A Summary of Recent IGCC Studies of CO_2 Capture for Sequestration

By

Neville Holt, George Booras (EPRI) and Douglas Todd (Process Power Plants)

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Abstract

In response to concerns over the possible effects of fossil fuel based CO_2 emissions on global climate several studies have been conducted over the past 15 years on the costs of CO_2 capture from various power plant technologies. Most studies concluded that the costs of pre-combustion CO_2 capture from syngas in an IGCC plant was much lower than post combustion removal from Pulverized Coal (PC) or Natural Gas Combined Cycle (NGCC) plants. While this remains true for bituminous coals the costs of CO_2 removal do vary significantly between the various coal gasification technologies and the advantage in capture costs over PC plants will depend very much on the gasification technology selected. The IGCC studies surveyed in this paper cover the main gasification technologies offered by ChevronTexaco, Shell and ConocoPhillips (E Gas) as evaluated by several different engineering companies. For CO_2 capture there is a distinct advantage for gasification operation at high-pressure 55-69 barg (800-1000 psig). Most studies focused on the use of bituminous coals but some have included sub-bituminous coal and lignite. Indications are that at the current state of gasification technology for low rank coals the Cost of Electricity (COE) for IGCC with CO_2 capture is close to the COE from PC plants with CO_2 capture for sub bituminous coals and maybe greater for lignite.

The effect of a potential carbon tax on a variety of existing and new fossil fuel power plants has also been evaluated. It is generally concluded that because of the economic advantage of their sunken investment that most existing PC plants would probably just pay the tax. This raises the broader question of just what incentives can current PC plant owners be offered to reduce CO_2 emissions?

There are many significant issues concerning CO_2 capture and sequestration. The major issue is whether geologic or oceanic sequestration of CO_2 is permanently effective. Even if sequestration is proven successful in multiple regions the sheer scale of effort in making even a 50% reduction in CO_2 emissions from US coal power plants is enormous. The costs of CO_2 capture and sequestration from new IGCC plants adds 40-50% to the COE and with new PC plants the added COE costs can be 80-90%. Is society prepared to pay for these additional costs?

Potential Responses to Concerns of the Effects of Anthropogenic CO_2 on Global Climate

The options for response to the CO_2 climate concern are mainly:

- Conservation
- Renewables
- Nuclear
- Adaptation
- Switch from coal to natural gas
- CO_2 capture and sequestration

Conservation in the US and the rest of OECD should certainly be encouraged. However the 5 billion majority of the World's population aspire to the living standards of OECD and that will inevitably mean more energy demand on a worldwide basis.

Renewables should also be encouraged and supported, but their contribution is still going to be small. The sun doesn't always shine and the wind doesn't always blow when wanted. Biomass is probably best considered as a partial feed to coal units since the capital cost of small biomass plants is very high.

Nuclear is probably the ultimate solution, however, for it to be used to tackle the worldwide energy supply means wide proliferation. It will be decades before the World gets to an arrangement of international treaties and cooperation where nuclear can play to its full potential. In the US many of the existing nuclear plants will be relicensed and a few new ones may be built but public opposition is quite widespread.

Adaptation has usually been the world population's response to social and other changes. The North American continent was relatively unpopulated 150 years ago. Climate change would probably be gradual and some people will move and others adapt to changing circumstances

Switching from coal to natural gas may be a partial response in some locations. However it is unlikely that natural gas supplies are going to be sufficient or low enough in cost to make any substantial change in coal usage. Even under the very optimistic DOE Energy Information Administration (EIA) forecast of 3 years ago with US natural gas consumption rising to 30 TCF/year in 2020 at a price of 3.5-4$/MBtu in 2020 EIA still forecast a 25% increase in US coal usage.

CO_2 Capture and Sequestration. Even with IGCC, and assuming that sequestration works, the added costs of CO_2 capture and sequestration are very substantial. Although there may be improvements and reductions in capture costs the inevitable costs and energy penalties for CO_2 compression, pipelining and sequestration will always be substantial. Will society be willing to pay these increased costs and will the public accept sequestration? The US coal power plants contribute ~33% of the US CO_2 emissions and

~8% of the Worldwide CO_2 emissions. This represents ~2.1 billion metric tons/year of CO_2 and it has been calculated that 1 billion metric tons/year (equivalent to 50% reduction) is a volume equivalent to ~ 25 million barrels/day (US oil usage is ~15 million barrels/day.). So to undertake CO_2 capture and transportation at a level to make serious reductions in US coal based CO_2 emissions is a huge undertaking. Conversely, of course, it can be argued that doing anything to make marked reductions in US coal based CO_2 is going to be a huge undertaking.

