Section 13

APPLICATION OF THE BRITISH GAS/LURGI SLAGGING GASIFIER FOR COMBINED-CYCLE POWER GENERATION

H. S. Davies
J. A. Lacey
J. E. Scott
B. H. Thompson

British Gas Corp.

H. Vierrath
P. K. Herbert

Lurgi GmbH

ABSTRACT

The British Gas/Lurgi Slagging gasifier is shown to be a robust gasifier capable of gasifying a wide range of run-of-mine bituminous coals. High ash coals can be accommodated, as also coals with about 50% fines content (i.e. coal less than ¼ in.). The medium calorific value gas produced is ideal as fuel for modern gas turbines. An Integrated Slagging gasifier Combined Cycle Power Generation Scheme of nominal 500 MW capacity has been developed using near term advanced gas turbines. The study shows that base load power can be generated at a cost 10-15% lower than with conventional coal fired plant and with greatly reduced emissions of dust, SO_x NO_x etc.

SUMMARY

The British Gas/Lurgi Slagging gasifier and the treatment of the gas and byproducts produced are described. It is shown that the gasifier can handle coal fines (less than ¼in.) contents typical of "run-of-mine' coal by feeding the fines partly to the top of the gasifier and the excess to the gasifier bottom.

A recent comprehensive study of power generation by an Integrated Gasification Combined Cycle (IGCC) route, based on Slagging Gasification of coal and which was conducted by the Ralph M. Parsons Co. for the Electric Power Research Institute (EPRI), has shown that the Slagging Gasifier process in ideally suited for this application, producing electricity more efficiently and cheaply than conventional methods while meeting future environmental standards and compares very favourably with other competing coal gasification technologies. Emissions (dust, SO_x, NO_x, etc) are considerably lower than from pulverised coal fired power plants. Other studies are described.

1. INTRODUCTION

The British Gas/Lurgi Slagging gasifier has been developed jointly by British Gas and Lurgi to commercial status at the British Gas Westfield Development Centre in Scotland. Based on earlier development carried out by British Gas at its Midlands Research Station in the late 1950's, a 6 ft diameter gasifier has been operated since 1975 demonstrating the ability to gasify run-of-mine bituminous coal, to produce a clean medium calorific value gas suitable as a fuel in its own right or for further processing to produce synthesis gas or SNG.

Medium calorific value gas is an ideal fuel for modern gas turbines and hence for the generation of electricity by combined cycle or other techniques with a completely acceptable environmental performance. This paper describes the results of the development work undertaken at Westfield where a new 8 ft diameter 550 tons/day Slagging gasifier (Extended gasifier) has recently been commissioned and which is to be used to demonstrate the performance and operability of a commercially scaled unit. The application of the Slagging gasifier within a combined cycle plant using an advanced turbine which will shortly become available, has been studied by Parsons under contract to EPRI and the results of this study are outlined.

2. STATUS OF TECHNOLOGY

2.1 The Slagging Gasifier

The Slagging gasifier is illustrated in Figure 1. The refractory lined water cooled pressure vessel contains the fixed bed of coal, into the base of which a mixture of steam and oxygen is injected through tuyeres. The oxygen is completely consumed by reaction with carbon, creating temperatures which ensure that a very high proportion of the steam is decomposed and the ash is melted to form a slag that is essentially free of carbon.

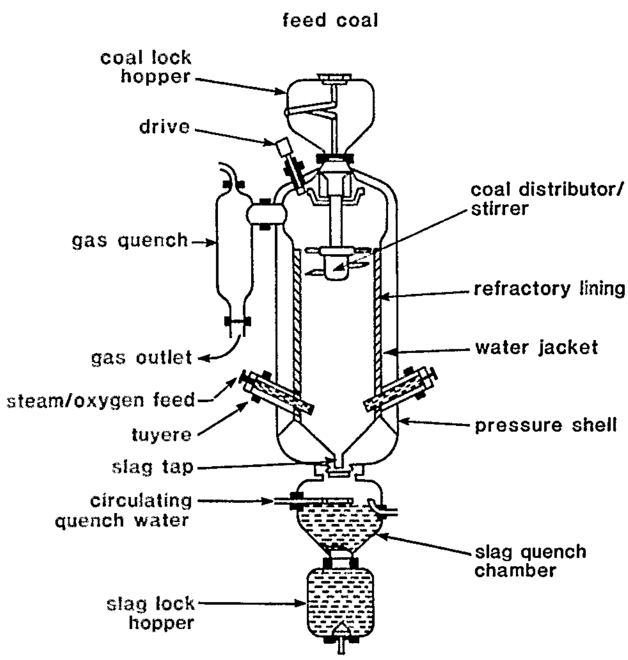

Figure 1. The British Gas Lurgi Slagging Gasifier

The resultant slag drains to the hearth where it collects in a pool. The slag is automatically discharged into water and quenched to form a granular, black frit that is readily removed from the system via a lock-hopper.

Coal is introduced into the pressurised reactor through a lock- hopper from which it passes to a distributor located above the coal bed. This distributor rotates and lays down coal, via chutes, on the bed top. In this way, intermittent coal feeding is translated to steady flow to the gasifier. A stirrer is used to break up agglomerates which form in the bed when caking coals are gasified.

The maximum pressure of the stream and oxygen supplies at Westfield has restricted the operation of the gasifier to a pressure of 350 psig, but higher pressures (up to 1000 psig) are feasible.

2.2 Features of the Slagging Gasifier

The Slagging gasifier is a simple and robust reactor based on well proven technology. In the slagging zone high temperatures ensure very rapid char gasifiction. At the top of the fuel bed the gas temperature is reduced to about 930°F after the gaseous products from the slagging zone have flowed through and exchanged heat with the fresh coal, thereby achieving a high efficiency without the need of high temperature heat recovery equipment downstream of the gasifier.

The large inventory of carbon in the gasifier ensures safe operation in the event of interruption to the feedstock supplies. It also allows the gasifier readily to be put on, and returned from, standby. Moreover, the gasifier load can be rapidly changed with no control problems.

The injection of the steam and oxygen mixture into the fuel bed creates a turbulent raceway in which carbon burns in the oxygen. Mineral matter in the char rapidly melts to form a slag. The raceway is surrounded by an envelope of char in which reaction with steam occurs, the endothermic reaction rapidly reducing the temperatures. Virtually all the steam injected to the gasifier bottom is consumed, resulting in low steam usage. Moreover, oxygen consumption is low, because most of the heat generated by combustion;

$$C + O_2 = CO_2 \qquad H_{1000k} = -\ 169{,}740 \text{ Btu/lb mole}$$

is absorbed in the gasification reactions, with very little heat being used to heat excess gasification steam

$$C + H_2O = CO + H_2 \qquad H_{1000k} = +\ 58500 \text{ Btu/lb mole}$$
$$C + CO_2 = 2CO \qquad H_{1000k} = +\ 73440 \text{ Btu/lb mole}$$

Differences in coal ash properties can be accommodated, if necessary, by utilising a fluxing agent (usually limestone or blast furnace slag). Fluxing rates are determined by the need to ensure good molten slag properties in the hearth, the principal criterion being that slag should drain freely.

