Producing Fuel and Electricity from Coal with Low Carbon Dioxide Emissions

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Abstract. New energy technologies are needed to limit CO_2 emissions and the detrimental effects of global warming. In this article we describe a process which produces a low-carbon gaseous fuel from coal. Synthesis gas from a coal gasifier is shifted to a gas mixture consisting mainly of H_2 and CO_2. The CO_2 is isolated by a physical absorption process, compressed, and transported by pipeline to a depleted natural gas field where it is injected. What remains is a gaseous fuel consisting mainly of hydrogen.

We describe two applications of this fuel. The first involves a combined cycle power plant integrated with the coal gasifier, the shift reactor and the CO_2 recovery units. CO_2 recovery and storage will increase the electricity production cost by one third. The second provides hydrogen or a hydrogen-rich fuel gas for distributed applications, including transportation; it is shown that the fuel can be produced at a cost comparable to projected costs for gasoline.

A preliminary analysis reveals that all components of the process described here are in such a phase of development that the proposed technology is ready for demonstration.

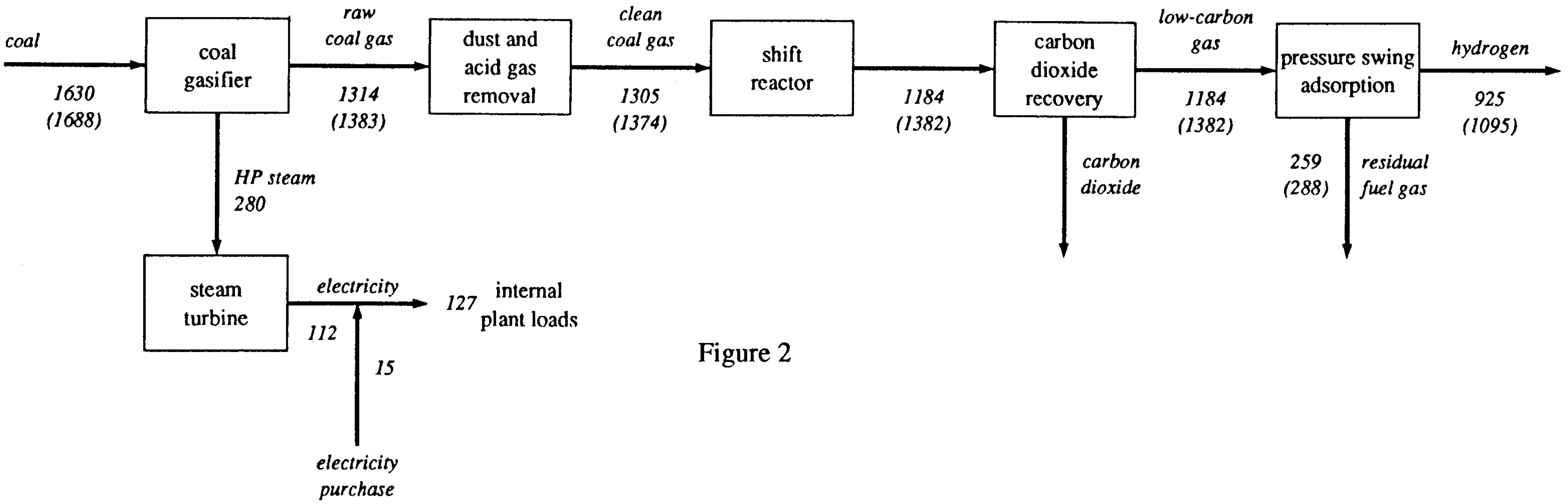
coal
1630
(1688)
coal gasifier
raw coal gas
1314
(1383)
dust and acid gas removal
clean coal gas
1305
(1374)
shift reactor
1184
(1382)
carbon dioxide recovery
carbon dioxide
low-carbon gas
1184
(1382)
pressure swing adsorption
259
(288)
residual fuel gas
hydrogen
925
(1095)
HP steam
280
steam turbine
electricity
112
15
electricity purchase
127
internal plant loads

Figure 2

1. Introduction

The ongoing increase of carbon dioxide (CO_2) emissions could lead to a considerable global and regional climate change in the next century *(1)*. Interest in reducing this change is leading to an examination of alternative options for reducing CO_2 emissions. Important options are more efficient use of energy and a shift to less carbon dioxide emitting energy sources *(2)*. In most cases the latter means a shift away from coal to e.g. natural gas, nuclear energy and renewable energy sources. Since coal is the most abundant fossil energy source low CO_2-emitting coal-based energy supply options should also be examined.

In this article, we analyze the feasibility of such an option based on the use of commercially ready technologies involving coal gasification for power generation. After a number of chemical conversion steps coal is converted to a gas of low carbon content from which CO_2 has been recovered for storage. Here the following issues are addressed:

- the status of the proposed coal conversion technology and research and development needed to make it available;
- end-use energy demands to which this process can be applied;
- the costs of energy production compared to the costs of conventional energy supply systems;
- the bottlenecks for widespread applications of this option.

In this article all energy quantities are given both as lower heating values (LHV) and as higher heating values (HHV). Weight quantities are given in metric tonnes. In cost calculations all taxes are excluded.

2. Technical description of the conversion from coal to a low-carbon fuel

The complete coal conversion process can be divided in a number of sub-processes which will be described step by step. Figures given here are valid for a gasifier of the entrained bed type as designed by Shell *(3)*; gasifiers developed by Dow and Texaco have similar characteristics *(4)*.

Coal gasification. After milling and drying, coal is fed into a 25 bar gasifier together with oxygen and steam. In this gasifier the coal, which in a simplified way can be described as $CH_{0.8}$, is converted into a synthesis gas, consisting mainly of carbon monoxide (CO) and hydrogen (H_2).
More than 99% of the carbon in the coal is converted. Of the original chemical energy content of the coal about 81% is converted into chemical energy of the synthesis gas (LHV basis), while the remainder is converted into heat. This heat is used to generate superheated high pressure steam. Most of the ash originally contained in the coal leaves the gasifier as a molten slag that is solidified by cooling in a water bath. A small part of the ash leaves the reactor as particulates in the synthesis gas stream *(3)*.

