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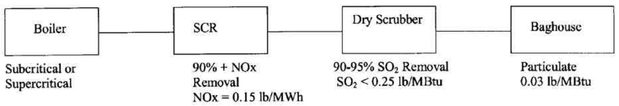
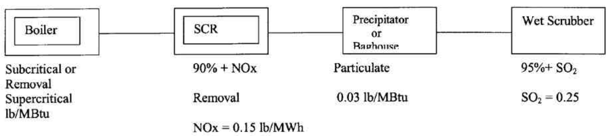
Example: Low Sulfur Coal Configuration with representative emissions performance.

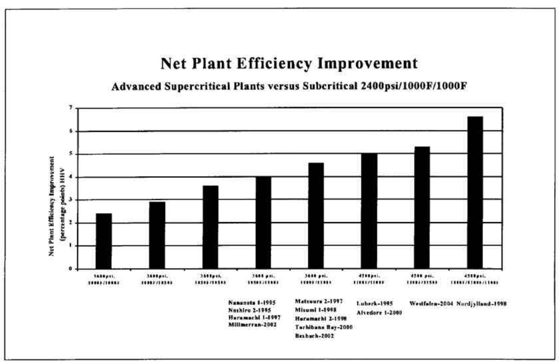


Example: High Sulfur Coal Configuration with representative emissions performance.



Heat Rate

Over the last 10 years, higher efficiency pulverized coal plants have been placed in commercial operation. The higher efficiencies are due not only to advanced pressure and steam cycles, but also to improvements in turbines and reductions in auxiliary power requirements. Pulverized coal power plant heat rate improvements versus steam parameters are shown below. (The actual operating plants have steam parameters close to the examples under which they are listed.)



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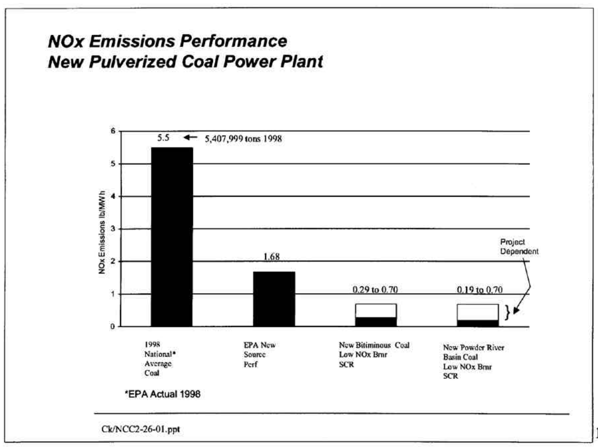
The summary point is that higher efficiency cycles are now being demonstrated with commercially required availability/reliability. Higher efficiency cycles will reduce the production cost by reduced fuel consumption and will result in a lower capital cost for all of the environmental equipment (on a $/kW cost basis). The ambient air emissions levels (NOx, SOx, particulate, and mercury) will primarily be a function of the emissions control devices installed (SCR, scrubber, baghouse, etc.). More efficient plants will provide an emissions reduction as well. For the U.S. market, the economically optimum cycle efficiency will be very project specific. However, today's advanced cycles have been demonstrated commercially and can be applied where project economics dictate.

Emissions Performance

NOx
Significant improvements in NOx emissions are being achieved in pulverized coal-fired power plants today. This is through both advances in Low NOx Burner Combustion technology and advances in Selective Catalytic Reduction systems, both of which are being widely applied. Low NOx Burner Combustion technology has resulted in combustion NOx levels being in the range of 0.15 to 0.30 lb/MBtu, depending on the coal. Selective catalytic reduction systems are in operation with NOx removal efficiencies up to 90-95%. An existing plant retrofit this year with an SCR will result in NOx emissions of approximately 0.30 lb/MWh, (approximately .03 lb/MBtu which is lower than the best natural gas combined cycle unit utilizing dry Low NOx Combustion, according to the most recent EPA actual operating data).

