

# COMMERCIAL OPPORTUNITIES FOR COAL

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**Energy & Environmental Research Center, UND**  
**Grand Forks, North Dakota**

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by: Mr. Kent E. Janssen  
Vice President and Chief Operating Officer  
Dakota Gasification Company  
Bismarck, North Dakota

# **"BENEFICIATION BY OIL AGGLOMERATION OF CENTER NORTH DAKOTA LIGNITE"**

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## BENEFICIATION BY OIL AGGLOMERATION OF CENTER NORTH DAKOTA LIGNITE

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### Introduction

Utilization of North Dakota lignitic coals has been primarily restricted to mine-mouth power generation of electricity. In a few cases, past and present, it has been economical to transport lignites moderate distances via rail. However, high moisture, dustiness, spontaneous combustion, and competition from Wyoming and Montana subbituminous coals have reduced the demand for North Dakota lignites in these markets.

Most attempts to promote the export of North Dakota lignite, by reducing moisture and enhancing the energy content, have used evaporative drying which accelerates the dusting and spontaneous combustion problems. An additional detriment is that the excellent reactivity of the raw lignite may be severely reduced by oxidation, if gaseous thermal drying is used. In addition, and perhaps most importantly, these drying processes do not significantly reduce the moisture-free sulfur or ash levels in the coal products. This is a concern because of the adverse environmental effects of acid rain generated from fossil fuel emissions. Lignite can be marketed as a premium quality fuel if a beneficiation process is developed which economically reduces moisture, preserves coal reactivity, reduces sulfur and ash, and enhances stability during handling. Oil agglomeration is a developing technology that holds promise for achieving these objectives, while leaving the coal product in a manageable, exportable form for dry rail transportation.

This paper describes bench-scale testing of an oil agglomeration technique developed at the University of North Dakota Energy and Environmental Research Center (EERC) for both raw and hot-water dried (HWD) Center North Dakota lignite. The Center lignite mine is owned and operated by BNI, Inc., a wholly owned subsidiary of Minnesota Power, Inc. This project was funded on a joint venture basis between Minnesota Power and the Department of Energy (DOE) Morgantown Energy Technology Center (METC). DOE contracting officer representative (COR) for the project is Ms. Jacqueline Balzarini, Pittsburgh Energy Technology Center.

## Objectives

The primary purpose of the oil agglomeration testing was to assess the recovery of hot-water dried coal fines, as an easily transportable, nondecrepitating fuel agglomerate. The fines would be produced during hot-water drying of lump coal in Minnesota Power/BNI's Enhanced Lignite (ELFUEL) process. The agglomerated coal fines would be transported and combusted with a lump ELFUEL HWD product, as proposed by Minnesota Power, for Round Three of the DOE Clean Coal Technology Program (1). While recovering the HWD fines, it was proposed that the oil agglomeration would clean the fines by reducing sulfur and ash levels. As a secondary objective, the raw Center lignite was tested by the EERC agglomeration process to assess ash reduction, dewatering potential, and sulfur reduction via pyrite removal (2).

## Experimental Procedure

### Hot-Water Drying

Center lignite coal fines were HWD at 280°, 290°, 300°, 310° and 320°C, in a 7.6 liter, externally heated autoclave for a residence time of 15 minutes. The details of hot-water drying have been reported earlier (3). The feed for the testing consisted of -3.35 mm (6 mesh) x 0" coal to simulate the fines produced by the ELFUEL process. The slurry charge consisted of 2000 gms of coal and 2000 gms of deionized water, and heat-up to the desired temperature was approximately two hours. The HWD products and the raw Center lignite were analyzed for proximate and ultimate composition, heating value, sulfur forms, and equilibrium moisture values. In addition, the raw coal and the 310°C-HWD sample were analyzed by XRFA to determine the mineral elements in the ash. The filtrate from HWD was analyzed to determine the concentration of dissolved mineral elements.

### Oil Agglomeration

Oil agglomeration of the raw and hot-water-dried (HWD) BNI lignite was achieved with only minor modifications to the procedure used for agglomerating other lignites (4). Table A shows the experimental matrix test conditions used on the -30 mesh (595  $\mu$ m x 0  $\mu$ m) raw and -6 mesh HWD coal samples. Acid strength, oil volume, acid-coal mixing speed, high-speed mixing times, and oil-coal mixing speed were the process variables used to select optimum conditions for agglomerating the coal. Agglomerates were formed in 21 of the 30 tests performed. Nine tests on raw Center lignite, and twelve tests on the HWD samples prepared at five different temperatures, produced agglomerates. In the other nine tests agglomerates over 30 mesh size were not formed.

## Results

### Hot-Water Drying

Analyses for the raw and HWD Center lignite, and the process water (filtrate) are presented in Table B. The major improvements to the coal were a reduction in ash and sulfur contents, and an increase in heating value due to hot-water drying. Increased HWD temperatures lowered the equilibrium moistures and increased the heating values, but did not result in lower ash levels. The ash reduction from HWD was near 25% for all tests. In addition,

sulfur contents were reduced by 22% to 32% during hot-water drying, with a slight increase in the removal as the HWD temperature increased from 280°C to 320°C.

Comparison of the XRFA analyses of the raw coal and the 310°C product indicated that the iron, sulfur, and sodium contents were reduced significantly. The decrease in iron and sulfur were a result of pyrite reduction. Sodium, as well as other soluble cations, bound to carboxyl groups in the coal, was liberated during decarboxylation. As a result of the removal of these elements, silicon, aluminum, and calcium were concentrated. Concentration of silicon and aluminum will most likely increase the ash fusion temperature, and reduce ash fouling during combustion. Calcium concentration increases the Ca/S molar ratio from 0.93 to 1.17, consequently, increasing the potential calcium-sulfur capture during combustion.

TABLE A  
RANGE OF EXPERIMENTAL AGGLOMERATION CONDITIONS  
FOR RAW AND HWD CENTER LIGNITE

Test No.	Coal Type R(Raw) H(HWD)	Acid Conc. (wt%)	Oil Vol. (mls)	Acid Mix Speed (rpm)	Oil Mix Speed (rpm)
02	R	6.2	50	550	550
03	R	6.2	60	550	550
04	R	6.2	50	5500	1000
08	R	3.1	40	5500	800
09	R	1.5	40	5500	800
10	R	1.5	50	5500	800
18	R	0.75	50	5500	600
19	R	0.75	50	5500	1000
21	R	0.75	45	5500	1000
16	H @280°	1.5	40	5500	1200
17	H @280°	1.5	35	5500	550
20	H @290°	1.5	35	5500	800
22	H @290°	1.5	30	5500	800
23	H @300°	1.5	30	5500	800
24	H @310°	1.5	30	5500	800
25	H @320°	1.5	30	5500	800
26	H @320°	1.5	30	5500	550
27	H @310°	1.5	30	5500	550
28	H @300°	1.5	30	5500	550
29	H @290°	1.5	30	5500	550
30	H @280°	1.5	30	5500	550

\* Acid Mix Time for all tests was 30 minutes

\*\* Oil Mix Time for all tests was 10 minutes

TABLE B  
RAW & HWD BNI LIGNITE  
(Moisture Free Basis)

	Raw	280°C	290°C	300°C	310°C	320°C
<b>PROXIMATE ANALYSIS, wt%</b>						
Volatile Matter	42.23	38.80	38.76	38.85	37.77	37.40
Fixed Carbon	45.80	51.35	51.15	51.41	52.02	52.06
Ash	11.97	9.85	10.09	10.24	10.21	10.54
<b>ULTIMATE ANALYSIS, wt%</b>						
Hydrogen	3.93	4.06	4.33	3.88	3.86	3.95
Carbon	63.60	68.28	68.70	69.10	70.16	69.53
Nitrogen	1.04	1.11	1.14	1.14	1.15	1.14
Sulfur	1.33	1.08	1.15	1.16	1.05	1.14
Oxygen*	18.10	15.60	14.57	14.46	13.55	13.67
Ash	11.97	9.85	10.09	10.24	10.21	10.54
<b>ASH, wt%</b>						
Silica, SiO <sub>2</sub>	9.4				25.5	
Al. Oxide, Al <sub>2</sub> O <sub>3</sub>	2.4				17.0	
Fe. Oxide, Fe <sub>2</sub> O <sub>3</sub>	20.1				8.8	
Titan. Oxide, TiO <sub>2</sub>	0.5				1.0	
Phosph. Pentoxide, P <sub>2</sub> O <sub>5</sub>	1.7				1.3	
Calcium Oxide, CaO	18.5				21.3	
Magnesium Oxide, MgO	5.0				6.7	
Sodium Oxide, Na <sub>2</sub> O	9.4				1.3	
Potassium Oxide, K <sub>2</sub> O	0.1				0.5	
Sulfur Trioxide, SO <sub>3</sub>	33.0				21.5	
<b>HEATING VALUE, Btu/lb</b>						
	10,690	11,470	11,540	11,800	11,850	11,900
<b>SULFUR FORMS,** wt%</b>						
Organic	0.62	0.75	0.74	0.73	0.79	0.67
Pyritic	0.53	0.34	0.38	0.46	0.23	0.41
Sulfate	0.09	0.02	0.03	0.02	0.05	0.04
Total	1.24	1.10	1.15	1.21	1.07	1.13
<b>EQUIL. MOIST, wt%</b>						
(Three-Day)	36	23	20	22	20	20
(Six-Day)***				18	19	16
<b>FILTRATE, ppm</b>						
Silicon		59	75	68	66	62
Alum num		<0	<0	<0	<0	<0
Iron		<0	<0	<0	<0	<0
Phosphorus		<2	3	<2	<2	<2
Calcium		320	253	297	444	439
Magnesium		703	627	403	237	250
Sodium		1826	2338	2420	2446	2474
Potassium		45	57	63	64	68

\* Oxygen determined by difference.

\*\* Duplicate analyses by independent laboratory.

\*\*\*Six day values were necessary to allow wet samples more time to come to equilibrium moisture.

The dry solids and Btu recoveries, plus ash and sulfur reductions, are listed in Table C, for the five HWD temperatures (5). The Btu recoveries decreased from 97% to only 93%, while dry solids recovery decreased from 91 to 84 wt%, as the temperature was increased from 280° to 320°C. The high Btu/solids ratio indicated that the majority of the dry solids were lost to decarboxylation, while heat content was lost during volatile matter reduction.

The reduction in sulfur content represented a reduction in theoretical SO<sub>2</sub> emissions. Table C also lists the estimated SO<sub>2</sub> emissions for the raw coal and the HWD products. These worst-case numbers were determined based on the assumption that the total sulfur will be converted to SO<sub>2</sub> during combustion. The total possible emission for the raw coal is 2.49 lb SO<sub>2</sub>/MM Btu, and the lowest total emission after HWD is 1.77 lb SO<sub>2</sub>/MM Btu. Hot-water drying can reduce sulfur emissions, but the compliance emission ceiling of 1.2 lb SO<sub>2</sub>/MM Btu has not been met for this specific coal sample. It should be pointed out that the sulfur levels of the sample of raw Center lignite used in this study were higher than the mine average of around 1.0 wt% (6). In addition, the actual emissions will likely be lower than these worst-case calculated values, because sulfur can be captured by inherent alkali minerals, mainly calcium and sodium. The high sulfur trioxide and calcium oxide levels in the HWD coal ash, as indicated in Table B, represent potential sulfur capture during combustion. The actual sulfur emissions and ash sulfur retention can only be determined by combustion testing.

#### Raw Coal Agglomeration

Table D shows the TGA modified proximate analyses of the raw coal, and the agglomerates formed under the test conditions described above. An example of the raw data obtained from this analysis is shown in Figure 1. In this analytical procedure, the first weight change occurs over the range ~25-110°C, and is termed "H<sub>2</sub>O & Light Oil," since Karl Fischer water determination typically finds <5% moisture, whereas the thermogravimetric weight loss over this temperature range is >5% in all cases except that of the distilled agglomerates. "Oil" is assumed to be the agglomerating oil adhered to the coal, and is volatilized over the temperature range ~110-250°C. "Volatiles" is assumed to originate from the coal being agglomerated. This fraction is removed over the range ~250-900°C. "Combustible residue" can be compared to fixed carbon of the ASTM 271 proximate analysis. With the addition of air to the sample chamber at ~900°C, this fraction burns off, and "Ash" is the oxidized inorganic residue remaining. The "moisture-oil-free" (MOF) value for ash was calculated to provide the ash content of the agglomerates, for comparison with moisture-free BNI lignite. Although not a primary objective, ash removal from the raw coal on a moisture-oil-free basis ranged from 40% to 75%. The ash removal from the raw coal as a result of the process appeared to be a function of acid concentration, except in two cases. Test No. 08 was the only test with 3.1% acid, so it is not known whether the low ash is characteristic of the acid concentration; however, Test No. 18 was much lower in ash than the other two tests run with the same acid concentration of 0.75%, indicating that the other test conditions were also factors to be considered for optimization.

Table D shows the agglomerate yields for raw and hot water-dried BNI lignite, and, in conjunction with the ash removal discussed above, gives an indication of the effectiveness of the process. The agglomerate yield is



reported in grams of air-dried agglomerates obtained from 50 grams of coal. The agglomerate recovery is best represented as a ratio of the combustible residue content (fixed carbon of agglomerates - FC<sub>a</sub>) in the agglomerate and the combustible residue content of the raw coal (FC<sub>c</sub>). The fixed carbon content of the coal was assumed to be relatively unchanged by the agglomeration process. From Figure 2 (which shows the ratio as a function of the agglomerate weight recovered, and gives the test number for each point), it can be seen that raw coal test numbers 04, 10, 18, and 19 were most successful on the basis of FC<sub>c</sub> recovery. Moisture and ash were both reduced by design of the process and, with the adsorption, absorption and recovery of the oil, significant volatiles content changes were also expected. The moisture reduction that occurred as a result of agglomeration was substantial. Although the Karl Fischer moisture analysis was not performed on every product, sufficient numbers were tested to indicate that the behavior of the process regarding moisture reduction was not different from that of previous tests with other lignites, where moisture levels, as determined by the Karl Fisher method, were routinely reduced to less than 5%.

TABLE C  
ANALYSIS OF RAW AND HWD BNI COALS

Drying Temperature, °C	Raw	280	290	300	310	320
Solids Recovery, %		90.8	89.3	86.9	85.5	83.5
Btu Recovery, %		97.4	96.4	95.9	94.8	92.9
Ash Reduction, %		25.6	24.8	25.6	27.4	26.3
Sulfur Reduction, %		26.6	22.4	24.3	32.2	28.4
Sulfur Emission, lb SO <sub>2</sub> /10 <sup>6</sup> Btu	2.49	1.88	1.99	1.97	1.77	1.92

TGA proximate analyses of three fines from the agglomerating process are also shown in Table D. As in the agglomerates, the ash content of the fines was reduced, but over a narrower range, 45-60%. In many agglomeration experiments, the fines appeared to be agglomerates. However, they are small enough to pass the 30 mesh (595 um) product screen.

#### Hot-Water-Dried Coal Agglomeration

Agglomeration testing of the HWD coal was accomplished with the same mechanical methodology as the raw coal, but with fewer variables. When agglomerating the HWD coal, only oil volume and oil mixing speed were process variables, all others were held constant. The recoveries were similar to those of the raw coal agglomerates, as shown in Table D. Generally, coal dried at the lower temperatures gave agglomerates with the lower moisture-oil free ash values. The ash content of all HWD agglomerated samples remained high relative to agglomerates of the raw coal.

TABLE D  
RAW AND HWD CENTER LIGNITE AGGLOMERATE TGA PROXIMATE ANALYSES

SAMPLE NO.	H2O*/LT OIL	OIL	VOLATILES	-WT%		-YIELD	
				FIXED CARBON	ASH AR MOF	FC <sub>a</sub> /FC <sub>c</sub>	
Coal (ASTM)	34.3	---	27.7	30.1	7.86	11.96	--
Coal (TGA)	33.4	3.2	25.7	31.9	5.80	9.16	--
Coal (TGA)	33.9	3.0	25.6	31.7	5.73	9.09	--
02	22.5	18.4	26.3	31.1	1.65	2.79	0.91
03	27.1	21.3	23.2	27.1	1.29	2.50	1.02
04	21.4	23.3	24.7	29.3	1.27	2.30	1.12
08	21.3	18.7	27.0	31.5	1.51	2.52	0.77
09	18.5	18.5	27.7	33.3	2.11	3.35	0.78
10	18.4	23.0	25.8	30.4	2.42	4.13	1.14
18	20.6	22.9	25.4	29.9	1.21	2.14	1.10
19	18.3	20.0	26.9	31.5	3.31	5.37	1.14
21	18.6	20.8	26.7	30.9	3.02	4.98	1.07
16	19.6	13.3	26.0	37.0	4.08	6.08	1.11
17	17.3	13.0	27.5	38.0	4.16	5.97	1.09
20	13.9	12.2	27.9	41.3	4.79	6.48	1.12
22	16.0	10.8	27.3	40.9	5.10	6.96	1.08
23	15.8	9.8	26.9	42.0	5.61	7.53	1.13
24	13.8	9.0	27.5	44.1	5.67	7.34	1.28
25	11.0	8.0	28.6	46.4	5.93	7.33	1.16
26	13.1	8.7	27.2	44.8	6.09	7.79	1.15
27	15.4	10.0	26.4	42.7	5.63	7.54	1.28
28	13.6	10.8	27.4	42.7	5.51	7.29	1.13
29	9.2	10.4	30.5	44.7	5.09	6.33	0.26
30	15.0	12.2	27.9	40.2	4.76	6.53	0.99
02*	12.0	15.3	32.9	37.2	2.64	3.63	--
03*	19.9	16.4	28.1	33.0	2.64	4.15	--
04*	7.5	14.9	35.1	38.5	4.01	5.17	--

\* Average moisture levels for agglomerates of raw coal 2.85% and for that of HWD coal was 4.31%.

\* Fines from agglomeration process.

From Figure 2 (which also shows the fixed carbon ratio as a function of the agglomerate weight recovered for the hot-water dried samples), it can be seen that HWD coal test numbers 16, 24, and 27 were most successful on the basis of FC<sub>a</sub> recovery. Test number 16 involved more oil than the other HWD tests, and 24 and 27 were the only tests in which the feed was dried at 310°C. Other factors were held constant for the HWD coal agglomeration tests.

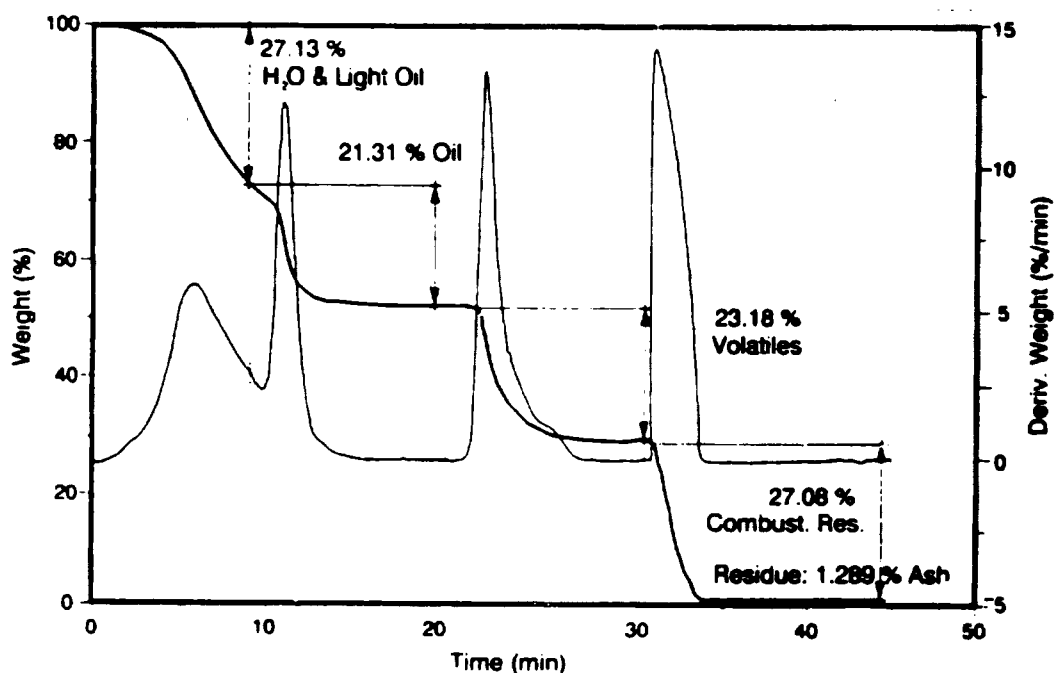


Figure 1. TGA THERMOGRAM OF AGGLOMERATES FROM RAW CENTER LIGNITE, TEST NO. 10.