Gas clean-up. The cooled raw synthesis gas (see table 1) has to be cleaned of components which would otherwise damage downstream equipment or cause atmospheric pollution. The bulk of the fly ash is removed by bag filters or cyclones. A further clean-up involves wet scrubbing which, besides remaining particulates, removes NH_3. Subsequently the synthesis gas is fed into an absorber where acid components (mainly H_2S) are absorbed by an appropriate solvent. The absorber is regenerated and the recovered acid components are converted into elementary sulfur in a Claus unit. After these process steps a clean synthesis gas is available with a composition as given in table 1 *(3)*.

Shift reaction. In the water gas shift reaction carbon monoxide is converted into carbon dioxide according to the following reaction equation.

$$CO + H_2O\ (g)\ \texttt{<--->}\ CO_2 + H_2 \qquad (\Delta H = -41.1\ kJ/mole)$$

The equilibrium of this slightly exothermic reaction shifts to the right hand side of the equation with decreasing temperatures. Sufficient conversion is obtained by two serial reactors, the first one working at 400 °C and the second at 220 °C. After the second reactor 90% of the carbon will be present in the form of carbon dioxide *(5)*. Catalysts are employed to obtain sufficiently fast conversion. The composition of the fuel gas after the conversion is presented in table 1. Note that the energy content of the gas is reduced 9% in this step on a

LHV basis, but that the energy content remains virtually unchanged on a HHV basis. This is due to the fact that the latent heat of the water vapor contained in the gas is taken into account in the higher heating value.

Carbon dioxide recovery. The carbon dioxide content of the shifted fuel gas is about 37% by volume. The gas pressure is still very near to the pressure of the gasifier: 24 bar. This means that the partial pressure of carbon dioxide in this gas stream is about 9 bar, which is high compared to the partial carbon dioxide pressure in combustion product gases at coal steam-electric power plants. At such an elevated pressure a physical absorption process can be used to remove the carbon dioxide. Such a process is energy efficient compared to conventional chemical absorption processes. The physical absorption proceeds as follows. The fuel gas is passed countercurrent through a flow of the physical absorber (e.g. selexol, a 95% solution in water of dimethyl ether of polyethylene glycol) in which the carbon dioxide will dissolve. Next the flow of the absorber is expanded in a number of stages. In each stage a part of the carbon dioxide desorbs. The carbon dioxide is released from the desorber at various pressure levels. After expansion to atmospheric pressure the absorber is recompressed and recycled to the absorption unit.
By this process 98-99% of the carbon dioxide in the fuel gas is removed. The process requires power for the compression of the absorber, which can be partly recovered in the expansion stages using turbo-expanders. The net power requirement is 65 MJ_e per tonne of carbon dioxide removed *(5)*. An additional benefit of CO_2 recovery is that virtually all the remaining sulfur compounds are removed from the gas stream as well.

Compression of the carbon dioxide. The carbon dioxide that is released by the recovery unit should be compressed to an appropriate pressure for pipeline transport, e.g. 60 bar. A four-stage compressor with intercooling requires on average 200 MJ_e per tonne of carbon dioxide *(5)*. During and after compression the carbon dioxide is dried to prevent corrosion.

Utilities. The conversion plant requires a number of supporting utilities. Oxygen is needed for the gasification. Each MJ of coal requires 0.028 kg of

oxygen. This oxygen can be produced by a conventional cryogenic air separation process which requires 1.42 $MJ_e/kg\ O_2$ *(3)*.
Steam is produced at high pressure by the gasifier and by the shift reactor, while some of it is consumed again in the same components at various lower pressure levels. A surplus of high pressure steam can be utilized in a condensing steam turbine to generate approximately the amount of electricity needed for the oxygen plant, the carbon dioxide recovery unit, and the compressors.

Transport. After compression carbon dioxide leaves the plant to be transported to an injection site. At the conditions of 60 bar and 15 °C the carbon dioxide is a liquid. The energy requirement for transportation is 5.4 MJ_e per tonne of carbon dioxide per 100 km *(5)*.

Injection in a depleted natural gas reservoir. Finally the carbon dioxide is injected into a depleted natural gas reservoir. We assume a natural gas reservoir at a depth of 3000 m which had an initial pressure of 300 bar. After depletion the reservoir pressure is decreased to 50 bar or lower. It is assumed that carbon dioxide is injected until the original 300 bar is reached. For each tonne of natural gas extracted 3.5 tonnes of carbon dioxide can be injected at this pressure, which means that the carbon content of the injected carbon dioxide is 1.4 times the original carbon content.
Injection can be accomplished in production wells at or near the end of production. New well linings may be necessary due to the corrosive character of carbon dioxide. The required injection pressure at the well-head depends on the reservoir pressure and on the carbon dioxide injection rate. The potential energy of gravity has a decreasing influence on the required well-head pressure. The average energy requirement for compression of the carbon dioxide to the required injection pressure (at maximum 100 bar at the well-head) is 3.6 MJ_e per tonne of carbon dioxide injected *(5)*.
A possible benefit of CO_2-injection not taken into account here is that additional natural gas can be produced *(6)*.

Recapitulation. As can be seen from table 1 the process described above

converts 1 MJ of coal into 0.73 MJ of low-carbon fuel gas at LHV whereas this conversion efficiency is 82% at HHV *(7)*. The fuel gas mainly consists of hydrogen and has a carbon dioxide emission factor of 4.0 kgC/GJ LHV (3.4 kgC/GJ HHV). For comparison: typical LHV emission factors are 25, 20 and 15 kgC/GJ LHV for coal, oil products and natural gas respectively *(8)*.
Ninety percent of the carbon originally present in the coal is converted to CO_2 in the shift reactors, of which 98-99% is removed by the physical absorption process. Overall about 88% of the carbon is recovered and stored, and therefore prevented from entering the atmosphere.