The reaction products from the slagging zone are cooled, initially by the steam-carbon reaction, and, at the top of the bed, by drying and devolatilisation reactions as well as heat exchange with the descending solid fuel. The devolatilisation reactions, as well as yielding tar, oils and naphthas, also include hydrogasification of the volatile matter in the coal, principally to methane.

The presence of oil and tars in the gas outlet components is beneficial in protecting metal heat exchanger surfaces from corrosive attack. Consequently conventional materials can be used for the downstream equipment and long lifetimes are achieved.

The tuyere system at the bottom of the gasifier has an additional process advantage in that it allows substantial quantities of fine coal as well as liquid by-products to be injected into the raceway and gasification.

3. COAL FEEDSTOCKS

The Slagging gasifier is particularly suitable for high volatile bituminous coals of which the United Kingdom is well-endowed. The emphasis has been on the gasification of these feedstocks, although experience has been gained with other fuel types. A list of some of the feedstocks that have been gasified at Westfield is given in Table 1. Coals with a wide range of properties have been gasified; even the strongly caking and swelling U.S. coal, Pittsburgh 8, can be gasified without detriment to operability or to efficiency.

3.1 Fines Content of Coals

The Slagging gasifier is also tolerant to a significant amount of fine coal (defined as material less than $^1/_4$ in) in the feedstock supplied to the top of the reactor. Tests have been performed at Westfield where the amount of fines in the feedstock has been increased progressively until the fines carryover from

Table 1

FEEDSTOCKS TESTED IN THE 350 TPD GASIFIER

Fuel	Proximate Analysis				Swelling No.	Caking Index	Sulphur %	Origin
	H_2O	Ash	VM	FC				
Blast Furnace Coke	0.7	9.7	1.9	87.7	0	A	0.69	England
Rawdon	7.3	5.1	39.4	48.2	1	B	1.45	England
Seafield (Unwashed)	6.3	21.0	28.2	44.5	1	A	0.39	Scotland
Markham Main (Washed)	10.0	4.3	30.4	55.3	1½	C	1.17	England
Markham Main (Unwashed)	6.1	20.1	29.4	44.4	1	B	1.24	England
Rossington	6.9	4.3	33.3	55.5	1½	E	1.03	England
Manton	3.0	7.3	31.9	57.8	6½	G_6	2.00	England
Pittsburgh 8	2.1	11.5	36.1	50.3	7	G_7	1.87	USA
Ohio 9 (Washed)	1.4	12.0	39.7	46.9	6	G_4	3.40	USA
Ohio 9 (Unwashed)	4.7	20.8	32.3	42.2	3½	G	4.29	USA
Petroleum Coke	1.6	0.6	8.5	90.3	0	A	1.46	North Sea Oil
Pelleted Markham Main	26	11	22.35	40.65	1	C	1.20	England

the bed became unacceptable.

The gasifier tolerance to fine coal in the top feed increases with the caking properties of the fuel, as might be expected. For non-caking coals there was a tendency for a relatively high dust carry over from the gasifier bed when the fines content of the feed was over 10%. Fines contents of more than 30% can be used with strongly caking coals such as Pittsburgh 8. Allowance has to be made for the variations in the fines content that can arise from stockpiling, handling and storage in hoppers.

3.2 Size Distribution of Coals

In addition to the total fines content, the particle size range and the size distribution varies for different coal feedstocks. An example of the size range of coals used in the gasifier is shown in Fig. 2. The size range of washed and graded Rossington (a moderately caking coal) and the same coal with a high fines content are shown. The gasifier operated well at full load with these feedstocks with only small variations in bed behaviour illustrating the operational flexibility of the gasifier.

3.3 Ash Content of Coals

The preferred feedstock for the Slagging gasifier is a fairly low ash content coal. However, the gasifier can accept higher ash coals as shown in table 2, the optimum level being a matter of economics.

The Rossington Coal was deliberately overfluxed with blast furnace slag to simulate a high ash coal (about 20%). Slagging gasification was satisfactory even when the total ash and flux content was 33%. At the lower end of the range petroleum coke with an ash content of 0.6% has been successfully gasified. Unwashed coals were gasified satisfactorily but problems in handling occurred outside the gasifier in wet conditions. The unwashed Ohio 9 and Markham Main coals contained clay constituents that caused the coal to 'hang' in the bunkers as well as causing operating problems in storage and transportation.

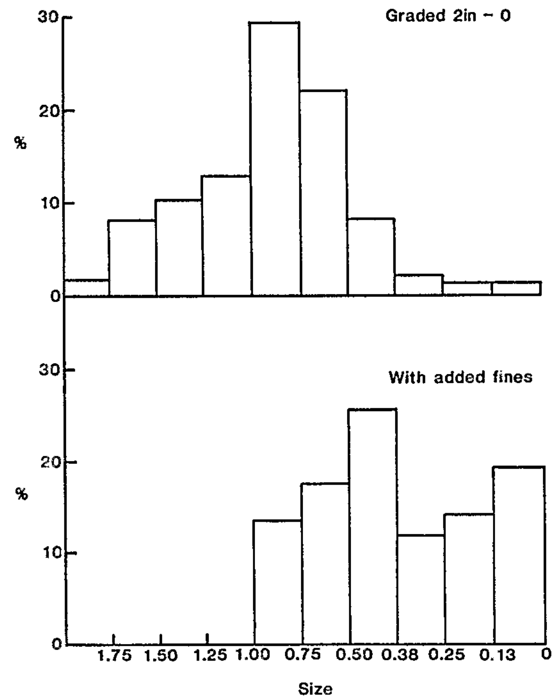

Figure 2. Size Distribution of Rossington Coal

Table 2

HIGH ASH CONTENT COALS GASIFIED IN THE SLAGGING GASIFIER

Coal	Ash Content (dry basis) %	Total Ash including flux %	Flux L = Limestone B = Blast Furnace Slag
Unwashed Seafield	22.5	31.2	L
Washed Rossington	4.7	26.8	B
Unwashed Markham Main	21.4	32.1	L
Washed Ohio 9	12.3	16.8	L
Unwashed Ohio 9	22.6	32.9	B

4. PERFORMANCE OF THE SLAGGING GASIFIER

4.1 Gasifier Performance

The Slagging gasifier has been found to give a similar performance across a wide range of feedstocks and conditions. This is illustrated by the performance data given in Table 3 for two widely differing coals, Pittsburgh 8 and Markham Main. The results clearly demonstrate the low steam consumption characteristic of the Slagging gasifier.