The US and China each use about a billion metric tons/year of coal and together they represent over 50% of the World coal usage. If there is a major issue with regard to coal based CO_2 emissions then it will have to be tackled by these two countries. However neither the US or China is a signatory of the Kyoto accord.

CO_2 emissions related regulation could have a major effect on power plant technology and fuel selection – particularly for coal technology and more particularly for existing coal plants.

Recent IGCC Studies with and without CO_2 Capture

EPRI is currently participating in a new series of engineering economic studies of IGCC plants with the major gasification technologies and engineering contractors. Some of the results are included and discussed in this paper. The new capital cost and performance estimates include the effects of the key lessons learned from the four IGCC demonstration plants. The designs are based on multi train plants (typically 500-600 MW net output for the 60 Hz market and ~800 MW for the 50 Hz market) using state of the art (FA) gas turbines and include realistic sparing for a coal based syngas availability of 85% or better.

These designs generally reflect more conservative estimates from GE of gas turbine performance on syngas or hydrogen. With the increased mass flow in the IGCC application due to the use of diluents (nitrogen and moisture) for NOx control and because of (in some cases) higher moisture content flue gases GE believes that heat transfer to the turbine blades will be greater. In order to maintain blade temperatures similar to those in NGCC service (where GE offers Long Term Service Agreements (LTSAs)) they have reduced the firing temperature. This adversely affects both gas turbine and steam turbine performance so that the heat rates are typically 200-400 Btu/kWh higher than those reported in prior years.

The results of the studies in which EPRI is currently participating are broadly consistent with those reported for the IEA GHG R&D sponsored study and which has also been presented at this Conference. (Although the latter results were for a larger plant in a European situation with 50 Hz turbines)

EPRI is participating in a number of IGCC studies on various topics, coals and several different engineering organizations as shown below in Table 1.

Table 1 (Slide 3) EPRI IGCC Studies 2002-3

Study	Eng. Company	Texaco	Shell	EGas	Coals	Notes
NYPA	Parsons	Q, R and R+C	Full HR	Full HR	Pitts # 8	w & w/o capture
We Power	Fluor	Q, R and R+C	Full HR	Full HR	Pitts # 8 PRB	No capture
Canadian CPC	Fluor	Q	Full HR	Full HR	Pitts # 8 Sub-bit Lignite	Capture only
EPRI Phased Construction	Jacobs Consultancy	Q			Pitts # 8	w & w/o capture
EPRI Phased Construction	Parsons	Q		Full HR	Pitts # 8	w & w/o capture
EPRI IGCC & Hydrogen	Parsons	Q		Full HR	Pitts # 8	w & w/o capture

The study with the New York Power Authority (NYPA) compares all three major gasification technologies with Pittsburgh # 8 coal at a site in upstate western New York. The study has also looked at the costs of CO_2 capture and the potential for CO_2 sequestration or use in that location.

We Power (with EPRI consulting) is also studying the three technologies for an IGCC plant at their Oak Creek, WI site adjacent to Lake Michigan. Both Pittsburgh # 8 and Powder River Basin (PRB) sub-bituminous coals are being evaluated.

Texaco cases with Radiant(R) only and Radiant plus Convective(R+C) syngas coolers are also being evaluated. This is largely because of the potential tax incentive benefit of higher efficiency designs that are included in the draft Energy Bill. Previous estimates of these Texaco IGCC configurations had generally found a higher capital cost by ~120-150 $/kW for the full radiant plus convective (R+C) design versus the Quench design. However at current US coal prices the higher efficiency of the R+C was not sufficient to compensate for the higher capital and the COE was lower for the Quench case. If the heat rate incentives contained in the draft Energy Bill are enacted then this situation could change and the proposed tax incentives would make R+C the preferred Texaco IGCC configuration.