3. Application for power production

In recent years interest in coal gasification has been growing, especially for power generation via the Integrated Coal Gasifier/Combined Cycle (IGCC) power plant. Compared to a conventional pulverized-coal fired steam-electric plant, such a unit holds out a prospect of an increased conversion efficiency and lower emissions of sulfur dioxide and nitrogen oxides. When the technology is mature, an IGCC plant is expected to produce power at generating costs (¢/kWh) that are about the same as for conventional coal fired plants. It is from such an IGCC power plant that we derive an integrated power plant with low carbon dioxide emissions.

Design of the low-carbon-emission-IGCC. We base our analysis on an IGCC design as described in *(3)*. This design is based on the Shell gasifier combined with an advanced gas turbine (GE Frame 9F) and a steam turbine bottoming cycle. This combination is expected to lead to a relatively high coal-to-busbar efficiency for power production of 43.6% (HHV 42.1%), see also *(9)*. The simplified power balance of such a plant is depicted in figure 1a. Compared to this IGCC plant a number of process units have to be added for CO_2 removal: the shift reactors, the carbon dioxide recovery unit, the carbon dioxide compressor, pipelines, and the CO_2 injection system.
In figure 1b the power balance of an IGCC with low carbon dioxide emissions (LCE-IGCC) is given. The coal input is kept constant compared to the power

plant without CO_2 removal. The energy flows are modified in such a way that the steam production and consumption is balanced within the plant *(5)*. It shows that the efficiency for power production decreases to 37.9% (HHV 36.6%). Compared with the original plant the main power losses are caused by the fuel energy loss in the shift reactor and by the electricity consumption for the carbon dioxide compression. The specific carbon dioxide emissions decrease from 205 to 28 gC per kWh.
A similar calculation made for an IGCC plant based on Texaco gasification technology shows that the plant efficiency decreases in a similar way: from 40.8 to 35.8% LHV (from 39.4 to 34.6% HHV).

Costs. On the basis of these figures we estimate the increase of the production costs which can be attributed to the carbon dioxide removal (table 2). At a discount rate of 5% electricity production costs will rise 33%, from 4.2 to 5.6 ¢/kWh. At a discount rate of 10% this increment is slightly higher: 35%. From these figures we calculate that, at discount rates of 5 and 10%, respectively, it costs $77 and $102 to avoid one tonne of carbon entering into the atmosphere as carbon dioxide.

Discussion. It should be noted that others report different cost increments. Smelser and Booras *(10)*, in a study performed for the EPRI, conclude that the increase of the electricity production cost due to CO_2 removal in a gasification/combined cycle power plant is much higher, some 60%. The main reason for their higher cost estimate is that they start from a much lower base case coal-to-busbar efficiency: 35.6% where we use 43.6% (both LHV). The efficiency loss in percent-points is about the same. Furthermore Smelser and Booras assume higher additional investment costs, associated mainly with a longer transport distance (540 km) and with more expensive ocean injection. In a study performed by an oil company *(6)* for a first-of-its-kind plant, an electricity cost increase of 40% is estimated. In the latter study carbon dioxide is recovered from the synthesis gas by using chemical absorption which is less energy-efficient than the physical absorption that we propose.

Carbon dioxide recovery from an IGCC power plant as described here is much less costly than carbon dioxide recovery from a conventional steam-electric power plant by means of flue gas scrubbing using a chemical absorber or associated with combustion carried out in a CO_2/O_2 atmosphere instead of air (so that the flue gases consist mainly of CO_2 and water vapor). In these cases estimated production cost increases of about 70% are reported *(11,12,13,14)*.

4. Application to the production of fuel for distributed use

An alternative to burning the fuel gas where it is produced in a combined cycle power plant is to deliver it by pipeline to distributed users in industry, commercial and residential buildings, or transportation, where it might be used as a substitute for petroleum fuels.

The hydrogen-rich gas can either be used "as is" or purified. A frequently used, low-cost option for purifying hydrogen is pressure swing adsorption (PSA), which utilizes activated carbon and/or zeolite molecular sieves that selectively remove the carbon dioxide, carbon monoxide, nitrogen and methane from the high pressure gas to yield a gas that is 99 to 99.999% pure hydrogen containing about 85% of the hydrogen in the feed *(15,16)*. The residual fuel gas, which contains approx. 20% of the energy content of the gas stream before purification, can either be burned locally or reinjected into the shift reactors and shifted further.

While hydrogen has a heating value only one-third that of natural gas, the cost of transport and the pumping power requirements for hydrogen are typically only about 1.5 times as large *(17)*, mainly because hydrogen has a specific gravity just one-eighth that of natural gas *(18)*. Thus hydrogen can be transported long distances by pipeline at relatively moderate cost *(19)*.

A major motivation for considering hydrogen as an oil substitute, aside from the greenhouse benefit and the prospect of utilizing a larger resource base, is the air pollution benefit. Only water vapor and oxides of nitrogen are generated in its combustion, and the latter can be controlled to very low levels at low cost.

Hydrogen fuel cells. Hydrogen would be best used in fuel cells, which can convert chemical energy directly into electricity without first burning it (thus avoiding the Carnot efficiency trap of the heat engine), at efficiencies of 40 to 70% (LHV basis). For stationary cogeneration applications, where heat is recovered as a byproduct, overall energy utilization efficiencies of up to 85% can be achieved. Hydrogen fuel cells will generate zero air pollution, eliminating even NO_x emissions.

Phosphoric acid and molten carbonate fuel cells might be commercialized in the 1990s *(20)*. Moreover, it may also be feasible to commercialize solid polymer electrolyte (SPE) fuel cells by the turn of the century for specialty applications *(21)*. The high power density of SPE fuel cells makes them attractive candidates for automotive applications, where space and weight constraints are severe *(22,23)*. A fuel cell car with an electric drive train would require less than half the fuel energy per km as an internal combustion engine car having the same performance, thereby greatly easing the weight and volume constraints associated with storing hydrogen in cars. For heavily polluted urban areas like Los Angeles, the fuel cell car would offer the environmental benefits of the electric car, the focus of current interest for such areas, without the range and recharging time limitations of the electric car *(19)*.