Table 3

PERFORMANCE DATA FOR MARKHAM MAIN AND PITTSBURGH 8 COALS

Coal	Markham Main	Pittsburgh 8
Flux	Limestone	Blast furnace Slag
Steam/oxygen ratio (v/v)	1.21	1.27
Gas composition (% v/v)		
CH_4	6.8	7.2
CO	59.2	57.3
H_2	28.0	28.3
CO_2	2.1	3.0
N_2 + Ar	3.9	4.2
Steam consumption (lb/lb DAF Coal)	0.35	0.39
Liquor production (lb/lb DAF Coal)	0.18	0.17
Oxygen consumption (lb/lb DAF Coal)	0.53	0.55
Gasifier thermal output (million Btu/ft^2.h)	10.5	9.9

The nominal gasifier loading of 850 lb/ft^2.h at 350 psig represents a load at which good gasification can be sustained with good stability and operability, but higher loadings are possible. For example, loadings of over 1000 lb/ft^2.h have been achieved on washed Ohio 9 and over 1100 lb/ft^2.h on Rossington coal. These figures do not represent the limits of loading for the Slagging gasifier.

Oxygen consumption is generally not coal dependent but rises as ash content rises (the differences in Table 3 between Pittsburgh 8 and Markham Main are largely attributable to this).

Liquor production rates are dependent upon steam/oxygen ratios but with, typically, well over 90% steam decomposition the major liquor contribution comes from the moisture in the coal.

4.2 The Gasification of Coal Fines

The bulk of unscreened coal supplies available on the commercial market contain up to 50% and more of material below $^1/_4$in. in size (fines)--and one of the main challenges in the development of the Slagging gasifier has been to utilise such feedstocks. There are a number of techniques for introducing coal fines into the gasifier; they can be supplied in limited quantities with the lump coal; the fines can be agglomerated in the form of pellets, briquettes or extrudates, or, they can be injected into the combustion zone of the gasifier through the tuyeres. A mix of these techniques is possible. However, as top feeding of coal to the gasifier minimises oxygen consumption and maximises the methane yield this method of fines utilisation is preferable in most cases.

4.2.1 Gasification of Agglomerated Fines

Pellets can be produced by pulverising coal fines, adding a clay binder, then wetting and rotating the mixture on an angled disc. A batch of pellets of ½ in diameter was produced by Lurgi using this technique and they were successfully gasified at Westfield. Performance data from this test is shown in Table 4.

A second method is to briquette the fines by mixing with a pitch or other binders before hot pressing into briquettes of the required size. This is a relatively attractive option as it has little effect upon the overall process efficiency and additional costs are modest. Briquettes strong enough to withstand the handling and charging of coal to a gasifier can be made from a pitch derived from the gasifier tar. Strong briquettes can be made with particles up to $^1/_4$in. which means little crushing of the fine coal is necessary. It is also possible to use the briquettes as a vehicle for adding flux to the gasifier.

Large scale briquette production is being pursued and a batch of these is to be tested in the 550 ton/day Slagging gasifier.

Table 4

PERFORMANCE DATA FROM MARKHAM MAIN PELLETS

Coal Type	Markham Main Pellets
Steam/oxygen ratio (v/v)	1.1
Gasifier pressure (psig)	350
Outlet gas temperature (°F)	680
Gas composition (% v/v)	
CH_4	5.5
CO_2	4.1
H_2	25.1
CO	55.2
N_2 + Ar	10.1
DAF coal gasification rate ($lb/ft^2.h$)	773
Oxygen consumption (lb/lb DAF Coal)	0.54
Steam consumption (lb/lb DAF Coal)	0.32
Liquor production (lb/lb DAF Coal)	0.46

4.2.2 Gasification of Dry Fines

Extensive experience has been obtained with the injection of powdered coal through the tuyeres into the combustion zone of the Slagging gasifier and this is another attractive option for dealing with the coal fines. A plant with the capacity to supply 100 ton of pulverised fuel (p.f) per day to the gasifier has been built at Westfield and has been successfully operated. Figure 3 shows a schematic diagram of the system; it includes a low pressure storage silo, a transfer system to a lock hopper and then to a feed hopper, from which the p.f is entrained in dry nitrogen and carried to the gasifier tuyeres. Table 5 shows gasifier performance data with fines injection.

40% of the total coal feed has been fed through the tuyeres without blinding of the bed. With p.f. injection, the gasifier displays sustained stable operation. Increasing the amount of fines to the tuyeres results in a moderate increase in oxygen consumption and higher offtake temperatures. At levels of fines injection above 20% the methane content is reduced to below 5% but the calorific value of the gas decreases by only about 5%.

