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TECHNOLOGY ASSESSMENT GUIDE

NO. 11

COAL-OIL MIXTURES, ETC.

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

Coal/oil mixtures (COM) have been developed as a hybrid fuel to enable the use of significant amounts of coal in processes otherwise incapable, without major renovation, of using coal. To form COM, finely pulverized coal (200 mesh) is blended with residual oil in a homogeneous slurry. The coal composition of the mixture usually varies between 20 and 50 percent, depending on process requirements. When heated, this mixture shares many characteristics with residual oil and can be pumped using similar equipment. At high coal compositions, however, the mixture behaves less like oil and is more difficult to handle. This can increase costs and the potential that the fuel will be incompatible with specific processes.

Additives or an ultrasonic homogenization process are used to maintain the coal in suspension. Water is also added in same process, which improves the combustion properties of the resultant mixture. The amount of water added varies by process from zero to twenty percent of the COM by weight. COM can be prepared on-site or in a central preparation facility and trucked to the user.

Because COM is a low-technology coal-based liquid fuel, it will allow substantial near-term substitution of coal for oil in industrial and utility installations currently burning oil. Of these existing installations, those originally designed for coal and now burning oil will be more easily retrofit to COM use than those originally designed for oil. COM will probably be used only in existing facilities; new facilities are likely to be built to burn 100 percent coal or a synthetic fuel with handling properties superior to those of COM.

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The economic feasibility of COM use depend on the capital costs of retrofitting an existing facility for COM and the fuel cost savings derived from coal utilization. COM can consist of a maximum of 50 percent coal by weight. Such a mixture would derive 40 percent of its energy from coal. Because coal costs approximately one third as much as oil per Btu, usage of 50 percent COM would allow a 25% fuel cost saving. In many utility and industrial situations, particularly these facilities originally designed for coal and now burning oil, COM retrofit will prove economically optimal.

In facilities initially designed for coal now burning oil, an additional retrofit alternative will be complete conversion to coal. In comparison to COM conversion, full coal conversion will entail greater capital costs, but will allow greater fuel cost savings.

1.2 Engineering Issues

1.2.1 Preparation

COM is prepared by blending pulverized coal (70-80 percent through 200 mesh) with residual oil and water. These mixtures will contain a maximum of 50 percent coal by weight. Because coal has less energy than oil by weight, in 50 percent COM only about 40 percent of the energy is supplied by coal. Residual oil must be used instead of distillate because distillate is not viscous enough to hold the coal in suspension.

COM may be prepared either at the user's site or in a central facility. Off-site preparation requires COM to be transported by tank truck to the user. On-site preparation requires sufficient fuel use to economically justify the construction costs of the preparation facility.

1.2.2 COM Use

There are no major engineering problems which seriously impede the use of COM. However, there are two problems which make the use of COM somewhat more difficult and costly than burning oil: fuel preparation and system wear.

The solid particles contained in COM present several problems. If the fuel is allowed to sit, the coal particles can settle or agglomerate, making subsequent handling difficult and causing uneven combustion. Alternatively, if the additives in the mixture are sufficient to hold the mixture in suspension, the fluidity of the mixture could be reduced greatly after long periods of standing.

Erosion in pipes and pumps resulting from fuel handling and the effects of this erosion can be controlled through the selection of proper materials. Pumps designed to handle abrasive fluids will be required in the COM plant. In addition, the piping configuration of the plant will have to be evaluated and possibly redesigned to minimize bends and low spots that cause erosion and particle sedimentation. Burners will need larger orifices and lower atomization pressures to handle the COM. Ash handling equipment, such as soot blowers and a bottom ash hopper, will be necessary in oil-designed boilers.

A third problem is that of boiler derating. COM requires a larger volume for complete combustion than either oil or gas. Therefore, there is doubt as to whether heat output can be maintained at design rating in boilers initially designed for oil and gas that are converted to COM. At test burns conducted at Florida Power and Light and the Pittsburgh Energy Technology Center, no derating occurred in equipment initially designed for oil. However, other facilities may have problems with boiler derating.

1.2.3 Environmental Issues

COM will replace some oil with coal. Because coal, when burned, produces more SO_x, NO_x, and particulates than does oil, combustion of COM will increase air quality problems. SO_x emissions will be predictable from the sulfur content of the coal and oil, and can be controlled through the use of low-sulfur coal and oil in the mixture. Alternatively, flue gas desulfurization systems may be installed, but these are costly.

NO_x emissions will be partially predictable from the nitrogen content of the coal and oil used. NO_x can be controlled by limiting the excess air in the boiler.

Because coal is much higher in non-combustible ash than is oil, particulate emissions will increase when COM is used. Electrostatic precipitators will be needed to control particulates.

Wastewater treatment and solid waste disposal which will be associated with COM use is similar to that developed for coal combustion and is well understood. No serious environmental problems associated with COM preparation exist.

1.2.4 Technology Status

COM development is proceeding under both private and Department of Energy sponsorship. Large-scale commercial use of the technology is nearly a reality, and demonstrations have been carried out on both industrial and utility boilers.

Two utilities, New England Power Service Company (DOE sponsored and Florida Power and Light (private), test COM in utility-size boilers. The Department of Energy operates a package oil-designed 700-hp boiler to demonstrate COM firing at PETC. These facilities have all built their own COM preparation plants. One corporation, CoaLiquid, Incorporated, of Shelbyville, Kentucky, has built a demonstration COM preparation plant and has staged test burns of its product at several industrial facilities. CoaLiquid plans the construction of several commercial-size COM plants in the near future.

COM technology is well developed, and COM will replace appreciable amounts of oil in the near future.

1.3 Economic Issues

COM market penetration is propelled by the fact that coal costs only one-third as much as oil on a heat-content basis. In a COM containing 50 percent coal by weight (the maximum possible), coal supplies 40 percent of the energy, replacing large amounts of oil. As a result, COM fuel costs will be only about 75 percent of the costs of residual oil.

The fuel cost advantage can make a switch from residual oil to COM economical for industrial and utility users of residual oil. The cost of out-of-service time and the capital cost of COM conversion must be compared to the fuel cost savings. Facilities that are originally designed for oil will have greater retrofit costs than those originally designed for coal; so the economics of COM conversion are likely to be less favorable for the former. Also, the economies of scale in COM retrofit are such that larger facilities have lower retrofit costs per unit of energy.

COM can be prepared either on-site or at a central preparation facility and trucked to the user. For smaller installations (industrial boilers), it will be more economical to buy COM from a central distributor. A utility's fuel needs would be large enough so that the cost of an on-site preparation facility would be justified. The decision as to whether to build an on-site facility or to buy from a dealer will be based on whether fuel cost savings generated by mixing COM on-site are greater than increases in capital and operating costs associated with owning a dedicated COM preparation facility. The more fuel used, the greater will be the incentive to construct a dedicated preparation facility.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 General Description of the Technology

Coal-oil mixture (COM) is a liquid boiler fuel which can be used instead of residual oil. In COM, coal and oil are mixed together, allowing substitution of coal for oil while retaining the convenience of liquid fuel.

Engineering aspects of coal-oil mixtures (COM) may be divided into three general categories: preparation of COM, boiler and facility modifications needed to burn COM, and environmental control systems associated with the preparation and combustion of COM.

2.2 Process Description (Coal-Oil Mixture Preparation)

The methods of COM preparation described here are those used by the New England Power Service Company (NEPSCO) which has set up a COM preparation facility in Salem, Massachusetts, and/or the methods used by CoaLiquid, Incorporated, a Shelbyville, Kentucky corporation (2,3). CoaLiquid has built a COM preparation demonstration plant in Kentucky, and is planning the construction of several commercial plants to serve industrial customers.

Coal-oil mixtures (COM) consist mainly of mixtures of coal and residual oil. Ten percent water is added to the mixture in the CoaLiquid, Inc., proprietary process. Chemical additives (0.5 percent) may be added to COM to improve the stability and flowability of the mixture. Residual oil must be used instead of distillates because lighter grade oil is not viscous enough to hold the coal in suspension.

The first step in the manufacture of COM is the preparation of the coal in Area 200. The coal is generally pulverized until 70-80 percent will pass 200 mesh in Unit 220. Coal fines from the pulverizing mill must be captured and disposed of in Unit 250. They may be injected directly into the boiler at dedicated COM preparation facilities.

Fine pulverization ensures that the coal will mix well. After pulverization, the coal is dried and transferred to a storage bin. The bin is typically kept under an inert nitrogen or CO_2 atmosphere to reduce the risk of fire.

In the second step, the pulverized coal is fed into a blending tank with heated No. 6 or No. 4 fuel oil in Unit 260. The contents of the blending tank are constantly agitated through the use of a mixing blade. At this point chemical additives may be introduced to the mix to improve stability. In the CoaLiquid, Inc. process, water is blended into the mixture.

