Process for
Conversion of Coal to
Substitute Natural Gas (SNG)

- **Steam-Oxygen Gasification**
- **Catalytic Gasification**
- **Hydrogasification**
- **Underground Steam-Oxygen Gasification**
- **Underground Hydrogasification (PCM)**

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**PROCESSES FOR CONVERSION OF COAL TO
SUBSTITUTE NATURAL GAS (SNG)**

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Summary

This report covers a review and process comparison of the three major processes for conversion of coal to substitute natural gas (SNG): (1) Steam – Oxygen gasification; (2) Catalytic gasification; and (3) Hydrogasification.

In addition, two of these three processes are compared for underground coal gasification application at depleted coal bedded methane (CBM) sites. The process chemistry, flowsheets, and mass and energy balances are presented.

An economic analysis, including capital investment and production cost estimates is given. A critical comparative evaluative analysis of the coal to SNG process is made.

The information presented indicates that for above ground conversion of coal to SNG, hydrogasification is the most thermally efficient process, reaching 80%, has the least CO_2 emission and is the most economical process, producing SNG for \$4.61/MSCF. For underground depleted CBM well conversion of the unminable coal seam, the hydrogasification process, applied to multiple wells using the latest capital investment for methane reforming for the hydrogen production, can produce SNG for as low as \$1.44/MSCF. This value yields a large profit margin considering current natural gas market price is reaching \$9.00/MSCF.

A limited field test is recommended at a depleted CBM site and is described to prove out the system at a cost of about \$1 million.

Introduction

Because the increasing demand for natural gas (methane) in the United States and the limited domestic supply, foreign natural gas imports have grown and the cost has risen to current values

of \$6 and \$9 / MSCF. Unconventional sources such as coal bedded methane (CBM) are increasing in supply importance. A singularly large indigenous energy resource in the United States is coal. It therefore becomes prudent to examine the technology and economics of processes for conversion of coal to substitute natural gas (SNG), which would open another source of supply for methane. Table 0 lists important reasons for converting U.S. coal to SNG.

Process Description

There are at least 5 process methods for conversion of coal to SNG.

1. Steam-Oxygen Gasification

2. Catalytic Steam Gasification

3. Hydrogasification

4. Underground Steam-Oxygen Gasification

5. Underground Hydrogasification

1. Steam-Oxygen Gasification

FIG. 1 shows a process flow sheet and Table 1 gives the process chemistry, mass balance and energy balance for the steam-oxygen gasification process. This process is demonstrated in the North Dakota Gasification Plant in Beulah, North Dakota, where approximately 20,000 T/D of lignite is converted to 150×10^6 SCF of methane (SNG). (S. Stelter, "The New Synfuels Energy Pioneers," published by Dakota Gasification Co., Beulah, North Dakota (2001)). The calculated thermal efficiency based on data in the Table 1 indicates a thermal efficiency of 61.9% for conversion of the heating value of lignite to the heating value of the methane produced. The capital investment for the plant is high because of the need for an air liquefaction plant, a steam-oxygen coal gasifier, and a catalytic methanator.

It is estimated that the capital investment is of the order of \$6,250 / MSCF/D of methane produced, determined by updating the North Dakota plant investment. For estimating the

production cost, the financial factors used previously (HCEI-11-04-2 PCM for SNG Production, Cost Estimate (November 25, 2004)) are adopted here.

Production Cost based on $12 / ton lignite = $0.73 / MMBTU and Thermal Efficiency = 61.9% is calculated as follows:

Factor	Calculation	$ / MSCF
Lignite	= 0.73 / 0.619 =	1.18
Fixed Charges	= (0.20 x 6250) / (0.8 x 365) =	4.28
O&M	= 0.15 x 4.28 =	0.64
Production Cost		6.10

2. Catalytic Steam Gasification

FIG. 2 shows a process flow sheet and table 2 gives the process chemistry and mass and energy balance for catalytic steam gasification of lignite. The process was originally developed by Exxon in the 1970s. (R.F. Probstein and R.E. Hicks, Synthetic Fuels, pp. 195-201, pH Press, Cambridge, MA (1990). The catalyst is potassium carbonate used in large quantities, amounting to about 20% by weight of the feedstock, which combines with the coal ash, and has to be separated and recovered from the alumina and silica in the ash. It is estimated that the energy requirement for the recovery process is equivalent to 0.05 moles CH_4 per mole of lignite. Catalytic gasification requires less energy input to the gasifier than steam-oxygen gasification and the methane is produced directly. There is no requirement for an oxygen plant and a methanator. The capital investment would, therefore, be about 75% of the investment in the steam-oxygen gasification plant, which results in a capital investment of $4,688 / MSCF per day. The catalyst cost assumes that 1% of the weight of the coal carrying 20% catalyst is lost and has to be replace at $500 / ton of K_2CO_3.

Production Cost Based On $12 per ton lignite = $0.73 / MMBTU and thermal efficiency = 71.4%

Factor	Calculation	$ / MSCF
Lignite	= 0.73 / 0.714 =	1.02
Fixed Charges	= (0.20 x 4688) / (0.8 x 365) =	3.21
O&M	= 0.15 x 3.21 =	0.48
Cost of Catalyst	=	0.41
Production Cost		5.12

3. Hydrogasification

FIG. 3 shows the process flow sheet and Table 3 gives the mass balance and energy balance for the hydrogasification of lignite to produce substitute natural gas (SNG). Much laboratory data is available on coal hydrogasification and a 10 T/hr pilot plant has been operated in Germany in the early 1980s. (S. Lambertz, et al., "Recent Operational Results of the High Temperature Winkler (HTW) and Hydrogasification (HKV) Process," presented at Second EPRI Conference on Synthetic Fuels in San Francisco, CA (April 1985)). The main feature of this process is that the hydrogasification is exothermic, which makes the process thermally energy efficient. The main problem is the necessity of making up for the deficiency of hydrogen by reforming part of the methane produced in the hydrogasifier.

The thermal efficiency of the process is 79.6%, which is 30% higher than the steam-oxygen gasification.

It is estimated that the capital investment for this plant is 75% of that of the steam-oxygen plant - $4,688 / MSCF per day, about the same as the catalytic gasification process.

Production cost estimate is based on $12 / ton lignite = $0.73 / MMBTU:

Factor	Calculation	$ / MSCF
Lignite	= 0.73 / 0.796 =	0.92
Fixed Charges	= (0.20 x 4688) / (0.8 x 365) =	3.21
O&M	= 0.15 x 3.21 =	0.48
Production Cost		4.61

The estimated production cost is 25% lower than the steam-oxygen gasification plant and 10% lower than for the catalytic gasification plant.

4. Underground Steam-Oxygen Gasification of Coal (UCG)

This process is the same as the above-ground steam-oxygen gasification of coal with the exception that two boreholes are drilled into a coal seam: one is an injection borehole and the other is an extraction borehole. (C.R.F. Probstein and R.E. Hicks, Synthetic Fuels, pp 202-208, pH Press, Cambridge, MA (1990)). Fracturing the coal seam between the boreholes is accomplished by explosives or directional drilling to provide a path for the steam and oxygen between the injection and extraction boreholes. The oxygen permits burning the coal, which creates the temperature and pressure and provides the energy for the steam to endothermically react with the coal in the seam. Oxygen instead of air avoids dilution of the gases with nitrogen.

The gasification reaction produces carbon monoxide and hydrogen synthesis gas. The sulfur and nitrogen in the coal are converted to H_2S and NH_3, which are extracted with the synthesis gas. Above ground, the sulfur and nitrogen compounds and any entrained coal or ash particulates are removed using hot gas cleaning operations.

The hydrogen to carbon monoxide ratio in the extracted reaction gas is adjusted by water gas shift to provide a 3 to 1 ratio of hydrogen to carbon monoxide. This ratio is needed to covert the gas to methane in a catalytic methanator. The methane reaction is exothermic and the heat generates steam for the process. The water produced in the methanator is condensed to produce a concentrated substitute natural gas (SNG) product for pipelining.

