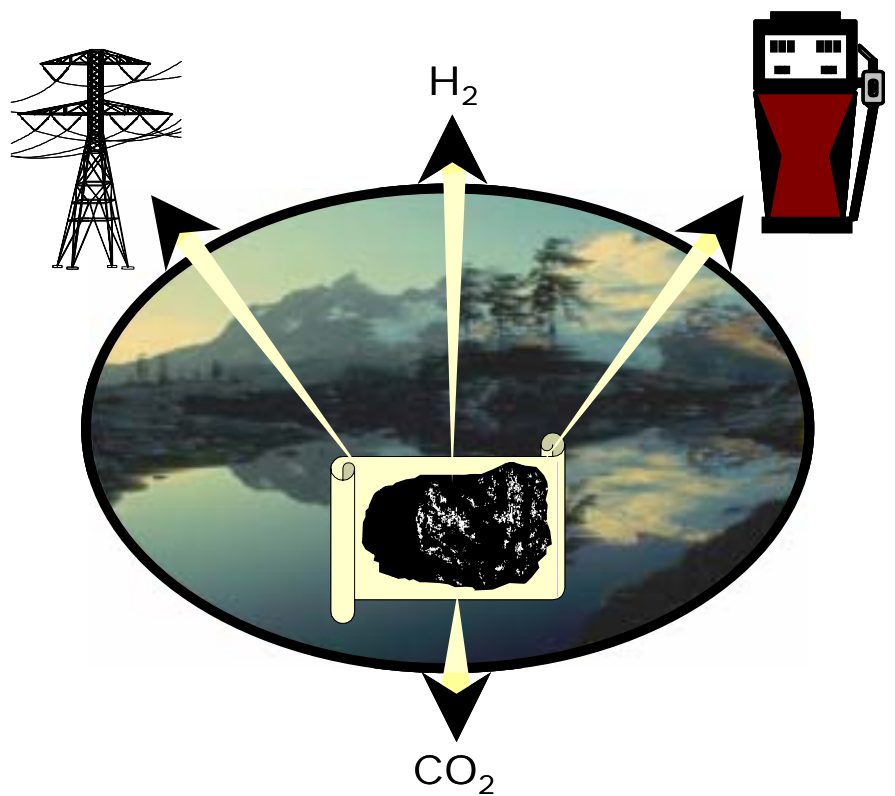


COPRODUCTION OF ULTRA CLEAN TRANSPORTATION FUELS, HYDROGEN, AND ELECTRIC POWER FROM COAL



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Introduction

Coal is our Nation's most abundant fossil fuel resource and currently is used to produce about 55 percent of our electric power. Coal gasification opens coal to new markets through the concept of coproduction where ultra clean liquid fuels, hydrogen, and other chemicals can be produced in addition to electric power. Transforming coal into a clean synthesis gas (syngas) using advanced gasification technology is a metamorphosis that allows coal to be used more efficiently and cleanly both for the production of electric power and for production of liquid and gaseous fuels and chemicals.

Once the coal is in gaseous form, the high efficiencies associated with gas turbine combined cycle performance now become accessible to coal. This is the rationale behind the Integrated Coal Gasification Combined Cycle (IGCC) concept. However, once the clean syngas has been produced from the coal, it is even more efficient to use this gas to synthesize other products like ultra clean Fischer-Tropsch (F-T) fuels, chemicals, or hydrogen in addition to electric power. This coproduction approach often avoids the inefficiencies of carbon dioxide removal, syngas recycle, and light hydrocarbon reforming that would be necessary in configurations producing just F-T fuels. The clean synthesis gas can also be used to produce chemicals like methanol and dimethyl ether, or can be shifted to produce pure hydrogen.

Gasification allows coal to be used almost as cleanly as natural gas. It allows production of electric power using advanced gas turbines and fuel cell technology at high efficiency. Sulfur is recovered as elemental sulfur rather than being emitted as SO_x. NO_x is low, and the residual coal ash is transformed into a non-leachable slag. Also coal gasification configurations allow easy production of a concentrated stream of almost pure carbon dioxide that could readily be sequestered once sequestration technology is successfully developed. This report examines performances and costs of using coal to coproduce ultra clean liquid fuels, hydrogen, and electric power. Configurations that produce multiple products are analyzed together with zero emissions facilities that include carbon dioxide sequestration. The performance and economics of these facilities are analyzed and the required selling prices (RSP) of products are estimated

There are three critically important energy supply issues facing the U.S. in the coming decades. These are adequate *electricity supply, adequate natural gas supply, and an adequate supply of clean liquid fuels*. The Energy Information Administration (EIA) is forecasting that by 2020 the U.S. will need 200 GW of additional electric power capacity, 10 trillion cubic feet (TCF) of additional natural gas annually, and 5 million barrels per day (MMBPD) of additional oil. Using domestic coal in coproduction configurations addresses all three of these supply issues. Using the concept of coproduction, electricity is generated

during the production of the ultra clean fuels and the use of domestic coal feedstock to produce this power will reduce the burgeoning demand for natural gas. Also, most importantly, if we as a nation are committed to limiting our imports of foreign oil then this concept of coproducing clean liquid fuels and power can play a vital role. In combination with increased domestic oil production producing additional clean fuels from our domestic coal resources will allow us to attain the goal of limiting our oil imports.

In the longer term, hydrogen may become the future transportation fuel of choice because of resource limitations of conventional petroleum, the opportunity for high efficiency usage in fuel cell vehicles, and the essentially zero emissions resulting from its usage. Therefore, using domestic coal to coproduce hydrogen in addition to clean liquid fuels and power anticipates the production and use of ultra clean liquid fuels in the shorter term and the gaseous fuel hydrogen in the longer term. Both these liquid and gaseous fuels will be produced from secure domestic resources.

The Importance of Ultra Clean Fuels

Ultra clean liquid fuels for transportation will not only be necessary in the near future as the Environmental Protection Agency (EPA) Tier 2 regulations for low sulfur gasoline and diesel become law in 2004 and 2007 but will also be required if more stringent environmental regulations are promulgated in the next decade. Tier 2 will require cars and light trucks regardless of fuel used to begin to comply with a nitrogen oxide (NO_x) standard of 0.07 grams per mile in 2004 with full compliance by 2007. Tier 2 also reduces average gasoline sulfur levels nationwide at the refinery gate to 30 ppm by 2005. For heavy duty vehicles, Tier 2 requires a NO_x standard of 0.2 grams per horsepower hour (g/hp-hr), non-methane hydrocarbons (NMHC) of 0.14 g/hp-hr, and particulate matter (PM) of 0.01 g/hp-hr beginning in 2007 with final phase in by 2010 for both diesel and gasoline trucks. Tier 2 also reduces on-highway diesel fuel sulfur to a 15-ppm cap beginning in 2006 with full compliance by 2010. ***The ultra low sulfur fuels are necessary because current technology exhaust aftertreatment systems designed to reduce NO_x and PM to these low levels cannot function with fuels containing sulfur levels in excess of about 10-15 ppm for diesel and 30 ppm for gasoline.*** Therefore, if highway vehicles are to comply with the regulations and achieve these low emission levels then it is essential to have ultra low sulfur gasoline and diesel fuel available to power them.

Transportation is a major contributor to air pollution and the Tier 2 regulations in the U.S. and other similar regulations in Europe and Asia are being implemented to mitigate this problem and improve public health. Of the total manmade air emissions in the U.S., transportation is responsible for nearly 80 percent of the carbon monoxide (CO), over one half of the nitrogen oxides (NO_x), and 40 percent of the volatile organic compounds (VOC). Combinations of these pollutants are responsible for ground level ozone and other causes of urban air quality deterioration that significantly impact public health.

The expected worldwide dramatic increases in vehicle numbers and miles traveled will lead to greater transportation-derived pollution unless significantly improved fuel-vehicle systems are developed and deployed. At the same time that the quality requirements for refined transportation fuels are becoming more stringent, the quality of the feedstock conventional crude oil, with respect to sulfur content and increasing gravity, is expected to deteriorate in the future. This increasing quality gap between feedstock and product will necessitate more advanced and capital-intensive petroleum refining technologies to produce fuels of the necessary quality from lower quality crude oils. This also provides the opportunity for the deployment of alternative ultra clean fuels that could be used as blending stocks or neat fuels to assist petroleum-based fuels in meeting these more stringent specifications.

Future transportation systems will require fuels for a wider range of engine designs than are currently available. There will be a transition from the conventional fleet of vehicles burning today's gasoline and diesel to those using ultra-low or zero sulfur fuels. Also, a new generation of more efficient engines including diesel/gasoline/electric hybrids and fuel cell vehicles will enter the market. In the shorter term, diesel/gasoline/electric hybrids and fuel cell vehicles using on-board reforming will use the ultra clean liquid fuels produced from these alternate resources. In the longer term, fuel cell powered vehicles will ultimately require pure hydrogen as the energy source. Hydrogen may become the future transportation fuel of choice because of resource limitations of conventional petroleum, the opportunity for high efficiency usage in fuel cell vehicles, and the essentially zero emissions resulting from its usage. Therefore, the coproduction concept anticipates the production and use of ultra clean liquid fuels in the shorter term and the gaseous fuel hydrogen in the longer term. Both liquid and gaseous fuels will be produced from secure domestic resources.

Worldwide oil demand is expected to increase dramatically as world vehicle use is anticipated to quadruple in the next 50 years. Because conventional petroleum is a finite resource its production will eventually peak and decline in the face of continually increasing demand. Exactly when this peak will occur is uncertain but Figure 1 shows two potential scenarios.

