Herrick, Will
Campton, KY
Page 89 of 108

Example: Low Sulfur Coal Configuration with representative emissions performance.

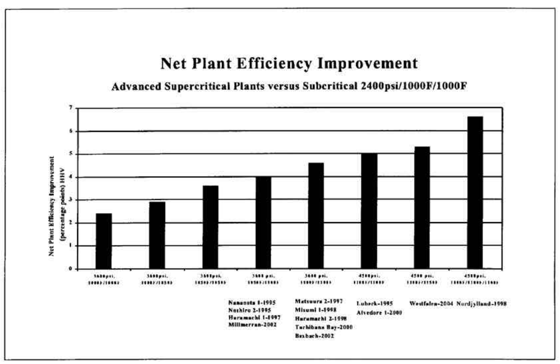
Boiler	SCR	Dry Scrubber	Baghouse
Subcritical or Supercritical	90% + NOx Removal NOx = 0.15 lb/MWh	90-95% SO_2 Removal SO_2 < 0.25 lb/MBtu	Particulate 0.03 lb/MBtu

Example: High Sulfur Coal Configuration with representative emissions performance.

Boiler	SCR	Precipitator or Baghouse	Wet Scrubber
Subcritical or Removal Supercritical lb/MBtu	90% + NOx Removal NOx = 0.15 lb/MWh	Particulate 0.03 lb/MBtu	95%+ SO_2 SO_2 = 0.25

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.)



12

Herrick, Will
Campton, KY
Page 90 of 108

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.

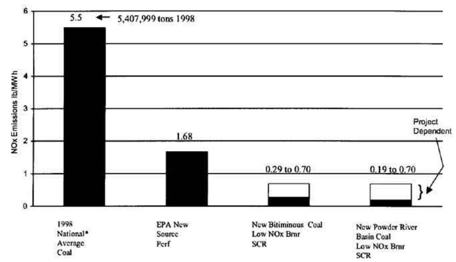
Emissions Performance

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.

NOx Emissions Performance
New Pulverized Coal Power Plant



*EPA Actual 1998

Ck/NCC2-26-01.ppt

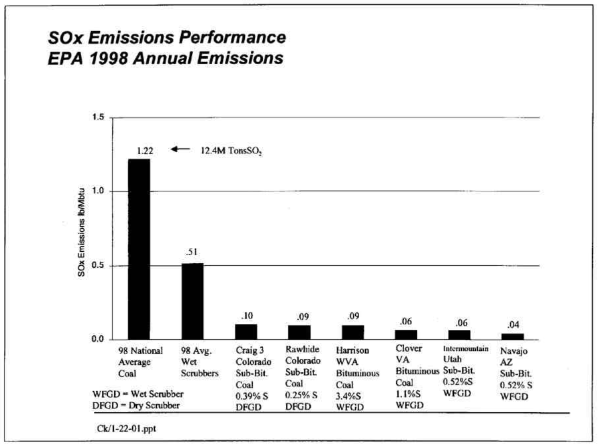
13

Herrick, Will
Campton, KY
Page 91 of 108

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.



14

Herrick, Will
Campton, KY
Page 92 of 108

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.

Herrick, Will
Campton, KY
Page 93 of 108

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).

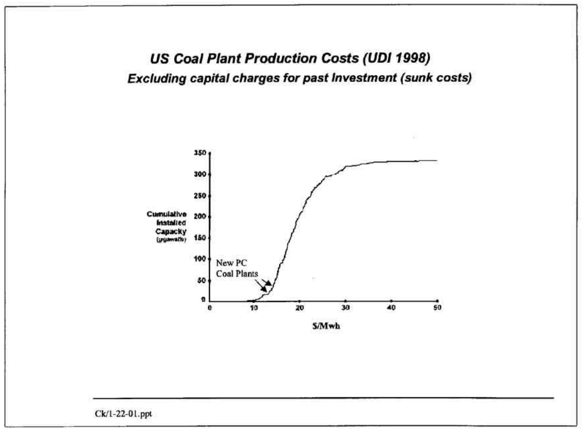
The curve is a plot of the variable production cost of every coal-fired power plant, ranked from the lowest to the highest. It only shows the fuel and O&M cost, and not the sunk capital costs. This would also indicate the relative order of competitive dispatch.

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.

16

Herrick, Will
Campton, KY
Page 94 of 108

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.

Herrick, Will
Campton, KY
Page 95 of 108

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.

18

Herrick, Will
Campton, KY
Page 96 of 108

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%

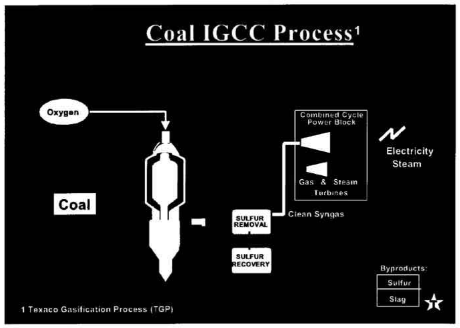
Herrick, Will
Campton, KY
Page 97 of 108

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

20

Herrick, Will
Campton, KY
Page 98 of 108

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

21

Herrick, Will
Campton, KY
Page 99 of 108

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.

22

Herrick, Will
Campton, KY
Page 100 of 108

Another issue that utilities will potentially face in the near future is the need to reduce CO_2 emissions. The existing coal-fired fleet in the U.S. is responsible for about one-third of all of the CO_2 emissions. While automobiles and other industries make up a large portion of U.S. CO_2 emissions, coal-fired power plants are an easier target to identify, measure, and control. Due to its high overall efficiency, repowering an existing coal-fired power plant with IGCC can reduce CO_2 emissions by as much as 20%.

Overall, repowering with IGCC provides a utility with significant increases in environmental performance. By reducing SO_2 and NOx emissions, minimizing solid waste disposal issues, and addressing potential near-term emission limitations for mercury and CO_2, repowering with IGCC allows the utility to move forward with the knowledge that it has addressed environmental issues effectively. For capacity additions and repowering over the next five years, IGCC is an option that utilities can seriously consider.

IGCC Power Plant Applications

Recent History and Applications

Coal gasification technology has been used for over a hundred years. The production of town gas worldwide is a simple form of gasification. Coupling this proven technology with efficient combined cycle technology was seen as a way to enjoy the advantages of using low-cost coal with the high efficiency of combined cycle technology. The 100-MW Cool Water IGCC project, which went in service in 1984, was the first commercial-scale demonstration of IGCC. That project was done in a consortium of EPRI, Southern California Edison, Texaco, GE, Bechtel, and others. The plant operated for more than four years, achieving good performance, low emissions, and developing a base of design for full-scale IGCC plants.

Since then, IGCC technology has improved greatly through DOE's Clean Coal Technology program. The Wabash River IGCC Project and Polk Power Station IGCC Project are in operation as a part of this program. Installations in other countries include the Buggenum plant in the Netherlands and the Puertollano plant in Spain. IGCC performance and reliability continues to see significant improvements. In the fourth year of operation of Tampa Electric's Polk Power Station, the gasifier had an on-stream factor of almost 80%, a considerable improvement over previous years. This project no longer suffers from the serious problems encountered over the first three years, including convective syngas cooler pluggage, piping erosion and corrosion, and sulfur removal problems. The on-going pluggage problems in the convective syngas coolers have been resolved by modifying start-up procedures to minimize sticky ash deposits, and by making configuration changes in the inlet to the coolers to reduce ash impingement at the tube inlets. In the fourth year, the coal gasification portion of the plant became so reliable that the leading cause of unplanned downtime was not there, but rather in the distillate oil system for the gas turbine (problem has been addressed).

