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Project Summary

Costs for Advanced Coal Combustion Technologies

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This project was undertaken to evaluate the development status of advanced coal combustion technologies and to prepare performance and economic models for their application to electric utility plants. The technologies addressed were atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC). The development status was also reviewed for pulverized coal-fired boilers incorporating supercritical steam cycles. Although advanced combustion technologies are attractive due to decreased SO_2 and NO_x emission characteristics and potentially higher generating efficiencies, full commercial readiness does not appear feasible before the mid to late 1990s. Capital cost estimates for a new plant at 500-MW ranged from $1,250 to $1,910/kW (in 1988 dollars) for the advanced technologies and from $1,380 to $1,810/kW for the conventional systems. Capital cost estimates for PFBC (turbocharged cycle) and conventional plants with add-on SO_2 and NO_x controls were within 4 % of the median cost ($1,580/kW) of all of technologies evaluated. AFBC costs averaged 12% less than this median while integrated gasification combined cycle costs averaged 11% above the median. Potential capital cost savings for repowering an existing plant versus constructing a new facility at the same final capacity are between 10 and 40%.

This Project Summary was developed by EPA's Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back.)

Introduction

This report documents performance and economic models developed for advanced coal combustion and conventional power generation technologies. The models developed in this report are simplified to minimized computational time and data requirements, but they incorporate important parameters that have significant impacts on performance and costs. The models are based on recent information available from Electric Power Research Institute (EPRI) reports and other published sources. The sources of information are referenced in the report.

The advanced power generation technologies covered in the report include: atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC). These technologies incorporate processes for removal of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM).

The conventional power generation technology covered in the report is pulverized coal-fired (PC) plants. The economic model developed in this study for PC plants excludes the costs for flue gas desulfurization (FGD) and selective catalytic reduction (SCR) NO_x controls. The costs for these control systems were drawn from other models and were combined with the PC base plant costs. The user has the option to include or exclude the cost of a baghouse for PM control. As such, the user of the model can add the desired control options to the uncontrolled PC boiler and compare the cost of a PC plant with those estimated for the advanced coal combustion technologies.

Table 1 describes the technologies covered in this study. The FGD configuration described has been considered as the EPA "base case" system. The SCR system is a hot-side, high-ash configuration, located upstream of the air heater. The nominal NO_x removal efficiency for this system is estimated at 75%. The advanced technologies—AFBC, PFBC, and IGCC—are near-term or first generation versions of each system. Both the AFBC and PFBC combustors are of the bubbling bed design. The PFBC reference plant is a turbocharged design and does not include a gas turbine generator for combined cycle electricity production. The IGCC reference plant utilizes an oxygen-blown, entrained-flow gasifier with cold gas cleanup prior to combustion turbine firing.

Although both conventional and advanced technologies have been evaluated in this study, direct economic comparisons are difficult for several reasons. First, a technology such as FGD is mature and fully commercialized with many vendors competing in the marketplace. Therefore, cost estimates for FGD systems are developed from a data base of actual installation and operating costs. In contrast, the advanced technologies, particularly PFBC and IGCC, are in relatively early stages of development with commercial service unlikely before the mid to late1990s. Cost estimates made during such early stages of development can significantly underpredict actual costs for the first commercial version of a new technology. However, costs for subsequent commercial installations often decline as improved versions of the technology are built. Second, the cost effectiveness (cost to remove a given quantity of pollutant) is much easier to define for an add-on control such as FGD or SCR than for integrated technologies. To varying degrees, processes for removal of SO_2, NO_x, and PM are intrinsic to the basic designs of the advanced generating technologies. Finally, advanced technologies may offer significant capacity increases and increased fuels flexibility when retrofitting or repowering existing plants. These features also need to be considered when comparing technologies.

For each technology covered, the following information is presented:

- description of the technology,
- reference plant description defining the coverage of process equipment included in the cost models,
- system performance models relating to emission reduction,
- capital cost model,
- operating and maintenance cost model, and
- key technical issues discussion - dealing with technical factors that will affect further development and use of the technology.

Summary and Results

Algorithms for the performance and economic models are presented in the report. These algorithms have also been incorporated in Version 4.0 of the Integrated Air Pollution Control System (IAPCS) cost model. Version 4.0 of IAPCS was used to generate the cost presented herein.

Example cost estimates are presented for newly constructed AFBC, PFBC, and IGCC plants as well as for new PC plants equipped with wet limestone FGD and SCR systems. These capital and operating cost estimates are based on early or near-term versions of the advanced technologies. As the advanced technologies are developed further, revised capital cost estimates may either increase or decrease. Revised annual operating cost estimates, however are likely to decrease as more efficient versions of the technologies are evaluated. Cost estimates are also presented for repowering existing PC plants with advanced coal combustion technologies. To compare the repowering approaches, cost estimates are presented for life extension and retrofit of existing PC plants. Equipment refurbishment and upgrade costs associated with a 20-year life extension were combined with retrofit FGD and SCR costs for existing plants.