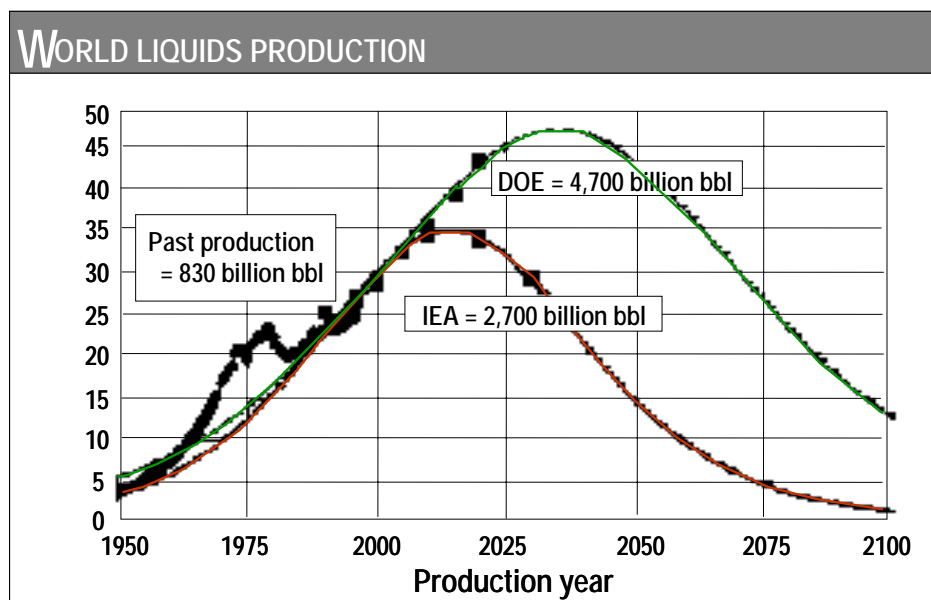


Figure 1. World Conventional Oil Production

Source: J.H. Laherrere, Oil and Gas Journal, February 1999.

The U.S. transportation sector already consumes substantially more oil than is produced domestically. Currently, the U.S. uses nearly 20 MMBPD of petroleum and imports over 11 MMBPD of crude oil and refined products. EIA projects global petroleum consumption will increase from 76 to 115 MMBPD by 2020 and that U.S. demand will grow to 25 MMBPD.

In addition to leaving us vulnerable to potential oil supply disruptions, high imports adversely affect our balance of payments situation. At current oil prices, our yearly petroleum import bill now exceeds 100 billion dollars. Because the vast majority of the remaining world oil resides in OPEC countries, the influence that OPEC will have on determining the future supply and price of petroleum will only be further enhanced. The ability to increase domestic liquid transportation fuels production for the first time in 20 years by using domestic coal will empower the U.S. and, if a sufficient quantity of these fuels is produced, could have an impact on moderating the OPEC controlled world oil price. The ability to produce hydrogen in the longer term will place us firmly on the path to a sustainable energy future.

Benefits

Using domestic coal in the coproduction concept, if implemented successfully, will result in the following major benefits:

A Cleaner More Stable Environment

This will be achieved in three ways:

- Ultra clean liquid fuels in the transportation sector will enable exhaust aftertreatment systems to be used on gasoline and diesel engines that will significantly reduce NOx, CO, hydrocarbons, and particulates.
- The availability of ultra clean liquid fuels and gaseous hydrogen will enable the rapid deployment of advanced high efficiency transportation systems like hybrid electric and fuel cells, thus significantly reducing criteria pollutants and carbon dioxide emissions.
- Deployment of these advanced technologies for conversion of domestic coal will efficiently coproduce electric power in an essentially pollution-free manner, thus greatly reducing emissions associated with conventional power production.

- Coproduction configurations allow ready sequestration of carbon dioxide thus reducing greenhouse gas emissions.

Greater National Energy Security

- Production of ultra clean liquid and gaseous transportation fuels from domestic resources will reduce dependency on imported oil and enhance national energy security.
- The Strategic Petroleum Reserve (SPRO) is important as a quick response to emergency petroleum shortfalls but it can only provide 2 MMBPD for about 6 months without restocking. However, successful implementation of the coproduction concept could provide a stable supply of 2 MMBPD of ultra clean fuels for more than 30 years for a total capital cost of about \$100 billion. This is equal to the cost of one year's oil imports. In the longer term, production of hydrogen initially from fossil resources and ultimately from renewable sources will free us from future dependency on foreign energy supplies and set us on the path to true energy sustainability.

Economic Benefits

- Production of ultra clean transport fuels from domestic resources could have the effect of reducing the world oil price. This would have a beneficial effect throughout the U.S. economy and reduce the oil import bill. Production of hydrogen from domestic resources will eventually free us from the need to import foreign oil.
- Construction and operation of an industry to produce domestically produced fuels and coproduct electric power will provide direct and indirect employment.
- Another important benefit is improving U.S. competitiveness in the energy industry by maintaining a leadership position in development, deployment, and marketing of advanced energy conversion technologies.

The Technology Base for Ultra Clean Liquid Fuels Production:

The technology basis for the coproduction concept to produce both ultra clean liquid transportation fuels and electric power is shown schematically below (Figure 2). The carbon-containing feedstock is first converted into a synthesis gas consisting essentially of carbon monoxide and hydrogen. This synthesis gas is then cleaned to remove all impurities like sulfur and then sent to a synthesis process where the clean gas is converted into ultra clean liquid fuels. Electric power is often generated as a coproduct. Some of this power is used in the conversion process and excess power is sold. Because the process produces more than one product, the concept is known as coproduction.

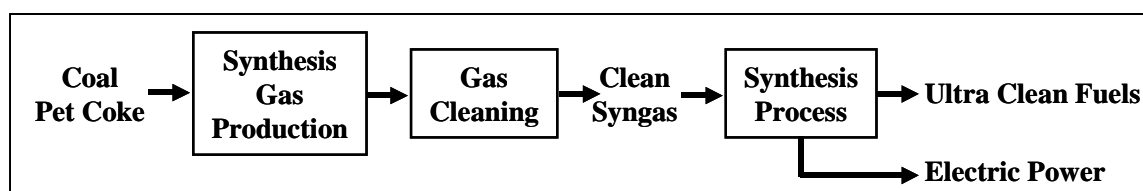


Figure 2. The Technology Concept

Figure 3 shows the evolution of coproduction from Integrated Coal Gasification Combined Cycle (IGCC) producing only electric power through a coproduction/cofeed (CoCo) concept that uses both coal and natural gas to an all-coal coproduction configuration. In its simplest form (shown in Figure 4), the CoCo concept consists of diverting clean coal-derived synthesis gas from the combined-cycle-power block of an IGCC unit to a slurry-phase Fischer-Tropsch (F-T) synthesis reactor. The tail gas from the F-T reactor consisting of unreacted synthesis gas, carbon dioxide, water, and light hydrocarbons is then combined with imported natural gas and combusted in the combined-cycle power generation unit. Combining processes in this manner has certain technical and economic advantages. Coal cannot be combusted directly in gas turbines; it must first be converted into clean synthesis gas. Once the coal is in gaseous form, the high efficiencies associated with gas turbine combined cycle performance now become accessible to coal. This is the rationale behind the IGCC concept. However, once the clean synthesis gas has been produced from the coal, it is even more efficient to use this gas to produce liquid transportation fuels through F-T synthesis technology. Using a once through F-T process in this configuration avoids the inefficiencies of carbon dioxide removal, synthesis gas recycle, and light hydrocarbon reforming that are necessary in configurations producing an all-liquid product. In CoCo, the

unconverted synthesis gas, the light hydrocarbon gases produced in the F-T synthesis and imported natural gas are directly combusted in the gas turbines.

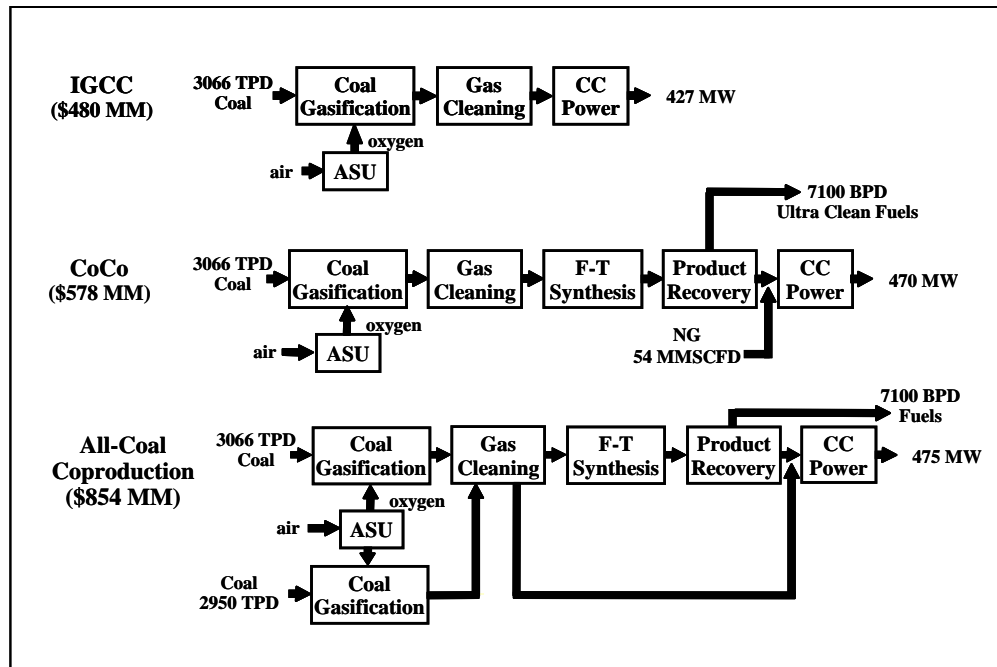


Figure 3. Evolution of Coproduction

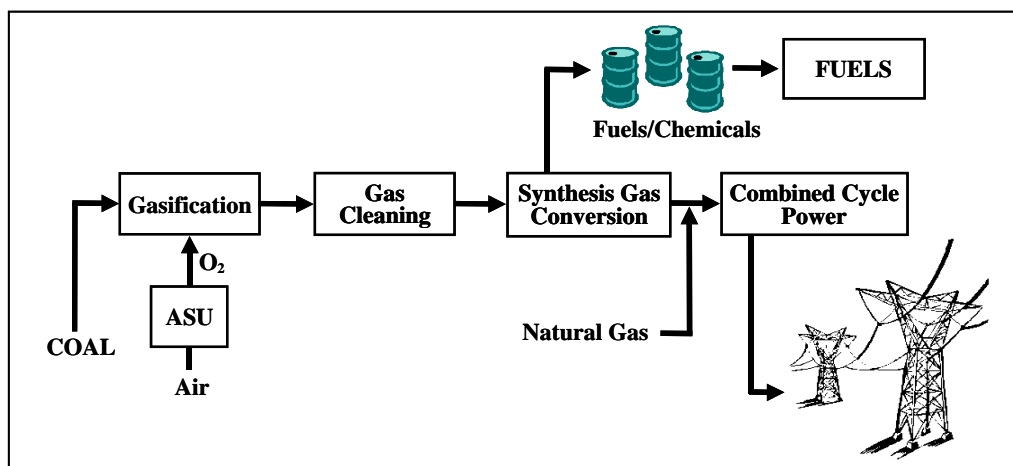


Figure 4. Coproduction/Cofeed (CoCo) Concept

The basic IGCC plant was modified to reconfigure it as a CoCo facility. The additional equipment required includes a single slurry-phase F-T reactor, product recovery, hydrogen recovery, wax hydrocracking, sulfur polishing for synthesis gas cleaning, and product tankage and shipping facilities. In addition to this equipment, it is necessary to modify the steam system of the combined cycle section since the F-T reactors produce steam that is used to supplement the steam cycle of the combined cycle electric power generation system.