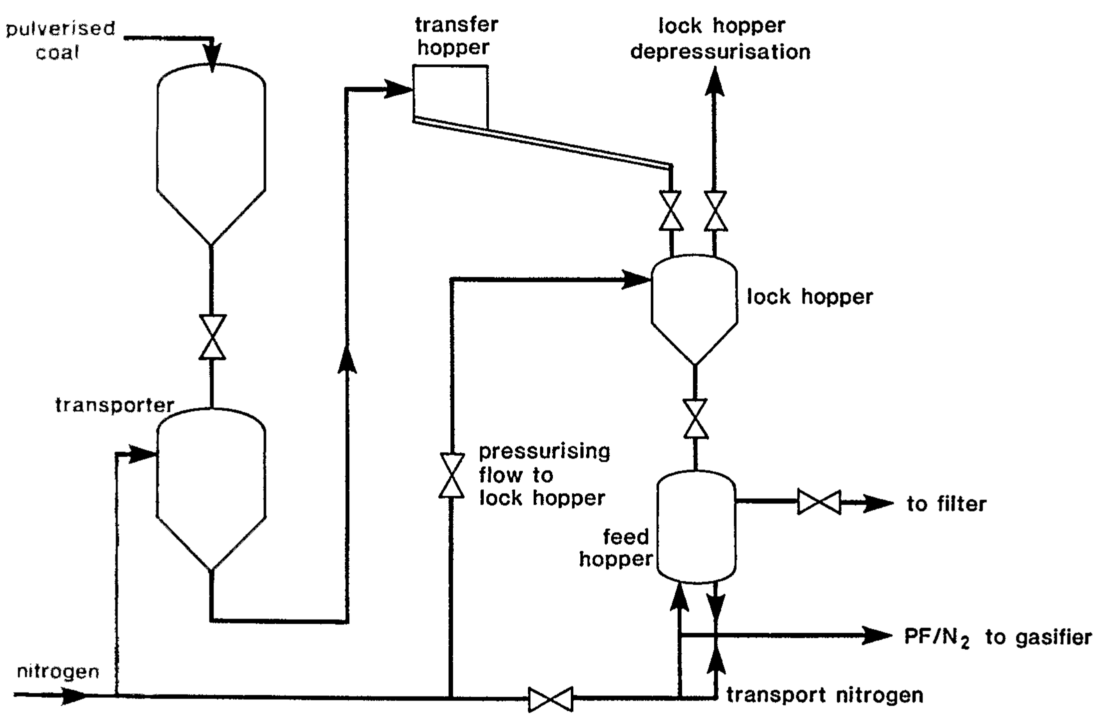

Figure 3. P.F. Plant - General Layout

Table 5

PERFORMANCE DATA FOR FINES INJECTION AT THE TUYERES

Fines/total fuel (Coal + Fines)	(wt %)	10.00	30.24
Product gas composition (% v/v)	CH_4	5.50	4.50
	CO_2	1.85	1.80
	H_2	27.00	28.00
	CO	59.05	56.65
	N_2 + Ar	6.60	9.05
Total oxygen consumption	(lb/lb DAF coal)	0.57	0.61
Liquor production rate	(lb/lb DAF Coal)	0.14	0.22
Gasifier offtake temperature	(°F)	1025	1155

This method of dealing with fine coal thus represents a process route for the complete gasification of coal containing about 50% fines as the 40% that can be injected down the tuyeres can be supplemented by accommodating a proportion of fine coal in the top feed.

4.2.3 Gasification of Coal Water Slurry

An alternative technique that has been tested for the introduction of fines is the use of coal/water slurry. This is a good option because of the lower cost of preparation and the substantial reduction in the gasification steam requirement owing to the water in the slurry. Performance data obtained during a trial on a proprietary coal water slurry containing 70% wt coal which was pumped through the tuyeres at a rate of 2.5 ton/h, are given in Table 6.

Table 6

PERFORMANCE DATA FOR SLURRY INJECTION AT THE TUYERES

Coal Type	Markham Main
Slurry loading (% wt)	10.68
Steam/oxygen ratio (v/v)	0.97
Product gas composition (% v/v)	
CH_4	5.55
CO_2	1.30
H_2	26.75
CO	58.55
N_2 + Ar	7.85
Oxygen consumption (lb/lb DAF coal)	0.57
Liquor production rate (lb/lb DAF Coal)	0.22
Gasifier offtake temperature (°F)	1048

For convenience, a stabilised slurry, available as a fuel oil substitute, was used in the tests on the Slagging gasifier. In practice coarser slurries are adequate and much cheaper to produce. A plant to manufacture 10 ton/h of slurry is under construction at Westfield and will be used to supply the 550 ton/day gasifier.

Because of the limited availability of coal water slurries, tests to establish the ability of the gasifier to accept a high thermal load in the combustion zone have been carried out by injecting effluent liquor through the tuyeres. Operation of the gasifier was satisfactory when 50% of the gasification steam was replaced by effluent liquor. The organic constituents in the liquor were destroyed by this technique. Recirculation of part of the effluent liquor in the form of a slurry with coal has the potential to cut the capital and operating costs of the effluent treatment plant and greatly reduce the steam requirement at the expense of a modest increase in oxygen consumption.

4.3 Gasification of Tar Hydrocarbon Byproducts

In the gas cooling train that follows the Slagging gasifier, the hydrocarbons are separated as tar (heavier than water) and oil (lighter than water). The tar is separated into a "clean" fraction and a "dusty" fraction in a gravity separator. The dusty tar fraction, containing the solids carried over from the gasifier, is recycled to the top of the gasifier to help reduce the carry over of dust as well as returning the carbonaceous dust to the gasifier. Part of the tar is redistilled and cracked to lighter oils and part is pyrolysed to carbon and subsequently gasified in steam and oxygen. The clean tar can be gasified to extinction by injection down the tuyeres and to demonstrate and develop the technique a number of tests have been done at Westfield. Performance data from one such test is shown in Table 7.

Table 7

PERFORMANCE DATA FOR SLAGGING GASIFICATION WITH TAR INJECTION DOWN THE TUYERES

Coal Type	Markham Main
Tar injected (w/w) (% of coal gasified)	7.18
Steam/oxygen ratio (v/v)	1.10
Product gas composition (% v/v)	
CH_4	6.35
CO_2	2.05
H_2	28.40
CO	57.70
N_2 + Ar	5.50
DAF Coal gasification rate ($lb/ft^2.h$)	779
Oxygen consumption (lb/lb DAF Coal)	0.58
Liquor production rate (lb/lb DAF Coal)	0.15
Gasifier offtake temperature (°F)	1048

5. THE EXTENDED GASIFIER

The 6ft diameter gasifier operated at Westfield since 1975 has been replaced by a second Slagging gasifier with a nominal 8ft diameter. This gasifier, like its predecessor, was fabricated by replacing the bottom of one of the original Lurgi dry grate gasifiers with a slagging bottom, but with an increased bed depth. In 1975, physical restraints in the gasifier house prevented this but these have been overcome. Extensive modification to the instrumentation have been carried out as well as further desirable plant modifications. The gasifier was commissioned in December 1984 and early operation has confirmed good operation of the gasifier. To date the operation has extended from the full design throughput of 550 ton/day down to operation at 25% load with excellent stability. The next phase of operation will be to demonstrate the gasification of run-of-mine coal using the full range of fines utilisation techniques.

The product gas is to be fired in a Rolls Royce 30MW gas turbine based on the Olympus aero engine to generate electricity which will be fed to the South of Scotland electricity grid.

EPRI supported by GRI are to participate in the programme at Westfield to demonstrate the use of Eastern American coals and in the case of GRI the purification and methanation of the gas to produce SNG. EPRI and Rolls Royce are to carry out tests on the turbine to assess the effect of changes on the production of NOx from the turbine fired with natural gas and medium Btu gas.

6. INTEGRATED COAL GASIFICATION COMBINED CYCLE POWER GENERATION PLANT (IGCC)

Integrated coal gasification combined cycle plants have been the subject of increasing interest for many years and one of the most recent detailed studies was that undertaken for EPRI by The Ralph M. Parsons Company,[1] the British Gas Corporation and Lurgi GmbH and which was reported to the 12th Energy Technology Conference at Washington D.C. on March 26th 1985[2].

The study has been used as a major reference for this paper, the basis for design being a nominal 500 MW station with combined cycle power generation from fuel gas manufactured in British Gas/Lurgi slagging gasifiers using Illinois 6 coal, the gas production plant providing sufficient fuel gas for operation of the gas turbine machinery at 20°F ambient.