Reliable performance has also been achieved at the Wabash River plant. During 2000, the gasification plant reached 92.5% availability, with the power block at 95%. In fact, the gasification technology caused no plant downtime at all. Other areas of the plant, such as coal handling and the air separation unit were available more than 98% of the time.

IGCC for New and Repowered Plants

These examples show that IGCC has met the challenges of the Clean Coal Technology program. Further, with almost 4,000 MW of IGCC in operation worldwide, and another 3,000 MW planned to go into

Herrick, Will
Campton, KY
Page 101 of 108

operation over the next four years, this technology is commercially proven and ready for the repowering market.

The U.S. now has about 320,000 MW of coal-fired power plants, just over one-third of all installed capacity. These coal-fired power plants generate over half of all of the electricity in the U.S. Many of these plants are over 30 years old, with some over 50 years of age. With a growing need for additional capacity in many parts of the country, and rising operation and maintenance costs on existing units, many utilities are looking hard at repowering with technologies that can increase capacity, while decreasing operation and maintenance costs.

Repowering with IGCC can meet those challenges. Repowering older, less efficient generating units with IGCC, results in capacity increases, lower production costs, higher efficiency, and environmental compliance. Since the IGCC plant uses coal as its feedstock, much of the existing coal-fired plant's coal handling and steam turbine equipment and infrastructure can be utilized, lowering the overall cost of repowering. With greater than 95% of the sulfur emissions removed, and further improvements in combustion turbine low-NOx burner technology, emissions of SO_2 and NOx now approach the performance of NGCC plants. By using low-cost and/or low-quality coals, the cost of electricity generated from a plant repowered with IGCC technology can meet or beat that produced by NGCC plants.

One of the key efficiency advantages comes with oxygen-blown IGCC technology. In this type of gasification system, air is first separated into its main constituents: oxygen and nitrogen. The oxygen is used in the gasifier, and the nitrogen is injected into the gas turbine, where it increases the mass flow through the gas turbine, increasing power output, and minimizing NOx formation during combustion. Efficiency increases through further integration can be realized by using extraction air from the gas turbine in other areas of the plant. Since this extraction air leaves the gas turbine at high temperature and pressure, it can be used to preheat boiler feed water. After the heat is removed, the cooled air, still at high pressure, is used to feed the air separation unit, reducing the amount of energy expended there to compress air.

A typical method of repowering an existing unit is to remove the coal-fired boiler and replace it with a gas turbine, re-using the steam turbine in combined cycle mode. In a combined cycle plant, the steam turbine usually provides about one-third of the total output. In a recent study conducted for DOE, a large number of plants with twin 150 MW units were identified as good candidates for repowering. There, the utility could repower one of the units with two 170 MW natural gas-fired gas turbines. The steam produced by the HRSGs for these units would power the existing 150 MW steam turbine, for a total of almost 400 MW.

A typical F class gas turbine produces about 170 MW when firing natural gas. At high ambient temperatures, output may fall to only 150 MW. In an IGCC plant, the syngas is fired in the gas turbine along with the nitrogen, providing significantly higher overall mass flow over a wide range of ambient temperatures. When firing syngas, this same F class gas turbine produces about 20% more output, reaching 190 MW or more. This additional capacity from firing syngas is valuable when additional peaking power is needed during hot, summer days. The additional exhaust flow results in more steam production in the HRSG, making up for steam uses in the gasification area. By firing syngas, the overall capacity is increased to almost 550 MW, more than tripling the capacity of the unit. Repowering the twin 150-MW unit could increase the overall capacity from the original 300 MW to almost 1,100 MW.

While the typical repowering study targets coal-fired boilers, existing NGCC units also provide a technical and economic opportunity for repowering with IGCC. In the case of NGCC units presently firing natural gas, rising fuel costs have lead to increases in the cost of producing electricity. This

24

Herrick, Will
Campton, KY
Page 102 of 108

typically results in a lower capacity factor, and the unit generates fewer MW-hours and revenues. Given the inherent high efficiency of the gas turbines, and the ability to utilize low-cost coal, repowering with IGCC can turn an NGCC unit with a high dispatch price into a unit that dispatches at a much lower cost. As described above, the additional 20% capacity gained from firing syngas instead of natural gas can have significant economic value in areas where there is insufficient peaking power capacity.

IGCC technology has become a more attractive option for new capacity because:

- the technology has been successfully demonstrated at commercial scale in the U.S. and worldwide;
- the enhancements made by the companies operating these IGCC plants, as well as by the technology suppliers, have decreased the cost and complexity of IGCC, while at the same time substantially improving the efficiency and reliability; and
- the price differential between natural gas and coal has risen sharply over the last year.

Economics

The ability to repower units and gain the capacity increases noted in the previous section is a major economic driver for repowering with IGCC. Another advantage of repowering with IGCC is the ability to reuse a significant amount of the existing infrastructure at the plant. Areas such as buildings, coal unloading, coal handling, plant water systems, condenser cooling water, transmission lines, and substation equipment can be incorporated into the repowered IGCC plant This helps to minimize the time for repowering and can reduce the overall cost by about 20%.

With uncertainty in the pace and extent of utility industry restructuring, as well as with changes in environmental regulations, utilities have been reluctant to make large capital expenditures for new capacity. Almost all of the capacity installed over the last few years has been natural gas-fired gas turbines and NGCC. With ongoing decreases in the cost per kW for NGCC technology, along with forecasts of low natural gas prices, NGCC has been the choice for almost all of the new planned baseload capacity in the U.S. Most of this new generation has been built and is being planned in states that have completed their electric utility industry restructuring, making for easier entry into power markets. Unfortunately, the greatest needs for new generation have been in California and the Southeast where deregulation has either been incomplete, inconsistent, or delayed.

With recent increases in the price of natural gas, and stability or even decreases in coal costs, the electric utility industry has renewed its interest in coal-based technologies. Announcements by Tucson Electric Power and Wisconsin Electric Power to build the first coal-fired power plants in years puts coal back in the picture for new capacity. One important result of the improved performance of existing IGCC plants has been an overall decrease in second-generation IGCC plant capital costs. If the current differential price between coal and natural gas continues or grows larger, the economics for repowering with IGCC will become even more attractive.

In the paper "EPRI Analysis of Innovative Fossil Fuel Cycles Incorporating CO_2 Removal," various power generation technologies were analyzed with and without CO_2 removal systems, in a study performed by Parsons. The allowable capital costs were analyzed to determine a break-even cost of electricity based on a range of gas prices. For IGCC, the break-even point with $5/mmBtu gas was found to be about $1,200/kW, dropping to about $1,000/kW with $4/mmBtu gas prices. As IGCC plant costs continue to decrease, it will become an even more serious choice for repowering. If CO_2 removal is required in the future, the costs shown in the study for CO_2 removal and the cost of producing electricity from IGCC will be competitive with NGCC at gas prices of only $3.70-4.00/mmBtu.