Figure 5 shows a simplified block flow diagram of this CoCo facility. The same coal input was used as in the basic IGCC facility (3,066 tons per day (TPD) as-received coal), but natural gas (54 MMSCFD) was added to the combined cycle section of the plant to compensate for the coal-derived synthesis gas used to produce F-T liquids. Figure 5 shows the Btu flow through the plant from coal and natural gas inputs to product outputs. Overall efficiency on a high heating value (HHV) basis for this plant is almost 60 percent.

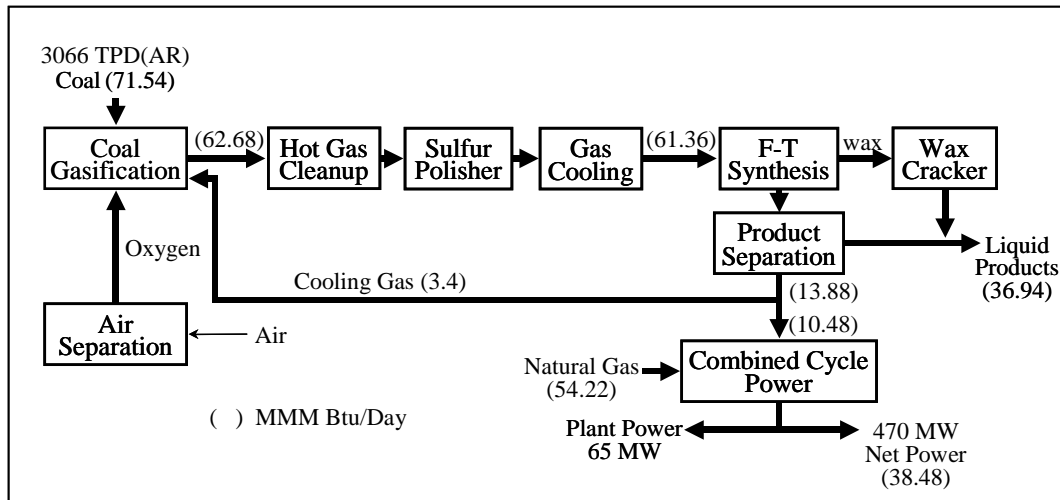


Figure 5. Schematic of CoCo Facility

Net power output is 470 megawatt (MW) or 10 percent higher than the basic IGCC plant. This is the result of the additional steam generated in the F-T synthesis unit. The parasitic power requirement is about 65 MW. Total production of ultra clean fuels is 7,000 barrels per day (BPD) two thirds of this product is ultra clean diesel.

The value of the CoCo concept is that it provides a hedge against continuing low natural gas prices when considering investment in a coal-fired IGCC plant. Selling both power and ultra-clean fuels allows a higher return on equity (ROE) to be realized when natural gas prices (and hence electric power value) are relatively low. As natural gas prices increase (above about \$3.75/MMBtu), it becomes more economically attractive to

discontinue buying the natural gas for the gas turbines and to convert the CoCo plant into an all coal coproduction facility.

Figure 6 is a schematic of an all coal coproduction facility. In this plant, there are two trains of gasification. One train feeds the F-T unit and the other directly feeds the combined cycle plant. This plant is configured to produce essentially the same net power output (470 and 475 MW) and the same liquid product output (7,000 BPD) as the CoCo facility. In this case, though, only coal is used as feed. The plant is a combination of a once-through F-T plant and an IGCC facility. High-purity synthesis gas is only required for the F-T feed.

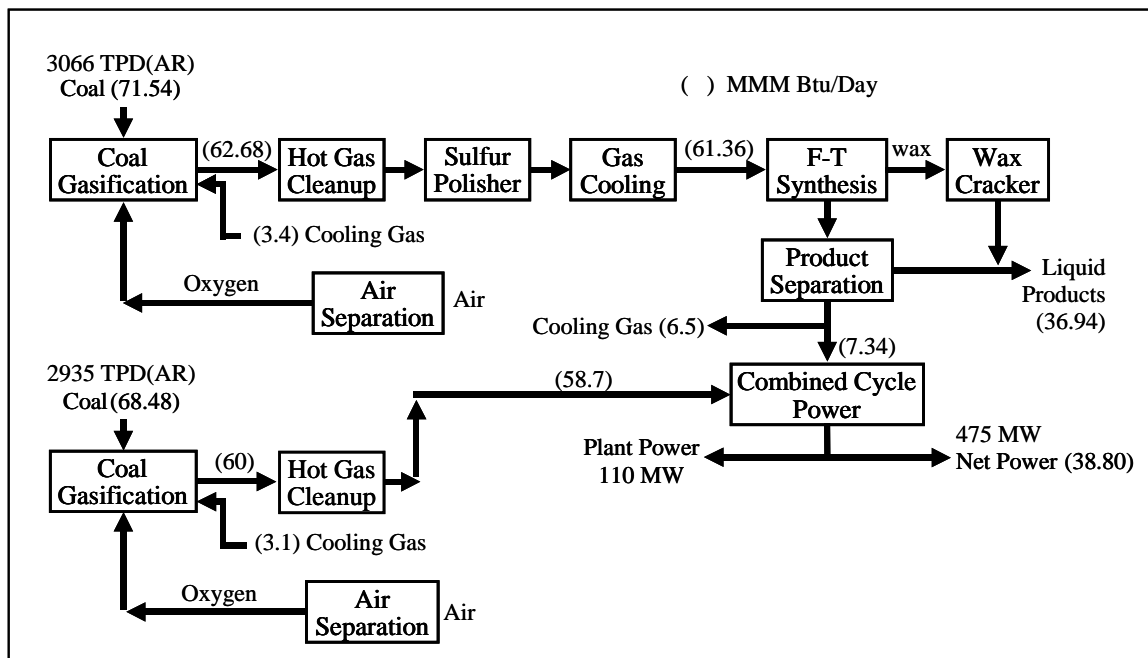


Figure 6. Schematic of all Coal-Based Coproduction Facility

It is assumed that hot gas cleanup is sufficient for the gasification train that directly feeds the combined cycle block. Overall HHV efficiency for this plant is 54 percent.

The configurations have all shown modifications to the basic IGCC plant. These plants have all been relatively small scale with respect to the production of ultra clean fuels. If the purpose is to produce larger quantities of ultra clean fuels from coal, then coproduction facilities will be constructed that process much larger quantities of coal. Figure 7 shows a schematic of a facility that processes 16,400 TPD of coal to produce over 33,000 BPD of ultra clean fuels and nearly 700 MW of electric power at an efficiency of about 60 percent

(HHV). The coal input to this plant is equivalent to the coal input for three 500 MW conventional pulverized coal power plants.

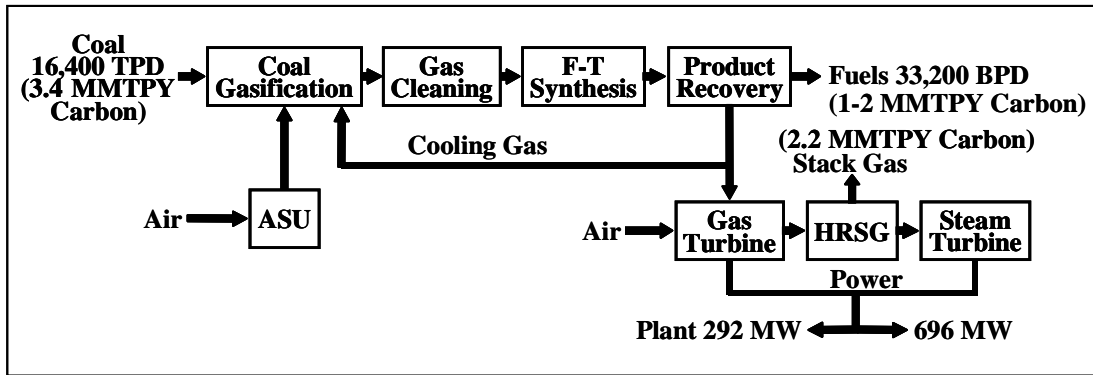


Figure 7. Large Scale Coproduction Plant with No Carbon Sequestration

Opportunities for Carbon Dioxide Sequestration for Liquid Fuels Production:

Advanced clean coal technologies exemplified by IGCC and coproduction are enabling coal to be used in an increasingly clean and efficient manner. The major characteristics that make coproduction so clean are:

- It produces electric power from clean synthesis gas using advanced combined cycle technology at high efficiency with minimal emissions of sulfur oxide (SO_x), NO_x and with a non-leachable slag.
- It produces ultra clean liquid transportation fuels that contain zero sulfur, zero aromatics, and high cetane number. These fuels allow utilization of advanced exhaust aftertreatment systems on vehicles so that the resulting emissions of NO_x and PM meet the stringent Tier 2 standards.
- Coproduction can be configured to produce a concentrated stream of almost pure carbon dioxide that could be readily sequestered once appropriate sequestration technology has been demonstrated.

There are several configurations that can be used with coproduction to produce a concentrated stream of carbon dioxide. Three such configurations are examined in this report.

