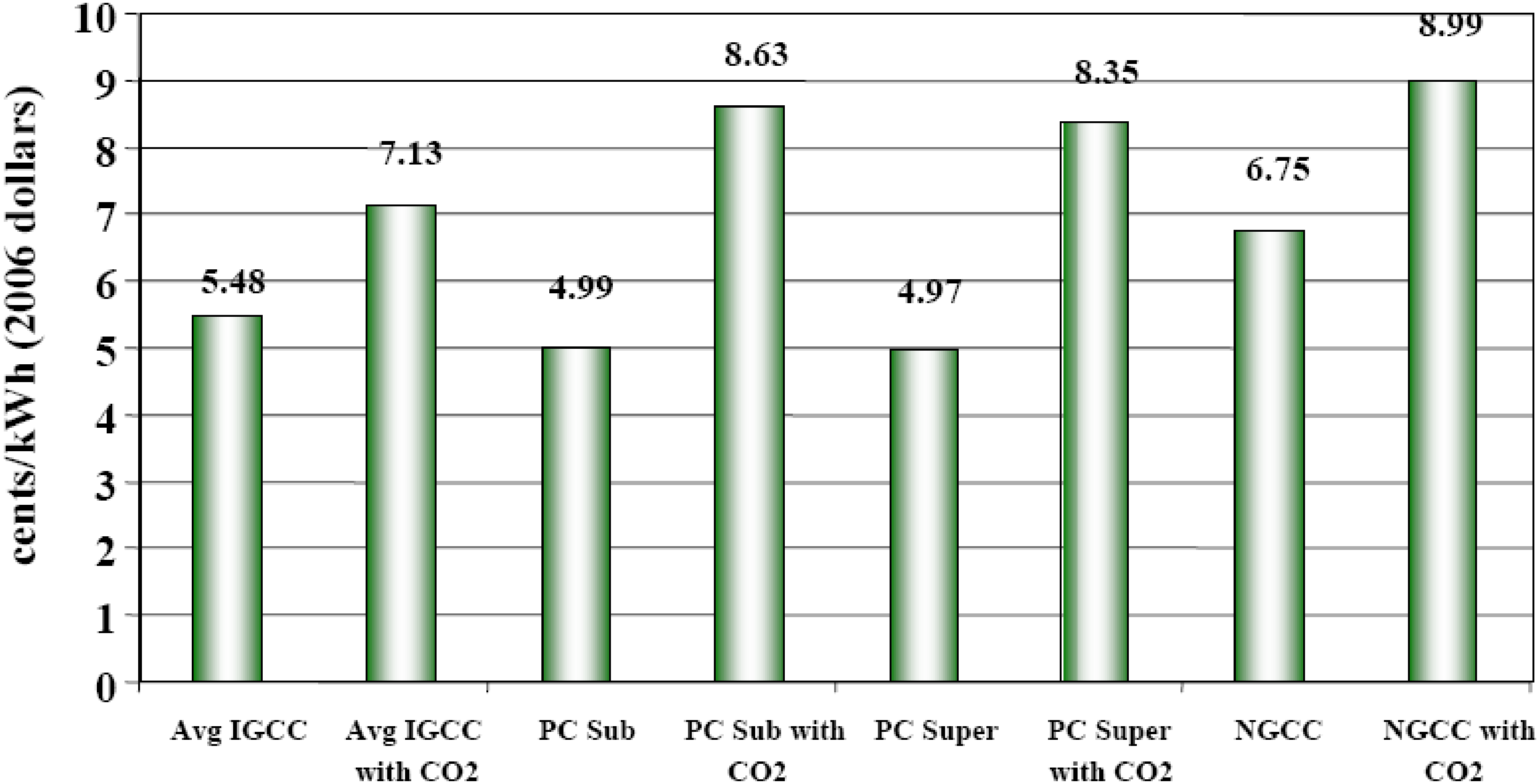
NETL 2006 Cost and Performance of Fossil Energy Power Plants Draft Report Results



TCR = Total Capital Requirement (Includes equipment, materials, labor, indirect construction costs, engineering, contingencies, cost of money, real estate, royalty allowance, preproduction costs, and initial inventories.)

Source: NETL Presentation at 2006 Gasification Technologies Conference

NETL 2006 Cost and Performance of Fossil Energy Power Plants Draft Report Results



January 2006 Dollars
13.8% Levelization Factor

Coal cost $1.34/10^6Btu
Gas cost $7.46/10^6Btu

IGCC capacity factor 80%
PC capacity factor 85%
NGCC capacity factor 65%

Source: NETL Presentation at 2006 Gasification Technologies Conference

Differential COE Costs for Designs without and with CO_2 Capture (without Sequestration costs) -Illinois #6 Coal

N.B, These are not to be confused with the costs of adding capture to an existing design without capture !!

Technology	COE Differential % increase for Design with Capture	Source
GE Radiant IGCC	23	DOE NETL 2006
COP E-Gas IGCC	29	DOE NETL 2006
Shell IGCC with gas recycle	38	DOE NETL 2006
KBR IGCC Air KBR IGCC Oxygen	60 73	Southern Company 2006
SubCritical PC	73	DOE NETL 2006
USC PC	68	DOE NETL 2006
NGCC	31	DOE NETL 2006

IGCC Designs with Shift and CO_2 Capture

- Water Quench is the least cost way of adding the moisture for the Shift reaction.
- Higher pressure e.g. 800-1000 psig decreases the cost of CO_2 removal and compression through use of a physical absorption system (e.g. Selexol) where solvent recovery is largely achieved through depressurization and without large steam (energy) penalty. Some CO_2 can be recovered at pressure reducing the needed MW for compression.
- GE can offer high pressure and either Q or RQ provide more moisture for shift
- COP E-Gas, Shell, Siemens and KBR are lower pressure (< 600 psig) and have lower moisture in the syngas

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Syngas Composition affects Shift Steam requirements (Need > 3/1 H_2O/CO Ratio) and Overall Performance

Technology	Pressure Psig	H_2O/CO Molar Ratio	Relative HP Steam Flow to Shift	Steam Turbine MW Output
GE Radiant Quench	800	1.3	1.0	270
GE Total Quench	1000	>3.0	Zero	242
COP E-Gas Full Slurry Quench	600	0.4	2.0	216
Shell Gas Recycle Quench	600	0.1	2.8	202