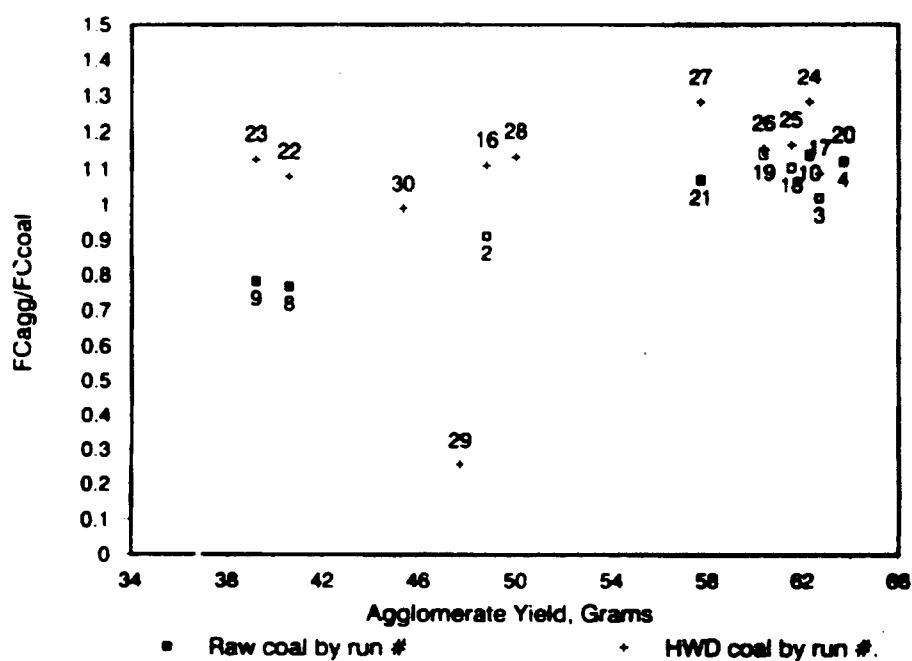


Figure 2. FIXED CARBON RATIO VS. OF AGGLOMERATE WEIGHT RECOVERED FOR AGGLOMERATES FROM BOTH RAW & HWD CENTER LIGNITE.

TABLE E  
ULTIMATE AND HEATING VALUE ANALYSIS ON SELECTED TEST SAMPLES  
OF BNI LIGNITE AGGLOMERATES

Test No.	04	10 Before Distillation	10 After Distillation
<hr/>			
Ultimate Analysis wt%			
Carbon	70.2	70.5	69.6
Hydrogen	5.9	5.8	5.0
Nitrogen	1.0	0.8	1.1
Sulfur	0.7	0.8	1.1
Oxygen (by difference)	20.9	20.0	19.6
Ash	1.3	2.1	3.6
Heating Value Btu/lb	12,600	12,560	12,120
Ash Reduction, % (from raw coal)	89	77	70
Sulfur Reduction, % (from raw coal)	46	38	15
Sulfur Emission, lb SO <sub>2</sub> /10 <sup>6</sup> Btu	1.11	1.27	1.80
<hr/>			

#### Oil Recovery

Test 10 involved conditions which were nearly optimum for all defined objectives of this study. Using this method, approximately 200 grams of agglomerates were prepared for further analyses. Besides TGA proximate analysis; ASTM ultimate analysis, calorific value, oil recovery, and Hardgrove grindability were carried out on this sample. The ASTM ultimate and calorific value are shown in Table E. The hydrogen content of the agglomerates decreased after oil removal by heating, while the nitrogen and sulfur content, on a weight percent basis in the oil recovery residue, was increased over that of the original agglomerates. The heating value of the agglomerates was >12,000 Btu/lb, as compared with 10,700 Btu/lb for the moisture-free coal, and those from which the excess oil had been removed had only slightly less heating value (i.e., 3.5%) on a Btu/lb basis than the original agglomerate. In addition, the projected total sulfur emissions for these three agglomerates are also shown in Table E. The levels are below or near compliance for the agglomerates, which include recoverable oil. A slight increase in ash, and a significant increase in sulfur, occurred after oil removal to the agglomerates for sample MPOA-10. This caused the calculated total emissions to go above the 1.2 lbs SO<sub>2</sub>/MM Btu for this sample. As mentioned previously, these calculations make no accounting for the sulfur capture potential of calcium in the ash, which has been concentrated as a result of the cleaning to the coal.

Oil recovery from the agglomerates at ambient pressure, at temperatures of ambient to 140°C, to 180°C, and to 200°C, resulted in removal of most of the oil from the agglomerates in a recyclable form. The hardness of the agglomerates following oil recovery, was greater than that prior to recovery, and the agglomerates maintained their roughly spherical geometry. The process did not result in agglomerate break-up but instead, it resulted in harder agglomerates, while reducing the oil content by 50%-90+%, as analyzed by TGA. Material closures for the process, shown in Table F were 92%, 87%, and 98% for the heat treatment carried out at 140°, 180° and 200°C, respectively. The improved closure at the highest temperature was due to the use of an additional cold-trap and the improved efficiency of the trap design for this test.

TABLE F  
OIL RECOVERY AT THREE TEMPERATURES FROM BNI OIL AGGLOMERATES

	140°C	180°C	200°C
AGG, G	15.80	16.60	50.0
OIL, G*	3.00	3.30	16.4
OIL, G <sup>o</sup>	----	----	1.0
RESID, G	11.50	11.20	31.6
TOTAL, G	14.50	14.50	49.0
MATERIAL CLOSURE, %	91.80	87.40	98.0

\* oil recovered at 0°C using water-ice bath

<sup>o</sup> oil recovered at -78°C using isopropanol-dry ice bath

Figure 3 shows the oil, volatiles, and fixed carbon for the raw coal and the agglomerates, prepared according to the method used in MPOA-10, before oil recovery and after oil recovery at each of the three temperatures, 140°, 180° and 200°C. TGA proximate of the residues of the lower two temperatures indicated that recovery at 140°C removed approximately one-half of the oil, whereas two-thirds of the oil was removed at 180°C. The analysis of agglomerates after 200°C showed an oil content on a moisture-free basis that was only slightly greater than that of the raw coal, and significantly less (5 to 8-fold, depending on what value is used for moisture in calculating moisture-free agglomerates) than that of the agglomerates before the treatment, indicating that the potential for oil recovery for re-use is excellent. Removal of excess oil also contributes to improved handling characteristics, including less odor and reduced oiliness.

#### Hardgrove Grindability

A commercially important characteristic of the agglomerates is their ability to maintain structural integrity during transportation and storage. The test of hardness adapted for this study was an extended Hardgrove

Grindability Index (HGI). The HGI of a coal sample is defined according to ASTM Method D-409 as:

$$\text{HGI} = 13 + 6.93W$$

Where W is the weight of material passing a 74  $\mu\text{m}$  sieve, determined as the difference of 50 grams of starting material, minus the weight retained on the sieve.

The standard coals used for the test have a size range from 16 to 30 mesh (1,180 microns by 600 microns), which easily applied to the agglomerates because of their bottom size of 30 mesh. Figure 4 is the HGI curve determined for the standard coals, as indicated by the line, and for the raw coal and selected agglomerate samples, indicated by symbols. The standard values are determined by the amount of coal that passes through a 200 mesh (75 microns) screen versus the designation for the standard sample. The highest standard used has an HGI of 102, so a linear regression was performed in order to obtain higher agglomerate values than those for the standard coals.

The hardness of the agglomerates was not affected greatly by removal of the excess oil, as indicated by their HGI values. Although the agglomerates are somewhat softer than the coals for which the test was designed, the ASTM test did give a basis for determining the relative hardness of the samples. MPOA samples 04, 10, and 27 fell on the calibration curve which was prepared from indices of raw coals of measured hardness. The other samples listed occurred on the extrapolated portion of the HGI curve. The HGI of 04, 10, and 27 would imply that these agglomerates may be physically handled in a manner similar to the raw coal during transportation and utilization.

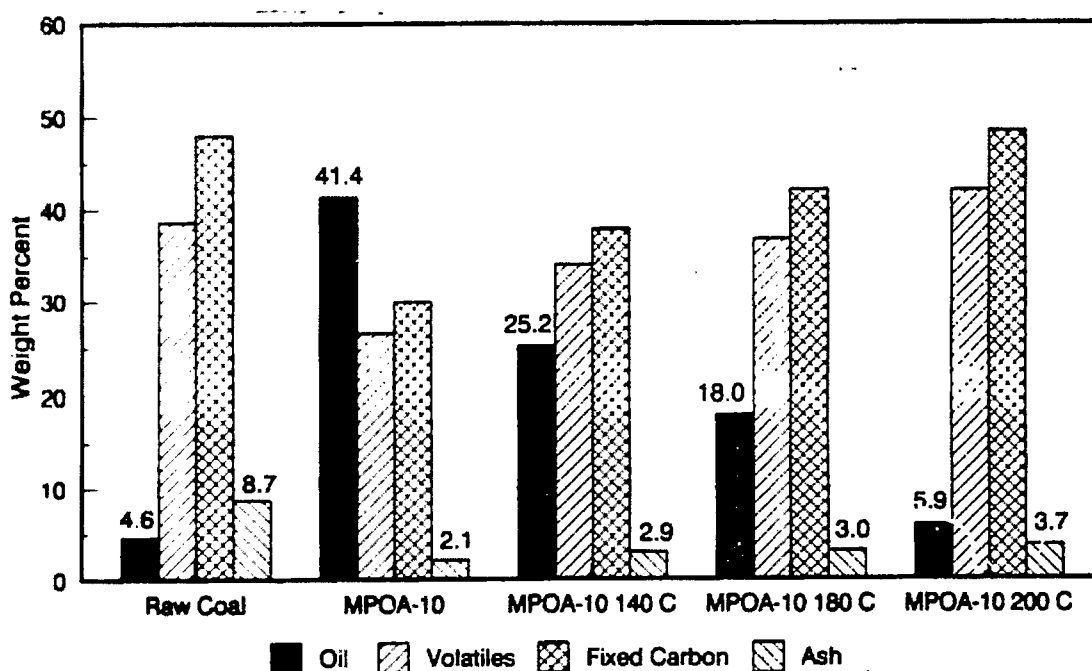


Figure 3. TGA PROXIMATE ANALYSES COMPARISON FOR RAW CENTER LIGNITE, RAW COAL AGGLOMERATES AND RAW COAL AGGLOMERATES AFTER OIL RECOVERY.

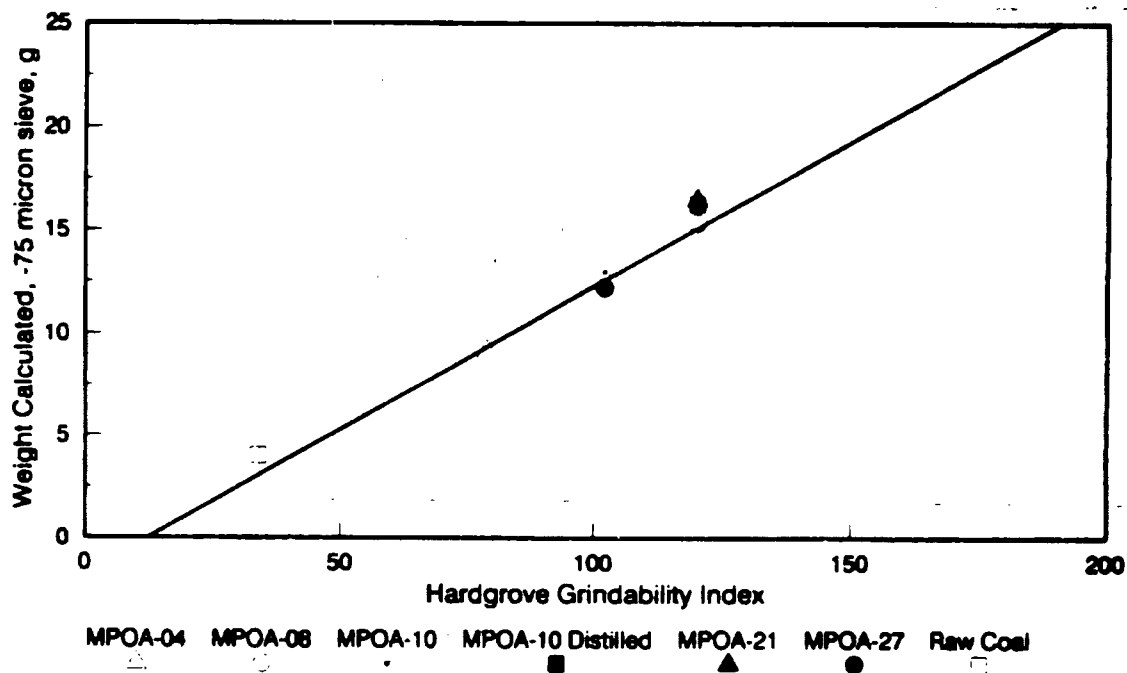


Figure 4. HARDGROVE GRINDABILITY INDEX VALUES FOR RAW CENTER LIGNITE AND CENTER LIGNITE AGGLOMERATES.

### Conclusions

- o Raw and HWD Center lignite, of -6 mesh, can be easily and quantitatively agglomerated by parameter modification of the EERC oil agglomeration technique.
- o Moisture in the Center agglomerates can be reduced by as much as 95% from the raw coal after oil agglomeration.
- o Although only a secondary effort was made in this study to reduce sulfur and ash content of the coal, the data indicates that over 40% sulfur and 80% ash reduction in the Center lignite is inherent to the agglomeration process.
- o The oil content of the BNI agglomerates can be reduced to as little as 3% by heating, and the oil removed has the potential to be recycled to greatly reduce processing costs.
- o The BNI agglomerates can be prepared with a hardness comparable to soft coals, which should permit transportation and handling by conventional means.

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# **"USE OF OIL SHALE WASTE IN A CIRCULATING FLUID BED BOILER"**

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## USE OF OIL SHALE WASTE IN A CIRCULATING FLUID BED BOILER

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### ABSTRACT

Oil shale produced during development mining of Occidental Oil Shale, Inc.'s modified in situ (MIS) retorts may be processed by an aboveground retort, or can be burned to produce steam and power in a circulating fluidized bed (CFB) boiler. The calcium-based minerals in the shale provide efficient sulfur capture capacity during combustion in the CFB boiler. The burning of shale, alone and in combination with H<sub>2</sub>S-laden low Btu gas from MIS retorting and coal, has been recently demonstrated in two boiler manufacturers' pilot plants. The pilot plant tests showed extremely high sulfur capture, high combustion efficiency, and low emission levels of NO<sub>x</sub>, carbon monoxide and hydrocarbons. As a result of these tests, both boiler manufacturers would design, build, and guarantee a commercial facility burning the shale plant waste streams.

### BACKGROUND

Oil shale is a fine-grained sedimentary rock which contains an organic material known as kerogen. When the rock is heated the kerogen decomposes to oil and gas and leaves residual carbon on the mineral matrix. The quality or grade varies in layers in the deposits. The United States deposits are wide spread with the most extensive being the Devonian-Mississippian black shale of the Appalachian area and the Green River formation of Utah, Wyoming and Colorado. The Piceance Creek basin in Colorado contains the richest and thickest deposit of oil shale. The recoverable reserves of western oil shale are estimated at one thousand (1,000) billion barrels.

The immense size of the resource continues to stimulate national interest in its commercialization. During the past 70 years, billions of dollars have been spent in pursuit of oil shale commercialization. Efforts have been cyclic because of swings in world oil prices and prevailing political views. During the late 1970's and early 1980's, a number of major firms prepared to build

commercial-scale projects. Ultimately, only Unocal constructed a 10,000 barrel per day facility utilizing their retorting technology. The plant has reached 70% capacity some six (6) years after start up.

Occidental Oil Shale, Inc. (OOSI) has been active in the development of oil shale for nearly 20 years. A versatile technology was developed known as Modified-In-Situ (MIS) processing which mines out a small portion of the shale and retorts the remaining shale in the ground. In the 1970's and 1980's, OOSI conducted programs that verified the technical viability of the technology in full scale retorts. It remains to be demonstrated that the technology can be replicated on a continuous commercial basis.

Both Unocal and MIS retorting technologies produce shale fines that are not usable in proven retorting technologies. In addition, MIS processing and some other retorting processes generate a low Btu gas laden with  $H_2S$  gas which must be utilized in an environmentally sound manner. The circulating fluid bed boiler technology, which has been commercialized so successfully in the past 10 years with coal, coal wastes, wood, and other low grade fuels, appeared ideal to handle all the waste fuel streams. Bench scale testing by various investigators held out great promise for the technology. Therefore, by integrating a CFB boiler into a project with a retorting process, useful energy in the form of steam and electric power could be recovered from the waste streams generated by oil shale processing. However, this approach had never been tested by a boiler manufacturer or demonstrated commercially.

Therefore, industry is still left with limited technology options for responding to the need to commercialize production from Western oil shales. A logical response to this dilemma is to conduct engineering-scale proof-of-concept demonstrations to provide technologies which will be ready for commercialization after the year 2000.

OOSI has pursued that option at the urging of State and local government officials. During fiscal year 1990, the U.S. Department of Energy, State of Colorado, Rio Blanco County and OOSI entered into a cooperative agreement to determine the feasibility of a proof-of-concept test facility. The tasks to be accomplished in 1990 were firming up design and cost information for the plant and mine, preparing marketing plans for oil and electricity, determining financing requirements, reviewing of the many permits required, and finally testing of the combustion of oil shale in a large CFB pilot plant.

The results of the testing of oil shale and other fuels conducted as the first step of this Colorado Tract C-b demonstration oil shale project are discussed in the remainder of this paper.

## FUEL STREAMS

The project is being designed to incorporate three fuels in the CFB boiler: oil shale, mined out during the development of the MIS retorts; low Btu MIS gas, produced during the retorting process; and, supplemental coal, readily available in the area, to provide additional Btu's to generate the amount of steam and power planned for the project. The demonstration project will provide process steam requirements and up to 50 megawatts of power for internal use and external sales. Engineering studies for a commercial facility of 25,000 Barrels/Day envision integrating MIS and aboveground retorting technologies and using a CFB boiler to burn shale fines, low Btu gas and other waste streams.

Oil shale at the C-b tract in the horizons that will be mined for the MIS retorting process varies in grade from under 20 gallons per ton (GPT) to over 40 GPT. This corresponds to a range of 2000 to 4000 Btu/pound in higher heating value. The analysis of the expected grade of shale mined for the project is shown in Table 1. The shale is about 15% organic matter, 30% carbonate minerals such as dolomite and calcite, and 55% inert minerals. The calcium compounds were expected to provide the sulfur capture in the CFB boiler. In the current design, the shale represents about 47% of the energy to the CFB boiler and contain 45% of the sulfur.

The low Btu MIS gas stream is laden with  $H_2S$  from the shale retorting and contains about 70 Btu/SCF. This represents about 23% of the Btu's in the boiler design and 51% of the sulfur load. The composition of the average gas is shown in Table 2.

Supplemental coal is available from several operating coal mines within trucking distance of the C-b site. Coal represents the remaining 30% of the Btu's into the boiler and introduces about 4% of the sulfur. Table 3 shows analyses of two typical coals. Each was used in pilot plant tests.

In addition, small waste streams, such as sour water stripper overheads rich in ammonia, may also be combusted in the CFB boiler in the demonstration project.

## THE PILOT PLANTS

The first test series was run at Tampella-Keeler's facility in Williamsport, PA. The second test series was run at Pyropower's pilot plant in San Diego, CA.

The Tampella Keeler test facility is the largest CFB pilot unit in the U.S. It is rated at about 10 MM Btu/hr fired load. It is about 3 feet in internal diameter and is the same height as commercial units (70 feet). Waste heat recovery and a baghouse for dust emission control are included. During the testing that covered one and a half weeks, 100 tons of oil shale and 10 tons of coal were burned. In order to simulate MIS gas, recycled flue gas spiked with natural gas and  $H_2S$  was injected into the boiler.

The Pyropower pilot plant is rated at 2 MM Btu/hr fired load. It is about 16-inches by 16-inches in inside dimension and about 30 feet high. Waste heat recovery, baghouse for dust emission control and backup sulfur scrubbing facilities are included. During the testing which covered about two weeks, 20 tons of oil shale and 5 tons of coal were burned. MIS gas was simulated with recycled flue gas spiked with propane and  $H_2S$ .

A matrix of steady state cases was run in each pilot plant to investigate the affects of temperature, load, mixes of fuel and partial load design conditions. Based on the results of the Tampella-Keeler test, the range of the Pyropower tests was expanded to get a larger variation in sulfur capture.

### COMBUSTION BEHAVIOR

The three fuels burned intensely and very efficiently in both pilot plants. Carbon utilization was over 99% in all runs. The main fuel, oil shale, proved very reactive due partly to its high volatiles content. On introduction into the bed, much of the organic matter promptly devolatilizes. The loss of volatiles and decomposition of the calcite and dolomite, results in a highly porous and fragile particle which tends to decrepitate into fines. As a result, though the size of the shale was below 1/4 inch at Tampella-Keeler and below 3/4 inch at Pyropower, much of the combusted solid ended up as fly ash recovered in the baghouse. A smaller stream, typically less than 20% of the ash, was withdrawn as bottom ash.

### SULFUR CAPTURE

Various investigators have shown in bench scale tests that Western oil shale could be an effective absorbent for sulfur dioxide in a fluid bed boiler. One of the major objectives of the pilot tests was to verify that low sulfur emission limits could be achieved. The data are to be used to obtain permits for the facility from the State regulators and to allow the manufacturers to provide accurate cost estimates and guarantee plant performance. Due to feed restrictions at the Tampella Keeler plant, two mixtures of shale and coal, and shale only were burned. Simulated MIS gas could be added at any time. Figure 1 shows the sulfur dioxide ( $SO_2$ ) in the stack gas for all the runs at various temperatures. Over 95% sulfur capture was achieved by the minerals inherent in the shale ash. The sulfur capture efficiency decreased with increasing temperature and fell off rapidly above 1600 F.

The shale ash contains about 30% calcite and dolomite (mostly the latter) which represents a calcium to sulfur ratio of 3.0 at normal conditions. However, the shale appears to be more effective than typical limestone. Other tests achieved very high sulfur reductions at Ca/S molar ratios that are well below those expected when coal is burned with limestone as the sorbent. This is due primarily to the phenomena, noted above, in which the shale particles break down into many fines affording a high amount of reactive surface for the  $SO_2$ .