Figure 8 shows a configuration where the carbon dioxide is removed from the F-T tailgas. The tail gas from the F-T unit after product removal contains the unconverted synthesis gas, methane, ethane, and ethylene produced in the synthesis, water, and carbon dioxide. The carbon dioxide is removed using a conventional amine system to provide a pure concentrated stream. This can be sent for sequestration. The F-T tail gas with the carbon dioxide removed is then sent to the gas turbine combustor. The exit gas from the gas turbine is sent to the heat recovery steam generator (HRSG) where steam is produced for the steam turbine. The flue gas from the HRSG is then vented to the stack. Because the F-T tail gas contained carbon-containing species, the flue gas will contain some of the input coal carbon. The carbon input in the feed coal is 3.4 million tons per year (MMTPY). The carbon residing in the ultra clean F-T fuels is 1.2 MMTPY. In this configuration 2 MMTPY of carbon is removed in the carbon dioxide removal system and is ready for sequestration. The remaining 0.2 MMTPY is emitted in the HRSG stack.

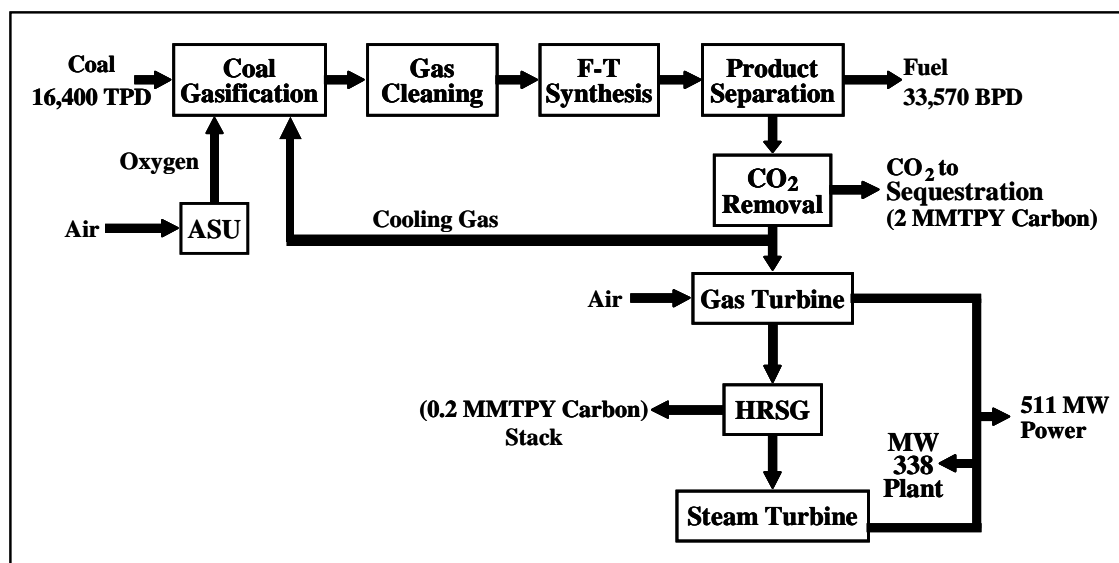


Figure 8. Coproduction with Sequestration: F-T Tailgas Less CO₂

Therefore, approximately 6 percent of the input carbon is emitted in the stack in this case. Carbon dioxide removal and compression requires energy, and of the total gross power generated (849 MW), 338 MW are used in the plant leaving 511 MW for sales.

Figure 9 shows an alternate configuration where, after removal of carbon dioxide, the F-T tail gas is sent to a pressure swing adsorber (PSA) unit to separate hydrogen. Because iron-based F-T catalyst is used in the F-T unit, internal shift occurs producing a large

proportion of hydrogen in the F-T tail gas. The separated hydrogen is combusted in the gas turbine. PSA let down gas is recompressed and used as gasifier cooling gas. A portion of this stream is bled off to limit build up of nitrogen. Combustion of this bleed stream is the only source of carbon dioxide emitted from the plant. This amounts to only 0.05 MMTPY of carbon or only 1.4 percent of the feed carbon in the coal. The stack gas from the HRSG unit contains no carbon containing species because the gas turbine is combusting only hydrogen. In the carbon dioxide removal system, 2.15 MMTPY of carbon is concentrated prior to sequestration. Internal plant power requirement is 364 MW leaving 467 MW for sales.

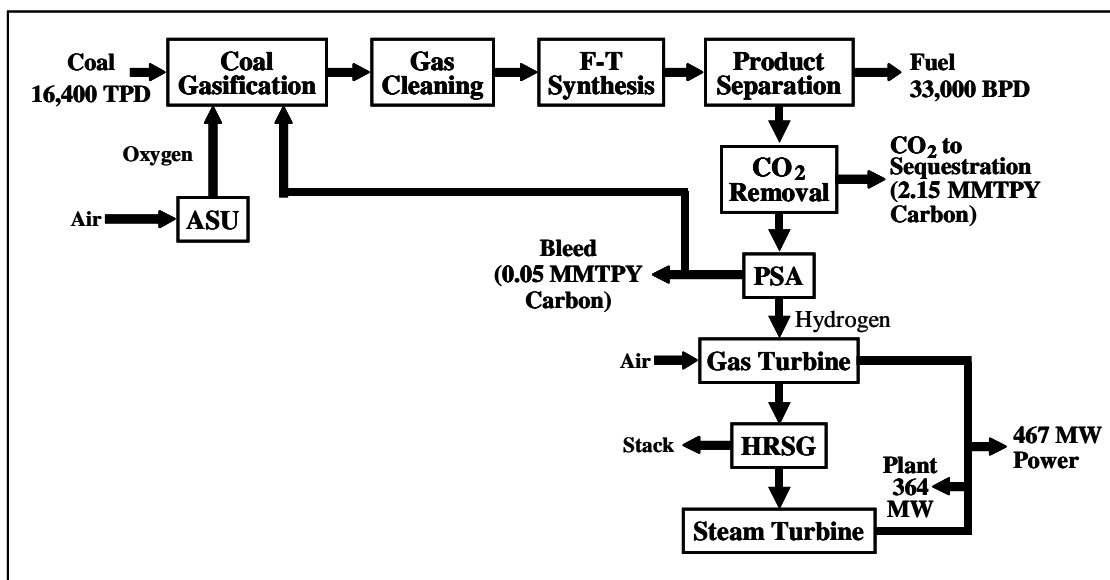


Figure 9. Coproduction with Sequestration: Hydrogen-Fired GT

Figure 10 shows another carbon sequestration configuration. In this case, the F-T tail gas is sent to the gas turbine combustor where it is combusted with pure oxygen instead of air. The stack gas exiting the HRSG, therefore, contains only carbon dioxide and water vapor with no nitrogen dilution. After water removal, the stack gas is almost pure carbon dioxide. This steam is split into two separate streams. One is recycled to the gas turbine where the carbon dioxide is used as the working medium. The other stream is sent to sequestration. In this configuration, all of the carbon can be sequestered with no net carbon dioxide emissions from the plant. Plant internal power required is 554 MW, mostly because of the larger air separation unit required. Net power for sales is 527 MW.

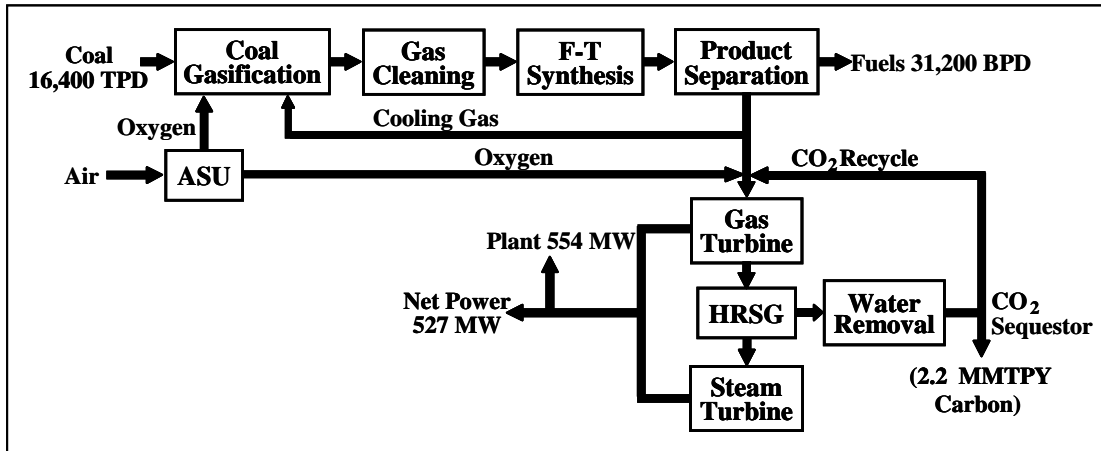


Figure 10. Coproduction with Sequestration: Oxygen-Blown GT

Economics for Coproduction of Liquid Fuels and Power:

Table 1. Coproduction Configurations with Sequestration GE H Turbine Power Plant

Case	1	2	3	4
Sequestration	No	Yes	Yes	Yes
Turbine Fuel	Tailgas	Tailgas Less CO ₂	H ₂ From Tailgas	Tailgas
GT Oxidant	Air	Air	Air	Oxygen
F-T Liquids BPD	33,200	33,570	32,970	31,200
Gross Power MW	989	848	839	1081
Net Power MW	697	510	475	527
Capital \$MM	2,162	2,244	2,573	2,463
Efficiency (HHV)	59.9%	56.4%	54.9%	53.5%
Fuels RSP \$/BBL (No Premium)*	29.16	30.17	36.87	33.91
Carbon Emissions Tons Per Year	2,199,570	201,331	48,408	0
C emissions Percent of Input	64.9	6.2	1.4	0
Carbon Saved Tons Per year**	0	490,000	640,400	695,700

*RSP to realize a ROE of 15 percent with assumptions in Table 2. Assuming a coproduced power value of \$35.6/MWh for case 1 (no sequestration) and \$53.6/MWh for cases 2, 3, and 4 (with sequestration).