EPRI has also been a participant in the studies conducted by the Canadian Clean Coal Power Coalition. These studies are aimed primarily at evaluation of technologies for CO_2 capture from existing and new coal plants. A paper on this work was also presented at this 2003 conference. Three separate locations were studied in Nova Scotia, Alberta and Saskatchewan based on Pittsburgh # 8 coal, Alberta low sulfur sub-bituminous and Saskatchewan Lignite respectively. IGCC cases using Texaco Quench, EGas and Shell gasification technologies with Shift and CO_2 capture were evaluated for each site. The screening analysis showed Texaco Quench as the preferred gasification technology for the Pittsburgh # 8 and sub-bituminous coals. Texaco declined to quote performance for Lignite and Shell was selected for that fuel.

The phased construction of IGCC with later addition for CO_2 capture is being studied under contracts with Parsons and Jacobs Consultancy. Each of the studies evaluates the effect on a standard IGCC design of later adding capture but also evaluates different approaches to degrees of pre-investment on the ultimate cost, performance and COE. The interim results of these studies are also presented at this conference. These results will be finalized later this year and will enable various scenarios of projected incentive or regulatory timing for capture to be evaluated e.g. a net present value of different pre-investment options can be calculated under different scenario assumptions.

IGCC Studies without CO_2 Capture

One common denominator in many of these studies is the use of Pittsburgh #8 coal with the Texaco Quench gasifier. This enables some interesting comparisons as to how the various engineering companies assess cost and performance as shown in Table 2.

Some areas of difference are still being investigated. The gasification area and combined cycle costs are fairly consistent across the studies but differences occur in the general facilities/balance of plant area, gas clean up and sometimes (surprisingly) in the ASU area. However there are some areas of general agreement and common conclusions that can be made.

- The heat rate ranking of the technologies is the same for all contractors with TexacoQ>E Gas > Shell. The difference between Texaco Q and E Gas is 700 – 1000 Btu/kWh whereas the difference between E Gas and Shell is only 150-270 Btu/kWh.

- There is fairly good agreement in the heat rate estimates for Texaco R+C, E Gas and Shell gasification technologies. However there are some significant differences in the heat rate estimates for the Texaco quench cases that have not yet been analyzed (the Jacobs estimates are quite low)

- The plant cost rankings in $/kW are the inverse of the heat rate rankings with Shell> E Gas> Texaco Q. However the E Gas plant costs are closer to Texaco Q than to Shell and to date Shell has been consistently evaluated as being of higher cost in $/kW than either Texaco Q or E Gas. Shell with no spare gasifier is still higher cost than Texaco Quench and E Gas with spare gasifiers i.e. when credit is given for the higher availability of the Shell’s membrane cooled gasifiers versus the refractory lined Texaco and E Gas gasifiers.

Table 2 (Slide 5) IGCC Studies without CO_2 Capture – Bituminous Coal. Comparison of Results

Study # (Gas turbines)	**#1 (2x 7FA)**	**# 2 (2x7FA)**	**#3 (2x 9FA)**	**#3 (Adj. 2 x 7FA)**	**#4 (3x7FA)**	**#4 (Adj. 2x7FA)**
Texaco Q TPC Cost $/kW (# gasifiers)	1337 (2+1)	1158 (2+1)	1187 (3+1)	1312 (2+1)		
E Gas TPC Cost $/kW (# gasifiers)	1392 (2+1)	1226 (2+1)			1135 (3+1)	1254 (2+1)
Shell TPC Cost $/kW (# gasifiers)	1471/1668 (2+0)(2+1)	1417/1569 (2+0)(2+1)	1371 (2+0)	1515 (2+0)	1470 (3+1)	1624 (2+1)
Texaco Q Heat Rate Btu/kWh HHV	9292	9653	9400	9400		
E Gas Heat Rate Btu/kWh HHV	8619	8637				
Shell Heat Rate Btu/kWh HHV	8468	8365	8281	8281		
COE range $/MWh	55-60 (real)	37-42	45-48	48-51		

- At the typical US coal costs of 1-1.5$/GJ the COE for Texaco Q and E Gas are very similar with the heat rate differences roughly compensating for the plant cost differences. Both are refractory lined gasifiers and with these gasifiers refractory replacement is the largest source of plant outage so the plants are designed with a spare gasifier to enable them to reach 90% target availability.