Herrick, Will
Campton, KY
Page 103 of 108

Reducing Regulatory Barriers

The Clean Air Act ("CAA") imposes a number of regulatory burdens on the expansion of electric generating capacity. EPA's recent interpretations of several existing laws have led to confusion and perhaps additional burdens. Formally proposed EPA revisions to existing CAA programs may impose further burdens if they are adopted. These burdens impact three activities that increase U.S. generating capacity: (1) the construction of new units; (2) efficiency and availability improvements at existing units; and (3) the repowering or reactivation of existing units.

New Construction

The CAA provides two main programs to control emissions from new coal-fired sources: New Source Performance Standards ("NSPS") and New Source Review ("NSR"). Both programs are intended to require the adoption of controls at the time it is most economical to do so – when a new unit is designed and built.

A utility wishing to construct a new coal-fired generating station must comply with NSPS. NSPS require new sources to meet numerical emissions limitations based on the best technology that EPA determines has been "adequately demonstrated." EPA revises these standards periodically to reflect advances in emissions control technology.

In areas that are in attainment with National Ambient Air Quality Standards ("NAAQS"), a new major source also must comply with prevention of significant deterioration ("PSD") requirements. PSD rules require new sources to adopt the "best available control technology" ("BACT") and to undergo extensive pre-construction permitting. This includes air quality modeling and up to one year of air quality monitoring to determine the impact of the new source on air quality. EPA or state permitting authorities determine what type of control constitutes BACT on a case-by-case basis. BACT may require control beyond NSPS for that source category, but may not be less stringent than applicable NSPS.

A company that constructs a new major source near a "Class I" attainment area must satisfy additional requirements. Class I areas include most national parks, and federal land managers ("FLMs") are charged with protecting air quality in these areas. PSD rules require that FLMs receive copies of PSD permit applications that may impact air quality in Class I areas. In cases where the new source will not contribute to emissions increases beyond allowable levels for the attainment area (*i.e.*, beyond the PSD "increment" for that area), the FLM may still object to issuance of the permit based on a finding that construction of the source will adversely impact "air quality related values" ("AQRVs") (including visibility) for that area. The FLM bears the burden of making that adverse impact demonstration. If the state concurs with the determination, then a permit will not be issued. In cases where the new source would contribute to emissions beyond the PSD increment, the company must satisfy both the FLM and the permitting authority that the unit will not adversely impact any AQRVs, before the permit may be issued.

A company that constructs a new major source in a nonattainment area must satisfy NSR requirements similar to, but more stringent than, PSD requirements. Instead of adopting BACT, the source must adopt control as needed to meet the Lowest Achievable Emission Rate ("LAER") for that source category. LAER is based on the most stringent emissions limitation found in the state implementation plan ("SIP") of any state, or the most stringent emission limitation achieved in practice in the source category, whichever is more stringent. A new major source in a

26

Herrick, Will
Campton, KY
Page 104 of 108

nonattainment area also must demonstrate that any new emissions caused by the source will be offset by greater emissions reductions elsewhere.

In July 1996, EPA proposed changes to these new source programs that would increase the burdens on the construction of new generating stations. EPA's proposal would give FLMs the authority to require companies to perform AQRV analyses even where their new units would not cause exceedence of the PSD increment. A company's PSD application would not be considered complete until it had completed these analyses. EPA's proposal also would transfer authority from EPA to FLMs to define AQRVs and determine what qualifies as an "adverse impact" on those values. These changes, as a whole, would increase the ability of FLMs to control the timing and eventual issuance of PSD permits. EPA also would require state and federal permitting authorities to adopt a "top down" method for determining BACT. Under this method, a PSD applicant must adopt as BACT the most stringent control available for a similar source or source category, unless it can demonstrate that such level of control is technically or economically infeasible. The effect of the policy is to make BACT more similar to LAER in the stringency of control required. The proposed rule is now under review by the Bush EPA.

Following another recent EPA determination, new sources may be required to meet technology-based emission limitations for mercury and other air toxics. On December 20, 2000, EPA indicated that it would regulate emissions of mercury and possibly other air toxics from coal- and oil-fired utilities under the CAA's maximum achievable control technology ("MACT") program. Depending on the basis for the determination, state and federal permitting authorities may be required to impose unit-specific MACT limits on new coal- and oil-fired units until a categorical federal standard is promulgated in 2004. As its name implies, MACT would require units to meet a numerical emissions limitation consistent with the use of the maximum control technology achievable for regulated pollutants.

New source permitting is a lengthy process. The permit must be issued within one year of the filing of a "complete" application. Developing a "complete" application, however, can take another year or longer, as a source negotiates with the permitting authority, FLM, and others regarding modeling, monitoring, control technology, AQRVs, and other issues. If the proposed revisions to the NSR rules are finalized and if case-by-case MACT determinations are required, this permitting process for new sources will take even longer. Even without these proposed revisions, it will be important to consider how this permitting process can be streamlined and expedited.

Efficiency/Availability Improvements at Existing Units

Utilities have many opportunities to increase electrical output at existing units without increasing fuel burn by improving efficiency or reducing forced outages through component replacement and proper maintenance. In some cases, utilities do so as a reaction to unexpected component failures (reactive replacement). In others, utilities replace worn or aging components that are expected to fail in the future or whose performance is deteriorating (predictive replacement). In some cases, utilities replace components because more advanced designs are available and would improve operating characteristics at the unit. Such component replacement can restore a unit's original design efficiency or, in some cases, improve efficiency beyond original design.

Babcock & Wilcox ("B&W"), industry experts on the construction, operation, and maintenance of coal-fired boilers, identify a number of components that electric generating stations typically replace or upgrade during their service lives to maintain or improve operations. These include

27

Herrick, Will
Campton, KY
Page 105 of 108

economizers, reheaters, superheaters, furnace walls, burner headers and throats, and other assorted miscellaneous tubing. In their book Steam, the B&W authors identify predictable ages for the failure of these components and offer a variety of upgrade options to be incorporated as replacement parts. Other components that utilities frequently replace or upgrade include fans, turbine blades and rotors, feed pumps, and waterwalls.

NSR rules apply to "modifications" of existing facilities that result in new, unaccounted for pollution. For the first 20 years of these programs, EPA identified only a handful of "modifications." In 1999, however, EPA sued several major utility companies for past availability and efficiency improvement projects like those described above, characterizing them as modifications subject to NSPS and NSR. EPA has further indicated that it will treat innovative component upgrades that increase efficiency or reliability without increasing a unit's pollution-producing capacity as modifications as well. EPA's current approach to these projects strongly discourages utilities from undertaking them, due to the significant permitting delay and expense involved, along with the retrofit of expensive emission controls that are intended for new facilities. This is the greatest current barrier to increased efficiency at existing units.

NSR rules define a modification as a physical change or change in the method of operation that results in a significant increase in annual emissions of a regulated pollutant. However, the rules exclude activities associated with normal source operation from the definition of a physical or operational change, including both "routine maintenance, repair, and replacement" and increases in the production rate or hours of operation.

For more than a decade following the establishment of these programs, EPA made very few determinations that projects triggered NSR as "modifications." These determinations involved sources that: (1) added new capacity beyond original construction, for example by adding an entirely new generating unit; or (2) reactivated a long-shutdown unit.