Costs. Cost estimates presented in table 3 indicate that at the present world coal price of $50 per tonne, a hydrogen-rich fuel gas could be produced for $6.7/GJ (5% discount rate) to $8.2/GJ (10% discount rate), LHV basis. Purified hydrogen (99.99%) would be about 5% more costly *(24)*.

Air quality concerns might make urban transportation a major initial application of hydrogen *(19)*, so that one yardstick for economic performance is the gasoline price. While the estimated cost of coal-derived hydrogen is more than the present wholesale gasoline price of about $5/GJ, the price of oil will probably increase in the future. The 1990 projection of the US Department of Energy is that the world crude oil price may increase to $28/barrel by 2000 *(25)*, corresponding to wholesale gasoline prices of about $7/GJ. While a direct comparison of fuel prices is not adequate for comparing gasoline and hydrogen (storage costs, conversion efficiencies and other changes in vehicle characteristics must also be taken into account), the prospect that coal-derived hydrogen might be comparable in price to gasoline in the decades immediately ahead provides strong motivation for exploring in detail the use of hydrogen as a clean alternative fuel for transport.

5. Bottlenecks for the introduction of the process

In this section we discuss some problems which might be encountered if the technology described above were implemented. We firstly concentrate on the technology status of the several components of the process. Subsequently a number of other bottlenecks are explored.

Technology status of the LCE-IGCC. The applicability of integrated gasification combined cycle plants has been demonstrated at the 100 MW_e plant at Cool Water, California. Further demonstration on a larger scale is underway in the Netherlands and at several places in the USA. A 253 MW_e IGCC power plant presently under construction in the Netherlands is designed for a coal-to-busbar efficiency of 43% (LHV basis) *(26)*. Thus IGCC technology is on the threshold of commercialization.
Transforming an IGCC to an LCE-IGCC means the addition of a number of process units: shift reactors, a CO_2 recovery unit and a CO_2 compressor. All these technologies are proven and widely used in basic chemical industries (e.g. ammonia production), though shift reactors in use at present are mostly fed with synthesis gas derived from natural gas. So for CO_2 recovery in an LCE-IGCC plant a demonstration stage is needed.
Improvements might be found in further optimization of the plant (mainly by further integration of the processes) and in developing oxygen production technology which is cheaper and more energy-efficient than current technology (e.g. with help of membrane separation technology). Such improvements could reduce overall generation costs.

Technology status for hydrogen production and use. The production of hydrogen from coal can be accomplished with commercially ready technology, as is the case for LCE-IGCC technology.
One major challenge relating to large-scale hydrogen use is infrastructure

development. Introducing a new energy carrier like hydrogen will not be accomplished easily or in a short time in a world where the present energy infrastructure has been shaped to a large degree by the use of oil.

The demonstration of hydrogen storage technologies and hydrogen-using equipment is needed. The fuel cell, the most interesting conversion device for hydrogen, may only begin to be used commercially in the 1990s, and years of experience will be needed before its long-term outlook can be described with confidence.

Niche markets that would enable the launching of a hydrogen economy might be developed. One possibility would be the introduction of hydrogen/natural gas fuel mixtures. Hythane, consisting of 5-15% hydrogen in natural gas, has been proposed as an alternative to compressed natural gas (CNG) for use in internal combustion engines for urban transport. Preliminary measurements indicate very low emissions for vehicles fueled with hythane and good prospects for meeting tough emissions standards proposed for California *(27)*.

Beyond the turn of the century hydrogen from other sources such as photovoltaics *(19)* and wind energy sources might also be able to compete in applications such as transportation *(28)*. Thus the development of hydrogen from coal could not only provide the basis for beginning to build an infrastructure for hydrogen, but also it would buy time to develop alternative hydrogen sources for the long term.

Technology status of underground CO_2 injection. Injection of gases in underground reservoirs is very common, e.g. the seasonal storage of natural gas and the injection of carbon dioxide for enhanced oil recovery. A key concern is whether the carbon dioxide will stay underground. The fact that natural gas resided in natural gas fields for millions of years suggests that long-term storage can be assured. After production and injection of course a new situation is created, but oil company experts *(6,29)* expect that the integrity of the cap rock above the reservoir can be guaranteed if the initial reservoir pressure is not exceeded. Furthermore they expect that escape to the atmosphere through leaking wells or around well casings is unlikely if the casings are properly cemented and the wells are properly abandoned at the end of the project.

Nonetheless, research into the possible problems and side-effects associated with the storage of large quantities of carbon dioxide in gas wells is needed. A demonstration project should be part of such research work.

Risks and environmental effects. The option of producing a low-carbon fuel from coal is obviously attractive only if there are substantial net environmental and safety benefits. Clean and safe production of the low-carbon fuel is possible if chemical industry safety standards are applied. The same goes for the transportation and injection of carbon dioxide if the safety standards of the natural gas production industry are applied. In particular, measures should be taken to prevent the release of large volumes of CO_2, which would stay close to the ground level and displace air. Hydrogen must also be managed safely. While safety issues differ from fuel to fuel, hydrogen is not inherently more dangerous than natural gas or gasoline *(19,30)*.

Storage capacity for carbon dioxide. An important question is how much storage capacity will be available for carbon dioxide. The worldwide extraction rate of natural gas, according to *(31)*, is 2280.10^9 cubic meter per year (72 EJ/yr). From the figures mentioned earlier we can calculate that each year a storage capacity of up to 1.5 Gtonne of carbon (as carbon dioxide) might become available. This figure should be compared with the annual carbon dioxide emissions from coal combustion which can be estimated at 2.4 GtonneC in 1989 *(31,32)*. Ultimately, as gas reservoirs are depleted, this storage capacity would become saturated, but this would be decades away. Other storage possibilities, e.g. (depleted) oil fields, aquifers, excavated rock and salt domes should also be investigated.