Third, the mixed resultant coal-oil-additive-water (simply coal-oil mixture, or COM, hereafter) is pumped to a storage tank in Unit 2120. In the CoaLiquid process, it is first forced through an ultrasonic device which improves the stability of the mixture (2).

The storage tank may contain mixer blades, or with CoaLiquid, COM, may be simply a normal No. 6 oil storage tank. The tank must be heated in order to reduce the viscosity enough to pump the COM.

Utilities which have their own dedicated COM preparation plant pump COM directly from the storage tank to the boiler. Central COM preparation plants, serving many facilities, will transport the fuel from the plant to the user by tank truck.

A block diagram of COM preparation is shown in Figure 1.

2.3. Boiler and Feed System Modifications

COM is intended for use in two types of boilers: those designed for coal and currently burning oil and those designed for oil and currently burning oil. Boilers designed to burn coal will need substantially fewer modifications than those designed to burn oil as they will already be equipped with ash handling equipment. In both cases, modifications to the burners and feed systems will be needed because COM is more viscous and abrasive than is fuel oil.

Piping from the COM storage tank to the burners must be slightly larger than is used for No. 6 fuel oil because of the high viscosity of COM. Provisions should be made in the piping for a possible flush of the pipes with oil in case settling occurs. Because of the abrasive qualities of the coal particles, pumps and valves need to be made of wear-resistant materials such as case-hardened or carbon-tungsten steel. Avoidance of 90° elbow joints will also reduce localized wear.

Within the boilers, the burners must be changed. Burners designed to burn oil have narrower orifices than are needed for COM combustion. In addition, soot blowers and an ash handling system will be needed to handle the increased ash deposition associated with burning coal instead of oil. In plants designed to burn coal, soot blowers will already be present, as will a bottom ash handling system. In boilers originally designed to burn oil, soot blowers and a bottom-ash-handling system (if not present) must be added substantially increasing the difficulty and cost of conversion.

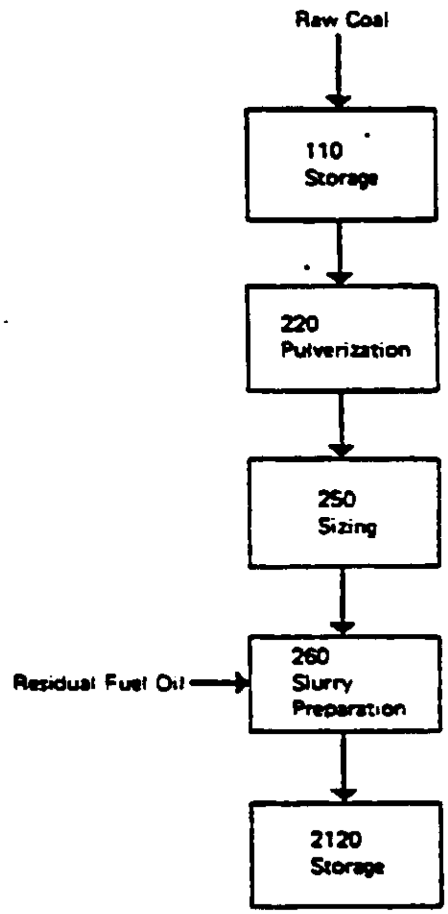

Figure 1. Flow Diagram of Coal-Oil Mixture Preparation.

2.4 Physical Characteristics of COM

The physical characteristics of coal-oil mixtures depend on the percentage of coal in the mixture and the properties of the coal used in the mixture. The sulfur, nitrogen, ash and oxygen content of the COM will increase with the coal content in the mixture. That is because residual oil is lower in all the above minerals than is coal. Because residual oil is less dense and contains more energy per unit weight than does coal, the heating value of COM decreases with coal content while its specific gravity increases with coal content. Table 1 details the physical characteristics of different batches of coal-oil mixture made with Pittsburgh seam coal. The analysis of this Pittsburgh seam coal is shown in Table 2.

Another important characteristic of COM is its viscosity. A highly viscous COM will be difficult to pump and to atomize. Viscosity of COM varies with the proportion of coal in the COM as is shown in Figure 2.

2.5 Preparation Plant Siting

COM is a retrofit fuel: it will be used in plants currently burning oil but will not be used for new plants. New plants will choose coal over COM. Therefore, COM will be prepared in two types of facilities: central preparation facilities, which will provide fuel to industrial users who do not use enough fuel to require their own preparation facility, and dedicated preparation facilities, built to supply large retrofitted central power plants. This configuration rules out minemouth plants in the unpopulated Western regions. There are no boilers to retrofit in those regions, and a COM preparation plant will need to be located near the user if high transport costs are to be avoided.

Test	50% COM		50% COM			40% COM			30% COM		No. 6 Fuel Oil		
Run Number	(Washed Coal) 1	2	3	4	5	6	7	8	9	10	11	12	13
Coal Concentration (%)	49.0	48.5	49.0	54.3	46.7	40.5	40.0	40.5	29.0	29.9	0	0	0
Ultimate Analysis (%) Hydrogen	7.9	8.0	8.3	7.8	8.3	8.9	8.7	8.8	9.4	9.3	10.8	11.0	11.0
Carbon	80.0	80.7	80.4	78.91	79.2	79.9	81.6	82.7	82.8	82.8	87.3	86.7	86.7
Nitrogen	1.0	0.9	0.7	0.8	0.7	0.6	0.8	0.7	0.5	0.6	0.3	0.1	0.1
Sulfur	1.3	1.3	1.2	1.4	1.2	1.1	1.1	1.0	1.0	0.9	0.8	0.7	0.7
Oxygen	5.4	4.6	3.9	4.1	4.5	4.5	3.5	2.2	2.6	2.6	0.8	1.4	1.4
Ash	4.5	4.5	5.6	7.0	6.1	5.0	4.4	4.6	3.7	3.9	0	0	0
Heating Value (Btu/lb)	16188	16161	16135	15652	16058	16523	16851	16759	17186	17309	18551	18642	18642
Specific Gravity at 140°F	1.1015	1.1022	1.0998	1.1185	1.1051	1.064	1.0621	1.0638	1.0406	1.0638	0.953	0.939	0.939

TABLE 1. FUEL ANALYSES FOR COAL-CONCENTRATION TESTS

SOURCE: (1)

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	Washed Coal	Unwashed Coal
Proximate Analysis		
Moisture	1.2	1.9
Volatile Matter	37.5	32.9
Fixed Carbon	52.1	50.4
Ash	9.2	14.8*
Ultimate Analysis		
Hydrogen	5.0	4.9
Carbon	73.9	69.3
Nitrogen	1.5	1.5
Sulfur	1.8	1.8
Oxygen	8.6	7.7
Ash	9.2	14.8*
Heating Value (Btu/lb)	13417	12338
Ash		
Initial Deformation (°F)	2020	2140
Softening Temp (°F)	2110	2250
Fluid Temp (°F)	2240	2460

*Ash content in unwashed coal varied in the range of 11 to 14.8%

TABLE 2. TYPICAL COAL ANALYSES

SOURCE: (1)

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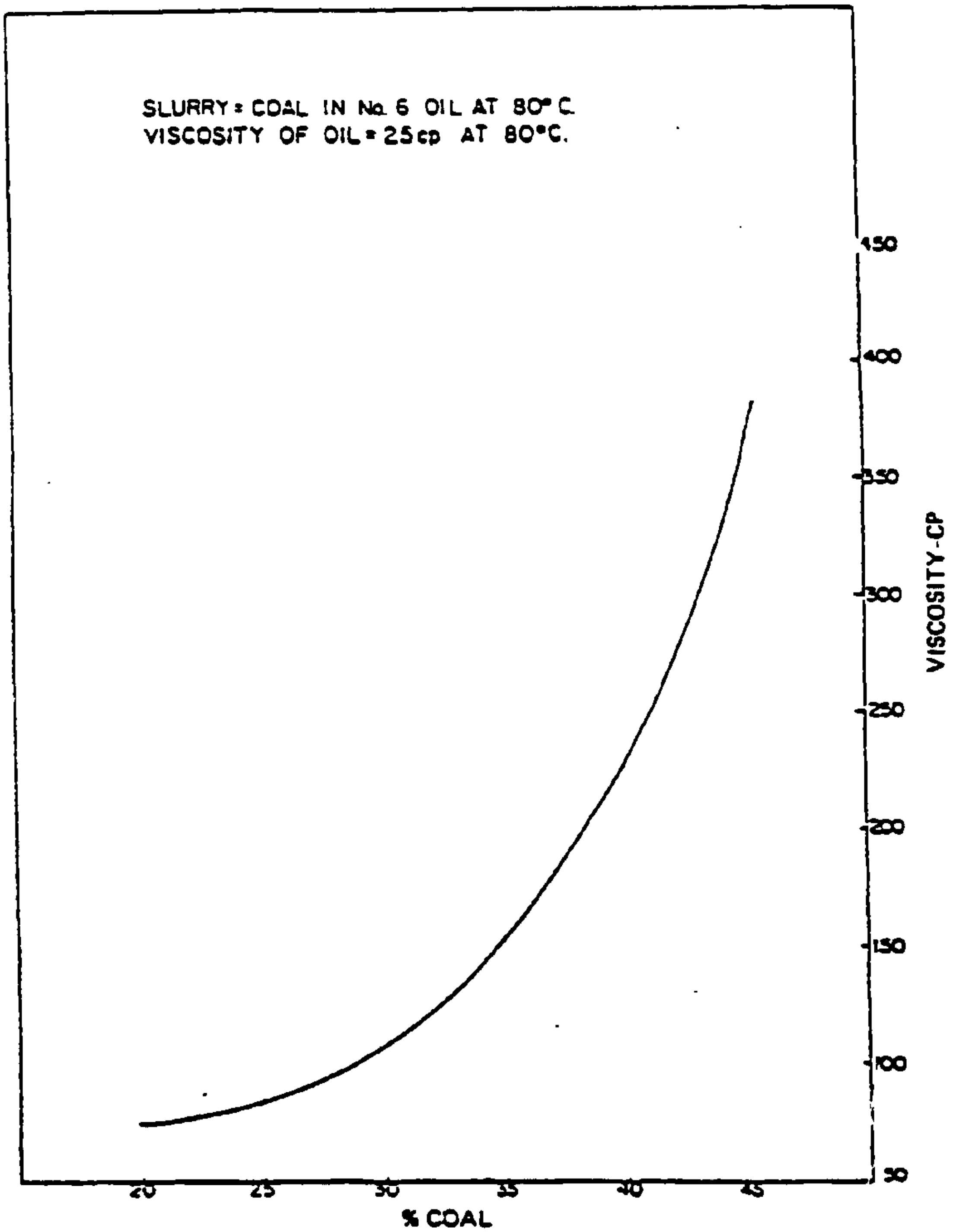