Status of Advanced Coal Combustion Technologies

Advanced coal combustion technologies have received considerable attention because of decreased SO_2 and NO_x emissions characteristics, potential improvements in overall generating efficiency, and the ability to increase generating capacity when repowering existing stations. Table 2 compares net plant generating efficiencies which are available currently or on a near-term basis against projected efficiency for mature or second generation configurations for the technologies considered. Cur-

Table 1. *General Descriptions of the Technologies Considered*

Technology	*Process Description*
FGD	*Forced oxidation wet limestone with in-line steam reheat; spray tower type absorber modules with liquid/gas ratio of 80 gpm/1000 acfm*; three modules are assumed for 200 and 500 MWe plants, and four modules are assumed for 1000 MWe plants; sludge disposal is by landfill.*
SCR	*Hot-side location between economizer and air heater; economizer bypass to maintain nominal catalyst temperature of 700 °F at low load operation; air heater modifications to resist impact of ammonia salt formation; vertical reactor vessels with fly ash hopper and handling systems; complete catalyst replacement at 3-year intervals.*
AFBC	*Bubbling bed combustor; limestone sorbent; overbed coal and limestone feed system; dry waste disposal by landfill.*
PFBC	*Bubbling bed combustor; dolomite sorbent; underbed coal and sorbent feed system; turbocharged cycle; dry waste disposal by landfill.*
IGCC	*Texaco entrained flow gasifier; oxygen blown; radiative and convective raw gas cooler; cold gas cleanup by Selexol acid gas removal; Claus sulfur recovery; SCOT tail gas treatment; turbine firing temperature 2200 °F.*

**Readers more familiar with metric units may use the factors at the end of this Summary to convert to that system.*

Table 2. *Net Plant Generating Efficiencies*[a]

Technology	Current or Near-Term Efficiency %	Mature Technology Projected Efficiency %
Conventional PC/FGD	33-35	35
Supercritical PC/FGD	39	41
AFBC	34	35
PFBC (Turbocharged Cycle)	33	35
PFBC (Combined Cycle)	34	45
IGCC	34	40

[a]Net plant efficiency is the inverse of net plant heat rate times the conversion factor, 3413 Btu/kWh.

rent or near-term achievable efficiencies for advanced technologies show no improvement over conventional PC plants with FGD systems. However, projected efficiencies for mature (or second generation) versions of IGCC and PFBC are about 14-29% higher, respectively, than that achievable for the conventional system. Supercritical PC plants operate at steam cycle pressures above the critical pressure of water, but utilize an essentially conventional (low NO_x) PC firing system and FGD scrubbers. Supercritical plants have been available in the U.S. since the late 1950s. However, due to materials-related reliability problems in the boiler superheater and reheater surfaces, main steam lines, and high pressure turbine valves, nozzle chambers, and casings, supercritical plants have not been fully commercialized. Near term net plant generating efficiencies of about 39% are based on the performance levels of the pre-NSPS Philadelphia Electric Company Eddystone No. 1 (Eddystone, Pennsylvania) and The Ohio Power Company Philo No. 6 (near Zanesville, Ohio) plants in the late 1950s and early 1960s. Proposed supercritical plant designs have efficiencies of about 41% or about 17-24% higher than current subcritical designs.

Advanced coal combustion technologies may also be used to repower existing steam electric plants. Repowering consists of substantial modification or replacement of the existing boiler. Where economically feasible, the existing steam turbine generator and the remaining balance-of-plant equipment is reused. In the combined cycle configurations of PFBC and IGCC, additional electricity is produced by a new gas turbine generator. Repowering cannot only provide a plant service life extension, but can also result in significant capacity increases without developing new greenfield power plant sites.

At their current status of development, however, advanced technologies may not be fully available for utility application until the mid to late 1990s. Significantly technical issues must be overcome before these technologies will fully penetrate the utility market. These issues include materials limitations, process control, load following ability, hot gas cleanup, and secondary environmental impacts. Table 3 lists some of the major issues and provides time frame estimates of commercial availability for the technologies. The development issues and availability status of the advanced technologies are more fully discussed in the main report.

General Costing Assumptions

Assumptions used to estimate both constant and current 1988 dollars are shown in Table 4. EPRI's general cost procedures were used to incorporate inflation, cost of capital, and levelization of future expenses. Cost adjustments to account for the technical issues discussed above affecting further development and future use of each technology are not presented in this cost analysis.

Process contingencies are used to address the uncertainty associated with developing technologies while project contingencies reflect the level of detail in estimating overall project cost. In developing detailed cost estimates for a technology, process contingencies are determined for each process area or section according to its development and commercialization status. For example, in an IGCC plant, the steam turbine generator section is typically assigned a process contingency at or near

Table 3. *Development and Availability Status of Advanced Coal Combustion Technologies*

