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CO_2 control technology effects on IGCC plant performance and cost

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A R T I C L E I N F O

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A B S T R A C T

As part of the USDOE's Carbon Sequestration Program, an integrated modeling framework has been developed to evaluate the performance and cost of alternative carbon capture and storage (CCS) technologies for fossil-fueled power plants in the context of multi-pollutant control requirements. This paper uses the newly developed model of an integrated gasification combined cycle (IGCC) plant to analyze the effects of adding CCS to an IGCC system employing a GE quench gasifier with water gas shift reactors and a Selexol system for CO_2 capture. Parameters of interest include the effects on plant performance and cost of varying the CO_2 removal efficiency, the quality and cost of coal, and selected other factors affecting overall plant performance and cost. The stochastic simulation capability of the model is also used to illustrate the effect of uncertainties or variability in key process and cost parameters. The potential for advanced oxygen production and gas turbine technologies to reduce the cost and environmental impacts of IGCC with CCS is also analyzed.

1. Introduction

As an emerging coal-based technology for electric power generation, integrated gasification combined cycle (IGCC) systems are gaining attention as a potentially attractive option to limit emissions of carbon dioxide (CO_2) as well as conventional air pollutants. CO_2 emissions can be prevented in a gasification-based power plant by transferring almost all carbon compounds to CO_2 through the water gas shift (WGS) reaction, then removing the CO_2 before it is diluted in the combustion stage. CO_2 removal from IGCC requires considerably smaller and simpler process equipment than the post-combustion CO_2 removal (IPCC, 2005).

IGCC power plants with CO_2 capture have been the subject of previous studies over the past 15 years (Holt et al., 2003). These studies included conceptual designs, flowsheet modeling and cost estimation based on different technology selections and assumptions (Doctor, 1994; Chiesa and Consonni, 1999; Haslbeck, 2002; O' Keefe and Griffiths, 2000; Buchanan et al., 2002; IEA, 2003). However, there are no generally available process models that can be easily employed or modified to systematically study the performance and cost of CO_2 capture and storage (CCS) options from IGCC systems for different user-defined assumptions and technology selections. Reported cost data also are relatively limited and often incomplete, and uncertainties in performance and cost are seldom considered.

As part of the United States Department of Energy's (USDOE) Carbon Sequestration Program, a general integrated modeling framework has been developed at Carnegie Mellon University to evaluate the performance and cost of alternative CCS technologies for pulverized coal (PC), natural gas combined cycle (NGCC) and IGCC power plants (Rao and Rubin, 2002; Rubin et al., 2005; IECM, 2008). The model (called IECM, for Integrated Environmental Control Model) combines plant-level mass and energy balances with empirical data and process economics. It also allows for explicit characterization of the uncertainty or variability in any or all input parameters. This paper briefly introduces the models developed for IGCC systems with and without CCS. Then, these models are used to assess the performance and cost impacts of CCS for an IGCC power plant.

The first section of this paper presents the plant configurations of IGCC systems with and without CO_2 capture. The following section presents a baseline analysis and discusses several factors influencing the performance and cost of IGCC systems with and without CO_2 capture, including coal quality and CO_2 removal efficiency. Additional factors are then considered in a probabilistic uncertainty analysis. Finally, we analyze the potential effects of two advanced technologies—an ion transport membrane (ITM) system for oxygen production and an H-frame gas turbine (GT) system for power generation—on the performance and cost of IGCC systems with CCS.

2. IGCC power plant model

In the IECM framework, engineering-economic models are developed to simulate the performance and cost of an IGCC

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system with and without CCS for different design assumptions. As the first step, a detailed engineering model of an IGCC system without CCS was developed in the Aspen Plus software environment. This involved updating IGCC cost models developed in previous research (Frey and Rubin, 1992; Frey et al., 1994) based on more recent studies (Chen, 2005). The nominal system design employed GE (formerly Texaco) water quench gasifiers, followed by a hydrolyzer for COS conversion and an acid gas removal system with byproduct sulfur recovery (including a tail gas treatment system). The nominal combined cycle power plant is based on a GE-7FA GT and a three-stage heat recovery steam generator (HRSG). The design philosophy was to base this power plant on commercially available equipment, with no integration of the air separation unit (ASU) and the GT system in order to maintain operational flexibility and reliability. The configuration of the plant is given in Fig. 1.

To incorporate CO_2 capture, the IGCC plant design employs two additional subsystems. The first is a two-stage WGS reaction unit (including a high-temperature reactor and a low temperature reactor) located downstream of the gasifier quench chamber. The WGS unit coverts almost all the CO in the syngas to CO_2 according to the following reaction:

$$CO + H_2O \rightarrow CO_2 + H_2 + 44.48\,\mathrm{MJ/moleCO} \qquad (1)$$

The source of the H_2O for this reaction is the moisture in the quenched syngas, plus additional steam added to the WGS reactor (Chen, 2005). The second sub-system is the CO_2 capture unit, which is a commercial Selexol unit employing physical absorption, similar to the Selexol process used for sulfur (H_2S) removal in plants without CCS. For the CCS plant, a two-stage Selexol process combining sulfur removal and CO_2 removal is employed. The Selexol process can be configured in various ways, depending on the requirements for H_2S and CO_2 removal, and whether the gas needs to be dehydrated. For a CCS plant, the captured CO_2 must be compressed to a supercritical stage for pipeline transport to the storage site. This requires dry, high-purity CO_2 at a pressure of approximately 13 MPa. For the IGCC plant, a two stage Selexol process has been configured to minimize energy requirements for CO_2 removal (Chen, 2005) based on modifications to a Selexol