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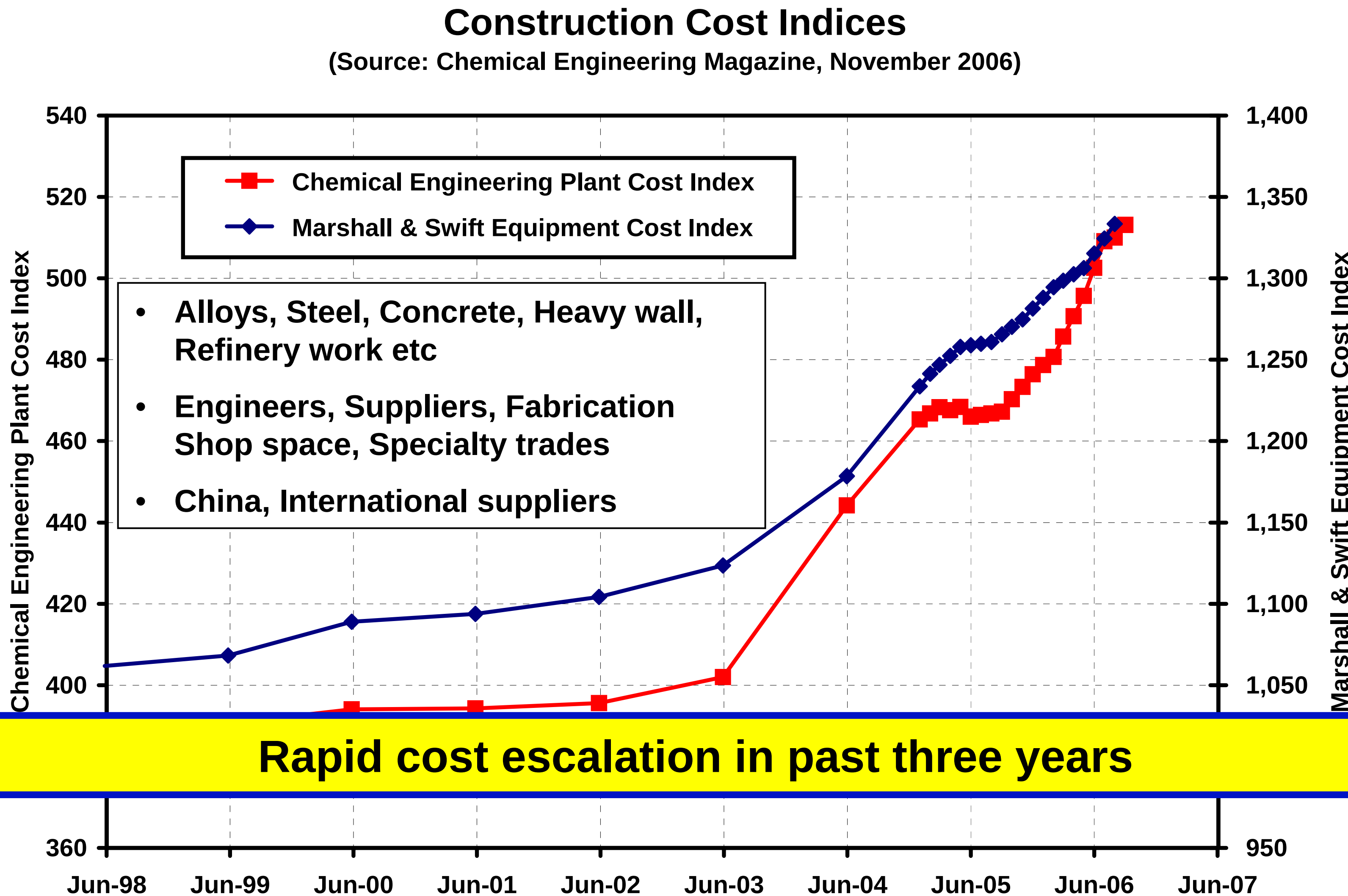
EPRI Evaluation of Plant Configurations for FutureGen Alliance

- Used the knowledge base of previous studies (2002–03) and adjusted to labor rates and productivity for a standard Midwest location
- Scaled up plant size to reflect the 7 FB and 5000F fuel requirements and improved performance
- Brought all estimates up to May 2006$ using the CEPCI
- 13 different FutureGen Configurations, all single train with CO_2 capture, and designed for a range of coals from bituminous to sub-bituminous and lignite, were evaluated
- From this work, EPRI separately developed cases both with and without capture for commercial size two-train IGCC plants at ~620 MW net
- **Caution: This methodology will inevitably show the same kind of percentage differential cost between technologies as in the 2002–03 studies. However, in absence of new studies, this is the only recourse.**

Plant Construction Costs Escalating

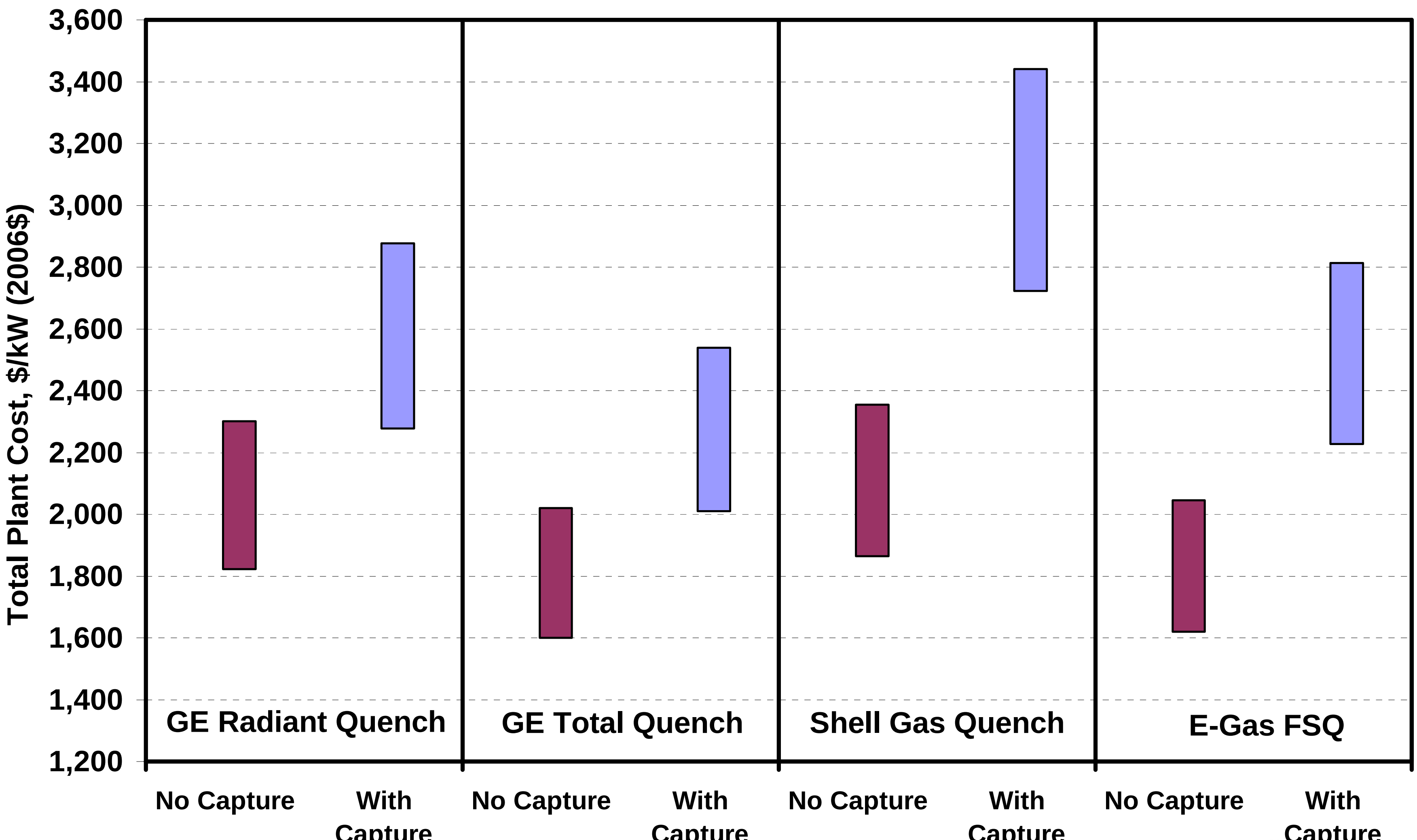


- Alloys, Steel, Concrete, Heavy wall, Refinery work etc
- Engineers, Suppliers, Fabrication Shop space, Specialty trades
- China, International suppliers

Rapid cost escalation in past three years

EPRI 600 MW (net) IGCC Capital Cost Estimates

(Illinois #6 Bituminous Coal With and Without CO_2 Capture)