Technology	Key Technical Issues	Estimated Commercial Availability: First Generation	Estimated Commercial Availability: Fully Mature Second Generation
Supercritical PC/FGD	Superheater materials limitations Main steam line creep and expansion failure Steam turbine erosion, creep, and expansion failure Load following and control Plant trip critical pressure letdown	1962	1993
AFBC (Bubbling Bed)	Modest combustion efficiency Poor limestone utilization Part-load efficiency and emissions control Solid waste production Potential N_2O emissions	1989	1995
PFBC	Erosion-corrosion of in-bed heat transfer surfaces Load following and control Solid waste production Alkali and halogen emissions Potential N_2O emissions	1995	2000
IGCC	Solid waste production from in-situ sulfur capture High temperature S, N, PM, and alkali removal High temperature gas turbine development	1988	1996

***Table 4.** Economic Assumptions Used in Cost Analysis*

Current Dollars (1988)			
Weighted Cost of Capital		12.5%	
Inflation Rate		6.0	
Carrying Charge Factor			
Economic Life:	*20 years*	0.189	(Retrofit, Repowered Plants)
	30 years	0.175	(New Plants)
Levelization Factor			
Economic Life:	*20 years*	1.57	
	30 years	1.75	
Current Dollars (1988)			
Weighted Cost of Capital		6.1%	
Inflation Rate		0%	
Carrying Charge Factor			
Economic Life:	*20 years*	0.123	(Retrofit, Repowered Plants)
	30 years	0.105	(New Plants)
Levelization Factor			
Economic Life:	*20 years*	1.00	
	30 years	1.00	
Indirect Cost		***Case 1***	***Case 2***
General Facilities		10%	10%
Engineering and Home Office Fees		10%	10%
Process Contingencies		10%	0%
Project Contingencies		30%	15%

zero. However, given that hot gas cleanup systems have generally not progressed from pilot demonstration scale to full commercial status, a process contingency within the range of 20-35% is more appropriate for this section. A weighted average of the process area contingencies can then be expressed for the technology.

A range of contingency values was used in the present costing analysis to represent optimistic as well as conservative estimates. Weighted average contingencies are shown in the analyses for each technology rather than individual process area contingencies. Contingencies of 0% for process and 15% for project are appropriate for mature processes and detailed project cost estimates. Contingencies of 30% for project and 10% for process give more conservative cost estimates corresponding to increased process uncertainties and reduced detail in project cost estimating. In other work, EPA has used a 15% contingency factor for the FGD base case estimate. Contingencies inherent to the example cost estimates contained in the 1986 Technical Assessment Guide (TAG) are on the order of 18-20% for AFBC and IGCC and are >30% for PFBC. As more experience is gained in some of the process areas and with improved project costing, these factors may be refined. Contingency factors developed by EPRI following detailed engineering and risk analyses currently fall within the range of 15-20% for AFBC, IGCC, and PFBC. Each technology in this study has been evaluated using contingency values representing both optimistic and conservative premises.

Table 5 presents coal characteristics for a midwestern bituminous coal used in the cost analysis. To be consistent with an EPRI study of FBC, a coal cost of $2.00/10^6 Btu was used for a hypothetical Illinois coal. (*Note:* Actual fuel costs may differ from this assumed price, thus affecting the relative economic ranking between the technologies. Higher fuel costs will have a greater impact on total annual operating costs for low efficiency technologies as compared to technologies with high generating efficiencies. Table 6 presents unit costs for estimating operating and maintenance costs. Annual costs were estimated using a capacity factor of 0.65. Costs are reported for technologies firing 2 or 4% sulfur coal.

Table 7 presents design specifications for acid gas control used to estimate costs for each technology. For SO_2 control, 90% removal is assumed for AFBC, PFBC, and FGD; 95% removal is assumed for IGCC. For NO_x control, a NO_x emission limit of 0.6 lb/10^6 Btu corresponding to the current New Source Performance Standard (NSPS) level, is assumed for AFBC plants and PC plants without SCR. For PC plants with SCR, the design NO_x removal efficiency is assumed to be 80%, corresponding to an emission level of 0.12 lb/10^6 Btu. Measured NO_x emissions from a large demonstration PFBC boiler ranged from 0.15 to 0.5 lb/10^6 Btu. In this study, an NO_x emission level of 0.2 lb/10^6 Btu is assumed based on conceptual bubbling bed PFBC performance levels. The NO_x emission level of 0.27 lb/10^6 Btu for IGCC is based on the use of wet injection in the gas turbine for complying with the gas turbine NSPS limit (75 ppm at 15% dry O_2).

***Table 5.** Coal Characteristics and Prices Used in the Cost Analysis*

Coal Characteristics		*Midwestern Bituminous Coal*
Sulfur Content, %		2.0 - 4.0
Ash Content, %		16
Carbon Content, %		57.6
Heating Value, Btu/lb		10,100
Net Heat Rate for Conventional Plants with FGD, Btu/kWh		10,060
Net Heat Rate for Conventional Plants with FGD and SCR, Btu/kWh[a]		10,160
Net Heat Rate for AFBC, Btu/kWh		10,000
Net Heat Rate for PFBC, Btu/kWh		10,278
Net Heat Rate for IGCC, Btu/kWh		9,280
Coal Price	*$/ton*	40.0
	$/$10^6$ Btu	2.00

[a]*Assumes that SCR will increase the net heat rate by 1% over that of conventional plants with FGD.*

