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Integration of Coal Utilization and Environmental Control in Integrated Gasification Combined Cycle Systems

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■ Integrated gasification combined cycle (IGCC) systems are a new generation of coal-fueled power generation technologies which embody the concept of integrated environmental control. IGCC systems are capable of significantly lower discharge rates of gaseous, liquid, and solid wastes relative to conventional coal-based systems. However, because few IGCC concepts have been demonstrated at a commercial scale, there is significant uncertainty regarding the technical and environmental performance of many of these systems in full-scale applications. Examples of IGCC system concepts involving both cold and hot gas cleanup are evaluated probabilistically to provide insights into the resulting differences in plant performance, emissions, and cost. For the specific technologies evaluated here, hot gas cleanup offers the potential for higher efficiency and lower cost than cold gas cleanup, but additional considerations may be required to reduce NO_x emissions.

Introduction

Integrated gasification combined cycle (IGCC) systems represent a promising new approach for the cleaner and more efficient use of coal for power generation, offering low levels of SO_2 and NO_x emissions along with benign solid wastes or byproducts, and zero or low wastewater discharges. A distinguishing feature of IGCC concepts is the type of fuel gas cleanup strategy employed. Typical designs for IGCC systems use "cold gas cleanup" (CGCU), including low-temperature removal of SO_2 and particulates from the coal syngas, sulfur byproduct recovery, and syngas moisturization to reduce NO_x formation in the gas turbine combustor. On-going research by the U.S. Department of Energy (DOE) and others is focused on developing dry physical and chemical hot gas cleanup (HGCU) techniques to reduce the efficiency penalty associated with syngas cooling (*1*). The cost and performance of IGCC systems with hot gas cleanup is expected to compare favorably with advanced alternatives for SO_2 and NO_x emission control in pulverized coal power plants.

In IGCC systems, environmental control is required not just to meet environmental regulations but also for proper plant operation. In particular, contaminants such as sulfur, particulates, and alkali must be removed prior to fuel gas combustion to protect the gas turbine components from erosion, corrosion, and deposition. Because of the close interactions among plant performance, environmental control, and cost, assessments of IGCC technology must be based on integrated analysis of the entire system.

Currently, however, there is limited commercial experience with IGCC power systems. The uncertain nature of the limited performance data for the first generation systems, coupled with uncertainties associated with alternative process configurations, suggests a strong need for systematic analysis of uncertainty in evaluating alternative designs and their environmental performance. Failure to fully account for uncertainties in process performance and cost analyses often results in misleading estimates for comparative analysis and planning, particularly for pioneer process plants (*2*). To explicitly represent uncertainties in IGCC systems, a probabilistic modeling approach has been developed. This approach features (1) development of sufficiently detailed engineering models of performance, emissions, and cost; (2) implementation of the models in a probabilistic modeling environment; (3) development of quantitative representations of uncertainties in specific model parameters based on literature review, data analysis, and elicitation of technical judgments from experts; and (4) modeling applications for cost estimating, risk assessment, and research planning.

Using the probabilistic modeling approach, this paper explores the interactions among environmental control, plant performance, and cost in IGCC systems. The study focuses on the implications of alternative fuel gas treatment technologies with respect to air, solid, and liquid discharges, plant efficiency, and plant cost.

IGCC Technology

An example of an IGCC system concept with CGCU is shown in Figure 1. The design basis for this system, which features fluidized-bed gasifiers, is described by Dawkins et al. (*3*). The fuel gas cleanup system is representative of the technology employed in the Cool Water demonstration plant (*4*). Coal is partially combusted with oxygen and gasified with steam in a reducing atmosphere to yield a fuel gas containing CO and H_2 as key constituents. Oxygen for the gasifier is provided by an air separation plant. Steam is supplied from the plant steam cycle. The hot fuel gas is cooled in a steam generator and then enters a low-temperature cooling section. As part of low-temperature cooling, nearly all of the particulate matter and ammonia in the fuel gas is removed by wet scrubbing. The fuel gas, at a temperature of about 100 °F, then enters a Selexol acid gas removal unit, where H_2S, the primary sulfur species in the fuel gas, is selectively removed. The clean fuel gas is then combusted in a gas turbine combined cycle system. A portion of the electrical output from the generators must be used to power equipment in the plant, most notably the air separation plant.

Environmental Performance for Cold Gas Cleanup. The approach to emissions control in an IGCC plant is fundamentally different from a pulverized coal-fired power plant. Emission control strategies focus on the fuel gas, which is pressurized (typically 300–500 psi) and has a substantially lower volumetric flow rate than the flue gas, which flows near atmospheric pressure, of coal-combustion power plants. Furthermore, sulfur in the fuel gas is in reduced form (mostly H_2S), which can be removed by a variety of commercially available processes (*5*). Typically, H_2S and COS are removed using a Selexol or similar process, and the concentrated acid gas is then processed for elemental sulfur recovery. Removal of ammonia in the fuel gas in wet scrubbing systems reduces substantially the amount of fuel-bound nitrogen in the fuel gas. In conventional gas turbine combustors, most of the fuel-bound nitrogen is converted to NO_x. Thermal NO_x emissions are controlled either by moistening the fuel gas or by gas turbine combustor steam injection to reduce the flame temperature.