In 1988, EPA concluded that a collection of component replacements intended to extend the lives of five Wisconsin Electric Power ("WEPCo") generating units that had been formally derated and were at the end of their useful lives triggered NSR. Pointing to the project's "massive scope," unusually high cost ($80 million spent on five 80-MW units) and "unprecedented" nature, EPA concluded that the project was not "routine," and calculated an emissions increase for purposes of NSR.

Following the WEPCo decision, utility companies and the Department of Energy asked EPA to clarify the impact of its ruling for common component replacement projects in the industry. Through a series of communications with Congress and the General Accounting Office, EPA assured utilities that "WEPCo's life extension project is not typical of the majority of utility life extension projects, and concerns that the agency will broadly apply the ruling it applied to WEPCo's project are unfounded."

In 1992, EPA issued regulations that confirm the historical meaning of the modification rule and provide special guidance on the application of the rule to electric utilities. Under the 1980 rules, the method used to determine an emissions increase for NSR purposes depends on whether a unit is deemed to have "begun normal operations." The preamble to the 1992 rule states that units are deemed not to have begun normal operations only when they are "reconstructed" or replaced with an entirely new generating unit. Units deemed not to have begun normal operations must measure an emissions increase by comparing pre-change actual emissions to *potential* emissions after a change. Since few facilities operate at full capacity around the clock before a change, this test – if applied to existing sources -- nearly always shows an apparent emissions increase (even where

28

Herrick, Will
Campton, KY
Page 106 of 108

emissions in fact decline after the change). Sources that have begun normal operations may compare actual emissions before the change to a projection of actual emissions after it. For utilities, the 1992 rule allows a comparison of past actual to "future representative actual emissions," a term defined to allow elimination of projected increases in utilization due to demand growth and other independent factors (provided that post-change utilization confirms the projections). Other units make a more generic comparison of pre- and post-project emissions holding production rates and hours of operation constant.

In the decade following the WEPCo decision, utilities continued to undertake the replacements described above without incident. In November 1999, however, EPA commenced a major PSD enforcement initiative against seven utility companies and the Tennessee Valley Authority alleging violations of PSD provisions. In complaints and notices of violation ("NOVs"), EPA alleged that replacements of deteriorated components undertaken at these units over the past 20 years were non-routine and triggered emissions increases under NSR rules. The complaints and NOVs target component replacements common in the industry, including economizers, superheaters, reheaters, air heaters, feedwater pumps, burners, turbine blades and rotors, furnace and water wall sections, and other components. EPA has since expanded the enforcement initiative to cover more than 20 companies, with plans to add more.

EPA's claim that these projects are now non-routine has left utilities highly uncertain about the coverage of the modification rule. In particular, EPA now suggests that it has discretion to classify projects as non-routine for several new reasons, including the fact that the replacement restores availability, improves efficiency, or involves a major component. At the same time, EPA has raised the stakes for a finding that a project is non-routine by assuming an emissions increase from all non-routine projects. Specifically, in contrast to the NSR rule, EPA now asserts that any non-routine change makes a unit into one that has not "begun normal operations" – necessitating use of an "actual to potential" emissions increase test that the unit is sure to fail. This is true even where such units have an extensive past operating history that would allow reliable predictions of future actual emissions.

A utility considering projects similar to those targeted in the complaints and NOVs must confront the fact that EPA has claimed broad discretion to classify availability and efficiency improvement projects as non-routine modifications subject to NSR. NSR requires the retrofit of BACT technology, which can cost hundreds of millions of dollars, and can delay projects by several years while permits are obtained and/or controls installed. Accordingly, EPA's actions strongly discourage utilities from undertaking projects that improve efficiency, and thereby increase generation without any increase in pollution.

B&W's Steam suggests the scope of projects blocked by EPA's current approach to modification. In order to reach a standard 55 to 65 year operating life, B&W estimates that a typical utility will replace its superheaters and burners at least twice, its reheaters at least once or twice, the economizer and lower furnace at least once, and all other tubing at least three times. Turbine blades are replaced more frequently still. Industry-wide, this means thousands of major component replacements may be prevented or delayed by EPA's approach, as well as other categories of projects EPA has not yet addressed but may find non-routine under its new discretion.

Moreover, EPA has extended its approach to innovative component upgrades that improve unit efficiency and other operating characteristics. In a letter dated May 23, 2000, EPA concluded that a plan by the Detroit Edison Company to replace worn turbine blades with new, improved blades was non-routine. Detroit Edison proposed to replace existing blading with a new, more durable

29

Herrick, Will
Campton, KY
Page 107 of 108

blading configuration that would increase the efficiency of two turbines by 4.5% each. This would allow these units each to produce 70 additional megawatts of power with no increase in fuel consumption, or to continue producing at past energy levels while reducing fuel consumption by 112,635 tons of coal per year, SO_2 emissions by 1,826 tons per year ("tpy"), and NO_x emissions by 1,402 tpy. This would also allow an incidental 259,111 tpy reduction in CO_2 emissions – a compound that EPA currently lacks authority to control. The company estimated that widespread adoption of the upgrade at compatible units would allow CO_2 reductions of approximately 81 million tpy, with correspondingly large reductions in NO_x and SO_2. EPA based its finding of non-routineness in part on the fact that the project made use of new, upgraded component designs. EPA reached a similar conclusion in 1998, finding that a proposed blade replacement project at a Sunflower Corporation power plant could not be routine because it involved redesigned/ upgrad[ed]" components. Accordingly, utilities contemplating innovative upgrades of turbine and other components to improve efficiency face a known risk that EPA will classify them as non-routine modifications based on their use of advanced technology. Although the exact numbers of innovative projects blocked by EPA's approach is difficult to quantify, the example of Detroit Edison suggests that the losses in generation and pollution reduction from these efficiency gains is substantial.

In sum, EPA's new approach to its NSR rules presents a significant regulatory barrier to projects at existing sources that would otherwise be undertaken to improve availability and efficiency. This barrier can be expected not only to prevent significant gains in generating capacity at existing units, but also to actively reduce availability of these units by preventing needed maintenance. As a related matter, this barrier also can be expected to inhibit development of more efficient generating technologies, reducing the amount of energy that may be produced from existing units, and to encourage prolonged reliance on units operating at lower efficiencies.

Repowering and Reactivation

Replacing a coal-fired boiler with a more efficient generating technology, such as fluidized bed combustion, or an integrated gasification combined cycle, or state-of-the-art pulverized coal technology, can increase generation at an existing facility. This process is commonly known as "repowering." Title IV of the CAA grants special treatment to utilities that meet the acid rain requirements of that title through repowering. A project that qualifies as "repowering" for Title IV purposes also gains exemption from NSPS requirements if the project does not increase the unit's maximum achievable hourly emissions. Such projects almost certainly require PSD review, but are granted expedited review under the Act. EPA has yet to implement these expedited review procedures. Additional uncertainties for permitting these facilities are created by EPA's proposal to "reform" the new source permitting process discussed above.