Table 6. Unit Costs for Estimating Operating and Maintenance Costs (1988 Dollars)

Item	*Units*	*Value*
Operating Labor	*\$/man-hour*	*21.40*
Water	*\$/1000 gal*	*0.65*
Limestone and Dolomite	*\$/ton*	*16.30*
Waste Disposal	*\$/ton*	*10*
Sulfur	*\$/ton*	*65*
Ammonia	*\$/ton*	*150*
SCR Catalyst	*\$/ton*	*20,300*
Steam	*\$/10^6 Btu*	*7.00*

New Plant Costs

Tables 8 and 9 present the capital and annual costs of new AFBC, PFBC, and IGCC plants firing 2 and 4% sulfur bituminous coals, respectively. The costs are reported for 200-, 500-, and 1000-MW plant sizes.

For comparison with advanced coal combustion costs, costs are also reported in Tables 8 and 9 for newly constructed PC plants with wet limestone FGD and SCR systems. Costs for new wet limestone FGD and SCR systems were estimated from the IAPCS model.The SCR costs are based on a 3-year catalyst life. Tables 8 and 9 include operating costs of conventional plants with baghouses for PM control. Annual costs of FGD and FGD plus SCR were added to the new plant costs so that the annual conventional plant cost can be compared directly with those for advanced coal combustion technologies.

The cost effectiveness, or unit cost per ton of acid gas removed is also presented for each technology in Tables 8 and 9. The tons of acid gas removed were determined by applying advanced technology removal efficiencies to emissions of NO_x and SO_2 from an uncontrolled PC plant at given plant sizes. For integrated techologies, FBC and IGCC, it is difficult to separate costs associated with acid gas control from the rest of the costs attributed to electrical generation. To estimate effective costs for acid gas control for new plants, annual costs (including annualized capital costs) for the conventional PC plant exclusive of FGD and SCR costs systems were subtracted from annual costs (including annualized capital costs) for a new AFBC, PFBC, and IGCC plant at the same plant size. This is represented by the following equation:

(Effective acid gas control costs)
=(Annual cost for advanced technology)
- (Annual cost for PC plant without FGD and SCR)

For conventional PC boilers, the cost for acid gas control is simply the annual costs for FGD and SCR.

Figures 1, 2, and 3 show the capital costs, annual costs, and unit cost per ton of acid gas removed from Table 8 as a function of plant sized for the 2% sulfur coal, respectively. Only constant 1988 dollar costs estimates and 30% for project and 10% for process contingencies are presented in these figures.

Repowered Plant Costs

Tables 10 and 11 present the capital and annual costs of repowering AFBC, PFBC, and IGCC on existing plants firing 2 and 4% sulfur bituminous coals, respectively. These costs are based on repowered plant final net capacity and are reported for 200-, 500-, and 1000-MW plant sizes. Whereas plant capacity is assumed to remain unchanged for AFBC and turbocharged PFBC repowering, it is assumed that IGCC repowering results in a tripling of net plant output.Capital costs are based on reuse and refurbishment factors for each technology. They do not however, include the costs for replacement power during the construction outage.

For comparison with costs of repowering, costs are also reported in Tables 10 and 11 for life extension of an existing plant for 20 years of additional operation and retrofit of add-on wet limestone FGD and SCR systems and fabric filter PM control. Retrofit of FGD and SCR systems results in decreased operating efficiency which may derate the plant. This analysis assumes that an FGD retrofit gives a 3% capacity derate and the addition of an SCR system gives another 1% derate. The capital cost of life extension is \$214/kW, which is the average cost reported by EPRI without considering downtime costs. Costs for wet limestone FGD systems were estimated from the IAPCS model. Capital costs for FGD and SCR systems are based on retrofit factors of 1.5 and 1.34, respectively, as shown in Table 7.

Conclusions

Advanced coal combustion technologies are of interest due to decreased SO_2 and NO_x emissions characteristics, potential improvements in overall generating efficiency, and the ability to increases generating capacity when repowering existing stations. Existing NSPS emission limits and proposed acid rain regulations are expected to be met by most AFBC, PFBC, and IGCC configurations. In addition, prevention of significant deterioration (PSD) requirements are expected to be satisfied under repowering scenarios. Projected net plant generating efficiencies for mature technology combined cycle configurations (IGCC and PFBC) are about 14-29% higher than for conventional PC boilers equipped with FGD scrubbers. Advanced supercritical PC/FGD designs have generating efficiencies comparable to those of mature IGCC plants but still about 8-9% below those of second generation PFBC designs.

At their current status of development, however, advanced technologies may not be fully available for utility application until the mid to late 1990s. Significant technical issues must be overcome before these technologies will fully penetrate the utility market. These issues include materials limitations, process control, load following ability, hot gas cleanup, and secondary environmental impacts.

Capital cost estimates for a new plant at 500-MW ranged from \$1,250 to \$1,910/kW for advanced technologies and from \$1,390 to \$1,810/kW for conventional systems. Capital cost estimates for PFBC (turbocharged cycle) and conventional plants with add-on SO_2 and NO_x controls were within 4% of the median cost (\$1,580/kW) of all of technologies evaluated. AFBC costs averaged 12% less than this median while IGCC costs averaged 11% above the median. Potential capital cost savings for repowering an existing plant versus constructing a new facility at the same final capacity are between 10 and 40%.