**Savings are relative to power generation using NGCC and fuels production from crude oil.

Table 1 shows a summary of the large-scale coproduction configurations. These include: case 1 with no sequestration (see Figure 7), case 2 with carbon dioxide removal from the F-T tail gas (see Figure 8), case 3 using hydrogen in the gas turbine (see Figure 9), and case 4 combusting the gas turbine fuel with oxygen (see Figure 10). Greater amounts of carbon are sequestered in changing from case 1 to case 4. In all of these cases, it is assumed that the combined cycle power plant contains a General Electric H series gas turbine. These cases are described in more detail below. Because these plants are large and have five trains of gasification, the capacity factor is assumed to be 90 percent.

For the no sequestration configuration (case 1), the capital cost of the coproduction plant is estimated to be about \$2.2 billion. Overall, HHV efficiency is about 59 percent. Gross electric power production is nearly 1000 MW. Parasitic power required is nearly 300 MW leaving 700 MW for sales. Ultra clean liquid fuels production is over 33,000 BPD. The required selling price (RSP) of the liquid fuels from this coproduction plant to realize a 15 percent ROE is about \$29 per barrel assuming no premium over crude. If it is assumed that these ultra clean fuels command a premium of \$5 per barrel over crude because of the fact that they are zero sulfur diesel and naphtha, then the RSP on a crude oil equivalent (COE) basis is \$24 per barrel.

In this analysis, for those coproduction cases with no carbon sequestration it is assumed that the value of electric power is equal to the cost of producing it from an advanced NGCC plant with no carbon dioxide sequestration. Parsons has developed a baseline NGCC plant (Parsons Infrastructure and Technology, 1998), and this plant was used as the basis for power price in this study. The Parsons NGCC plant has a heat rate of 6,396 British thermal units per kilowatt-hour (Btu/kWh) and a capital cost of \$494/kW. Using non-regulated financing assumptions (see Table 2) and assuming a capacity factor of 90 percent, the RSP of power produced from this NGCC plant to realize a 15 percent ROE was computed as a function of the natural gas feed cost. Figure 11 shows the RSP of electric power for an NGCC facility to realize a 15 percent ROE as a function of the natural gas prices ranging from \$2 to \$5 per MMBtu. The regression equation describing the straight line in Figure 11 relating the RSP of electric power to the natural gas price for the NGCC plant is calculated as:

$$\text{RSP of power in \$/kWh} = 0.0116 + 0.0064 * \text{natural gas price in \$/MMBtu}$$

Therefore, if the price of the natural gas feed to the NGCC plant is \$2.50/MMBtu, the RSP of the power produced by that plant would have to be \$0.0276/kWh (\$27.6/MWh) to realize a ROE of 15 percent. If the natural gas price were \$3.75/MMBtu, the RSP of the electric power would be \$0.0356/kWh. These RSPs derived from the NGCC plant are used to determine the *value* of the electric power produced in the coproduction plants where there is no carbon sequestration. For cases with carbon sequestration, the coproduced power is

assumed to have a value that is \$18/MWh higher than in the case with no sequestration (reference EPRI report 1000316). In this EPRI report the costs of natural gas combined cycle power with sequestration is estimated to be \$18/MWh higher than with no sequestration. Therefore the coproduced power value for the 15 ROE case will be $\$35.6 + \$18 = \$53.6/\text{MWh}$ for cases 2, 3, and 4 with carbon sequestration. Figure 11 also shows the RSP of producing electric power to realize a 15 percent ROE from an IGCC plant. This cost of 35.6 mills per kWh ($\$35.6/\text{MWh}$) is independent of the price of natural gas because coal is the only feedstock to the IGCC plant. However, as shown in Figure 11, when natural gas is $\$3.75/\text{MMBtu}$, both the IGCC plant and the NGCC plant realize the same 15 percent ROE. This occurs at an electric power price of $\$35.6/\text{MWh}$ for plants with no sequestration.

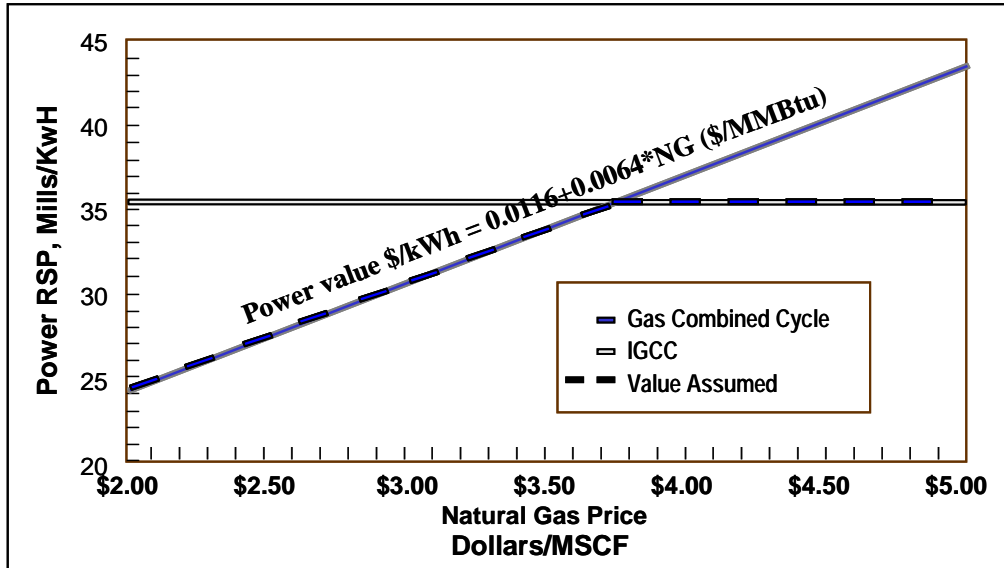


Figure 11. Relationship of Required Selling Price of Power to Natural Gas Price

The economics of case 1 is shown graphically in Figure 12. Here the ROE is plotted against the natural gas price in $\$/\text{MMBtu}$. As mentioned above, the natural gas price determines the value of the electric power produced by the coproduction plant. When the natural gas price exceeds $\$3.75$ per MMBtu, the electric power value remains fixed at 35.6 mills per kWh (this is the power value assumed in Table 1 Case 1). This provision is used because at that price of gas the lowest cost electric power producer will be an advanced IGCC plant (see Figure 11). The value of the liquid fuels coproduced is shown by the band from $\$24$ to $\$28$ per barrel, the so-called OPEC target world oil price (WOP) range.

Figure 12 clearly shows that coproduction realizes a greater ROE than an IGCC plant until natural gas prices exceed \$3.75/MMBtu. If the WOP is greater than \$24 per barrel, the coproduction plant will always realize a higher ROE than the IGCC plant that only produces electricity.

Table 2. Financial Assumptions

Debt: Equity	67:33 percent
Return on Equity (ROE)	15 percent
Debt Interest	8 percent
General Inflation (Coal de-escalation of 1.5 percent below general inflation)	3 percent
Plant Life	25 years
Depreciation (Double declining balance)	16 years
Federal Tax Rate	34 percent
State Tax Rate	6 percent

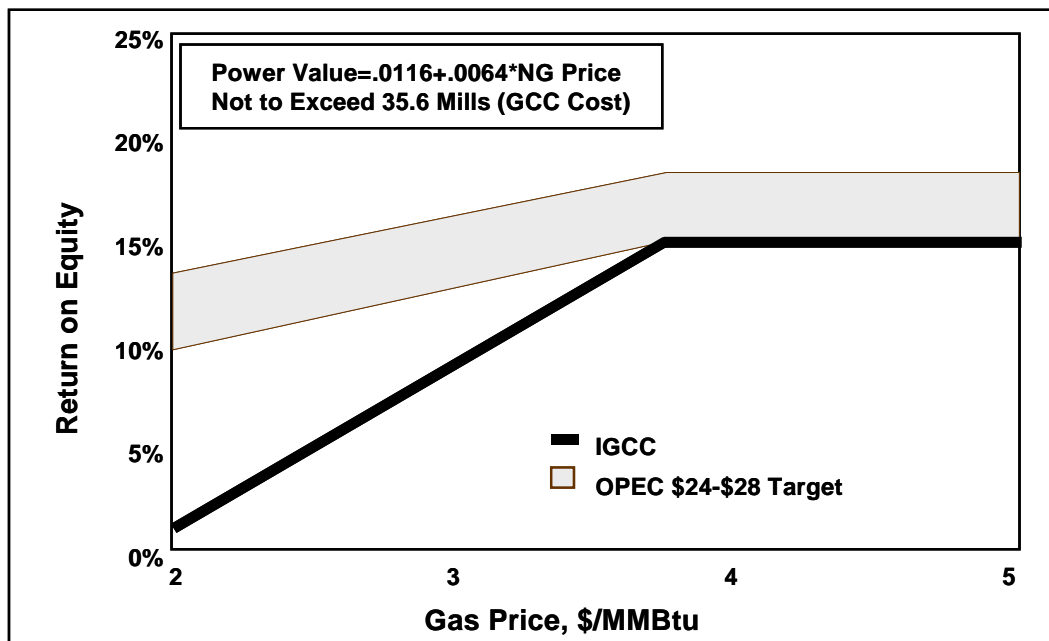


Figure 12. Return on Equity for IGCC and Coproduction Plants vs. Natural Gas Price (no Sequestration)

Figure 13 shows the ROE for this plant as a function of the WOP. This assumes that the ultra clean fuels command a premium of \$5 per barrel over crude oil. When the crude oil price is \$24 per barrel the ROE for this coproduction plant is 15 percent. This also assumes that the electric power can be sold for 35.6 mills per kWh (equivalent to a natural gas price of \$3.75 per MMBtu).