- However if the heat rate hurdles and tax credits in the draft Energy Bill are enacted then the COE rankings could change markedly. Texaco Q would probably not qualify for the credits.

- Studies C & D were for 800 MW plants. The plant costs have been factored down by EPRI to comparable two train ~ 500 MW plants as shown in the preceding table (Using ratio of 2x7FA to 2x9FA and to 3x7FA costs and traditional exponential power factor for rest of the plant).

- Shell was generally highest in capital and COE with Texaco Quench and E Gas similar. With Texaco R and R+C (2+1) the COE is closer to Shell (2+0). However the heat rates of all 3 technologies with Syngas Coolers are close to 8500 Btu/kWh (a key hurdle rate in the draft Energy Bill). What happens if Energy Bill credits are enacted and design/cost pencils are sharpened?

- It will be noted that the COE estimates vary considerably from study to study. Individual organizations have different financing arrangements and differ greatly on the allocation of additional capital costs (mostly so-called Financing and Owner's Costs) on top of the EPC (TPC) estimates. This can result in significant differences in COE estimates. The COE estimates shown for Study A also include escalation forward to a future start up date.

In addition to the studies shown in **Tables 1 and 2** IGCC cost and performance estimates were also presented in papers by Texaco (L.O'Keefe and K.Sturm) and E Gas (D.Breton and P.Amick) at the 2002 Gasification Technologies conference.

In the Texaco paper Texaco R and R+C cases showed EPC costs of $ 1300-1400 $/kW and heat rates of 8860-8420 Btu/kWh. These numbers are fairly consistent with estimates from more recent studies by NYPA and We Power of ~8700 and ~8500 Btu/kWh respectively and EPC costs (with contingency) for 2+1 gasifiers of ~1400 -1500 $/kW for two train plants of ~500 MW for Mid West location and Pittsburgh #8 coal. The TPC in $/kW is about the same for both the R and the R+C cases.

The 2002 E Gas paper include IGCC cost and performance estimates for a wide range of UC coals. The results are summarized in **Table 4** (slide 11). The E Gas results were presented in bar graph form and have been rounded by EPRI to the EPC costs shown in Table 3. Another row has been added EPRI with an additional 10% contingency to be consistent to that used in the other studies reported in this paper. E Gas estimated 1250$/kW for Pitts #8 without a spare gasifier. In another E Gas paper (P.Amick and R.Jones (GE)) at the 2002 conference a case was made for no spare for those instances where Spring and Fall power demand is lower so that planned outages could be taken at such times. Careful considerations need to be made of the IGCC plant Equivalent Availability required to meet the annual power demand profile in order to decide on sparing. Most of the other studies have included spare gasifiers in order to meet an overall IGCC plant Equivalent Availability of 90%. Adding a spare gasifier to the E Gas estimate in **Table 3** brings their estimate closer to the high range of other studies.

The overall results of all of these IGCC studies (without CO_2 capture) for the various gasification technologies based on bituminous coals are shown in **Table 3.** The Engineering Procurement and Construction (EPC) costs are presented both as a range and also as an average as assessed by the authors. The EPC costs do include a contingency and are roughly equivalent to the EPRI TAG definition of Total Plant Costs (TPC) that includes Total Field Costs (TFC) (Equipment and Labor), construction Management, Engineering and contingency.

Table 3 (Slide 8) Summary of IGCC Cost and Performance without CO_2 Capture –Bituminous coals

Gasification Technology	EPC Cost Range $/kW	Approximate Average EPC $/kW	Heat Rate Range Btu/kWh HHV	Average Heat Rate Btu/kWh HHV
Texaco Quench (2+1 gasifiers)	1160-1340	1270	9300-9650	9450
Texaco R and R+C (2+1 gasifiers)	R 1400-1500 R+C 1390-1500	R 1450 R+C 1440	R 8610-8860 R+C 8420-8550	R 8750 R+C 8480
E Gas (2+1 gasifiers)	1230-1390	1300	8400-8630	8550
Shell (2+0 gasifiers) (2+1 gasifiers)	1420-1520 1470-1670	1470 1620	8280-8470	8370