Reactivation of shutdown existing units presents another means for utility companies to increase generation. A source that has been shutdown for an extended period may be subject to NSPS and/or NSR when it is reactivated. Early determinations on this topic are often unclear or inconsistent as to whether the reactivated unit is subject to NSPS or NSR because it is deemed to be a new unit, or because it is deemed to be an existing unit that has undergone a "modification." In its most recent determination on the subject, EPA has suggested that a unit could be subject to NSPS/NSR for either reason – making for a stricter, two-part standard. Clarification of EPA's reactivation policy, and streamlining of NSR requirements for reactivated facilities, would contribute capacity needed to respond to demand peaks.

30

Herrick, Will
Campton, KY
Page 108 of 108

Solutions

EPA's proposed rule on NSR would impose significant additional burdens for new sources if it is finalized in its current form. EPA's recent listing of coal- and oil-fired electric utility steam generating units as major sources of hazardous air pollutants could require additional, extended pre-construction review for new and reconstructed facilities. EPA's recent reinterpretation of the modification rule with respect to routine repair and replacement, calculating emissions increases, and source reactivation imposes additional burdens that discourage projects that increase unit availability and efficiency or reactivate shutdown units, including cases where shutdown was never intended to be permanent. EPA should return to its historic interpretation and application of these rules.

31

Howe, J.
Clark County, KY
Page 1 of 3

FW: comment on KY Pioneer IGCC draft EIS Page 1 of 1

Itani, Maher -- Tt, Inc.

From: Preston, John S LRH
Sent: Wednesday, January 23, 2002 1:22 PM
To: Maher Itani (maher.itani@tetratech.com)
Cc: Roy Spears (rspear@netl.doe.gov)
Subject: FW: comment on KY Pioneer IGCC draft EIS

Maher: Below is a "phone-in" comment Lloyd forwarded to me. Thanks.

-----Original Message-----
From: Lloyd Lorenzi [mailto:Lloyd.Lorenzi@NETL.DOE.GOV]
Sent: Wednesday, January 23, 2002 11:48 AM
To: Preston, John S; Roy Spears
Subject: comment on KY Pioneer IGCC draft EIS

Commenter - J. Howe
Residence - Clark County, KY
Tele - 859-842-3914
Date - 23 January 2002
Time - ~10:00 am
Method - toll-free number

Comments:
1. "called to protest the waste-to-energy project at the Trapp site" 1/16
2. concerned about emissions of metals and carbon dioxide, and health effects of air emissions 2/06, 3/11
3. "opposed to burning trash from outside sources in New York and New Jersey - if they need to get rid of their trash, the plant should be built there." 4/16

4. "opposed to burning trash, even if the trash is from Kentucky" 5/22
5. the stacks would create a visibility issue 6/04
6. water usage from the Kentucky river is a concern 7/07
7. he would be interested in having DOE or the participants schedule another public meeting; his friends in Trapp are also concerned, and he believes that more than 50 people would attend a future meeting 8. he requested direct notification if another meeting is scheduled, and he communicated no other requests 8/21

Background:
Mr.Howe's residence is located about 5 miles from the proposed project site, and he lived there for the past 7 years. He works as a nurse in Lexington, has 4 children, and moved to Clark County from out of state for, among other reasons, relocation away from areas of high pollution. He did not attend either of the public meetings sponsored by DOE or any other participant- or permit-related meetings on the project. He was not aware of the prior meetings, and he does not receive the local (Winchester) newspaper. He also was not aware of plans for the proposed project, only recently learned about the proposed project from a friend, and he indicated that news is substantially communicated by "word-of-mouth."

Comment No. 1 Issue Code: 16
Comment noted.

Comment No. 2 Issue Code: 06
Comment noted. Heavy metal emissions from the proposed project are identified in Chapter 5, Table 5.7-2, of the EIS. These emissions would average 4.68 metric tons (5.16 tons) per year. The estimated maximum lifetime cancer risks associated with exposure to these emissions from the proposed project are presented in Table 5.7-4. As noted in the EIS, the proposed project would produce about 1.45 million metric tons (1.6 million tons) of greenhouse gas emissions per year (mostly carbon dioxide). This would be about 25 percent less than the amount produced by a comparable natural gas fueled power plant. Additional discussion of metal deposition issues has been added to Chapter 5, Section 5.7.4, for the Final EIS.

Comment No. 3 Issue Code: 11
Incremental ambient air quality impacts from the proposed project would be a very small fraction of the relevant federal and state ambient air quality standards (less than 1 percent for gaseous pollutants such as nitrogen dioxide, sulfur dioxide, and carbon monoxide and less than 4 percent of the federal 24-hour PM_{10} standard). Total heavy metal deposition in areas downwind of the project would be much less than 1.1 kilogram per hectare (1 pound per acre) accumulated over 20 years. The maximum air pollutant increase associated with emissions from the proposed project would have no significant short- or long-term air quality impacts and the health risks are expected to be minor.

Howe, J.
Clark County, KY
Page 2 of 3

Comment No. 4 **Issue Code: 16**

Because of DOE's limited role of providing cost-shared funding for the proposed Kentucky Pioneer IGCC Demonstration Project, alternative sites were not considered. KPE selected the existing J.K. Smith Site because the costs would be much higher and the environmental impacts would likely be greater if an undisturbed area was chosen. Also, the relatively small amounts and generally widely dispersed nature of MSW in Kentucky does not economically support exclusive utilization of Kentucky-generated MSW to produce RDF supplies, which makes it necessary to import RDF. Importing RDF from a densely populated metropolitan area is more economically viable in order to supply the necessary amount of RDF required to operate the plant.

Comment No. 5 **Issue Code: 22**

Comment noted.

Comment No. 6 **Issue Code: 04**

Comment noted. Impacts to the aesthetic and scenic environment of the project area are presented in Section 5.5, Aesthetic and Scenic Resources, of the EIS.

Comment No. 7 **Issue Code: 07**

The cumulative effects of withdrawals from the Kentucky River by power plants have been discussed by the Kentucky Natural Resources and Environmental Protection Cabinet in their cumulative assessment report (KNREPC 2001) addressed in Section 5.14, Cumulative Impacts, of the EIS. The report acknowledges that because many of Kentucky's power plants are exempt from water withdrawal requirements, the Cabinet does not have an accurate inventory of the volume of water being removed each day by the existing power plants. However, the Cabinet is able to limit withdrawals from permitted sources during periods of abnormally low flow. Although the proposed plant would not be a permitted withdrawal source, KPE has stated that they would cease water withdrawals if requested to by the state.

Howe, J.
Clark County, KY
Page 3 of 3

Comment No. 8 **Issue Code: 21**

NEPA requires that one public hearing be held during the public comment period. Based on public input during the scoping period, DOE decided to hold two public hearings during the public comment period, one in Lexington and another in Trapp, Kentucky. The meeting in Lexington was included as a result of the public input. All requirements in state and federal laws, rules, and regulations regarding public hearings were satisfied and surpassed. DOE will consider all public comments before issuing the ROD. The ROD will be issued no sooner than 30 days after the Final EIS is distributed and a notice of its availability is issued.