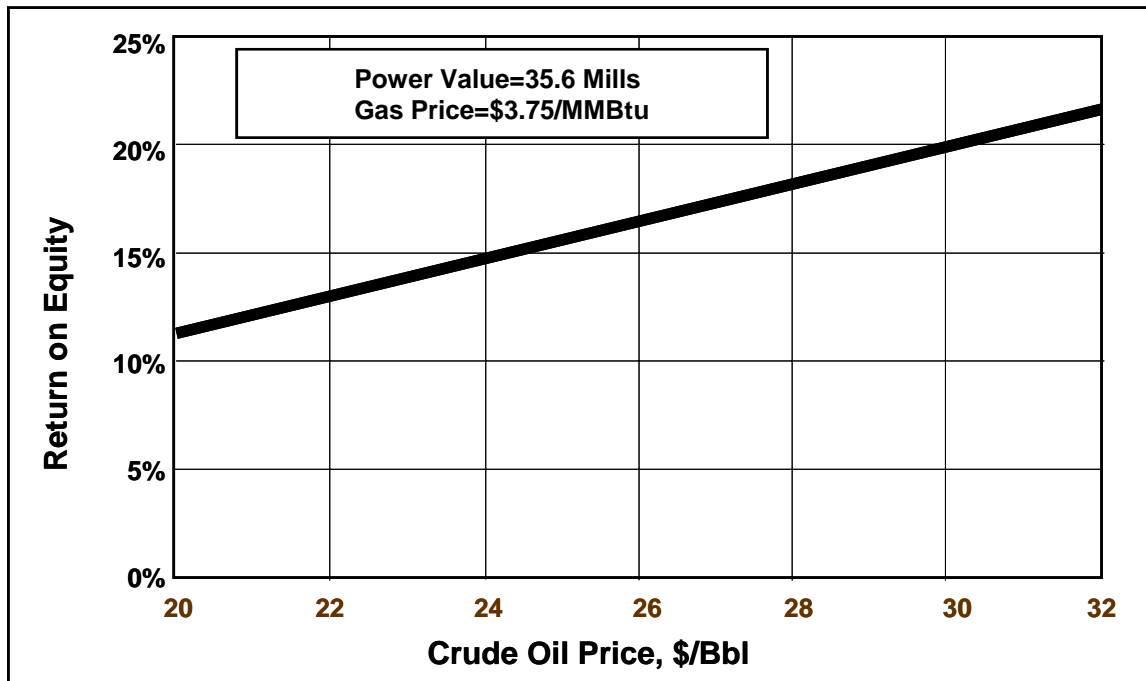


Figure 13. Return on Equity for Coproduction vs. Crude Oil Price

Economics for Coproduction of Liquid Fuels and Power with Carbon Sequestration:

The economics of coproduction with sequestration was analyzed for case 2 where the carbon dioxide was removed from the F-T tail gas and sequestered (see Figure 8). In this configuration sequestration is not complete and 6.2 percent of the incoming carbon in the coal is vented to the atmosphere. The results of this economic analysis are shown in Figure 14. This shows the ROE plotted against the crude oil price for this coproduction plant with sequestration for two cases. The lower line on the figure shows the ROE for this plant with no credit a situation similar to that of Figure 13 for the plant with no sequestration. The lower line on Figure 14 shows the resulting ROE that could be realized if the plant could qualify for a Section 29 tax credit of \$0.50 /MMBtu of synthesis gas. The economics would be greatly improved as shown if a Section 29 credit could be applied. However, in spite of

the higher capital for the sequestered plant and the lower overall efficiency, the resulting economics is very similar to that of case 1, the plant with no sequestration. This is because of the assumption that the value of the coproduced electric power is much higher at \$53.6/MWh rather than \$35.6 in the non-sequestered case.

Table 1 also shows two other configurations for carbon dioxide sequestration. In case 3, the F-T tailgas is shifted to hydrogen and this is burned in the gas turbine combustor (see Figure 9). In this case only 1.4 percent of the feed carbon is vented to atmosphere. However, the cost of this configuration is greater than all of the other sequestration cases and the overall plant efficiency is about 8 percent lower than the base case (case 1). In case 4 (Figure 10), the F-T tailgas is combusted with oxygen in the gas turbines and some of the carbon dioxide combustion product is recycled to the gas turbine to act as the working fluid. This results in total carbon sequestration and the coproduction plant is a zero emissions facility. The capital cost of this configuration is \$2.46 billion, or 14 percent higher than case 1. The overall efficiency is about 11 percent lower than case 1.

Table 1 also shows the tons per year of carbon saved by these three sequestration configurations. The carbon savings are compared to generating electric power using a natural gas combined cycle (NGCC) plant and providing the liquid fuels from petroleum crude. Details of the capital and operating costs for the configurations shown in Table 1 are given in the appendix.

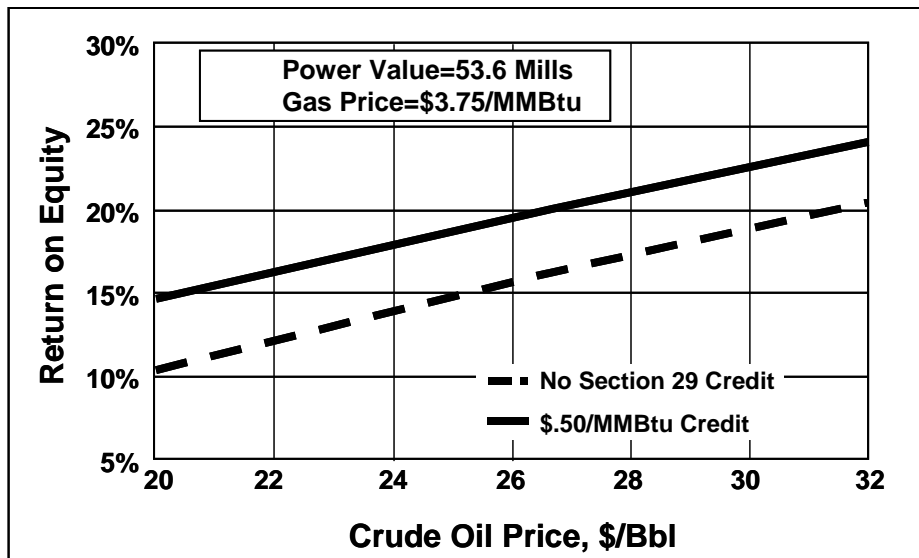


Figure 14. Return on Equity for Coproduction Plant vs. Crude Oil Price (Case 2)

The Technology Base for Hydrogen Production from Coal:

Table 3 summarizes three cases that coproduce electric power and hydrogen from coal.

Table 3: Summary of Coproduction Cases for Hydrogen and Power:

	CASE 5	CASE 6	CASE 7
CARBON SEQUESTRATION	NO	YES (95%)	YES (100%)
HYDROGEN MMSCFD	149	153	153
COAL T/D (AR)	6000	6000	6000
EFFICIENCY (%HHV)	62.4	56.5	59
NET POWER MW	475	358	417
POWER VALUE (MILS)	35.6	53.6	53.6
CAPITAL \$MM	910	950	945
RSP OF HYDROGEN \$/MMBTU	5.42	5.64	3.88

Notes:

- 1) Coal cost is \$29/ton and the assumed capacity factor is 85 percent.
- 2) For case 5 with no sequestration, the coproduced power value is assumed to be \$35.6/MWh based on the cost of power production from Natural Gas Combined Cycle (NGCC) plants if natural gas costs \$3.75/MMBtu. In cases where there is carbon sequestration (cases 6 and 7), the coproduced power is assumed to have a value of \$53.6/MWh based on an additional cost of power production from Natural Gas Combined Cycle (NGCC) plants with sequestration of 18 mills/kWh (reference EPRI report 1000316).
- 3) For cases with sequestration it is assumed that \$10 per ton of carbon is added for sequestration after the concentrated carbon dioxide stream has been isolated, and the carbon dioxide stream is compressed to 2000 psi.
- 4) For Case 7, the membrane configuration assumed is adapted from the Parsons study reference "Hydrogen Plant Cost Comparisons" letter report Sept 2000.

In Case 5, (see Figure 15) two trains of advanced entrained gasification are used. One train produces synthesis gas to feed a pressure swing adsorber (PSA) unit for hydrogen separation and the other train makes synthesis gas to feed a combined cycle power plant. The PSA tail

gas is compressed and also fed to the gas turbine. There is no sequestration in this case. Capital cost is estimated to be \$910 million and the RSP of the hydrogen is estimated to be \$5.42/MMBtu if the coproduced power can be sold for 35.6 mills.

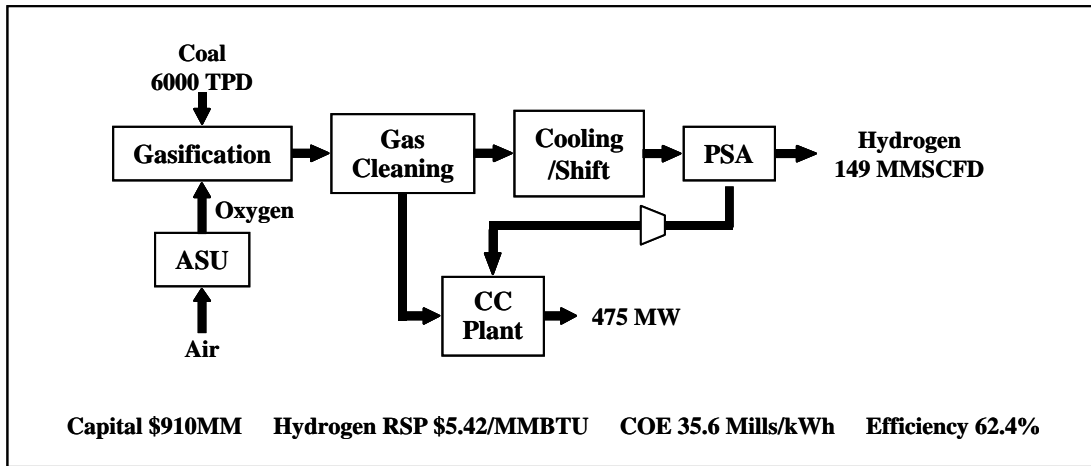


Figure 15: Case 5: Coproduction of Hydrogen and Power (no sequestration)

Case 6, (see Figure 16) is similar to Case 5 except that about 95 percent of the carbon dioxide is sequestered after removal in the amine system. Capital cost is estimated to be \$950 million for this coproduction facility and the RSP of the coproduced hydrogen is estimated to be \$5.69/MMBtu if the coproduced power can be sold for 53.6 mills.