The E Gas results shown in Table 4 document the drop off in performance and increase in capital costs as you move from the higher quality feedstocks such as Petroleum coke and Pittsburgh # 8 coal through to the Illinois # 6, PRB and lignite coals. As the moisture content of the coals increases the achievable slurry concentration becomes lower and combined with the increased ash content in the lower rank coals the energy density of the slurry deteriorates markedly. Accordingly the relative oxygen requirement increases because the ratio of moisture in the slurry to moisture ash free coal (H_2O/MAF coal) increases and more oxygen is required to evaporate the moisture.

The relative feed rate is related primarily to the Heating Value of the feedstock although it is exacerbated by the additional auxiliary power consumption due to increased oxygen usage and coal handling, preparation and feeding – all leading to increased heat rates. Gasifier cold gas efficiency reduces with coal rank and more of the coal's energy is in the sensible heat from the gasifier. That leads to higher steam production, however less of the feedstock energy is available to the more efficient Brayton (gas turbine) cycle and the overall IGCC efficiency is reduced. (The higher steam generation is also more than offset by the increased auxiliary power consumption with lower rank coals).

Table 4 (Slide 9) E Gas IGCC Estimates for Domestic US Coals

Feedstock	**Petroleum Coke**	**Pittsburgh #8**	**Illinois # 6**	**PRB**	**Lignite**
Carbon % dry basis	88	78	70	62	60
Ash % dry basis	~0.5	7.5	12.5	17	20
Oxygen % dry basis	2	6	8	17	15
Approximate Heating Value AR Btu/lb HHV	13,000	13,100	11,000	8200	7500
Slurry conc. Wt% dry solids	66	66	63	56	50
Relative Feedstock Rate	1.0	1.0	1.25	1.8	2.0
Relative Oxygen needed	1.0	0.96	1.11	1.33	1.65
Number of Gasifiers (no spares)	2	2	2	3	4
Cold gas efficiency HHV	82	81	77	72	69
Relative Steam turbine Power Generation	1.0	1.04	1.09	1.17	1.20
Relative Auxiliary Power Required ASU/Gasification	1.0/1.0	0.97/0.97	1.11/1.17	1.30/1.60	1.55/1.85
Relative Net Power (Base 513 MW)	1.0	1.022	1.017	1.014	0.988
Relative Heat Rate Btu/kWh HHV (Base 8380)	1.0	1.0	1.06	1.14	1.22
EPC Cost $/kW	1160	1140	1240	1410	1580
EPC + 10% Contingency	1276	1254	1364	1551	1738

The cost estimates in the E Gas paper were prepared by Bechtel and were based on a Mid West location. It can be seen that the IGCC cost in **Table 4** for Pittsburgh # 8 coal falls in the same range as the other estimates shown in **Table 3.** It should be noted that the PRB chosen by the E Gas authors had an unusually high ash content (~17%) whereas 5-7% ash is more normal for a PRB coal. This means that the heat rate of ~ 9700 Btu/kWh and the EPC cost + contingency of 1551 $/kW are a bit higher than for a more typical PRB coal.

For PRB coals with a spare gasifier one other study showed E Gas (3+1)~1640 $/kW & HR 9630, and Shell 2+0/2+1 ~ 1470/1690 $/kW and HR 8800. EPRI estimates that a Supercritical PC of the same size would have a TPC of ~1350$/kW and a HR ~ 9200. i.e. a 200-300 $/kW difference in TPC. However if the proposed tax credits in the draft Energy Bill were enacted there is the intriguing possibility that the heat rate for the Shell IGCC with PRB would qualify and could make the COE quite competitive.

A study by Great River Energy with S&W for N.Dakota Lignite 500 MW IGCC (NOELL technology) showed capital cost ~400 $/kW > than PC. HR was estimated at 8165 Btu/kWh (very low!) versus 10,047 for the sub critical PC. EPRI estimates that a 500 MW sub critical PC in North Dakota would have a TPC of 1335$/KW and a HR of 10,170. The lignites of Texas, North Dakota and Saskatchewan are fairly similar with regard to moisture, ash and sulfur contents and heating value (the key parameters that affect gasification efficiency and equipment size).