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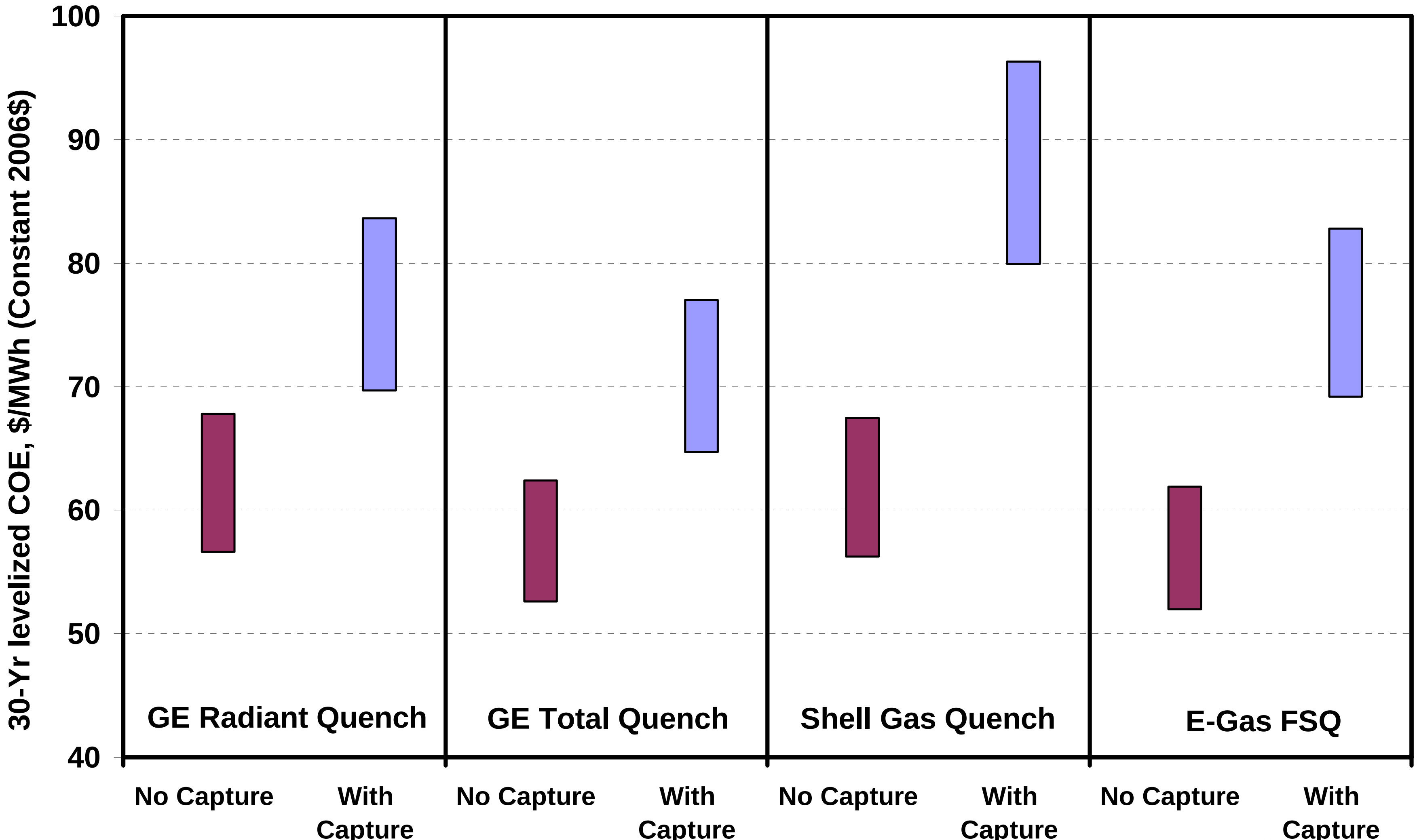
EPRI 600 MW (net) Cost of Electricity (COE) June 2006 Estimates

(Illinois #6 Coal $1.50/MBtu; with and without CO_2 capture, No spare gasifiers)



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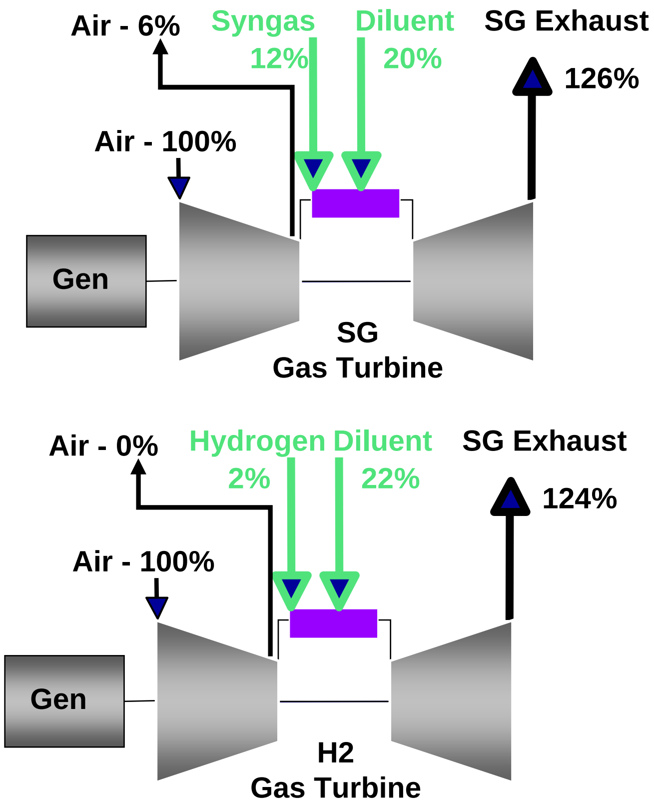
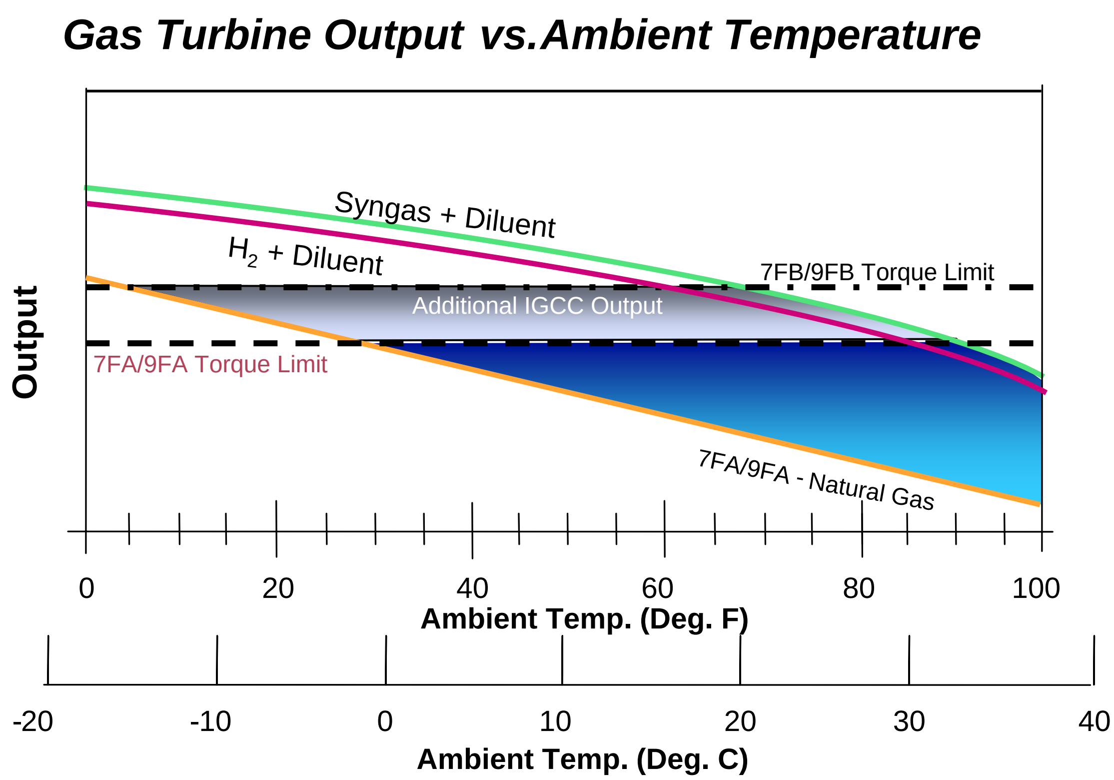
H_2 Output Impact – Source General Electric





Gas Turbines – Syngas and Hydrogen

- GE 7 FB designed for 232 MW with Syngas at ISO conditions and ability for air extraction. However at higher ambient temperatures and elevations the ability to extract is constrained.
- So the ASU Main Air Compressor (MAC) may have to be designed for full air flow for plant operation at high ambients. In some cases could consider use of inlet air chilling to maximize output over a wider range.
- The Good News & Bad News (Trade Offs & Ironies).

  - Plant can be operated with extraction at lower ambients (if designed in) with better efficiency (less auxiliary power).

  - Capital cost is higher with full air flow Main Air Compressor (MAC)

  - Net output lower at higher ambients (more MAC MW).