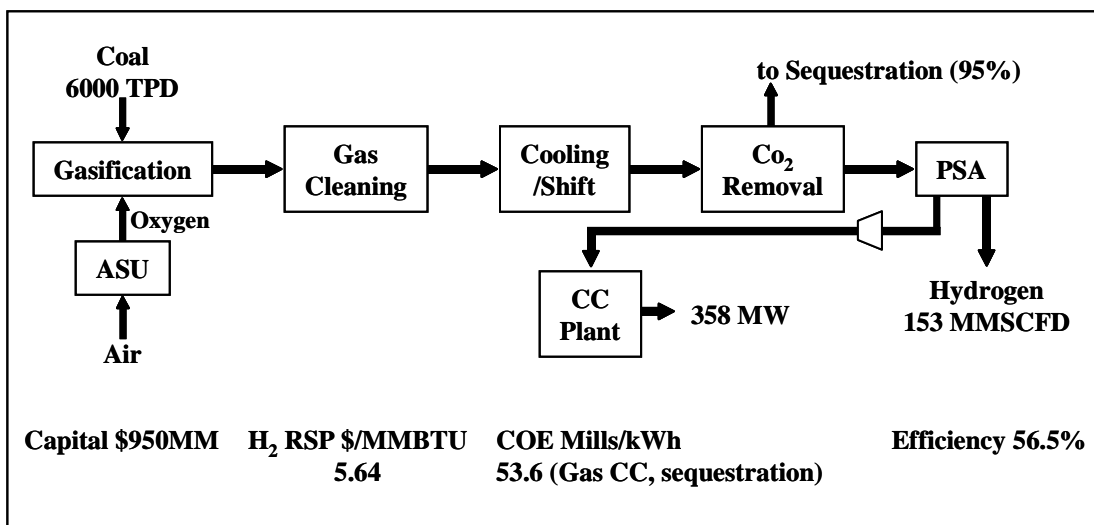


Figure 16: Case 6: Coproduction of Hydrogen and Power (sequestration)

The overall configuration for Case 7 is shown in Figure 17. Two trains of gasification are used to provide synthesis gas to a ceramic membrane hydrogen separation device (HSD). This is assumed to be similar to a high temperature, ceramic K25-type membrane system under development at the Oak Ridge National laboratory (ORNL). It is assumed that the differential hydrogen partial pressure across the membrane must be 100 psi in order to maintain a viable permeance. It is also assumed that the syngas in contact with the membrane will be in shift equilibrium. The hydrogen separated by the membrane is recompressed and split into two streams. One becomes the hydrogen product and the other is sent to a hydrogen-fired gas turbine combined cycle system to produce the power. The non-permeate stream from the membrane is sent to a gas turbine where it is combusted with oxygen. The carbon dioxide produced by combustion of the non-permeate steam is sequestered. Preliminary analysis shows that the capital cost of the membrane system is equal to that of a similar size PSA unit (Judkins). Capital cost for this plant is estimated to be \$945 million and the RSP of the hydrogen is estimated to \$3.88/MMBtu if power is sold for 53.6 mills/kWh.

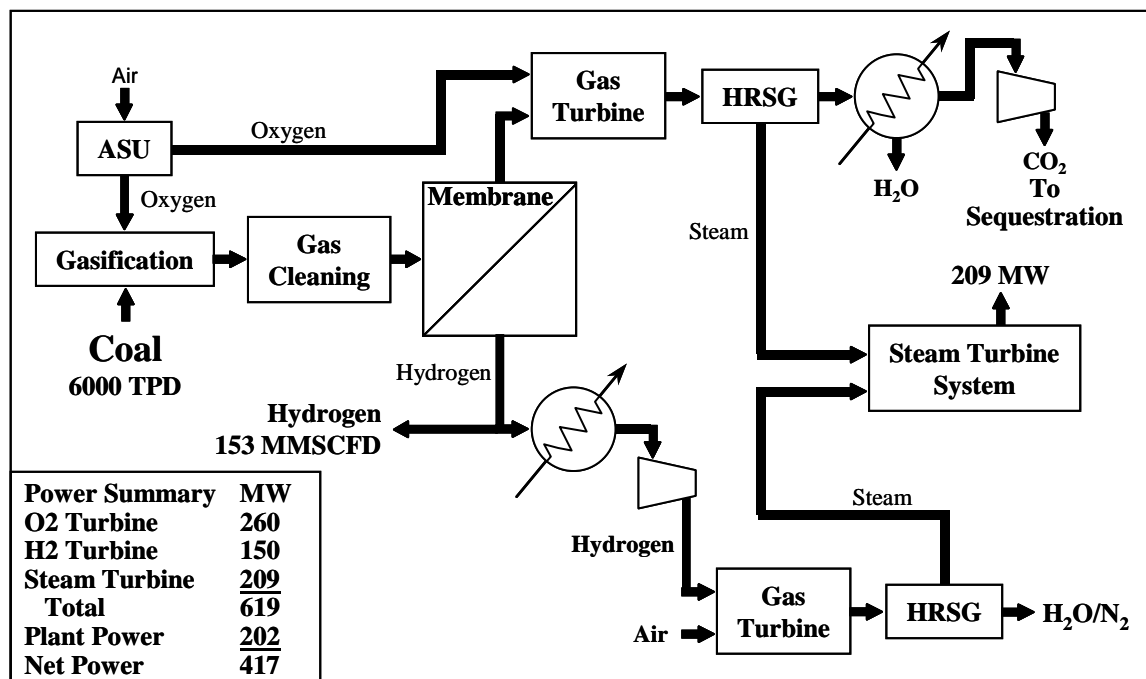


Figure 17: Case 7: Coproduction of Hydrogen and Power using a 600°C Hydrogen Membrane Separation System

The Technology Base for Production of Ultra Clean Liquid Fuels, Hydrogen, and Electric Power from Coal:

If all three products are required in a coproduction facility with carbon sequestration, these can be produced in a configuration such as is shown in Figure 18. In Figure 18, after product separation, the F-T tail gas is sent to carbon dioxide removal where approximately 64 percent of the input carbon is removed for subsequent sequestration. The tail gas from carbon dioxide removal is then split into two streams. One stream is sent to a PSA unit for hydrogen recovery, and 153 MMCSFD of hydrogen is produced. The let down from the PSA unit is compressed and sent to the gas turbine combustor of the combined cycle power plant. The other stream is sent directly to the gas turbine in the combined cycle plant. The flue gas exiting the HRSG unit in the combined cycle plant contains about 7 percent of the input carbon. The balance of the feed carbon is sequestered and contained in the F-T product. The capital cost for this facility is estimated to be \$2,158 million, overall efficiency is 58.5 percent (HHV), and the RSP of the coproduced hydrogen is \$5.47/MMBTU if it is assumed that the value of the F-T liquids are \$30.17/BBL (given by case 2 above) and the value of the coproduced power is \$53.6/MWH.

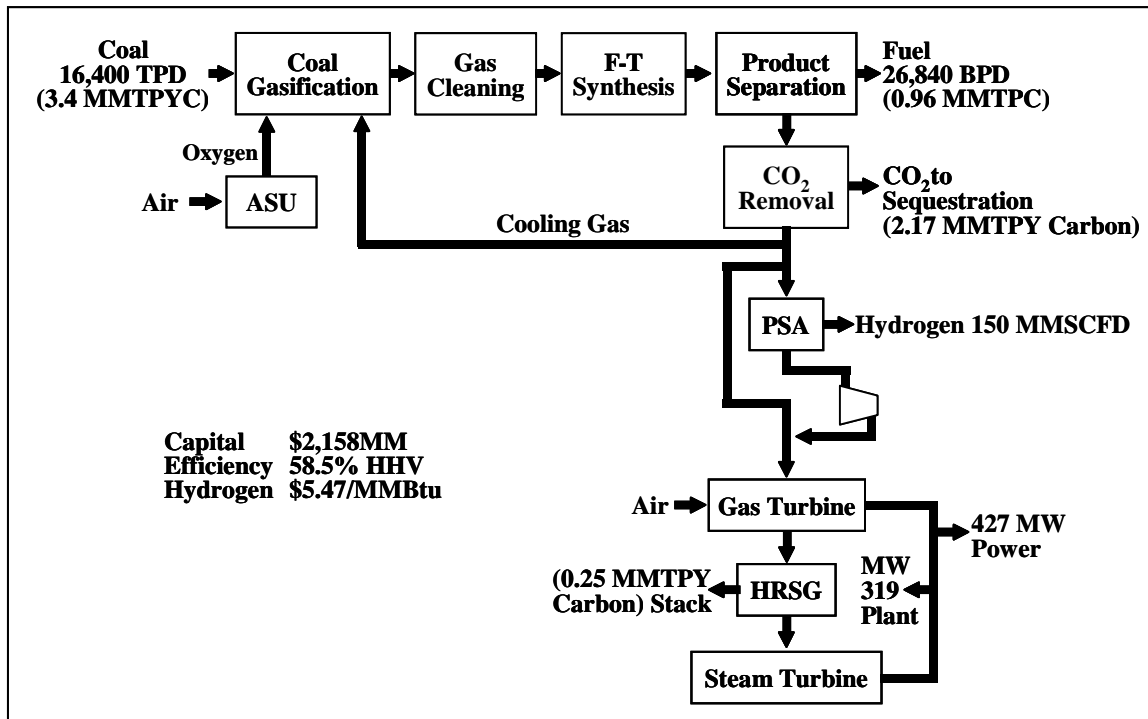


Figure 18: Coproduction of F-T Fuels, Hydrogen and Power with Sequestration

Government Role

In a highly developed and industrialized society like the U.S., the availability of clean, affordable energy is essential for sustaining economic growth, social stability, and public health. A critical and appropriate role for government is to help promote the development of technologies that will provide this nation with such a clean, affordable, and secure energy supply for the 21st century. This government role is an insurance policy designed to protect the U.S. against possible future oil supply disruptions and high oil prices, to limit our dependence on foreign oil imports, and to help ensure an affordable and dependable supply of ultra-clean transportation fuels, hydrogen for future fuels, and electric power from domestic resources. In the long term the production of hydrogen from secure domestic resources will enable us to be free from foreign energy imports and firmly place us on the road to a sustainable energy future. The ability to readily capture a concentrated stream of carbon dioxide from these plants for carbon sequestration will allow these plants to be essentially zero emissions facilities.