Although the gas production and power generation are described separately in the following sections, the two plants are arranged such to ensure the highest overall efficiency. The plant has been designed to give an onstream factor of effectively 100% by judicial consideration of spare equipment, plant and process reliability, turndown, maintenance requirements and adequate storage for intermediate products.

6.1 Fuel Gas Production

To provide the specified clean fuel gas from coal the following main unit processes are required:

- coal gasification
- acid gas removal
- recompression of lock and flash gases
- gas liquor separation
- gas liquor evaporation
- gas liquor incineration

and these are shown as a simplified block diagram in Figure 4.

Approximately 5,250 tons/day of Illinois No. 6 coal are gasified with steam and oxygen in nine 8ft diameter gasifiers at a pressure of 315 psig. To facilitate the removal of slag from the gasifier flux is added to the coal.

The crude gas leaving the gasifier contains tar, oil, naphtha, phenols, fatty acids and ammonia as well as hydrogen cyanide, hydrogen sulphide and carbonyl sulphide. Most of the tars are condensed in the first and second coolers, the gas being quenched in the first cooler with recirculated liquor. The gas and liquor from the quench are further cooled in a following waste heat boiler where LP steam is generated, the condensate from this second cooler making up some of the quench for the first cooler.

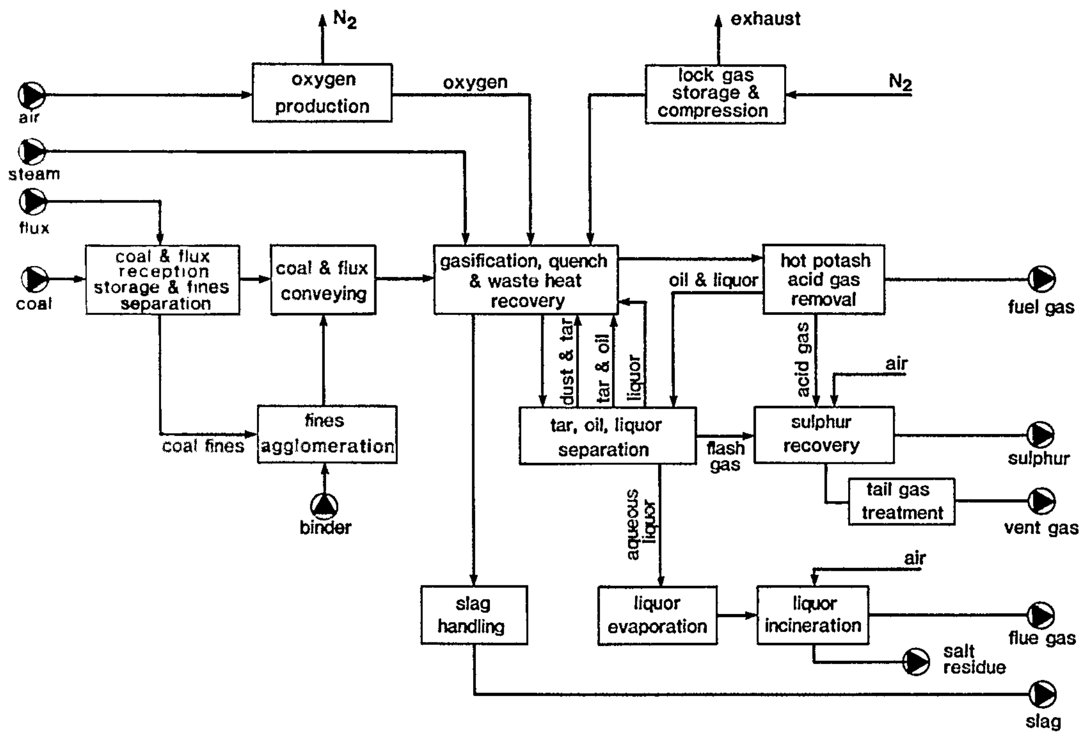

Figure 4. Fuel Gas Plant Block Flow Diagram

After condensing the tars in the waste heat boiler, the gas is further cooled and oily liquor separated before going to a Lurgi hot potassium carbonate acid gas removal plant where nearly 95% of the sulphur originally in the coal feed is removed as H_2S. Commercial processes are available which will achieve sulphur recovery of up to 99% plus with marginal additional cost of electricity (2 to 4%). The high H_2S/CO_2 ratio in the gas makes conditions favourable for selective removal of the H_2S. The CO_2 removal is minimised thereby keeping the mass flow to the power plant high. Because the absorber operates at temperatures of 100-120°C, much of the naphtha is left in the gas and is burnt in the turbines. HCN is removed by absorption in sodium carbonate solution in a prewash before the main H_2S removal tower. The acid gases from the plant are treated in a Claus sulphur recovery unit.

All gas liquor streams arising from the gasification area and acid gas removal are directed to the gas liquor separation unit where they are cooled, expanded and various gases, and liquid and solid components separated. From here:

1. Dusty tar is returned to the top of the gasifier to minimise dust carryover.

2. Clean tar and oil are recycled to the bottom of the gasifier where they are gasified to extinction.

3. Flash gas is directed to the recompression unit, where after mixing with lock hopper depressurisation gas, it is recompressed to the inlet of the acid gas removal plant.

4. Some liquor is recycled to the gas quench, the remainder going to the evaporation unit after filtration to remove residual dust and tar.

In the Lurgi evaporation unit, the liquor from gas liquor separation and the waste water from the prewash on the AGR plant are stripped to remove NH_3 and HCN and any sulphur compounds to the required level for incineration; the off gases going to the Claus unit. The stripped liquor is further heated with LP steam and then flashed, the vapour and residual liquor being directed to separate Lurgi incineration.

6.2 Power Generation

The power generation system comprises three near term advanced gas turbines and a single steam turbine generator. The fuel gas is combusted giving a turbine entry temperature of 2200°F (1200°C) producing nominally 130-140 MW each depending on ambient conditions. The exhaust gas from the turbines generates steam in heat recovery steam generators, (HRSG) the steam being used for power generation in a 1800 psia/950°F/900°F reheat steam turbine, drive for the air separation plant compressors and as process and heating steam for gasification and gas treatment processes. The scheme is illustrated by a simplified flow diagram in Fig 5.

The steam and power generation system was designed to recover an economically optimum amount of heat energy before the exhaust gases are vented via the stack to atmosphere at an ambient temperature of 59°F. However, all components of the plant, including the fuel gas preparation unit, were sized so as to avoid restrictions on operation of the combustion gas turbines over the ambient temperature range of 20°F to 88°F. The implication of this condition is the capacity of the fuel gas production facility is set by the maximum demand of the gas turbines, i.e. at 20°F.