Policy issues. The present U.S. carbon dioxide policy is based on the 'no regrets' principle: CO_2 mitigation measures should be taken if they serve other purposes as well. Such a situation could arise if hydrogen or hydrogen-rich fuel were used as a clean automotive fuel in heavily polluted urban areas or if recovered carbon dioxide were used for enhanced recovery of oil or natural gas. Carbon dioxide removal combined with power production in an IGCC shows a cost increase of about one third. This is considerable, though low compared to the cost increase if carbon dioxide were instead recovered by means of flue gas scrubbing techniques. Therefore electricity production by LCE-IGCC power plants would not be consistent with a 'no regrets' policy but might well be in accordance with a CO_2 policy based on the 'precautionary principle' *(33)*.

6. Conclusions

In this article we have shown that it is technically feasible to convert coal into a low-carbon (hydrogen-rich) fuel with low emissions of carbon dioxide. Because this fuel can be used both for electricity production and as distributed fuel, potential applications in the energy supply sector are broad.

The technology status is such that, after some modest development work (e.g. process optimization), the demonstration phase can be entered. The technology makes it possible to continue using coal for at least the next several decades, while meeting tough constraints on CO_2 emissions, and to initiate thereby a transition to hydrogen as a major fuel source.

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38. For the plant under consideration 487 metric tonnes of carbon dioxide per hour have to be transported. Assumed is a capital cost of \$800 per km per tonne of carbon dioxide per hour, according to R.S. Park, Description of a North Sea CO_2 Enhanced Oil Recovery Project, in Recovery and Use of Waste CO_2 in Enhanced Oil Recovery, Proc. of a Workshop in Denver, A.M. Wolsky, C. Brooks (eds.), Argonne National Laboratory, ANL/CNSV-TM-186, June 1988. Reference *(12)* gives similar figures.

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40. For an annual capital charge rate of 0.1111 and 0.0701 for unregulated private and regulated utility ownership respectively, based on a 10 and 5% discount rate, a 30-year plant life, and an insurance rate of 0.5%/yr.
41. Assumed is a world coal price of $50 per tonne, equivalent to $1.92 per GJ LHV ($1.86 per GJ HHV).
42. For the plant mentioned in *(34)* the fixed operation and maintenance costs are $33.6/kW-yr. Variable O&M costs are 3.2 mills/kWh, where consumables cost 0.4 mills/kWh. As we assume the use of low sulfur (0.9% S) coal a credit of only 0.35 mills/kWh for recovered sulfur is subtracted *(3)*.
43. The additional O&M cost is assumed to be proportional to the capital cost of the power plant (3.6% of the investment cost), apart from the shift reactors where the O&M costs are 6.3% of the investment cost *(35)*. For transportation and injection the O&M cost are assumed to be somewhat lower: 2.1% of the capital cost.
44. The additional consumables consist mainly of the regular replacement of the catalysts in the shift reactor, written communication from mr. S.W. Madsen, Haldor-Topsoe A/S, Lyngby, Denmark, March 1990.
45. The cost of the basic gasification plant (including the oxygen plant and the synthesis gas clean up) are derived from the IGCC figures (see note *(34)*). From a cost breakdown given in *(3)* it can be estimated that removing the combined cycle and replacing it by a single steam turbine would save approx. 35% on the investment cost.
46. From the power balance of the plant it can be estimated that the internal power consumption of the plant is 127 MW, of which 112 MW can be delivered by the steam turbine driven by the steam produced in the gasifier. The remaining electricity is assumed to be purchased at a cost of $0.05/kWh.
47. We thank the Ministry of Housing, Physical Planning and the Environment of the Netherlands, the Geraldine R. Dodge Foundation, and the W. Alton Jones Foundation for supporting this research.

Table 1. Characterization of the fuel gas after different stages of gas treatment. All values are given on a dry gas basis. The figures here only concern the gas flows themselves; steam and electricity production and demand figures for the several fuel gas processing steps are not taken into account (see figures 1 and 2). The flow indicated as 'exiting gasifier' has already been stripped of the particulates and the ammonia present in the raw synthesis gas.

	Exiting gasifier	After sulfur removal	After CO shift	After CO_2 removal
Composition (vol.%, dry)				
Hydrogen	30.2	30.4	55.7	87.5
Carbon monoxide	63.1	63.5	4.1	6.4
Carbon dioxide	1.5	1.2	37.1	1.2
Hydrogen sulphide	0.3	0.0	0.0	0.0
Nitrogen	3.8	3.8	2.4	3.8
Argon	1.1	1.1	0.7	1.1
Heating values (MJ/m^3, dry)				
Lower heating value	11.3	11.3	6.5	10.3
Higher heating value	11.9	11.9	7.6	12.0
Energy content, relative to coal (%)				
Lower heating value basis	80.6	80.1	72.6	72.6
Higher heating value basis	81.9	81.3	81.8	81.8

Table 2. Overview of the production costs for IGCC plants without (711 MW$_e$) and with carbon dioxide recovery (618 MW$_e$). All investment figures include installation costs. The figures are valid for an operation period of 6000 hours per year.

	without carbon dioxide recovery		with carbon dioxide recovery	
Capital cost (million $)				
Base plant *(34)*	1043		1043	
Shift reactors *(35)*			33	
Carbon dioxide recovery unit *(36)*			45	
Carbon dioxide compressor *(37)*			46	
Pipeline 300 km *(38)*			117	
Injection system *(39)*			17	
Total capital costs	1043		1300	
Discount rate	5%	10%	5%	10%
Annualized costs (million $/year)				
Capital charges *(40)*	73.1	115.9	91.1	144.4
Coal feedstock *(41)*	67.7	67.7	67.7	67.7
O&M for basis plant *(42)*	37.8	37.8	37.8	37.8
Additional O&M *(43)*			5.3	5.3
Additional chemicals and catalysts *(44)*			1.0	1.0
O&M transportation and injection *(43)*			2.8	2.8
Total annualized costs	178.6	221.4	205.7	259.0
Cost of electricity produced (¢/kWh)	4.19	5.19	5.55	6.99

Table 3. Breakdown of investment costs and annual costs of a production plant for low-carbon gas with a production of 25.6 PJ_{LHV} of fuel per year, assuming 6000 hours of operation per year. The low-carbon gas has the composition indicated in the last column of table 1.