Johnson, Peggy
Lexington, KY
Page 1 of 1

From: Lloyd Lorenzi [Lloyd.Lorenzi@NETL.DOE.GOV]
Sent: Monday, January 14, 2002 10:39 AM
To: John.S.Preston@lrh01.usace.army.mil; Roy Spears
Subject: comment on KY Pioneer IGCC draft EIS

Commenter - Peggy Johnson
Address - 1628 Prairie Circle
Lexington, KY 40515
Tele - 859-744-3123
Date - 11 January 2002
Time - ~12:30 pm
Method - toll-free number

Comments:
1. "project would be detrimental to the area in Winchester and Clark County" 1/16
2. project would affect property (values and quality) in the vicinity, now and in the future 2/02
3. stacks would create adverse visible impact 3/04
4. "no telling about problems to be created by the waste" 4/12

Background:
Ms. Johnson works for the Winchester Sun newspaper. She enjoys boating on the river and the scenic beauty of the area. She did not attend either of the public meetings, and she has not read/examined the draft EIS. She made no requests for additional information.

1

Comment No. 1 **Issue Code: 16**

Comment noted. The impacts from the proposed project are detailed in Chapter 5, Environmental Impacts, of the EIS.

Comment No. 2 **Issue Code: 02**

The land at the 1,263-hectare (3,120-acre) tract is currently zoned agricultural, as discussed in Section 4.2, Land Use. Areas surrounding the proposed site are residential and agricultural. These agricultural areas could be developed for residential housing. Property values are based on several factors, including willingness to buy and psychological criteria. Depending on the potential buyer, the power plant could impact property values in the surrounding area. However, the closest residence to the site is approximately 1.6 kilometers (1 mile) away, which would mitigate many factors, including proximity to the site, thus mitigating the impact to property values. Section 5.3, Socioeconomics, has been modified to address impacts to property values.

Comment No. 3 **Issue Code: 04**

Comment noted. Visual impacts to the project area are presented in Section 5.5, Aesthetic and Scenic Resources, of the EIS.

Comment No. 4 **Issue Code: 12**

Waste generated at the proposed facility would be managed in accordance with applicable state and federal regulations. Solid wastes would be disposed of at one of several licensed facilities in the surrounding area, as discussed in Section 5.13, Waste Management. Because there are no hazardous waste treatment facilities in the State of Kentucky, any hazardous waste generated at the site would be managed in accordance with RCRA hazardous waste regulations (40 CFR Parts 260 to 270) and disposed of at an "out-of-state" licensed hazardous waste disposal facility. Frit is considered a commercial product, not a waste, and would be marketed for use in road construction.

Jones, Michael B.
Lexington, KY
Page 1 of 2

Kentucky Pioneer Integrated Gasification
Combined Cycle Demonstration Project
Draft Environmental Impact Statement
U.S. Department of Energy
National Energy Technology Laboratory

12/29/01

Written Comment Form
Must be received by January 4, 2002.

1/22 I would like to Voice my opposition to the operation of The coal and Pelletazied Garbage Fired Power Plant. Not only are the unknown
2/12 impact to the surrounding Area From Burning of this Garabage Product
3/12 But the Problems with Storage and Possible leakage into the River and landscape could Be A Disaster.
4/02 Aslo I can not see the Benefits of what few Jobs created By this Plant outweighing the Possible Problems and Risks.
5/16 In Addition to this, we in this Area Don't Need the extra Power. It seems that A Plant (Experimental) such as this one should be in A Area where the Power is Needed and that! Area should Bear the Risks.
Please Consider other options. Thank you

Michael B Jones

Please use other side if more space is needed.

Comment forms may be mailed to:
Mr. Roy Spears
U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, WV 26507-0880

Comment forms may be faxed to:
Mr. Roy Spears
(304) 285-4403

Comment No. 1 **Issue Code: 22**
Comment noted.

Comment No. 2 **Issue Code: 12**
There are distinct differences between gasification and incineration. Incineration occurs at atmospheric pressures and temperatures and mineral matter or ash in the waste is not completely fused. With incineration, there is increased production and emission of criteria pollutants. In contrast, gasification occurs at high temperatures and pressures which significantly reduces the formation of oxidative species such as SO_x and NO_x. Incineration produces semi-volatile and volatile organic compounds and dioxin/furan compounds not produced with gasification. Ash from hazardous waste incinerators is considered a hazardous waste under RCRA. Analysis of vitrified frit produced from gasification processes has consistently proven to be nonhazardous as defined by RCRA. In gasification, nonvolatile trace metals concentrate in the vitrified frit and are effectively immobilized eliminating or reducing their leachability.

The proposed project is not a conventional power plant burning coal or RDF. Instead of burning such fuels in a boiler system, the proposed project would use gasification technologies to convert the coal and RDF co-feed into a syngas fuel consisting primarily of CO and H_2. The gasifier operates as a completely enclosed pressurized system. Gasification occurs at high temperatures which ensures complete destruction of toxic organic compounds and incorporation of heavy metals in molten slag. The molten slag is recovered by quenching as a nonleachable glassy frit. Since gasification occurs in a carefully controlled environment, the process produces no air emissions. Furthermore, the high temperatures achieved during gasification from the use of oxygen instead of air prevent the formation of dioxins/furans. A description of the gasification process can be found in Chapter 3, Section 3.1.2.2, of the EIS.

Jones, Michael B.
Lexington, KY
Page 2 of 2

Comment No. 3 **Issue Code: 12**

RDF and vitrified frit are solid materials and would not leak into the Kentucky River. These materials would be held in covered storage and protected from the weather to avoid contact with precipitation and runoff.

Comment No. 4 **Issue Code: 02**

Comment noted. The EIS is designed to present all of the possible environmental impacts of the various alternatives relating to the proposed federal action, both beneficial and detrimental. The economic benefits associated with the project are not intended as justification for the environmental costs of the project; however, they are presented as one of many resource areas impacted by the project.

Comment No. 5 **Issue Code: 16**

The purpose of this EIS is to evaluate public and environmental impacts caused by the proposed project. DOE will consider the information provided in the EIS and public comments in this decision process. Chapter 2 of the EIS discusses EKPC's 1998 Power Requirements Study which indicates that the electrical load for the region is expected to increase by 3.0 percent per year through 2017. Net winter peak demand is expected to increase by 3.3 percent per year and net summer peak demand is projected to increase by 3.0 percent per year. Peak demand is projected to increase from 2,031 MW in 1998 to 2,394 MW in 2003 and 3,478 MW in 2015. Based on this load growth, EKPC will need additional power supply resources of 625 MW in 2003. The need is further shown by EKPC's plans to construct four new CT electric generating units to provide peaking service alongside the three existing peaker CTs at the J.K. Smith Site. Because of DOE's limited role of providing cost-shared funding for the proposed Kentucky Pioneer IGCC Demonstration Project, alternative sites were not considered.

Jones, Remona
Lexington, KY
Page 1 of 1

Kentucky Pioneer Integrated Gasification
Combined Cycle Demonstration Project
Draft Environmental Impact Statement
U.S. Department of Energy
National Energy Technology Laboratory

12-27-01

Written Comment Form
Must be received by January 4, 2002.

I am very much against having a trash burning power plant This is a experiment that I think

1/16

should take place in the desert some where away from family homes and live stock. The Clark County citizens do not need the trash

2/07

hauled in from NY. and contaminate their land water etc. How could they (Clark Co.) benefit

3/02

from it? Twenty or so jobs is NOT worth it" Other States NEED the power Let them

1/16 (cont.)

have this experimental project. Please Consider other States for this "Gasification Project"!

Thank you
Remona Jones
Remona Jones

Please use other side if more space is needed.