  - Since apparently no air extraction is allowable when firing Hydrogen, then when adding capture the MAC is already sized more appropriately.
- Do the Siemens 5000F and 6000G gas turbines have similar limitations?

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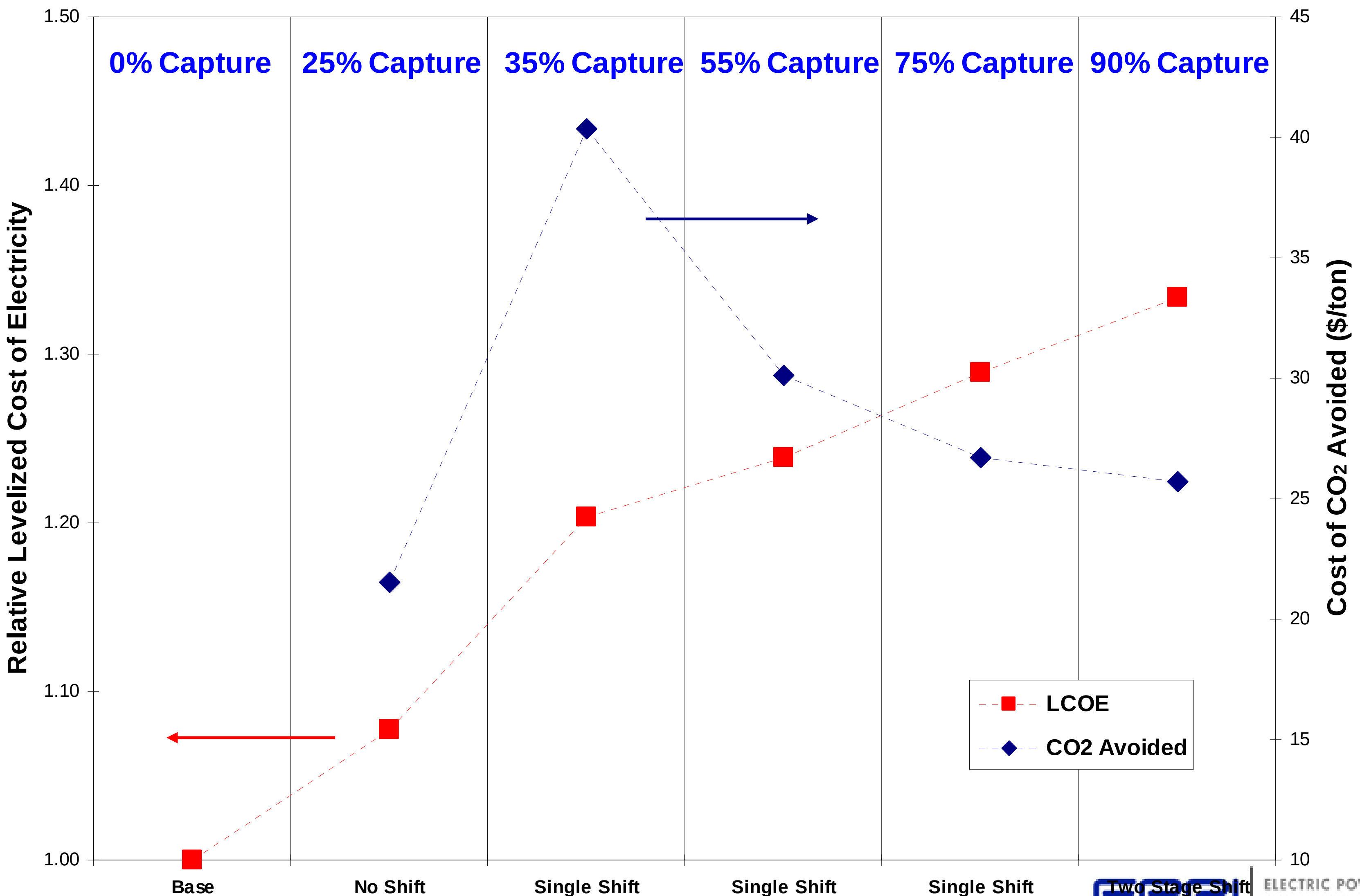
IGCC/Gasification Improvements Needed for more Cost-effective Capture

- Need Gas Turbines that enable air extraction across the ambient range and with Hydrogen firing
- GE larger HP Quench. New feed/design for LR coals
- COP HP tall Cylinder, higher throughput for LR coals
- Shell larger Quench (with water) design, CO_2 transport of feed for capture and synthesis, lower cost drying or new feeder for LR coals
- Siemens larger gasifier
- Need larger, higher pressure, lower cost Quench gasifiers for Capture, new GTs and 50 Hz markets otherwise IGCC may lose its perceived advantage over PC for CCS.

IGCC CO_2 Capture Design Options

- For slurry fed gasifiers the CO_2 in the syngas can represent 20-25% of the coal's carbon that could be removed without using the Shift reaction. This relatively small amount of capture is unlikely to generate much support from Federal or State Authorities.
- For all gasification technologies can use sour High Temperature Shift followed by two column AGR. Maybe still use standard syngas GT combustors ? This could result in 60 - 80 % CO_2 capture which would satisfy California's criteria that the CO_2/MWH be no more than from NGCC. Lower COE than maximum capture option.
- If > 90% removal is required then both high and low temperature shift beds can be used. Needs Hydrogen combustors for GT. Higher COE.

Impact of CO_2 Capture on IGCC COE & CO_2 Avoided Cost (without Transportation & Storage) (June 2006 $ Basis, Bituminous coal)



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IGCC Pre-Investment Options for later addition of CO_2 Capture

- **Standard Provisions**
  - Space for additional equipment, BOP, and site access at later date
  - Net power capacity, efficiency and cost penalty upon conversion to capture
- **Moderate Provisions**
  - Additional ASU, Gasification and gas clean-up is needed to fully load the GT's when Shift is added.
  - If this oversizing is included in the initial IGCC investment the capacity can be used in the pre-capture phase for supplemental firing or co-production.
  - This version of "capture ready" would then permit full GT output with Hydrogen (at ISO) when capture is added. Mitigates the cost and efficiency penalty.
  - However when shift is added considerable AGR modifications will be required (See following slides)
- **Extensive Provisions**
  - Design with conversion-shift reactors, oversized components, AGR absorber sized for shifted syngas but no CO_2 absorber and compressor
  - No need for major shutdown to complete the conversion to CO_2 capture

Gas Compositions and Flows before and after Shift - Adding Shift increases Syngas flow to AGR

(Mol % Clean Dry Basis – Typical Bituminous Coal)

Gasifier	GE no Shift	GE with Shift	COP no Shift	COP with Shift	Shell no Shift	Shell with Shift
Pressure psig	500-1000	500-1000	600	600	600	600
H_2	37	81	30	76	28	88
CO	47	3	49	3	64	4
CH_4	<0.1	<0.1	6	6	<0.1	<0.1
CO_2	14	58	12	58	2	62
N_2 + A	2	2	3	3	6	6
Total Flow Mols	100	144	100	146	100	160

IGCC Design Issues for adding Capture to a Plant designed without Capture

- Addition of Sour Shift increases gas flow to the AGR particularly for the dry coal fed gasifiers with high CO content (next slide). Unlikely that the AGR would be able to take the extra flow unless there was pre-investment oversizing. May need to add a parallel absorber or replace the entire AGR plant (with a new two column absorption system) if capture is to be added to an existing IGCC designed without capture.
- Alternatively the original AGR (focused on H_2S Removal) could be retained and a Sweet shift added after the AGR with a simpler bulk CO_2 removal AGR (ADIP, MDEA, Selexol) added after shift. This would minimize intrusion into existing plant. This trade off of Sour versus Sweet Shift needs to be examined and may differ among the Gasification Technologies. Sweet Shift may incur additional efficiency and output penalties. Quench gasifiers would probably favor Sour Shift.