The thermal efficiency for this process is 61.9%. FIG. 4 is a schematic of the underground steam-oxygen gasification of coal process.

By eliminating the mining of the coal, but including underground site preparation, it is estimated that the capital investment for steam-oxygen gasification is reduced to $6095 / MSCF/D of methane. Continuous operation, gas storage and redundant equipment can provided a high capacity factor.

The production cost is calculated as follows:

Factor	Calculation	$ / MSCF
Fixed Charges	= (0.20 x 6095) / 365 =	3.34
O&M	= 0.15 x 3.34 =	0.50
Production Cost		3.84

5. Underground Hydrogasification of Coal (aka Pumped Carbon Mining, PCM)

The underground hydrogasification of coal for SNG production is similar to the above ground process with the exception that the hydrogasification takes place underground. This process is especially useful for unminable coal seams and where methane is produced from coal bedded methane (CBM) in these seams. (HCE, LLC Report, HCEI-10-04-3rl, "Pumped Carbon Mining (PCM) for Substitute Natural Gas Production (October 4, 2004)).

The coal seam is accessed by two vertical boreholes spaced a distance apart; one is the intended injection borehole and the other is the intended extraction borehole. A flow connection is then established between the boreholes. This can be accomplished by a number of means, one of which is by horizontal drilling between the holes.

The existing methane resource in the coal seam is removed through the extraction borehole using established coal bedded methane extraction procedures. In this process, the water in the seam is also removed and this is beneficial to the subsequent hydrogasification process.

The hydrogasification process then begins with the injection into the coal seam of heated and pressurized hydrogen. Under these conditions, the hydrogen exothermically reacts with the coal, producing methane and carbon monoxide. Some of the nitrogen and sulfur in the coal is converted to ammonia and hydrogen sulfide. An excess of hydrogen is used to convert the carbon to methane under equilibrium conditions (see HCEI 10-04-3).

The reaction gas flowing out of the extraction borehole is subjected to hot gas cleanup, which removes most of the unwanted contaminant gases and particulates and leaves a methane-rich stream containing hydrogen and carbon monoxide. The methane is separated from the other gases by pressure swing adsorption (PSA) or cryogenically. Since there is insufficient hydrogen in the coal to combine with the carbon in the coal to form methane, the hydrogen must be produced by reacting part of the methane produced with water in a steam-reforming operation. The net methane produced results in a thermal efficiency of 79.6% for conversion of the energy in lignite to the energy in the methane.

When connecting the hydrogasification to coal bedded methane (CBM) operations, the underground site preparation cost is borne by the CBM operation and there is no oxygen or methanator investment. This reduces the capital investment to about $4,571 / MSCF/D (HCEI-11-04-2).

The production cost is estimated as follows:

Factor	Calculation	$ / MSCF
Fixed Charges	= (0.20 x 4571) / 365 =	2.50
O&M	= 0.15 x 2.50 =	0.38
Production Cost		2.88

**Qualitative Comparative Analysis of Processes for
Production of Substitute Natural Gas (SNG) from Coal Resources**

There are at least five processes for conversion of coal to substitute natural gas (SNG) as described previously. The following is a critical qualitative analysis of these processes.

1) Steam Oxygen Gasification of Coal

The steam-oxygen gasification of coal is a well-know process, which has been practiced since the 1940s. Various types of gasifiers have been developed employing steam and oxygen with coal feedstock. The following is a list of the drawbacks in using this process for conversion of coal to SNG:

1.   The steam-oxygen reaction with coal to form synthesis gas (CO and H_2) is highly endothermic.

2.   An oxygen plant is required.

3.   A methanator is required.

4.   The thermal efficiency is low, about 60%.

5.   Capital investment is high.

2) Catalytic Gasification of Coal

Exxon developed this process during the 1970s, operating it in a pilot plant. A full scale production plant was never built because it was not competitive. The features of the process compared to steam-oxygen gasification are as follows:

1.   The catalytic steam reaction is endothermic, but much less so than the steam-oxygen process.

2.   There is no need for an oxygen plant.

3.   There is a huge requirement for catalyst, amounting to as much as 20% of the coal feedstock. Recovery of catalyst, K_2CO_3 from coal ash is costly.

4.   There is no requirement for a methanator.

5.   The thermal efficiency is higher than steam-oxygen gasification, reaching into the 70%.

6.   The capital investment is lower than for steam-oxygen gasification.

3) Hydrogasification of Coal

Hydrogasification of coal for production of methane (SNG) was pilot planted in Germany in the 1970's, but the process was never put into practice at full scale. The features of this process are as follows:

1. The hydrogasification of coal is exothermic, thus requiring no oxygen or steam addition.

2. There is no requirement for a methanator.

3. The process has a high thermal conversion efficiency reaching into the 80%.

4. It is necessary to convert part of the methane back to hydrogen by reforming with steam.

5. The capital investment is lower than for steam-oxygen gasification.

6. There is no requirement for a catalyst.

4) Underground Steam-Oxygen Coal Gasification (UCG)

There has been much research and development on underground coal gasification in the United States and Russia during the 1970s. The features of the process are as follows:

1. Coal mining and preparation for above ground processing is eliminated.

2. Steam-oxygen injection is required underground, which may have safety problems due to incomplete reaction and production of explosive gaseous mixtures in confined spaces.

3. Difficult to control problems with fissures and crossovers to keep inflow and outflow paths separated.

4. An oxygen plant and methanation reactor are required.

5. Thermal conversion efficiency is lower than hydrogasification.

5) Underground Coal Hydrogasification (Pumped Carbon Mining, PCM)

The underground hydrogasification of coal has been proposed in the 1980s, but was never tested. It has been recently proposed in conjunction with coal bedded methane extraction. The hydrogasification is beneficial in configuration with the extraction of methane from unminable coal deposits. The features of the process are as follows:

1. After the coal bedded methane is extracted, the hydrogasification of the remaining coal would increase the production of methane from the coal seam by a factor of 20 or more times that produced from the coal bedded methane recovery operation alone (HCEI-11-04-2).

2. There is no mining or handling of coal for above ground processing.

3. The additional hydrogen needed is produced by steam reforming part of the methane directly produced by hydrogasification.

4. No oxygen or methanator plants are needed, so that the capital investment is lower than steam-oxygen processing.

5. The cost of the preparation of the mine for underground hydrogasification is borne by the coal bedded methane operations.

It should be noted that underground catalytic gasification of coal as developed by Exxon is not feasible because of the large loss of catalyst underground even if it were possible to inject catalyst underground.

Table 4 gives a summary comparison of the various factors for conversion of coal to SNG. Underground hydrogasification of coal (PCM) for SNG appears to have the highest thermal efficiency and lowest production cost.

CO_2 Emissions

Increasing efficiency also has an impact on carbon dioxide emissions. All of these processes essentially emit concentrated carbon dioxide streams, which can be captured and sequestered. However, the higher the thermal efficiency, the lower the carbon dioxide volume and thus the lower sequestration requirements. Thus, the hydrogasification process at 79.6% thermal efficiency emits 59% less carbon dioxide than the steam-oxygen gasification process at a thermal efficiency of 61.9%, as shown in Table 4. It is also possible to sell and sequester the CO_2 in depleted oil wells for enhanced oil recovery (EOR). A large part of the CO_2 is emitted at almost 100% concentration, which can be sequestered directly.

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Pumped Carbon Mining (PCM) Cost Estimate
Based on Large Central Plant Servicing A Number of
Depleted Coal Bedded Methane (CBM) Wells

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As noted in the cost estimate report, HCEI 11-04-2, it is possible to optimize the size of the hydrogen production plant so that it can supply hydrogen to a number of underground hydrogasification wells. The optimized hydrogen plant would collect the gas from a number of extraction boreholes of the wells and deliver hydrogen to the injection boreholes. Insulated piping to and from centralized processing would be utilized to deliver the high temperature and high pressure hydrogen and carbon monoxide to the wells and carry back the methane rich gas to the central processing plant. The central processing plant would contain the hot gas cleanup, heat exchangers, water gas shift and methane and carbon dioxide gas separation and pumping equipment as well as the steam reformer for the hydrogen production. The concept of a central processing plant is important because each well may have variable production. It would become expensive to locate all processing equipment at each such well especially for those wells that had relatively small production capacity.