The tests at the Pyropower unit gave generally similar results to those observed at Tampella Keeler. The dependence on temperature was similar. During these tests, the proportions of fuels were varied to achieve different Ca/S ratios. The results are shown in Table 4. They confirm the high sulfur capture and the high sorbent efficiency of the combusted shale ash.

### NO<sub>x</sub> EMISSIONS

Shale is a high nitrogen fuel and on this basis one would expect high nitrogen oxide emissions. Burning shale alone did result in elevated levels of NO<sub>x</sub> emissions which would require some control technology. Burning shale in combination with low Btu gas and with coal resulted in acceptable emission levels. Due to the unique characteristics of the shale we noted behavior that is not typical of normal coal/limestone results in a CFB boiler. As the bed temperature decreased, the NO<sub>x</sub> in the flue gas actually increased.

The experimental data from Tampella Keeler is shown in Figure 2. The data clearly show the increasing NO<sub>x</sub> level with decreasing temperature. The effect of secondary air injection, within the limits of the experimental conditions, was not significant.

We cannot offer any plausible explanation for the temperature dependence of the NO<sub>x</sub> levels. The sulfation level of the sorbent has a strong influence on NO<sub>x</sub>. For example, introducing H<sub>2</sub>S with oil shale alone brought down the NO<sub>x</sub> promptly to below 200 ppmv. Further, when the amount of H<sub>2</sub>S was doubled, there was an additional drop in NO<sub>x</sub>. However, the higher NO<sub>x</sub> level measured at the lower temperature cannot be explained along these lines, since sulfur capture was more effective at the lower temperature. Hence, at these lower temperatures, there was less free lime, more sulfate, and comparatively less H<sub>2</sub>S. The rationale for the observed temperature dependence must therefore be sought in other parameters and mechanisms.

During the Pyropower tests, more emphasis was given to the study of NO<sub>x</sub> and its control. Table 5 summarizes the emission data from these tests. Again the same temperature dependency as observed.

Ammonia injection into the outlet of the CFB boiler is a NO<sub>x</sub> control technology. Table 6 shows that the emissions can be controlled when shale is burned alone. Test 11 simulated injection of an ammonia stream produced during the MIS retorting. The ammonia is recovered from the MIS gas wash water in a sour water stripper. This ammonia waste stream was injected it into the bottom bed and cyclone outlet at various ratios. Injecting 100% into the bottom of the bed lowers NO<sub>x</sub> somewhat; injecting it all to the top of cyclone results in the lowest NO<sub>x</sub> emission level. As Table 7 shows this represents a high molar ratio of NH<sub>3</sub> to NO<sub>x</sub>: 8 versus 3 normally used for control. However, the ammonia is a small waste stream from which anhydrous ammonia can not be economically recovered for the demonstration project.

Shale, alone or in combination with other low quality fuels, can be burned and achieve low NO<sub>x</sub> emission levels by using standard ammonia injection or by using the sour water ammonia produced during the shale retorting.

### ASH CHARACTERISTICS

The characteristic of the ash which contributes to it being an effective sulfur capture agent is the fine particle size after combustion. As noted before, in both test units over 80% of the ash was recovered as fly ash in the baghouse. The baghouses at both test units showed no problem in handling the heavy loading of fly ash or in blowing the ash from the bags.

The quantity and particle size of shale ash did require that precautions be taken in the waste heat recovery sections of the two pilot plants. The fine ash did build up on the heat transfer surfaces in the waste heat boilers and the economizers.

The Tampella Keeler plant has a soot blower in the economizer but not in the waste heat boiler. During the run, baghouse inlet temperatures increased and were controlled initially by blowing the economizer. Eventually, the waste heat boiler outlet temperature became too high for the economizer to cool, forcing a shut down to clean out the waste heat boiler. An air lance was fabricated to blow the waste heat boiler during the remainder of the runs. The dust adhered to the tubes but was easily blown off by the soot blower and air lance.

The Pyropower plant has soot blowers in their waste heat boiler/economizer exchanger. A similar buildup was noted by temperature changes in the exchangers. Soot blowing effectively controlled the buildup. In a normal 10 hour burn with coal and limestone, soot is blown at the beginning and end. With shale/coal/low Btu gas, soot was blown every 2 to 4 hours; and, with shale alone, soot had to be blown every 20-30 minutes.

Both manufacturers feel that soot blowing will control the dust buildup on the heat transfer tubes. The units will be conservatively designed for proper tube spacing, soot blowers, and baghouse capacity.

The fly ash from the pilot plant tests has been tested using the EPA TCLP method and found to have no leachable heavy metals or organics. Thus the ash can be handled as a non-hazardous material. The large quantity of fly ash looks like brown cement. Tests are currently underway to determine the material's properties as a cement additive, roadbase enhancer and waste stabilizer. Preliminary results are encouraging.

### CONCLUSIONS

A test program has been completed at two CFB boiler manufacturers' pilot plants. The results demonstrate that oil shale alone and in combination with other fuels can be burned

efficiently in an environmental acceptable manner. The CFB boiler technology will allow OOSI to burn mined shale wastes and low Btu gas from its MIS processing in a commercially proven technology and produce steam and power. The combustion can be accomplished in an environmentally acceptable manner with very low emissions without the addition of limestone to the CFB or the use of flue gas desulfurization technology. The waste ash stream is non-hazardous and may eventually find uses as building materials.

#### **ACKNOWLEDGEMENTS**

The testing described in this paper was jointly sponsored under a cooperative agreement between OOSI, the U.S. Department of Energy, the State of Colorado, and Rio Blanco County.



TABLE 1  
SHALE ANALYSIS

## COMPOSITION

## Ultimate Analysis

As Received, wt%	
Carbon	17.74
Hydrogen	1.80
Nitrogen	0.34
Sulfur	0.89
Oxygen	9.97
Ash	66.13
Moisture	1.03
	100.00

Dolomite ( $MgCa(CO_3)_2$ )	20.16
Calcite ( $CaCO_3$ )	7.75

Grade, Gallons/ton 27

Heating Value, Btu/Lb. 2789

Pounds of Sulfur/MM Btu 3.64

TABLE 2  
MIS RETORT OFFGAS ANALYSIS

## COMPOSITION

Volume %	
Hydrogen	6.6
Nitrogen	63.9
Oxygen	0.1
Carbon Monoxide	2.9
Carbon Dioxide	28.1
Methane	1.3
C <sub>2</sub> 's	0.4
C <sub>3</sub> 's	0.2
C <sub>4</sub> 's	0.1
C <sub>5</sub> +	0.15
Ammonia	0.15
Hydrogen Sulfide	0.75
Other Sulfur	0.0002
Water	2.5
	100.00

Heating Value, Btu/Scf 70

Pounds of Sulfur/MM Btu 9.1

TABLE 3

## COAL ANALYSES

	COLOWYO Meeker	Powderhorn Palisade
Proximate Analysis		
As Received, wt%		
Moisture	15.86	9.50
Ash	4.94	10.00
Volatile Matter	32.82	33.50
Fixed Carbon	<u>46.37</u>	<u>47.00</u>
	100.00	100.00
 Btu/Lb	 10710	 11500
Ultimate Analyses		
Dry Basis, wt%		
Carbon	72.12	73.50
Hydrogen	4.91	4.86
Nitrogen	1.65	1.16
Chlorine	0.02	0.01
Sulfur	0.42	0.67
Ash	5.87	11.05
Oxygen	<u>15.01</u>	<u>8.78</u>
	100.00	100.00
 Pounds of Sulfur/MM Btu	 0.33	 0.53

TABLE 4

PYROPOWER RESULTS  
SULFUR DIOXIDE EMISSIONS

DESIGN MIX: 47% SHALE; 23% MIB GAS; AND, 30% COAL ON BTU BASIS

RUN	FEED	TEMPERATURE	C/S RATIO	SO <sub>2</sub> , PPM
1	DESIGN MIX	1600	3.0	16
2	DESIGN MIX	1550	3.0	1
4	DESIGN MIX, LOW LOAD	1470	3.0	1
5	DECREASE SHALE	1550	1.9	25
6	HIGH S MIB GAS	1550	1.8	138
7	SHALE WITH FG RECIRC	1470	6.6	2
8	SHALE WITH S IN RECIRC	1550	3.3	1
11	DESIGN WITH NMS	1530	2.3	3
12	SHALE ALONE	1550	6.7	6

TABLE 5

PYROPOWER RESULTS  
NITROGEN OXIDE EMISSIONS

DESIGN MIX: 47% SHALE; 23% MIB GAS; AND, 30% COAL ON BTU BASIS

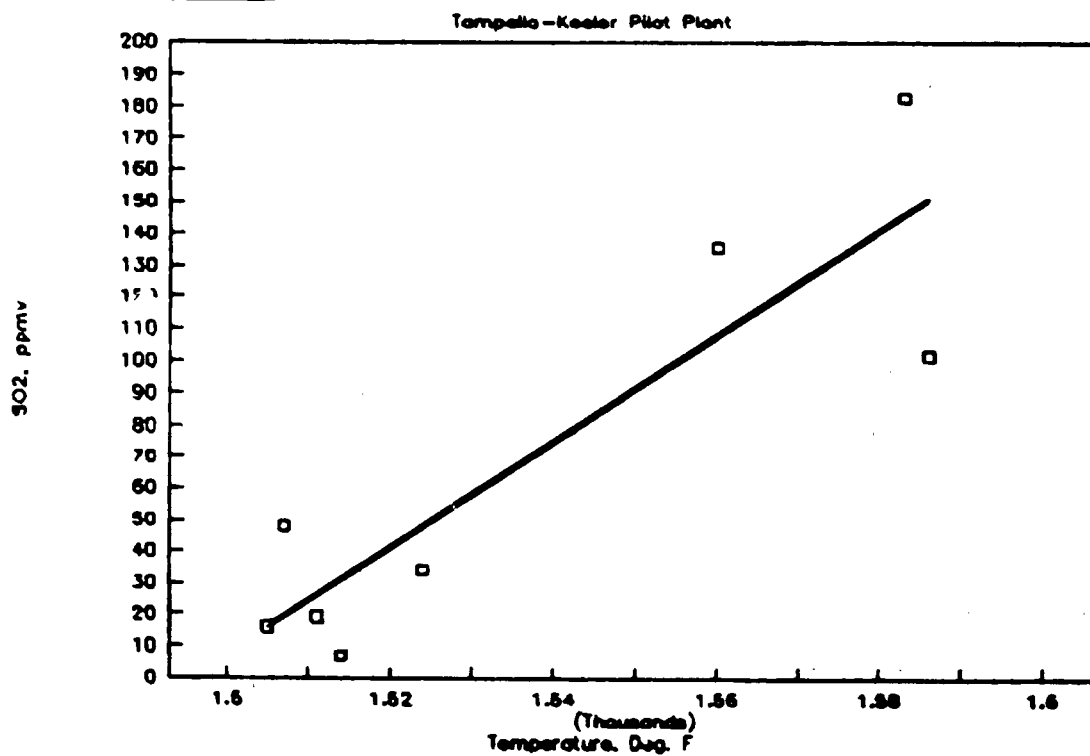
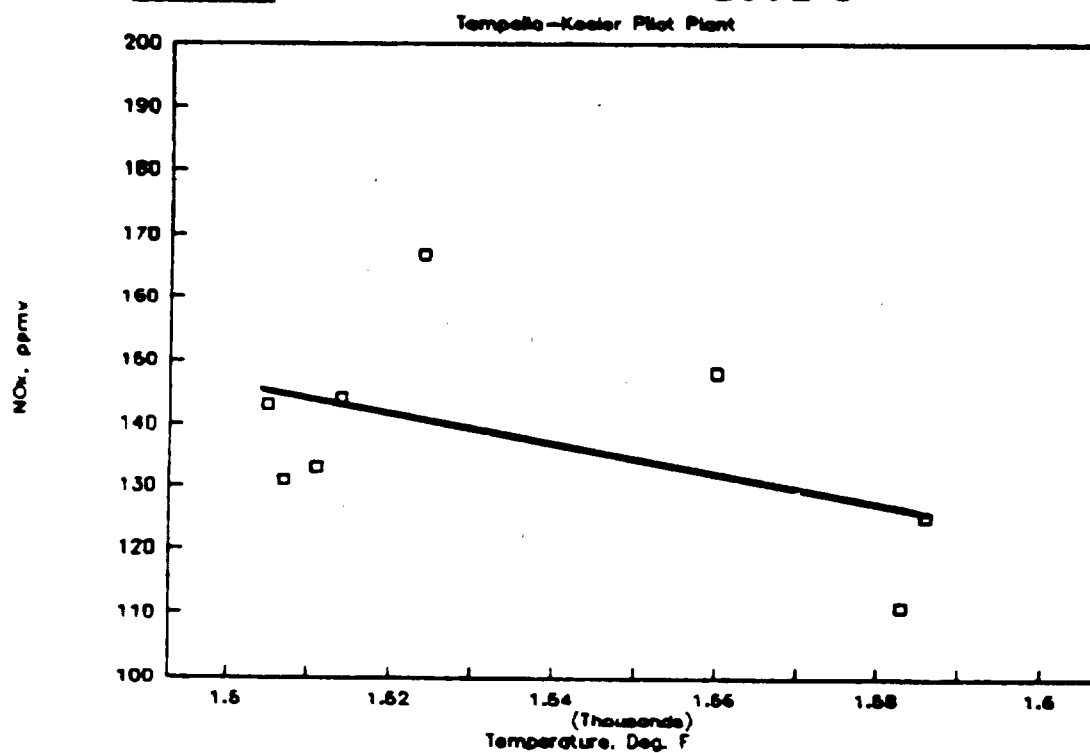
RUN	FEED	TEMPERATURE	C/S RATIO	NO <sub>x</sub> , PPM
1	DESIGN MIX	1600	3.0	167
2	DESIGN MIX	1550	3.0	222
4	DESIGN MIX, LOW LOAD	1470	3.0	283
5	DECREASE SHALE	1550	1.9	140
6	HIGH S MIB GAS	1550	1.8	148
7	SHALE WITH FG RECIRC	1470	6.6	574
8	SHALE WITH S IN RECIRC	1550	3.3	238
11	DESIGN WITH NMS	1530	2.3	Varied
12	SHALE ALONE	1550	6.7	395

TABLE 6**NO<sub>x</sub> EMISSION CONTROL****Burning Shale Alone with Recycle Flue Gas @1500F**

<b>NO<sub>x</sub> ppmv</b>	<b>NH<sub>3</sub>/NO<sub>x</sub> Molar Ratio</b>	<b>% NO<sub>x</sub> Reduction</b>
800	0	0
450	1.1	25
267	2.2	53
200	3.3	67

TABLE 7**NO<sub>x</sub> EMISSION CONTROL****Injection Sour Water Ammonia into Bed and Cyclone****NH<sub>3</sub>/NO<sub>x</sub> = 8.8**

<b>NO<sub>x</sub> ppmv</b>	<b>% to Cyclone</b>	<b>% NO<sub>x</sub> Reduction</b>
160	None	None
122	0	19
98	25	35
66	50	63
39	75	74
33	100	78

FIGURE 1 - SULFUR DIOXIDE RESULTSFIGURE 2 - NITROGEN OXIDE RESULTS

# **"REVIEW AND UPDATE OF THE COAL FIRED DIESEL ENGINE"**

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REVIEW AND UPDATE  
OF THE  
COAL FIRED DIESEL ENGINE

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GE Transportation Systems  
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ABSTRACT

GE Transportation Systems, manufacturer of diesel-electric locomotives, has been pioneering the development of a coal fired diesel engine. The project is the consequence of the 1982 study to find the most effective way to reintroduce coal as a locomotive fuel, to alleviate high fuel costs and unavailability. The project which was initially sponsored by two American railroads has since been funded largely by the U.S. Department of Energy. Feasibility of using a coal water slurry has been demonstrated and preliminary test results for commercial practicality are most encouraging. Engine thermal efficiencies are comparable to oil engines and materials have been identified to withstand the erosive effects of the fuel and its combustion products. The presence of the water in the fuel has a significant effect in controlling NOx emissions, HC and CO emissions are very low and particulates can be controlled with a particulate trap. Economic studies indicate coal slurry fuel is an attractive economic alternative for railroads. A 2200KW engine is scheduled to be installed on a locomotive this year. The success of this project may influence the development of coal burning diesels of this power output and higher for utilities.

INTRODUCTION

The volatility of oil prices and its potential limited availability continue to support the need for alternative fuel sources for America's railroads. The recent environmental concerns have also demanded that any alternative fuel meet stringent emission standards. The outlook for a coal fired diesel engine to satisfy these requirements is promising.

In 1973, the days of the oil crises, U.S. imported oil was about one-third of our domestic production and was rising rapidly. It reached about two-thirds in 1978 and then fell again to the 1973 level.<sup>1</sup> (See Figure 1.) It is on the rise again and domestic supply is falling, such that in 1989 the imported supply was equal to three-fourths the domestic supply. However, because oil prices have become a function of economic growth and exchange rates as well as supply and demand,<sup>2</sup> current low oil prices do not reflect the need for alternative fuels and there is a tendency to ignore the seriousness of the need for alternate fuels.

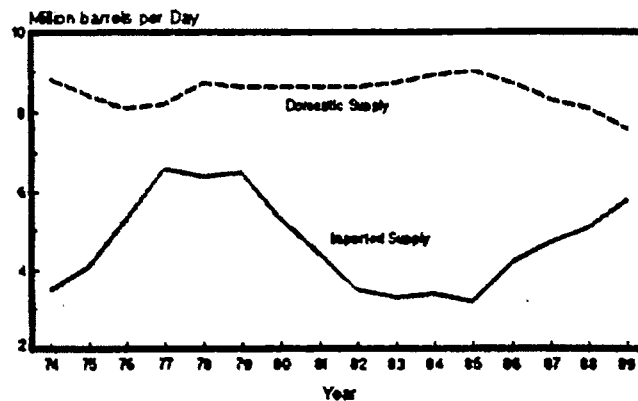


FIGURE 1 - U.S. OIL SUPPLY

There is also a renewed emphasis on environmental issues, especially the latest "panic" concern about global warming.<sup>3</sup> Because coal has little hydrogen content, it will have a somewhat higher CO<sub>2</sub> emissions content per million BTU liberated than other recently popular fuel candidates such as natural gas or methanol.

It is the purpose of this paper to review the development of the coal fueled diesel engine and to postulate its future relative to practicality, economic desirability and environmental acceptance.

#### BACKGROUND

The idea of using pulverized coal as an engine fuel began in the beginning of this century, mainly in Germany, with the first encouraging results reported by Pawlikowski in the mid-twenties. His work spurred the activities of many developers throughout the war years, but unfortunately most of the development was curtailed at the end of World War II. Most of these engines were developed to burn coal dust, with minor attempts to use coal mixtures, and but one attempt to gasify the coal. During the post war



period a few studies in the United States were conducted using dry pulverized coal or coal slurried with oil."

Within the last 15 years, interest was renewed as a result of the oil crises, and development effort sponsored by the U.S. Department of Energy culminated with tests of a single cylinder Sulzer engine operating first with coal-oil slurry fuel and then with coal-water slurry. This engine was a large slow speed diesel engine (120 RPM), with a bore of 760mm and a stroke of 1550 mm. The results of this study were encouraging in that they showed that operation on slurry fuel was feasible.<sup>3</sup> (A fuel slurry is preferred due to the more explosive nature of dry powdered coal and the consequential need for special fuel handling.) However, the tests also pointed out the need for hardware development. More intensive fuel processing developments have also been taking place within the last 15 years. These parallel development efforts encouraged GE Transportation Systems to consider a coal fueled diesel engine for use in a locomotive. However, the locomotive application would necessitate the use of a medium speed engine (1050 RPM) for size and power reasons, and feasibility for this higher speed engine had not been successfully demonstrated using coal-water slurry fuel. Coal-water slurry would have more potential fuel savings than coal-oil slurry, due to the high cost of oil, and a coal loading limit of about 50 percent to prevent high viscosity.

Ignition and combustion feasibility of the fuel within the engine had to be demonstrated, which necessitated developing fuel injection systems. The effects of the fuel on engine durability had to be understood and studies of economic desirability and exhaust emissions had to be undertaken.

#### THE FUEL

Most of the early GE experimentation was carried out using fuel produced by the OTISCA process. (See Figure 2.) Briefly described, the process first pulverizes the coal, and then comminutes the coal with water in a ball mill to a mean particle size of about 5 microns. (The developments by OTISCA demonstrated the feasibility of fine comminution with reasonable cost. Heretofore, it had been assumed that a process to produce such a fine particle size would be prohibitively expensive.) After grinding, the fuel is mixed with an agglomerate in a high shear mixer. The coal is agglomerated and the mineral matter can now be separated from the fuel agglomerate. The ash is easily separated from the water and the water recycled. The agglomerate is recovered from the fuel by heating and is also recycled. The fuel is then slurried with demineralized water to the desired fuel concentration and any necessary additives are included. The ash content of the final fuel is less than 1.5 percent (dry), and most of the pyritic sulphur is removed. Because it is a mechanical process, organic sulphur is not removed. Fuels made from other processes have also been studied.