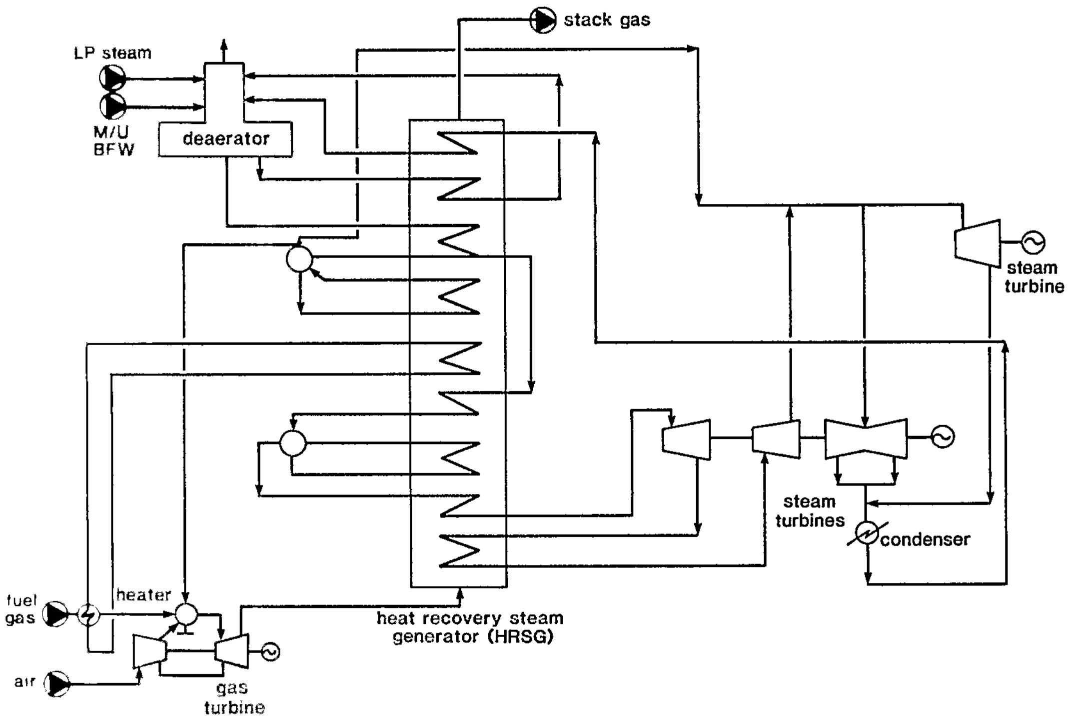

Figure 5. Combined Cycle Power Plant

Alternate steam and power generation cycle configurations were therefore developed which used the excess gas production capacity at temperatures above 20°F and when one of the gas turbines was out of service. The excess gas is fired in duct burners located between the gas turbine exhaust and the heat recovery steam generator. the extra steam generated being used to make further power. A larger HRSG would be required and also a larger generator, but the extra expenditure was shown to be a very cost effective approach for using the excess gas production. Refer to Section 9.

7. PLANT PERFORMANCE

7.1 Operational Flexibility

EPRI have sponsored trials at Westfield where the Slagging gasifier was shown to be very versatile in satisfying the load following, turndown performance and steady state stability requirements set by EPRI in three, 5 day runs with strongly caking coals. A British coal similar to Illinois No. 6 was used for the first test and Pittsburgh No. 8 for the others. Details of these trials are given in EPRI report AP1922.[3]

7.2 Output

Plant performance figures have been evaluated in the EPRI/Parsons study for a number of conditions and are presented in Table 8 where most of the data has been taken from the Parsons/British Gas Lurgi paper. The net efficiency (based on a coal HHV of 11,241 btu/lb) is shown to vary from 39.7% to 39.2% over the ambient temperature range 20°F to 88°C. Use of the advanced gas turbines is shown to increase cycle efficiency by 2.7%.

When the extra gasification capacity is used at higher ambient temperatures, it can be seen that there is a significant increase in net power (8.5% at 59°F and 14.9% at 88°F) for a drop in overall efficiency of 1.1 and 1.9% respectively. When one gas turbine is not operational, the overall efficiency is shown to be reduced quite significantly.

8. ENVIRONMENTAL ASPECTS

The system meets the stringent E.P.A. requirements. Nearly 95% or, if required, upto 99% plus, of the sulphur in the coal is recovered as saleable elemental sulphur therefore pollution of the atmosphere with sulphur is small and the NOx level has been controlled to 75 ppm by steam injection to the combustor. These are important factors in the fight against acid rain. All streams leaving the gasification plant which come into contact with the environment are either solid or have been treated thermally to make them innocuous prior to emission. These streams include:-

- hot gas generator ash from the agglomeration unit
- gasifier slag
- dry residue (salt) from the incinerator, and
- flue gases from the incinerators and hot gas generator

Table 8

SUMMARY OF PLANT PERFORMANCE

	SPARE GASIFICATION CAPACITY - NOT USED					SPARE GASIFICATION CAPACITY - USED		
Ambient Temperature, °F	20	59	88	88	59	88	59	88
Coal Feed Rate ("as received"), TPD	5,248	4,705	4,347	4,859	5,248	5,248	5,248	5,248
Combustion Turbine Type	Advanced*	Advanced	Advanced	Current#	Advanced	Advanced	Advanced	Advanced
Combustion Turbine Out of Service	None	None	None	None	None	None	One	One
Combustion Turbine Power, MW	452.56	389.67	348.55	366.73	389.62	348.47		
Steam Turbine Power, MW	131.34	130.64	130.27	138.85	175.10	201.88		
Total Gross Power, MW	583.90	520.31	478.82	505.58	564.72	550.35	478.31	465.01
Power Consumed, MW	12.48	11.36	10.62	13.92	12.49	12.49	17.49	17.49
Net Power, MW	571.42	508.95	468.20	485.67	552.23	537.86	460.82	447.52
Net Heat Rate, Btu/kWh	8,603	8,661	8,697	9,353	8,902	9,140	10,668	10,985
Net Efficiency, %	39.7	39.4	39.2	36.5	38.3	37.3	32.0	31.1
Increase in Net Power by Use of Spare Gasification Capacity, MW					43.28	69.66		

* inlet turbine temperature 2200°F

inlet turbine temperature 2000°F

All other streams are treated within the gasification plant battery limits. The use of an incineration step for the waste water treatment results in no process water leaving the gasification area.

None of the solid wastes is classified as hazardous. The ash from the hot generator is a typical coal ash and can be disposed of as common practice. The gasifier slag frit is a clean, black glassy granular material which separates completely from its quench water. It is highly unleachable and can be used as road fill or a component of building materials. The dry residue from the incinerator can be handled as any bulk material but owing to the high solubilities of some of its components, it must be disposed of in areas with aquifer protection.