A rough example of an optimized central processing plant is as follows:

A methane reforming plant producing 100,000 MSCF / D of hydrogen should cost today
approximately $100 million (HCEI-11-04-2). This amount of hydrogen can service the
following capacity of methane produced by the Pumped Carbon Mining or lignite
gasification process following extraction of the coal bedded methane.

Net Methane Production	=	46,000 MSCF / D
Methane to Reformer	=	25,000 MSCF / D
Methane to Furnace	=	9,000 MSCF / D
Total Well Methane Produced	=	80,000 MSCF / D

If the average CBM capacity per well is only 200 MSCF / D (Mike Gatens, Oil & Gas , pp.
41-43, Dec. 13, 2004) and the production of hydrogasified coal is 20 times that of the CBM
capacity, then the central plant can handle gases from about 20 wells, or if the CBM wells
produce an average of 400 MSCF / D, then the central plant can process gas from about 10
wells.

A rough capital and production cost estimate for this capacity is as follows: The flow sheet of
FIG. 5 is followed scaled up to the 46,000 MSCF/D methane production and where only one
central methane reforming plant and one water gas shift reactor is used to connect the CO to H_2
with steam. The highest cost element is the methane reformer. The other equipment is roughly
estimated relative to the reformer.

Capital Investment

Unit	$ Millions
Hot Gas Cleanup	10
Heat Exchanger	10
Water Gas Shift	
(Included in the H_2 plant costs)	---
Gas Separation (PSA or Cryo)	20
Circulator Pumping	10
Methane Reforming for H_2	100
Total Capital Investment	150

Production Cost: (using same financial factors as in HCEI-11-04-2)

Factor	Calculation		$ / D
The underground lignite well preparation			charged to CBM
Fixed Charge = $(0.2 \times 150 \times 10^6) / (365$ D / yr)		=	82,190
Op. & Maint. = $0.15 \times 82{,}190$		=	12,330
	Total Production Cost	=	94,520

Unit production Cost of Methane = 94,520 / 46,000   = $2.05 / MSCF

Thus, it is shown that by centralizing the processing and collecting the gas from a number of wells, the unit methane production cost can be reduced significantly, resulting in a higher rate of return.

New Cost Information

Recently, a paper appeared in the Hydrocarbon Engineering Journal (February, 2004) by C. A. Boyce, M.A. Crews and R. Ritter of Chicago Bridge and Iron Company (CB&I) entitled, "Time for a New Hydrogen Plant?" In it, a comparison is made between old style and a modern hydrogen production plant. The process deals with a plant producing 90 million SCFD of hydrogen based on the steam reforming of natural gas is estimated to cost $50 million.

The new capital investment for the PCM plant based on 100 million SCFD of hydrogen is thus estimated to be $55 million. In contrast, the old capital investment number assumed in the above PCM plant for a 100 million SCFD hydrogen plant was assumed to be $100 million. The reduction in new capital investment is credited to higher efficiency and the use of lower cost gas separation equipment and improved water gas shift units.

A revised PCM production cost estimate based on this new capital investment estimate, which assumes a capital investment of $55 million for 100 million SCFD hydrogen production is as follows:

The PCM central hydrogen plant services 10 to 20 CBM wells, as shown in FIG. 6. The capital investment includes heat exchangers and gas cleanup at the wells and methane separation at the central plant.

Capital Investment

Unit	$ Millions
Hot Gas Cleanup	10
Heat Exchangers (located at each well)	10
Water Gas Shift	
(Included in the H_2 plant costs)	---
Gas Separation (PSA or Cryo)	20
Circulator Pump and Piping	10
Methane Reforming for H_2	55
Total Capital Investment	105

Production Cost: (using same financial factors as in HCEI-11-04-2), 20% fixed charges on investment and 15% for operation and maintenance.

Factor	Calculation	$ / D
Underground lignite well completion		charged to CBM account
Fixed Charge = $(0.20 \times 105 \times 10^6) / (365$ D $/$ yr$)$ =		57,530
Op. & Maint. = $0.15 \times 57,530$	=	8,630
	Total Production Cost	= 66,160

Unit production Cost of Methane = 66,160 / 46,000   = $1.44 / MSCF

Thus a modern methane steam reforming plant to provide the additional hydrogen for hydrogasification of the lignite coal provides a larger margin of profit than the older plant. More definitive design and application of local financing factors can refine and validate the above estimates.

A summary comparison of process parameters for conversion of Coal to substitute natural gas (SNG) is shown in Table 4. It is noted for the three above ground processes, hydrogasification has the highest thermal efficiency at about 80% and at $4.61/MSCF indicates the lowest production cost for SNG production. For underground processing, hydrogasification at $2.88/MSCF is less than the steam-oxygen gasification.

A summary of Production rates and production cost base on various assumptions for underground PCM processing for SNG production is given in Table 5. A single well, which had the highest CBM production rate of 700 MSCF/D is compared to multiple well production at an average per well that produced 200 MSCF/D during its lifetime. An optimized 100,000 MSCF/D hydrogen steam reforming plant can process 20 wells that had the average CBM production rate. By applying the new modern cost of hydrogen plant, the production cost can be reduced from $2.05/MSCF to $1.44/MSCF, thus providing a wide margin of profit from the current market price of natural gas reaching $9.00/MSCF.

Limited Field Test of Pumped Carbon Mining (PCM) for Methane (SNG) Production

As shown above, Pumped Carbon Mining (PCM) of depleted coal bedded methane (CBM) wells for substitute natural gas production (SNG) appears very lucrative in today's natural gas market. To prove out this process, it is recommended that a limited field test be run (HCE, LLC Report, HCEI-3-05-002, "Limited Field Test of Pumped Carbon Mining (PCM) for Methane (SNG) Production," (February, 2005).

The test consists of pumping hydrogen through a depleted CBM well to obtain the following information:

1. determine the optimum concentration of methane in the gas produced as a function of process conditions;

2. loss of hydrogen, if any underground; and,

3. determine the quantity of residual water and methane produced during ambient and warm hydrogen flushing of the depleted well.

The preliminary estimated cost of conducting the test is between $600,000 and $1,000,000, depending on whether a once thru hydrogen system is used or recirculating compressor and condenser is installed for the hydrogen flow. A schematic of the test setup is shown in FIG. 7.

Table 0
Why Convert Coal to
Substitute Natural Gas (SNG)?

1. Coal is Largest Indigenous Energy Resource in the United States.

2. Natural Gas is the Most Convenient and Cleanest Consumer Fuel For Heat, Power & Automotive Use.

3. Transportation and Distribution of Natural Gas by Pipeline are Widely Available and Economical.

4. Natural Gas Resource in the U.S. is Limited.

5. Natural Gas Demand is Increasing – Resulting in Reliance on Imports (Gas from Canada and LNG from Overseas).

6. Natural Gas has Significantly Increased in Cost.

7. Processes for Conversion of Coal to SNG are Increasing in Competitiveness.

8. Coal Bedded Methane (CBM) Production is increasing in Supply.

Table 1
Steam-Oxygen Coal Gasification for Production of Substitute Natural Gas (SNG)

Unit Operations and Process Chemistry
Basis: Lignite Coal

1) Steam-Oxygen Gasification of Lignite

$$CH_{0.8}O_{0.2} + 0.8\ H_2O = 1.2H_2 + CO$$
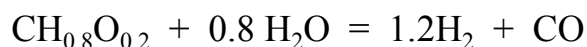
$\Delta H = +38.2$ Kcal/mol lignite – endothermic - 90% lignite conversion