Interim Conclusions on IGCC with Provisions for later Addition of CCS

- IGCC with Standard Provisions of Space not very CCS ready
- IGCC with some Moderate Provisions are much more CCS ready – Incremental Capital may be justified
- AGRU/SRU for CCS – Selexol more ready than MDEA-particularly with Moderate Provisions
- Sour Shift more CCS ready than Sweet
- Quench with Sour shift is CCS ready. SGC designs with either Sour or Sweet Shift less ready for CCS
- Major Issues – H_2S content of CO_2

  - Thermodynamic penalty for Syngas reheat and HP steam injection (with Sweet CO shift and non Quench gasifiers)

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CPS San Antonio IGCC Study
- Project Background and Overview

- CPS Energy is constructing a 750 MW subcritical PC plant fired with PRB coal. The plant is known as Spruce 2, southeast of San Antonio.
- The plan was opposed by some environmental groups because of the projected greenhouse gas and mercury emissions
- As part of a settlement with the environmental group, CPS Energy agreed to enhance its energy conservation and renewable energy programs and to pay increased attention to CO_2 emissions from future coal plants
- CPS Energy also committed to fund a study of IGCC with combinations of fuels such as PRB and pet coke. Under the terms of the settlement, the IGCC study will be made available to the public.
- CPS Energy selected Burns & McDonnell to perform the study, with assistance from EPRI
- **Study adds capture to existing designs – as distinct from designing plants with capture from the start (as in nearly all previous studies by DOE, IEA and EPRI)**

CPS IGCC Study- Cost and Performance Summary

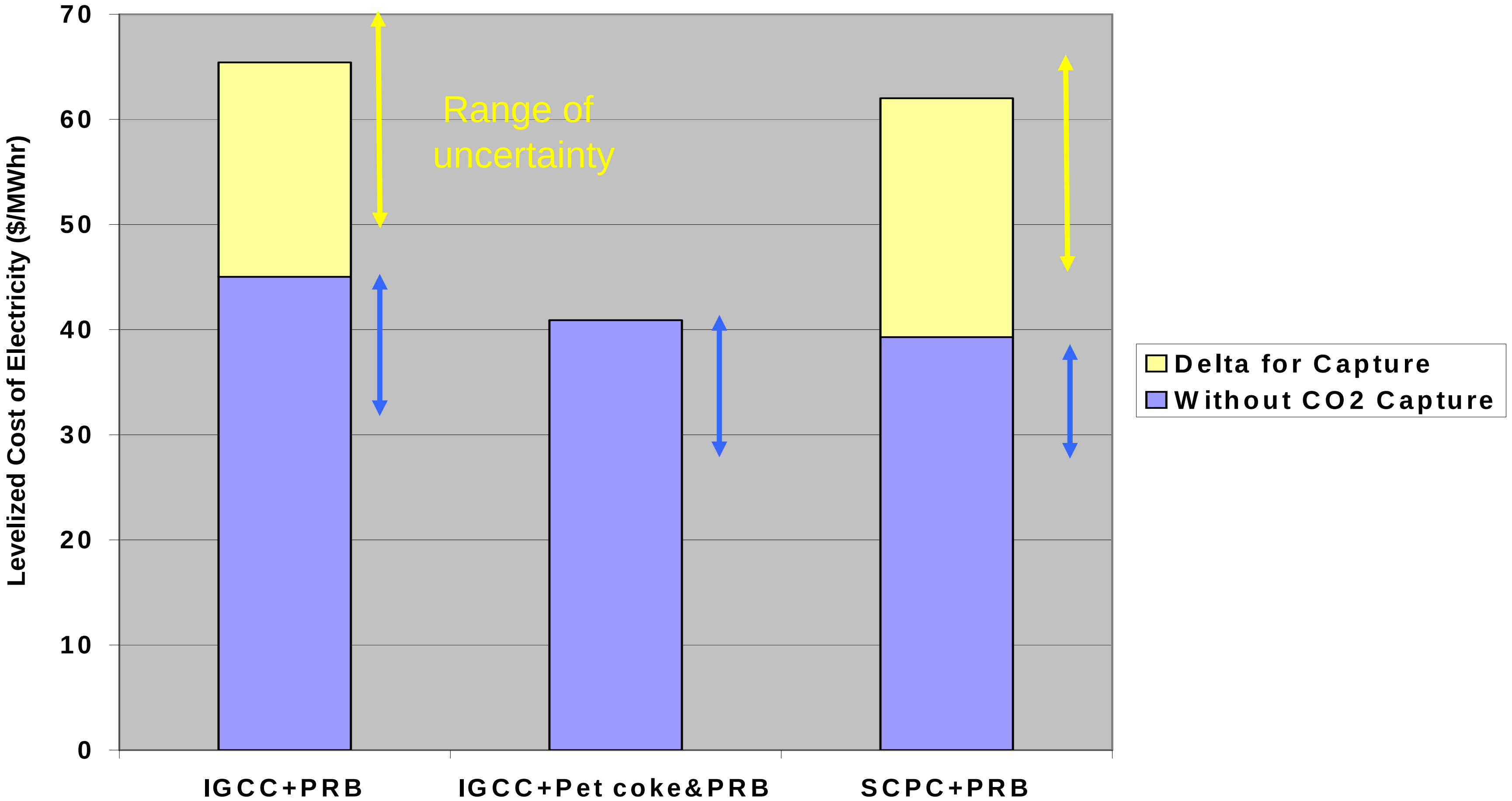
Notes: • All analysis at 73 ^{0}F. • 50%/50% PRB-Petcoke blend by weight	IGCC 100% PRB	IGCC 50%/50%	SCPC 100% PRB	IGCC 100% PRB CO_2 Capt	SCPC 100% PRB CO_2 Capt
Gas Turbine Output (MW)	450	453		427	
Steam Turbine Output (MW)	260	258	615	203	521
Gross Plant Output (MW)	710	711	615	630	521
Auxiliary Load (MW)	157	158	65	217	132
Net Plant Output (MW)	553	553	550	413	390
Net Heat Rate, HHV (Btu/kWh)	9,220	9,070	9,150	12,800	12,911
EPC/TPC ($/kW)	2,390	2,330	1,950	3,630 [1]	3,440 [1]
20-yr LCOE ($/MWh) (Constant 2006$) [2]	45.0	40.9	39.2	65.4	62.0
Cost of CO_2 Avoided ($/tonne CO_2)				26.3	29.6

Notes

1. CO_2 Capture capital costs are based on retrofit of the existing IGCC or PC facilities as provided in the base case alternatives. $/kW values reflect total installed cost to date (including original costs provided in the base case) divided by net plant output with CO_2 capture.
2. COE based on 85% Capacity Factor, Public Power Financing (30 yr loan), $1.65/MMBtu PRB and $1.14/MMBtu Petcoke

Low Rank Coal Study IGCC & PC w and w/o Capture

2006 EPRI study (1014510) Texas location and municipal utility financing



PRB Estimate Shows Even with Capture PC May be an Option

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CPS IGCC Study
-Environmental Performance Summary

Notes: 1. All analysis at 73 ^{0}F. 2. 50%/50% PRB-Petcoke blend by weight	IGCC 100% PRB	IGCC 50%/50%	SCPC 100% PRB	IGCC 100% PRB CO_2 Capt	SCPC 100% PRB CO_2 Capt
NO_X, lb/mmBtu, (HHV)	0.063	0.062	0.050	0.061	0.045
lb/MWh (Net)	0.581	0.562	0.458	0.781	0.581
ppmvd @ 15% O_2	15	15	N/A	15	N/A
SO_2, lb/mmBtu, (HHV)	0.019	0.023	0.060	0.004	0.0003
lb/MWh (net)	0.173	0.210	0.549	0.051	0.003
CO_2, lb/mmBtu, (HHV)	215	213	215	22	22
lb/MWh (net)	1,985	1,934	1,967	276	278
Total Makeup Water (acre-ft/yr) (85% CF)	6,830	7,170	7,950	8,430	10,640