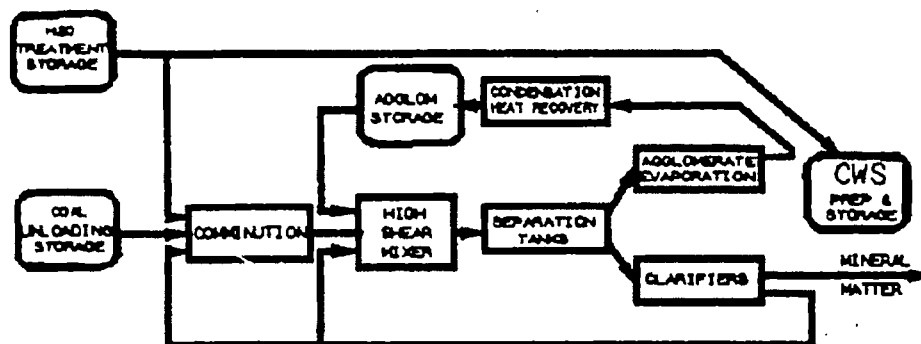


FIGURE 2 - THE OTISCA COAL SLURRY PROCESS

The nominal requirements of the engine grade coal fuel are shown in table I.

Proximate Analysis	
% Ash	1.5 max
% Volatiles	35 to 40
% Fixed Carbon	60 max.
Particle Size	
Mean Diameter (microns)	7 to 10
High Heating Value (MJ/kg)	28 to 34
Sulphur Content	1% max.

TABLE I

#### NOMINAL ENGINE GRADE COAL SLURRY FUEL REQUIREMENTS

The engine grade fuel cost is composed of three pieces: the cost of the raw coal itself; the fuel processing cost; and the transportation cost. These costs have been estimated for railroad applications<sup>6</sup> and recently reverified.<sup>7</sup> The current estimate of the fuel cost is approximately \$3.10 per million BTU, with variations depending upon process plant site location, which affects transportation costs, the source of the raw fuel and the reasonableness of the fuel process business markup.

Results to date of fuels, both bituminous and sub-bituminous which have been processed and successfully burnt in the diesel engine are shown in Table II.

POEL NO.	POEL SUPPLIER	STAT2, SEAB & TYPE	CLEANING PROCESS	HEAD MICRON SIZE	PROX ANALYSIS (Wt%)	LOWER HEATING VALUE	POEL BURN OUT	SPC
					VOLI- PIZED ASH		SOLID %	%
1.	OTISCA	KY-BlueGen Bitum	Physical	4.6	39.5 59.8 0.7	33.48	49.0	98.8 8399*
2.	OTISCA	KY-BlueGen Bitum	Physical	4.8	38.8 60.4 0.8	33.48	50.2	98.8 8812
3.	OTISCA	KY-BlueGen Bitum	Physical	3.1	39.5 59.8 0.7	33.48	49.3	98.7 8707
4.	OTISCA	KY-BlueGen Bitum	Physical	3.2	39.3 60.0 0.7	33.48	48.9	99.2 8342
5.	OTISCA	PA-Marianna Bitum	Physical	2.5	36.9 61.4 1.7	33.52	50.9	98.6 8191*
6.	ONDERC	WY-Kenner Subbit	Chemical	13.9	40.7 56.5 2.8	28.46	48.9	99.3 8564*
7.	ONDERC	WY-SprgCrk Subbit	Phys+Che	14.7	40.5 57.4 2.1	28.71	52.3	98.9 9064*
8.	ONDERC	WY-SprgCrk Subbit	Chemical	14.9	40.7 56.5 2.8	28.68	50.3	99.2 8282*
9.	ANAX	KY-Splint Bitum	Physical	8.2	37.3 60.2 3.5	32.80	49.3	97.9 8769

TABLE II

FUEL COMBUSTION RESULTS  
(\* Average of several test point)

#### THE ENGINE

Engine development began by separating the task into three phases: combustion development; fuel injection systems; and wear resistance.

#### Combustion Development:

Combustion of the coal-water fuel began with simulation in a combustion bomb at GE's Corporate Research and Development center. "Single shot" tests were conducted to determine the ignition characteristics of the fuel. These tests with sufficient combustion parameter variation, aided with high speed combustion film photography led to chemical combustion models indicating that not only was coal water slurry combustion possible in a medium speed diesel environment, but that the general character of combustion was similar to oil combustion. Indeed, based on the differences which do occur, and with later experimentation, more understanding of the entire combustion process for coal or oil is being achieved.

#### Fuel Injection Systems:

Several fuel injection system designs were conceived, and experimental hardware and single cylinder engine testing began. Coal slurry is not only erosive, it tends to clog pumps, injectors, and fuel lines. Figure 3. is a diagram of the first fuel injection system which was successful. This

system was characterized by the separation of coal slurry from the high pressure injection pump by the use of an intermediate diaphragm. Circulating fuel oil is used to provide injection pressure, volume and timing via the diaphragm. The coal slurry was prevented from clogging the injection needle by using back pressure on the needle valve. This system led to single cylinder operation of the coal slurry fueled engine at 1050 RPM and at power levels equal to that of an oil fueled engine. (The capacity of the high pressure pump was doubled to accommodate the increased fuel volume due to water.)

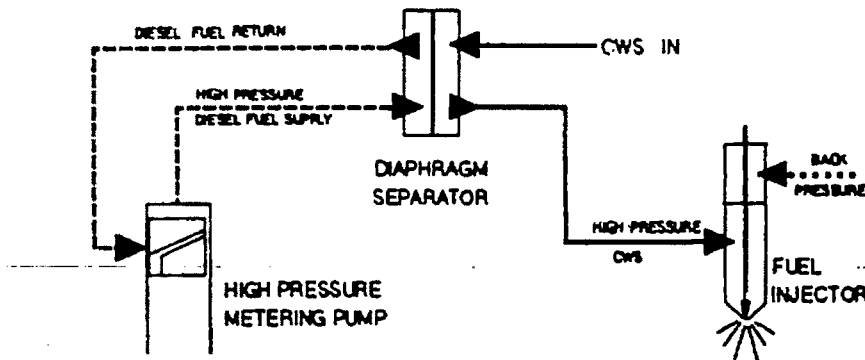


FIGURE 3 - MECHANICAL FUEL INJECTION SYSTEM

The feasibility of operating the coal fired diesel at medium speed (1050 RPM) had been demonstrated but the rapid wear of the injector nozzle holes, less than 5 hours life, underscored the need for a wear resistant development program. Other injection systems were subsequently developed, including electronically actuated accumulator systems.\* Ironically, it had been presupposed that it might be difficult to obtain such high power levels with coal fuels, but as it evolved, it was found that low power levels were more difficult, necessitating the need for diesel fuel pilot injection at these low power levels. At this stage of the development, a small quantity of diesel fuel (about 3% energy) is used at full power to promote ignition stability, and operation at low power levels is on diesel fuel only.

#### Engine Wear:

Unlike engine designers of the turn of the century, today's designers have a greater repertoire of materials and processes available to them to solve the problems of a coal fired diesel.

Injector tip wear was the most obvious shortcoming of the coal fired

diesel, and work to identify harder materials for the nozzle tips was begun. Of all the materials investigated, drilled industrial diamonds which were implanted in the injector tip were found to have the best life. In fact, no appreciable wear has been experienced to date after 60 hours of engine operation and bench scale tests exceeded 1000 hours of equivalent engine operation. The development of these tips is now underway even for use in today's oil diesels.

The wear response of the production nitrided cylinder liner to coal water slurry fuel was about six times higher than when operated with diesel fuel. Research activities on ring and liner coatings have concentrated on determining the plasma spray parameters necessary to deposit a tungsten carbide coating with optimum characteristics to resist the coal-water slurry ash sliding wear. Using a chromium carbide coated top ring, a chromium plated middle ring and a chromium plated cast iron oil ring, liner wear was reduced to only twice that of an oil diesel engine. Top ring wear was also reduced to about twice that for an oil engine by using the tungsten carbide coated top ring. The chromium plated middle ring showed better performance than when operated on oil, and the chromium plated oil ring after limited testing showed no wear at all. The fact that this first attempt to reduce the wear rate using harder materials was so dramatic indicates that the cylinder liner and ring wear problems can be solved with "reasonable advances in material technology".<sup>9</sup>

When the coal fired diesel program began, many other wear problems had been anticipated. Even though only limited durability testing has been done, to date no problems of wear have developed beyond those cited above.

#### ENVIRONMENTAL CONSIDERATIONS

Unlike the currently popular alternative fuel candidates such as natural gas and methanol, coal-water slurry is a much safer handling fuel. It is non-toxic, and non-flammable because of the high water content. It is truly an ideal fuel for mobile applications in this respect.

Table III, depicts the projected emissions from a coal fired diesel both as a bare engine and an engine with emission controls. A comparison is made with the current production oil engine.

The predictions show that the coal fired diesel with cleanup has every chance to be environmentally acceptable. Test data indicates that the HC's are slightly lower which would seem to be natural since the oil has largely been replaced with coal.

NOx emission of the coal engine is less than half of the oil engine because of the low firing temperature due to the high water content in the fuel.

	OIL DIESEL	BARE COAL DIESEL	CONTROLLED COAL DIESEL
HC	.25	.20	.20
NOx	11.50	4.80	4.80
SOx	.56	2.00	1.00
CO	.75	1.00	1.00
PM	.20	3.00	.30

Diesel fuel sulphur content= 0.5%

Coal slurry sulphur content= 1.0%

Table III

EMISSIONS COMPARISON (gr/HP-hr)

Development is underway to control exhaust particulate emissions. To date, a small scale cyclone was able to collect most of the unburned char particles in the stream, which accounts for about one-half of the particulate emissions. The smaller ash particles (less than 3 microns) passed through the cyclone. Several mesh filters were investigated. Although they were very effective, they clogged easily. Precoating the filter with lime greatly improved the ability of an air pulse to restore filter effectiveness. The high temperature (750 deg F) exhaust degraded the filters and Inconel fabric showed the most stable performance. Because the current program has locomotive application preference, the filtering system must be installed on a locomotive, thus severely limiting possible alternatives. Still, current investigation shows that a system can be designed which renders particulate emission not much greater than current oil engine output. On the other hand, removal of the size constraint which is possible with stationary applications will most likely result in a system which will capture most all of the particulate.

It seemed logical to try to capture oxides of sulphur by premixing CaO sorbent in with the coal-water slurry. For a Ca/S ratio of 2, 25 % of the initial SO<sub>2</sub> was removed as Calcium sulfate (a solid). Not only was the sulphur capture poor, it coated the head liner and valves in less than 8 hours operation.

Another concept of injecting a calcium slurry containing 25% of Ca(OH)<sub>2</sub> into the exhaust stream before the turbocharger removed 40% of the SO<sub>2</sub>.<sup>10</sup> In addition, bench scale tests showed that CuO granular bed is very effective at capturing SO<sub>2</sub> at engine temperature. It is possible to capture over 90% of the SO<sub>2</sub>. Development is under way to establish the best method of using powdered CuO in the actual engine. Thus, a great deal of SO<sub>2</sub> can be removed by post combustion techniques and as with the particulate control, even better results can probably be achieved without space constraints for stationary applications.

The lower hydrogen content of coal as compared to other fuels will result in a higher CO<sub>2</sub> emission content per unit of heat liberated. When comparing the effects of the CO<sub>2</sub> emission with other fuel characteristics, one should consider fuel process manufacturing and distribution requirements and engine efficiencies to determine overall system CO<sub>2</sub> generation. Furthermore, there are other emissions likely to be present in greater quantities in the exhaust of engines using other fuel alternatives. (e.g. formaldehyde when using methanol.) The probable greater dangers from such emissions could outweigh any CO<sub>2</sub> reduction advantages.

### ECONOMICS

An economic analysis of the coal fired diesel locomotive has been carried out. The analysis indicates that with diesel fuel costs of \$0.85 per gallon (\$6.18/million BTU), most railroads could expect an attractive discounted rate of return of more than 20% by switching to coal which includes the incremental capital costs for new locomotives and the necessary changes in railroad fueling infrastructure.<sup>6,7</sup>

Coal costs have historically been independent of the supply, demand and price structure of other fuels and there is an abundant supply. Thus, as oil prices rise, the cost of other non-coal fuel alternatives rise also, limiting their economic advantage.

### CLOSURE

The coal fired diesel engine concept is finally a reality. A 12 cylinder medium speed locomotive size engine has been run in a development test at power levels comparable to oil fueled engines. This engine is scheduled to provide locomotive power before the end of this year. Coal-water slurry fuel is non-toxic and safe and fuel savings can amount to as much as 50% over oil fuel. (Diesel fuel costs assumed at \$0.85/gallon). Materials are being developed that should make engine wear comparable to present day engines, and the engine emissions control outlook looks favorable.

Interest in the coal engine is waning somewhat because of the current low oil prices. However, coal is an abundant fuel supply and its price has historically been independent of the supply, demand and price structure of other fuels. The coal engine development could lead to reduced dependence on imported oil, especially if further engine development results in coalfueled diesels for on-highway vehicle use. Use of a safe fuel like coal-water slurry for transportation would be most welcome. For stationary applications, the highly efficient diesel engine, burning coal could certainly supplement utility prime mover needs. At some point in the future

it seems certain that coal fired diesels will find their way into our economy.

#### ACKNOWLEDGMENTS

The support of and permission of the U.S. Department of Energy to publish these updated results is gratefully acknowledged. The author also wishes to thank all of the GE coal fuel diesel team and in particular Drs. Bert Hsu and Paul Flynn for their help and support.

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## **"FLUID BED OPERATIONS TO DATE"**

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## FLUID BED OPERATIONS TO DATE

By:

Bruce Imsdahl and Duane Steen  
Montana-Dakota Utilities Company  
Mandan, North Dakota

### INTRODUCTION

Good morning ladies and gentleman, it's a pleasure to have this opportunity to speak here at the Syn Ops 90. I first want to express my appreciation to the Energy and Environmental Research Center for the invitation to speak. Also, I want to thank them for the assistance that they provided us during the initial planning, start-up, and operation of the fluid bed unit of which I will be telling you about today.

Montana-Dakota Utilities retrofitted the existing 75 mw stoker fired unit at the R.M. Heskett Station near Mandan, North Dakota, to a 80 mw fluidized bed during the winter of 1986. For those of you that are not familiar with Montana-Dakota Utilities, I would first like to give you a little explanation of our company.

Montana-Dakota Utilities is an investor owned utility that serves a territory encompassing approximately 5% of the continental United States. Our service territory includes communities in the states of North Dakota, South Dakota, Montana, and Wyoming. The R.M. Heskett Station is located approximately in the center of the state of North Dakota. We are a combination utility in that we not only service our communities with electricity, but we also have natural gas service as well.

The R.M. Heskett Station consists of two centrally independent units. The unit on the north side of the station property is unit #1. It was built in 1954, and is a 20 MWe unit. The boiler is a Riley traveling grate stoker fired unit. Unit #2, located on the south, is a 66 MWe unit that was built in 1963. The original boiler was a Riley traveling grate stoker fired unit.

There were a number of reasons for our decision to retrofit unit #2 to a fluid bed. Our expectations were to solve the problems experienced with this unit since it's initial operation. Those expectations were (1) reduction of furnace slagging (2) reduction of convection pass fouling (3) increase boiler availability (4) increase boiler efficiency (5) increase unit capacity.

The design of the fluid bed included the following parameters:

Fluidization velocity: 12 foot per second (3.7 m/s)

Normal bed temperature: 1500 degrees F. (816 degrees C.)

Bed depth: 51 inches (1.3 m)

Overall excess air: 25%

Air heater gas exit temperature: 275 degrees F. (135 degrees C.)

Bed material: Sand

Because time is money, we wanted the retrofit to be completed as quickly as possible with a minimum down time. The fast track schedule was as follows:

Contract award: January, 1986

Begin demolition: October 14th, 1986

Hydrostatic test: February 18th, 1987

First coal fire: April 16th, 1987

First generation: May 10th, 1987

Commercial operation: May 15th, 1987

The steaming conditions as set by the contract, included the following parameters:

Superheat flow: 700,000 pounds per hour

Superheater outlet pressure: 1,300 PSIG

Superheater outlet temperature: 955 degrees F.

Feedwater temperature: 443 degrees F.

Figure one is a side view of the unit prior to the retrofit. So that you are familiar with the design of this unit, I would like to point out the following features. The unit has a traveling grate that travels towards the coal feeders which are located about five feet above the grate. Below the grate is the bottom ash collection system.

This unit is a two drum boiler. The unit has three division walls in the radiant section. It has a multi-clone dust collection system in the gas path after the economizer. There was a Ljungstrom regenerative air heater located just prior to the electrostatic precipitator.

The figure number 2 shows the areas that were changed in the retrofit. Notice that the traveling grate has been removed with the fluid bed section located again just below the coal feeders. The fluid bed consists of a boiling bank and a superheater section. Below the floor of the bed, is the wind box. Below the wind box there are ash collection screw conveyors, located both towards the front and rear of the unit. The in-bed boiling bank is supplied by three new 50% capacity wet stator boiler circulation pumps. The feed for these pumps is from the lower drum. The water flow therefore is through the in-bed surface and up in to the existing three division walls. The retrofit also consisted of a new three pass tubular air heater and a new forced draft fan.

In order to accommodate the fast track schedule, Babcock & Wilcox modularized the construction. The fluid bed was made in three sections or modules. The three sections were manufactured in West Point, Mississippi. They were then loaded on flat bed trailers and hauled north to the R.M. Heskett Station. The lightest module, consisting of part of the boiling bank, weighed 87,000 pounds. The heaviest module consisting of the entire in-bed superheat section weighed 108,000 pounds. The modules were made up of the wind box, floor and their associated headers, and the respective in-bed section.

Upon arrival at the station, the three modules were pushed individually under the boiler, welded together, and lifted up in to position so that the structural steel supporting them, could then be installed.

The firing deck where the stoker feeders are located is essentially unchanged. This frontal area, forty feet long, contained the ten stoker feeders. These feeders were grouped in to four groups to match the division of the wind box. The feeders continue their original design to spread the lignite over the entire twenty five foot depth of the boiler. The top of the in-bed surface, is at the same elevation as the firing deck. The fluid bed uses sand as bed material. Figure number 3 is the analysis of the sand used in our operation. The sand is washed and sized in a pit near Washburn, North Dakota. The sand pit is a glacial deposit. The sand is delivered in trucks on a daily basis. We use approximately sixty to eighty tons of sand material per day.

Our coal is North Dakota lignite. The lignite is delivered by rail from an open pit mine located near Beulah, North Dakota. Figures number 5 and 6 reflect the typical analysis of the lignite, and the size as fired.

Part of the retrofit included the installation of a new Bailey Network 90 control system. This control system is a hybrid. To keep the cost of the project down. Those elements in the control system not necessarily part of the fluid bed, remained the original pneumatic control system as installed in 1963. The Net 90 control system included a single operator interface unit, as well as a number of hand auto stations mounted in the existing boiler board.

The graphics capability of the Net 90 system allowed for the creation of a plan view of the bed. The plan view includes twenty four thermocouples identifying temperatures through out the dense bed. The graphics includes the ten feeders, two sand feeders, and indicates the air flow through the eight air ducts supplying the segmented eight bed wind boxes. Although the bed was designed for fifty one inches of bed material, it has been our operational experience that full load can be achieved best with approximately forty eight inches of bed material. The splash zone of the bed material extends some five feet above the top of the in-bed surface. Through out the some twenty thousand operating hours, we have noted that there is very little slag build up within the boiler. This slag build up is very easily removed.

That is not to say however that we have not experienced large agglomerations within the last three years. With the North Dakota lignite being relatively high in sodium, we continuously note small agglomerates or eggs being formed during operation. We have found however, that should foreign material in particular clay, be introduced with the fuel, that large agglomerations can be easily formed predominately during start-ups.

We have however noted that with fresh bed material, the chances of large agglomerate formation is minimized during start-up.

The in-bed boiling bank and superheat section was designed with erosion shields to protect the under side of the lower tube rows. These have since been removed from the superheat section. The erosion shields have been falling off the tubes in the in-bed boiling bank. The erosion shields, due to their higher temperature, have aided in the formation of slag material. Where the erosion shields have fallen off, we have been unable to determine appreciable erosion.

The tube bends in the in-bed surface were protected with refractory covered pin studs. Again, due to the temperature of the refractory, build up of slag material is also evident in these areas. Through out the operation of the unit, the superheat section gradually acquires a coating of calcium sulfate. Figure number 7 shows the plot of steam temperature entering the in-bed surface, as well as steam temperature leaving the in-bed surface. The graph also shows the reduction in steam outlet temperature due to an agglomeration formed in the in-bed superheat section on day 108. On day 36, the unit was shut down and the in-bed surface cleaned after a 2,500 hour run. From this, we project about a 40 degree F. decrease in steam temperature over a four month period.

The results of emission tests ran in November of 1988 are listed in figure number 8. At full load, our opacity is approximately 6%.

The unit's availability is shown in figure number 9. During the months of November and December of 1987, the unit was unavailable due to the failure of the 4,000 horsepower FD fan motor. The outage in June of 1988 was to install additional in-bed boiling bank surface. Since that time, the unit has had an exceedingly good availability. For the year 1989, the unit's availability was 88%. This brief description of our fluid bed and operation to date shows that fluid beds are indeed a viable option for retro-fitting older boilers.

STEEN -5-

I hope I have shown that fluid beds can be operated with exceedingly good availability. A lot of this is attributable to the persistence of those people involved with this project, not withstanding the determination of the operators and maintenance people involved in day to day operation of our unit. I would encourage you to consider the tour of our unit that is scheduled for the last day of this conference. I think you will find this tour to be very interesting.

Thank you for your attention.



Sample Identification: Geidd Pit - McLean CountyChemical Analysis

% $Al_2O_3$ .....	8.29
% $CaO$ .....	12.12
% $Fe_2O_3$ .....	2.77
% $K_2O$ .....	1.96
% $H_2O$ .....	4.52
% $Na_2O$ .....	2.26
% $SiO_2$ .....	59.40

Fusion Temperature: ASTM D1857-68(1980)

	<u>Reducing Atmosphere</u>	<u>Oxidizing Atmosphere</u>
Initial Deformation	2210 ° F.	2200 ° F.
Softening Temperature	2230 ° F.	2230 ° F.
Hemispherical Temperature	2240 ° F.	2240 ° F.
Fluid Temperature	2285 ° F.	2280 ° F.