Lignite Combustion - $CH_{0.8}O_{0.2} + 1.1\ O_2 = 0.4\ H_2O + CO_2$ $\Delta H = 110.3$ Kcal / mol
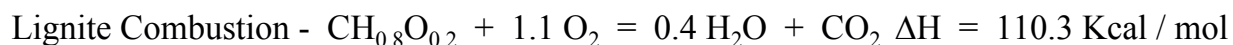
Moles at 80% efficiency $= 38.2 / 0.8\ (110.3) = 0.432$

2) Oxygen Plant – Using an Electricity Powered Cryogenic Process

Energy $= 11.4$ Kcal / g-mol lignite

3) Hot Gas Cleanup – Remove Sulfur and Nitrogen Compounds

4) Water Gas Shift for H_2 Production

$$0.45\ CO + 0.45\ H_2O = 0.45\ CO_2 + 0.45\ H_2$$
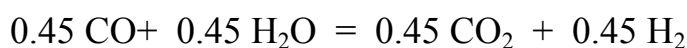
$\Delta H = 0$ – energy neutral

5) CO_2 Separation – Pressure Swing Adsorption - PSA

6) Methanation

$$0.55\ CO + 1.65\ H_2 = 0.55\ CH_4 + 0.55\ H_2O$$
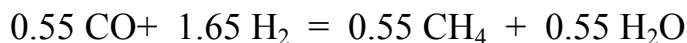
$\Delta H = -33.0$ Kcal – exothermic for steam production

Overall Stoichiometry

$$CH_{0.8}O_{0.2} + 0.7\ H_2O = 0.55CH_4 + 0.45\ CO_2$$
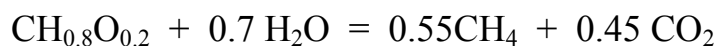
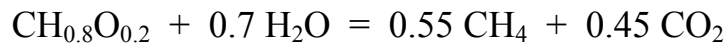$$\text{Thermal Efficiency} = \frac{0.55\,CH_4\ x\,0.9}{(1.0 + 0.432)\ CH_{08}O_{0.2} + O_2\ Plant\ Energy}$$

$$= \frac{0.55\ x\,0.9\ x\,212}{1.432\ x\,110.3 + 11.4}\ X\ 100 = 61.9\%$$

Table 2
Catalytic Steam Gasification of Coal for Production of Substitute Natural Gas (SNG)

Unit Operations and Process Chemistry
Basis: Lignite Coal

1) Catalytic Steam Gasification of Lignite

$$CH_{0.8}O_{0.2} + 0.7\,H_2O = 0.55\,CH_4 + 0.45\,CO_2$$

$$\Delta H = +5.2 \text{ Kcal/mol lignite} - \text{endothermic}$$

In presence of K_2CO_3 catalyst -- 90% Conversion

Catalyst Content is 20% of lignite feedstock by weight

2) Separation and Recovery of K_2CO_3 from ash containing silica and alumina

Takes 0.05 g-mol CH_4 of equivalent energy for process per g-mol lignite

3) Pressure Swing Adsorption or cryogenic separation of CH_4 and CO_2 from H_2 and CO

4) Recycling H_2 and CO and preheating in a methane-fired furnace takes 0.08 mols CH_4 / g-mol lignite

Net CH_4 produced $= 0.55 - 0.05 - 0.08 = 0.42$ g-mol

Thermal Efficiency $= [\,(0.9 \times 0.42 \times 212) / 110.3\,] \times 100 = 72.7\%$
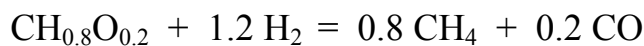
Table 3
Coal Hydrogasification for Production of Substitute Natural Gas (SNG)

Unit Operations and Process Chemistry
Basis: Lignite Coal

1) Hydrogasification of Lignite:

$$CH_{0.8}O_{0.2} + 1.2\ H_2 = 0.8\ CH_4 + 0.2\ CO$$

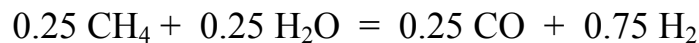$$\Delta H = -9.8\ Kcal/g\text{-}mol\ lignite - exothermic\ \text{--}\ 90\%\ Conversion$$

2) Hot Gas Cleanup. Remove Sulfur and Nitrogen Compounds.

3) Water Gas Shift : $0.2\ CO + 0.2\ H_2O = 0.2\ CO_2 + 0.2\ H_2$

$$\Delta H = 0 - energy\ neutral$$

4) Pressure Swing Adsorption or Cryogenic Separation of CH_4 and CO_2 from H_2 and CO

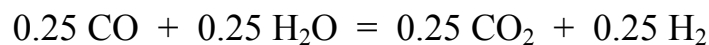(5) Steam Reforming of Methane for H_2 Makeup Production

$$0.25\ CH_4 + 0.25\ H_2O = 0.25\ CO + 0.75\ H_2$$

$$\Delta H = +15.0\ Kcal\ \text{-}\ endothermic$$

(6) Methane Combustion: $CH_4 + 2\ O_2 = CO_2 + 2\ H_2O$

$$\Delta H = 212\ Kcal\ /\ g\text{-}mol - at\ 80\%\ eff.\ CH_4 = 15\ /\ (0.8 \times 212) = 0.09\ g\text{-}mol$$

(7) Water Gas Shift for H_2 production:

$$0.25\ CO + 0.25\ H_2O = 0.25\ CO_2 + 0.25\ H_2$$

(8) CO_2 Separation – PSA

(9) Overall Stoichiometry:

$$CH_{0.8}O_{0.2} + 0.7\ H_2O = 0.55\ CH_4 + 0.45\ CO_2$$
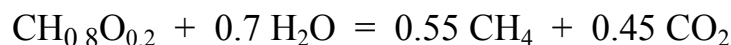
(10) Net CH_4 produced $= 0.55 - 0.09 = 0.46$ g-mol

(11) Thermal Efficiency $= [\ (0.46 \times 212 \times 0.9)\ /\ 110.3\ ] \times 100 = 79.6\%$

Table 4
Comparison of Processes for
Conversion of Coal to Substitute Natural Gas (SNG)

| Item	Steam-Oxygen Gasification	Catalytic Steam Gasification	Hydrogasification	Underground Steam-Oxygen Gasification	Underground Hydrogasification Pumped Carbon Mining (PCM)
Coal Feedstock	Mined, Crushed, Transported	Mined, Crushed, Transported	Mined, Crushed, Transported	Underground Fracturing of Coal Seam	Following Coal Bedded Methane Extraction
Oxygen Plant	Yes	No	No	Yes	No
Methanator	Yes	No	No	Yes	No
Thermal Efficiency	61.9%	71.9%	79.6%	61.9%	79.6%
Catalyst Requirement	No	Yes	No	No	No
CO_2 Emission Lbs CO_2/MSCF	123	78	51	123	51
% Reduction CO_2 From S-O gasif.	0	37	59	0	59
Capital Investment $ per MSCF per day	6250	4688	4688	6095	4571
Production Cost $ per MSCF	6.10	5.12	4.61	3.84	2.88

Table 5
Pumped Carbon Mining (PCM) For SNG Production
Underground Hydrogasification in
Depleted CBM wells in Unminable Coal Seams
Summary of Production Rates and Production Cost

NUMBER OF WELLS	SINGLE - 1	MULTIPLE - 20	MULTIPLE - 20
CBM Methane Production MSCF/D/Well	700	200	200
Net Methane PCM Production MSCF/D	14,000	46,000	46,000
Methane to Reformer MSCF/D	7,600	25,000	25,000
Methane to Reformer Furnace MSCF/D	2,700	9,000	9,000
Plant Cost Millions	64*	150*	105**
Unit Production Cost $/MSCF	2.88	2.05	1.44

*Scaled based on conventional methane reforming plant producing 100,000 MSCF/D of hydrogen costing $100 million.