CPS IGCC - Areas of Further Study

- Potential efficiency improvements
  - Gas turbine inlet chilling
  - Upgrade syngas cooler from IP to HP steam
  - Two-pressure HRSG instead of three-pressure
- Use higher pressure flash for recovery of CO_2 in Selexol
- Investigate use of SCR with syngas-firing
  - NO_X allowance cost is high in Gulf Coast area
- Investigate other gasification processes that may have more favorable cost and performance with CO_2 capture
- CO_2 storage capital and operating costs
- CO_2 pre-investment tradeoffs
- Legal and regulatory aspects of CO_2 storage

Range of Estimated CO_2 Capture Costs with Current Technology from DOE NETL,IEA, EPRI etc 2000-2004 Studies

- As reported by each study – no consistency of reporting basis

	New NGCC with Post Combustion Capture	New PC with Post Combustion Capture	Existing PC with Post Combustion Capture	New IGCC with Shift and Pre – Combustion Capture
Avoided Cost CO_2 US $/mt	37-74	29-55	45-73	13-37 GE Q 13-25 Shell 24-37
% COE increase with Capture	37-69	42-84	150-290	20-55 GE Q 20-40 Shell 31-55
% more input/MWh with Capture	11-22	24-40	43-77	16-25 GE Q 16-25 Shell 18-25

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CO_2 Capture Costs- Cautions

- The basic assumptions for calculation of COE vary between studies.
- Assumptions that lead to lower COE and particularly a lower capital cost component of the COE lead to lower avoided costs for CO_2 Capture (See next Slide)

  - a lower capital charge rate (e.g. US DOE/EPRI 15% Europe 11-12%)

  - a higher assumed Capacity Factor (e.g. DOE/EPRI 80% IEA 85-90%)

  - a larger capacity plant with economies of scale (e.g. IEA 800 MW versus DOE/EPRI 500 MW)

  - a lower cost of fuel (e.g. IEA Natural gas at 2$/GJ)

Avoided or Mitigation Cost of CO_2 Capture & Storage (CCS) – Is this the best Metric?

Avoided cost or Mitigation Cost is defined as =

($COE_{\text{with CCS}}$ – $COE_{\text{Reference}}$) divided by

(mt CO_2/$MWh_{\text{Reference}}$ – mt CO_2/$MWh_{\text{with CCS}}$)

What is the Reference case?
Conventionally the same technology without CCS has been used as the reference. Is this the most relevant?

Should the reference case should be the technology that would have been used if no CCS was required?

Perhaps the more appropriate measure is COE. After all it is on this basis that technology selection is really made (while conforming to all applicable regulations)

CPS Study Results will differ from IOU

- CPS San Antonio as a public entity has access to low cost financing
- Investor Owned Utilities (IOU) have higher cost of money/financing costs
- IOU financing leads to higher COE
- Higher COE means higher Avoided Cost of CO_2
- **COE used for calculating Avoided cost of CO_2 should include the estimated cost of transportation, storage/sequestration and monitoring. EPRI uses a nominal 10$/mt**
- EPRI has recalculated the CPS results for 30 year LCOE for IOU financing and including 10$/mt for Transportation and Sequestration

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CPS Results compared to IOU
(30 year LCOE. For CCS includes 10$/mt for Transportation and Sequestration)

	CPS	IOU
COE $/MWh IGCC No capture	47.3	64.9
COE $/MWh SCPC No Capture	41.1	55.5
COE $/MWh IGCC with Capture & Seq. (CCS)	80.1	106.9
COE $/MWh SCPC with CCS	76.7	102.1
Avoided Cost of CO_2 $/mt IGCC Capture/CCS	27.9/42.4	39.7/54.2
Avoided Cost of CO_2 $/mt SCPC Capture/CCS	31.7/46.5	46.1/60.8

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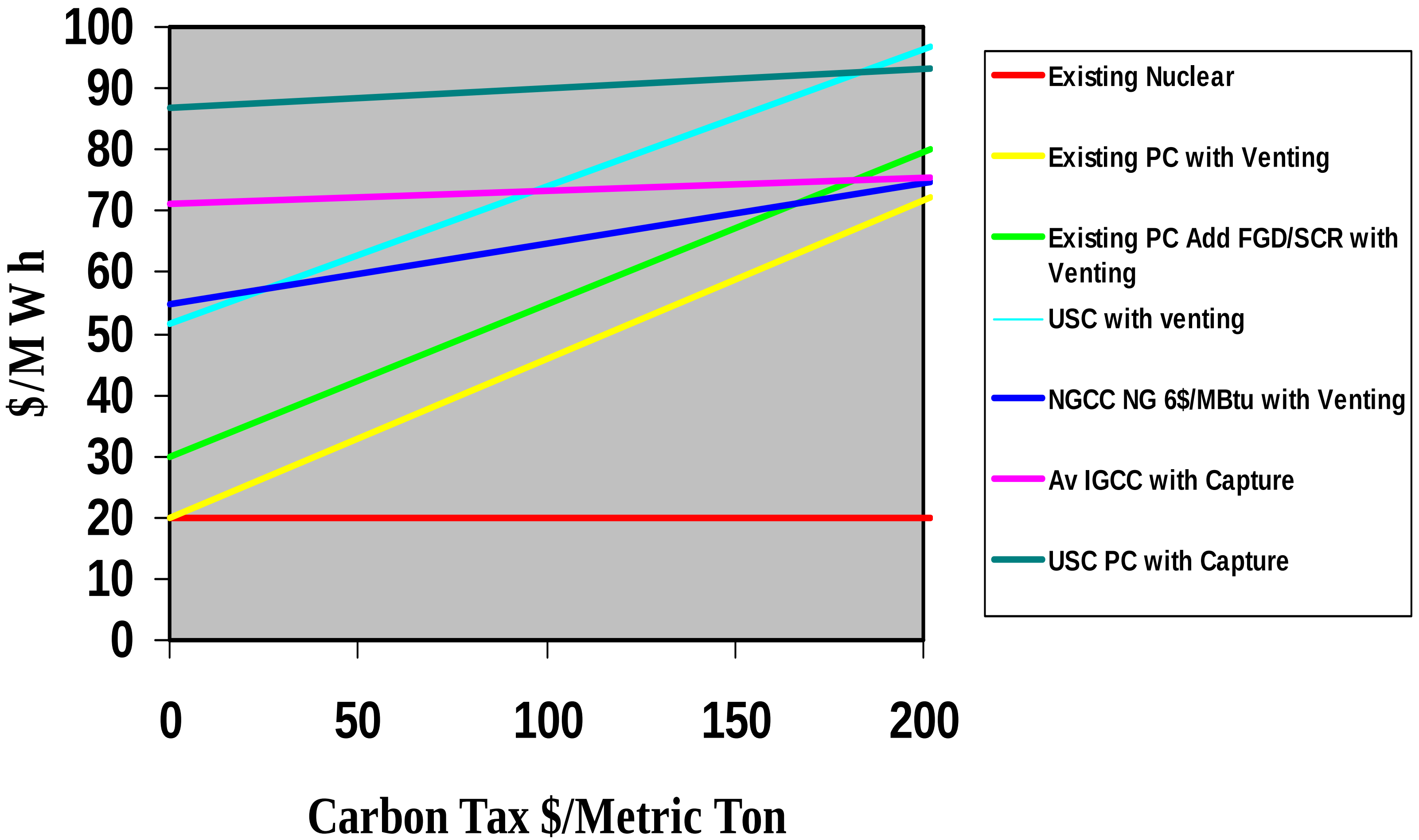
Effect of Capital Cost Increases on:

- COE
- CO2 Cost
- Continued Operation of Existing PC plants
- Strategic Selection of Future Generation
- Conclusions

Effect of Carbon Tax on Cost of Electricity for Various Technologies – Bituminous Coal

(All evaluated at 80% CF – DOE NETL 2006 data Average IGCC TPC 1522 $/kW w/o Capture)



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Effect of Carbon Taxes on Fuel and Technology Selection – Using DOE NETL Draft Jan 2006 Estimates