In the Cool Water IGCC demonstration plant, which operated from 1984 to 1989, air emissions with low-sulfur coal were reported to be 0.06 lb of NO_2/MMBtu, 0.07 lb

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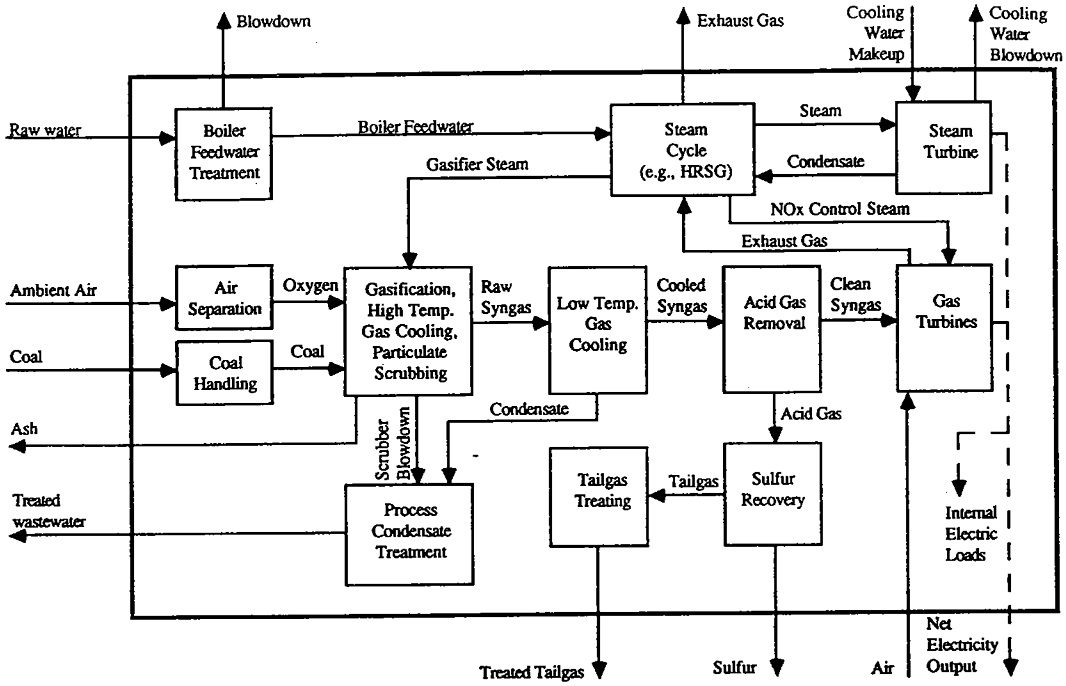

Figure 1. Schematic of oxygen-blown fluidized-bed gasifier IGCC system with cold gas cleanup (conventional design).

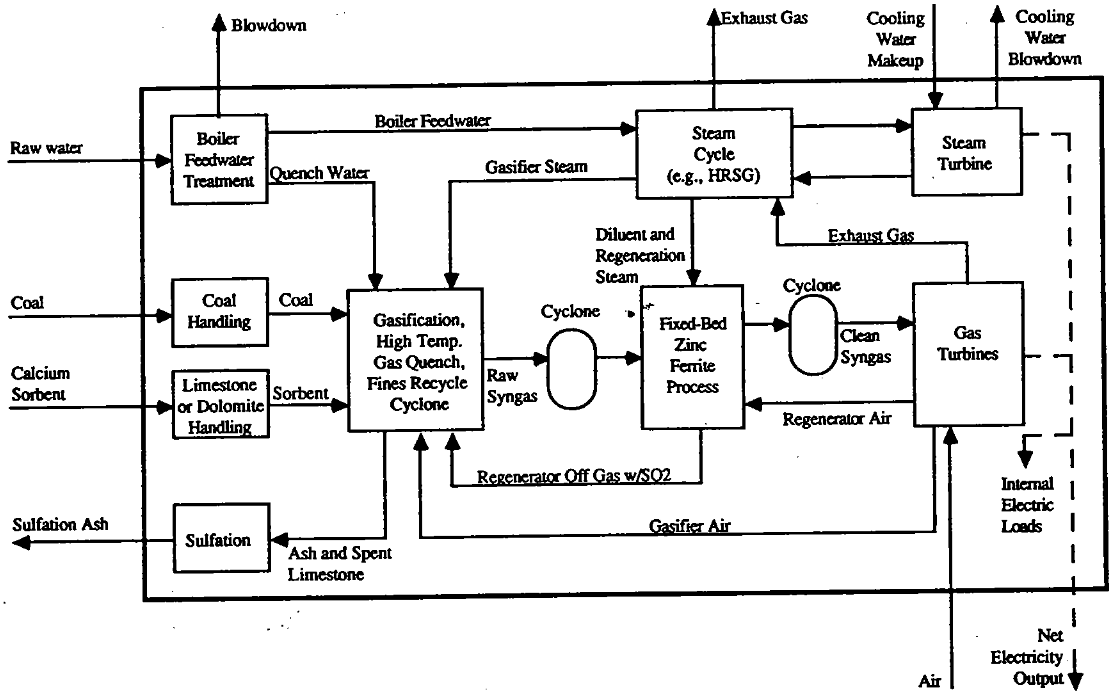

Figure 2. Schematic of air-blown fluidized-bed gasifier IGCC system with hot gas cleanup (advanced design).

of SO_2/MMBtu, and 0.008 lb of particulate matter (PM)/MMBtu (*4*). All three rates are well below federal New Source Performance Standard (NSPS) levels for conventional coal-fired power plants.