**Scaled based on recent capital cost of a new modern methane reforming plant for hydrogen production, producing 90,000 MSCF/D of hydrogen costing $50 million.
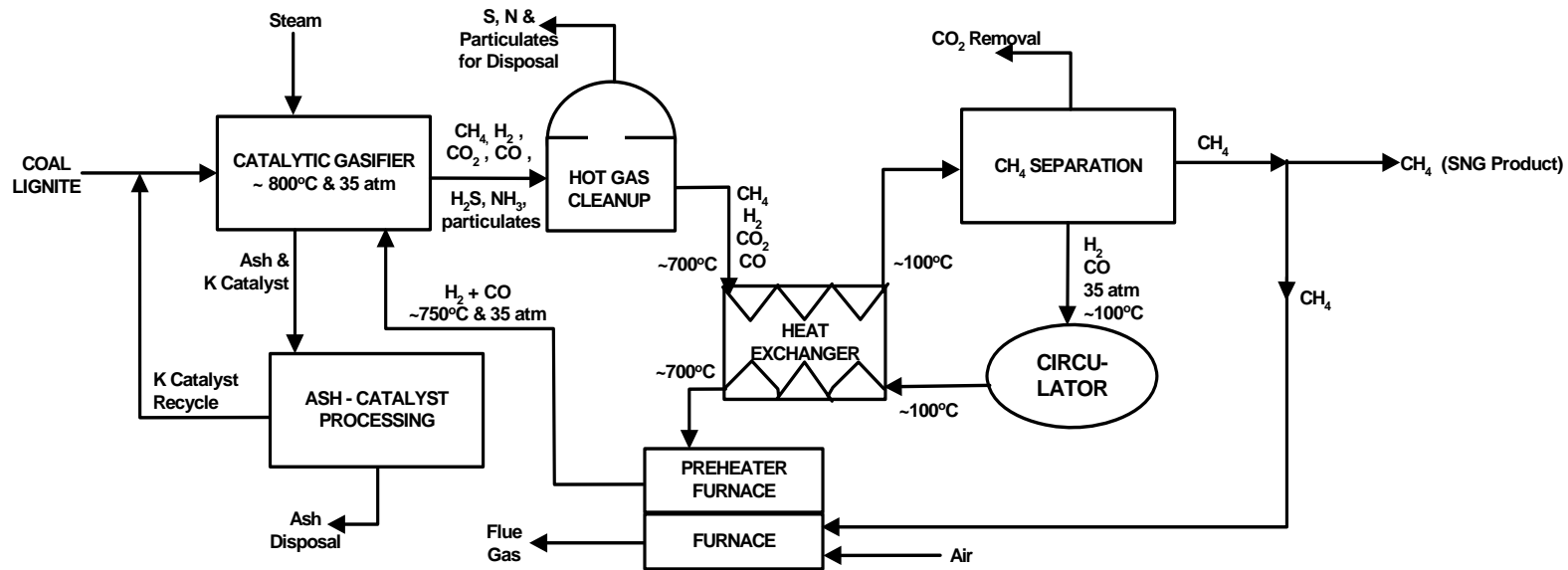
FIG. 1
STEAM-OXYGEN COAL GASIFICATION FOR
SUBSTITUTE NATURAL GAS (SNG) PRODUCTION
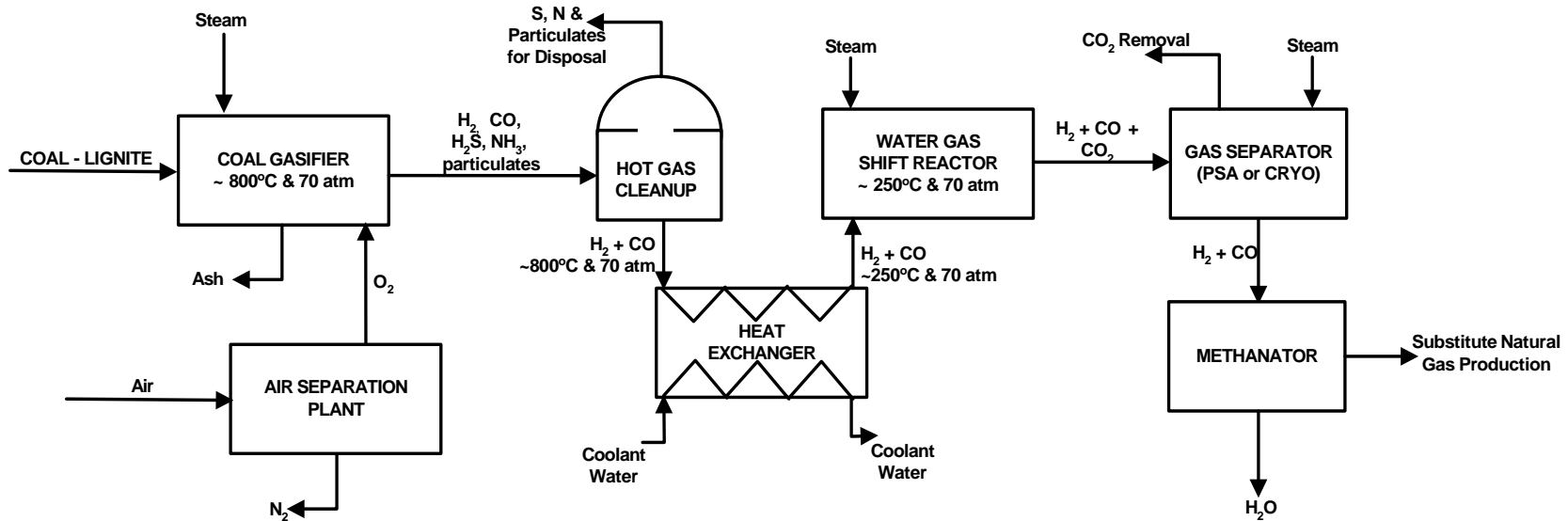
REACTION CHEMISTRY -Calculated Thermal Efficiency = 61.9%

(1) Steam Gasification of Coal Lignite: $CH_{0.8} O_{0.2} + 0.8 H_2O = 1.2 H_2 + CO$ ---   Delta H = + 47.7 Kcal / g-mol lignite - endothermic

(2) Lignite Combustion: $CH_{0.8} O_{0.2} + 1.1 O_2 = 0.4 H_2O + CO_2$ ---   Delta H = - 110.3 Kcal / g-mol

(3) Hot Gas Cleanup removes N, S & particulates

(4) Water Gas Shift $0.45 CO + 0.45 H_2O = 0.45 CO_2 + 0.45 H_2$

(5) Gas Separator, e.g. Differential Pressure Swing Adsorption or Cryogenic Separation, takes out CO_2

(6) Methanation: $0.55 CO + 1.65 H2 = 0.55 CH_4 + 0.55 H_2O$ --- Delta H = - 33.0 Kcal – exothermic for steam production

(7) Overall Mass Balance: $CH_{0.8} O_{0.2} + 0.7 H_2O = 0.55 CH_4 + 0.45 CO_2$

FIG. 2
CATALYTIC STEAM GASIFICATION FOR
SUBSTITUTE NATURAL GAS (SNG) PRODUCTION

REACTION CHEMISTRY -Calculated Thermal Efficiency = 72.7%

(1) Catalytic Steam Gasification of Lignite: $CH_{0.8}O_{0.2} + 0.7 H_2O = 0.55 CH_4 + 0.45 CO_2$ --- Delta H = + 5.2 Kcal / g-mol lignite - endothermic
(2) Hot Gas Cleanup removes N, S & particulates
(3) K_2CO_3 / SiO_2 ash separation
(4) CH_4 Cryogenic Separation 0.05
(5) CH_4 for Preheat - 0.08 g-mol