- Issue with the existing power plants. U.S. 320 GW of coal, ~100 GW FGD but + 50 GW planned. China soon 300 GW.
- The paid off capital on most US coal plants is a great economic advantage. Only at a Carbon tax of tax ~200$/mt is their COE up to that of a new IGCC with capture. Even with additional capital of 500$/kW (for FGD + SCR + Hg removal) to existing coal plants the crossover for new coal with capture is still over 180$/mt of C.
- With NG @ 6$/MBtu new NGCC (at 80% CF) with CO_2 venting is lower COE than new IGCC with CCS until the C tax is >200$/mt.
- At 100$/mt C new USC with venting same COE as IGCC with capture

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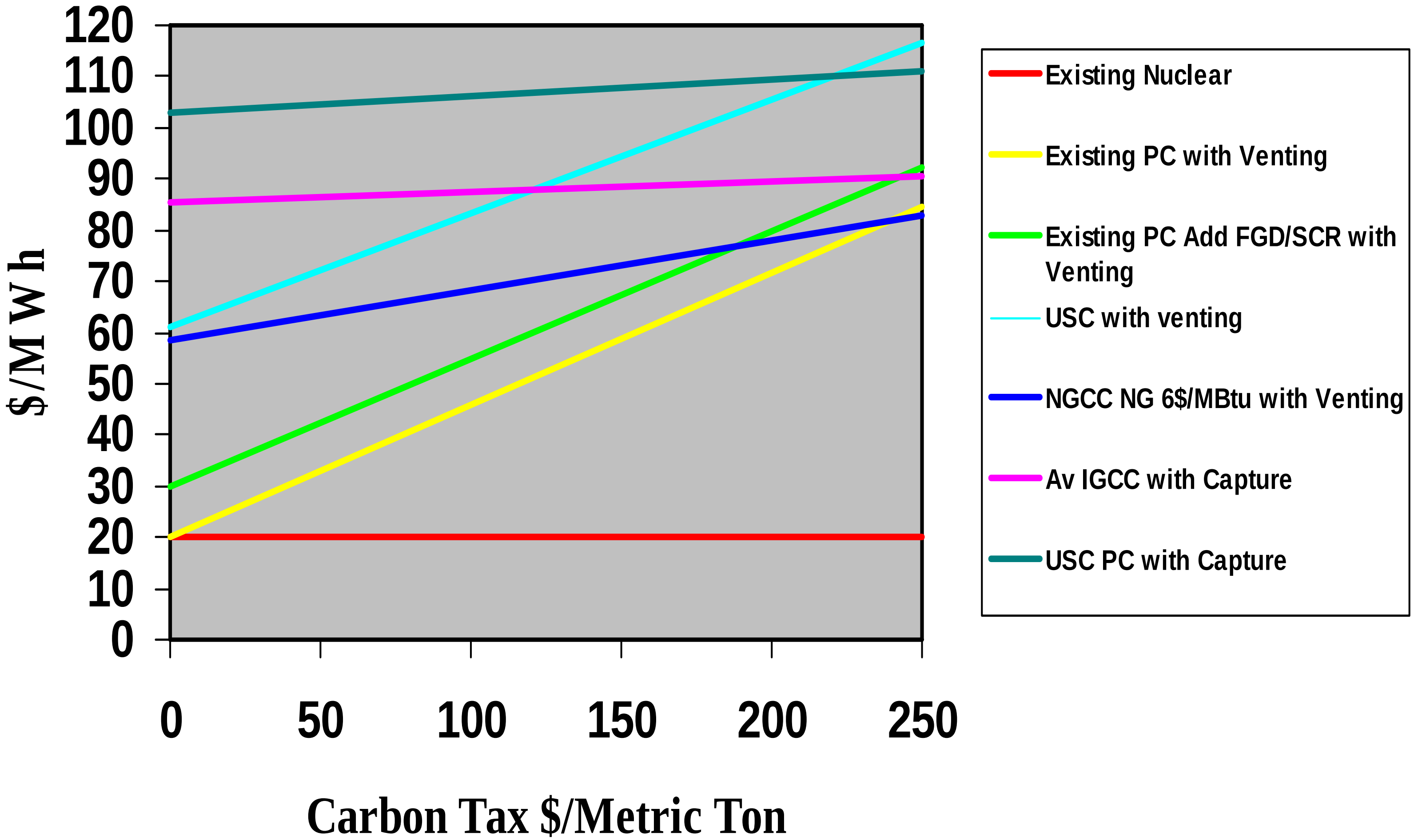
Effect of Carbon Tax on Cost of Electricity for Various Technologies – Bituminous Coal

(All evaluated at 80% CF – Av.IGCC TPC 2000$/kW w/o Capture)



Effect of Increased Capital costs on Technology and Fuel Selection with Carbon Taxes

- The large increase in capital costs over the last year means that IGCC or PC with capture would need an even larger carbon tax (>250$/mt C or ~62$/st CO_2) for their COE to be competitive with existing coal plants (with FGD + SCR + Hg removal) with venting CO_2 and just paying the tax).
- With NG @ 6$/MBtu new NGCC (at 80% CF) with CO_2 venting is lower COE than new IGCC with CCS until the C tax is >330$/mt.
- Or with NG @ 7.46$/MBtu and new NGCC at 65% CF venting is lower COE than new IGCC with capture until C tax is >200$/mt.

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Future Coal Generation and CCS – Issues and Observations

- **Does CO_2 Sequestration work?** Where ? For how long? Multiple Integrated Demos urgently needed ASAP.
- Demand for New Coal Generation. **However CCS costs add~40-50% to COE for IGCC and ~70-90% for PC with bituminous coals. Is this going to be acceptable? Can it be significantly reduced?**
- The paid off capital on most US coal plants is a great economic advantage. Even with adding FGD, SCR and Hg removal and a large C tax their COE would be much less than new coal. They will probably be kept going as long as possible (AEO 2006) **Question/Issue - How can CO_2 emissions be reduced from existing power plants?**
- Significant (>50%) CO_2 reductions at new and existing coal plants can only be achieved with CCS. **Question/Issue - Could Carbon tax proceeds be used to support the costs of CCS?**

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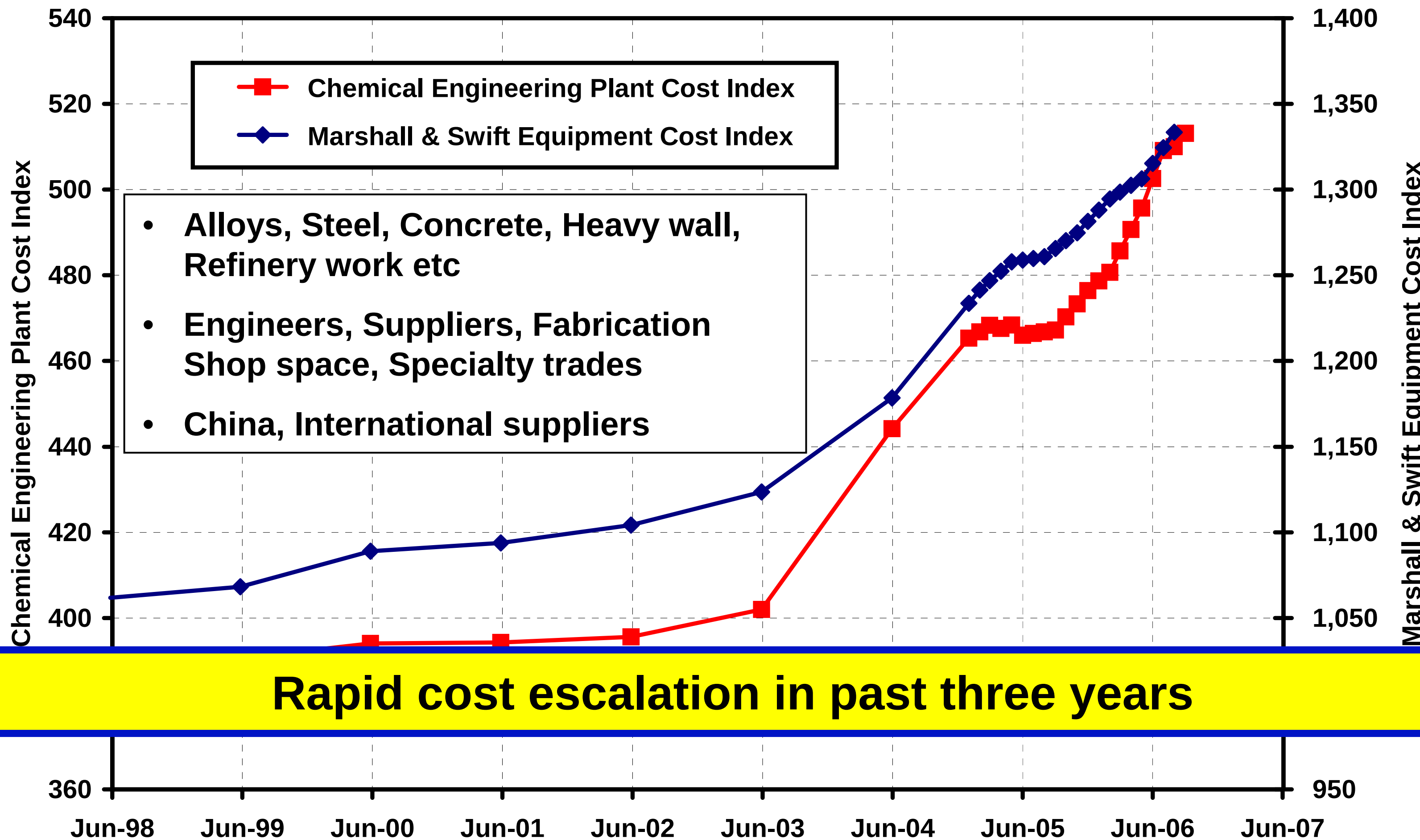
DOE CO_2 Capture Market analysis
(Source J. Figueroa DOE NETL presentation to APPA June 28, 2006)