Figure 2. Viscosity of Coal/Oil Mixture; Source (4)

A likely site for a central COM preparation plant will be in an area with one or more large industrial users of residual fuel oil. Large industrial users of residual fuel oil are concentrated in the Eastern and mid-Western states (5). These states are also close to supplies of higher rank coals which have the Btu content necessary to yield a COM which will not cause boiler derating (see Section 2.6 for effect of coal type).

Dedicated preparation plants for utilities may be built where there is room for the coal storage area and the COM plant. For plants located in urban areas, such space will probably not be available.

Because COM preparation plants produce no effluents and do not use large amounts of water, siting them should not cause problems within communities. The primary factor affecting a decision to site a COM preparation plant will be economics. The economics of siting will be addressed in Section 2.10, Regional Factors.

2.6 Raw Material and Support System Requirements

2.6.1 Raw Materials

The raw materials for COM consist of coal and residual oil, and sometimes water and chemical additives. No chemical catalysts are needed to produce the mixture. Preparation of COM will not place strains on water supply systems nor increase the demand for scarce catalysts.

2.6.2 Support Systems

Preparation plants require a rail siding or barge landing for coal delivery, coal unloading facilities, and coal storage areas. If COM is prepared at a dedicated facility adjacent to a facility originally designed for coal, new retrofit support system construction requirements will be less extensive than for a dedicated facility next to a plant designed for oil.

2.6.3 Effect of Coal Type

Coal type is important to COM in two ways: first, it determines the heating value of the COM fuel produced, and second, it affects the pollution which may be caused by burning COM. Research indicates that a third factor, the poor mixture properties of certain coals, can be effectively handled by the addition of chemicals to the COM (6).

The higher the ash, sulfur, and nitrogen content of the coal, the higher will be the particulate, sulfur oxide, and nitrogen oxide content of the flue gas. In areas with sulfur oxide problems, it will probably be necessary to use low sulfur coals in the COM. Use of low suffur coals will make expensive flue gas desulfurization systems unnecessary.

The heating value (in Btu/lb) of the coal will also be an important criterion by which coal is chosen. Use of low-rank coals with low Btu content will result in the production of a COM with a heating value well below that of residual fuel oil. Boiler derating could occur as furnace pressure will not be maintainable at optimal levels. Therefore, higher rank coals will be chosen for COM production in order to simulate the heating characteristics of fuel oil.

This discussion suggests that the ideal coal for use in COM is a coal with low sulfur content and high heating value.

2.7 Pollution Control Technology

This section divides pollution control for coal-oil mixtures in three parts: air, water, and solid waste.

2.7.1 Air Pollution Control

Because the production of COM does not involve any combustion, production of COM will create minimal air pollution. The only air pollutant from production of COM will be coal dust from the grinding of the coal. Dust may be controlled through the use of baghouses and cyclones on the pulverized coal transport system.

The combustion of COM will increase air pollution. The coal in COM will displace oil in combustion. Coal is a dirtier fuel than oil, as it contains more sulfur, nitrogen, and ash than oil. When COM is burned instead of oil, more sulfur oxides, nitrogen oxides, and particulates will be released if emissions are uncontrolled.

Particulates can be controlled with electrostatic precipitators and sulfur oxides can be controlled through the use of low-sulfur coal or flue gas desulfurization (FGD). Nitrogen oxides will be more difficult to control.

Because control technology is similar to that for coal-fired plants and is therefore well developed, economic questions about air pollution control are more important than technical ones. Industrial users will have to install particulate control. Utility plants may have to install large and expensive FGD systems to control sulfur in addition to particulate control systems, although discussions with the EPA suggest that most COM conversions will not have to install FGD systems (7).

Under the regulations governing stationary boilers, modifications to large boilers fall under the New Source Performance Standards (NSPS). The NSPS would require installation of sulfur control systems. However, if the boiler was built before 1971, and was originally designed to burn coal, a switch from oil to COM would not be considered a modification. Boilers designed to burn coal and burning oil would then not be forced to comply with the NSPS if a conversion to COM was made.

Utility boilers built to burn oil and retrofitted to burn COM are a more complex case. The modifications needed to burn COM in these boilers could possibly be construed as a modification which places the boilers under the NSPS. According to an EPA spokesman (7), these plants would be judged on a case-by-case basis and would probably not have to install flue gas desulfurization systems.

2.7.2 Solid Waste

No solid waste will be generated during COM production. Bottom ash and fly ash are both generated by the combustion of COM. Bottom ash is collected through the ash hoppers of the boiler and fly ash is collected from the electrostatic precipitators or other particulate control systems. Both types of ash are generally transported away from the boiler by a slurry system. Ash can be dried by using a vacuum drier or by discharging the slurry into a settling pond. Dried ash can be sold or disposed of in a secure landfill (8). In general, bottom ash is more salable than fly ash.

The FGD sludge is created from dewatered FGD wastewater. Dried sludge is hazardous and should be t.ansported to a secure landfill. FGD sludge disposal will be a substantially costly aspect of COM use, where FGD systems are required.

2.7.3 Wastewater Treatment

This section focuses on wastewater treatment for electric power plants which burn COM. Treatment needs in COM-fired power plants will be similar to those for coal-fired plants. Wastewater streams will be created during cooling, steam generation, ash handling, flue gas desulfurization and intermittent plant cleaning. Because they operate on a smaller scale than power plants, industrial COM users will generate less wastewater. For example, ash sluice water and FGD wastewater might not be created at an industrial user, since systems generating these effluents may not be required. Therefore, this discussion of power plant wastewater treatment encompasses some treatment needs that an industrial user will not have.

Contaminated effluents are usually handled by combining compatible streams for subsequent central treatment. Oily wastes from equipment cleaning are taken in one group, organic wastes in another, and flood drains in a third (see Figure 3). After individual pretreatment, the streams converge on a central clarifier. Table 3 lists treatment