FIG. 3
LIGNITE COAL HYDROGASIFICATION FOR
SUBSTITUTE NATURAL GAS (SNG) PRODUCTION
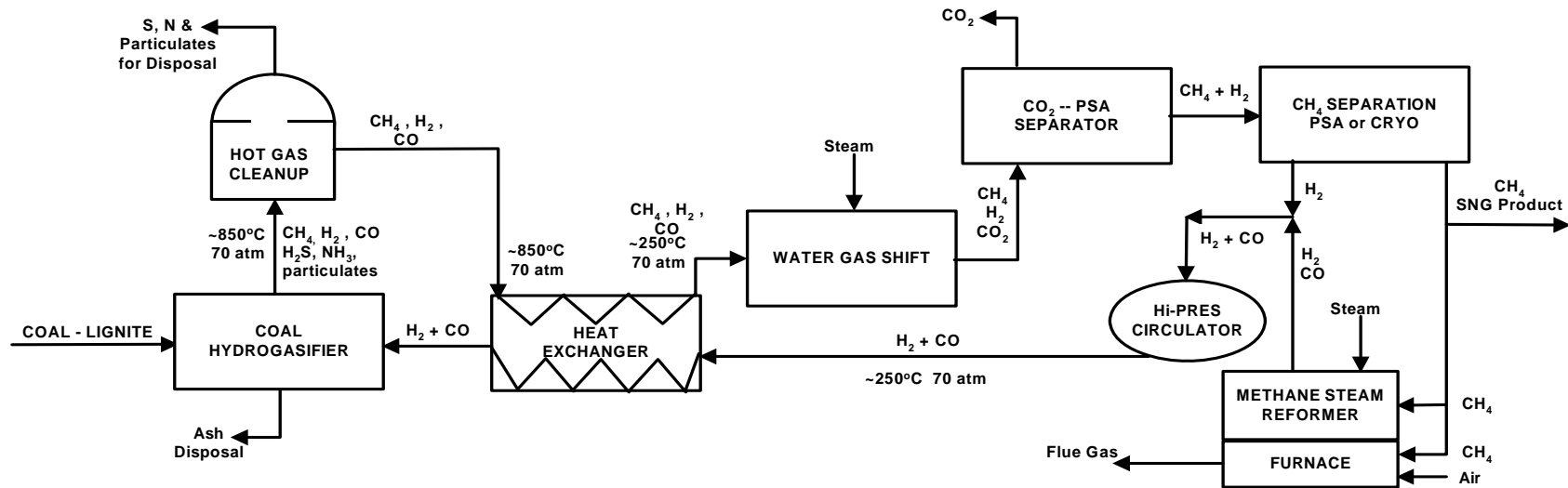
REACTION CHEMISTRY - Calculated Thermal Efficiency for SNG Production = 79.6%

(1) Hydrogasification of Lignite: $CH_{0.8} O_{0.2} + 1.2 H_2 = 0.8 CH_4 + 0.2 CO$ --- Delta H = - 9.8 Kcal / g-mol lignite - exothermic.

(2) Hot Gas Cleanup Removes N, S & particulates

(3) Water Gas Shift: $0.25 CO + 0.25 H_2O = 0.25 CO_2 + 0.25 H_2$ --- Delta H = 0 Neutral

(4) Steam Reforming of Methane: $0.25 CH_4 + 0.25 H_2O = 0.25 CO + 0.75 H_2$ Delta H = + 15.0 Kcal - endothermic

(5) Methane Combustion: $CH_4 + 2 O_2 = CO_2 + 2 H_2O$ --- Delta H = - 212 Kcal / g-mol , requires only 0.09 g-mol CH_4

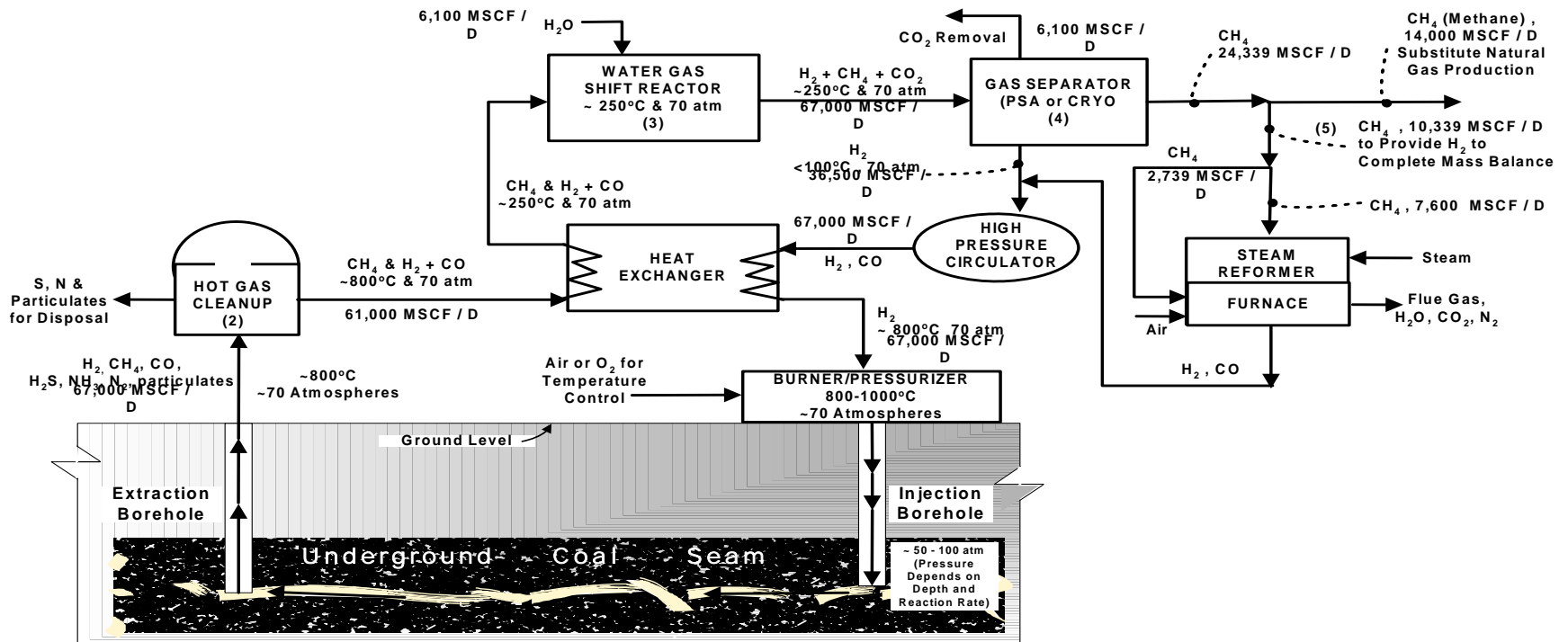(6) Overall Stoichiometry: $CH_{0.8}O_{0.2} + 0.7 H_2O = 0.55 CH_4 + 0.45 CO_2$