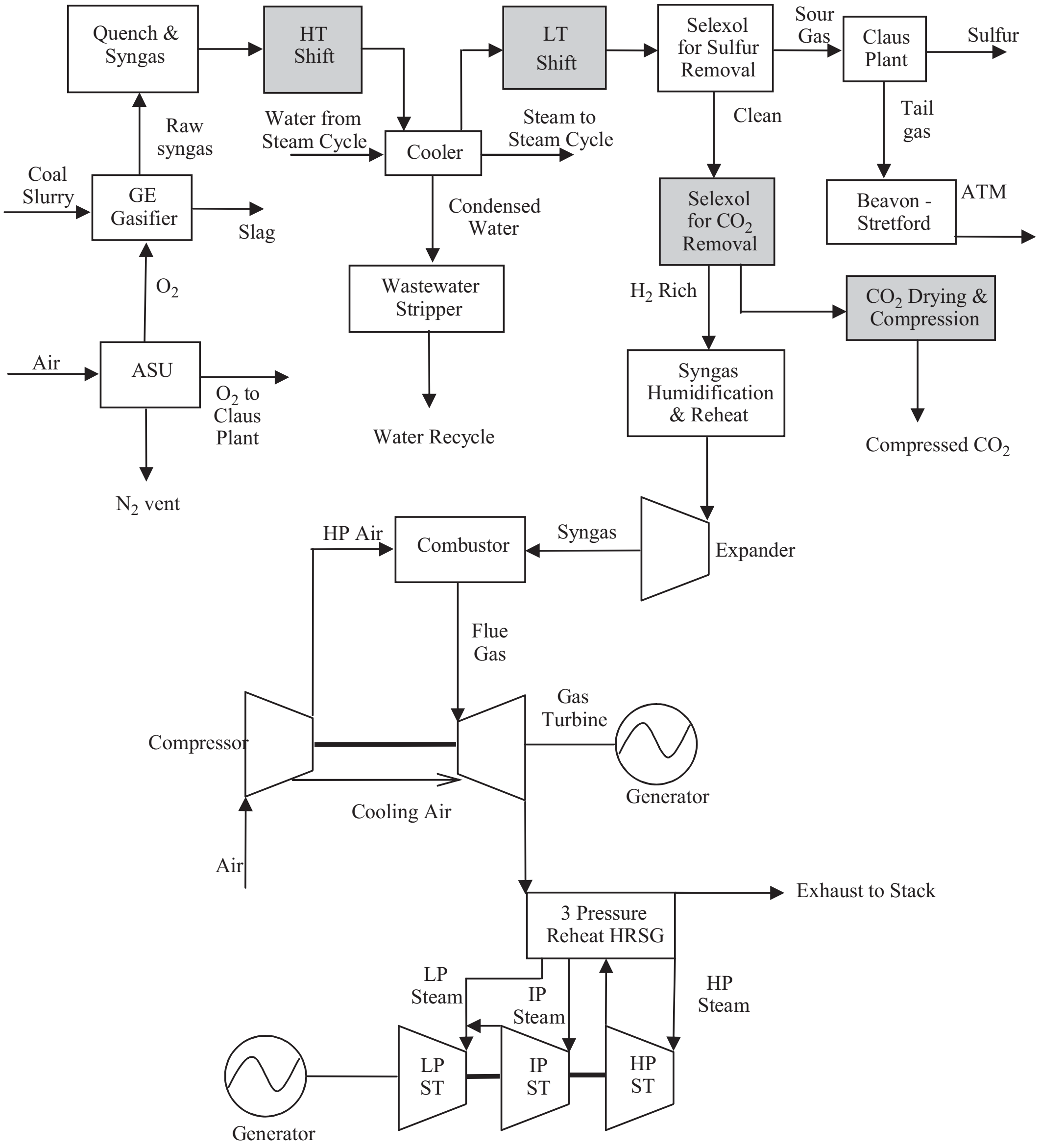

Fig. 1. Schematic representation of the IGCC plant with CO_2 capture using a two-stage WGS reaction followed by a two-stage Selexol process for sour gases removal. The shaded boxes are not present in the reference plant without CO_2 capture.

process design for H_2S and CO_2 removal from syngas for the production of ammonia (Breckenridge et al., 2000).

Fig. 1 illustrates the IGCC plant with CO_2 capture. This embodies the conceptual design of the IGCC system, but adds the WGS reaction and two-stage Selexol unit for sour gas removal, shown shaded in the figure. The captured CO_2, after compression, is assumed to be transported via pipeline to a geological storage site where it is injected into a deep saline formation.

The CO_2 capture system (WGS plus Selexol) was incorporated into the IGCC model in Aspen Plus with a re-design of the plant heat integration. New performance and cost models of a two-stage WGS reactor system and a Selexol unit for CO_2 capture were derived using detailed chemical simulations, theoretical analysis, and regression analysis of published performance and cost data (Chen, 2005). All models for IGCC components (with or without CO_2 capture) were directly coupled to the plant level models, so that any process design changes directly affect overall plant performance and costs (capital cost, operating costs and maintenance costs). The probabilistic capability of the IECM also facilitates risk and uncertainty analysis. Thus, the overall modeling set (IECM, supported by more detailed Aspen Plus performance models) provides the analytic environment and tools for technical and economic assessments of gasification-based energy conversion systems on a systematic basis.

3. Case studies for current plant designs

The newly developed IGCC process models are used in this paper to explore several factors influencing the performance and cost of IGCC power plants with and without CCS. The general technical design assumptions of our "base case" power plant and the key economic and financial assumptions are given in Table 1. Details of other model input assumptions are given elsewhere (Chen, 2005).

Table 1
Design assumptions for the IGCC power plant model.

Parameter	Value
Technical parameters	
Reference fuel-type	Pittsburgh #8 coal
Gasifier-type	GE quench
Gasifier temperature & pressure	1343 °C, 4.24 MPa
No. of gasifiers	2 operating plus 1 spare
ASU oxygen purity	95%
Gas turbines	2 GE 7FA
Ambient temperature & pressure	15 °C, 0.101 MPa
Steam cycle	9.65 MPa/538 °C/538 °C
Condenser pressure	0.0046 MPa
Syngas sulfur removal efficiency	99%
CO_2 capture efficiency	90%
CO_2 product final pressure	14.5 MPa
Economic/financial parameters	
Cost year	June 2008
Fixed charge factor	14.8%
Plant capacity factor (levelized)	75%
Construction period	4 years
Plant lifetime	30 years
Coal price	1.5 $/GJ
CO_2 transport and storage cost	9.5 $/tonne CO_2

The overall performance and cost of this IGCC system with and without CCS are given in Table 2 based on the plant configurations and design assumptions in Table 1. In both cases, the net power output is approximately 500 MW. However, the plant with CO_2 capture has an 8% lower electrical output and is 14% less efficient than the "reference plant" design without CCS. This is due to the differences in GT performance and coal input requirements for plants burning syngas (reference plant) or hydrogen (capture plant). Table 2 shows that the total capital cost of the CCS plant increases by about 38%, and the levelized cost of electricity (COE) increases by 45%. These results agree well with other studies based on similar designs (IEA, 2003). On an absolute basis, however, the capital cost of IGCC systems—and plant construction in general—has increased sharply in recent years, driven largely by higher costs for materials as well as construction labor (CEPCI, 2008). For this reason, the relative cost differences in Table 2 are more robust than the absolute costs, which may escalate further in the future. The effects of recent and possible future cost increases on the results presented in this paper are discussed in later sections.