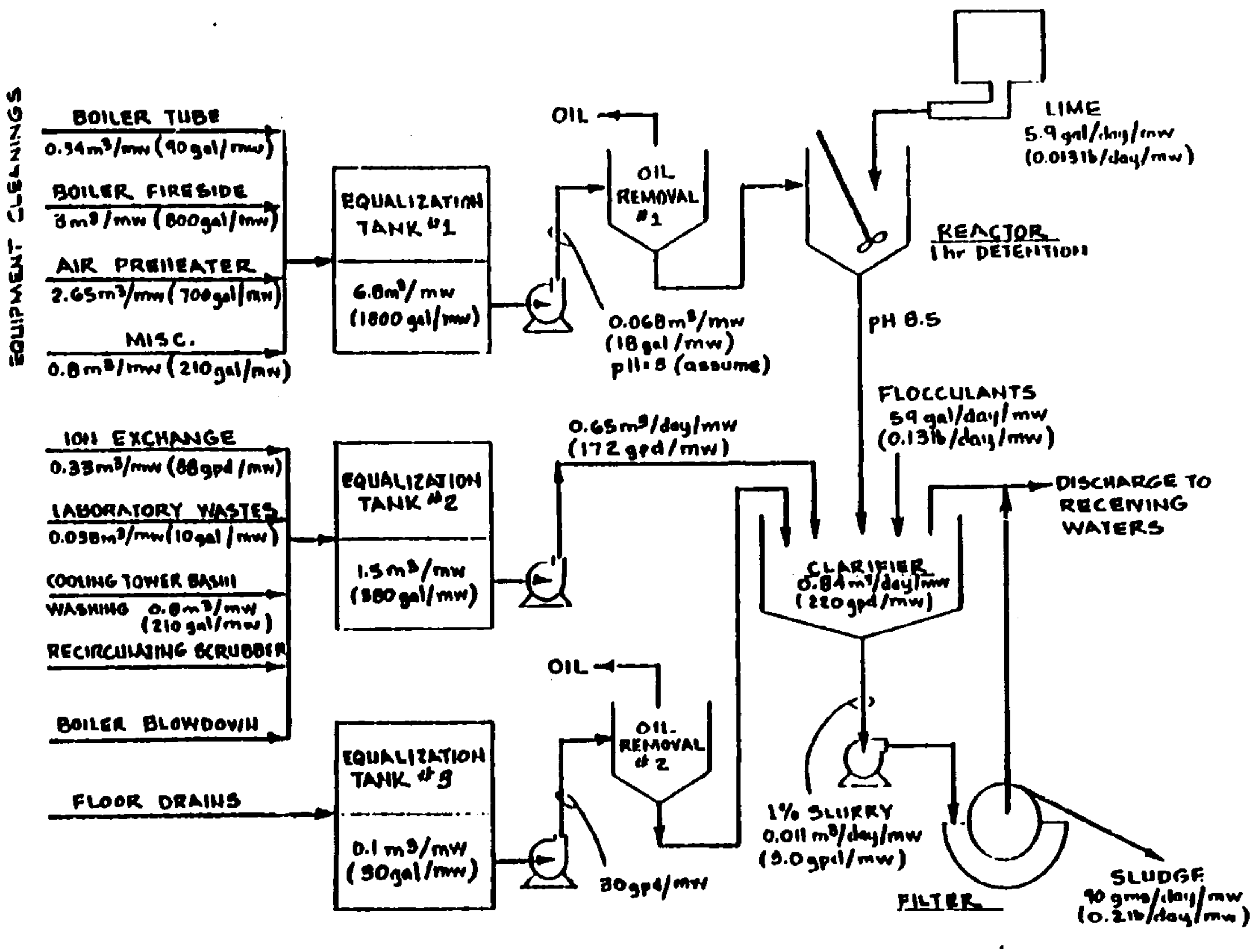

Figure 3: Wastewater Treatment; Source: (9)

Table 3

WASTEWATER TREATMENT TECHNOLOGY FOR COM-FIRED PLANTS

Number	Pollutant Parameter	Control and/or Treatment Technology	Effluent Reduction Achievable	Utility Industry Usage
I	GENERAL:			
	pH	Neutralization with chemicals	Neutral pH	Common
	Dissolved Solids	1. Concentration and evaporation	Complete Removal	Not generally in use - desalinization technology
		2. Reverse Osmosis	[illegible]	Limited use - desalinization technology
		3. Distillation	[illegible]	Not in use - desalinization technology
	Suspended Solids	1. Sedimentation	[illegible]	Extensive
		2. Chemical Coagulation and Precipitation	[illegible]	Moderate
		3. Filtration	[illegible]	Not generally practiced - water treatment technology
II	SPECIFIC POLLUTANTS:			
	Aluminum/Zinc (Water Treatment, Chemical Cleaning, Coal Ash Handling, Coal Pile Drainage)	1. Chemical Precipitation	Removal to 1.0 mg/l	Limited usage
		2. Ion Exchange	Similar to Copper	
		3. Deep Well Disposal	As described above	
	Ammonia (Water Treatment, Blowdown, Chemical Cleaning, Closed Cooling Water Systems)	1. Stripping	[illegible]	Not practiced; several installations in sewage treatment
		2. Biological Nitrification	Removal to 2 mg/l	Not practiced for these waste streams
		3. Ion Exchange	[illegible]	Not practiced
	BOD/COD (Sanitary Wastes)	Biological Treatment	[illegible]	Common practice
	COD (Water Treatment, Chemical Cleaning)	1. Chemical Oxidation	[illegible]	Limited usage
		2. Aeration	[illegible]	Not practiced
		3. Biological Treatment	[illegible]	Not practiced
	Chromium (Cooling Tower)	1. Reduction	0.05 mg/l	Limited usage
		2. Ion Exchange	•	• •
		3. Electrochemical	•	• •
		4. Substitute Chemicals	-	• •
	Chlorine (Once-through Condenser Cooling)	1. Control of Residual Cl_2 with Automatic Instrumentation	Control to 0.2 mg/l	Limited usage in the industry - technology from sewage treatment practiced in some plants - all systems are not capable of being converted to mechanical cleaning
		2. Utilize mechanical Cleaning & Chlorine	Reduces Cl_2 Discharge	

Table 3 (Continued)

Wastewater Treatment Technology for COM-Fired Plants

[illegible]	[illegible]	[illegible]	Effluent [illegible]	[illegible]
[illegible]	[illegible]			
	[illegible]	1. [illegible]	[illegible] described above	
		2. [illegible]	[illegible]	[illegible]
	[illegible]	1. [illegible]	[illegible]	[illegible]
	[illegible]	1. [illegible]	Removal to 0.1 mg/l	Limited usage
		2. Ion Exchange	Removal to 0.1 mg/l	Not practiced
		3. Deep Well Disposal	[illegible] described above	
	[illegible]	Chemical Precipitation	Removal to 1 mg/l	Limited usage
	[illegible]	1. [illegible]	Removal to 0.1 mg/l	Limited usage
		2. Deep Well Disposal	[illegible] described above	
	[illegible]	Ion Exchange [illegible]	[illegible]	[illegible]
	[illegible]	1. [illegible]	Removal to [illegible] mg/l	[illegible]
		2. Air Flotation	Removal to 10 mg/l	Limited usage
	[illegible]	[illegible]	[illegible]	Limited usage
	[illegible]	1. Biological Treatment	Removal to [illegible] mg/l	Not practiced in the industry
		2. Ozone Treatment	Removal to [illegible] mg/l	Not practiced in the industry
		3. Activated Carbon	Removal to [illegible] mg/l	Not practiced in the industry
	[illegible]	1. Chemical [illegible] and Precipitation	Removal to 3 mg/l	[illegible]
		2. Deep Well Disposal	[illegible]	Not practiced
	[illegible]	1. [illegible]	Removal to [illegible] mg/l	Limited usage
		2. Ion Exchange	Removal to 0.1 mg/l	Not practiced
		3. Adsorption	Removal to 10 mg/l	Not practiced
	[illegible]	1. [illegible]	[illegible]	Not practiced
		2. Ion Exchange	Difficult to achieve	Not practiced

Source: (9)

methods available, potential effluent reductions achievable, and use in existing plants. Pollutants which are incompatible with the central treatment system require individual consideration to assure total water management. The following streams fall into these categories:

- once-through cooling or cooling tower blowdowns
- sanitary wastes
- roof and yard drains
- coalscreen backwash
- noncirculating ash or FGD system wastes
- recirculating bottom ash system

2.8 Process Performance Factors

There are few uncertainties regarding the handling and preparation of COM and so the primary process performance uncertainties affecting COM use is of the effective performance of a boiler burning COM. An evaluation of the process performance of COM must be made according to the operation of boilers designed to burn oil but retrofitted to burn COM and of boilers designed for coal and switched from oil to COM. Boilers designed to burn coal which are retrofitted to COM will generally have fewer problems than those designed to burn oil. Boiler performance may be evaluated according to the following six criteria:

1. combustion and heat-transfer characteristics
2. carbon conversion efficiency
3. boiler efficiency
4. ash deposition
5. erosion and corrosion
6. reliability, availability, and dependability

Combustion and heat-transfer characteristics, carbon conversion efficiency and boiler efficiency are operational boiler characteristics. Ash deposition and erosion and corrosion are potential inhibitors of boiler performance. Reliability, dependability and availability measure the amount of time the boiler may be usefully employed.

Combustion and heat-transfer characteristics can be indirectly monitored through measurement of the flue gas temperature. Tests at the DOE's Pittsburgh Energy Technology Center indicate that combustion and heat-transfer characteristics of COM are much like that of No. 6 fuel oil (1). In these tests, different batches of coal and No. 6 fuel oil were burned in a 700-horsepower water-tube boiler originally designed to burn No. 6 oil. The flue gas temperatures for the various burns of coal-oil mixture were close to those recorded with burns of No. 6 fuel oil.