FIG. 4
UNDERGROUND STEAM-OXYGEN COAL GASIFICATION FOR
SUBSTITUTE NATURAL GAS (SNG) PRODUCTION
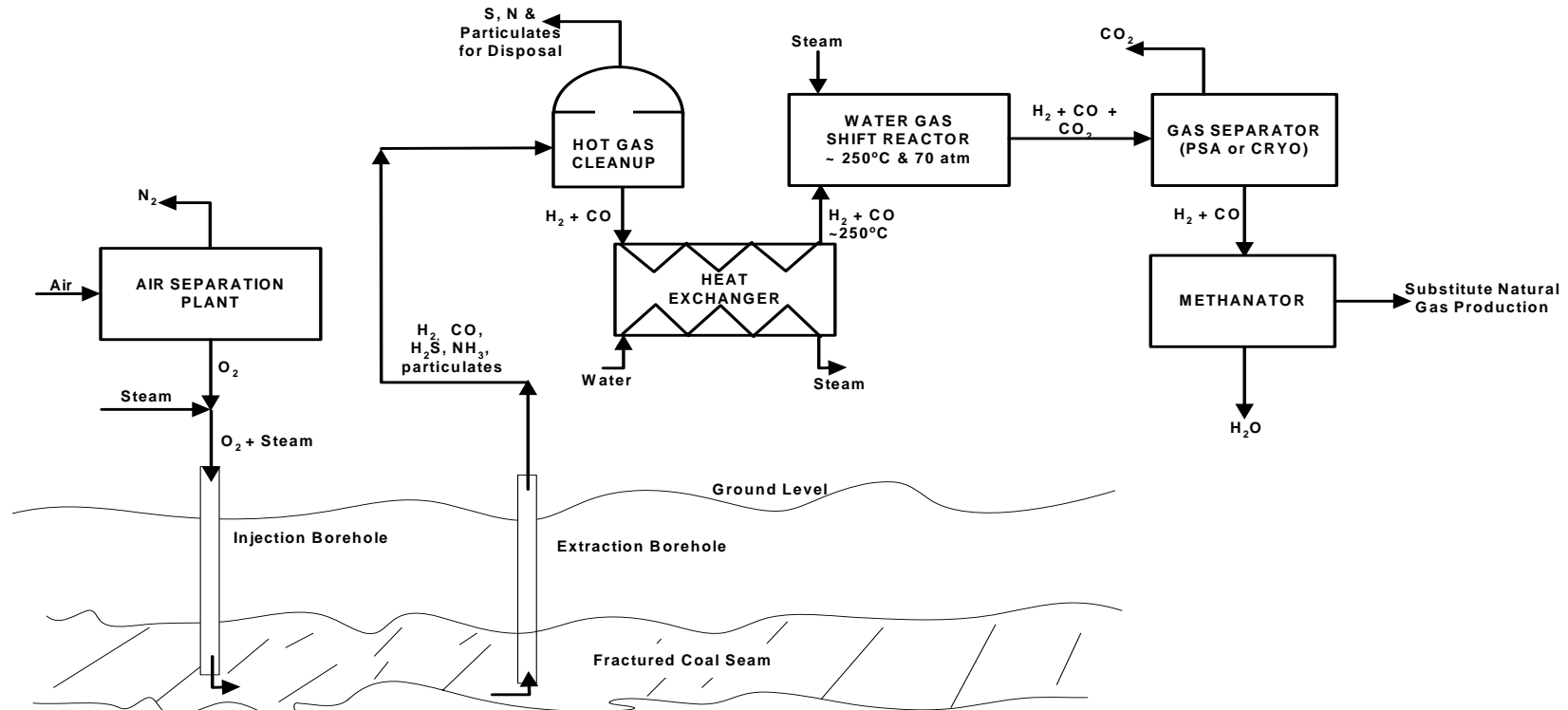
REACTION CHEMISTRY -Calculated Thermal Efficiency = 61.9%

(1) Underground Lignite Gasification: $CH_{0.8} O_{0.2} + 0.8 H_2O = 1.2 H_2 + CO$ --- Delta H = + 47.7 Kcal / g-mol lignite - endothermic

(2) Combustion of Lignite: $CH_{0.8} O_{0.2} + 1.1 O_2 = 0.4 H_2O + CO_2$ --- Combustion = endothermic Delta H = - 110.3 Kcal / g-mol

(3) Hot Gas Cleanup removes N, S & particulates

(3) Water Gas Shift $0.45 CO + 0.45 H_2O = 0.45 CO_2 + 0.45 H_2$ --- Delta H = 0

(4) Gas Separator, e.g. Differential Pressure Swing Adsorption or Cryogenic Separation, takes CO_2

(5) Methanation: $0.55 CO + 1.65 H_2 = 0.55 CH_4 + 0.55 H_2O$ --- Delta H = 33.0 Kcal – exothermic for steam production

(6) Overall Mass Balance: $CH_{0.8} O_{0.2} + 0.7 H_2O = 0.55 CH_4 + 0.45 CO_2$

FIG. 5 PUMPED CARBON MINING: SUBSTITUTE NATURAL GAS PRODUCTION
Underground Coal Hydrogasification With Above Processing
Process to Increase Initial Coal Bedded Methane Net Production Rate of 700 MSCF / D to 14,000 MSCF / D

6,100 MSCF / D H_2O

WATER GAS SHIFT REACTOR ~ 250°C & 70 atm (3)

CO_2 Removal

6,100 MSCF / D

GAS SEPARATOR (PSA or CRYO) (4)

CH_4 24,339 MSCF / D

CH_4 (Methane), 14,000 MSCF / D Substitute Natural Gas Production

$H_2 + CH_4 + CO_2$ ~250°C & 70 atm 67,000 MSCF / D

(5) CH_4, 10,339 MSCF / D to Provide H_2 to Complete Mass Balance

H_2 <100°C, 70 atm 36,500 MSCF /- D

CH_4 2,739 MSCF / D

CH_4, 7,600 MSCF / D

CH_4 & H_2 + CO ~250°C & 70 atm

67,000 MSCF / D

HIGH PRESSURE CIRCULATOR

H_2, CO

STEAM REFORMER

Steam

HOT GAS CLEANUP (2)

CH_4 & H_2 + CO ~800°C & 70 atm

HEAT EXCHANGER

FURNACE

Flue Gas, H_2O, CO_2, N_2

S, N & Particulates for Disposal

61,000 MSCF / D

H_2 ~ 800°C 70 atm 67,000 MSCF / D

Air

H_2, CO

H_2, CH_4, CO, H_2S, NH_3, N_2, particulates 67,000 MSCF / D

~800°C ~70 Atmospheres

Air or O_2 for Temperature Control

BURNER/PRESSURIZER 800-1000°C ~70 Atmospheres

Ground Level

Extraction Borehole

Injection Borehole

Underground Coal Seam

~ 50 - 100 atm (Pressure Depends on Depth and Reaction Rate)

REACTION CHEMISTRY - Calculated Thermal Efficiency = 79.6%
(1) Hydrogasification of Coal Lignite: $CH_{0.8}O_{0.2} + 1.2H_2 = 0.8CH_4 + 0.2CO$
   1.2 H_2 excess is circulated to reach equilibrium CH_4 concentration (40%). Other gases formed are H_2O, CO_2, H_2S, NH_3, N_2
(2) Hot Gas Cleanup removes N, S & particulates
(3) Water Gas Shift $0.2CO + 0.2H_2O = 0.2CO_2 + 0.2H_2$
(4) Gas Separator, e.g. Differential Pressure Swing Adsorption or Cryogenic Separation, takes out all gases except hydrogen. PSA removes CO_2 with zeolite, CH_4 on carbon adsorbant.
(5) To complete balance, 1 mole H_2 must be added. It is obtained by steam reforming
   0.25 mole CH_4 : $0.25 CH_4 + 0.25 H_2O = 0.25 CO + 0.75 H_2$
   $0.25 CO + 0.25 H_2O = 0.25 CO_2 + 0.25 H_2$; Furnace heat required: $0.09 CH_4 + Air = 0.09 CO_2 + 0.18 H_2O$
   Overall Mass Balance: $CH_{0.8}O_{0.2} + 0.7 H_2O = 0.55 CH_4 + 0.45 CO_2$; Net CH_4 Production = 0.8 - 0.34 = 0.46 CH_4