- US 2005 CO_2 emissions 6 Billion stpy, 39% from Electricity, 36% from coal (323 GW installed capacity)
- AEO 2006 BAU forecast for 2030 - today's existing coal plants will be 66% of US Power CO_2 emissions and 75% of all US coal CO_2 emissions
- Which of today's units are most likely to adopt CO_2 capture under a regulatory environment?
- Existing boilers > 300 MW and > 35 years old represent 184 GW. If 90% CO_2 capture was applied to these units this would provide a 50% reduction in coal power CO_2 emissions
- **Q. What is the cost of adding capture to these existing plants and the cost and source of replacement power?**

Plant Construction Costs Escalating

Construction Cost Indices

(Source: Chemical Engineering Magazine, November 2006)



- **Alloys, Steel, Concrete, Heavy wall, Refinery work etc**
- **Engineers, Suppliers, Fabrication Shop space, Specialty trades**
- **China, International suppliers**

Rapid cost escalation in past three years

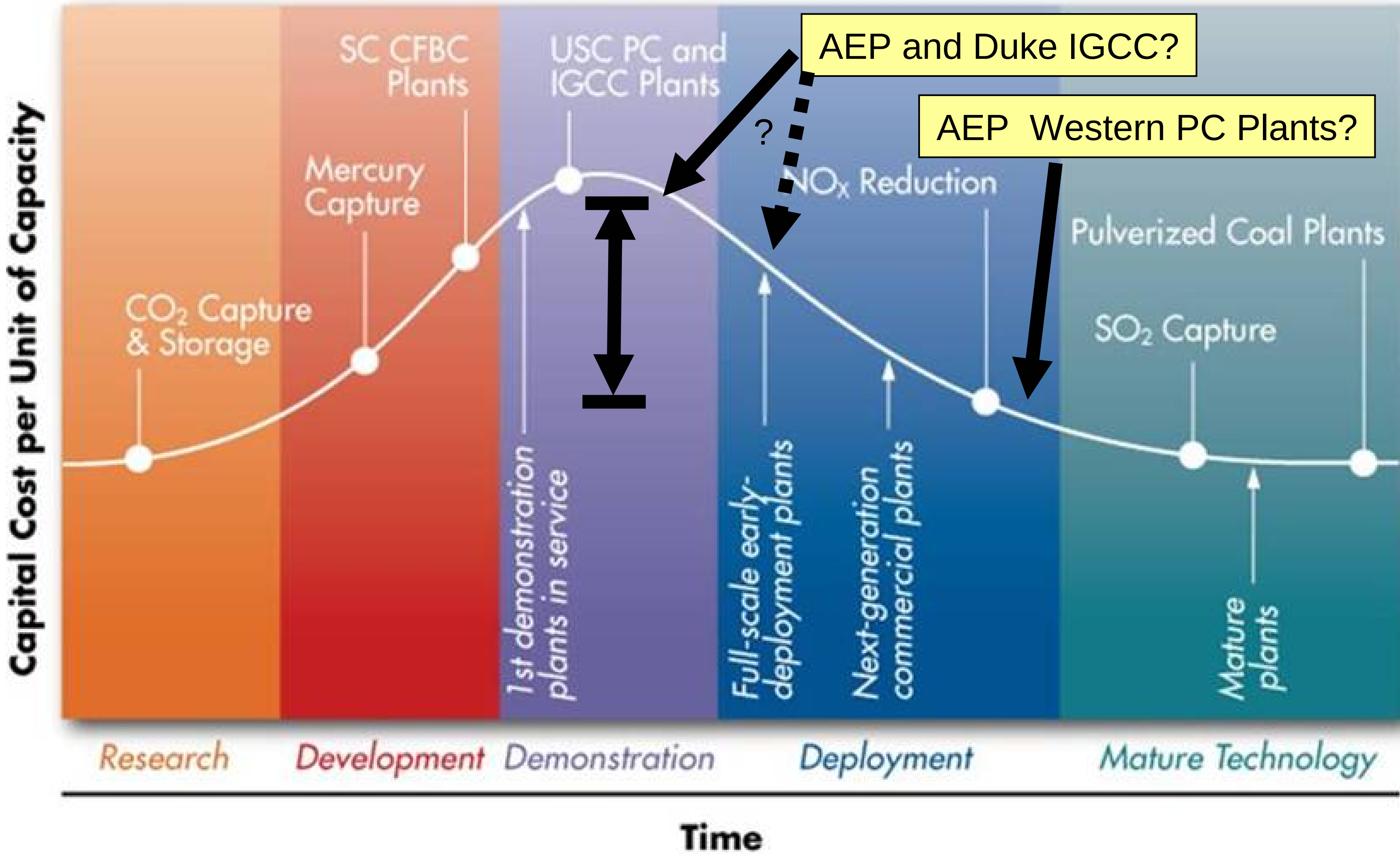
Recently Reported Costs Through Late Last year

Owner	Plant Name /location	Net MW	Technology/Coal	Reported Capital $ Million	Reported Capital $/kW
AEP SWEPCO	Hempstead, AR	600	USC PC/PRB	1300	2167
AEP PSO/OGE	Sooner, OK	950	USC PC/PRB	1800	1895
AEP	Meigs County, OH	630	GE RQ IGCC/ Bituminous	1300	2063
Duke Energy	Edwardsport, IN	630	GE RQ IGCC/ Bituminous	1300-1600	2063-2540
Duke Energy	Cliffside, NC	2 x 800	USC PC/ Bituminous	3000	1875
NRG	Huntley, NY Montvale, CT Indian river, DE	620	Shell IGCC/ Bituminous, Pet Coke and PRB	1466	2365
Otter Tail/GRE	Big Stone, SD	620	USC PC/PRB	1500	2414

Source: CoalFleet for Tomorrow® EPRI Report 1012224

Costs Up even with minimal or no provisions for CO_2 Capture

First of a Kind vs. More Mature Technology?



AEP IGCC costs not as low as expected >20% gap

Conclusions

- All generation options (Coal Natural Gas, Nuclear, Renewables) will be needed in a Carbon Constrained World
- Emissions for all new coal plants are down approaching "near zero" without CO_2 capture
- Costs for new coal plants are up
- CO_2 Capture is costly for both IGCC and PC plants and probably feasible – integration/costs uncertain
- EPRI believes PC and IGCC will compete in the future even with capture for some coals and conditions
- Multiple Storage (preferably Integrated CCS) demonstrations needed ASAP at large scale

Questions?

Post Combustion

CO2 Capture

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