Comment forms may be mailed to:
Mr. Roy Spears
U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, WV 26507-0880

Comment forms may be faxed to:
Mr. Roy Spears
(304) 285-4403

Comment No. 1 **Issue Code: 16**

Comment noted. Because of DOE's limited role of providing cost-shared funding for the proposed Kentucky Pioneer IGCC Demonstration Project, alternative sites were not considered. KPE selected the existing J.K. Smith Site because the costs would be much higher and the environmental impacts would likely be greater if an undisturbed area was chosen.

Comment No. 2 **Issue Code: 07**

All materials transported on land would be enclosed in vehicles and would not be released to the environment under normal circumstances. In the event of an accident, some materials could be released to the environment. KPE would develop an Emergency Response Plan and an SPCC Plan during the project engineering and construction phase. These plans would detail KPE's planned response and clean-up methods for any spills or emergencies that occur on the J.K. Smith Site. In addition, the Kentucky Division of Water's Emergency Response Team should be called ([502] 564-2380 or 1-800-928-2380) in the event of an "environmental emergency." The spill or unexpected discharge of a hazardous material that threatens the life, health, or safety of citizens or the environment is considered an environmental emergency. More information on the Emergency Response Team can be found on the Internet at http://water.nr.state.ky.us/dow/dwert.htm.

Comment No. 3 **Issue Code: 02**

The EIS is designed to present all of the possible environmental impacts of the various alternatives relating to the proposed federal action, both beneficial and detrimental. The economic benefits associated with the project are not intended as justification for the environmental costs of the project; however, they are presented as one of many resource areas impacted by the project. The project will create 120 jobs in Clark County and 270 indirect jobs throughout the ROI.

Kentucky Environmental Foundation
Berea, KY
Page 1 of 5

Kentucky Environmental Foundation
P.O. Box 467 Berea, Ky. 40403
Phone: 859-986-7565 Fax: 859-986-2695
e mail : kefwilli@acs.eku.edu web: www.cwwg.org

Mr. Roy Spears
U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Rd.
Morgantown, WV 26507-0880

January 25, 2001

SUBMITTED BY MAIL AND ELECTRONIC MAIL

Dear Mr. Spears,

Following are comments on the draft Environmental Impact Statement for the Kentucky Pioneer Integrated Gasification Combined Cycle Demonstration Project. These comments are made on behalf of the Kentucky Environmental Foundation, a non-profit organization located in Berea, Madison County, Kentucky.

This EIS is indicative of a fundamentally flawed regulatory process: one that seeks to manage a set of unacceptable or unnecessary risks rather than find comprehensive solutions which may prevent risks altogether. In this case, citizens are asked to provide comments on a set of bad options in an EIS; this does not allow for review of the broad issues of energy needs and resources in Kentucky and elsewhere. 1/22

For this reason and those listed below, KEF advocates the "No Action Alternative 1," which states that no plant is constructed. 2/17

GENERAL COMMENTS

1. The EIS is not convincing in its argument that this power plant is necessary by any definition. In fact, the document states outright that "the need for greater electrical generation...is demonstrated by the stated intention of Global Energy, Inc., to proceed with the construction of two combined cycle combustion turbines regardless of whether DOE provides cost-shared funding for the proposed project." (p. 2-2). Decisions which affect public health and the environment should not be determined by corporate intent.

The fact that the proposed facility site has laid vacant for decades shows that neither DOE nor the companies involved in this project have a good perspective on the power supply needs of eastern Kentucky. 3/14

2. KEF supports a sustainable energy plan that would not include construction and operation of new power plants. Power plants are a leading contributor of greenhouse gases, heavy metals and other toxic contaminants into the environment. Considering the current background levels of all such contaminants in the environment, any new power plant -- including "waste-to-energy" facilities like this one -- is unacceptable. 4/22

Comment No. 1 **Issue Code: 22**

The CCT Programmatic EIS, released in 1989, addresses potential environmental consequences of the widespread commercialization of the successfully demonstrated CCTs. Energy use was reviewed under the purpose and need analysis. The analysis of other power sources is outside the scope of this EIS.

Comment No. 2 **Issue Code: 17**

Comment noted.

Comment No. 3 **Issue Code: 14**

Chapter 2 of the EIS discusses EKPC's 1998 Power Requirements Study which indicates that the electrical load for the region is expected to increase by 3.0 percent per year through 2017. Net winter peak demand is expected to increase by 3.3 percent per year and net summer peak demand is expected to increase by 3.0 percent per year. Peak demand is expected to increase from 2,031 MW in 1998 to 2,394 MW in 2003 and 3,478 MW in 2015. Based on this load growth, EKPC will need additional power supply resources of 625 MW in 2003. The need is further shown by EKPC's plans to construct four new CT electric generating units to provide peaking service alongside the three existing peaker CTs at the J.K. Smith Site.

Comment No. 4 **Issue Code: 22**

Comment noted. The issue of alternative power sources is outside the scope of the EIS.

Kentucky Environmental Foundation
Berea, KY
Page 2 of 5

Rather than manage the unacceptable risks of such a facility, which is only expected to function for twenty years, KEF instead urges an energy plan that is sustainable and non-polluting and which includes power from solar and wind, and other renewable resources. 4/22 (cont.)

3. The Precautionary Principle states that where there is doubt or scientific gaps, decisions should be based in precaution. This EIS greatly lacks in detail in a number of areas around known and suspected health effects from the IGCC plant. What we *do* know about emissive technologies, and the toxic chemical being emitted from these facilities, is enough to condemn the project (see specific comments below). 5/11

SPECIFIC COMMENTS

1. The EIS does not reflect any intent by DOE or Kentucky Pioneer to take public comment seriously; the document states in numerous places (e.g. the statement mentioned in General Comment #1 above) that some sort of plant will be constructed regardless of DOE funding. 6/21

2. What little IGCC process details exist in the EIS, seem to contradict the statement that this project "would best further the objectives identified in the [Clean Coal Technology] Program" (S-3). The EIS is not clear on the actual amounts of coal used in the process for the long-term. 7/14

3. The proposed facility could be more accurately described as a municipal waste combustion facility which happens to produce electricity. This poses several problems: 8/22

- burning municipal waste in any form -- including refuse derived fuel pellets -- will likely result in release of persistent organic pollutants, or POPs, including dioxins and heavy metals. This action alone poses a very serious health risk. The most recent draft of the USEPA's dioxin reassessment states that dioxins are a known carcinogen, and that the U.S. population on average already has a body burden of dioxin which exceeds any "safe" standard. Both the EPA, the World Health Organization and other independent health agencies consider dioxins alone to be the most toxic manmade chemicals. The seriousness of the existence of dioxins and other POPs in the world's environment, food chain and human bodies has resulted in the international POPs treaty which calls for the ultimate elimination of these chemicals. Specifically, the treaty recognizes the importance of preventing new sources of these chemicals. 9/06
- the details around the composition of the RDF is so lacking that it is impossible to make any more specific comments on that waste stream. 10/16
- there is no reference in Section 6 to Kentucky regulations regarding municipal waste combustion facilities. This facility should be required to, at the very least, meet these regulations. 11/21

4. The finding of no health or safety impact for the proposed IGCC facility is completely unfounded. Merely stating that the facility will meet all regulatory requirements has no bearing whatsoever on the plant's safety. There is no discussion whatsoever of the effects of facility emissions other than the "estimated lifetime cancer risk" table. The risks of acute and chronic exposures for both cancer and non-cancer effects need to be assessed for all segments of the population. Until more detail on these health effects is presented, it is impossible to provide meaningful comment. 12/11

Comment No. 5 **Issue Code: 11**

The emissions from the proposed project would have a less than significant impact because the incremental increase from air emissions is a small fraction of the relevant state and federal ambient air quality standards. Acute and short-term noncancer health effects would be very low because pollutant concentrations are below criteria pollutant and/or air quality standards. Conservative estimates of lifetime exposure risk (probability of developing cancer) for points of maximum downwind exposure are shown in Chapter 5, Table 5.7-4, of the EIS. An estimated lifetime exposure risk of 5E-05 (5.0×10^{-5}) applies to location of maximum exposure which is within the boundaries of the J.K. Smith Site. Cumulative estimate lifetime risk for offsite locations would be less than 5E-05 (5.0×10^{-5}) and decrease with distance from the site.