3.1. Effects of coal quality on plant performance

An entrained flow gasifier, like the GE gasifier, can process many varieties of coal regardless of rank, caking characteristics, or amount of coal fines. However, the coal quality measures reflected in coal rank have a significant influence on the performance of gasifiers and the overall IGCC system. Here, four coals commonly used for power plant analyses are used to investigate this influence for bituminous, sub-bituminous and lignite coals. The composition of each coal is given in Table 3.

For the slurry-fed GE-type gasifier, each coal has a minimum requirement for water needed to pump the slurry into the gasifier (Todd, 2002). When added to the inherent moisture in the coal, the total water content in the slurry feed for the Pittsburgh #8, Illinois #6, Wyoming PRB and ND lignite coals are 34%, 37%, 44% and 50%, (Breton and Amick, 2002) respectively, as shown in Table 3.

Fig. 2 compares the gasification efficiency, net plant thermal efficiency and net plant heat rate (the reciprocal of net efficiency) using the four coals, with the Pittsburgh #8 coal used as the reference case, as in the base case analysis (Tables 1 and 2). The gasification efficiency in Fig. 2 is defined as

$$\eta_{\text{gasifier}} = \frac{H_g Q_g}{H_s M_s} \times 100$$

where η_{gasifier} = gasification efficiency (%), H_g = heating value of the syngas (kJ/m^3), Q_g = volumetric flowrate of syngas (m^3/s), H_s = heating value of gasifier fuel input (kJ/kg) and M_s = gasifier fuel consumption rate (kg/s).

Fig. 2 shows that the coal quality significantly influences the overall plant performance. The heat rate of the IGCC power plant

Table 2
Comparison of IGCC with and without CO_2 capture and storage.

Plant design	Net capacity (MW)	Total Capital requirement (June 2008$/kW)	Cost of Electricity ($/MWh)	Thermal efficiency (HHV) (%)	CO_2 emission (kg/kWh)
Reference plant	538	1823	65.9	38.1	0.819
Capture plant (90% CO_2 Capture)	495	2513	95.8	32.9	0.094
Change %	−8.0%	37.8%	45.4%	−13.7	−88.5%

Table 3
Composition of the case study coals and total water content of slurry feed.

Coal type	Pittsburgh #8	Illinois #6	Wyoming PRB	ND Lignite
Coal rank	Bituminous	Bituminous	Sub-bituminous	Lignite
HHV (kJ/kg)	30,822	25,336	19,386	13,993
Moisture (%)	5.05	13.00	30.24	33.03
Ash (%)	7.24	11.00	5.32	15.92
Carbon (%)	73.81	61.20	48.18	35.04
Hydrogen (%)	4.88	4.20	3.31	2.68
Nitrogen (%)	1.42	1.16	0.70	0.77
Oxygen (%)	5.41	6.02	11.87	11.31
Sulfur (%)	2.13	3.25	0.37	1.16
Chlorine (%)	0.06	0.17	0.01	0.09
Cost ($/tonne)	43.2	35.4	9.2	12.5
Cost ($/GJ)	1.40	1.39	0.48	0.89
Total water content of IGCC slurry feed				
Water (%)	34	37	44	55

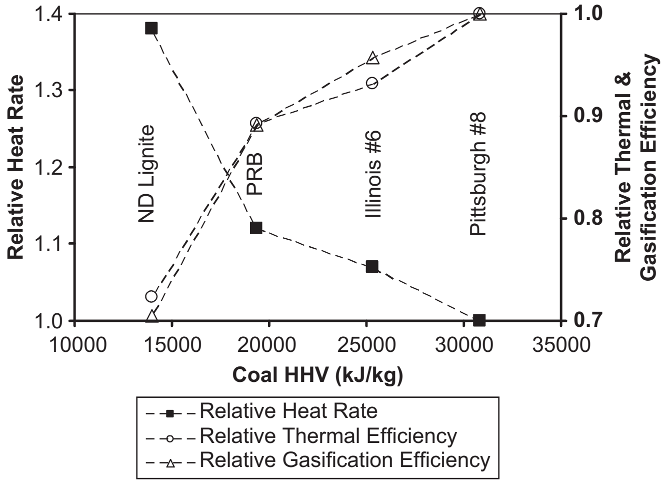

Fig. 2. Effects of coal rank on IGCC plant efficiency.

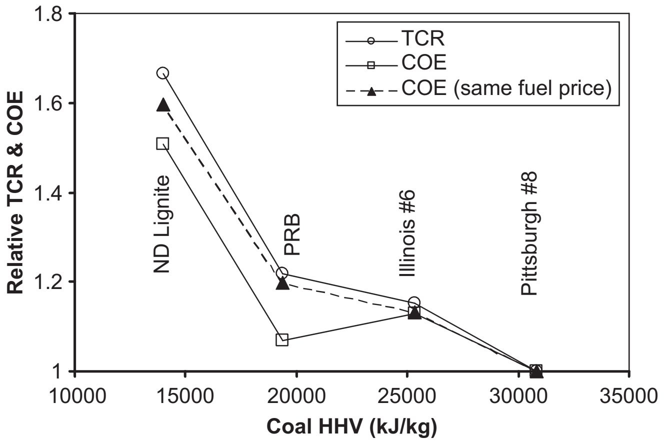

Fig. 3. The effect of coal rank on TCR and COE. (For the COE calculation, the coal price ratios based).

using ND lignite and PRB are about 37% and 12% higher, respectively, than the plant using Pittsburgh #8. Differences are also seen for the two bituminous coals. The lower efficiencies for the low-rank coals are primarily a result of the decreased gasification efficiencies and the increased oxygen required to maintain the gasifier temperature for these high-moisture feedstocks. Other gasifier designs, including dry-feed systems, may yield better performance for these low-rank coals.

Fig. 3 shows that coal quality also influences the economics of IGCC power plants. The total capital requirement (TCR) ($/kW) of the plants using ND lignite and PRB is about 67% and 23% higher, respectively, than the plant using Pittsburgh #8 coal. On the other hand, the lower-rank coals typically have a lower price, which tends to reduce the COE. For the case study plants modeled here, the COE of the IGCC plant using PRB coal is lower than the plant using Illinois #6 based on recent minemouth fuel prices. Had the energy cost ($/GJ) of all four coals been the same, Fig. 3 shows that the COE for the lower-rank coal would have been higher than for the bituminous coals.