IGCC for Low Rank Coals – Need for Gasification Improvements

With these estimates the current E Gas IGCC does not appear to compete with PC plants for PRB coals and lignites. Most IGCC studies have been based on using bituminous coals. The entrained flow gasifiers of Texaco, Shell and E Gas all perform better with the lower ash lower moisture bituminous coals. Given the abundance and low cost of US resources of low rank coals such as Powder River Basin (PRB) and the Texas and North Dakota Lignites there is a great need to improve the performance of IGCC with these coals.

Although entrained flow gasifiers can process all ranks of coal the existing commercial gasifiers all show a marked increase in cost and reduced performance with low rank and high ash coals. For slurry fed gasifiers (Texaco, E Gas) the energy density of high moisture and/or high ash coal slurries is markedly reduced which increases the oxygen consumption and reduces the gasification efficiency. For dry coal fed gasifiers (Shell) there is an energy penalty (and therefore reduced steam turbine output) for drying the high moisture coals to the low moisture content necessary for reliable feeding via lock hoppers and pneumatic conveying

Although IGCC is closely competitive with PC for bituminous coals the IGCC–PC capital cost and COE gap widens for low rank coals. For PRB ~ 200-300$/kW and ~ 400 $/kW for US lignites.

Potential improvements include slurry preheating & flashing, Coal/CO_2 slurry, coal pump (e.g.Stamet) or other device to deliver as received (AR) coal reliably at pressure, Transport gasifier etc. These potential improvements were described and discussed in papers (N.Holt – EPRI and G.Stiegel –DOE) at the 2001 Gasification Technologies Conference.

IGCC Studies with CO_2 Capture

If emissions including CO_2 were ever subject to externality charges or taxes this would make IGCC a more attractive technology. Several studies have shown that if CO_2 removal from fossil- based power plants is ever required (for subsequent disposal, use or sequestration) it would be much less costly to remove the CO_2 from syngas under pressure prior to combustion rather than removal from the huge volumes of stack gases after combustion at atmospheric pressure. The absorption process is driven by partial pressure and the size of vessels is much reduced under pressure.

Recent IGCC studies have been completed on each of the major candidate gasification technologies with and without CO_2 capture. The results for the cases with capture are shown in Table 5. These cost and performance estimates are based on the delivery of supercritical CO_2 to the plant battery limits at 110 barg. They do not include any costs for CO_2 transportation or sequestration:

Table 5 (Slide 12) Results of IGCC Studies with CO_2 Capture (Bituminous Coal)

Study # (Gas turbines)	**X (2x7FA)**	**Y (2x9FA) IEA GHG**	**Y (Adjusted to 2x7FA)**	**Z (2x7FA)**
Texaco Quench TPC $/kW (# gasifiers)	1522 (2+1)	1495 (3+1)	1652 (2+1)	1914 (2+1)
E Gas TPC $/kW (# gasifiers)	1770 (2+1)			
Shell TPC $/kW (# gasifiers)		1860 (2+0)	2055 (2+0)	
COE $/MWh (% over base)	57 Texaco (25) 63 E Gas (36)	56 Texaco (25) 63 Shell (31)	60 Texaco (25) 67 Shell (31)	61 Texaco
Heat Rate Btu/kWh HHV	11,550 Texaco 11,050 E Gas	11,330 Texaco 10,345 Shell	11,330 Texaco 10,345 Shell	10,815 Texaco

Study Z results are shown for completeness but the TPC cost is an outlier and seems unreasonably high.

The IGCC study results with capture in **Table 5** show that Texaco Quench IGCC has the lowest COE, followed by E Gas and Shell. These differences can be readily explained by the differences in pressure and gasifier type.

Table 6 (Slide 13) IGCC Studies with and without CO_2 Capture. Costs of CO_2 Capture. Bituminous Coal. Rounded average numbers.