In IGCC systems with fuel gas cooling, liquid condensates from the high-temperature fuel gas must be removed and treated prior to discharge. Additionally, blowdown from the fuel gas wet scrubber must also be treated. These wastewater streams are in addition to the steam cycle and cooling water cycle blowdown streams typical of modern thermal power stations.

IGCC solid wastes include gasifier bottom ash and particulate cake from the scrubber system. These solid wastes are suitable for landfilling. Compared to a pulverized coal-fired plant with flue gas desulfurization (FGD), the solid waste burden from an IGCC system is reduced by the production of an elemental sulfur byproduct and the lack of a spent sorbent waste.

Hot Gas Cleanup. So-called "hot gas cleanup" systems reduce or eliminate the need for syngas cooling prior to particulate removal and desulfurization. This improves the plant thermal efficiency and reduces or eliminates the need for heat exchangers and process condensate treatment. Thus, HGCU offers a more highly integrated system in which a major wastewater stream is eliminated.

An example of an air-blown fluidized-bed gasifier IGCC system with HGCU is shown in Figure 2. The schematic represents process elements based on design and cost studies prepared for the Gas Research Institute (*6*, *7*) and for DOE (*8*, *9*). The primary features of this design, compared to the IGCC system with CGCU, are as follows: (1) elimination of an oxygen plant by using air, instead of oxygen, as the gasifier oxidant; (2) in-situ gasifier desulfurization with limestone; (3) external (e.g., not in the gasifier) desulfurization using a high-temperature removal process; (4) high-efficiency cyclones for particulate removal; (5) elimination of heat exchangers for fuel gas cooling at gasifier exit; (6) elimination of sulfur recovery and tail gas treating; and (7) addition of a circulating fluidized-bed boiler for sulfation of spent limestone (to produce an environmentally acceptable waste) and conversion of carbon remaining in the gasifier ash. The design basis assumed here includes the use of water quench, rather than heat exchange, for high-temperature syngas cooling from 1850 °F at the gasifier outlet to 1100 °F prior to gas cleanup. Therefore, there is no knockout drum for process condensate removal. The clean fuel gas is then combusted in a gas turbine modified to fire low-Btu coal gas.

In-bed desulfurization is expected to result in 90% sulfur capture within the gasifier. The external zinc ferrite desulfurization process is expected to reduce the sulfur content of the syngas to 10 ppmv, resulting in low SO_2 emissions from the gas turbine combustor. Upon regeneration, the sulfur captured by the zinc ferrite sorbent is evolved in an offgas containing SO_2, which is recycled to the gasifier for capture by the calcium-based sorbent.

Thermal NO_x emissions are expected to be quite low for air-blown IGCC. However, the HGCU system assumed here does not remove fuel-bound nitrogen from the fuel gas. Thus, fuel-bound NO_x emissions may pose a concern. Alternative NO_x control technologies, such as rich/lean staged combustion and/or postcombustion selective catalytic reduction (SCR), are under consideration for future applications if fuel NO_x emissions must be reduced more stringently.

The IGCC/HCGU system is not expected to have any liquid discharges other than those normally associated with the steam cycle and plant utilities. The solid waste streams include bottom ash (which includes spent limestone sorbent), fines collected in the secondary cyclones, and spent zinc ferrite sorbent. However, it is assumed that the spent zinc ferrite sorbent is returned to the manufacturer for reprocessing.

Commercial Status. IGCC systems are not yet commercialized. Several demonstration plants have been built, notably the Cool Water plant in California (*4*) and the Dow Chemical IGCC plant in Louisiana (*10*). These systems employ CGCU, which is considered to be a "baseline" technology representing the lowest technical and economic risks for future IGCC systems. HGCU systems have not yet been demonstrated at a commercial scale, although testing of process development unit (PDU) scale systems has been sponsored by DOE. Thus, there is still considerable uncertainty in predicting the commercial-scale performance and cost of IGCC systems with HGCU.

Process Models

To characterize the effect of alternative environmental control system designs on IGCC performance and cost, process models of the IGCC systems given in Figures 1 and 2 were developed. A number of IGCC performance models have been developed by DOE's Morgantown Energy Technology Center (DOE/METC) using ASPEN, a chemical process simulator (*11, 12*). Two of these models were adapted for this study. In addition, new cost models for these two technologies were developed.

Performance Models. IGCC performance models originally developed by DOE/METC are comprised of approximately 80-unit operation blocks and were tested against published design studies (*11*). For this work, the ASPEN performance models were modified to more completely account for process performance, environmental discharges, and auxiliary power consumption using new unit operation blocks, FORTRAN blocks, design specifications, and chemical species components (as appropriate). These modifications include the addition of the sulfation process area, estimation of ammonia yield in the gasifier, estimation of fuel gas consumption for reductive regeneration in the zinc ferrite process, characterization of NO_x emissions, and additional detail regarding the gas turbine, including blade and vane cooling requirements (*13, 14*).

Cost Models. To evaluate the economics of selected IGCC systems, new cost models, which estimate capital and annual costs, have been developed and directly coupled to the modified METC performance models. Analytical relationships between direct capital costs and key performance and design parameters were developed from approximately 30 conceptual design studies, typically based on regression analysis. The total capital cost is calculated based on direct, indirect, contingency, construction, startup, and initial inventory costs, in accordance with typical utility costing practice. Fixed and variable operating costs are calculated based on percentages of capital costs, operating labor requirements, and the consumption rates of consumables. The levelized cost of electricity is calculated using standard economic and financial parameters. These models have been tested against published studies (*15*).