Carbon conversion efficiency measures the completeness of combustion in the boiler, and boiler efficiency measures the effectiveness of useful energy transfer in the boiler. The carbon conversion and boiler efficiencies indicate the compatibility between the coal-oil mixture and boiler operation. For the tests at the PETC, boiler efficiency was only slightly lower for coal-oil mixture than for No. 6 fuel oil when unwashed coal was used. When washed coal was used in a 50 percent mixture, boiler efficiency for the COM and the fuel oil was equivalent. Carbon conversion efficiency was slightly lower for COM than for the No. 6 fuel oil (99 percent vs. 100 percent) because some of the coal particles became entrained in the flue gas instead of burning.

Coal ash deposition can cause tube fouling and reduce the efficiency of combustion and heat transfer. Because existing oil-fired boilers are often not equipped to handle heavy ash accumulation, ash accumulation may present a problem in retrofits to COM. After 370 hours of burning 50 percent COM, researchers at the PETC found 4,830 pounds of ash in the boiler described above. Despite the ash accumulation, no boiler derating (drop in heat output) occurred. Problems with ash accumulation may be solved through the installation of soot blowers and a bottom ash handling system in the boiler.

Use of coal-oil mixture may increase erosion and corrosion of pumps, burner nozzles, and fuel feed lines. The coal particles within the COM may abrade various parts, thus increasing wear and tear, maintenance and out-of-service time. During a 500-hour test burn of 50 percent COM at the PETC, several test sections in the fuel transport system were selected for corrosion studies for the long-duration testing. Relevant dimensions of pump and nozzle components were measured before and after the test. Results show significant wear for tool and stainless steel parts. The rate of wear seems to decrease with an increase in operating hours. No significant wear was found for hardened, tungsten-carbide and carbon steel parts. Therefore, fuel line wear can be alleviated through the selection of proper materials.

The process performance measures most important to potential users of COM are reliability, dependability, and availability that is, how often a COM-fired boiler will be out of service, and whether the costs of increased out-of-service time will outweigh the fuel savings associated with a switch from oil to COM. The results of a 500-hour test at the PETC show that dependable boiler operation can be achieved while burning COM (1). This agrees with tests made at an 80-MW boiler of the New England Power Service

Company and a 400-MW boiler of the Florida Power and Light Company, where few problems with boiler operation were encountered while using COM (2,3). Tests on a lime kiln of the St. Regis Paper Company in Jacksonville, Florida, also indicated dependable performance can be achieved while burning a coal-oil mixture (9).

In general, data on coal-oil mixture's process performance suggest that COM is a viable alternative to fuel oil in a practical setting. Boiler efficiency, carbon conversion efficiency and combustion characteristics of COM are comparable to those of fuel oil. Ash deposition and fuel line wear can be corrected through the use of soot blowers and wear-resistant steels. Testing has demonstrated that boilers burning COM are dependable.

2.9 Technology Status

COM development is proceeding under both private and Department of Energy sponsorship. Commerical use of the technology is nearly a reality, and demonstrations have been carried out on both industrial size and utility size boilers. This section describes Department of Energy Research and Development efforts as well as private attempts to commercialize the technology.

2.9.1 Department of Energy Efforts

The objectives of DOE efforts are to modify or retrofit, operate, and test existing boilers, heaters and furnaces to demonstrate combustion technology and practicability of burning coal-oil mixtures (10). DOE will investigate combustion of COM in existing oil-fired combustors to determine the extent to which this retrofit technology can be implemented practically. The goal is to encourage substitution of coal for an appreciable fraction of oil in appropriate industrial and utility combustors within the near term.

Two contractors were selected to apply COM technology beginning in 1977. The New England Power Service Company has retrofitted an 80-MW boiler in Salem, Massachusetts, to burn COM. The boiler had been initially designed for coal and later converted to oil. A COM preparation facility was also built at the Salem site. Testing of COM has taken place at the plant. Thus far, problems with particulate control have limited coal concentrations to 20 percent in the COM. The other selected contractor, Interlake Incorporated, has retrofitted a blast furnace to burn COM.

A 700-hp combustion test facility using coal-oil mixture for combustion has also been completed at PETC. Preliminary COM information has been and is presently being obtained from this unit. The objectives of the PETC projects are to develop in-house technical capability in COM combustion technology and to supply direct technical support to the total COM combustion program.

2.9.2 Private Efforts

This section describes the status of two private COM projects, those of CoaLiquid, Inc., and Florida Power and Light.

2.9.2.1 CoaLiquid, Incorporated

CoaLiquid, Inc., of Shelbyville, Kentucky, is the leading private firm in the area of preparation of COM. CoaLiquid has a 2500-gph demonstration plant in Shelbyville, Kentucky, which is expandable to 5,000 gph. The firm has successfully demonstrated that its product, an ultrasonically blended mixture of 50 percent coal, 40 percent No. 6 oil and 10 percent water, is stable in storage and can be transported (11). The fuel has been successfully burned at St. Regis Paper in Jacksonville, Florida, and McDonnell-Douglas in St. Louis.

CoaLiquid has plans for five new plants (12). These will be built by licensees. The first of these plants will be built by Banklick, Inc. in Jacksonville, Florida, during 1981. It will initially produce 6,000 bbl/day of COM, but will be expandable to 18,000 bbl. This plant has received a cooperative agreement from the DOE and has applied for a loan guarantee. Scotia Coal in Nova Scotia, Canada, as of October 1980, had a CoaLiquid-type plant 80 percent complete. Other faciities are planned for Pittsburgh and the New England area.

2.9.2.2 Florida Power and Light

Florida Power and Light has retrofitted a 400-MW boiler designed to burn oil to burn COM in Sanford, Florida. They have also built a COM preparation plant on their site. Tests with up to a 50 percent coal in COM in April, 1980 were satisfactory, and 10,000 barrels of COM were burned successfully (13). Another phase of testing began in November, 1980.

2.10 Regional Factors

The most important regional factor will be the location of oil- and gas-fired boilers which are convertible to COM. Two types of such boilers exist: large utility boilers which provide steam for electric power generation and industrial boilers which produce steam for process use and space heating. This section will examine regional factors influencing utility use and industrial use of COM.

2.10.1 Utility Regional Factors

In the 1960's and early 1970's, a large number of coal-designed utility boilers were converted to burning oil. These boilers are prime candidates for conversion to COM. Table 4 shows that these boilers are concentrated in the New England and Mid-Atlantic states.

Utility boilers designed to burn oil and currently burning oil are heavily distributed along the eastern coastal states and in California. This is shown in Table 5. These oil-fired boilers are also targets for conversion to COM, although conversion will be more difficult than for boilers designed to burn coal.

The evidence presented in Tables 4 and 5 point to the eastern states as the primary region where COM conversion in utility boilers can be expected. The eastern states are also close to the higher rank coals needed to maintain the heating value of COM.

2.10.2 Industrial Regional Factors

The McKee company made a preliminary assessment of the industrial market for COM in 1978. The McKee analysis was based on a survey sent to industrial fuel users and an economic analysis of boiler retrofit costs. The survey asked various questions concerning industrial awareness of and attitude toward COM technology.

The results of the survey indicated that COM use would need to have at least a 30 percent higher return on investment than is normally expected before industry would consider a switch from oil or gas to COM (5). In addition, fuel users in the East were more favorable toward COM use than were those in the West. Using an analysis of the economics of COM conversion and the survey results, McKee reached the following conclusions:

- The available market for a COM conversion is one which meets or exceeds its target rate of return (15 percent).
- Of the available market defined above, 17 percent will convert to COM.

The regional results of the analysis are shown in Table 6. These are boilers currently burning oil or gas. As Table 6 demonstrates, the industrial market for COM is concentrated in the East and North Central regions.

REGION*	STATE	# STATIONS	# UNITS	TOTAL MW
I	CT	5	13	1,825
	ME	-	-	-
	MA	8	17	3,700
	NH	1	3	150
	RI	1	1	63
	TOTAL	15	34	5,738
II	NJ	9	21	3,029
	NY	16	48	8,097
	TOTAL	25	69	11,126
III	DE	1	4	392
	DC	1	4	200
	MD	5	12	1,233
	PA	9	16	1,946
	VA	4	14	1,950
	TOTAL	20	50	5,721
IV	FL	1	4	618
	GA	3	10	491
	MS	1	1	781
	SC	1	2	100
	TOTAL	6	17	1,990
V	IL	3	11	1,236
	IN	-	-	-
	MI	7	19	1,952
	MN	1	1	81
	OH	4	11	638
	WI	1	2	120
	TOTAL	16	44	4,027
VI	AR	2	4	1,042
	LA	1	1	446
	NM	-	-	-
	TX	-	-	-
	TOTAL	3	5	1,488

Table 4

SUMMARY OF UTILITY BOILERS DESIGNED FOR COAL-FIRING CURRENTLY BURNING OIL ($\geq$50 MW)

SOURCE: (14)

REGION	STATE	# STATIONS	# UNITS	TOTAL MW
VII	NONE			
VIII	CO SD	1 -	1 -	75 -
	TOTAL	1	1	75
	AZ CA	- -	- -	- -
	TOTAL	-	-	-
	U.S. TOTAL	86	220	30,165

* Standard Federal Region

Table 4 (Concluded)