If not indicated otherwise the costs of components are calculated in the same way as indicated in the footnotes of table 2. The capacity of the gasifier and the fuel gas treatment facilities are the same as for the plant described in table 2.

Capital cost (million $)	
Base plant *(45)*	678
Shift reactors	33
Carbon dioxide recovery unit	45
Carbon dioxide compressor	46
Pipeline 300 km	117
Injection system	17
Total capital costs	927

Discount rate	5%	10%
Annualized costs (million $/year)		
Capital charges	65.5	103.8
Coal feedstock	67.7	67.7
Electricity purchase costs *(46)*	4.5	4.5
O&M for basis plant	24.5	24.5
Additional O&M	5.3	5.3
Additional chemicals and catalysts	1.0	1.0
O&M transportation and injection	2.8	2.8
Total annualized costs	171.3	209.7
Cost of fuel produced ($/$GJ_{LHV}$)	6.7	8.2
Ibid. ($/$GJ_{HHV}$)	5.7	7.0

Figure captions

Fig. 1. Schematic diagram with power balances of an IGCC plants without and with carbon dioxide recovery.

a. Original plant (upper).

b. Modified plant with carbon dioxide recovery (lower).

The power flows are given in MW. For the fuel flows lower heating value figures were given, with the higher heating values given in parenthesis. It should be noted that, apart from the steam flows given here, there is a complicated exchange of steam at various pressure levels within the plant.

Fig. 2. Schematic diagram of a coal gasifier with subsequent gas treatment resulting in the production of hydrogen or hydrogen-rich fuel. The pressure swing adsorption unit is optional and only necessary if high purity hydrogen is required.

Fig. 1. Schematic diagram with power balances of an IGCC plants without and with carbon dioxide recovery.

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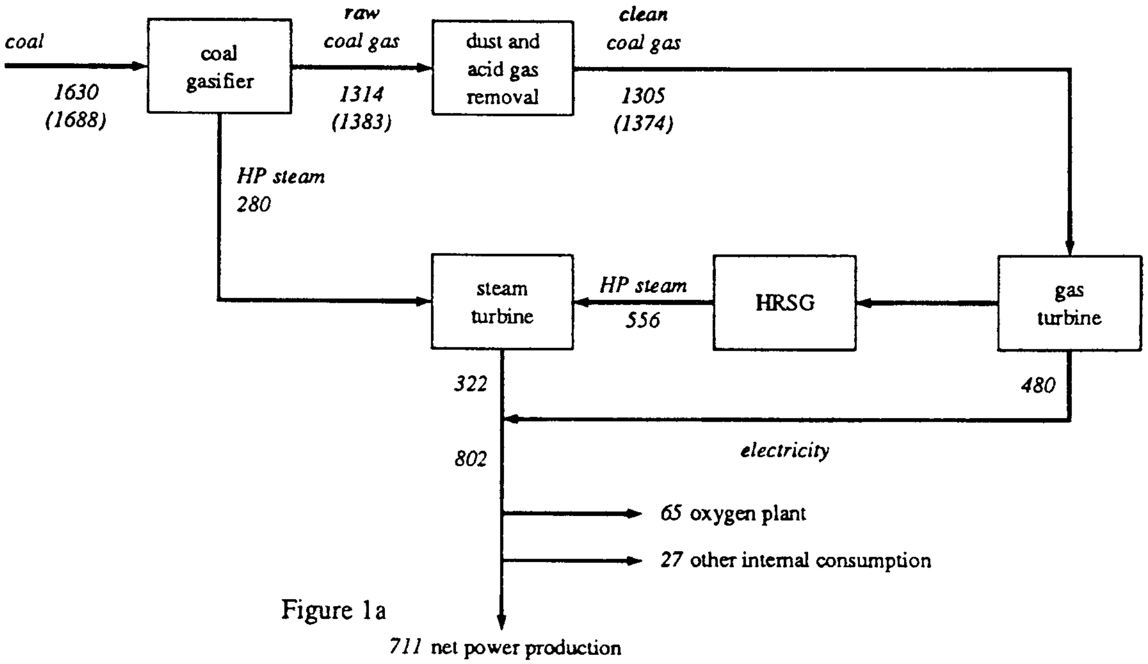