New pulverized coal power plants, through the application of commercially demonstrated Low NOx Burners and SCRs, can achieve NOx emissions as shown in the table below. In order to compare NOx emissions with natural gas-based power generation, the performance is reported in lb NOx per MWh.



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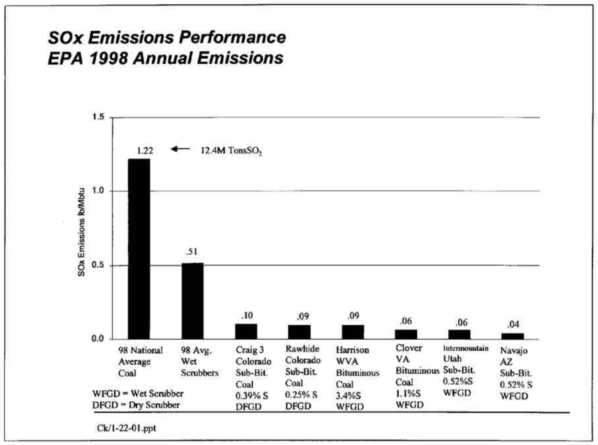
The NOx emissions performance represented in this section of the report and in the two case studies is derived from applying the state of the technology, Low NOx Burners, with the state of the technology Selective Catalytic Reduction Controls. These are applied to representative Eastern and Western coals and typical project parameters. The actual NOx emissions that can be obtained from a given new coal-fired project will depend on the analysis of the actual coal to be burned. It will also depend to some extent on the local ambient air conditions and condenser water availability and temperatures, which will impact the available heat rate of the cycle. The actual achievable NOx emissions rate for a given project can only be determined after the specific project and fuel parameters have been defined.

It should also be noted that this section of the report only addresses new, coal-fired generating plants. Whereas significant NOx reductions can be achieved from retrofits to an existing coal-fired generating unit, in many cases constraints from the original furnace design or other project constraints that cannot be modified will result in it not being possible to achieve the same NOx reductions on a retrofit as will be available for a greenfield generating unit that has maximum design flexibility for the boiler and environmental equipment.

SOx
Similarly, outstanding performance is being demonstrated on low SOx emissions technology, from a number of pulverized coal-fired power plants ranging from high sulfur Eastern bituminous coals to low sulfur Western coals. The graph shown below reflects actual SOx emissions from a number of coal-based power generating facilities as reported in the EPA 1998 Annual Emissions. In summary, the technology is available and is being commercially demonstrated to achieve extremely low SO_2 emissions.



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Particulate
High efficiency precipitators and baghouses are routinely achieving particulate emissions levels under .020 lb/MBtu.

Mercury
Significant mercury removal research from pulverized coal power plants has been underway over the last 10 years. In 2001, this will culminate in plant demonstrations for Advanced Mercury Removal Systems at Alabama Power's Gaston Station, Michigan South Central's Endicott Station, and Cinergy's Zimmer Station. These demonstrations are aimed at positioning coal-fired power plants for the announced future regulation of mercury emissions. Additionally, aggressive research and plant demonstrations are underway to substantially reduce mercury emissions.

Pulverized Coal Power Plant Applications

Following are two cases, which illustrate the impact of building new pulverized coal power generation plants.

1. Greenfield site or addition of a new generating unit to an existing power plant. This case shows typical plant efficiencies, emissions levels, electricity produced, and production costs for new pulverized coal power plants for both a low and high sulfur coal options.

2. Repowering of an old existing pulverized coal-fired power plant.

This case examines the performance emissions and production cost of repowering an entire old, coal-fired power plant consisting of multiple old, low-efficiency units that have high emissions rates with a single modern pulverized coal-fired generating unit.

Case 1

This case examines the efficiency, emissions performance, and production cost for adding a new coal-fired generating unit, either to a Greenfield site or to an existing power plant. Performance is shown for both an eastern bituminous coal and a Powder River Basin Coal Plant.