SOURCE: (14)

REGION*	STATE	# STATIONS	# UNITS	TOTAL MW
I	CT	3	3	1,248
	ME	1	2	426
	MA	4	4	2,060
	NH	1-	1	414
	RI	0	0	0
	TOTAL	9	10	4,148
II	NJ	3	5	1,165
	NY	6	12	6,560
	TOTAL	9	17	7,725
III	DE	2	2	580
	DC	1	3	633
	MD	3	3	1,236
	PA	2	4	2,482
	VA	1	2	1,727
	TOTAL	9	14	6,658
IV	FL	26	54	12,656
	GA	1	1	163
	MS	1	1	548
	SC	1	1	633
	TOTAL	29	57	14,000
V	IL	2	6	2,849
	IN	1	2	218
	MI	2	3	1,395
	MN	-	-	-
	OH	-	-	-
	WI	-	-	-
	TOTAL	5	11	4,462
VI	AR	2	4	890
	LA	1	1	592
	MN	1	3	266
	TX	3	3	1,246
	TOTAL	7	11	2,994

Table 5
SUMMARY OF UTILITY BOILERS DESIGNED FOR OIL-FIRING
CURRENTLY BURNING OIL (≥50 MW)

SOURCE: (14)

REGION	STATE	# STATIONS	# UNITS	TOTAL MW
VII	NONE			
VIII	CO	-	-	-
	SC	1	1	75
	TOTAL	1	1	75
IX	AZ	8	15	1,616
	CA	30	109	21,601
	TOTAL	38	124	23,217
	U.S. TOTAL	107	245	63,279

* Standard Federal Region

Table 5
(Concluded)

SOURCE: (14)

2.11 Occupational Safety

The main occupational safety issue associated with COM production or use if that care be taken when handling the coal. Dust from milling should be trapped by baghouses. Pulverized coal should be stored in an inert atmosphere to avoid the danger of fire.

TABLE 6

AVAILABLE INDUSTRIAL MARKET FOR COM

BOILER SIZE (10^6 Btu/hr)	REGION OF UNITED STATES (MMBtu/hr) EAST	NORTH CENTRAL	TEXAS-LA	NORTH-WEST	SOUTH-WEST
0-100	0	0	0	0	0
101-250	101,108	67,799	0	0	0
251-1,000	0	89,699	18,257	0	24,497
1,001-10,000	0	333,660	60,338	0	62,156
10,000+	352,683	739,172	0	0	246,967
TOTAL	453,891	739,172	78,595	0	333,620

Source: Reference 5.

CHAPTER THREE: ECONOMIC ANALYSIS

In this section, the economics of COM are analyzed. The economic analysis is divided into three subsections: methodology, capital costs, and model plant economics.

3.1 Methodology

The economic analysis was carried out through a literature search and discussions with firms involved with COM production and/or use. Rather few cost estimates for COM conversion exist in the literature (5, 14, 15, 16).

An analysis made by the MITRE Corporation (14) was chosen as the best available assessment of COM preparation and retrofit costs. The fuel costs used in the MITRE study are up to date (December 1980). Capital costs agreed fairly closely to costs experienced by the three commercial COM preparation and/or combustion firms spoken to. These firms were willing only to discuss costs for entire facilities and did not provide publishable results. Discussions with these companies indicate that the MITRE study provided results which were in agreement with actual experience. An earlier (1978) DOE study (15) included more detailed cost estimates, but based on industry experience, these estimates seemed too low.

The MITRE study (14) also included a detailed analysis of the economics of a model COM preparation plant. Rather than repeating MITRE's work, the MITRE analysis was used to provide the basis of Section 3.3, Model Plant Economics.

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3.2 Cost Details

The capital costs for a COM conversion of an oil-fired boiler (14) are shown in Table 7. As was noted in the Methodology Section these costs were not broken out by equipment item, but totals agree with those actually experienced by industry.

Table 7 shows that pollution control expenditures for COM conversion exceed boiler modification costs for cases above 100 MW even without flue gas desulfurization. With flue gas desulfurization, pollution control expenditures would exceed boiler modifications by a factor of three to one. Flue gas desulfurization would be necessary if high sulfur oil and coal were used. Pollution control is discussed in detail in Section 2.7.

Table 8 presents conversion costs in dollars per megawatt of boiler capacity to demonstrate economics of scale. The formula:

$$\frac{X_2}{X_1} = \frac{C_2}{C_1}^{n}$$

where

- X_2 is the capacity of the larger unit
- X_1 is the capacity of the smaller unit
- C_2 is the cost of the larger unit
- C_1 is the cost of the smaller unit
- n is the capital cost scaling factor

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TABLE 7

CAPITAL COST OF CONVERTING AN OIL-FIRED BOILER TO COM AND OF A DEDICATED PREPARATION PLANT (1980 $)

	CAPITAL COST SCALING FACTOR	BOILER CAPACITY		
		100 MW (MILLION $)	200 MW (MILLION $)	400 MW (MILLION $)
Boiler retrofit (burners, bottom ash, hopper, soot blowers)	0.7	5.3	8.6	14.0
Electrostatic Precipitator (ESP)	0.9	4.65	8.6	16.2
Flue Gas Desulfurization (FGD)	0.7	13.6	22.4	36.8
COM Preparation Plant	0.6	8.1	12.2	18.6
Totals				
Retrofit: No FGD, no preparation plant		9.95	17.2	30.2
Retrofit: Preparation plant, no FGD		18.05	29.4	48.8
Retrofit: FGD, preparation plant		31.65	51.8	85.6

Source: Reference 14.

TABLE 8

CAPITAL COSTS IN DOLLARS PER MEGAWATT OF CAPACITY FOR COM CONVERSION (1980 $)

EQUIPMENT ITEM	BOILER CAPACITY 100 MW (THOUSAND $)	200 MW (THOUSAND $)	400 MW (THOUSAND $)
Boiler (including burners, bottom ash, hopper, soot blowers)	53	43	35
Electrostatic Precipitator (ESP)	46.5	43	40.5
Flue Gas Desulfurization (FGD)	136	112	92
COM Preparation Plant	81	61	46.5
Totals			
Retrofit: No FGD, no preparation plant	99.5	86	75.5
Retrofit: Preparation plant, no FGD	180.5	147	122
Retrofit: FGD, preparation plant	316.5	259.0	214.0

Source: Reference 14.

shows that the capital cost scaling factor used by MITRF for boiler modifications was 0.7.

The 0.7 scaling factor indicates that substantial economies of scale are present in COM conversion costs. A scaling factor of 0.7 was used for the flue gas desulfurization system and a factor of 0.9 was used for the electrostatic precipitator system.

Economies of scale were also estimated for capital costs of a COM preparation facility. These estimates were designed to cover a COM plant either at the boiler site or located off-site. These costs are shown in Table 8. As with the boiler modifications, substantial economies of scale were exhibited. The capital cost scaling factor was 0.6.

Incremental operating and maintenance expenses associated with COM conversion are shown in Table 9. Operating and maintenance costs increase after COM conversion because the high viscosity and ash content of COM make it more difficult to use than fuel oil.

TABLE 9

INCREASE IN OPERATING AND MAINTENANCE EXPENSES BECUASE OF COM CONVERSION (1980 $)

	BOILER CAPACITY		
FIXED COSTS	100 MW (MILLION $)	200 MW (MILLION $)	400 MW (MILLION $)
Boiler	2	3	4
Electrostatic Precipitator	1.2	2.36	4.64
Flue Gas Desulfurization	15.5	27	47
COM Preparation Plant	10	14	22
Totals			
Retrofit: No FGD, no preparation plant	3.2	5.36	8.64
Retrofit: No FGD, with preparation plant	13.2	19.36	30.64
Retrofit: With FGD, with preparation plant	28.2	46.36	77.64
Variable Costs			
FGD ($/$10^6$ Btu)	0.294	0.257	0.233

Source: Reference 14.

3.3 Model Plant Economics

3.3.1 Introduction

Evaluation of a typical COM retrofit must examine the following factors:

- Capital cost of the retrofit.
- Remaining boiler life.
- Increased O&M costs due to COM use.
- Out-of-service cost while boiler is being retrofitted.
- Fuel savings due to COM use.
- COM preparation on-site or purchase from a central preparation facility.
- Economics of full coal conversion.

Retrofit capital costs will depend on the original configuration of the boiler. A boiler designed originally for oil will need ash hoppers, soot blowers, and an electrostatic precipitator (ESP) to control particulates. Coal-designed boilers currently burning oil will not need these modifications. Both boiler types will need new fuel lines, pumps and burners to accommodate the viscous, abrasive COM.

Retrofit capital costs were presented in Tables 7 and 8. Retrofit capital costs will need to be balanced against the remaining life of the boiler. Boilers generally have a service life of 40 years (14). The closer the boiler is to the end of its service life, the less profitable will be a COM conversion. Older boilers will have shorter useful lives and will have smaller load factors than newer boilers.