4. Effects of CO_2 capture efficiency on plant performance

Studies of CO_2 capture from IGCC power plants typically assume an overall CO_2 capture efficiency in the range of 75–92% (Holt et al., 2003; Doctor, 1994; O' Keefe and Griffiths, 2000; IEA, 2003; IPCC, 2005). There is usually no explanation for the choice of capture efficiency nor an analysis of the effect of different capture efficiencies on plant performance and cost. In this section, we study the effect of different CO_2 capture efficiencies on the performance and cost of IGCC power plants, including effects on energy penalty (EP), capital cost, COE and CO_2 avoidance cost. An objective is to determine the least-cost CO_2 capture efficiency for a given plant design. Here, the total CO_2 removal efficiency is defined as

$$CO_2 \text{ removal efficiency} = \frac{CO_2 \text{ captured(moles)}}{\text{Total carbon in syngas from gasifier(moles)}} \tag{2}$$

The economic impacts of CO_2 capture are disaggregated into three stages: (1) CO_2 captured in the Selexol unit without further compression; (2) CO_2 captured and compressed to 2100 psia; and (3) CO_2 captured, compressed to 2100 psia, then transported via pipeline and sequestered in a geological formation at a cost of $9.5/tonne CO_2 for transport and storage. Stage 1 reflects the impacts of water addition in the WGS reactor as well as the Selexol capture unit. Stage 2 reflects the impact of additional CO_2 compression required for pipeline transport and storage, but typically charged to the CO_2 capture system. Stage 3 reflects additional costs of transport and storage.

An EP is defined to characterize the influence of the CO_2 capture system on the performance of an IGCC power plant. It is defined for this study as

$$EP = \frac{\text{Reference plant efficiency} - \text{Capture plant efficiency}}{\text{Capture plant efficiency}} \tag{3}$$

This represents the increase in plant energy input per unit of net electrical output. Fig. 4 shows the EP of the base case IGCC power plant (Table 1) as a function of the total CO_2 removal efficiency. Without additional CO_2 compression, the EP increases almost linearly up to a CO_2 removal efficiency of about 85–90%, after which it rises more sharply. CO_2 compression further increases the EP. For 90% of overall CO_2 removal, the EP including compression is 15.8% (vs. 10.2% before compression). This means that 15.8% more coal (as well as oxygen and other plant inputs) must be supplied per net kWh generated relative to a similar plant without CCS.

The capital cost of the IGCC plant is also influenced significantly by the CO_2 removal efficiency, as seen in Fig. 5. For 90% removal, the cost of CO_2 compression adds approximately 11% to the TCR ($/kW). As noted earlier, while the compression cost is

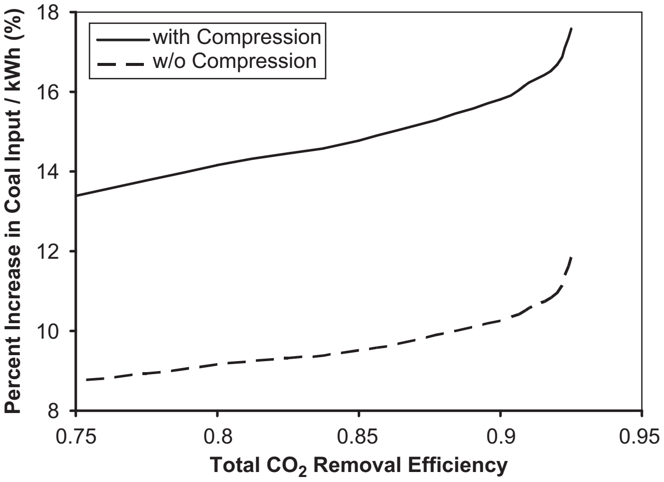

Fig. 4. EP of an IGCC system with various CO_2 removal efficiency.

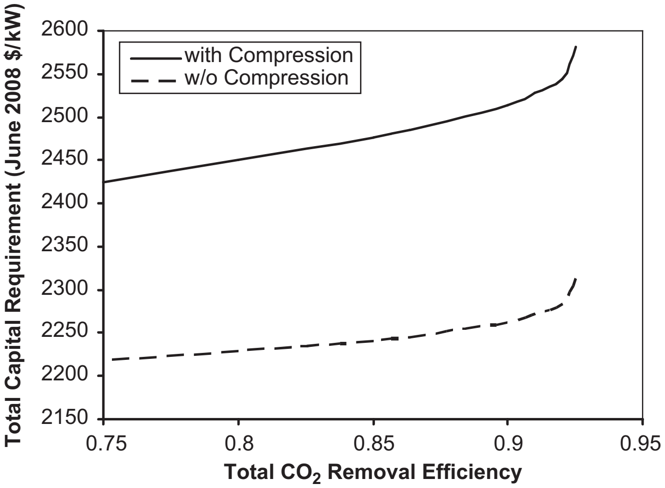

Fig. 5. TCR of an IGCC power plant as a function of total CO_2 removal efficiency.

commonly attributed to the capture system, it is the CO_2 transport and storage, components of CCS that require the higher pressure for their operation.

The total COE generation also increases more rapidly at high CO_2 removal efficiency, as depicted in Fig. 6. That figure also shows the breakdown of costs for CO_2 capture, compression, and disposal. Compared to the reference plant without capture, the COE of the CCS plant with 90% CO_2 removal increases by 19% before CO_2 compression, by 30% after CO_2 compression, and by 45% with additional CO_2 transport and storage costs.

Another widely used measure of CCS cost is the CO_2 avoidance cost, which is defined as

$$\text{Cost of } CO_2 \text{ Avoided} = \frac{\text{COE of capture plant} - \text{COE of reference plant}}{\text{Reference plant } CO_2\text{ /kWh} - \text{Capture plant } CO_2\text{/kWh}} \tag{4}$$

Fig. 7 shows the variation of CO_2 avoidance cost with CO_2 removal efficiency, again disaggregated into the three components shown earlier. Notice that the avoidance cost is minimized when the total CO_2 removal efficiency is around 90%. At that removal efficiency the cost of capture alone is \$17.4/tCO_2 avoided for this case. CO_2 compression increases this by 57% to \$27.4/tCO_2, then transport and storage costs raise it another 50% to the final value of \$41.5/tCO_2 avoided.