Metric Conversion Factors

Readers more familiar with metric units may use the following factors to convert to that system:

British	Multiplied by	Yields Metric
Btu	*1.06*	*kJ*
Btu/lb	*2.33*	*kJ/kg*
cfm	*0.000472*	*m^3/s*
°F	*5/9 (°F - 32)*	*°C*
gal.	*0.00379*	*m^3*
gpm	*0.0000633*	*m^3/s*
lb/10^6 Btu	*0.430*	*lb/GJ*
ton	*907*	*kg*

Table 7. Design Specifications for Acid Gas Control

Design Specifications	AFBC	PFBC	IGCC	PC/FGD/SCR	PC/FGD
	Technologies Evaluated [a]				
SO_2 Control:					
- SO_2 Removal %	90	90	95	90	90
- SO_2 Control Method	in-situ	in-situ	Selexol Process	wet limestone FGD	wet limestone FGD
- Sorbent Type	limestone	dolomite	Selexol	limestone	limestone
- Ca/S Ratio	3.1	1.5	NA [c]	NA	NA
- L/G Ratio	NA	NA	NA	80	80
- Stoichiometric Ratio	NA	NA	NA	1.15	1.15
- Retrofit Factor [b]	NA	NA	NA	1.5	1.5
NO_x Control:					
- NO_x Emissions, lb/10^6Btu	0.6	0.2	0.27	0.12	0.6
- NO_x Control Method	in-situ	in-situ	wet injection	SCR	NA
- NH_3: NO_x Ratio	NA	NA	NA	0.82	NA
- SCR Space Velocity, 1/hr	NA	NA	NA	25,000	NA
- SCR Catalyst Replacement, years	NA	NA	NA	3	NA
- Retrofit Factor [b]	NA	NA	NA	1.34	NA

[a] AFBC = atmospheric fluidized bed combustion.
PFBC = pressurized fluidized bed combustion.
IGCC = integrated gasification combined cycle.
PC = pulverized coal-fired plant.
FGD = flue gas desulfurization.
SCR = selective catalytic reduction.

[b] For estimating new plant costs, retrofit factor is 1.0. For estimating repowered AFBC, PFBC, and IGCC costs, costs of new plants were adjusted using the reuse and refurbishment factor approach discussed in this report.

[c] NA = Not applicable.

Table 8. New Plant Cost Estimates for Advanced Coal Combustion Technologies Firing 2% Sulfur Bituminous Coal[a]

Technology [b]	Net Plant Capacity MW	Capital Costs $/kW	Annual Costs, mills/kW-h Constant $	Annual Costs, mills/kW-h Current $	Unit Cost per Ton of Acid Gas Removed, $/ton [c] Constant $	Unit Cost per Ton of Acid Gas Removed, $/ton [c] Current $
Case 1, Project Contingencies = 15%, Process Contingencies = 0%						
AFBC	200	1530	60	103	270	460
	500	1250	52	90	210	360
	1000	1080	48	82	180	300
PFBC	200	1800	68	116	580	1000
	500	1440	58	99	420	720
	1000	1220	52	89	320	560
IGCC	200	1890	65	112	470	800
	500	1540	55	95	310	540
	1000	1330	50	85	230	390
PC/FGD/SCR	200	1840	70	120	680	1150
	500	1490	61	104	550	940
	1000	1310	56	96	510	870
PC/FGD	200	1720	65	112	570	980
	500	1390	57	97	450	760
	1000	1122	52	89	400	680

(Continued)

Table 8. *(Continued)*

Technology [b]	Net Plant Capacity MW	Capital Costs $/kW	Annual Costs, mills/kW-h Constant $	Annual Costs, mills/kW-h Current $	Unit Cost per Ton of Acid Gas Removed, $/ton [c] Constant $	Unit Cost per Ton of Acid Gas Removed, $/ton [c] Current $
		Case 2, Project Contingencies = 30%, Process Contingencies = 10%				
AFBC	200	1860	67	115	310	530
	500	1510	58	99	240	410
	1000	1300	53	91	190	330
PFBC	200	2190	76	130	670	1150
	500	1750	64	110	490	830
	1000	1470	58	98	370	630
IGCC	200	2300	74	127	580	990
	500	1880	63	107	400	680
	1000	1610	56	96	300	520
PC/FGD/SCR	200	2150	75	128	750	1280
	500	1750	65	110	600	1030
	1000	1540	59	101	550	940
PC/FGD	200	2070	73	125	640	1100
	500	1670	63	107	490	840
	1000	1460	57	98	440	750

[a] Cost are in 1988 dollars.
[b] AFBC = atmospheric fluidized bed combustion.
PFBC = pressurized fluidized bed combustion.
IGCC = integrated gasification combined cycle.
PC/FGD/SCR = pulverized-coal plant with wet limestone flue gas desulfurization and selective catalytic reduction.
PC/FGD = PC plant with wet limestone FGD.
[c] Tons of acid gas removed = sum of the tons of SO_2 and NO_x removed.
Hypothetical acid gas control cost = annual cost for advanced technologies - annual cost for PC plant without FGD and SCR.