As a result, the older boilers will burn less COM over their remaining service lives and yield smaller fuel cost savings than will retrofitted new boilers.

COM conversion will also increase operating and maintenance expenses. COM is more viscous and abrasive than is oil. As a result, it will increase wear on equipment and require greater care during its use. An estimate of increased operating and maintenance expenses was shown in Table 9.

Fuel cost savings because of COM use will also need to be closely examined. Depending on the price of available coal and on air quality constraints, these may be large or relatively small. Coal transportation costs will also be important. In general, however, fuel costs savings will be about 25 percent, because coal is only about one-third the cost of residual oil and coal in COM will replace about 40 percent of the energy supplied by oil.

COM conversion will require some out-of-service time for the retrofitted boiler. Therefore, the cost of replacement steam must be considered in any financial analysis. In some cases, it will be possible to take the boiler out of service because no backup will be available. Boiler out-of-service time for COM preparation is estimated at 2 to 7 months (14). The out of service time will be considerably lower for equipment initially designed for coal.

COM can be prepared at the user's site or at a central preparation facility and delivered to the user. The less fuel used, the less economical it would be for a user to prepare COM on-site. This is because the capital cost scaling factor of 0.6 for a COM preparation plant causes unit capital costs for a preparation facility to increase rapidly as the size of the facility falls. For example, a 10,000-barrel-per-day plant would have only 75 percent the per-barrel capital costs of a 5,000-barrel-per-day plant.

An important consideration will be the choice between conversion to COM and full conversion to coal burning. Full coal conversion would require the installation of coal handling equipment, and more (2 to 4 months) boiler downtime (14). Conversely, full coal conversion would allow 100 percent of coal substitution for oil, rather than the 40 percent which is achieved with COM.[1] Newer boilers would find full coal conversion more favorable than COM conversion, because these boilers would have a long service life over which to amortize the capital costs of coal conversion.

The MITRE study described above assessed the economics of COM conversion. Two cases were evaluated. The first was a COM retrofit where the user purchased fuel from a central supplier. In the second case, COM was prepared on site.

The MITRE analysis did not include the steam costs due to boiler downtime. It also did not assess the relative advantages of COM conversion versus full coal conversion for the boiler evaluated. It assumed the boiler had 14 years remaining useful life (17). Other key assumptions are found in Table 10. The boiler capacity factor was assumed to be 60 percent with a 50/50 debt equity ratio. Cost of debt was 11 percent and cost of equity was 18 percent.

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[1]Although COM is 50 percent coal by weight, it is only 40 percent coal by energy, because coal has less energy per unit weight than oil.

Table 10

PARAMETERS FOR FINANCIAL ANALYSIS

Additive Cost	$.08/$10^6$ Btu of COM
Boiler Capacity Factor	60%
Heat Rate	10,000 Btu/Kwh
Capital Structure	50/50 debt/equity
Depreciation Method	Sum of Years Digits
Inflation Rate	8%
Coal Escalation	9%
Oil Escalation	12%
Corporate Income Tax	50%
Energy Content of Oil	6.1×10^6 Btu/bbl
Energy Content of Coal	24×10^6 Btu/ton
Additive Content of COM	.5% by weight, 0% by energy
Water Content of COM	4.5% by weight, 0% by energy
Coal Content of COM	50% by weight, 41.7% by energy
Oil Content of COM	45% by weight, 58.3% by energy
Property Tax	2%
Debt Rate	11%
Equity Rate	18%
Base Year	1980
First Year of Operation	1981

Source: (17)

3.3.2 Centralized COM Preparation Facility

The first case analyzed (assumptions in Table 10, capital costs in Table 7) was that of a large, centralized COM preparation facility, which would deliver COM to local boilers using barge, tank car, or truck transportation. Converting the boiler to COM from oil increases costs due to capital expenditures for burners, sootblowers, ash removal equipment, and pollution control equipment (see Table 7). Operating and ma[illegible]nce expenses would also increase due prima[illegible]er viscosity and higher ash content of the C[illegible] These increased costs would be offset by the[illegible]osts of COM. As long as the fuel cost saving[illegible]M are greater than the increased costs result[illegible]boiler conversion, O&M and the delivery of COM, c[illegible]ion to COM will be a profitable investment.

In this case, it was assumed that a clean COM, made from coal with less than 1.5 percent sulfur and oil with less than 1 percent sulfur, would be used. As a result, no FGD system was needed. Coal cost was assumed to be 1.60/10^6 Btu (\$38.40/ ton) and oil was assumed to be \$4.14/10^6 Btu (\$25.25/barrel).

Using these assumptions, Figure 4 shows that the costs of converting a boiler larger than 100 MW to burn a clean COM are less than \$.20/10^6 Btu. Figure 5 shows that the fuel savings due to COM for large centralized preparation facilities are greater than \$.50/10^6 Btu. This implies that, depending on the size of the boiler and the size of the preparation facility supplying that boiler, \$.30/10^6 Btu or more can be spent for delivering the COM from the preparation facility to the boiler.

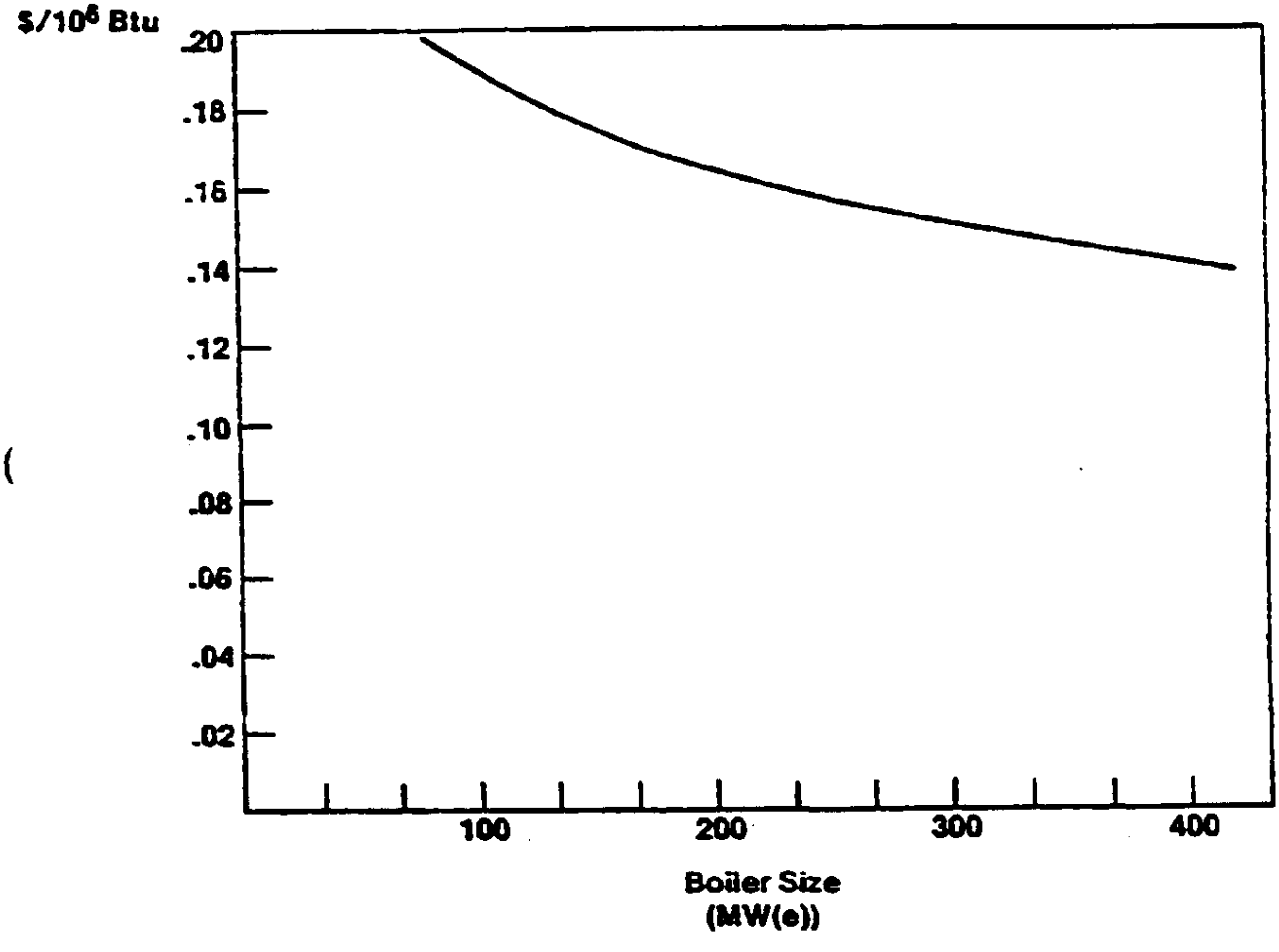

Figure 4. Boiler Conversion Costs: Source: (14).