FIG. 6
PUMPED CARBON MINING - FOR SUBSTITUTE NATURAL GAS (SNG) PRODUCTION
With Multiple Underground Coal Hydrogasification in CBM Wells and Above Ground Central Processing
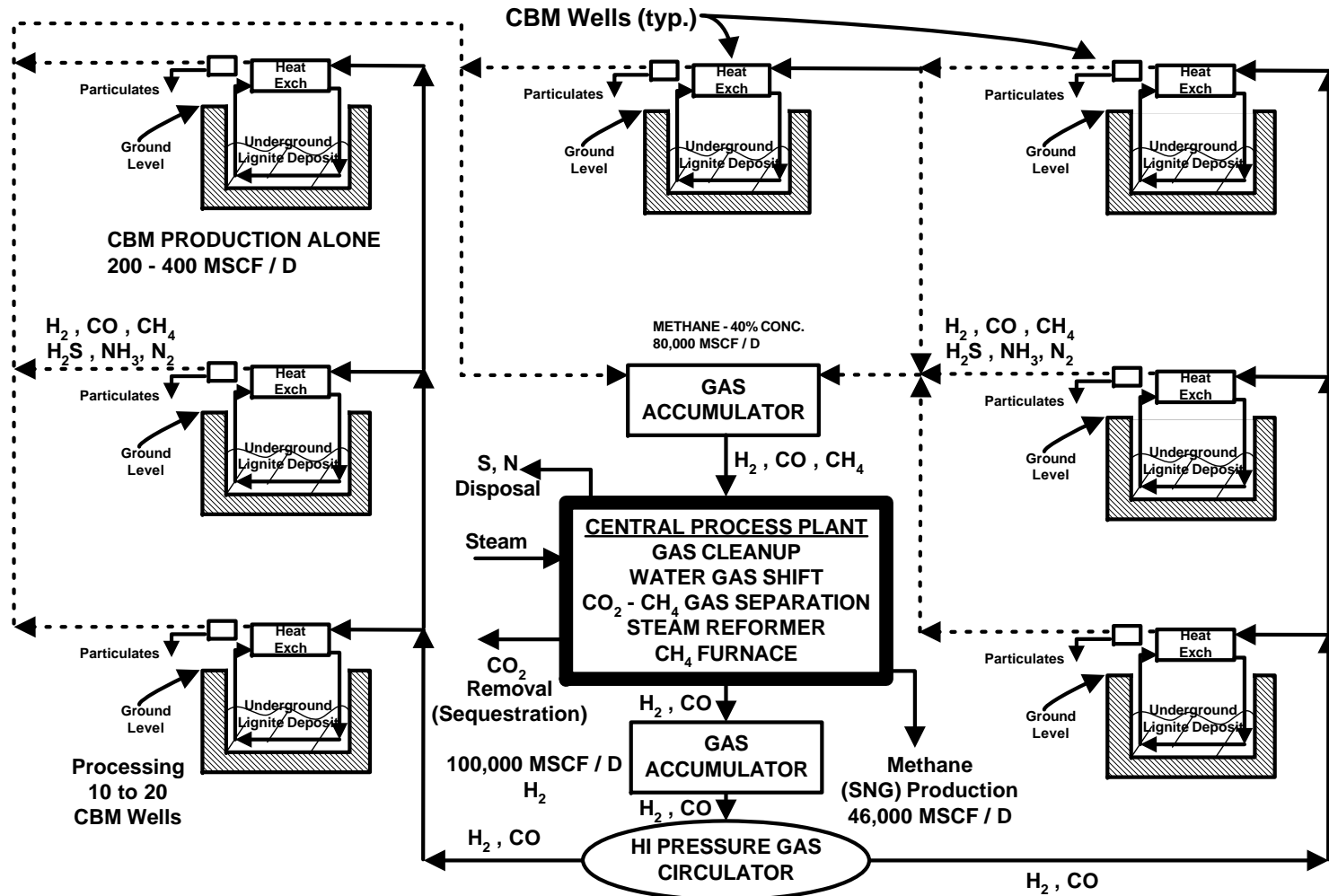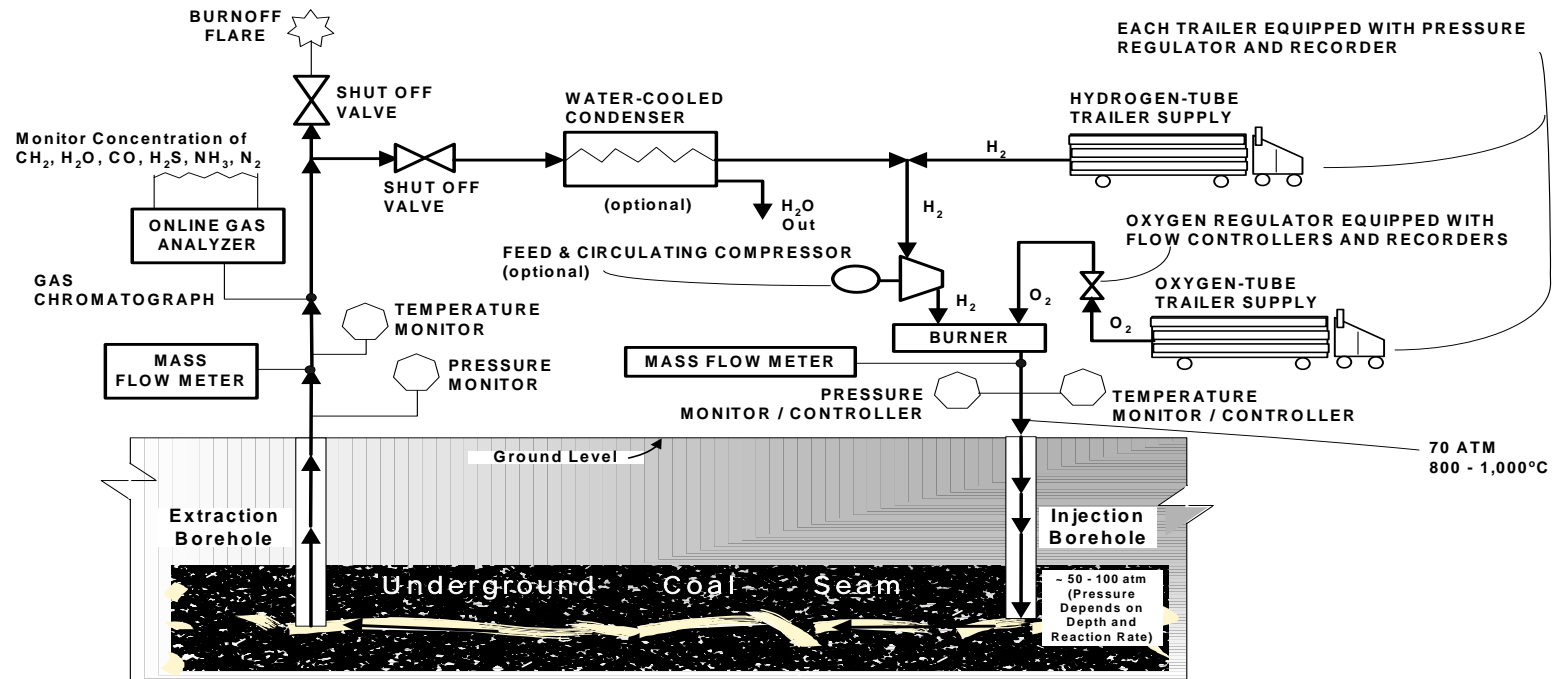### Following Coal Bedded Methane (CBM) Production

FIG. 7
PUMPED CARBON MINING: SUBSTITUTE NATURAL GAS PRODUCTION
Underground Coal Hydrogasification With Above Processing
Limited Field Test Run To Determine Methane Formation By Underground Hydrogasification

REACTION CHEMISTRY

(1) Hydrogasification of Coal Lignite: $CH_{0.8}O_{0.2} + 1.2H_2 = 0.8CH_4 + 0.2CO$
  1.2 H_2 excess is circulated to reach equilibrium CH_4 concentration (40%). Other gases formed are H_2O, CO_2, H_2S, NH_3, N_2

(2) Hot Gas Cleanup removes N, S & particulates

(3) Water Gas Shift $0.2CO + 0.2H_2O = 0.2CO_2 + 0.2H_2$

(4) Gas Separator, e.g. Differential Pressure Swing Adsorption or Cryogenic Separation, takes out all gases except hydrogen. PSA removes CO_2 with zeolite, CH_4 on carbon adsorbant.

(5) To complete balance, 1 mole H_2 must be added. It is obtained by steam reforming
  0.25 mole CH_4: $0.25 CH_4 + 0.25 H_2O = 0.25 CO + 0.75 H_2$
  $0.25 CO + 0.25 H_2O = 0.25 CO_2 + 0.25 H_2$; Furnace heat required: $0.09 CH_4 + Air = 0.09 CO_2 + 0.18 H_2O$
  Overall Mass Balance: $CH_{0.8}O_{0.2} + 0.7 H_2O = 0.55 CH_4 + 0.45 CO_2$; Net CH_4 Production = 0.8 - 0.34 = 0.46 CH_4