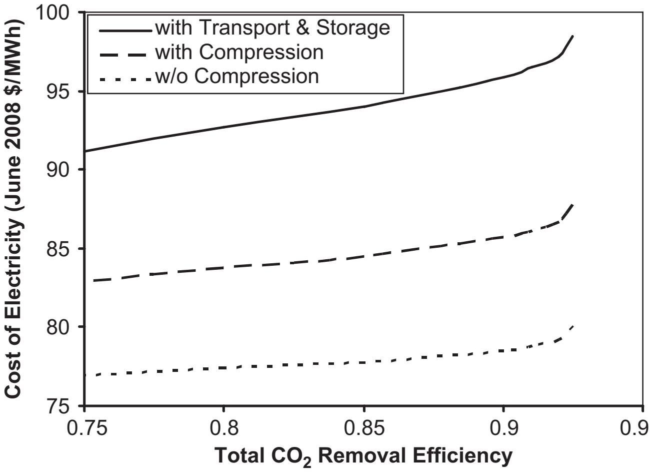

Fig. 6. Total cost of electricity (COE) of IGCC power plant as a function of total CO_2 removal efficiency showing effects of additional compression and costs of transport and storage.

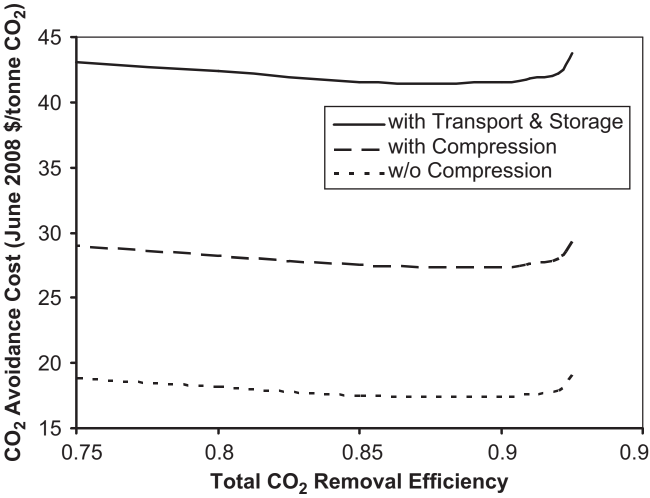

Fig. 7. CO_2 avoidance cost of an IGCC plant as a function of total CO_2 removal efficiency, showing the incremental costs for compression and transport/storage.

5. Effects of uncertainty

An IGCC plant is a complex chemical processing and energy conversion system. Large-scale commercial experience with IGCC power plants and systems for CO_2 capture is still limited. Consequently, there are substantial uncertainties associated with using the limited performance and cost data available to predict the commercial-scale performance and cost of a new IGCC facility. Uncertainties as well as variability in design assumptions may apply to different aspects of the process, including performance variables; equipment sizing parameters; process area capital costs; indirect capital costs; process area maintenance costs; requirements for catalysts, chemicals and consumables during plant operation; and the unit costs of consumables, byproducts, wastes and fuel (Frey et al., 1994). Model parameters in any or all of these areas may be uncertain or variable, depending on many factors including the state of technology development, the level of detail of performance and cost estimates, assumptions about future markets and prices for chemicals, catalysts, byproducts and wastes.

In light of these uncertainties for an IGCC system with CCS, this section undertakes a preliminary analysis to characterize their effects on plant performance and cost, and to rank the importance of different factors in terms of their contribution to overall uncertainty. In this analysis, the total uncertainty is calculated probabilistically based on estimates of uncertainty or variability in the key parameters used in the IECM performance and cost models.

During development of the technical and economic models of IGCC systems, we identified a number of parameters that should be treated as uncertain. Depending on the availability of information, estimates of parameter uncertainties or variability can be based on published judgments in the literature, published information that can be used to infer judgments about uncertainty, statistical analysis of data, or elicitation of judgments from technical experts. A probability distribution must then be assigned to each uncertain parameter. Some of the distributions used here came directly from published judgments in the literature. Most of the others were estimated through statistical analysis of published data. We relied most heavily on data from project reports and papers published by industrial companies with real-world experience. The detailed methodology and procedures for the uncertainty analysis are described by Chen (2005). The following simulation results are based on the parameter distributions shown in Tables 4 and 5.

Fig. 8 shows the probabilistic result for TCR, decomposed to show the separate contributions of the reference IGCC power plant and the CCS system. The deterministic value in this case was $2513/kW. The overall range varies from 2360 to 2760 $/kW, with a 90% confidence interval of 2400–2700 $/kW. From this figure, it is clear that most of the uncertainty in the total capital cost comes from the reference IGCC plant rather than from the CCS system. Note, however, that this analysis does not include additional uncertainties affecting the direct construction cost of an IGGC plant due to escalation of materials and construction labor costs. Nor does it include uncertainties or variability in technical factors such as the gasifier heat loss or carbon loss. Including additional uncertainties beyond those shown in Tables 4 and 5 would further broaden the overall range of TCR shown in Fig. 8.

In considering the effects of uncertainty on the COE, we pay special attention to the assumed capacity factor since this has a large influence on both the COE and the CO_2 avoidance cost. Because coal-based power plants typically are designed for baseload service, most IGCC cost studies assume a high (typically

Table 4
Distribution functions assigned to parameters of the IGCC reference plant.

Parameter	Unit	Nominal value	Distribution function
Performance parameters			
Carbon loss in gasifier	%	3	Triangular (1, 3, 5)
Heat loss in gasifier	%	0.5	Triangular (0.1, 1,1)
Sulfur removal efficiency	%	0.99	Triangular (0.97, 0.99, 0.99)
Shaft/generator efficiency	%	0.98	Uniform (0.975, 0.985)
Facility cost financial parameters			
Fixed charged factor	%	14.8	Triangular (7.1, 14.8, 17.4)
Engineering and home office fee	% TPC	10	Triangular (7,10,12)
Indirect construction cost factor	% TPC	20	Triangular (15,20,20)
Project uncertainty	% TPC	12.5	Uniform (10,15)
General facilities	% TPC	15	Triangular (10,15,25)
Process contingency factors			
Oxidant feed	% PFC	5	Uniform (0,10)
Gasification	% PFC	10	Triangular (0,10,15)
Selexol process	% PFC	10	Triangular (0,10,20)
Low temperature gas cleanup	% PFC	0	Triangular (−5,0,5)
Claus plant	% PFC	5	Triangular (0,5,10)
Beavon-Stretford	% PFC	10	Triangular (0,10,20)
Process condensate treatment	% PFC	30	Triangular (0,30,30)
Gas turbine	% PFC	12.5	Triangular (0,12.5,25)
Heat recovery steam generator	% PFC	2.5	Triangular (0,2.5,5)
Steam turbine	% PFC	2.5	Triangular (0,2.5,5)
General facilities	% PFC	5	Triangular (0,5,10)
Maintenance cost factors			
Gasification	% TPC	4.5	Triangular (3,4.5,6)
Selexol for sulfur removal	% TPC	2	Triangular (1.5,2,4)
Low temperature gas cleanup	% TPC	3	Triangular (2,3,4)
Claus plant	% TPC	2	Triangular (1.5,2,2.5)
Boiler feed water	% TPC	2	Triangular (1.5, 2, 4)
Process condensate treatment	% TPC	2	Triangular (1.5,2,4)
Gas turbine	% TPC	1.5	Triangular (1.5,1.5,2.5)
Heat recovery steam generator	% TPC	2	Triangular (1.5, 2, 4)
Steam turbine	% TPC	2	Triangular (1.5,2,2.5)
Other fixed operating cost parameters			
Labor rate	$/h	29	Triangular (20,29,32)
Variable operating cost parameters			
Ash disposal cost	$/tonne	13	Triangular (13,13,43)
Sulfur byproduct credit	$/tonne	96	Triangular (77,96,161)

Table 5
Distribution functions assigned to parameters of the CO_2 capture system.