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TABLE 2
New Pulverized Coal Power Plant

		Low Sulfur PRB Coal		High Sulfur Bit. Coal	
Coal Heating Value	Btu/lb	8,000		12,500	
Coal % Sulfur	%	0.4		3.5	
Steam/Turbine Cycle		Supercritical	Subcritical	Supercritical	Subcritical
Net Plant Heat Rate	Btu/kWh	8900	9600	8500	9200
Net Plant Efficiency	HHV	38.3%	35.6%	40.1%	37.1%
Net Plant Efficiency	LHV	41.6%	39.8%	42.2%	39.0%
Emissions - Ranges					
Combustion NOx	lb/Mbtu	0.20 to 0.40	same	0.40 to 0.50	same
SCR % NOx Removal	%	80 to 90	same	85 to 92	same
Outlet NOx	lb/Mbtu	0.020 to .080	same	0.032 to .075	same
Outlet NOx @ 3% 0_2	ppm	14 to 58	same	23 to 54	same
Outlet NOx @ 15% 0_2	ppm	5 to 20	same	8 to 18	same
Outlet NOx	lb/MWh	.18 to .70	.19 to .75	.28 to .66	.29 to .69
Uncontrolled SO_2	lb/Mbtu	1.0	same	5.6	same
Scrubber % SO_2 Removal	%	90	same	95	same
Outlet SO_2	lb/Mbtu	.10	same	.28	same
Outlet SO_2	lb/MWh	.89	.96	2.38	2.58
Coal Cost	$/MBtu	1.22	1.22	1.22	1.22
Fuel Production Cost	$/MWh	10.86	11.71	10.37	11.22
Non-Fuel O&M Cost	$/MWh	3.50	3.50	3.50	3.50
Total Production Cost	$/MWh	14.36	15.21	13.87	14.72

Total Production Cost
The curve below shows the variable production cost (Fuel + O&M, excluding capital investment costs) for all the coal-fired power plants in the U.S. in 1998 (UDI data).

The curve is a plot of the variable production cost of every coal-fired power plant, ranked from the lowest to the highest. It only shows the fuel and O&M cost, and not the sunk capital costs. This would also indicate the relative order of competitive dispatch.

Also shown on the curve is the variable production cost for the two plants discussed in the case studies. This shows that the total production costs for a new pulverized coal plant will be significantly lower than most of the existing coal fleet and will assure high capacity factors.

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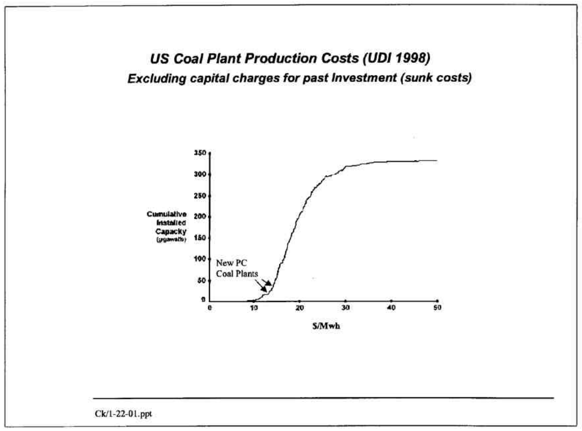
Case 1



Total Emissions Level
The total NOx and SOx emissions are significantly lower than what is being achieved in the existing coal-fired power plants today.

Total Emissions Performance
Table 3 (below) places a value on the total NOx and SOx emissions based on assumed allowance values for the examples in this case. To illustrate the low emissions level, the total outlet NOx and SOx emissions are given a monetary cost based on assumed allowance costs. When the emissions costs are stated as a production cost in $/MWh, it can be seen that these do not change the very favorable total production cost of electricity.