Figure 3 R.M. Heskett Station

SAMPLE NUMBER:

#1

LOCATION SAMPLED:Geidd Pit  
McLean County, NDTEST METHOD:Los Angeles Abrasion Resistance  
ASTM:C131, Modified  
Grading "D"Loss at 100 Revolutions  
Loss at 500 Revolutions3.3%  
18.4Weight of Balls Prior to Test  
Weight of Balls After Test2505.4 gr.  
2505.4 gr.

**REMARKS:** Material as represented by the above test results was tested in accordance with ASTM:C131, Grading "D" (6 balls) modified utilizing the #20 sieve in lieu of the #12 and the loss was determined after 100 and 500 revolutions. The abrasion balls were washed and dried to  $104^\circ \pm 1^\circ C$  prior to and after the test with those weights shown above.

Sample was submitted to and received here at the laboratory for test on August 7, 1986.

Figure 4 R.M. Heskett Station



## SIZE DISTRIBUTION OF BEULAH LIGNITE AS FIRED AT MDU'S HESKETT STATION

<u>SCREEN</u>	<u>WT. % THROUGH</u>	<u>NORMALIZED WT. % THROUGH</u>
1-1/2"	94.5	100.0
1"	86.0	91.0
3/4"	75.7	80.1
1/2"	63.9	67.6
1/4"	38.9	41.2
#8	19.3	20.4
#20	7.5	7.9
#25	4.7	5.0

Figure 5 R.M. Heskett Station

## COAL QUALITY

## Proximate Analysis (percent "as-received")

	<u>Average</u>	<u>Expected Range</u>	
		<u>Minimum</u>	<u>Maximum</u>
Heat Content (Btu/lb)	6849	6605	7464
Moisture	37.21	31.66	41.37
Ash	7.33	4.34	13.19
Volatile Matter	26.56	24.20	28.63
Fixed Carbon	27.70	24.16	35.79

## Ultimate Analysis (percent "as-received")

	<u>Average</u>	<u>Expected Range</u>	
		<u>Minimum</u>	<u>Maximum</u>
Moisture	38.20	36.59	40.17
Carbon	38.01	33.93	40.25
Hydrogen	7.01	6.28	7.41
Nitrogen	0.52	0.45	0.60
Chlorine	N/A	--	--
Sulfur	0.94	0.36	2.46
Ash	8.26	5.56	11.95
Oxygen	45.19	41.16	51.51

Mineral Analysis of Ash  
(percent weight, ignited basis)

	<u>Average</u>	<u>Expected Range</u>	
		<u>Minimum</u>	<u>Maximum</u>
Phos. Pentoxide, P <sub>2</sub> O <sub>5</sub>	0.46	0.14	1.03
Silicon Oxide, SiO <sub>2</sub>	27.69	17.59	38.26
Ferric Oxide, Fe <sub>2</sub> O <sub>3</sub>	8.32	3.34	16.10
Aluminum Oxide, Al <sub>2</sub> O <sub>3</sub>	11.93	7.40	16.30
Titanium Oxide, TiO <sub>2</sub>	0.67	0.45	0.99
Calcium Oxide, CaO	17.08	10.68	23.41
Magnesium Oxide, MgO	5.49	3.79	7.57
Sulfur trioxide, SO <sub>3</sub>	19.67	14.34	24.39
Potassium Oxide, K <sub>2</sub> O	0.63	0.39	1.27
Sodium Oxide, NaO <sub>2</sub>	6.26	0.51	16.20
Undetermined			

Figure 6 R.M. Heskett Station

# STEAM TEMPERATURE VS. TIME

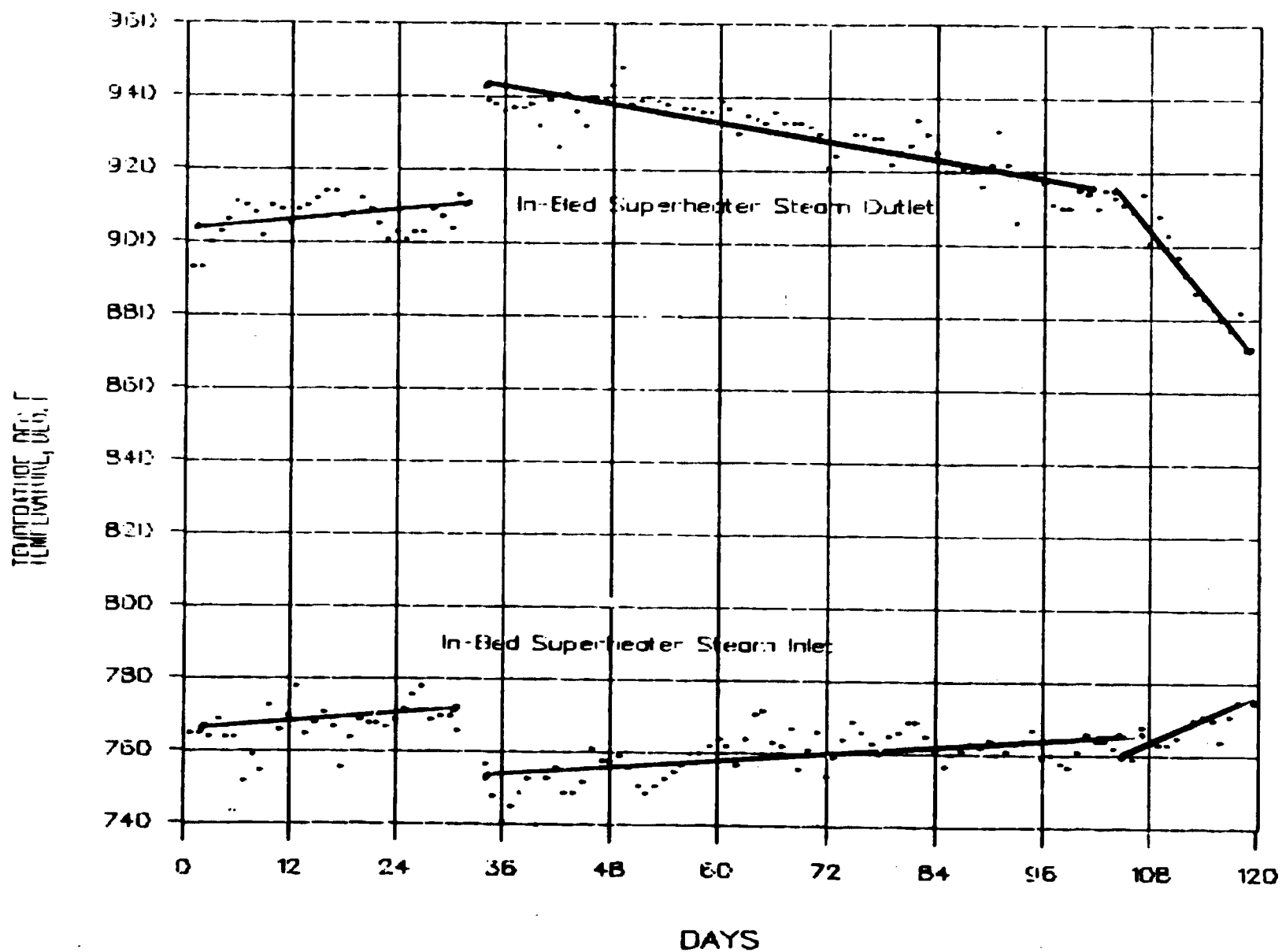


Figure 7 R.M. Heskett Station

STEEN -10-

## EMISSIONS

Particulate	0.057	lbs/10 <sup>6</sup> BTU	
SO <sub>2</sub>	0.6	lbs/10 <sup>6</sup> BTU	160 PPM
NO <sub>x</sub>	0.33	lbs/10 <sup>6</sup> BTU	127 PPM

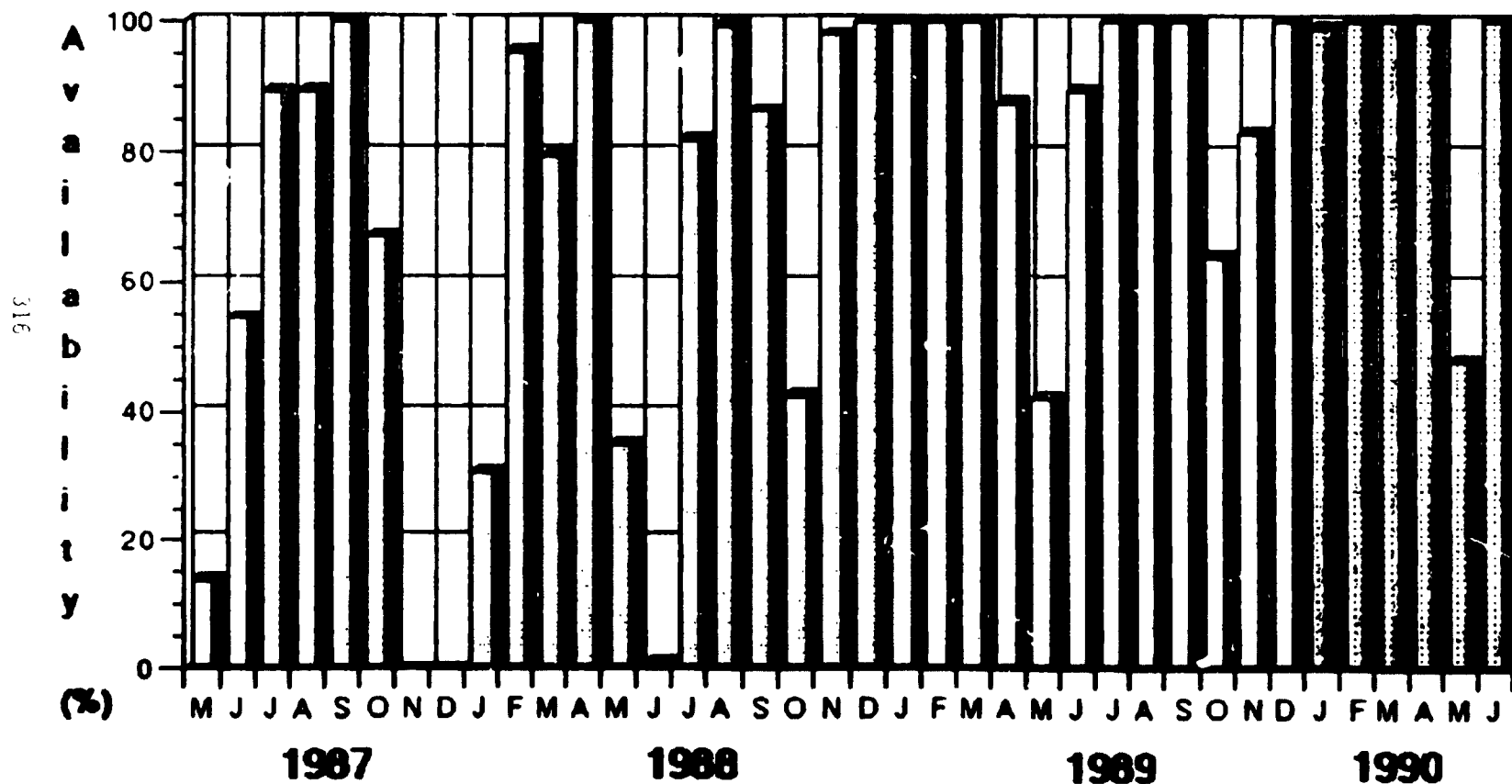
Figure 8 R.M. Heskett Station

# Availability - Heskett #2 F.B.C.

May 1987 - June 1990

## Availability Factor

$$(AF = [AH/PH] * 100 \quad AH = SH + RH)$$



STEEN -12-

# **"THE TECHNOLOGIES OF THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM"**

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THE TECHNOLOGY OF  
THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

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INTRODUCTION

Good morning ladies and gentlemen it's a pleasure to have this opportunity to speak of the Clean Coal Technology (CCT) Demonstration Program. Today, I would like to give a brief overview of the goals, objectives and current status of the program almost as an introduction and subsequently focus most of our discussion on the technology now in the program.

My goal will be to acquaint you with the progress the program is making in providing a wide range of advanced coal utilization technology options. These options will permit the industrial and utility sectors of the energy marketplace to continue to use coal in an environmentally responsive manner with greater efficiency and at lower overall costs.

THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

The program is a government-industry partnership that is demonstrating, at commercial or near commercial scale, a new generation of innovative coal utilization processes. For many technologies, it is the culmination of 15-20 years of research and development effort during which major improvements were made in the environmental and economic performance of these coal-based energy production systems.

As a goal, the program will make available to the energy marketplace a number of advanced, more efficient and environmentally responsive coal utilization technologies. These technologies will reduce or eliminate the economic and environmental impediments that limit the use of coal. We believe that this activity and the resulting processes that will be commercialized are a recognition of the strategic importance of coal as an energy resource.

The program as planned (i.e., Figure 1), currently consists of five phases with a total funding level of \$2.747 billion. To date three phases of the program have been implemented by completing three competitive solicitations. The 38 projects, with an estimated total cost of \$3.5 billion, that have been selected represent approximately \$1.3 billion of federal funding and \$2.2 billion of private sector cost sharing.

Of these projects, nineteen have been started under the terms of Cooperative Agreements between the participants and the Government and negotiations are in progress on the remaining nineteen. These negotiations are expected to be completed before the end of this year. Of particular importance to the Department of Energy (DOE) is the level of financial participation by the private sector in these projects. Although the U.S. Congress, in its guidance to the program, requires that such participation be a minimum of 50 percent, the participants are providing over 60 percent of the funds in the Cooperative Agreements signed to date.

The fourth phase of the program has been initiated. Although currently on hold, the next solicitation funded at a level of \$600 million is in the final stages of preparation. After it is released, the industrial participants (IP) will have 120 days to prepare their proposal and the technical evaluation teams will have 120 days to select the new projects.

The program also is benefiting from strong international participation. To date, companies from 10 foreign countries are supporting projects in the program. These countries include: Canada, Denmark, England, Finland, Italy, Japan, Spain, Sweden, West Germany, and Switzerland. These 10 projects will further develop a wide range of technologies that range from new concepts such as the pressurized fluidized-bed combustor from ASEA now ABB Carbon of Sweden to the continued development of an innovative near commercial flue gas scrubber that can operate on high sulfur U.S. coal. We expect that such participation will continue to the mutual benefit of the U.S. and other members of the international community.

#### WHAT ARE CLEAN COAL TECHNOLOGIES

Turning now from the statistics about the program to an examination of the technologies themselves, the role they play in the coal utilization process and the degree to which they contribute to accomplishing the programmatic goals.

When we speak of CCTs we are referring to advanced coal-based utilization systems that offer significant economic and environmental benefits when used for power generation, pollution control, or the conversion of coal into other alternate energy products.

First, in the area of power generation, the characteristics of the CCTs such as improved thermal efficiencies, modular construction, improved environmental



performance, fuel flexibility, repowering capability, etc., will help the power industry accommodate a time of significant change caused by such factors as regulatory reform, aging boilers, uncertain growth in power demand, limited capital resources, and environmental pressures.

Second, the name Clean Coal emphasizes their role in pollution control. In this case, the technologies can directly remove  $SO_2$  and  $NO_x$  acid rain precursors and substantially reduce the amount of  $CO_2$  generated when coal is burned. The specific type and amount of pollutants removed will be determined by the particular process used. It should be noted, also, however, that some CCTs (e.g., pressurized fluidized-bed combustion and gasification combined cycle systems) have the ability to remove these pollutants while at the same time increasing the power output of the facility from 50-150 percent.

In the third case, some CCTs can be used to produce coal derived liquids to replace oil and gas in some applications. This capability will permit coal to have a greater role in providing energy to the industrial, commercial, and transportation sectors.

#### THE TECHNOLOGIES

There are at least four points in the coal utilization process where innovative technologies might be used either to remove pollutants or to contribute to improved operational efficiencies. These are:

- o Before Combustion - By advanced coal cleaning processes generally located at or near the mine mouth; (Figure 2)
- o During Combustion - By modifying the combustion process or by injecting pollutant absorbing substances into specifically designed boilers; (Figure 3)
- o After Combustion - By using devices that remove the impurities from the flue gases leaving the boiler; (Figure 4)
- o Through Conversion - By changing the coal into a fuel gas, synthesis gas or liquid products; (Figure 5)

Of the 38 clean coal projects that have been selected, one or more can be applied at each of these four stages in the coal utilization process. The comparative advantages of these technologies include the following.

### ADVANCED COAL CLEANING (PRECOMBUSTION) PROCESSES

In the precombustion stage, conventional coal cleaning, a physical beneficiation process, can reduce CO<sub>2</sub> emissions by 10-13 percent by removing some pyritic sulfur along with a portion of the ash material. Advanced coal cleaning on the other hand removes a significant amount of the sulfur and ash achieving a 30 to 90 percent reduction in SO<sub>2</sub> and essentially upgrading the feedstock. Currently, there are three projects of this type in the CCT Program and they range in size or capability from 115 tons/day to 1200 tons/day. These projects are summarized in Figure 6.

### ADVANCED COMBUSTION PROCESSES

Advanced combustion processes include such concepts as control of the combustion process chemistry, advanced burners and innovative repowering technologies. The performance improvements that can be realized through the application of these technologies is best represented by the pressurized fluidized-bed combustion boiler. It captures over 95 percent of the sulfur dioxide, 60-80 percent of the nitrogen oxides, and can increase the power output of the facility by as much as 50 percent when used in a combined cycle application. The technology also is fuel flexible and produces a dry granular waste as opposed to the sludge generated by a state-of-the-art FGD. Projected commercial plant costs are lower than a conventional pulverized coal plant with an FGD system by some \$250 to \$300 per kilowatt. These systems also are compact and lend themselves to modular construction.

At the present time, the program has four advanced burner development projects for different applications that range in size from 24 tons/day to 840 tons/day coal feed. It also has eight repowering projects that feature: (1) atmospheric and pressurized circulating fluidized-bed technologies, (2) pressurized fluidized-bed combustors, and (3) gasification combined cycle systems. The names of these projects are listed in Figure 7 and Figure 8.

### ADVANCED POST COMBUSTION PROCESSES

There are two basic kinds of post combustion cleanup processes: (1) those that achieve moderate emission reductions with relatively minor modifications in the facility and low capital investment, and (2) those that achieve high emission reductions, but also require major modifications to the plant and comparable capital investment.

An example of the first kind is a gas reburn/sorbent injection technology. In this process natural gas is used to displace up to 20 percent of the coal

which creates a "staged combustion" for NOx control. A sorbent is injected into the boiler or downstream ductwork to capture the sulfur oxide emissions. This system has a demonstrated capability of reducing SO2 and NOx by about 70 percent and 60 percent, respectively. The capital costs are a function of plant size and gas availability, but have a range of \$50-\$110 per kilowatt. This cost is considerably less than that of a conventional scrubber. As indicated, this technology removes a significant amount of NOx, has little impact on plant efficiency, and generates a dry solid waste; whereas a conventional scrubber removes no NOx, reduces plant efficiency by about 3 percent and generates a difficult to dispose of sludge.

The other kind of advanced post-combustion cleanup system under development is much the same as a conventional scrubber in approach in that the unit is installed downstream of the boiler. Characteristics of these advanced systems include lower capital costs (approximately half that of a conventional scrubber) higher SO2 removal efficiencies as well as reductions in NOx emissions and in turn these systems generate a saleable byproduct and/or easily disposed of dry waste. Figure 9, 10, and 11 identify the projects of the Program in this category.

#### CONVERSION PROCESSES

While integrated gasification combined cycle systems are considered repowering technologies, they contain the key components of a coal conversion system. Coal is converted into a fuel/synthesis gas in the gasifier. This gas can be processed downstream of the gasifier to remove essentially all the sulfur while at the same time minimizing the amount of NOx generated. These systems when operated as a combined cycle system (combustion of the fuel gas in a combustion turbine accompanied by heat recovery and use in a steam generator) can increase the power output of a facility by 50-150 percent. The cleaned gas also can be used as a feedstock for a number of conversion processes capable of generating a wide range of liquid products. The modular nature of the gasifier gives the user flexibility in application as it can be sized to meet a wide range of demand.

Projected plant costs are as much as \$400-450 per kilowatt less than that required for a conventional PC facility with an FGD system. Efficiencies are in the range of 40 to 48 percent depending upon the application (i.e., repowering or new plant).

Currently, as shown in Figure 12, there are six projects in the program that represent either conversion or industrial processes. These projects are designed to produce a wide range of products from coal in a more economic and environmentally response manner.

### THE ROLE OF THE PROJECTS

Even at this stage of the program (i.e., 60 percent complete), the 38 projects will provide a number of operational, economic, and environmental advantages. In summary:

- o Clean coal power generation technologies now being demonstrated have the potential to reduce SO<sub>2</sub> emissions from 95-98 percent, achieve NO<sub>x</sub> reductions of 80-95 percent, operate with plant conversion efficiencies of 40-48 percent, and achieve continued economic improvements as the third, fourth, and fifth plants are constructed. Furthermore, some of these technologies offer incremental power increases of 50-150 percent, while using the same space requirements of the facility being modified.
- o Clean coal technologies address the global warming issue in that they can reduce the emissions of greenhouse gases in two fundamental ways. First, many of the CCTs improve significantly the efficiency of the conversion of coal to useful energy. As a general rule, a 5 percent increase in efficiency equates to a 15 percent decrease in CO<sub>2</sub> emissions. Second, they reduce NO<sub>x</sub> emissions which impacts the formation of N<sub>2</sub>O, another global warming gas.
- o The concept of placing an overall emissions limit (i.e., caps) as part of the Clean Air Bill currently being considered by Congress could indeed require the use of the more efficient CCTs in order to meet these emission caps.
- o The program may be the most important incentive for continuing the development of the next generation of more sophisticated and innovative CCTs now in the research and development pipeline. These technologies will permit greater increases in efficiency and further emissions reductions.