Parameter	Unit	Nominal value	Distribution function
Selexol system performance parameters			
Mole weight of Selexol	kg/kg mol	280	Triangular (265,280,285)
Pressure at flash tank 1	psia	60	Uniform (40,75)
Pressure at flash tank 2	psia	20	Uniform (14.7,25)
Pressure at flash tank 3	psia	7	Uniform (4,11)
Power recovery turbine efficiency	%	75	Uniform (70,80)
Selexol pump efficiency	%	75	Uniform (70,80)
Recycle gas compressor efficiency	%	75	Uniform (70,80)
CO_2 compressor efficiency	%	79	Triangular (75,79,85)
WGS and Selexol cost parameters			
WGS catalyst cost	$/L	10.3	Triangular (9.1,10.3,11.9)
Selexol solvent cost	$/kg	5.0	Triangular (3.4,5.0,7.5)
WGS process contingency cost	% PFC	5	Triangular (2,5,10)
Selexol process contingency cost	% PFC	10	Triangular (5,10,20)
Maintenance cost of WGS system	% PFC	2	Triangular (1, 2, 5)
Maintenance cost of Selexol system	% PFC	5	Triangular (2,5,10)

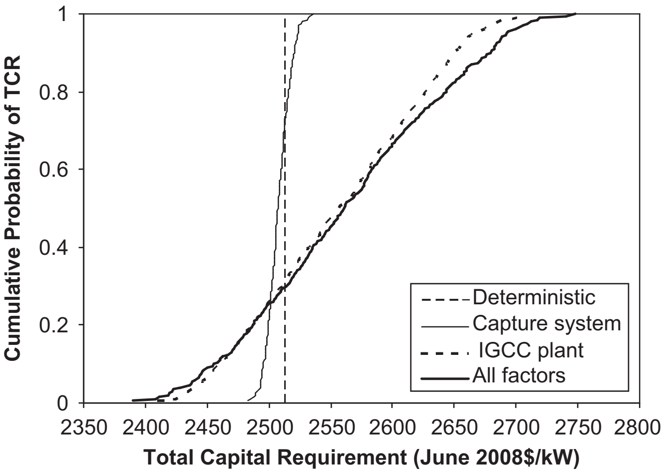

Fig. 8. Cumulative probability distributions of IGCC TCR (based on parameter distributions from Tables 5 and 6). The deterministic result is shown as a vertical dashed line.

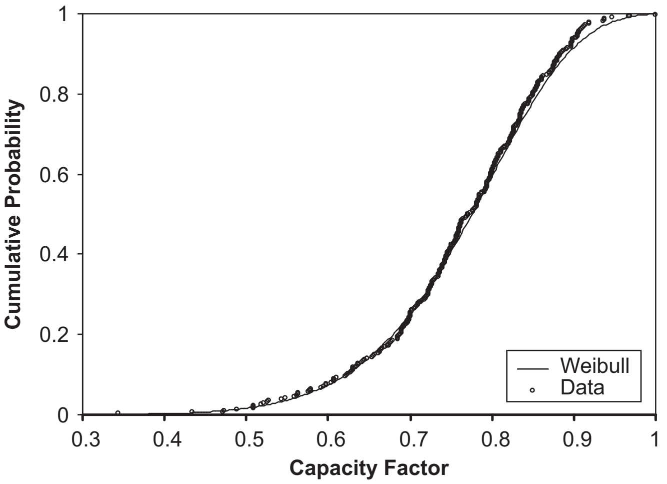

Fig. 9. Empirical cumulative distribution functions of the capacity factor data and the distribution of the Weibull (8.5, 0.81) with Trunc (0, 1).

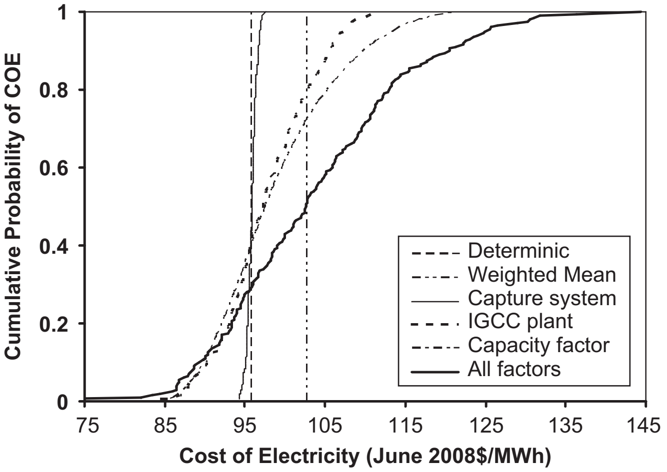

Fig. 10. Cumulative probability distribution of the COE of the IGCC plant with CCS based on the parameter distributions of Tables 4 and 5. Deterministic values are shown as vertical dashed lines.

85%) capacity factor over the life of the plant. While many modern power plants operate at high capacity factors for extended periods of time, we are not aware of any large coal-fired plants with a levelized capacity factor as high as 85% over a 20 to 30 year period, as assumed in many current cost studies. Thus, in this study we use historical capacity factor data for coal-fired power plants in the United States with capacities larger than 250 MW and age less than 30 years to estimate the capacity factor variability of an IGCC power plant. A Weibull distribution is found to fit the capacity factor data well, as shown in Fig. 9. The mean of that distribution, 75%, is used as our deterministic estimate of capacity factor.