The cost models for each IGCC system are sensitive to approximately 100 performance, design, and economic parameters. The performance and cost models are modular. Process areas that are common to both IGCC systems are modeled consistently, permitting comparative analysis of the alternative technologies.

Characterizing Uncertainties

Nearly all analyses of energy and environmental control technologies that are still in the research phase involve uncertainties. The most common approach to handling uncertainties is either to ignore them or to use simple "sensitivity" analysis. In sensitivity analysis, the value of one or a few model input parameters are varied, usually from "low" to "high" values, and the effect on a model output parameter is observed. Meanwhile, all other model parameters are held at their "nominal" values. In practical problems with many input variables which may be uncertain, the combinatorial explosion of possible sensitivity scenarios (e.g., one variable "high", another "low", and so on) becomes unmanageable. Furthermore, sensitivity analysis provides no insight into the *likelihood* of obtaining any particular result.

A more robust approach is to represent uncertainties in model parameters using probability distributions. Such an approach has been applied by Frey and Rubin in the analysis of advanced SO_2/NO_x control systems for coal-fired power plants (*16, 17*) and of an air-blown Lurgi-gasifier-based IGCC system with hot gas cleanup (*18*). The details of the procedure for probabilistic analysis are summarized by Frey and Rubin (*19*) and elaborated elsewhere (*14*). Morgan and Henrion (*20*) provided a more general overview of uncertainty analysis techniques. By use of Monte Carlo or similar simulation techniques, simultaneous uncertainties in any number of model input parameters can be propagated through a model to determine their combined effect on model outputs.

The development of ranges and probability distributions for model input parameters in the case studies reported here is based on information available in published studies, statistical data analysis, and/or the judgments of process engineers with relevant expertise. As detailed by Frey (*13*),

Table I. Summary of the Gasifier Base Case Parameter Values and Uncertainties for the Oxygen-Blown KRW-Based IGCC System with Cold Gas Cleanup (Conventional Design)

description	units	deterministic values	probabilistic values distribtn	probabilistic values params[a]
gasifier pressure	psia	465		
gasifier temp	°F	1850		
overall carbon conversn	wt % of feed coal carbon	95	triangular	75–95 (95)
oxygen/carbon ratio	lb mol O_2/C	0.34	uniform	0.33–0.35
steam/oxygen ratio	lb mol H_2O/O_2	1.35	uniform	1.1–1.6
sulfur retention in bottom ash	mol % of inlet sulfur	15	triangular	10–20 (15)

[a] For uniform distributions, the lower and upper bounds are given. For the triangular distribution, the mode is given in parentheses.

Table II. Summary of the Gasifier Base Case Parameter Values and Uncertainties for the Air-Blown KRW-Based IGCC System with Hot Gas Cleanup (Advanced Design)

description	units	deterministic values	probabilistic values distribtn	probabilistic values params[a]
gasifier pressure	psia	465		
gasifier temp	°F	1900	triangular	1900–1950 (1900)
overall carbon conversn	wt % of feed coal carbon	95	triangular	90–97 (95)
oxygen/carbon ratio	lb mol O_2/C	0.46	triangular	0.45–0.47 (0.46)
steam/oxygen ratio	lb mol H_2O/O_2	0.45	uniform	0.4–0.5
sulfur retention in bottom LASH	mol % of inlet sulfur	90	triangular	85–95 (90)
limestone calcium/sulfur ratio	lb mol Ca/S	2.6	triangular	2–2.8 (2.6)
gasifier ammonia yield	equiv fraction of coal N to NH_3	0.10	triangular	0.005–0.10 (0.10)

[a] For uniform distributions, the lower and upper bounds are given. For the triangular distribution, the mode is given in parentheses.

uncertainties were assigned to 41 engineering model parameters for the IGCC system with CGCU. For the IGCC system with HGCU, 46 parameters were treated probabilistically. As examples, the uncertainties assumed for the gasification process area of the systems with CGCU and HGCU are shown in Tables I and II, respectively. Uncertainties were also ascribed to other process area performance parameters (e.g., gas turbine, sulfation, and zinc ferrite), capital cost model parameters, process area direct cost estimates, maintenance cost factors, variable operating cost parameters (e.g., unit costs of consumables, waste disposal, and byproducts), and regression model error terms. Regression models are used to characterize the direct cost of several process areas as a function of key performance parameters and to estimate auxiliary power requirements for some process areas. The performance and cost models were run in ASPEN using a new probabilistic modeling environment to estimate the resulting uncertainties in model output variables (*21*). Probabilistic simulations were performed using Latin hypercube sampling, a variance reduction technique based on a stratified sampling approach compared to random Monte Carlo sampling (*22*, *23*).

Results for Single Processes

Case study results of both IGCC systems are first reported individually. Then, the two systems are compared probabilistically. The results reported here focus on characterizations of plant emissions, performance, and cost and their associated uncertainties.

Case 1: IGCC with Cold Gas Cleanup. The results for plant thermal efficiency, total capital cost, and the cost of electricity are shown as cumulative distribution functions (cdfs) in Figures 3–5, respectively, for a 650-MW plant using 3.86% sulfur Illinois No. 6 coal. Additional details regarding simulation results are reported by Frey (*13*).