Figure 1a

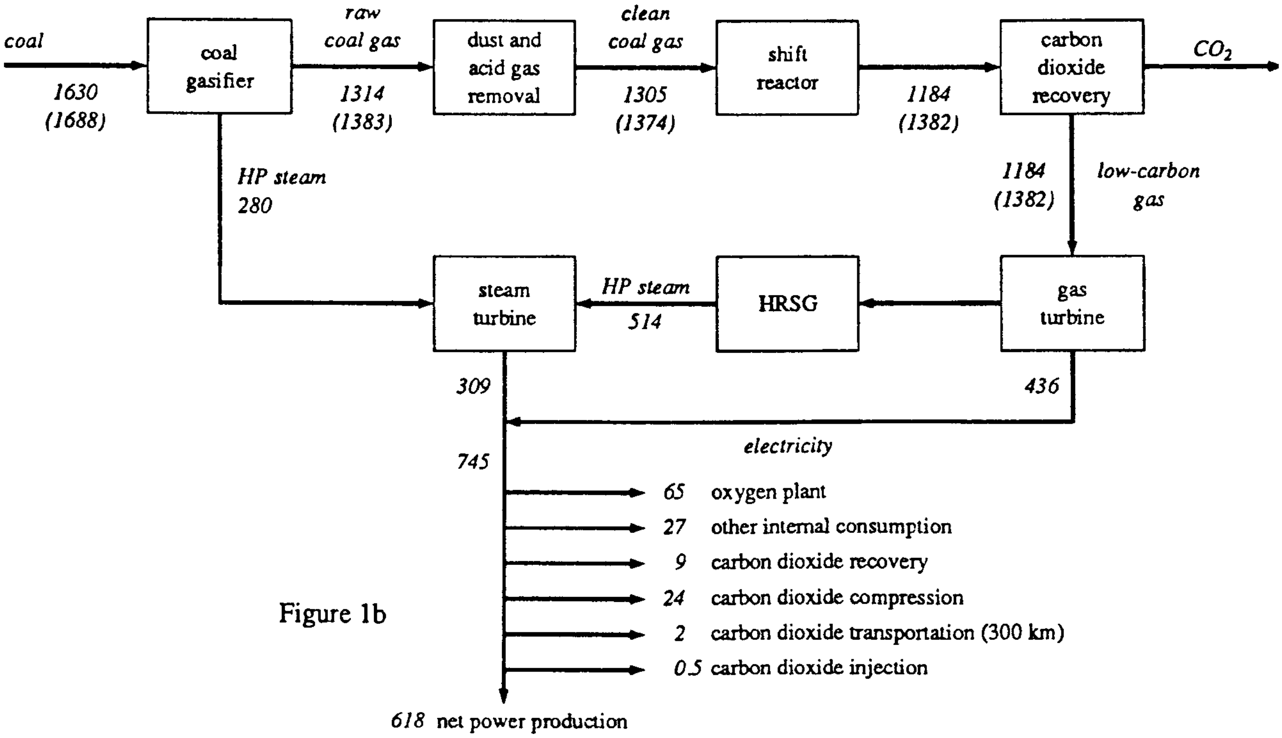

Figure 1b

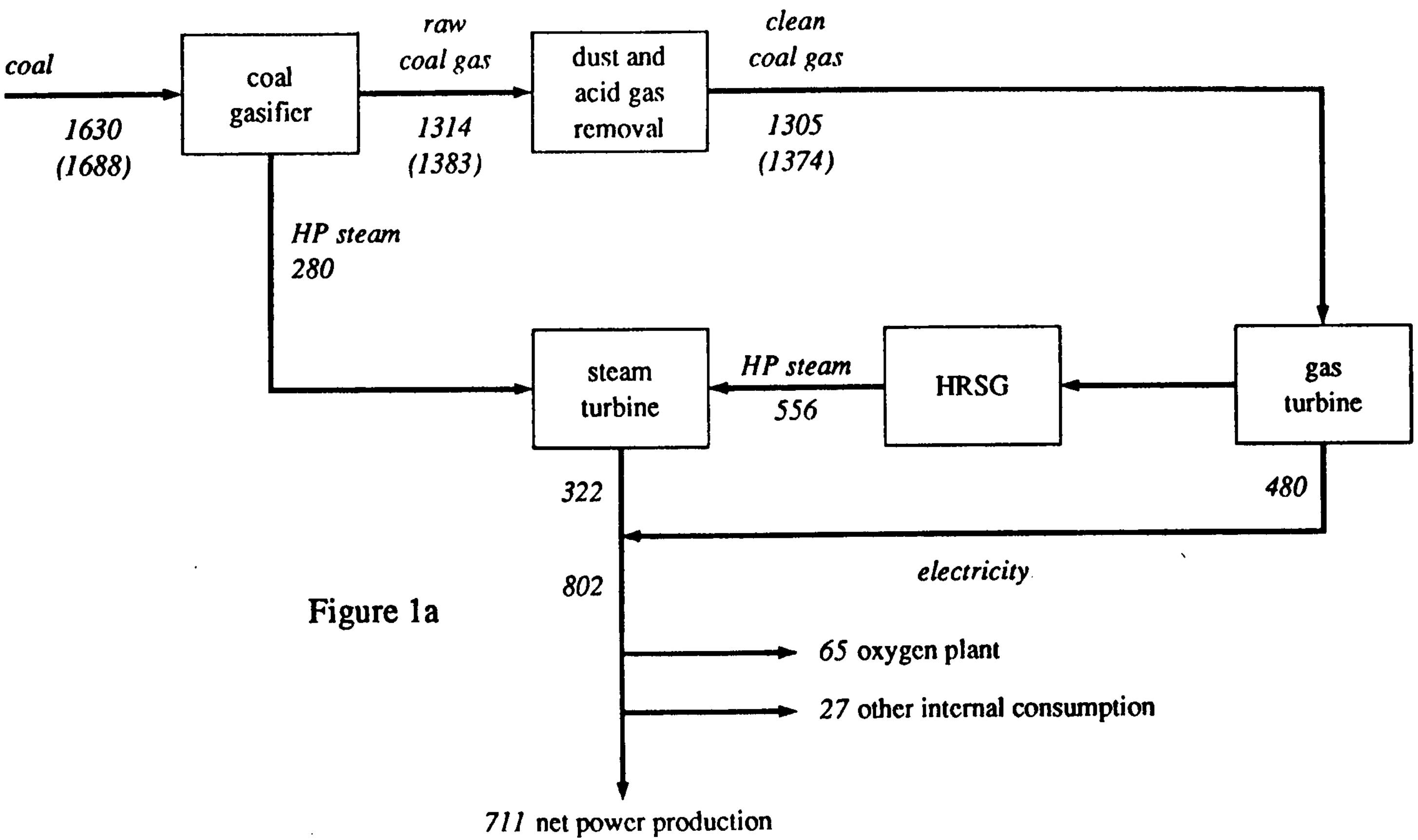
coal
1630
(1688)
coal gasifier
raw coal gas
1314
(1383)
dust and acid gas removal
clean coal gas
1305
(1374)
HP steam
280
steam turbine
HP steam
556
HRSG
gas turbine
322
480
electricity
802
65 oxygen plant
27 other internal consumption
711 net power production