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TABLE 3

		Low Sulfur PRB Coal		Eastern Bituminous Coal	
		Supercritical	Subcritical	Supercritical	Subcritical
NOx Allowance Value (assumed)	$/ton	1000	1000	1000	1000
Outlet NOx	lb/MWh	.18	.19	.28	.29
NOx Allowance Cost	$/MWh	.09	.10	.14	.15
SOx Allowance Value (assumed)	$/ton	200	200	200	200
Outlet SO_2	lb/MWh	.89	.96	2.38	2.58
SOx Allowance Cost	$/MWh	.09	.10	.24	.26
Total Emission Allowance Cost	$/MWh	.18	.20	.38	.41

Case 2: Coal Power Plant Repowering

This case considers the repowering of an existing Eastern U.S. coal-fired power plant, burning low sulfur Eastern bituminous coal. The plant consists of six generating units that were built between 1949 and 1956, with a composite average net plant efficiency of 29.4%. The total gross generating capacity from all six units is 387 MW. The plant has no emission controls for NOx and SOx except for Low NOx Burners on one of the units.

The plant is repowered by replacing the boiler and turbine islands for all six units with a single 506-MW supercritical boiler/turbine, with an average net plant efficiency of 38.8%. The plant's coal receiving and handling, ash disposal, and electrical distribution infrastructure is retained where possible. The repowered unit is redesigned for the same heat input as the original six units; Low NOx Burners, an SCR, a dry SO_2 scrubber, and baghouse are added. The same coal is used in the repowered unit as is currently being burned.

Table 4 shows the actual operating performance from this plant for 1998 and the projected repowered performance in 2004.

In summary, with the plant repowered at the same heat input, it will now be rated at 31% higher megawatt output and operating efficiency. Both the NOx and SOx emissions will be reduced by 87% of the actual 1998 emissions in tons. The total production cost per megawatt-hour will be reduced 42%. Because of the low production cost, the unit will be base loaded with a high capacity factor, which will result in more than triple the actual megawatt hours produced during the year.

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TABLE 4
Case 2
Repowering Existing Coal Plant

	Existing Plant 1998 Actual Operating Data	Repowered 2004 Performance	Improvement %
Design Plant Total Heat Input MBtu/hr	4140	4140	
Nameplate MW	387	506	
Total # of Units	6	1	
Total Actual MWh	1,082,180	3,544,296	+327%
Total Actual Capacity Factor	31%	85%	
Heat Rate – Annual Average Btu/kWh	11,594	8,800	
Average Plant Efficiency HHV	29.4%	38.8%	+32%
Average Plant Efficiency LHV	30.9%	40.8%	
NOx Tons – annual	3536	468	-87%
NOx Emission Rate lb/MBtu	0.509	.03	
NOx Emissions Rate lb/MWh	5.9	0.26	
Coal % S	1.08	1.08	
SOx Tons Annual	12,881	1565	-88%
SOx Emissions Rate lb/MWh	23.8	0.88	
Fuel Cost $/MBtu	1.05	1.05	
Fuel Production Cost Annual Avg $/MWh	12.18	9.26	
Non-Fuel (OEM) Production Cost Annual Average $/MWh	9.87	3.57	
Total Production Cost $/MWh	$22.04	$12.83	-42%

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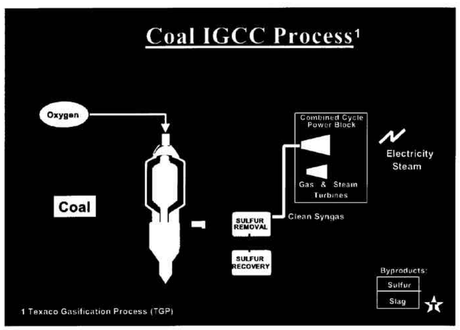
Opportunities for Greenfield Sites and Repowering Existing Facilities with Coal-Based Power Generation

When considering coal-based technologies for both greenfield applications and repowering of existing facilities, utilities have several primary options to consider. In addition to the modern pulverized coal technologies described earlier, integrated gasification combined cycle (IGCC) has become a viable, commercially available technology. With successes from the Clean Coal Technology Program in both new and repowered projects, much has been learned about IGCC performance, heat rate, cost, and emissions performance. This information, which has been widely published, has become an important tool for evaluation of this technology by electric utilities.