### SUMMARY

One of the major objectives of the CCT Program as identified in the Joint Envoy's Report on Acid Rain is to develop a suite of technology options for the control of acid rain emissions that would be significantly cheaper, more effective and yet highly efficient. This objective was subsequently expanded in guidance from Congress to include consideration of some processes that could increase the utilization of coal in an environmentally responsive manner. The projects now in the Program, when developed and commercialized, will advance the Program well along the road to achieving these goals.

# CLEAN COAL TECHNOLOGY PROGRAM

## FUNDING PROFILE (BASIS: FY 1991 BUDGET REQUEST)

FISCAL YEARS (\$ MILLION)

CCT	1986	1987	1988	1989	1990	1991	1992	1993	1994	TOTALS
I	99.4	149.1	149.1							397.6
II			50.0	190.0	135.0	200.0				575.0
III					419.0	156.0				575.0
IV						100.0	250.0	250.0		600.0
V							150.0	225.0	225.0	600.0
TTL:	99.4	149.1	199.1	190.0	554.0	456.0	400.0	475.0	225.0	2747.6

FIGURE 1

## Clean Coal Technologies— Pre-Combustion (Advanced Coal Cleaning)

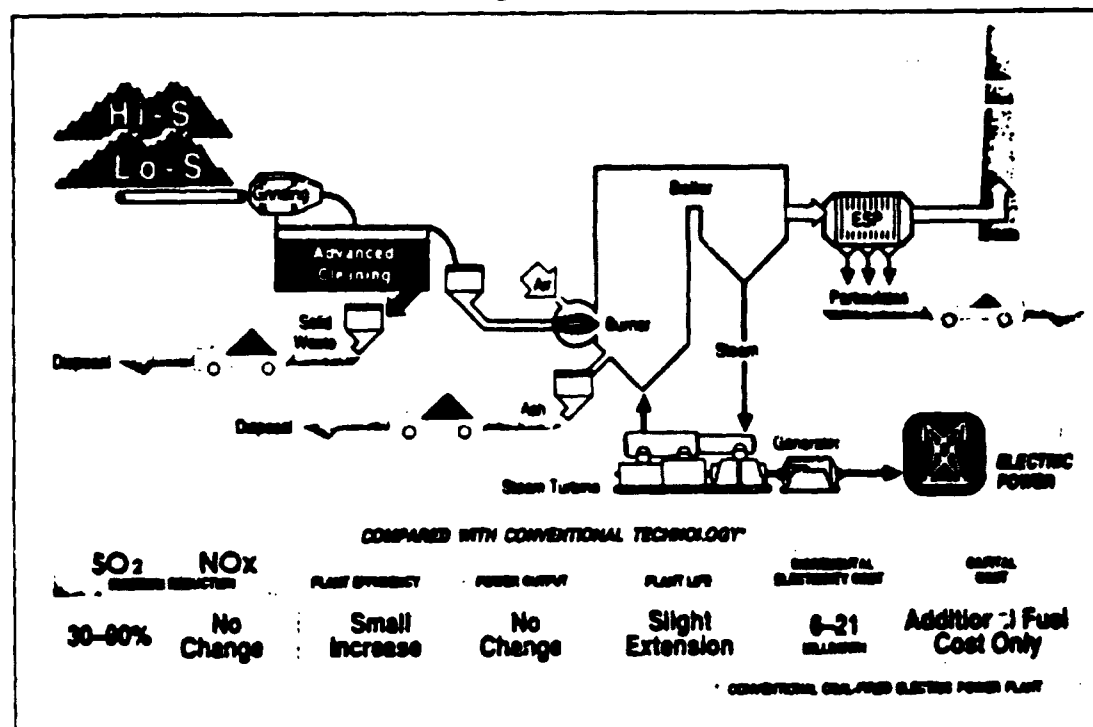


FIGURE 2

## Clean Coal Technologies— Advanced Combustion Processes

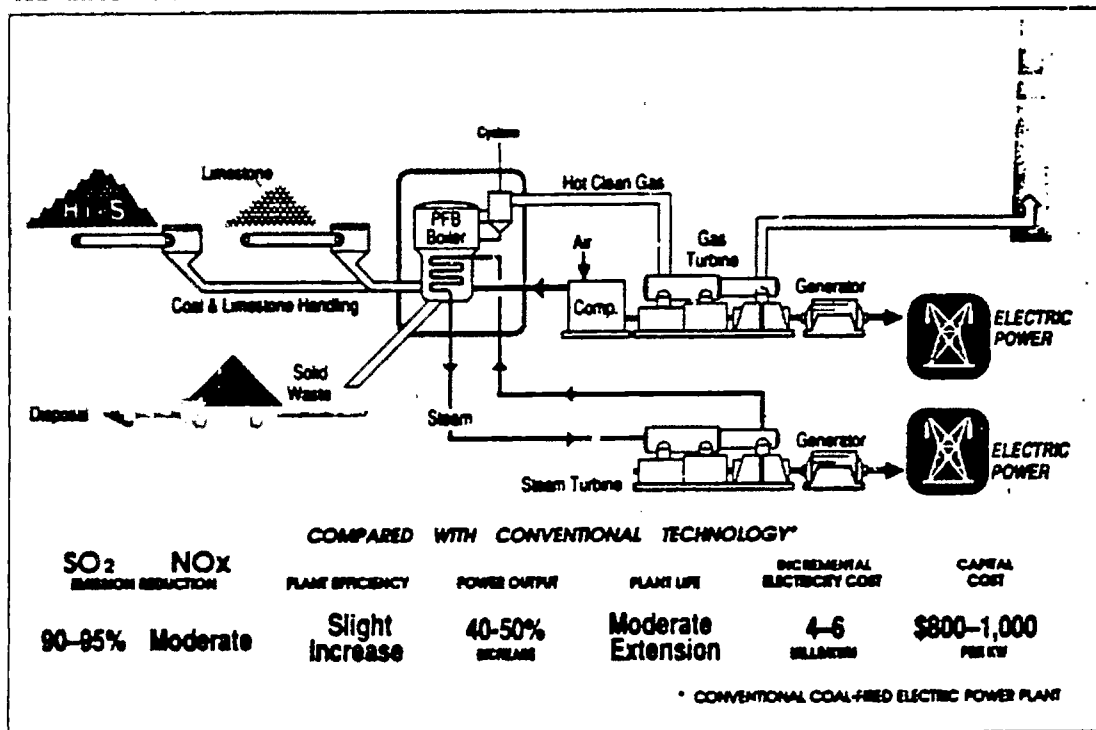


FIGURE 3

## Clean Coal Technologies— Advanced Post-Combustion Processes

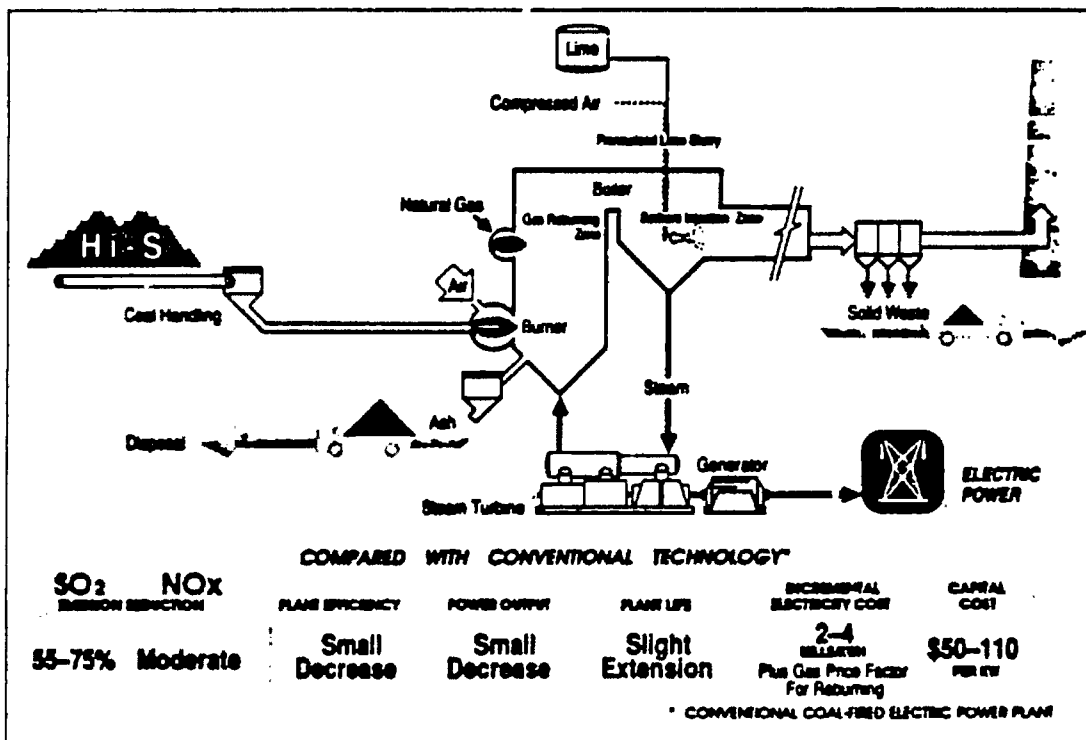


FIGURE 4

## Clean Coal Technologies— Conversion Processes

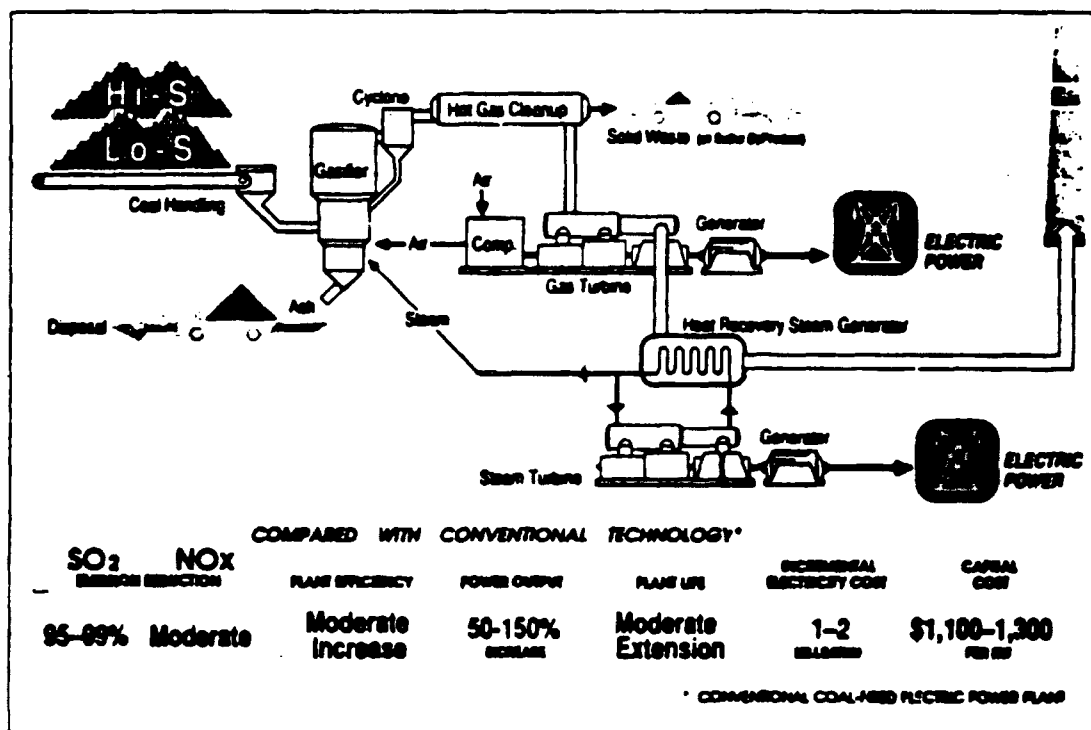


FIGURE 5

### CLEAN COAL TECHNOLOGY PROGRAM

## PRECOMBUSTION TECHNOLOGIES

- ADVANCED COAL CLEANING AND PROCESSING FACILITY - 1200 TONS/DAY
- CLEAN COAL COMBUSTION TESTING PROJECT - 480 TONS/DAY
- PRODUCTION OF OTISCA COAL SLURRY FUEL - 115 TONS/DAY

FIGURE 6

**CLEAN COAL TECHNOLOGY PROGRAM**

**ADVANCED COMBUSTION-BURNER TECHNOLOGIES**

- **ADVANCED CYCLONE COMBUSTOR FOR INDUSTRIAL USE - 24 TONS/DAY**
- **ADVANCED SLAGGING COAL COMBUSTOR FOR UTILITIES - 69 MWe**
- **LOW NO<sub>x</sub>/SO<sub>2</sub> BURNER RETROFIT FOR UTILITY CYCLONE BOILERS - 33/ MWe**
- **COMBUSTION/SLAGGING COMBUSTOR COGENERATION PROJECT - 840 TONS/DAY**

**FIGURE 7**

**CLEAN COAL TECHNOLOGY PROGRAM**

**ADVANCED COMBUSTION-REPOWERING TECHNOLOGIES**

- **NUCLA ATMOSPHERIC CFB COMBUSTOR UTILITY PROJECT - 110 MWe**
- **HOPKINS STATION ATMOSPHERIC CFB COMBUSTOR UTILITY PROJECT - 250 MWe**
- **NICHOLS STATION ATMOSPHERIC CFB COMBUSTOR UTILITY PROJECT - 256 MWe**
- **ALMA STATION PRESSURIZED CFB COMBUSTOR COGEN PROJECT - 40 MWe**
- **PHILIP SPORN PRESSURIZED FLUIDIZED BED COMBUSTION PROJECT - 330 MWe**
- **TIDD PRESSURIZED FLUIDIZED BED COMBUSTION PROJECT - 70 MWe**
- **INNOVATIVE CLEAN COAL GASIFICATION REPOWERING PROJECT - 65 MWe**
- **INTEGRATED GASIFICATION COMBINED CYCLE PROJECT - 120 MWe**

**FIGURE 8**



**CLEAN COAL TECHNOLOGY PROGRAM**

**POST COMBUSTION FLUE GAS CLEANUP - SULFUR CONTROL**

- **ADVANCED ON-SITE FLUE GAS DESULFURIZATION (FGD) PROCESS - 529 MWe**
- **APPLICATION OF CHIYODA THOROUGHbred - 121 FGD PROCESS - 100 MWe**
- **DEMONSTRATION OF GAS SUSPENSION ABSORPTION FGD PROCESS - 10 MWe**
- **DEMONSTRATION OF CONFINED ZONE DISPERSION FGD PROCESS -**
- **DEMONSTRATION OF LIFAC FGD PROCESS - 60 MWe**

**FIGURE 9**

**CLEAN COAL TECHNOLOGY PROGRAM**

**POST COMBUSTION FLUE GAS CLEANUP - NO<sub>x</sub> CONTROL**

- **ADVANCED TANGENTIALLY-FIRED COMBUSTION DEMONSTRATION - 180 MWe**
- **ADVANCED WALL-FIRED COMBUSTION DEMONSTRATION - 500 MWe**
- **DEMONSTRATION OF COAL REBURNING IN CYCLONE BOILERS - 100 MWe**
- **DEMONSTRATION OF SELECTIVE CATALYTIC REDUCTION PROCESS - 75 MWe**
- **DEMONSTRATION OF LOW NO<sub>x</sub> CELL BURNER RETROFIT - 60 MWe**
- **DEMONSTRATION OF COMBINED GAS REBURNING AND LOW NO<sub>x</sub> BURNERS -**

**FIGURE 10**

**CLEAN COAL TECHNOLOGY PROGRAM**

**POST COMBUSTION FLUE GAS CLEANUP -  
COMBINED SO<sub>2</sub> / NO<sub>x</sub> CONTROL PROCESSES**

- LIMESTONE INJECTION MULTI-STAGE BURNER PROJECT - 105 MWe
- GAS REBURNING AND SORBENT INJECTION PROJECT - 117 MWe
- DEMONSTRATION OF SO<sub>x</sub>-NO<sub>x</sub>-RO<sub>x</sub> BOX (SNRB) PROCESS - 5 MWe
- COMMERCIAL DEMONSTRATION OF WSA-SNOX TECHNOLOGY - 35 MWe
- NOXSO INNOVATIVE FLUE GAS CLEANUP TECHNOLOGY PROJECT - 65 MWe

FIGURE 11

**CLEAN COAL TECHNOLOGY PROGRAM**

**INDUSTRIAL / CONVERSION PROCESSES**

- COAL-PETROLEUM COPROCESSING PLANT - 800 TONS/DAY
- INNOVATIVE COKE OVEN GAS CLEANING SYSTEM - 5,687 TONS/HR
- RECOVERY SCRUBBER FOR REMOVING SO<sub>2</sub> EMISSIONS - 276 TONS/DAY
- BLAST FURNACE GRANULATED COAL INJECTION - 7500 TONS METAL/DAY
- COMMERCIAL LIQUID PHASE METHANOL PROCESS - 500 TONS/DAY METHANOL
- ENCOAL MILD GASIFICATION DEMONSTRATION PROJECT - 1000 TONS COAL/DAY

FIGURE 12

## **"HEALY CLEAN COAL PROJECT"**

**By: Dr. John Sims  
Vice President  
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Fairbanks, Alaska**

HEALY CLEAN COAL PROJECT

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## INTRODUCTION

The Healy Clean Coal Project (HCCP) will construct a state-of-the-art coal-fired power plant at Healy, Alaska. The power plant will provide 50 megawatts of competitively priced electricity to satisfy increasing demand in the Kenai, Anchorage and Fairbanks corridor known as the railbelt, will demonstrate innovative coal burning technologies, and may provide energy for the future development of a pilot-scale plant to beneficiate high-moisture Alaska coals. The combination of new coal-burning technologies and low-sulfur Alaska coal will result in one of the cleanest coal-burning plants in the world.

In August 1989 the Alaska Industrial Development and Export Authority (AIDEA), a state government corporation, submitted a proposal for the Healy Cogeneration Project (HCP), renamed the Healy Clean Coal Project, to the U.S. Department of Energy (DOE) under DOE's Clean Coal Technology Program. In December 1989 the HCCP proposal was selected from among 48 other projects for grant funding of up to \$93.2 million. The grant will finance nearly half of the design, capital and initial operating costs of the HCCP plant.

## ALASKA BENEFITS

The Healy Clean Coal Project will draw national and international attention to the demonstration of leading-edge technologies and provide a variety of benefits to the state's economy. The project will employ approximately 200 workers during a two year construction period and create about 50 year-round jobs in Healy once the plant is fully operational. In addition to employment, several other long-term economic benefits will contribute to the future well-being of Alaska's railbelt.

### Satisfying Growing Railbelt Energy Needs

The addition of a new, efficient 50 megawatt power plant will provide low-cost power to satisfy increasing regional energy demands. Between 1984 and 1988, kilowatt-hour sales by Golden Valley Electric Association (GVEA), serving the northern part of the railbelt, increased nearly 18 percent. By the mid to late 1990's additional base load generating capacity will be needed. While primarily serving northern customers, the strategically located generating plant would also be available for transmission to the southern railbelt.

### Technology for New and Existing Power Plants

The HCCP will demonstrate a clean-burning technology that can be used to retrofit or repower existing power plants in Alaska, the nation, and the Pacific Rim.

Many coal-fired power plants in Alaska and other states will require life extension work within the next 10 to 15 years.

EPA's stringent New Source Performance Standards will be applied to these plants and HCCP technology may be the lowest-cost solution for meeting these standards.

In addition to environmental advantages, the use of HCCP technology to retrofit coal-fired power plants in the Pacific Rim will open new markets for Alaskan coal. Currently, few Pacific Rim plants are designed to use Alaska's ultra-low sulfur, high-moisture, sub-bituminous coal. HCCP technology would allow Alaskan coal to be burned in such plants without the need for extensive boiler modifications.

Packaging the innovative combustion technology with a reliable coal supply from Alaska should present an attractive option to utilities and industrial customers in the Pacific Basin.

#### Beneficiation of Alaska Coal

A future component of the project concerns the use of process heat from HCCP plant to improve the quality of Alaskan sub-bituminous coal or to produce entirely new fuel products. Alaska sub-bituminous coal has superior environmental qualities compared to coal from virtually all other states and countries. However, its low energy value, due primarily to its high moisture content, makes the coal costly to transport and puts it at an economic disadvantage with international competition. The value and competitiveness of Alaska coal could be increased through drying, gasification, liquefaction or a combination of these processes. The excellent environmental qualities and high energy value of beneficiated Alaska coal would result in a premium fuel for export markets. This component of the project may involve a pilot plant capable of producing sufficient product for bulk market tests but should not be viewed as a commercial scale facility.

#### Focus on Alaska's Coal Resources

Alaska has enormous resources of coal and could become a major energy supplier to the Pacific Rim. The HCCP project will be a showcase for leading-edge coal-burning technology and will bring national and international attention to Alaska's low-sulfur coal resources. The project will also send a clear signal that Alaska is serious about using new and environmentally superior technologies to utilize the state's enormous natural resources.