The development of advanced technologies that can cleanly and efficiently produce ultra clean transportation fuels, gaseous hydrogen, and electric power from *coal with essentially zero emissions is clearly longer-term and higher-risk*. Industry by itself is not willing to conduct the necessary research, development, and deployment activities in these areas without significant and direct government involvement and leadership. There are both *technical barriers and economic risks associated with the deployment of these advanced technologies that convert coal into ultra-clean transportation fuels, hydrogen and power*. However, with the political will, continued R&D, the appropriate incentive mechanisms and government/industrial partnerships these risks and barriers can be overcome. Then, the ability to make clean transportation fuels, hydrogen and power from these domestic resources will be an economically viable option.

Proposed Commercialization Strategy

Because of these technical and economic barriers and risks, government could play a decisive role in assisting the commercial deployment of this coproduction technology. There are many potential strategies that government could use to accomplish this if commercial deployment of this technology is considered to be in the national interest.

One strategy could be to enable the construction and operation of a pioneer, commercial scale demonstration plant. This could be a plant such as is shown in Figure 6. Government could cost share the capital cost with an industrial partnership on a 50:50 basis. Cost to the government would be about \$450 million. Other incentives could be used such as Section 29, investment tax credits, accelerated depreciation, price, purchase, or loan

guarantees, or excise tax exemptions on the ultra clean fuels. This pioneer plant would produce about 7,000 BPD of ultra clean fuels for the transportation sector and about 475 MW of electric power for sales.

Once constructed this pioneer plant would demonstrate the integrated operation of the various components, clean synthesis gas production, synthesis of ultra clean fuels, and electric-power generation in one facility at commercial scale. Products from this plant would be sold to the transportation fuels and power markets for revenue. It is estimated that this plant would generate over \$120 million in net revenue annually. Depending on the financial agreements, a portion of this net revenue could be used to pay back the government investment. Other government income would be generated through payroll and other taxes.

This pioneer facility could also be used as a test bed to demonstrate the performance of emerging technologies. These could include ceramic membranes for oxygen production, advanced gas cleaning processes, catalyst testing, and other novel technologies resulting from a continuing R&D program in clean coal and fuels. In addition, a carbon dioxide removal system could be installed after F-T product separation and the concentrated carbon dioxide stream could be used to test sequestration technologies such as for coal bed methane (CBM) extraction and enhanced oil recovery (EOR). After successful demonstration of the integrated technology with sequestration of carbon, more unit trains could be added to the facility to increase output.

Conclusion

Coproduction of electric power, ultra clean transportation fuels, and hydrogen would appear to be a very promising strategy to cleanly and efficiently utilize our domestic coal resources if the assumptions regarding system performance and costs can be substantiated in commercial practice. The potential for carbon sequestration from these plants would attain the goal of a zero emissions coal conversion facility. Coproduction addresses the national concerns of adequate electricity supply, adequate natural gas supply, and a dependable supply of affordable ultra clean transportation fuels. Advanced coproduction technologies can produce ultra clean transportation fuels, hydrogen for future fuels, and clean electric power with minimal environmental footprint. Coproduction of ultra clean liquid fuels and electric power can be considered an economically viable technology with advanced coal gasification, synthesis, and combined cycle power technologies if the WOP remains above \$25 per barrel and electricity can be sold for at least \$36 per megawatt hour. Continuing R&D will improve the economics further. However, coproduction is an advanced novel concept that involves technical and economic risks that private industry may not be willing to absorb without government assistance in continued R&D, demonstration and deployment.

List of References

Market Based Advanced Coal Power Systems, report prepared by Parsons Infrastructure and Technology for the U.S. Department of Energy, December 1998, report No: 10198.

Evaluation of Innovative Fossil Fuel Power plants with CO2 Removal, EPRI report #1000316, December 2000.

Judkins, Rodney (ORNL) personal communication.

Appendix

Capital and Operating Costs of Coproduction Plants

CASE 1: ALL COAL COPRODUCTION, NO SEQUESTRATION OF CO2

Construction Cost	\$MM(1998)	Capital Cost	\$MM(1998)	Operating Costs	\$MM(1998)
Coal Handling	58	Construction Cost	\$1,670	Coal, 29.4 /ton AR	\$158.3
Gasification/Quench/Cln	590	Home Office, Fee 8.40%	\$140	Catalyst & Chemicals	\$33.4
Air Separation	268	Process Contingency 2.00%	\$33	Labor/Overhead	\$40.4
Sulfur Polishing	24	Project Contingency 14.56%	\$243	Administrative Labor	\$6.5
F-T Synthesis	117	TOTAL DEPRECIABLE CAPITAL	\$2,087	Local Taxes & Ins. @ 0.02	\$42.2
Hydrogen Removal	31			CO2 Sequestration @\$10/TON C	\$0.0
Refining	87	Start-up Costs 2.52% Capital	\$53	Other	\$5.9
Heat Rec/Power Gen	334	Inventory Capital 7.77% GAOC	\$22	GROSS OPERATING COST	\$286.8
Balance of Plant	161			Sulfur, 80 /ton	\$10.8
TOTAL	1,670	TOTAL CAPITAL REQUIRED	\$2,162	Ammonia, 150 /ton	\$0.0
				TOTAL BY-PRODUCT CREDITS	\$10.8
				NET OPERATING COSTS	\$276.1

CASE 2: SEQUESTRATION OF CO2 IN F-T TAILGAS

Construction Cost	\$MM(1998)	Capital Cost	\$MM(1998)	Operating Costs	\$MM(1998)
Coal Handling	58	Construction Cost	\$1,749	Coal, 29.4 /ton AR	\$158.3
Gasification/Quench/Cln	590	Home Office, Fee 8.40%	\$147	Catalyst & Chemicals	\$35.0
Air Separation	268	Process Contingency 2.00%	\$35	Labor/Overhead	\$42.0
Sulfur Polishing	34	Project Contingency 13.53%	\$237	Administrative Labor	\$6.8
F-T Synthesis	117	TOTAL DEPRECIABLE CAPITAL	\$2,167	Local Taxes & Ins. @ 0.02	\$43.8
Hydrogen Removal	34			CO2 Sequestration @\$10/TON C	\$19.7
CO2 Removal	108	Start-up Costs 2.52% Capital	\$55	Other	\$5.9
Refining	81	Inventory Capital 7.77% GAOC	\$23	GROSS OPERATING COST	\$311.5
Heat Rec/Power Gen	304			Sulfur, 80 /ton	\$10.8
Balance of Plant	154	TOTAL CAPITAL REQUIRED	\$2,244	Ammonia, 150 /ton	\$0.0
TOTAL	1,749			TOTAL BY-PRODUCT CREDITS	\$10.8
				NET OPERATING COSTS	\$300.8

CASE 3: CO2 SEQUESTRATION WITH HYDROGEN FUELED GAS TURBINE

Construction Cost	\$MM(1998)	Capital Cost	\$MM(1998)	Operating Costs	\$MM(1998)
Coal Handling	58	Construction Cost	\$1,891	Coal, 29.4 /ton AR	\$158.3
Gasification/Quench/CIn	592	Home Office, Fee 8.40%	\$159	Catalyst & Chemicals	\$37.8
Air Separation	292	Process Contingency 2.00%	\$38	Labor/Overhead	\$48.1
Sulfur Polishing	34	Project Contingency 12.43%	\$235	Administrative Labor	\$7.8
F-T Synthesis	117	TOTAL DEPRECIABLE CAPITAL	\$2,323	Local Taxes & Ins. @ 0.02	\$48.0
Hydrogen Removal	181	Start-up Costs 2.52% Capital	\$142	CO2 Sequestration @\$10/TON C	\$21.8
CO2 Removal	115	Inventory Capital 7.77% GAOC	\$31	Other	\$5.9
Refining	78	TOTAL CAPITAL REQUIRED	\$2,573	GROSS OPERATING COST	\$327.7
Heat Rec/Power Gen	273			Sulfur, 80 /ton	\$10.8
Balance of Plant	150			Ammonia, 150 /ton	\$0.0
TOTAL	1,891			TOTAL BY-PRODUCT CREDITS	\$10.8
				NET OPERATING COSTS	\$317.0

CASE 4: OXYGEN FIRED GAS TURBINE WITH CO2 SEQUESTRATION

Construction Cost	\$MM(1998)	Capital Cost	\$MM(1998)	Operating Costs	\$MM(1998)
Coal Handling	58	Construction Cost	\$1,818	Coal, 29.4 /ton AR	\$158.3
Gasification/Quench/CIn	592	Home Office, Fee 8.40%	\$153	Catalyst & Chemicals	\$36.4
Air Separation	407	Process Contingency 2.00%	\$36	Labor/Overhead	\$46.0
Sulfur Polishing	27	Project Contingency 14.45%	\$263	Administrative Labor	\$7.5
F-T Synthesis	117	TOTAL DEPRECIABLE CAPITAL	\$2,270	Local Taxes & Ins. @ 0.02	\$46.0
Hydrogen Removal	47	Start-up Costs 2.52% Capital	\$135	CO2 Sequestration @\$10/TON C	\$22.7
Refining	82	Inventory Capital 7.77% GAOC	\$30	Other	\$5.9
Heat Rec/Power Gen	311	TOTAL CAPITAL REQUIRED	\$2,463	GROSS OPERATING COST	\$322.7
Balance of Plant	177			Sulfur, 80 /ton	\$10.8
TOTAL	1,818			Ammonia, 150 /ton	\$0.0
				TOTAL BY-PRODUCT CREDITS	\$10.8
				NET OPERATING COSTS	\$312.0

Acronyms

CBM	Coal Bed Methane
CoCo	Coproduction/Cofeed
COE	Crude Oil Equivalent
EIA	Energy Information Administration
F-T	Fischer Tropsch
HHV	High Heating Value
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
MMBPD	million barrels per day
MMTPY	million tons per year
MW	megawatt
NGCC	Natural Gas Combined Cycle
NMHC	Non-methane Hydrocarbon
NOx	Nitrogen Oxide
PM	particulate matter
PSA	pressure swing adsorption
ROE	Return on Equity
RSP	Required Selling Price
SPRO	Strategic Petroleum Reserve
TCF	trillion cubic feet
TPD	tons per day
VOC	Volatile Organic Compounds
WOP	World Oil Price