IGCC Technology Options

The diagram below shows a typical IGCC plant. The coal gasification process replaces the conventional coal-burning boiler with a gasifier, producing syngas (hydrogen and carbon monoxide) that is cleaned of its sulfur and particulate matter, and used as fuel in a gas turbine. The power generation cycle is completed through the use of the Heat Recovery Steam Generator (HRSG) and steam turbine, just as in a natural gas-fired combined cycle (NGCC) plant, offering the high efficiency and continual advances achieved with this equipment configuration.



The two primary technologies which have had the most success in the U.S. are Texaco's oxygen-blown, entrained-flow gasifier (Tampa Electric Company's Polk Power Station, a greenfield plant) and the Global Energy E-Gas (formerly Destec) oxygen-blown, entrained-flow gasifier (Cinergy/PSI Energy's Wabash River Station, a repowering project at an existing power plant).

In the Texaco gasification process, a down-flow slurry of coal, water, and oxygen, are reacted in the process burner at high temperature and pressure to produce a medium-temperature syngas. The syngas moves from the gasifier to a high-temperature heat recovery unit, which cools the syngas while generating

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high-pressure steam. The cooled gases flow to a water wash for particulate removal. Molten ash flows out of the bottom of the gasifier into a water-filled sump where it is forms an inert solid slag. Next, a COS hydrolysis reactor converts COS into hydrogen sulfide. The syngas is then further cooled in a series of heat exchangers before entering a conventional amine-based acid gas removal system where the hydrogen sulfide is removed. The sulfur may be recovered as sulfuric acid or molten sulfur. The cleaned gas is then reheated and sent to a combined-cycle system for power generation.

The Global Energy E-Gas process uses a slurry of coal and water in a two-stage, pressurized, upflow, entrained-flow slagging gasifier. About 75% of the total slurry is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The gasification/oxidation reactions take place at temperatures of 2,400 to 2,600°F. Molten ash falls through a tap hole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 25% of the coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1,900°F. The 1,900°F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 1,100°F, generating saturated steam for the steam power cycle in the process.

Particulates are removed in a hot/dry filter and recycled to the gasifier. The syngas is further cooled in a series of heat exchangers. The syngas is water scrubbed to remove chlorides and passed through a COS hydrolysis unit. Hydrogen sulfide is removed in the acid gas columns. A Claus unit is used to produce elemental sulfur as a salable by-product. The clean syngas is then moisturized, preheated, and sent to the power block.

In Europe, Global Energy has successfully used the British Gas/Lurgi (BGL) gasification process. In the BGL process, the gasifier is supplied with steam, oxygen, limestone flux, and coal. During the gasification process, the oxygen and steam react with the coal and limestone flux to produce a raw coal-derived fuel gas rich in hydrogen and carbon monoxide. Raw fuel gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and sold as a by-product. Tars, oils, and dust are recycled to the gasifier. The resulting clean, medium-Btu fuel gas is sent to a gas turbine. Based on the success of the BGL process at the Schwarze Pumpe GmbH plant in Germany, Global Energy is building two plants in the U.S. The 400-MW Kentucky Pioneer Project and the 540-MW Lima Energy Project will both use BGL gasification of coal and municipal solid waste to produce electric power. The Kentucky project is being partially funded by DOE.

Heat Rate

DOE reports the Polk Power Station heat rate to be 9,350 Btu/kWh, with Wabash River at 8,910 Btu/kWh. These equate to about 38.4% and 40.2% (LHV) respectively. Overall IGCC plant efficiency of 45% LHV is likely to be demonstrated with the enhancements developed from the Clean Coal Technology Program projects and continued advances in gas turbine technology. As part of its Vision 21 Program, DOE has set a 2008 performance target of 52% on an HHV basis (about 55% LHV) for IGCC.