Because of the negative skewness of the assumption regarding uncertainty in the gasifier carbon conversion efficiency (see Table I), the plant thermal efficiency is also negatively skewed. The mode of the uncertainty in carbon conversion was taken to be at the upper bound of the distribution, and the modal value was used as the "best guess" in the deterministic analysis. The modal value of

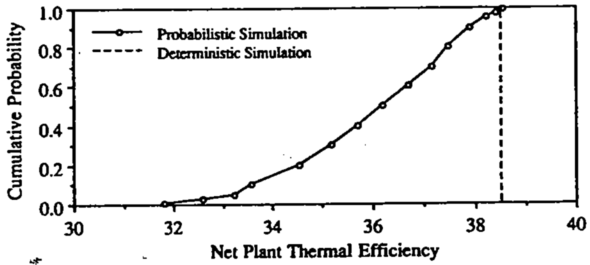

Figure 3. Comparison of deterministic and probabilistic results for the net plant thermal efficiency of the oxygen-blown KRW-based system (CGCU).

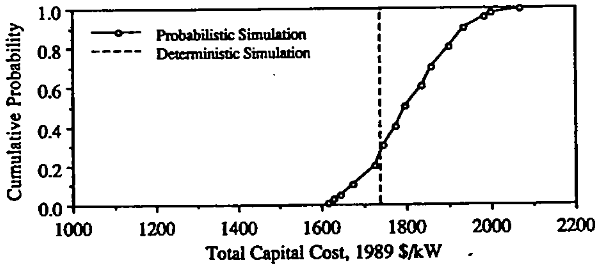

Figure 4. Comparison of deterministic and probabilistic results for the total capital cost of the oxygen-blown KRW-based system (CGCU).

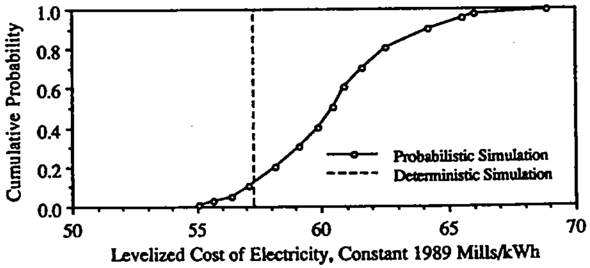

Figure 5. Comparison of deterministic and probabilistic results for the cost of electricity of the oxygen-blown KRW-based system (CGCU).

95% carbon conversion is also widely assumed in conceptual design studies [e.g., Dawkins et al. (*3*) and Gallaspy et al. (*24*)]. However, scale-up risks and inherent design limitations for the fluidized-bed gasifier may lead to lower carbon conversions and, hence, lower plant efficiencies, than commonly assumed (*25*).

Although the oxygen-blown fluidized-bed gasifier-based system considered here represents elements of "conventional" IGCC technology, particularly the cold gas cleanup system, there is still considerable performance and cost risk associated with the gasification process area. Uncertainty in both plant performance and capital cost-related parameters result in the uncertainty in total capital cost. Compared to the deterministic best guess estimate, which includes values of both process and project contingency factors typically assumed in the literature (*15*), there is a 70% probability of cost overrun. In contrast, contingency factors are not used in the probabilistic analysis; instead, explicit characterizations of uncertainty for process area direct costs and project construction costs are used. While estimates of uncertainties in capital cost parameters, including process area direct costs, were based on symmetric probability distributions, the underlying negative skewness of the major measures of plant performance, such as efficiency and coal consumption, shifts the resulting capital cost uncertainty toward higher values than the best guess. Thus, the interactions between performance and cost uncertainties, considered here, are shown to have important implications for capital cost, and the results indicate that typical contingency factors inadequately account for potential cost growth. These results are consistent with a Rand study of corporate cost-estimating practices which concluded that contingency factors are often badly underestimated (*26*).

The difference between the deterministic and probabilistic estimates of cost are more pronounced for the total cost of electricity. While typical cost-estimating practices include capital cost contingency factors, there is no accepted systematic notion of contingencies with respect to fixed and variable operating costs. Performance uncertainties play a key role in driving uncertainty in total cost. The negative skewness of the carbon conversion rate leads to positive skewness in consumable requirements such as fuel (coal) and process water and in the ash disposal rate. Furthermore, the unit costs associated with both ash disposal and byproduct recovery were assumed to have skewed distributions. In the case of ash disposal, it was assumed that costs could go up, but not down, due to increasingly stringent landfill requirements and associated difficulties in siting and complying with regulations. In the case of byproduct sale price, a negative skewness was assumed, representing the likelihood that market conditions at any given location in the United States may not be favorable to obtaining the maximum world market price. Thus, cost-related uncertainties are also important contributors to uncertainty in total costs.

The interactions among uncertainties in performance, capital cost, maintenance cost, and unit cost uncertainties result in the difference between the deterministic and probabilistic estimates for cost of electricity. Here, the deterministic estimate has an associated 90% probability of cost overrun. Furthermore, while the cost of electricity could be perhaps 2 mills/kWh less than the best guess, it could be over 10 mills/kWh (15–20%) higher. This analysis has permitted explicit characterization of the systematic error in the deterministic cost estimate.

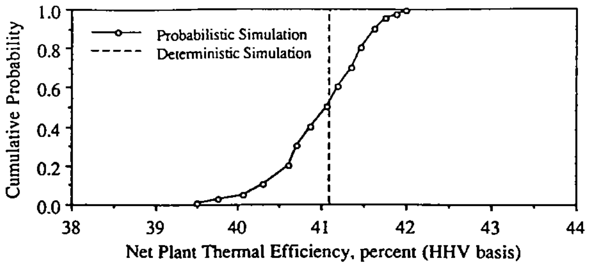

Figure 6. Comparison of deterministic and probabilistic results for the net plant thermal efficiency of the air-blown KRW-based system (HGCU).