### **CLEAN COAL TECHNOLOGY PROGRAM**

The Clean Coal Technology program (CCT) was created by the U.S. Congress in response to concerns about acid rain. The program is administered by the DOE and focuses on the reduction of air pollutants considered to be precursors of acid rain. Five rounds of funding totaling over \$2.5 billion have been planned. The first two rounds made \$973 million available while the third

and current round has \$540 million available to support qualifying projects. The \$93.2 million granted to HCCP represented approximately 17 percent of the total funding available in round three.

The objectives of the third round are to promote, through demonstration projects, the commercialization of innovative technologies which are capable of significantly reducing emissions of sulfur dioxide and nitrogen oxides in existing coal burning facilities and/or providing for future energy in an environmentally acceptable manner.

The DOE may match up to 50 percent of the costs for the design, construction and initial operation of selected projects. Project owners are responsible for financing the remainder of the cost. Under the terms of the program, AIDEA and DOE must negotiate an agreement during 1990 for the design, construction, demonstration and financing of the HCCP project before federal funding may be awarded.

#### HEALY CLEAN COAL PROJECT

The Healy Clean Coal Project involves six participants. These include the Alaska Industrial Development and Export Authority (AIDEA), which will own the project and be assisted by the Alaska Energy Authority; Golden Valley Electric Association (GVEA) which will operate, maintain and purchase power from the project; Usibelli Coal Mine, Inc. (UCM) which will supply coal and an alternate site for the project; Stone & Webster Engineering Corporation, which will act as project design and management engineer; TRW Combustion Business Unit, which will provide proprietary combustion technology to the project; and Joy Technologies Inc. which will provide proprietary emission control technology to the project.

The HCCP power plant will use an innovative design integrating advanced combustion, heat recovery, and emission control technologies. The stack emissions from the HCCP plant, including sulfur dioxide and nitrogen oxides, may be lower than any other coal-based power system in the world.

The HCCP plant will use approximately 300,000 tons per year of low-sulfur sub-bituminous coal. The plant will contribute to resource conservation by burning both run-of-mine coal and high-ash waste coal that could not be normally utilized. In the project's demonstration phase, various Alaska coals will be tested and the plant will be made available for testing coal from other states. The plant will be designed to provide process heat to an adjacent pilot coal beneficiation facility that is anticipated in a future phase of the project.

The estimated cost of the project is \$192 million. The HCCP was selected for up to \$93.2 million of cost-sharing by DOE. Additionally, in the 1990 session, the Alaska legislature

appropriated \$25 million from the Railbelt Energy Fund for the HCCP project. The balance of the project costs will be secured by AIDEA through the sale of revenue bonds. If available, tax-exempt bond financing will significantly improve the economics of the project.

### PARTICIPANTS

Six participants cooperated in the preparation of the HCCP proposal and will participate in the performance of the project.

1. The Alaska Industrial Development and Export Authority (AIDEA) supervised the preparation and submittal of the HCCP proposal to DOE and after selection submitted a financing plan to the state legislature, AIDEA will:

- be the HCCP project owner and coordinate the functions of the Alaska Energy Authority;
- issue revenue bonds to finance project costs not covered by federal or state grants.

2. Golden Valley Electric Association (GVEA) will:

- oversee the project's design and construction;
- operate and maintain the HCCP power plant;
- purchase electricity produced by the project;
- manage the training of operator personnel; and
- perform power plant start-up activities.
- provide access to land for plant siting.

3. Usibelli Coal Mine, Inc. (UCM) initiated, oversaw and funded the costs of preparing the HCCP proposal and will:

- make land owned or leased by UCM available for the alternate siting of the HCCP project;
- supply coal to HCCP and dispose of plant ash; and
- review project design and construction activities.

4. Stone and Webster Engineering Corporation acted as consulting engineer and prepared the HCCP proposal under contract to UCM and will:

- act as design engineer and supply key members to the project management and design team; and
- provide construction management services to AIDEA.

5. TRW Combustion Business Unit assisted in the preparation of the HCCP proposal and will:

- provide proprietary combustion technology to the project;
- participate in the project design; and
- provide warranties and guarantees covering the design and performance for the TRW scope of supply.

6. Joy Technologies Inc. with its European associate NIRO Atomizer assisted in the preparation of the HCCP proposal and will:

- provide proprietary technology for sulfur and ash removal;
- participate in the project design; and



- provide warranties and guarantees covering the design and performance of Joy Technologies equipment.

### INNOVATIVE TECHNOLOGIES

Two separate technology envelopes are featured in the HCCP. (Fig. 1) The HCCP will integrate entrained coal combustion (ECC) technology developed by TRW Combustion Business Unit and spray dryer absorber (SDA) technology developed by Joy Technologies Inc. in association with NIRO Atomizer.

#### Entrained Coal Combustion

TRW began developing new methods of clean coal combustion in the mid 1970's. The adaptation of advanced rocket propulsion fuel mixing technology, that TRW had created for the Apollo space program, is key to the ECC system. During a twelve year R&D phase, TRW fabricated six different combustors and conducted an exhaustive test program. In 1986 commercialization of the new system began.

The TRW system removes molten ash (slag) during combustion but a unique combustion process distinguishes it from other slagging systems. Pulverized coal is burned in entrained swirling flight under sub-stoichiometric conditions. This is in contrast with cyclone type furnaces in which combustion of granulated coal takes place on the walls of the unit under conditions which tend to exacerbate corrosion problems. In the ECC system combustion takes place away from the walls of the combustor.

Careful control of combustor stoichiometry in the TRW system promotes lower peak combustion temperatures and the formation of low  $\text{NO}_x$  levels. Thus are nullified the major failings of cyclonic combustion systems which produce high  $\text{NO}_x$  levels resulting from the combination of high peak temperatures and excess air.

In the ECC system, pulverized coal feed is injected into a precombustion chamber (Fig. 2) where it is entrained in swirling air and partially burned. About 25% of the pulverized coal feed is introduced in this stage which functionally heats the combustion air for the main stage to the high temperatures needed to induce slagging. The balance of the coal feed (+75%) is burned in the second, or main slagging, stage of the combustor at temperatures high enough to melt the ash. Carbon conversion or burn out in the combustor typically exceeds 99.5%.

Additional air is added in the secondary burner where further combustion of hot gases takes place before entering the boiler. Flue gases enter the boiler from the two stage combustion unit at 2800°F. to 3200°F and contain combustible gases  $\text{CO}$  and  $\text{H}_2$ . These gases represent the remaining heating value of the original coal feed and are burned in combination



with overfire air in the boiler.

The molten slag which coats the water-cooled walls of the main stage of the combustor is drained thru the slag recovery system. Removal of more than 80% of the coal ash as slag minimizes boiler maintenance associated with slagging and fouling, promotes thermal efficiency, and should enhance the attractiveness of using ECC technology in retrofit applications.

At the entrance to the boiler, limestone is injected into the combustion stream to react with and provide first stage removal of sulfur dioxide ( $\text{SO}_2$ ). Just as careful control of temperature and air quantities in the two-stage combustion process minimizes  $\text{NO}_x$ , so the injection of limestone maximizes initial  $\text{SO}_2$  removal.

ECC units are relatively compact, have no moving parts, are not prone to excessive wear and corrosion problems and are highly suited to modular construction. All are factors which suggest ease of adaptation in retrofit applications and a potential role, perhaps major role, in virtually all sizes of future greenfield plants.

#### Spray Dryer Absorber

In addition to sulfur reductions in the ECC system, Joy Technologies' SDA emission control system further reduces sulfur dioxide levels in the flue gases. Lime particles contained in baghouse ash are activated by abrasive removal of the calcium sulfate surface and returned to the SDA system. The recycled ash product, produced by the limestone injected during the combustion stage, is mixed with water and sprayed into the flue gases. Sulfur dioxide reacts with the spray and is removed along with the remaining ash in filter bags. The second-stage removal of sulfur dioxide and the reduced costs of limestone recycling contribute to the environmental and operational efficiencies of the HCCP design.

#### COAL SPECIFICATIONS

The performance coal for which the boiler is being designed is a 50:50 blend of waste and run-of-mine coal from the Usibelli Coal Mine. The typical analysis for this feed coal is:

Heating value	6960 Btu/lb.
Moisture	25.11%
Ash	16.6%
Volatiles	30.78%
Fixed Carbon	27.51%
Sulfur	0.15%

Preparations for test burns are underway, which will test the performance of Alaskan coals, proposed for long term use, in the HCCP. The coals will be tested, along with Alaskan

limestone, at TRW's industrial scale ECC demonstration unit in Euclid, Ohio. Various blends of waste and run-of-mine coal, at various feed rates, will be burned in the ECC and the performance monitored for ash capture in slag, grinding requirements, combustor tuning for NO<sub>x</sub> control, first stage SO<sub>2</sub> capture and impact on boiler design. After selection of optimum firing conditions, long duration tests will be used to produce samples of Flash Calcined Material, the lime laden baghouse ash, for testing in Joy/Niro's SDA pilot plant in Denmark.

Foster Wheeler has been selected to fabricate the boiler unit for the HCCP.

#### THE HCCP SCHEDULE

The HCCP, several months after selection for funding by DOE under round three of the Clean Coal Technology program is on schedule. Agreement with DOE and ratification by Congress should be complete by early in the New Year. Environmental permitting and engineering design and other factors should accommodate a construction schedule beginning in 1992. Construction will span a period of two years to be followed by a one-year demonstration phase. Full commercial operation of the HCCP should be a reality in 1996.

#### CONCLUSION

Emissions for the HCCP are predicted to be equal or better than any other coal based system and at lower capital costs than competing technologies. The HCCP emission levels should be less than 0.04 lbs/MM Btu for SO<sub>2</sub>, less than 0.2 lbs/MM Btu for NO<sub>x</sub> and less than 0.01 lbs/MM Btu for particulates. These are levels well below current federal and state requirements.

The HCCP is a project whose time has come. It is a project which I hope will showcase the strength and wisdom of the Clean Coal Technology program.

The author wishes to thank Alaska Industrial Development & Export Authority (AIDEA) for its permission and Charles B. Green and Steve Denton for their contributions to this paper.

**"COAL GASIFICATION COMBINED CYCLE  
POWER GENERATION ENHANCEMENT  
WITH METHANOL"**

**By: Mr. Kent E. Janssen  
Vice President and Chief Operating Officer  
Dakota Gasification Company  
Bismarck, North Dakota**

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POWER GENERATION ENHANCEMENT  
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## COAL GASIFICATION COMBINED CYCLE POWER GENERATION ENHANCEMENT WITH METHANOL

As environmental requirements become more stringent and costly, power generating companies will need to increase efficiency and at the same time maintain high environmental standards. A new concept is emerging wherein proven technologies will be combined to create an optimum system. In this concept, combined cycle power generation integrated with the coal gasification process could be greatly enhanced with methanol production.

A combined cycle system represents proven technology provided at relatively low installation costs along with improved efficiency levels compared to more traditional methods. Existing commercial units are being fired with oil or natural gas.

Basic elements of a combined cycle system include a combustion gas turbine, a heat recovery steam generator to recover the gas turbine exhaust energy and a steam turbine to utilize the recovered heat energy in the form of steam to produce additional kilowatts.

Combined cycle is a two stage production of electricity with generation from a gas turbine and a steam turbine. Combining the two power sources improves the efficiency of converting the combustion energy from fossil fuels to electricity.

The combustion energy not converted to power in the gas turbine, the hot turbine exhaust gases, are used to raise steam in a waste heat boiler. This steam then drives a steam turbine which generates additional electricity.

Combined cycle systems use about one-third less fuel to generate the same amount of electricity as that of the conventional steam turbine utility station. The cost of oil and natural gas per unit of heating value is two to three times that of coal, however.

Coal gasification combined cycle (CGCC) combines the technology of using coal in a gas turbine by converting the energy in coal to a fuel gas suitable for a gas turbine by gasifying the coal. Not only does CGCC increase efficiency, but is environmentally superior in the use of coal to generate power. Both sulfur dioxide ( $\text{SO}_2$ ) and nitrogen oxide ( $\text{NO}_x$ ) emissions are significantly reduced from that of a conventional utility station using flue gas desulfurization technology.

This presentation will demonstrate how methanol production can enhance coal gasification combined cycle power generation. I will also explain Dakota Gasification Company's involvement in commercializing a process that could be used for the methanol as a way of improving the economics of using coal for combined cycle power generation.

The main objective of this joint venture with Air Products is to demonstrate liquid phase methanol (LPMEOH)\* technology on a commercial-sized basis. However, an additional benefit would be proving that the technology is ideally suited for a combined cycle plant and, therefore, could greatly improve

\* LPMEOH is a trademark of Chem Systems, Inc.

the economics of generating electrical power from coal in a combined cycle plant. The production of methanol is attractive because the coal gasification section can be sized significantly smaller. A large cost savings is realized because the coal gasification equipment makes up a large portion of the capital investment of a coal-fired combined cycle plant.

Because power demand is less during weekends, holidays and nighttime, the average annual production from a typical power plant is only about 75 percent of its capacity. With liquid phase methanol technology, the gasification portion of such plants could be sized to match the average plant load factor. During low load levels, the unneeded gas turbine fuel would be used for the production of methanol. When the electrical loads exceeded the capability of the coal gasification system, methanol would be taken from storage and fired in the gas turbine.

It is estimated that integrated coal gasification combined cycle systems with LPMEOH requires 5 to 15 percent less capital investment and that operating costs are reduced by about 4 mills/kWh.

The merged technologies could offer yet another advantage. Currently, gas turbine peaking systems are fired with natural gas or fuel oil. The stored methanol could be used for fuel, reducing utilities' purchase of costly natural gas or fuel oil.

Abundant United States coal resources is another drawing card for methanol production from coal. The U.S. reserves for coal are much larger than natural gas or oil. Efficient production of energy from coal makes this country less dependent on foreign oil.

Air Products and Chemicals, Inc. (APCI), and Dakota Gasification Company (DGC), through a joint venture, propose to demonstrate the LPMEOH technology under the federal government's Clean Coal funding. The Clean Coal Technology Demonstration Program is a \$5 billion national commitment to demonstrate economic and environmentally sound methods for using our nation's most abundant energy resource, coal. The government shares costs up to 50 percent with the private sector. The Clean Coal program requires, however, that the money be repaid to the federal government from the commercialization of the technology.

The three Clean Coal Technology solicitations to date were issued in 1986, 1988 and 1989. We applied to Round Three which has \$545 million dollars available to assist in demonstrating technologies in the use of coal in an efficient and an environmentally acceptable manner.

APCI and DGC submitted a proposal to the Department of Energy (DOE) for a commercial-scale demonstration LPMEOH unit. The APCI/DGC proposal was one of 13 projects selected late last year out of 48 competing proposals.

APCI and DGC are equal partners in the projected \$214 million project. Costs include construction and four years of operation. Under the proposal, the DOE will contribute \$86.9 million to the project which will convert about 7.4 percent of the plant's synthetic natural gas (SNG) to 400 tons of methanol daily.

DGC owns the Great Plains Synfuels Plant near Beulah, North Dakota. The 650 acre plant is the only commercial-scale coal gasification plant in the United States that manufactures a high-Btu SNG. The synfuels plant began operation in the summer of 1984 and produces an average of 148 standard million cubic feet of SNG daily.



Through the proposed methanol project, the Great Plains synfuels plant would increase product diversity. Moreover, the knowledge gained from the demonstration would aid in the commercialization of this technology.

APCI is an international supplier of industrial gases headquartered in Allentown, Pennsylvania. They will install an advanced process for making methanol at the Great Plains plant, a technology which has been extensively tested at their process development facility in LaPorte, Texas.

Improved economics for coal gasification combined cycle is the main reason APCI pursues the demonstration project. This could increase the demand for large air separation plants, which they supply. Moreover, proving the LPMEOH technology on a commercial basis could create a market for their LPMEOH technology and equipment.

By choosing the Great Plains synfuels plant as the demonstration site, APCI and the DOE have chosen an ideal location to prove the LPMEOH technology. According to the proposal, DGC will provide the real estate, the utilities, the raw synthesis gas and the plant infrastructure. By having these services in place and available, the demonstration can be achieved far more economically than a grass-roots project.

The DOE has supported the LPMEOH technology since conception. The process was developed in the mid 1970's by Chem Systems. From 1975 to 1981 APCI conducted bench scale testing. The success of the those tests lead to laboratory testing in 1983. These pilots provided the groundwork for APCI's 7 ton/day demonstration plant in LaPorte, Texas, from 1981 to 1989. This project laid the groundwork for the proposed demonstration using carbon monoxide and hydrogen in synthesis gas available at the Great Plains Synfuels Plant.

Today's commercial methanol production technology is dominated by two processes, one developed by Lurgi and one by Imperial Chemical Industries. Both processes use gas-phase reactors with a zinc-copper catalyst to convert syngas to methanol.

Today methanol is made from methane (natural gas) by a two-step gas-phase conversion process. First, methane is reacted with water and heat to produce a syngas, consisting of carbon monoxide and hydrogen ( $\text{CH}_4 + \text{H}_2\text{O} \rightarrow \text{CO} + 3\text{H}_2$ ). This step is called steam reforming. Secondly, the syngas is converted to methanol, using a copper-based catalyst to promote the reaction ( $\text{CO} + 2\text{H}_2 \rightarrow \text{CH}_3\text{OH}$ ). Both steps carry built-in obstacles that cause energy loss and are costly.

The LPMEOH process is believed to be more cost effective than the conventional method. The process differs from gas-phase systems in that the catalyst is suspended as a slurry in an inert hydrocarbon liquid, such as mineral oil. This oil distributes the heat of the reaction throughout the reactor more efficiently than the current technology where these reactions take place in the gaseous state. In both processes, the heat of the reaction generates steam in a heat exchanger.

Another clear advantage, and perhaps the most significant to utilities, is that the liquid-phase can use syngas derived from coal gasification, which has a higher proportion of carbon monoxide than the syngas used by gas-phase reactors. This results in a higher conversion per pass and reduces the volume of recycling, with its associated energy penalty. Furthermore, the process can operate with a higher turn-down-ratio, which is necessary as power production fluctuates due to changes in the needs of the utility's electric system.

Further cost savings are realized in catalyst replacement. Spent catalyst can be pumped from the system and replaced with a fresh slurry on-stream rather than shutting down the reactor to replace the entire catalyst inventory. Production efficiency remains high through the addition of fresh catalyst and because shutdowns are not required for catalyst change.

In the demonstration project, the liquid-phase methanol unit will be integrated into the existing facility at the Great Plains synfuels plant. In the existing facility all of the clean syngas stream from the Rectisol unit is currently sent directly to the methanation system, for conversion to SNG. The proposed unit will be located downstream of the Rectisol unit, prior to methanation, and will process about 28% of the Rectisol outlet stream. The unreacted gas from the liquid phase methanol unit will be sent to the methanation section for conversion to natural gas.

The improved technology of using LPMEOH for converting synthesis gas ( $\text{CO} + \text{H}_2$ ) to methanol will raise electrical generation operating efficiency and lower production costs. Methanol will be more useful to electric utilities, both as a new fuel option for combustion turbines and as a salable by-product. Another benefit of the liquid product is that it is easier to transport and store.

As part of the demonstration project, the ACUREX Corporation will test the crude methanol produced in the liquid phase methanol process to determine its suitability for boiler, turbine and transportation fuel applications.

The DOE and the joint venture continue negotiations on the methanol project. The original DOE application is for a 500 ton per day, but plans are to reduce the size to a 400 ton per day plant and expand the facility to 560 tons per day during the demonstration period. The proposed reduction in plant size results because of the difficult economics of marketing the plant's production. Not only is this plant a great distance from the U.S. methanol market, but we can anticipate continued strong competition from foreign sources.

Methanol is used as a chemical feedstock in producing a wide variety of products, including formaldehyde, acetic acid and gasoline additives. Methanol is also used directly as a solvent and potentially as an alternative motor fuel.

Methanol is a commodity, so prices are partially influenced by world conditions, making economics difficult to predict as prices fluctuate with the world market.

Most of the large users of methanol either have their manufacturing near ports or water ways, such as the Mississippi or the Ohio River. Production from Great Plains will have to be shipped by rail in competition to both U.S. production, where natural gas is competitively priced, as well as foreign imports.

The future of methanol prices could be affected by legislation as well. Federal and State legislation, both existing and proposed, would increase the requirement of methanol for reformulated gasoline and as an alternative fuel.

Clean Air legislation will modify gasoline composition to improve air quality and reduce human exposure to potentially harmful hydrocarbons. The goal is to target the best fuel composition to reduce emissions, especially those contributing to ground level ozone formation, while maintaining transportation fuel quality.

The Clean Air Bill currently before Congress, which restricts the vapor pressure of gasoline could increase the need for methanol.

Hydrocarbon vapors cause ozone formation. Some hydrocarbons, like butane, are high vapor pressure components, which contributes to atmospheric pollution. By eliminating the high vapor pressure hydrocarbons from the fuel and replacing it with a lower vapor pressure component, such as ethers, the ozone forming characteristics are lowered.

Some industry analysts predict that ethers, including ethyl tertiary butyl ether (ETBE) and methyl tertiary butyl ether (MTBE), will have a major role in new reformulated gasolines. MTBE is produced from methanol, while ETBE is a product of ethanol.

While the large-scale manufacture of methanol from domestic coal could have a positive impact on the United States economy, there currently is a great concern about green house gases and the conversion of coal to methanol resulting in more CO<sub>2</sub> emissions than when produced from natural gas. The use of coal, however, for a larger share of our energy needs would reduce the need for imported oil.

DGC is still evaluating the financial risk of the LPMEOH project. The passage of the Clean Air bill would provide insight on the future requirements of reformulated gasoline, which would have a great impact on this country's requirement for methanol and ethanol.