Fig. 10 shows the effects of uncertainties on the COE, whose deterministic value is 95.8 $/MWh. Variability in the capacity factor alone causes the COE to vary from 85 to 121 $/MWh, with a 90-percentile range of 88–113 $/MWh. With other parameters fixed, there is a 60% probability that the plant would have a higher COE than the deterministic estimate. Thus, the assumed capacity factor contributes most to the total volatility of the COE in this analysis. Taking into account the uncertainty distributions for all factors (Tables 4 and 5), the COE varies from 72 to 144 $/MWh, with a 69% likelihood of exceeding the deterministic estimate. The mean value of the COE distribution is 102.8 $/MWh, which is 7 $/MWh higher than the deterministic result. As with capital costs, the inclusion of uncertainties for other factors held constant in this analysis (such as coal price) could further broaden the COE ranges reported here. In general, because the

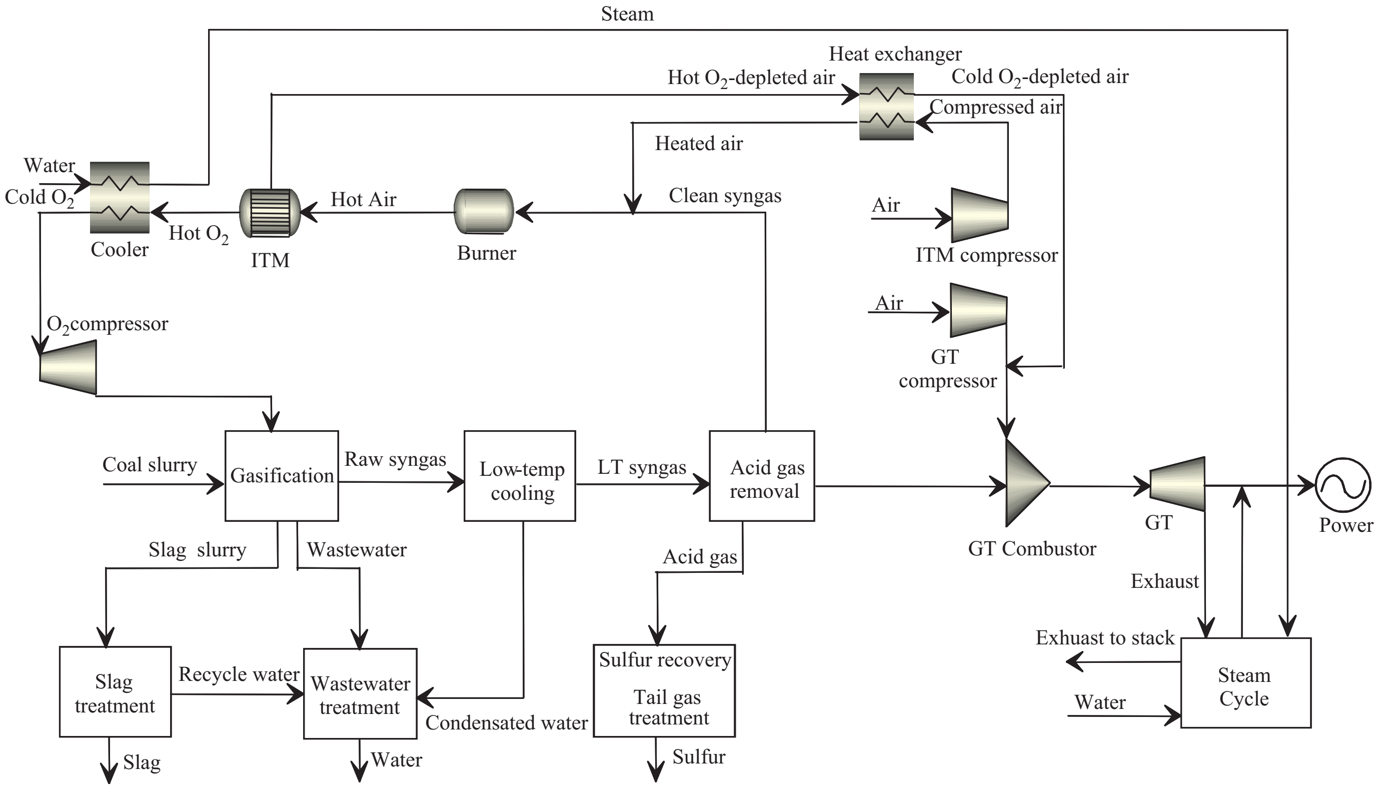

Fig. 11. A schematic of an IGCC system integrated with ITM oxygen production.

probability-weighted average COE takes into account many of the potential uncertainties in the IGCC plant cost estimate, it may be a more suitable measure than the deterministic result.

6. Advanced IGCC system designs

As a developing technology, there are opportunities for significant performance and cost improvements in IGCC plants and there are R&D programs in the US and elsewhere seeking those improvements. Over the next decade or so, gains are expected in the following five areas (Todd, 2002; O'Brien et al., 2004; Chase, 2001):

- Advanced gasifier concepts with higher efficiency and reliability, plus higher operating pressure for more economic CO_2 capture.
- Advanced ASUs with better thermal integration with IGCC systems.
- Syngas cleanup processes with less expensive particulate removal systems, including hot gas filtration.
- Advanced GTs with higher efficiency and ability to burn syngas and hydrogen-rich fuels.
- Optimal system integration with new technologies and components.

This section of the paper discusses two novel technologies that may influence the development and application of IGCC systems in the near future: (1) advanced ASUs based on ITM technology, and (2) advanced GTs based on the GE H-frame system.

Fig. 11 represents a schematic of an IGCC system with ITM oxygen production. In this design, the air fed into the ITM unit comes from a stand-alone compressor to allow more flexible operation. A simple performance model for the ITM assumes an operating temperature of 816 °C (1500 F), an air feed pressure of 1.38 MPa (200 psia), and a theoretical recovery of 50% (Air Product, 2002, 2004a, b; Prasas et al., 2002; Richards, 2001). Models of the WGS reactor and Selexol process for CO_2 capture also are integrated into this design to study the effects on performance and cost of a plant with CCS.

Table 6
Steam cycle parameters of the IGCC using GE H-frame gas turbine.

Parameter	HP throttle	Hot reheat	LP admission
Pressure (MPa, gage)	2400	2.38	0.21
Temperature (°C)	565	565	277

For IGCC plants using a GE H-frame GT, the steam cycle can operate at higher pressure and temperatures to achieve higher plant efficiency (Matta et al., 2000). The parameters of the three-pressure reheat steam cycle used in the H-frame simulation model are given in Table 6. Other technical and economic parameters for these case studies are the same as those given earlier in Table 1.

6.1. Case study results

Four IGCC designs were simulated: the baseline case with a current GE 7FA GT and conventional cryogenic air separation (case F GT); the conventional GT with ITM oxygen (case ITM); the GE H-frame GT with conventional cryogenic air separation (case H GT); and the GE H-frame GT with ITM (case ITM-H GT).