Figure 1a

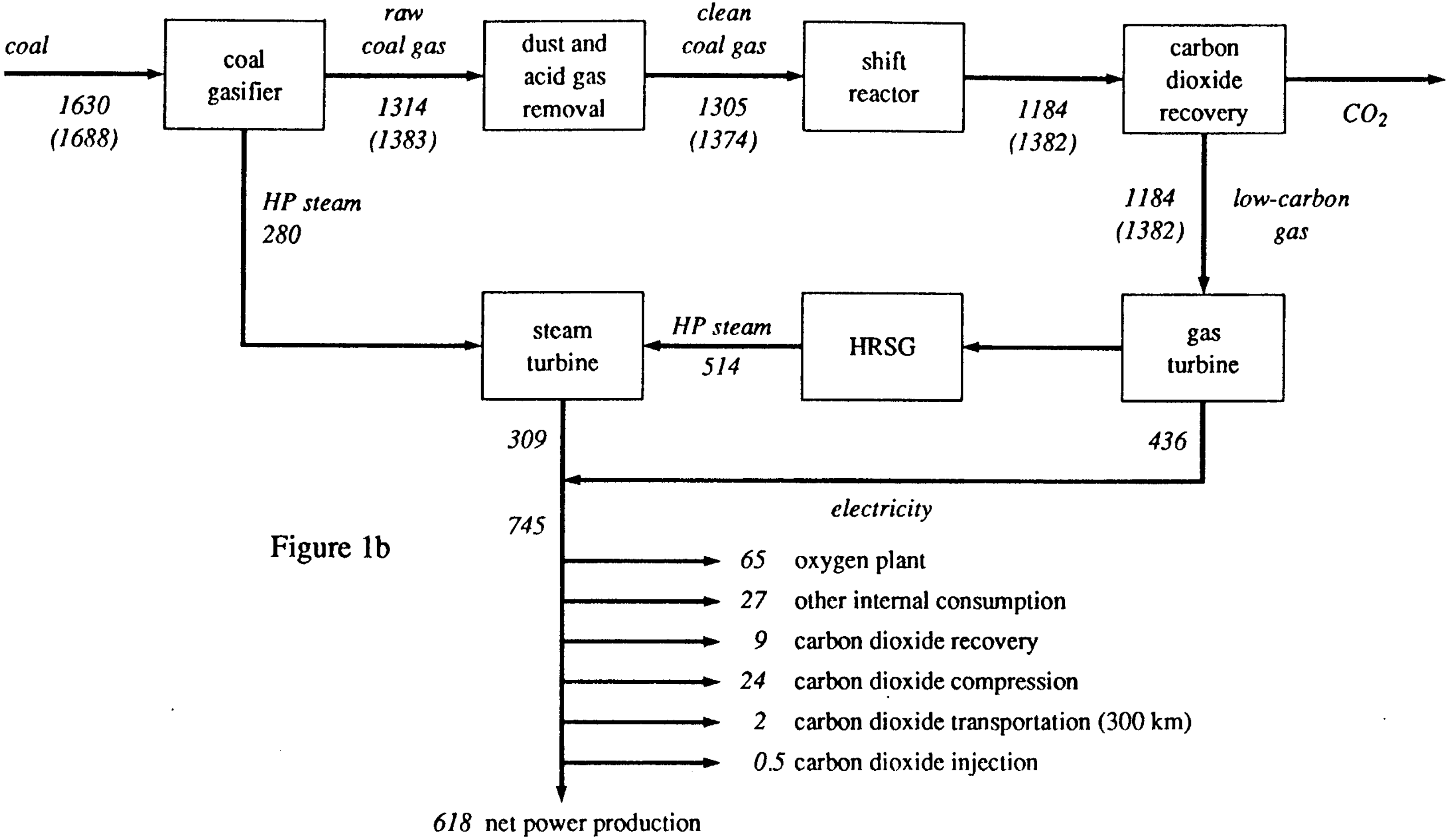
coal
1630
(1688)
coal gasifier
raw coal gas
1314
(1383)
dust and acid gas removal
clean coal gas
1305
(1374)
shift reactor
1184
(1382)
carbon dioxide recovery
CO2
1184
(1382)
low-carbon gas
HP steam
280
gas turbine
HRSG
HP steam
514
steam turbine
309
436
electricity
745
65 oxygen plant
27 other internal consumption
9 carbon dioxide recovery
24 carbon dioxide compression
2 carbon dioxide transportation (300 km)
0.5 carbon dioxide injection
618 net power production

Figure 1b

Fig. 2. Schematic diagram of a coal gasifier with subsequent gas treatment resulting in the production of hydrogen or hydrogen-rich fuel. The pressure swing absorption unit is optional and only necessary if high purity hydrogen is required.

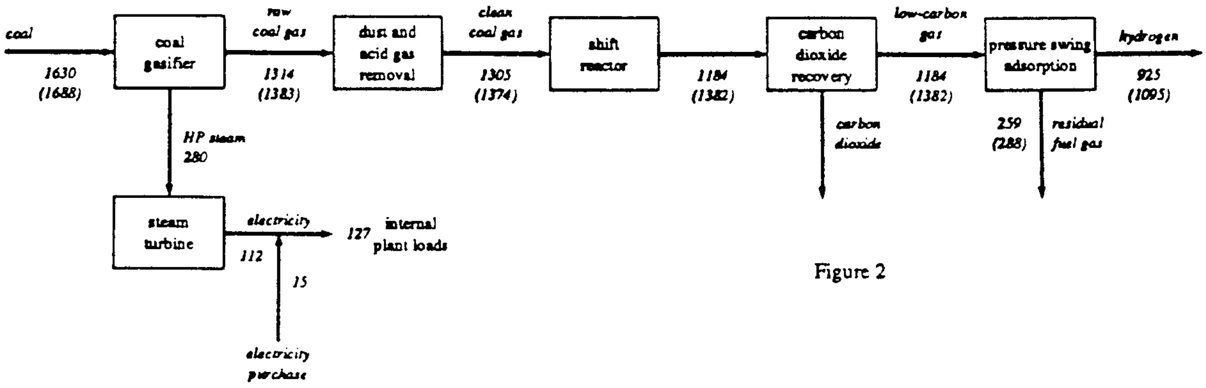

Figure 2