Table 9. *New Plant Cost Estimates for Advanced Coal Combustion Technologies Firing 4% Sulfur Bituminous Coal* [a]

Technology [b]	Net Plant Capacity MW	Capital Costs $/kW	Annual Costs, mills/kW-h Constant $	Annual Costs, mills/kW-h Current $	Unit Cost per Ton of Acid Gas Removed, $/ton [c] Constant $	Unit Cost per Ton of Acid Gas Removed, $/ton [c] Current $
		Case 1, Project Contingencies = 15%, Process Contingencies = 0%				
AFBC	200	1550	63	108	220	380
	500	1260	55	95	190	330
	1000	1090	51	87	170	300
PFBC	200	1810	70	120	380	660
	500	1440	60	103	300	510
	1000	1220	54	93	250	420
IGCC	200	1930	65	112	260	440
	500	1570	55	95	170	290
	1000	1350	50	85	120	210
PC/FGD/SCR	200	1810	69	117	420	580
	500	1480	60	102	350	470
	1000	1300	55	95	320	420
PC/FGD	200	1690	64	110	340	580
	500	1380	56	96	280	470
	1000	1200	52	88	240	420

(Continued)

Table 9. (Continued)

Technology[b]	Net Plant Capacity MW	Capital Costs $/kW	Annual Costs, mills/kW-h Constant $	Annual Costs, mills/kW-h Current $	Unit Cost per Ton of Acid Gas Removed, $/ton[c] Constant $	Unit Cost per Ton of Acid Gas Removed, $/ton[c] Current $
	Case 2, Project Contingencies = 30%, Process Contingencies = 10%					
AFBC	200	1870	70	120	240	420
	500	1520	61	104	210	350
	1000	1310	56	96	180	310
PFBC	200	2200	78	134	430	740
	500	1750	67	114	330	570
	1000	1480	60	102	270	460
IGCC	200	2340	74	127	320	550
	500	1910	63	107	220	380
	1000	1640	56	96	160	280
PC/FGD/SCR	200	2230	80	136	460	790
	500	1810	69	113	380	650
	1000	1590	63	108	350	600
PC/FGD	200	2090	75	128	370	640
	500	1690	64	110	300	510
	1000	1480	59	101	270	460

[a] Costs are in 1988 dollars.
[b] AFBC = atmospheric fluidized bed combustion.
PFBC = pressurized fluidized bed combustion.
IGCC = integrated gasification combined cycle.
PC/FGD/SCR = pulverized-coal plant with wet limestone flue gas desulfurization and selective catalytic reduction.
PC/FGD = PC plant with wet limestone FGD.
[c] Tons of acid gas removed = sum of the tons of SO_2 and NO_x removed.
Hypothetical acid gas control cost = annual cost for advanced technologies - annual cost for PC plantwithout FGD and SCR.

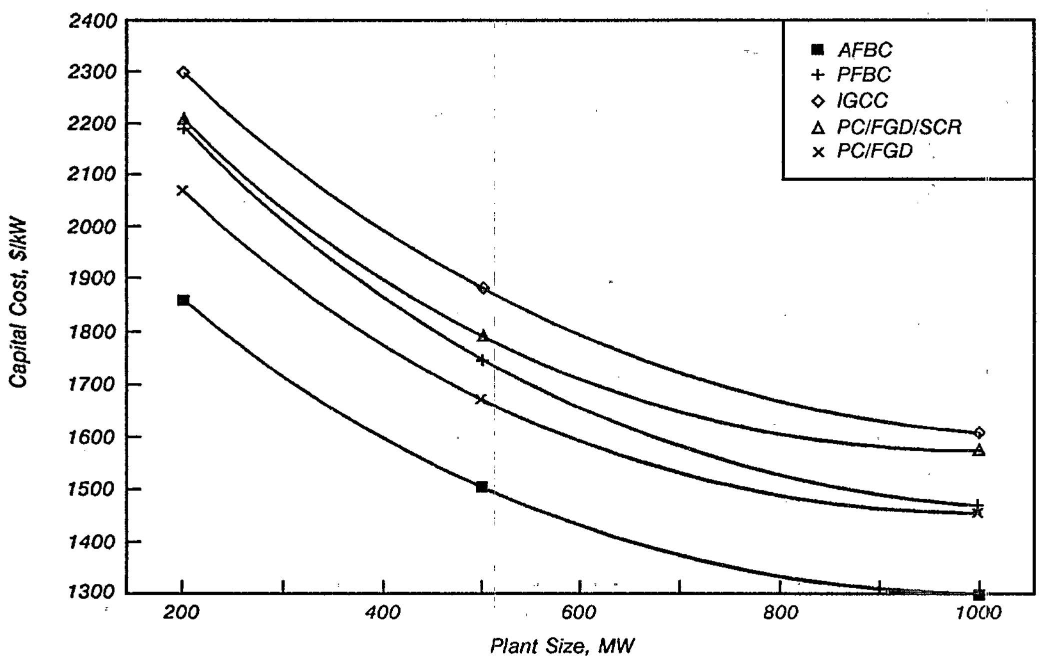

Figure 1. Capital costs for new plants as a function of size for plants using 2% sulfur coal (in constant 1988 dollars). Contingencies of 30% for project and 10% for process are assumed.