Emissions Performance

With gas becoming the fuel of choice for most new units, permitting agencies and environmental groups have become used to seeing very low emission limits for new units. Further, they have come to expect that repowering existing units should also meet those same low levels, regardless of economics or fuel choice. IGCC can approach the environmental performance of natural gas-fired power plants, opening the door for its application in new and repowered plants. As part of the Vision 21 Program, DOE has set a

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2008 performance target of 0.06 lb/mmBtu for SO_2, 0.06 lb/mmBtu for NOx, and 0.003 lb/mmBtu for particulate matter.

Conventional power plants that are candidates for repowering are typically 40-50 years old. Historically, the small upgrades and modifications that were made to maintain capacity or increase efficiency did not subject the utility to the New Source Review (NSR) process. With EPA's coal-fired power plants enforcement activities, many utilities are under enforcement pressure to meet very strict NSR limitations for SO_2, NOx, and particulates. Compliance with these limitations usually means retrofit with flue gas desulfurization (FGD) for SO_2 control, selective catalytic reduction (SCR) for NOx control, and possibly even upgrades to the electrostatic precipitator for increased particulate control. With such units being near the end of their economically useful lives, adding additional controls may not make economic sense for a unit that may be shut down in a few years.

Repowering with IGCC allows the utility to maintain or increase capacity, while significantly improving environmental performance and producing low-cost power. The coal gasification process takes place in a reducing atmosphere at high pressures. In the gasifier, the sulfur in the coal forms hydrogen sulfide, which is easily removed in a conventional amine-type acid gas removal system. The concentrated hydrogen sulfide stream can then be recovered as elemental sulfur or sulfuric acid, and sold as a commercial byproduct, eliminating the need to dispose of large amounts of combustion byproducts. The clean syngas is sent to the gas turbine to be burned. With the addition of nitrogen into the turbine for power augmentation, the combustion flame is cooled, minimizing NOx formation and eliminating the need for SCR.

Many existing coal-fired plants are also affected by the NOx SIP call, and utilities are facing the installation of SCR on these existing units in order to comply. With changes in utility regulation, and the age of the units, the economics of these retrofits presents a challenge to continued operation of the units. Further, the possibility of stricter limitations on SO_2 or other emissions in the next few years presents another layer of economic decisions. While the unit may still be economic to dispatch following the installation of SCR, the addition of FGD may not allow that to continue. In that case, the utility would face the stranding of its SCR assets after only a few years of operation. Repowering with IGCC would provide the utility with the ability to maintain or even increase capacity, meet NOx limitations, and prepare for stricter SO_2 emission limitations.

While the retrofit of emission controls reduces emissions, it leads to secondary environmental issues, such as the large amounts of land needed to dispose of the new FGD byproduct and groundwater protection. The SCR system raises issues regarding local exposure to risks of accidental release of ammonia and disposal of the SCR catalyst.

In the gasifier, the ash in the coal melts, and is recovered as a glassy, low permeability slag which can be sold for use in making roofing shingles, as an aggregate, for sandblasting grit, and as an asphalt filler. With the sulfur also recovered as a commercial byproduct, repowering with IGCC can eliminate the solid waste issues that utilities might face when retrofitting conventional coal-fired plants with FGD and SCR.

With EPA's recent determination to regulate mercury emissions from coal-fired units, utilities will face additional potential requirements for the retrofit of control equipment. With the reducing atmosphere, and by operating a closed system at high pressures, IGCC releases of mercury are minimized. Initial information from EPA's mercury-based Information Collection Request shows promising results for IGCC, with as much as 50% of the mercury in the coal feedstock reduced or removed, much of it bound in the slag and sulfur byproducts.

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