From Fig. 12, both the ITM unit and H-frame turbine each significantly improve the thermal efficiency of the IGCC system. A future IGCC plant incorporating both the ITM and H-frame turbine is projected to achieve a thermal efficiency as high as 43.5% (HHV basis). With CCS, the HHV efficiency is approximately

39.3%, which is about 1.2% points higher than the current IGCC reference system without CCS modeled earlier.

Based on recently published cost estimates for ITM and H-frame components, Fig. 13 shows that the estimated TCR of the advanced IGCC plant (case ITM-H GT) without CCS is approximately 10% less than the reference plant using current technology. With CO_2 capture, the capital cost of the advanced system is estimated to be18% higher than the current IGCC system without capture (compared to 38% higher cost for CCS using current technology). Due to the lower capital cost as well as higher plant efficiency, the COE for the advanced IGCC plant with CCS is projected to be 15% less than the current plant with CCS, as shown in Fig. 14.

Of course, there are also significant uncertainties associated with advanced IGCC designs and cost estimates, which remain to be quantified and analyzed in future work. Nonetheless, the initial analysis shown here indicates significant potential for reducing cost of low-carbon power systems based on coal gasification.

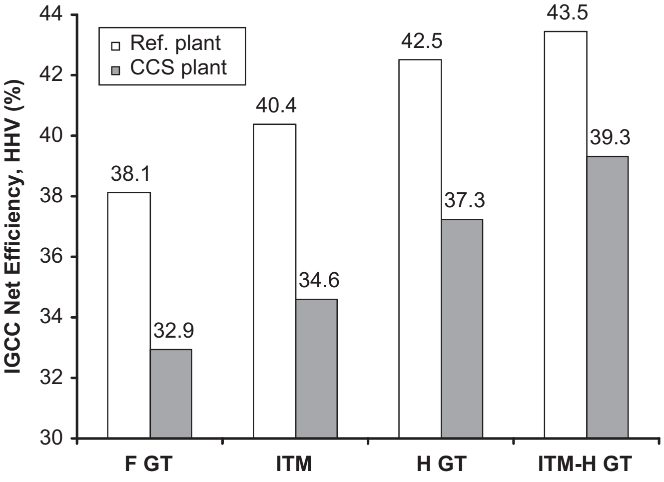

Fig. 12. Projected thermal efficiency of IGCC plants based on advanced technologies.

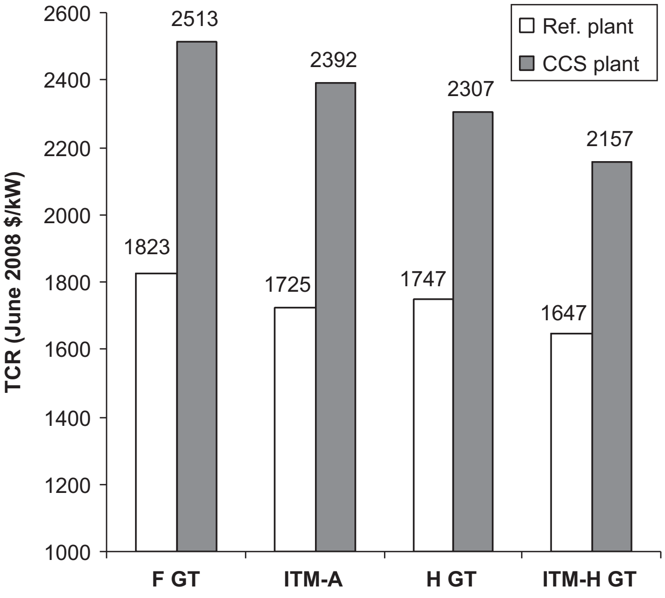

Fig. 13. Estimated TCR of IGCC plants based on advanced technologies.

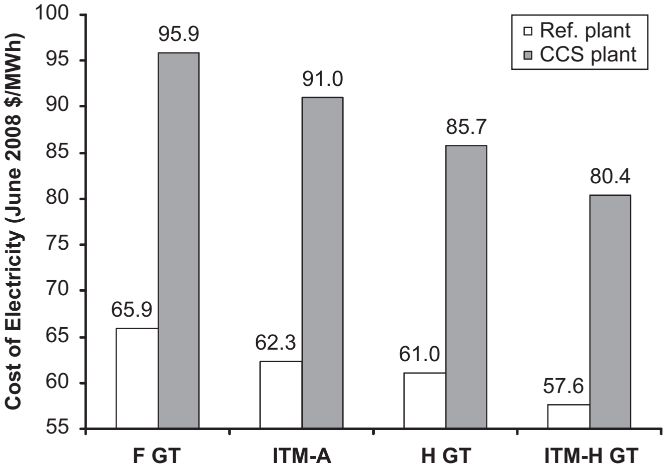

Fig. 14. Estimated COE of IGCC plants based on advanced technologies.

7. Conclusion

Using an integrated modeling framework for power plant analysis, several factors influencing the performance and cost of IGCC power plants with CO_2 capture and storage (CCS) were investigated. Four coals, including selections of bituminous, sub-bituminous and lignite, were used to investigate the effects of coal quality on the performance and cost of an IGCC system design employing a slurry-fed quench gasifier. Although this type gasifier is able to process all four coals, the coal rank significantly influenced the gasification efficiency, thermal efficiency and capital cost of the power plant. With low-rank coals, the total water input for the slurry-fed gasifier substantially lowered the gasification efficiency and increased total system cost.

The effects of different CO_2 capture efficiencies on auxiliary power requirements, thermal efficiency, capital cost, COE and CO_2 avoidance cost also were studied. For the case study plant, the CO_2 avoidance cost was lowest when the total CO_2 removal efficiency was approximately 90%, indicating this to be an optimal CO_2 capture efficiency for this plant design.

A probabilistic uncertainty analysis showed that most of the uncertainty in the total capital cost of an IGCC plant with CCS arose from uncertainty or variability in parameters for the basic IGCC system rather then the CO_2 capture system. The uncertainty analysis also highlighted the importance of capacity factor assumptions on the estimated COE of an IGCC plant.

Finally, a preliminary analysis of advanced IGCC systems showed that incorporation of advanced oxygen production and GT technologies holds promise to significantly improve the performance and reduce the cost of future IGCC systems with and without CCS. For plants with CCS, simulation results showed that these two advanced technologies can yield a system that is more efficient than a current plant without CCS, and reduce by approximately 50% the cost penalties currently associated with CCS. An analysis of the uncertainties associated with advanced IGCC designs remains for future research.

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