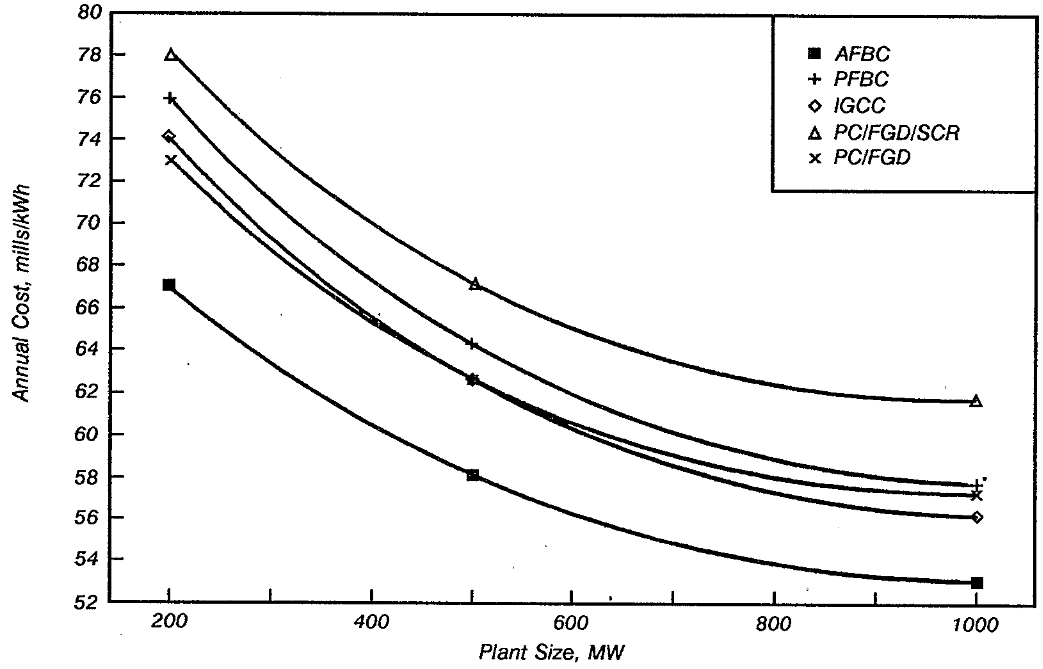

Figure 2. *Annual costs for new plants as a function of size for plants using 2% sulfur coal (in constant 1988 dollars). Contingencies of 30% for project and 10% for process are assumed.*

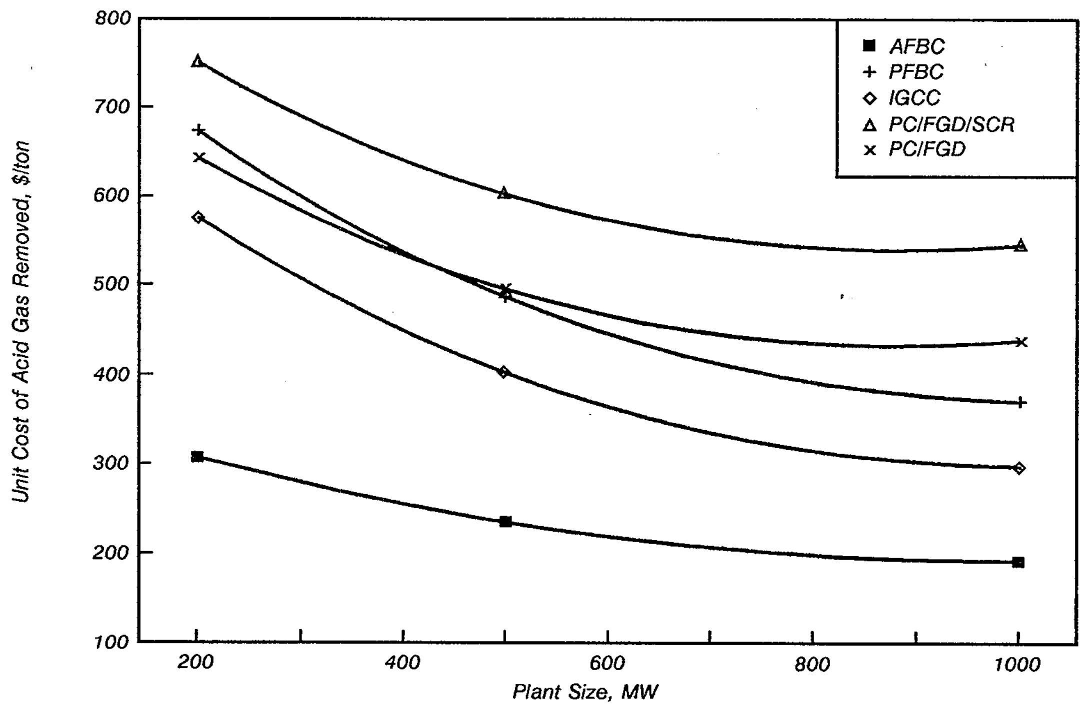

Figure 3. *Unit cost of acid gas removed as a function of size for plants using 2% sulfur coal (in constant 1988 dollars). Contingencies of 30% for project and 10% for process are assumed.*