9. COSTS

9.1 Plant Costs

The capital and operating costs derived in the Parsons Study were for a complete greenfield plant including coal reception and stocking areas, roads, railway sidings, buildings etc. and allowed for all charges including royalties, insurance, engineering fees, taxes etc.. All plant costs are reported as 1984 (first quarter) dollars.

The total plant investment is $527.9 million and the breakdown is given in Table 9 in dollars and also dollars/kWh. The steam and power production plant accounted for over 40% of the cost.

Fixed and variable operating costs are shown in Table 10. The labour costs were based on manhour requirements developed for the plant. Maintenance figures were based on the capital cost for each plant unit and ranged from 1.5 to 4.5%. Administrative and support labour was assumed to be 30% of all other labour costs.

9.2 Costs of Electricity Generation

The operating costs given in 9.1 were used to evaluate the cost of electricity along with the economic criteria given in Table 11 and the requirements of capital

Table 9

TOTAL PLANT FACILITIES INVESTMENT[a]
(First quarter 1984 $)

Item	$000s	$/kW
Direct Material[b]	259,172 (110,115)[e]	509.23
Direct Labour[c]	58,436 (12,225)	114.81
Support and Engineering[b]	103,293	202.95
Sales Tax	12,960 (5,508)	25.46
Sub Total	433,861	852.45
Process Contingency	24,790	48.71
Project Contingency	68,789	135.16
Sub Total	93,579	183.86
Total	527,440	1036.31
Initial Catalysts and Chemicals	472	0.93
Total	527,912	1037.24

a Based on 100 per cent plant design capacity of 508.95 MW

b All materials and equipment that become a part of the plant facility.

c Labour costs for installing direct field materials (exclusive of payroll burdens and craft benefits).

d Includes:

Indirect field costs including all labour, supervision, and expense required to support field construction.

Home office costs including all salaries and expenses required for engineering, design, and procurement.

Contractor's fee.

e Costs associated with steam and power generation.

Table 10

OPERATING AND MAINTENANCE COSTS

Fixed	$000s/Year
Operating Labour	5,642
Maintenance Labour	4,996
Maintenance Material	7,493
Administrative and Support Labour	3,191
	21,322
Variable at 100% annual capacity	
Raw Water	1,579
Catalysts and Chemicals	3,453
Fuel Oil	1,750
Ash Disposal	1,307
Salt and Stretford Solutions Disposal	1,180
	9,269
Total	30,591

as shown in Table 12. The results are summarised in Table 13 where the levelised cost over a thirty year operating period is shown as 44.91 mills/kWh. Adjustment to January 1st 1983 prices results in a levelised cost of 42.2 mills/kWh and this compares very favourably with competing technology. Values of 45.9 and 48.4 mills/kwh are reported respectively on the same basis in EPRI study AP.3486[4] for a Texaco Gasification Combined Cycle plant and in an EPRI report to be published[5] that includes a cost of conventional coal fired steam plant.

Cost sensitivity analyses were also performed for changes in a number of the evaluation parameters and these results are shown in Table 14. The price of coal has by far the greatest impact, a reduction of 33% causing a drop in the cost of electricity by 16%.

Table 11

ECONOMIC CRITERIA

General inflation rate	8.5%/year
Plant facilities investment and O & M cost escalation rate	8.5%/year
Illinois No. 6 coal cost (mid-1984 $)	$2.25/10^6 Btu*
Coal cost escalation rate	9.3%/year
Plant financing fractions	
Common equity	35%
Preferred stock	15%
Debt	50%
Financing costs	
Common equity	15.3%/year
Preferred stock	11.5%/year
Debt	11.0%/year
Investment tax credit	8.0%
Plant life	30 years
Tax life	10 years
Tax depreciation by accelerated cost recovery system	
Normalisation of deferred taxes and investment tax credit	
Year of commercial operation	1992
Design and construction period	1988-1991
By-product sulphur sales price (mid-1984 $)	$65/T
Sulphur sales price escalation rate	8.5%/year
Property tax and insurance cost	2% of escalated plant investment each operating year
Plant net capacity at 59°F ambient	508.950 kW
Annual capacity factor	65%

* This cost is considerably higher than the mid-1984 costs of Illinois high sulfur coal. It is based on the cost of coal from new mines needed to supply new power plants.

Table 12

TOTAL CAPITAL REQUIREMENTS
(Mid 1984 $)

	$000s	$/kW
Plant Facilities Investment	527,910	1,037.2
Land	1,560	3.1
Working Capital (and start-up oil)	33,540	65.9
Start-up Cost	14,480	28.5
Pre-paid Royalties	2,640	5.2
Allowance for Funds Used During Construction	33,340	65.5
Total Capital	613,470	1,205.4

Table 13

COSTS OF ELECTRICITY.
59°F AMBIENT TEMPERATURE
NO POST-FIRING
(Mills/kWh) (Mid 1984 $)

		Current $	Constant
First Year	(1992)	146.35	73.17
Fifth Year	(1996)	150.52	54.29
Tenth Year	(2001)	172.38	41.35
Thirtieth Year	(2021)	721.45	33.85
Levelised		190.94	44.91

Table 14

SENSITIVITY OF COSTS OF ELECTRICITY
59°F AMBIENT TEMPERATURE
NO POST-FIRING
(Levelised mills/kWh. Mid-1984 $)

Base case (rounded)	44.9
75% annual capacity factor	42.0
Increase of 35% in plant investment	49.7
10% increase in thermal efficiency	42.9
10% decrease in thermal efficiency	47.0
Coal cost at $1.50/10^6 Btu (mid-1984 $)	37.7
Plant operating at 20°F ambient	42.2
Plant operating at 88°F ambient	47.0

Levelised costs were also evaluated for the post firing options over a range of very low annual capacity factors (10 to 40%) for ambient temperatures 59°F and 88°F. The costs were extremely low, (38.9 to 33.5) and (37.1 to 33.8 mills/kWh) for the 59°F and 88°F cases relative to those of conventional power generation and this provides the opportunity to supply intermediate and peak load power with reduced costs using supplementary firing, as well as the displacement of petroleum fuels.

10. OTHER STUDIES

10.1 BGC/CEGB/NCB/DEn Study

The U.K. Department of Energy (DEn) is sponsoring two cost and feasibility studies into advanced technology electricity generation from coal. The first involves a pressurised fluidised bed combustion process being developed by the National Coal Board and the second an integrated Slagging gasifier combined cycle power generation system.

The latter study costing about \$0.55 million started in November 1984 and is scheduled for completion at the end of this year. The British Gas Corporation, the Central Electricity Generating Board (CEGB) and the National Coal Board (NCB) are co-sponsors with the DEn and Foster Wheeler Energy Ltd is the appointed process contractor. British Gas and Lurgi provide engineering, cost and environmental information for the gasification, gas cooling and gas/liquor separation areas. The objective is to provide a conceptual design with capital, operating and maintenance costs for a complete facility of nominal power output of 2000 MW comprising three separate modules of gasification/combined cycle of 660 to 700 MW. The plant will be required to have an availability of greater than 85% for full load 2 shift operation on weekdays for a three month period and the station life is for 40 years.