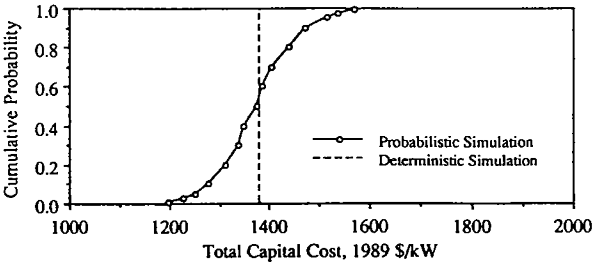

Figure 7. Comparison of deterministic and probabilistic results for the total capital cost of the air-blown KRW-based system (HGCU).

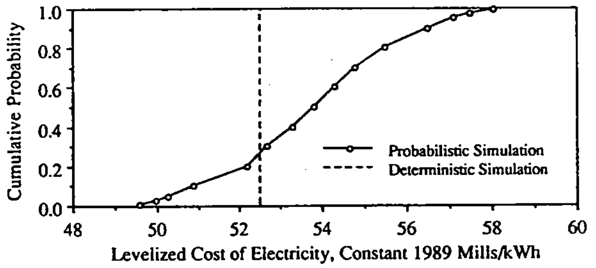

Figure 8. Comparison of deterministic and probabilistic results for the cost of electricity of the air-blown KRW-based system (HGCU).

Case 2: IGCC with Hot Gas Cleanup. The results for plant thermal efficiency, total capital cost, and the cost of electricity for the IGCC/HGCU system are shown as cdfs in Figures 6–8, respectively, for a 730-MW plant using 3.86% sulfur Illinois No. 6 coal. Additional details regarding these and other results are reported by Frey (*13*). For many of the results, the deterministic, median, and mean values are similar, indicating that uncertainties in this process are not strongly skewed, as for case 1.

The uncertainty in plant thermal efficiency is shown in Figure 6 compared to the deterministic estimate. The 90% probability interval covers a range of less than two percentage points. The distribution is slightly skewed toward lower values, due to the negative skewness of the uncertainty in carbon conversion. The range of uncertainty is substantially less than for case 1, due in part to the lower uncertainty in gasifier carbon conversion and the use of a boiler to combust unconverted carbon and oxidize CaS in the spent sorbent leaving the gasifier. In the case 1 design, unconverted carbon from the gasifier is disposed of with the bottom ash.

The SO_2 emission rate for the HGCU system is substantially lower than that of the CGCU system. The mean SO_2 emission rate for the CGCU system is 0.33 lb/10^6 Btu of coal input, whereas the emission rate for the HGCU system is less than 0.02 lb/10^6 Btu. However, the mean NO_x emission rate for the system with HGCU is 0.49 lb/10^6 Btu of coal input, compared to only 0.13 lb/10^6 Btu for the system with CGCU. To reduce NO_x emissions, postcombustion emission control using SCR or the development of advanced combustors that minimize fuel NO_x formation may be required. While these options are not considered in the present study, SCR is the nearest term alternative. However, SCR would increase costs and modestly reduce plant efficiency due to auxiliary power requirements and increased gas turbine back-pressure.

In Figure 7, the uncertainty in total capital cost is compared to the deterministic estimate. Unlike the previous case study, the deterministic estimate, which includes process and project contingency factors, coincides with the median value of the probabilistic simulation. Thus, there is a 50% chance of a cost overrun associated with the deterministic estimate of \$1380/kW. Because the performance and capital cost parameter uncertainties were symmetric or only moderately skewed, the uncertainty in capital cost is approximately symmetric.

In spite of the agreement between the deterministic and probabilistic capital cost results, the two analyses do not agree with respect to the cost of electricity, as seen in Figure 8. There is a 75% probability that the cost will be higher than the deterministic estimate. In the probabilistic analysis, the uncertainties in the maintenance cost of the gas turbine, zinc ferrite, and sulfation process areas were assumed to be positively skewed. Also the unit costs of limestone and ash disposal were assumed to be positively skewed. These assumptions affect fixed and variable operating cost and, in turn, the cost of electricity.

From other analyses (*13*), it is clear that performance-related uncertainties are a relatively minor component of overall cost uncertainty for this technology. Furthermore, while the variance in the result for the cost of electricity is strongly influenced by uncertainties in capital cost, it is the uncertainties in operating and maintenance costs that are responsible for the shift in the central tendency of the distribution compared to the deterministic estimate. Thus, the risk of cost growth is associated primarily with the operating costs of the hot gas cleanup system.

Comparative Analysis

The preceding sections have focused on individual case studies of each IGCC technology. In this section, the two systems are compared in the face of uncertainty. These comparisons are based on key measures of plant performance, emissions, and cost. For both technologies, additional research is likely to reduce uncertainties in both performance and cost. Therefore, sensitivity cases based on alternative assumptions regarding process uncertainties are considered.

Comparing Alternatives Probabilistically. Comparisons between the two technologies are based on probabilities distributions for the *differences* in performance, emissions, and cost. When systems are compared probabilistically, it is necessary to account for any underlying correlations between the two systems. Several of the variables common or similar to both flow sheets are assumed to be completely correlated. Examples of these include uncertainty in the direct capital cost of the gas turbine and general facilities process areas, the standard errors of the regression models used to estimate the heat recovery steam generator and steam turbine direct costs, the cost of ash disposal, and several indirect capital cost parameters.