Table 10. *Retropowered and Retrofit Plant Cost Estimates for Advanced Coal Combustion Technologies Firing 2% Sulfur Bituminous Coal*[a]

Technology[b]	Base Net Plant Capacity MW	Final Net Plant Capacity[c] MW	Capital Costs $/kW	Annual Costs, mills/kW-h Constant $ $	Current $ $
		Case 1, Project Contingencies = 15%, Process Contingencies = 0%			
AFBC	200	200	790	46	72
	500	500	660	42	65
	1000	1000	590	39	61
PFBC	200	200	1190	58	90
	500	500	950	50	78
	1000	1000	810	45	71
IGCC	70	200	1710	67	104
	170	500	1400	56	88
	330	1000	1210	51	79
PC/FGD/SCR	208	200	630	45	70
	520	500	540	40	63
	1040	1000	510	39	61
PC/FGD	206	200	490	40	62
	515	500	420	36	56
	1030	1000	400	34	53
		Case 2, Project Contingencies = 30%, Process Contingencies = 10%			
AFBC	200	200	950	50	78
	500	500	800	45	70
	1000	1000	710	42	66
PFBC	200	200	1440	64	100
	500	500	1150	55	85
	1000	1000	970	49	77
IGCC	70	200	2080	76	118
	170	500	1700	64	100
	330	1000	1470	57	89
PC/FGD/SCR	208	200	700	47	73
	520	500	570	42	66
	1040	1000	550	34	53
PC/FGD	206	200	540	41	64
	515	500	450	37	57
	1030	1000	420	35	55

[a] Costs are in 1988 dollars.
[b] AFBC = atmospheric fluidized bed combustion.
PFBC = pressurized fluidized bed combustion.
IGCC = integrated gasification combined cycle.
PC/FGD/SCR = pulverized-coal plant with wet limestone flue gas desulfurization and selective catalytic reduction.
PC/FGD = PC plant with wet limestone FGD.
[c] Station generating capacity is unchanged for simple cycle AFBC and PFBC repowering. Repowering with combined cycle IGCC results in an approximate tripling of capacity. Retrofit with FGD and SCR results in a capacity derate.

Table 11. *Retropowered and Retrofit Plant Cost Estimates for Advanced Coal Combustion Technologies Firing 4% Sulfur Bituminous Coal*[a]

Technology[b]	Base Net Plant Capacity MW	Final Net Plant Capacity[c] MW	Capital Costs $/kW	Annual Costs, mills/kW-h Constant $ $	Current $ $
	Case 1, Project Contingencies = 15%, Process Contingencies = 0%				
AFBC	200	200	800	49	76
	500	500	670	44	69
	1000	1000	600	42	65
PFBC	200	200	1200	60	94
	500	500	960	52	81
	1000	1000	810	48	74
IGCC	70	200	1750	67	104
	170	500	1420	56	88
	330	1000	1230	51	79
PC/FGD/SCR	208	200	690	47	73
	520	500	590	42	66
	1040	1000	550	40	63
PC/FGD	206	200	550	41	64
	515	500	470	37	58
	1030	1000	430	36	56
	Case 2, Project Contingencies = 30%, Process Contingencies = 10%				
AFBC	200	200	960	53	83
	500	500	810	48	75
	1000	1000	720	45	70
PFBC	200	200	1440	66	103
	500	500	1150	57	89
	1000	1000	980	52	81
IGCC	70	200	2120	76	119
	170	500	1730	64	100
	330	1000	1490	57	89
PC/FGD/SCR	208	200	770	49	76
	520	500	640	44	68
	1040	1000	590	42	65
PC/FGD	206	200	610	43	67
	515	500	510	38	60
	1030	1000	470	37	57

[a] Costs are in 1988 dollars.
[b] AFBC = atmospheric fluidized bed combustion.
PFBC = pressurized fluidized bed combustion.
IGCC = integrated gasification combined cycle.
PC/FGD/SCR = pulverized-coal plant with wet limestone flue gas desulfurization and selective catalytic reduction.
PC/FGD = PC plant with wet limestone FGD.
[c] Station generating capacity is unchanged for simple cycle AFBC and PFBC repowering. Repowering with combined cycle IGCC results in an approximate tripling of capacity. Retrofit with FGD and SCR results in a capacity derate.

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The complete report, entitled "Costs for Advanced Coal Combustion Technologies," (Order No. PB 90-255 688/AS; Cost: $23.00, subject to change) will be available only from:
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