As with the Parsons Study for EPRI, advanced near term gas turbines have been used, the power generation system for each module comprising 3 advanced General Electric Frame 9 gas turbines with a turbine entry temperature of 2300°F (1260°C) and a single heat recovery steam generator reheat steam turbine. All other process units are of present day commercial status of minimum technical risk.

A fresh critical review of many process areas is being undertaken and these include:-

- means of accommodating excess coal fines
- oxygen purity and response of oxygen plant to fast change of plant throughput
- gasification plant pressure and gasifier diameter
- choice of acid gas removal process
- more integration of gasification and combined cycle areas with due regard to operating restraints

Preliminary indications are that the overall cycle efficiencies given in the Parsons study may be exceeded.

It is planned to undertake a step off study later this year into the design of a dual purpose plant where SNG is manufactured using the British Gas HICOM process when power is not required. Advantages of this concept are:-

- steady operation of gasification plant giving constant CV fuel gas to turbines spread of capital and operating costs between Electricity and SNG production

SNG production favoured by higher pressures which could result in still higher efficiencies of power generation

sulphur has to be removed to 0.2ppm for the HICOM catalysts. If this gas is used for power regeneration then lower stack temperatures will be possible. This should enable improved turbine life to be achieved as well as increased efficiency by greater heat recovery and/or higher inlet turbine temperatures.

10.2 IGCC-Study for the German Federal Ministry of Research and Technology (BMFT)

The German 'Bundesministerium Fuer Forschung Und Technologie' (BMFT) is supporting a study to investigate the application of IGCC's based on British Gas/Lurgi Slagging Gasification Technology in Germany. Nordwestdeutsche Kraftwerke (NWK), a major german utility, Brown, Boveri and CIE. (BBC) of Mannheim, and Lurgi Gmbh supported by British Gas are co-operating in the work. Lurgi Gmbh, leader of the study, is responsible for all process units and for the overall integration. British Gas provides information and consultancy for the British Gas/Lurgi Gasification section. NWK's responsibility as prospective operator is to provide the requirements for the operation load characteristics of the power plant and the site-specific data. The combined cycle power plant and calculation of 'cost of electricity' is the responsibility of BBC.

Four cases are being investigated, all plants being designed for intermediate load following (2 shift operation, week-end shutdown) at a location near Emden:

The repowering of a 450 MW combined cycle plant in Emden which is presently fired with natural gas.

A 200 MW power plant, which represents one module with regard to the commercial size combined cycle plant.

An 800 MW commercial size power plant.

An 800 MW decentralised concept, where a gas plant would be in one location fueling a number of decentralised power plants generating power and district heat. This concept is of special interest for congested areas.

The results from the study are not yet available but the report which will be submitted shortly confirms that, in comparison with conventional coal fired power plants, IGCC's based on British Gas/Lurgi technology are far superior environmentally with respect to SOx, NOx and dust and the cost of electricity generation is certainly no higher.

10.3 Feasibility Study for Pacific Gas and Electric Corporation

Lurgi GmbH is currently carrying out for the Pacific Gas and Electric Corporation an investigation to compare Lurgi pressurised circulating fluidised bed (CFB) gasification with British Gas/Lurgi Gasification for I-STIG (intercooled-steam injected gas turbine) application. British Gas will provide information and consultancy for the British Gas/Lurgi gasification unit. The purpose of this study is to evaluate the economics for small size power plants for Californian conditions.

10.4 The Consolidated Edison Company of New York

The Consolidated Edison Company of New York, Inc. retained Bechtel Group, Inc. and Bechtel Associates Professional Corp. to evaluate the technical and economic feasibility of building a British Gas/Lurgi Slagging gasifier plant to produce a medium btu gas for boiler fuel. British Gas and Lurgi again provided information design and consultancy for the gasification area, and Lurgi for the acid gas removal, lock gas compression, gas cooling, and gas liquor separation, evaporation and incineration areas. This study was completed late 1984. The fuel gas production and power generation plant were separated by quite a long distance and hence, integration of the two plants was not possible. Nevertheless, the gasification area was shown to have many environmental advantages over conventional processes.

10.5 Niagara Mohawk Power Corporation

Bechtel were also retained by the Niagara Mohawk Power Corporation to undertake a study for an IGCC based on the British Gas/Lurgi Slagging gasifier. The study was completed in August 1983, and British Gas/Lurgi again provided detailed engineering data to allow Bechtel to complete the assignment. The significant reduction of environmental pollution of the IGCC route was again apparent when compared with conventional technology.

11. CONCLUSIONS

1. Integrated coal gasification combined cycle power generation produces electricity at lower cost, with higher efficiency and improved environmental acceptance compared with conventional coal fired plant and the Slagging gasifier combined cycle route has an edge over competing IGCC processes.

2. An IGCC based on the British Gas/Lurgi Slagging gasifier should have a significant impact in improving environmental aspects. At least 95% of the sulphur in the coal can be recovered as saleable sulphur and all flue gases have less than 800 ppm SO_2 and 75 ppm of NOx. There are no liquid effluents and all solid refuse can be easily disposed of. Higher (up to 99% plus) sulphur recovery can be achieved using available technology at marginal, additional cost of electricity (2-4%), irrespective of the sulphur content of the coal.

3. When the capacity of the fuel gas production plant is sized to satisfy the requirement of the gas turbines for operation at low ambient temperatures the incorporation of supplementary firing before the steam turbines offers the prospect of cheaper peak load power generation than with conventional plant and also the displacement of petroleum fuels.

12. REFERENCES

1. Evaluation of the British Gas/Lurgi Slagging Gasifier in Gasification Combined Cycle Power Generation. EPRI AP-3980 Research projects 2029-5, 2029-6, March 1985

2. Evaluation of British Gas/Lurgi Slagging gasifier for Combined Cycle Power Generation. T.R. Roszkowski, B.H. Thompson, T. Beyer and H.E. Vierrath. Twelfth Energy Technology Conference. March 26th 1985 Washington D.C.

3. U.S. Coal Test Program on BGC/Lurgi Slagging Gasifier. EPRI AP-1922. Research project 1267-1. August 1981.

4. Cost and Performance for Commercial Applications of Texaco-based Gasification Combined Cycle Plants. EPRI AP-3486. April 1984.

5. Cost and Performance of Kellogg-Rust/Westinghouse-based Gasification Combined Cycle Plants. EPRI research project 2029-4.

To be published.