Other uncertain parameters that are similar between the systems are assumed to be uncorrelated. For example, although the performance of the two gasifiers can be characterized using similar parameters, the gasifier operating modes are sufficiently different that no correlations are assumed to exist between them.

Based on the pairing of input uncertainties, the results of probabilistic simulations for the two IGCC systems also were paired, sample by sample. For each sample pair, the results from one system were subtracted from the results of the other system. The resulting sets of sample *differences* were used to construct cdfs for the performance, emissions, and cost savings of the advanced technology compared to the conventional technology.

The risk that the new technology will be more expensive can be quantified using the partial mean of the cost difference distribution for all negative values. The downward and upward partial means are defined as (*27*)

$$\mu_d(x) \equiv \int_{-\infty}^{0} x\, f(x)\, dx \tag{1}$$

$$\mu_u(x) \equiv \int_{0}^{\infty} x\, f(x)\, dx \tag{2}$$

where $f(x)$ is the probability density function for the random variable x. Buck and Askin (*27*) defined the conditional partial mean based on the partial mean and the probability that a loss or gain has occurred. The expected value of a loss, given that a loss has occurred is

$$\mu_{d|x<0}(x) \equiv \mu_d(x)/P(x<0) \tag{3}$$

where $P(x<0)$ is the probability that the random variable x has a value less than zero. The expected value of a gain, given that a gain has occurred, is defined similarly.

Effects of Uncertainty Assumptions. Additional research on each of the IGCC systems may reduce the magnitude of uncertainties in these technologies. Reduction in the uncertainties in one or both technologies affects the probability distribution for the differences between the two. Therefore, several comparisons are made for each key output variable, based on alternative combinations of base case and reduced uncertainty assumptions for the two technologies. Details of the assumptions are discussed elsewhere (*13*). The multiple comparisons provide insight into whether the advantages of one technology are robust when the underlying assumptions change.

Modeling Results. For base case uncertainty assumptions, the correlation between the total capital cost of the two systems was 0.75, and the correlation between total costs was 0.54. Because of the positive correlation between the two systems, the uncertainty in the cost differences is smaller than if the costs were completely uncorrelated.

The statistics associated with the differences in plant efficiency, emissions, and cost are summarized in Table III. From the table, it is clear that the air-blown system with HGCU is either markedly better or notably worse than the conventional system with CGCU for a given attribute; there is little ambiguity regarding the comparisons.

The system with HGCU holds clear advantages with respect to plant efficiency, total capital cost, and cost of electricity. It is likely to have lower water consumption and lower fixed operating cost. However, it is certain to have higher variable operating cost and is also likely to have higher CO_2 emissions in spite of its higher efficiency. As previously discussed, the advanced system with HGCU has substantially lower SO_2 emissions than the conventional system, but it also has higher NO_x emissions.

The efficiency advantage of the system with HGCU is attributable to the reduction in fuel gas cooling, a lower auxiliary power requirement for oxidant feed, and combustion of unconverted carbon in the gasifier ash to generate steam in the sulfation unit. However, in spite of substantially higher efficiency, the air-blown system has over an 80% probability of higher CO_2 emissions because of the use of a limestone sorbent for desulfurization in the gasifier. As the limestone is calcined in the gasifier, CO_2

Table III. Results of Comparative Studies between Conventional and Advanced IGCC Systems for Different Uncertainty Assumptions[a]

description of comparison[b]	probability of a loss, %	downward partial mean	expected value of a loss	expected value of a gain	mean
plant efficiency, %					
HGCU base vs CGCU base	0	0	0	5.0	5.0
HGCU reduced vs CGCU base	0	0	0	5.1	5.1
HGCU base vs CGCU reduced	0	0	0	3.9	3.9
HGCU reduced vs CGCU reduced	0	0	0	4.0	4.0
CO_2 emissions, lb/kWh					
HGCU base vs CGCU base	89	0.042	0.048	0.009	−0.041
HGCU reduced vs CGCU base	95	0.039	0.041	0.006	−0.039
HGCU base vs CGCU reduced	83	0.031	0.037	0.009	−0.029
HGCU reduced vs CGCU reduced	89	0.027	0.030	0.004	−0.027
ash disposal rate, lb/kWh					
HGCU base vs CGCU base	100	0.153	0.153	0	−0.153
HGCU reduced vs CGCU base	100	0.153	0.153	0	−0.153
HGCU base vs CGCU reduced	100	0.155	0.155	0	−0.155
HGCU reduced vs CGCU reduced	100	0.155	0.155	0	−0.155
total capital cost, 1989 $/kW					
HGCU base vs CGCU base	0	0	0	428	428
HGCU reduced vs CGCU base	0	0	0	425	425
HGCU base vs CGCU reduced	0	0	0	417	417
HGCU reduced vs CGCU reduced	0	0	0	414	414
fixed operating cost, 1989 $/kW-yr					
HGCU base vs CGCU base	9	0.16	1.77	8.84	7.88
HGCU reduced vs CGCU base	1	0.009	0.9	9.73	9.63
HGCU base vs CGCU reduced	3	0.03	1.1	8.39	8.10
HGCU reduced vs CGCU reduced	0	0	0	9.85	9.85
variable operating cost, 1989 mills/kWh					
HGCU base vs CGCU base	100	2.5	2.5	0	−2.5
HGCU reduced vs CGCU base	100	2.5	2.5	0	−2.5
HGCU base vs CGCU reduced	100	3.0	3.0	0	−3.0
HGCU reduced vs CGCU reduced	100	3.0	3.0	0	−3.0
levelized cost of electricity, constant 1989 mills/kWh					
HGCU base vs CGCU base	0	0	0	6.6	6.6
HGCU reduced vs CGCU base	0	0	0	6.9	6.9
HGCU base vs CGCU reduced	0	0	0	5.9	5.9
HGCU reduced vs CGCU reduced	0	0	0	6.2	6.2