Comment No. 6 **Issue Code: 21**

All comments received during the public comment period will be considered during preparation of the Final EIS and addressed in the comment response document. A final decision will be made based on the findings of the EIS and public input, in addition to other factors. DOE will consider all public comments before issuing the ROD. The ROD will be issued no sooner than 30 days after the Final EIS is distributed and a notice of its availability is issued.

Comment No. 7 **Issue Code: 14**

DOE selected the Kentucky Pioneer IGCC Demonstration Project for further consideration under DOE's fifth solicitation (CCT-V) of the CCT and concludes that the project meets CCT Program requirements due to the use of the co-fed BGL technology. The proposed federal action is to provide funds for demonstration of the BGL gasification technologies. The EIS provides analysis and impacts based on the fuel feed used for the 1-year demonstration. The impacts presented in this EIS are based on the full 20-year timeframe that the plant is expected to be operating.

Kentucky Environmental Foundation
Berea, KY
Page 3 of 5

5. Similarly, there is no mention of health in the section discussing cumulative effects. This section should include the cumulative health effects as listed above, and also a discussion of the synergistic effects of plant emissions with background contaminants levels.

IN SUMMARY, KEF strongly opposes the IGCC project. The project is unnecessary, and the wide data gaps in the EIS make it impossible to comment with any greater detail.

Please feel free to contact me if you have any questions.

Sincerely,

Elizabeth Crowe

Elizabeth Crowe
Kentucky Environmental Foundation

also on behalf of:

Ramesh Bhatt
Sierra Club Cumberland (Kentucky) Chapter
1000 Rain Court
Lexington, KY 40515

William S. Herrick
4859 Flat-Mary Rd
Campton, KY 41301

Naomi Schulz
Member, Kentuckians for the Commonwealth
109 Phillips St.
Berea, KY 40403

Lisa Collins
2344 Harrodsburg Rd.
Lexington, KY 40503

John Maruskin
Adult Services Librarian
Clark County Public Library
1101 Ironworks Rd.
Winchester, KY 40391

Tom FitzGerald
Kentucky Resources Council
PO Box 1070
Frankfort, KY 40602

encl: Addendum page

13/20
14/16

Comment No. 8 **Issue Code: 22**
Comment noted.

Comment No. 9 **Issue Code: 06**
Comment noted. Hazardous air pollutant emissions from the proposed project are identified in Chapter 5, Table 5.7-2 of the EIS. The estimated maximum lifetime cancer risks associated with exposure to these emissions from the proposed project are presented in Table 5.7-4.

Comment No. 10 **Issue Code: 16**
Chapter 3, Section 3.2.2.2, discusses the production and composition of the RDF pellets using all available relevant data. KPE intends to supply all RDF pellets for this project from the same manufacturer. Variation in RDF pellet composition due to different manufacturing processes should not be an issue for this project. The gasification technology used produces a very consistent syngas product, regardless of the variability of the feed. Chapter 3 has been modified to provide more detail on the gasification process, including the production of the vitreous frit.

Comment No. 11 **Issue Code: 21**
KPE is not attempting to circumvent KRS 224, or any other state or local laws. KPE has appealed to the state for an interpretation of the language of applicable solid waste laws regarding RDF. The Kentucky Natural Resources and Environmental Protection Cabinet has determined that the RDF is a recovered material, not waste. The Kentucky Pioneer IGCC Demonstration Project facility will be considered a recovered materials processing facility and the gasification process will not require a waste permit as long as the RDF conforms to the regulatory definition. A discussion of this issue has been added to Chapters 1 and 6 of the EIS.

Kentucky Environmental Foundation
Berea, KY
Page 4 of 5

Following is a list of commentors for the DOE/EIS-0318 Kentucky Pioneer Integrated Gasification Cycle Demonstration Project Draft Environmental Impact Statement. Also following is a list of citizens and names of organizations. On behalf of, and with permission of, the original commentors, we request that the names and organizations on the second list be added to the submitted comments in the first list.

List of comments submitted:

William S. Herrick, comments submitted 01/23/02
4859 Flat-Mary Rd
Campton, KY 41301

Ramesh Bhatt, comments submitted 01/20/02
Sierra Club Cumberland (Kentucky) Chapter
1000 Rain Court,
Lexington, KY 40515

Tom Fitzgerald
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602

Phil Crewe, comments submitted 01/24/02
1817 Traveller Rd.
Lexington KY 40504

Elizabeth Crowe, comments submitted 01/25/02
Kentucky Environmental Foundation
P.O. Box 467
Berea, KY 40403

List of names to be appended to the above listed comments:

John Maruskin
Adult Services Librarian
Clark County Public Library
1101 Ironworks Rd.
Winchester, KY 40391

Lisa Collins
2344 Harrodsburg Rd.
Lexington, KY 40503

William S. Herrick
4859 Flat-Mary Rd
Campton, KY 41301

Ramesh Bhatt
Sierra Club Cumberland (Kentucky) Chapter
1000 Rain Court
Lexington, KY 40515

Comment No. 12 (cont.) **Issue Code: 11**

Acute and short-term noncancer health effects would be very low because pollutant concentrations are below criteria pollutant and/or air quality standards. Conservative estimates of long-term health effects of cancer for points of maximum downwind exposure are shown in Chapter 5, Table 5.7-4, of the EIS. The proposed project would be permitted at levels to minimize the acute, short-term and long-term health impacts to the public. The air quality permit for the proposed project requires continuous emission monitoring for criteria pollutants and annual emissions testing for cadmium, lead, mercury, hydrogen chloride, and dioxins/furans. Noncompliance with permitted emission levels would result in a plant shutdown.

Comment No. 13 **Issue Code: 20**

Comment noted. Section 5.14, Cumulative Effects, has been revised to include an analysis of the cumulative health effects.

Comment No. 14 **Issue Code: 16**

Comment noted.

Kentucky Environmental Foundation
Berea, KY
Page 5 of 5

Tom Fitzgerald
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602

Elizabeth Crowe
Kentucky Environmental Foundation
P.O. Box 467
Berea, KY 40403

Naomi Schulz
Member, Kentuckians for the Commonwealth (KFTC)
109 Phillips Street
Berea, KY 40403

Phil Crewe
1817 Traveller Rd.
Lexington KY 40504