Study/Technology	Without Capture TPC $/kW HR Btu/kWh COE $/MWh	Delta TPC $/kW	With Capture TPC $/kW HR Btu/kWh COE $/MWh
Texaco Quench Texaco R + C	1270 (2+1) 9300 46 1450 (2+1) 8480 49	350 ?	1620 11,300 57 ?
E Gas	1300 (2+1) 8550 46	550	1850 11,000 62
Shell	1470 (2+0) 8370 49	550	2020 10,350 65

The Texaco quench gasifier is a slurry fed gasifier operating at 69 barg and the quenched raw gas has a CO/H_2 ratio of ~1.25/1 with a high moisture content sufficient to conduct the shift reaction without having to rob the steam cycle. The high pressure also enables the use of a physical solvent, Selexol, at a pressure where a majority of the CO_2 can be produced by flashing at ~ 4 barg thereby saving considerable compression costs and energy (auxiliary power). The capital cost for the base Texaco Quench IGCC plant is lower than for Shell and the additional cost for CO_2 capture is also less. The ratio of COE's with and without capture is ~1.25 for the Texaco Quench IGCC. There is very good agreement between two separate studies in this respect.

Evaluations of Texaco R and R+ C configurations with CO_2 capture are not yet available. However the added cost will depend on the pressure and syngas moisturization. The added cost will be less for the R only than for R+C since the R syngas will have higher moisture when quenched than the R+C syngas.

In contrast the dry coal fed Shell gasifier operates at 38 barg and the raw gas has a CO/H_2 ratio of ~2/1 with very low moisture content so that steam has to be supplied from the steam cycle to provide enough steam to conduct the shift reaction. The lower pressure is also less advantageous for CO_2 removal. The ratio of COE's with and without capture is ~1.31 for Shell IGCC.

The current design of the E Gas gasifier has a cross sectional shape of an inverted T and is limited in operating pressure to ~ 35 barg. Although the raw gas has a CO/H_2 ratio of ~1.33/1 the moisture content is not very high since the raw gas is not quenched and steam is therefore needed from the steam cycle for the shift reaction. The lower pressure also means additional cost and performance penalties for CO_2 removal. The ratio of the COE's with and without capture is ~1.36 for the E Gas IGCC.

If capture is required the Texaco quench has an overall COE advantage of 10-12% over current E Gas and Shell.

In a previous EPRI/DOE study a high pressure cylindrical design E Gas gasifier operating at 55 barg with a GE H gas turbine was evaluated with and without Capture. This was presented at the 2000 Gasification Technologies Conference. Capture added ~400 $/MWh and 30% to the COE. This contrasted to a Supercritical PC plant using flue gas amine scrubbing with added capture costs of 750$/kW and 60% increase to the COE. This corresponded to IGCC with capture COE 54$/MWh versus Supercritical PC with capture at 71$/MWh.

These latest estimates reported in this paper for currently commercially available Texaco, E Gas and Shell IGCC's using bituminous coals show a significant COE advantage over PC plants with when capture is required. There is also a particular advantage to high-pressure gasification operation. For the current lower pressure E Gas and Shell IGCC's there is a lower advantage over PC plants with amine scrubbing than with the higher pressure Texaco Quench IGCC.

IGCC with CO_2 Capture for Sub-bituminous Coals and Lignites

As described earlier in this paper at the current state of IGCC development for low rank coals IGCC does not compete favorably with PC plants. Although detailed IGCC studies with and without capture have not yet been completed on a consistent basis for sub-bituminous coals and lignites, IGCC with capture will be much less competitive with PC plants for these coals since the base IGCC TPC without capture is 300-400 $/kW higher than a PC plant.

For order of magnitude orientation consider the following: using the E Gas TPC estimate for PRB from **Table 3** of 1550 $/kW and add 550$/kWh from **Table 6** to give an estimate of 2100$/kW for E Gas PRB with capture, and then using the EPRI estimate of 1350$/kW for a Supercritical (SC) PC for PRB coal and the 750$/kW for added capture from the previous 2000 study also results in a TPC of 2100$/kW for SCPC PRB with capture.

There are also some pertinent results from the Canadian Clean Power Coalition (CCPC) study reported at this same 2003 conference. Fluor licenses the Econamine (MEA) process that can be use for post combustion removal of CO_2 from PC plant flue gases. In the CCPC study Fluor claims to have a new split flow process scheme that can reduce the steam consumption (the major cost and power impact of capture by amine) from 1750 to 1185 Btu/lb of CO_2. For the Saskatchewan lignite the Shell IGCC COE with capture (Texaco declined to provide an estimate for lignite) was greater than for PC with capture. For the Alberta sub-bituminous coal (similar to PRB) the Texaco Quench IGCC COE with capture was better than the PC COE with capture but only by 5%.