[a] The comparison is from the perspective of the advanced system with hot gas cleanup (HGCU). Thus, "loss" means that the advanced system will be worse in a given attribute than the conventional system with cold gas cleanup (CGCU) (e.g., lower efficiency, higher emissions, and higher cost). [b] HGCU, advanced system with hot gas cleanup; CGCU, conventional system with cold gas cleanup. The four sets of results for each parameter show the sensitivity to different uncertainty assumptions. "Base" refers to base case uncertainties for each technology. "Reduced" refers to reduced uncertainties that might be obtained from targeted research. Details of all uncertainty assumptions appear in Frey (*13*).

is released. The carbon retained in the bottom ash that is combusted in the sulfation unit is an additional source of CO_2 emissions. In the conventional system, unconverted carbon is sequestered in the bottom ash.

Because of the additional burden of spent limestone sorbent in the air-blown system, the ash disposal requirement is higher than for the conventional system. The CGCU system converts sulfur in the fuel gas to elemental sulfur, thereby reducing the solid waste burden and generating a saleable byproduct.

The air-blown IGCC system with HCGU has lower capital cost due to the reduction in equipment associated with fuel gas cooling and cleanup, and the substitution of a boost air compressor for the air separation plant. The expected cost savings is over $400/kW, regardless of the different uncertainty assumptions.

There is a low probability that the fixed operating cost of the air-blown system could be higher than for the conventional system due to the risks of contaminant-related problems in the HGCU system. However, for all assumptions regarding uncertainties, the air-blown system has higher operating costs than the conventional system. These costs are associated with limestone and zinc ferrite sorbents and disposal of spent limestone sorbent and ash.

Overall, the advanced system yields total cost savings over the conventional system. The uncertainty in this savings is shown graphically in Figure 9 for four cases with and without additional research to reduce uncertainties. While research on the conventional system will tend to reduce the expected cost savings of the advanced systems, the cost savings remain substantial nonetheless. Savings of over 2 mills/kWh are obtained from the analysis for all cases. The mean cost savings are typically 6 mills/kWh, with a chance that cost savings could be 10 mills/kWh or higher. Note that these estimated savings are for an established "fifth-of-a-kind" commercial plant. For earlier "pioneer" plants, different uncertainties would be expected.

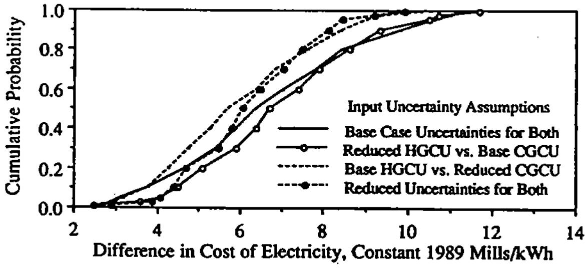

Figure 9. Effect of uncertainty assumptions on cost of electricity savings for air-blown IGCC system with HGCU compared to oxygen-blown system with CGCU.

The advantage of the air-blown system with hot gas cleanup is diminished as the plant capacity factor increases, because of its higher variable operating costs. However, the total costs for the system with HGCU are sufficiently low that it continues to have a 100% probability of cost savings even at a 90% capacity factor.

The results presented here are specific to the process configurations and modeling assumptions used in the case studies. For example, the results may differ if postcombustion SCR NO_x control is required for the system with HGCU. The performance and cost impacts of SCR will be evaluated as part of future work. Furthermore, other promising IGCC system concepts, with either cold or hot gas cleanup, may differ in performance and cost from the specific flow sheets considered here. Therefore, the results here should not be generalized to other IGCC systems.

Conclusions

Assessments of advanced process technologies that are in early stages of development should be based on a proper understanding and representation of uncertainties. For the two IGCC systems evaluated here, deterministic estimates based on single best guess values substantially underestimated total costs compared to more detailed probabilistic estimates. Thus, probabilistic analysis has implications for the development of more realistic cost estimates that capture the notion of "cost growth" often experienced with innovative process technologies. The case studies presented here include uncertainty estimates based on a combination of elicited expert judgments, data analysis, and preliminary judgments by the authors. The results of these case studies can be used to prioritize parameters for which improved estimates regarding uncertainties are warranted.

In the technology-specific comparisons presented here, the alternative environmental control system designs had a substantial effect on plant performance, emissions, and cost. The advanced system with hot gas cleanup offered advantages over a system with cold gas cleanup with respect to plant efficiency, SO_2 emissions, capital cost, and total cost. However, because of the sorbent requirements for SO_2 removal, the solid waste burden of the advanced system was substantially higher than for the conventional system. Also, the advanced system exhibited significantly higher operating costs. The robustness of these results to different probabilistic uncertainty assumptions provides additional confidence in the qualitative conclusions. However, additional changes in the advanced system design may be required to reduce NO_x emissions to acceptable levels. The additional costs associated with either combustor design modifications or postcombustion emission controls, if required, could affect the qualitative comparisons reported here. The ability to rigorously test both the implications and interactions of a large number of variables using probabilistic methods is a powerful tool for technology evaluation and research planning.

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