With project economics difficult to predict, the project is not yet a reality. The future of the methanol market is the key as to whether this technology can be demonstrated at the Great Plains plant on a financially sound basis.

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# PLANT STATISTICS

- Produces pipeline quality natural gas (55 billion cubic ft/yr)
- 0.3% of total U.S. consumption
- Construction cost for Phase I (\$2.1 billion)
- First production (July 1984)
- DOE ownership (August 1985)
- Dakota Gasification Company (DGC) ownership (November 1988)
- Parent Company (Basin Electric) provides power and water

# PLANT PERFORMANCE

- Technical success
  - Reliable production
  - Production rates exceed design
  - Process refinements continue to:
    - \* Increase production
    - \* Lower operation and maintenance costs
- Plant failed to meet environmental objectives
- Plant failed financially
  - Low energy prices

# **CLEAN COAL ROUND III**

**\$525 million available**

- Up to 50% matching
  - Capital investment
  - Demonstration expenses

# **FUTURE**

- Gas revenues have matched or exceeded plant operating cost
- Decline in synthetic natural gas revenue anticipated
- Byproduct development emphasized as source of additional revenue
- Methanol is a potential byproduct



# METHANOL PROJECT

- Partners
  - Air Products & Chemicals Inc. (50%)
  - Dakota Gasification Company (50%)
- Project Scope
  - 500 tons/day (approx. 10% of SNG production)
  - \$213.7 million project
    - \* Includes four years of production cost
  - \$92.7 million DOE share
- Demonstration (Alternate Fuels)
  - Transportation fuel
  - Power generation fuel

# DEMONSTRATION PROJECTS

## Demonstration Partners

## State

Kanawha Valley Regional  
Transportation Authority  
(KVRTA)

West Virginia

Southern California  
Rapid Transit District  
(SCRTD)

California

Miller Brewing Company

California

Hughes Aircraft Company

California

# **LIQUID PHASE METHANOL (LPMEOH)**

## **History**

<b>1975</b>	<b>Concept potential</b>
<b>1975-1981</b>	<b>Bench scale testing</b>
<b>1983</b>	<b>Laboratory size testing</b>
<b>1984-1989</b>	<b>Demonstration plant (7 to 13 tons per day) - LaPorte, Texas</b>

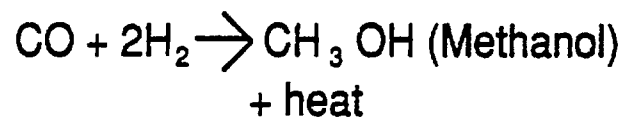
# METHANOL (WOOD ALCOHOL)

## Feed Stock

Natural gas ( $\text{CH}_4$ )

Coal gasification raw gas

## Process

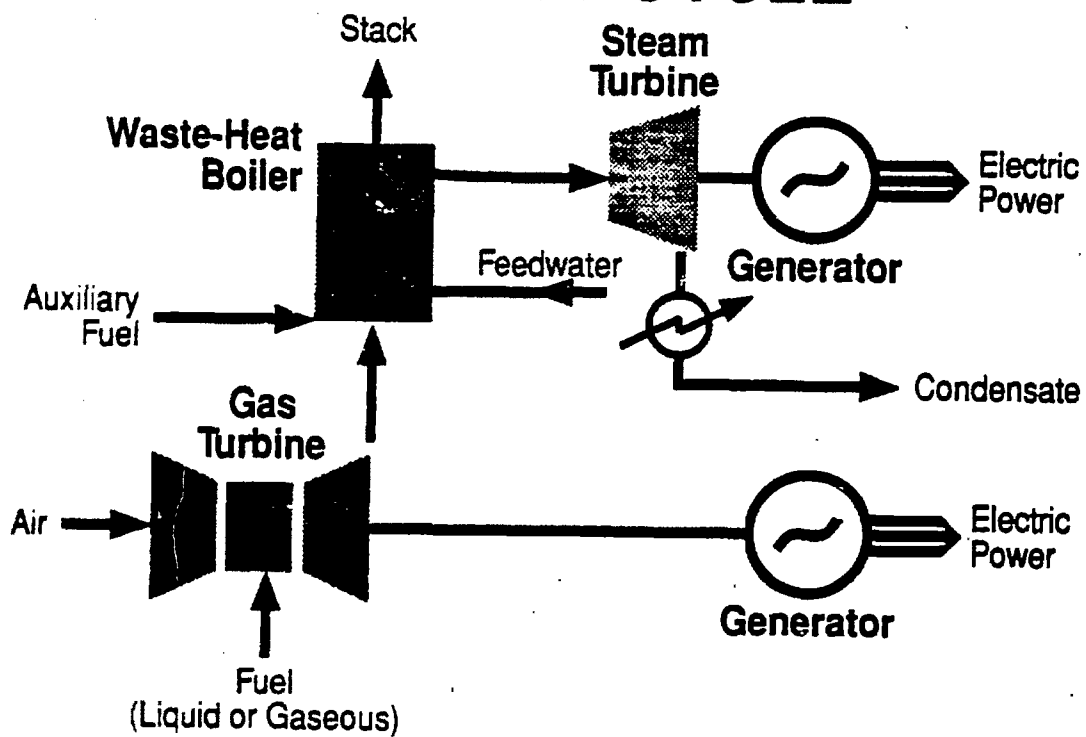


# **PROCESS ADVANTAGES**

## **Liquid Phase vs. Gas Phase**

- Higher throughput
- Better process control
- Rapid turn down
- Improved economics

# COMBINED CYCLE



# **COMBINED CYCLE POWER GENERATION**

- **Advantages**
  - High efficiency (1/3 less fuel)
  - Low capital cost
  - Low environmental emissions
  - Short lead time (planning to commercialization)
- **Disadvantage**
  - Burns liquid or gaseous fuels

# ESTIMATED U.S. ENERGY RESERVES

Coal  
478 billion tons\*

Petroleum  
28 billion barrels

Natural Gas  
205 trillion cubic feet

Shale Oil  
76 billion barrels

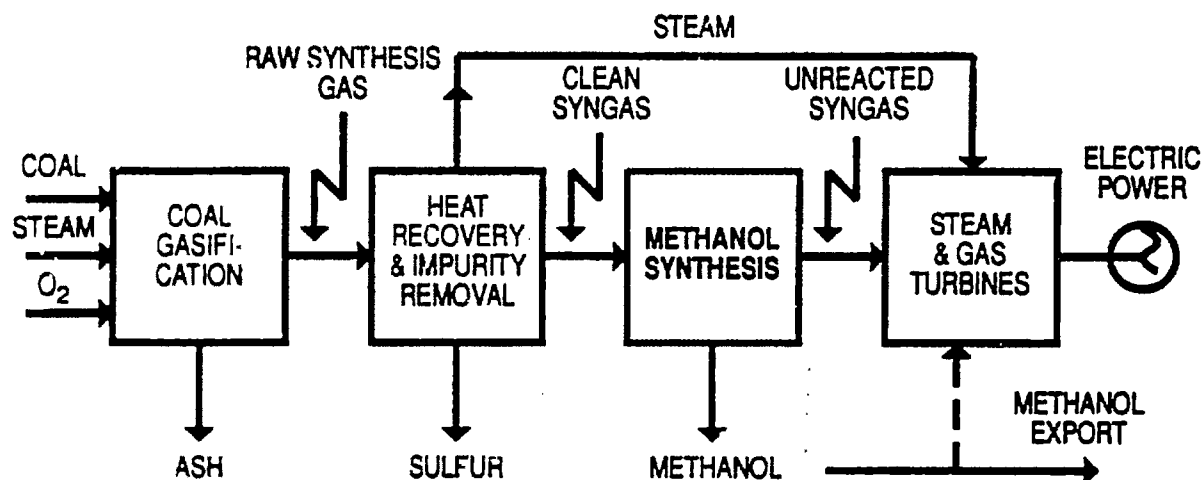
\* DOE states 268 billion tons  
of recoverable coal provide  
250 years supply at current usage.



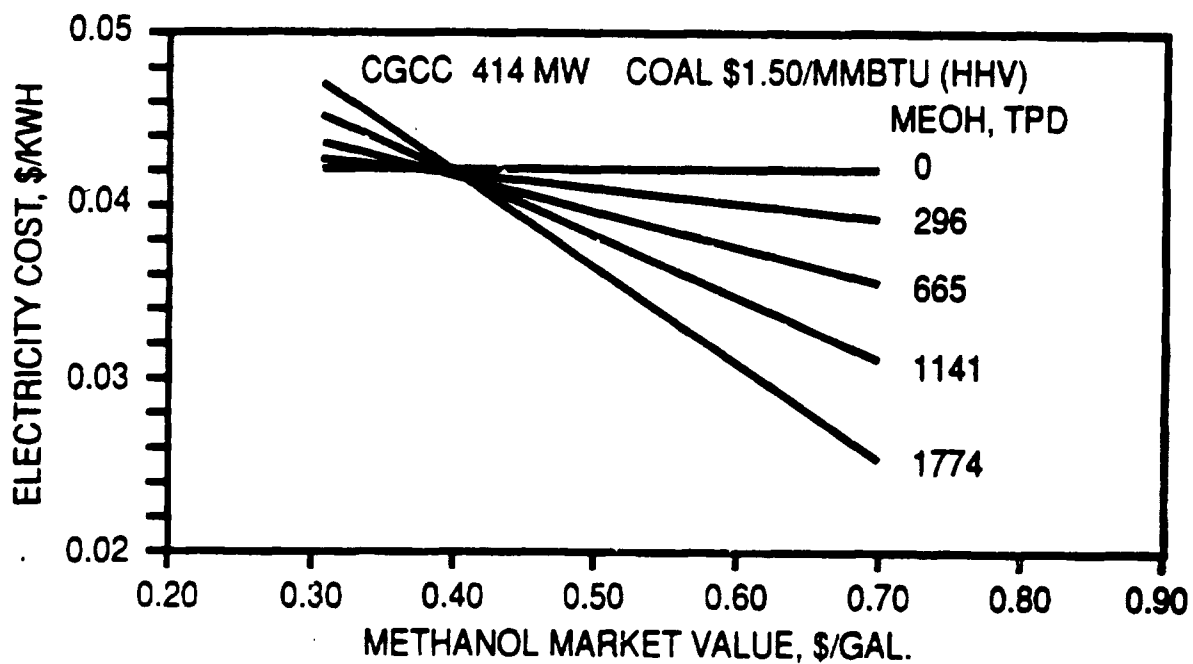
# **COAL GASIFICATION COMBINED CYCLE POWER GENERATION**

- **Advantage**
  - Utilize coal which is plentiful and economical
- **Disadvantages**
  - Increased capital cost
  - Not proven commercially
  - Public perception that use of coal increases pollution

## COPRODUCTION OF ELECTRIC POWER AND METHANOL VIA COAL GASIFICATION COMBINED-CYCLE (CGCC)



## ELECTRICITY COST AS A FUNCTION OF METHANOL PRICE

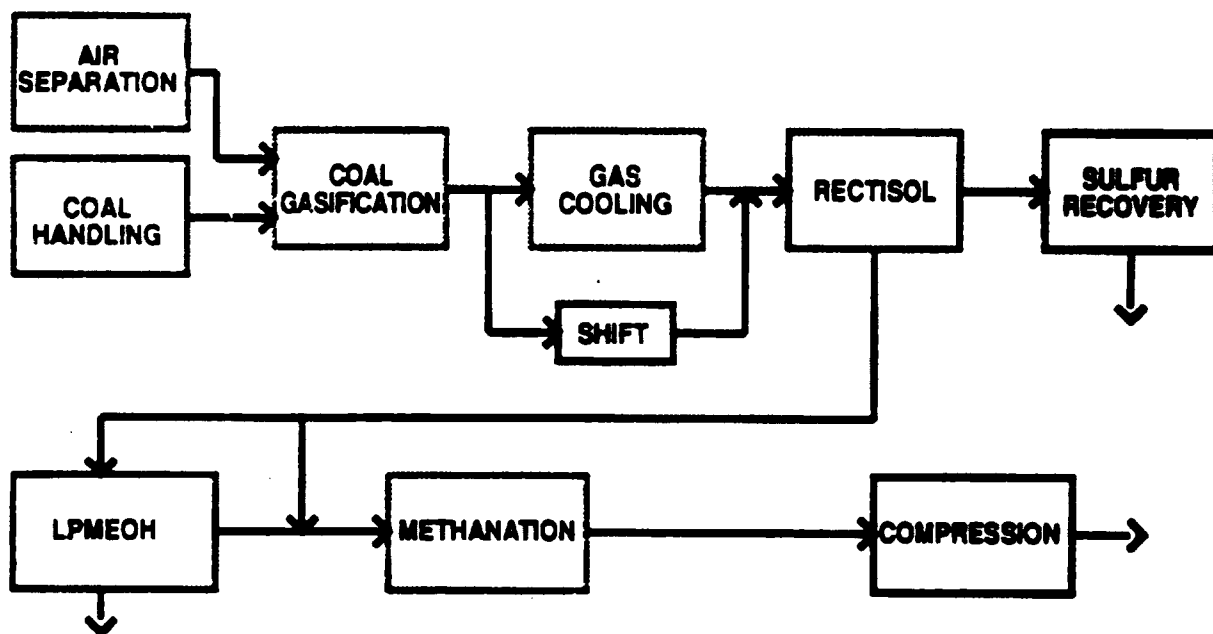


# ENVIRONMENTAL CONSIDERATIONS

Environmental Performance

ENV. P.T.S.	Source FC Pol.	Calc.	CO2 LPNECH
SO <sub>2</sub>	3.8	0.12	0.01
NO <sub>x</sub> as NO <sub>2</sub>	1.2	0.12	0.12
Particulate Matter	0.10	0.008	0.001

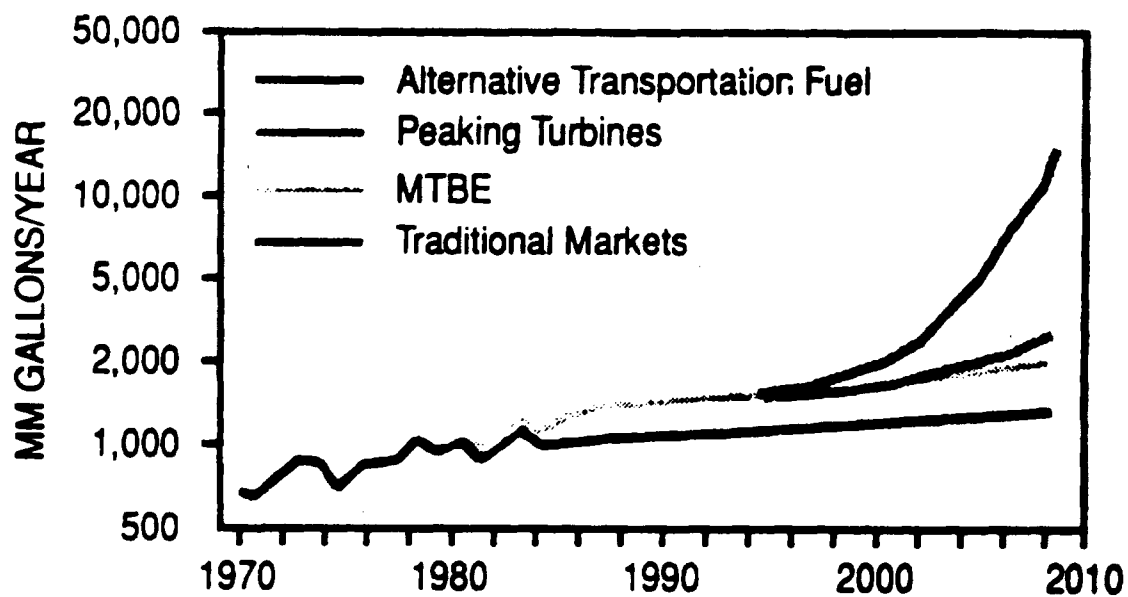
# DAKOTA GASIFICATION WITH LPMEOH PROCESS INTEGRATION



# **DEMONSTRATION PROJECT FEASIBILITY**

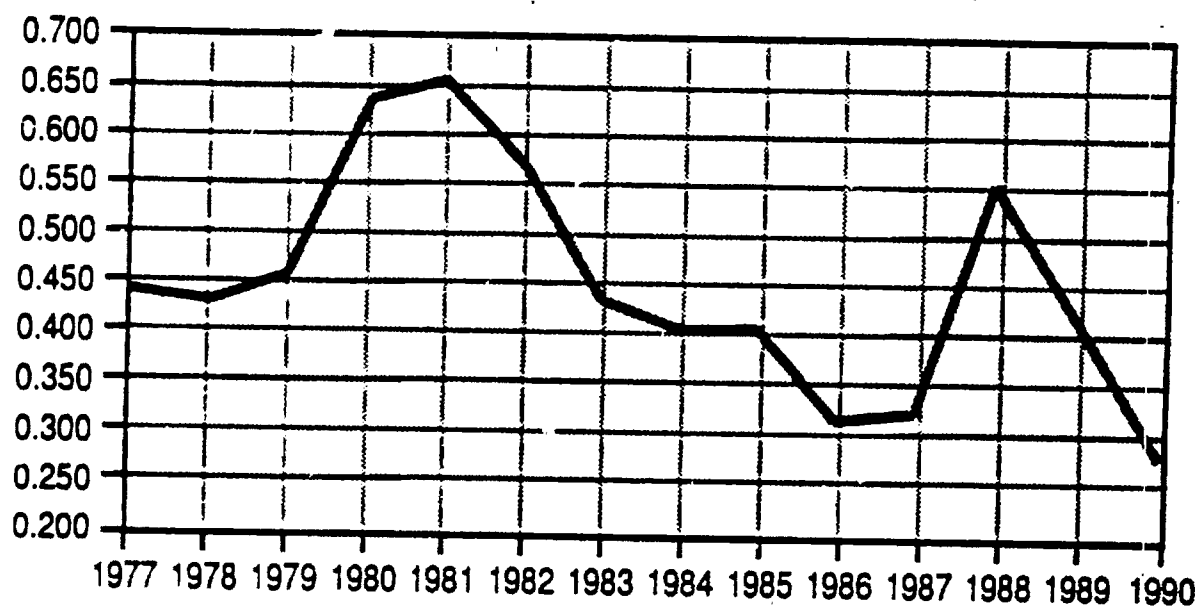
- Projected methanol consumption
- Methanol selling price
- Methanol markets
  - Transportation distance
  - Foreign competition

# U.S. METHANOL CONSUMPTION



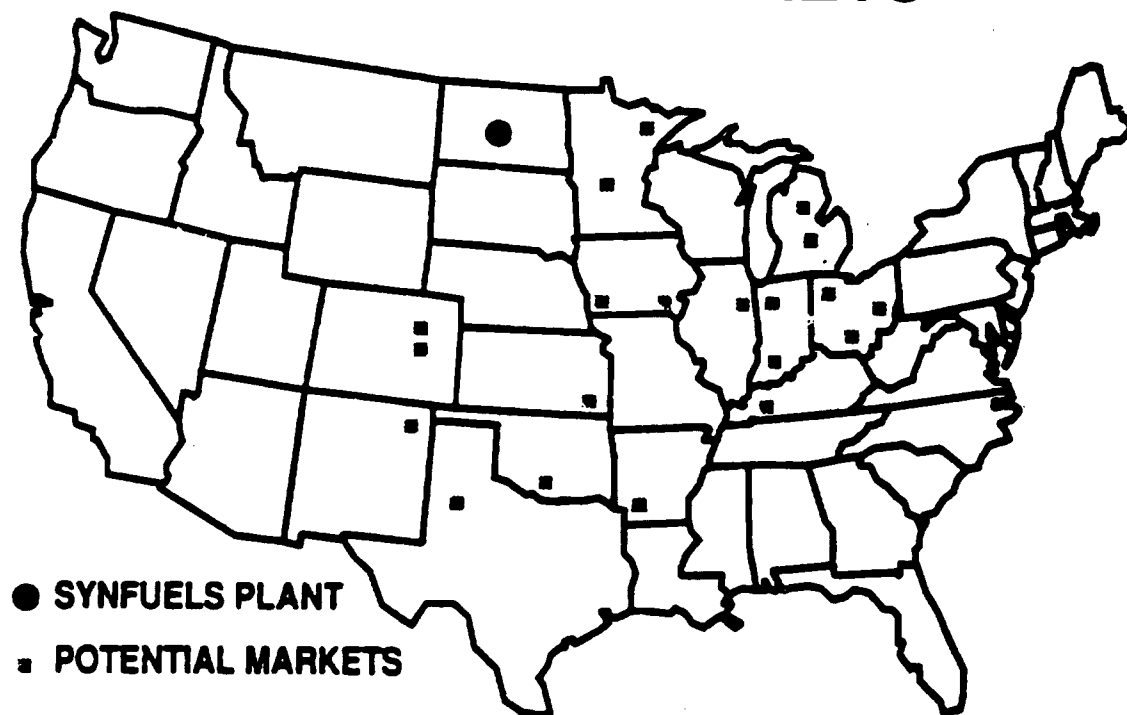
# GULF COST MEOH PRICES

\$/Gallon - 1977 to 1990





## METHANOL MARKETS



# PROJECT CONSIDERATIONS

- Clean coal funding vital to project feasibility
- DOE study finds methanol from U.S. natural gas will not be competitive with off-shore production
- Cost of feedstock from Synfuels plant even less competitive than natural gas
- Methanol U.S. spot prices currently at 27 to 28 cents/gallon
- Uncertainty of Federal legislation regarding energy taxes and environmental requirements
  - Will reformulated gasoline and/or alternate fuels be mandated?