Therefore at this point in IGCC development for lignites it does not look as if IGCC with capture has an advantage over PC with capture. For sub-bituminous coals with capture the IGCC advantage over PC is currently small but can probably be improved.

Effect of Potential Carbon Tax on Fuel and Technology Selection

The current US coal power plant fleet of ~320 GW generates ~ 2.1 billion metric tons per year of CO_2 emissions. This also represents about 31% of the US and ~8% of the World's emissions. Since the large coal power plants represent the largest single point sources they are likely to be targeted for attention in any carbon management related legislation. In order to remove CO_2 from flue gas with amine scrubbing the SO_2 and NOx levels in the flue gas must be very low since these species react irreversibly with the amine. Currently only ~100 GW of the coal power plants have FGD, however, the Clear Skies initiative, if enacted may require much more FGD installation.

The paid off capital on most US coal power plants (most of which were installed in the 50's, 60's and 70's) is a great advantage in the marketplace where most coal plants can produce power at ~20$/MWh. A tax of > 190$/metric ton of Carbon would be required for their COE to equal that from a new IGCC with capture and sequestration. Therefore it is most likely that these plants will continue to run and would most likely just pay the carbon tax. Even if FGD, SCR and Mercury controls were required to be added with an estimated additional capital cost of $500/kW the breakeven with new IGCC with capture and sequestration (for bituminous coals) is still about 100$/metric ton of Carbon.

Natural Gas combined Cycle (NGCC) plants have the great initial advantage over coal plants that their CO_2 emissions per MWh are only 40-45% of those from the coal plants. With natural gas up to 5$/GJ the COE from new NGCC (when evaluated at the same 80 % capacity factor as for coal plants) with CO_2 venting is lower than the COE from new IGCC with capture and sequestration up to a Carbon tax of 200$/metric ton. At 6$/GJ natural gas the breakeven with IGCC with capture and sequestration occurs at a Carbon tax of ~100$/metric ton.

If the purpose of a carbon tax is to reduce CO_2 emissions one possible policy could be to use the proceeds as credit for the CO_2 captured at the same Carbon tax rate. This would enable capture and sequestration technologies to compete more readily, and at a lower Carbon tax, with existing coal plants.

Future Coal Power Generation

Future coal power generation is faced with many unknowns, but resolving the energy/environment issue is paramount.

Does CO_2 sequestration work? If sequestered what is the leakage and is it acceptable? How does the effectiveness of sequestration vary among different geologic structures? What about seismic disruptions?

Can natural gas supplant coal in US power generation? Forecasts are very varied on this question. However even with the latest DOE EIA 2003 forecast with natural gas supply going from 23 TCF to 35 TCF by 2025 they are still forecasting the need for ~20% more coal usage. This natural gas forecast implies greatly increased importation of LNG, the Alaska pipeline and much more new gas from the lower 48 and offshore. The authors conclude that new coal will be required under most likely scenarios.

This paper reports the added COE costs of capture to be 25-35% with new IGCC plants and ~60% for new PC plants at the plant gate where the CO_2 is pressured up to 110 barg. These costs do not include pipeline transport and sequestration costs which will be very dependent on site location but have been estimated at 5-10$/metric ton of CO_2. These additional costs imply that the additional COE for both capture and sequestration could be 40-50% for new IGCC and 80-90% for new PC plants. The two main questions are: Is this going to be acceptable to the public? Can these costs be significantly reduced by further technology development?

Of all the economic sectors the US power industry has the most CO_2 emissions. The coal plants constitute the largest point sources of CO_2 emissions. With the huge economic advantage of the largely paid-off capital, the COE from these plants will continue to be less new coal even with a large Carbon tax. Most of them will probably still be kept in operation with a Carbon tax even if they have to add FGD, SCR and Mercury control. If CO_2 emissions are to be reduced how can they be reduced from existing coal power plants? What incentives can be offered?