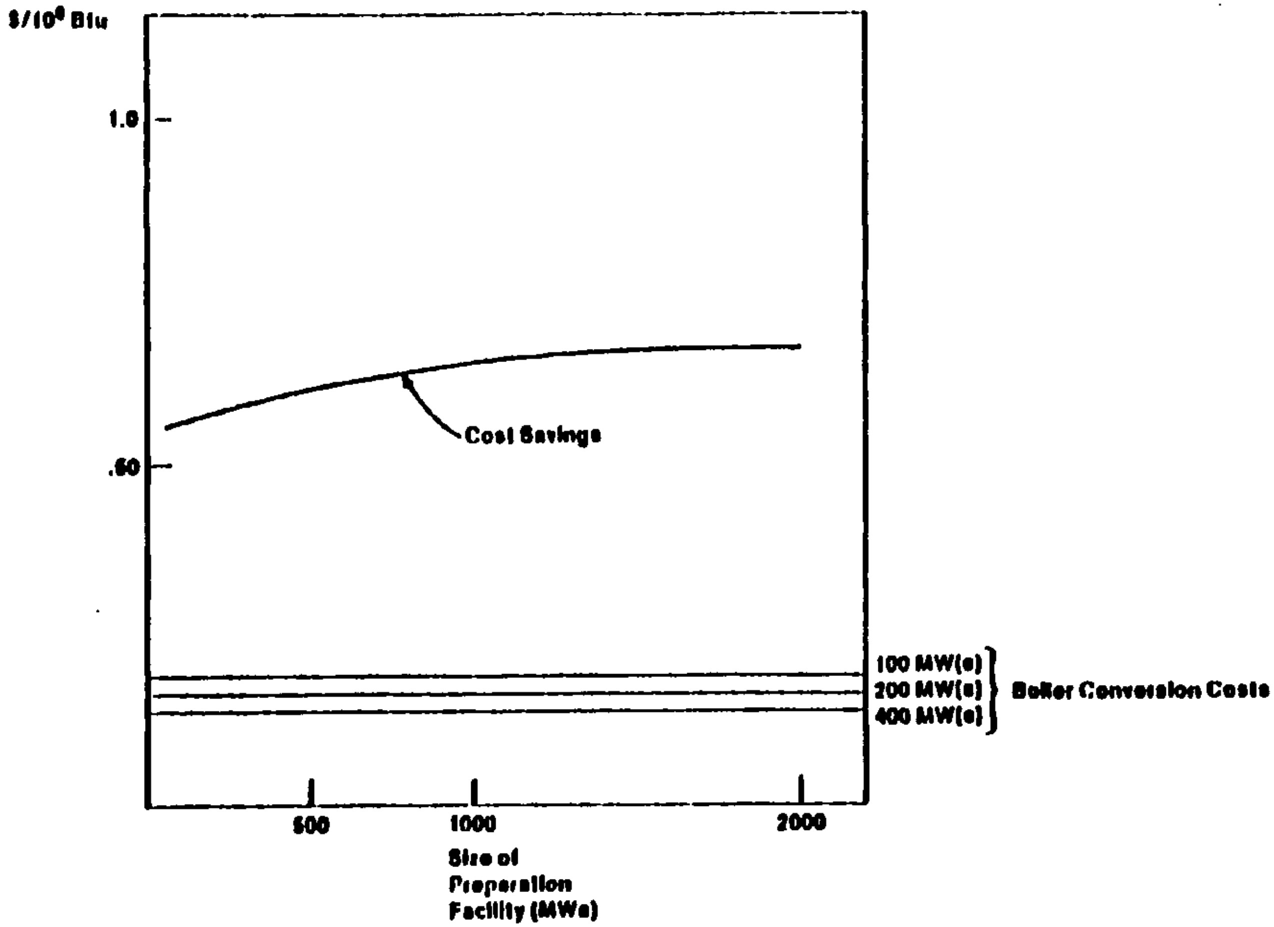

Figure 5. Cost Savings: COM vs. Oil -- Centralized Preparation Facility; Source: (14).

As a worse case, it was assumed that one wishes to build a centralized preparation facility that is capable of supplying COM to 500 MW of boiler capacity at a 60 percent capacity factor. Since transportation of COM by truck, the most expensive form of transportation, is estimated to cost approximately \$.30/10^6 Btu for 100 miles, this plant would be able to economically supply COM by truck to 100-MW boilers located within 100 miles radius. As the size of the preparation plant and the boiler increases, the economical delivery radius increases due to economies of scale. For example, a 2,000-MW COM preparation plant could supply COM by truck for up to five 400-MW boilers within a 160-mile radius. Less expensive modes of transportation would also increase the radius of economic deliverability. Transportation by rail would approximately double the radius of economic deliverability. Barge transportation of COM would increase the radius of economic deliverability by a factor of 5.

3.3.3 Dedicated Preparation Facility

The second case analyzed by MITRE was of a facility which constructs its own COM preparation facility. Figure 6 shows that fuel savings due to COM conversion are not limited to centralized preparation facilities. It is also economical to build dedicated preparation plants to serve large utility plants. The low-sulfur case assumes oil is \$4.14/10^6 Btu and coal is \$1.60/10^6 Btu. The high sulfur case assumes oil is \$3.54/10^6 Btu and coal is \$1.20/10^6 Btu. The cost of a low-sulfur COM or a high-sulfur COM with flue gas desulfurization (FGD) are both below the cost of oil and are profitable. The financial assumptions for this case are shown in Table 10 and are the same as those for the central preparation facility. Capital

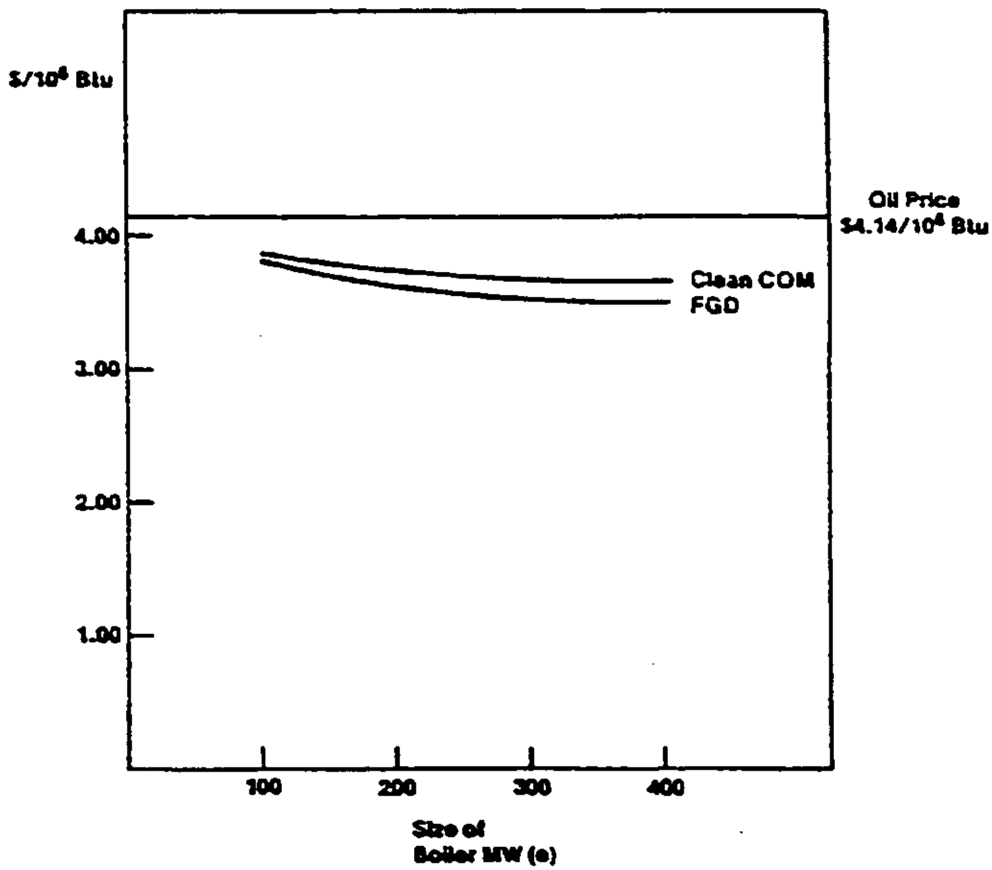

Figure 6. Cost of COM vs. Cost of Oil — Dedicated Preparation Plant; Source: (14).

and operating and maintenance costs were presented in Tables 7 and 9.

3.3.4 Conclusion

The MITRE model analyzed two cases: a 100-MW and larger boilers with a dedicated preparation facility and 100-MW and larger boilers which buy fuel from a central preparation facility. The MITRE analysis found that, based on the assumptions detailed above, COM conversion would be profitable. It lacked a comparison of COM conversion to total coal conversion. In addition, it did not include costs because of boiler downtime during retrofit. In general, however, the analysis seemed acceptable and because of resource constraints, was superior to that which could have been generated during this study.

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