LLNL-TR-488334

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# Final Report: Technoeconomic Evaluation of UndergroundCoal Gasification (UCG) for Power Generation
## and Synthetic Natural Gas

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June 16, 2011

This work performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under Contract DE-AC52-07NA27344.

# Technoeconomic Evaluation of Underground Coal Gasification (UCG) for Power Generation and Synthetic Natural Gas

Final Report, June 15, 2011

UCG Group, E-Program,

Global Security Directorate, Lawrence Livermore National Laboratory

## Executive Summary

LLNL has evaluated the economics of utilizing syngas from Underground Coal Gasification UCG for two scenarios:

- Power generation from UCG (at the 485 MW net output scale)
- Synthetic Natural Gas (SNG) from UCG (66 Trillion BTU/yr scale [34,500 Barrels Oil Per Day (BOPD) Equivalent])

For both scenarios, while the economics are not quite competitive at currently prevailing U.S. prices, they may be competitive for locations with higher prevailing energy and natural gas prices (e.g. Central Europe, Japan) or in the future if natural gas and electricity prices rise substantially in the U.S. The economics of power production become significantly more favorable after the depreciation period. Costs associated with sales taxes and corporate income taxes are not included in our cost estimates.

For the synthetic natural gas from UCG option, we see significant challenges meeting pipeline specifications for content of nitrogen and other impurities. We have found that even with low percentages of nitrogen (<1.8%) in the feed syngas, separation processes in the gas cleanup increase the percentage of nitrogen in the syngas as $CO_2$ is removed and CO and $H_2$ converted to methane. Minor intrusions of nitrogen in the underground formation, combined with nitrogen within the combusted coal itself, may cause the percentage of nitrogen in the product SNG to exceed specifications of <5%. Hence, we judge SNG from UCG as being challenging technically under current pipeline specifications.

*Table E.1*
*Cost Estimate Summary Table*

| Cost Parameter | Power Generation | Synthetic Natural Gas |
|---|---|---|
| | | |
| Nominal Capacity | 485 MW Net | 66 Trillion BTU/yr [34,500 BOPD Equivalent] |
| Total Fixed Capital | U.S.$886 million | U.S. $363 million |
| Production Costs including Cost of Capital | $93/MWh | $7.5/MMBTU |
| Production Costs including Cost of Capital but excluding depreciation | $60/MWh | $6.7/MMBTU |

# Introduction

## Scope Note

This report concerns the technoeconomics of using Underground Coal Gasification (UCG) for power generation and for production of synthetic natural gas. Lawrence Livermore National Laboratory was retained under the Work for Others Agreement L-13208 for ExxonMobil Upstream Research Laboratory[i] to investigate the economics of using UCG for feedstock supply for these two scenarios. The scope included conceptual designs, mass balances, and capital & operating cost estimates.

# Methodology

LLNL performed the work as follows:

- Capacity of the design scenarios was agreed with ExxonMobil. The hypothetical location used for cost estimates was the Powder River Basin, Wyoming, USA
- Likely compositions of the UCG product gas were estimated for both air-blown and $O_2$/steam-blown UCG operations, based on results from historic field tests
- Clean-up and use of the UCG syngas was simulated using ASPENTech process simulation software using the Predictive Soave-Redlich-Kwong (PSRK) property method. ASPENTech was also used for sizing of certain major process equipment items.
- A conceptual design of a UCG module was devised based on knowledge of previous and current UCG field tests and plans, supplemented by knowledge of geomechanical limitations
- Capital cost estimates were generated using published correlations, published cost & prices, and vendor quotes where available
- Operating costs were estimated using vendor quotes, published prices, and labor costs typical for the projected location from the U.S. Bureau of Labor Statistics. Numbers of operators were estimated subjectively using the rule-of-thumb of 1 operator per 2-3 major process equipment items. For the UCG field operations, it was similarly assumed that one UCG field operator would be needed for every three UCG modules in operation.
- Subjective cost factors (depreciation lifetime, discount rate, contingency percentage) were agreed between the client and the LLNL team

## Capital Cost Estimation

Vendor quotes were solicited from GE Power (for the cost of the power generation combined-cycle package plant). The cost of the Claus desulfurization unit was estimated by extrapolating published capital cost by Linde. Other capital equipment items were estimated using correlations in Peters & Timmerhaus, 5th Edition.[ii] Capital costs were separated into Battery Limits Investment (BLI) including equipment cost and installation of process equipment handling process streams, and Outside Battery Limits Investment (OBLI) which includes utilities, tankage, and general service facilities.

## Operating Cost Estimation

As drilling of new UCG modules would continue throughout the lifetime of the UCG operation, the cost of drilling was treated as an operating expense pro-rated annually rather than a capital cost. Quotes for drilling costs were solicited from Mitchell Drilling of Australia, a firm with extensive experience in UCG, based on a conceptual UCG design developed by LLNL. Mitchell's cost incorporated necessary well finishing to minimize the risks of failure of the integrity of the wells that could cause contamination of the UCG site. Table 1.1 indicates the additional cost parameters used by LLNL in the capital and operating cost estimates.

***Table 1.1***
***Cost Parameters Used***

| Cost Parameter | Value Used | Comments |
|---|---|---|
| | | |
| Location | Powder River Basin, Wyoming, USA | LLNL Estimate |
| Discount Rate | 12.5% | Client-specified |
| Depreciation Lifetime | 7 years | Client-specified |
| Contingency factor for capital costs and for drilling costs | 30% | Client-specified |
| General Service Facilities | 5% of Total Fixed Capital (power generation option)<br>20% of Total Fixed Capital (SNG scenario) | LLNL Estimate |
| Waste Treatment | 1% of Battery Limits Investment [BLI] (Power scenario)<br>5% of BLI (SNG scenario) | LLNL Estimate |
| Labor costs | $31/hour | Bureau of Labor Statistics Manufacturing Wage in Wyoming, May 2009 |
| Plant overhead | 80% of Operating Labor | |
| Maintenance Costs (Power Scenario) | $1.2/GWh Maintenance Labor<br>$1.8/GWh Maintenance Supplies | LLNL Estimate |
| Maintenance Costs (SNG Scenario) | Maintenance Labor : 1.6% of BLI<br>Maintenance Supplies : 2.4% of BLI | LLNL Estimate |
| Taxes & Insurance | 1.6% of BLI | LLNL Estimate |
| General, Admin, Sales & Research | 5% of Plant Gate Costs[1] | LLNL Estimate |
| Coal Royalty Costs | $3/tonne consumed | LLNL Estimate |
| Land Lease Costs | $1,800/hectare | LLNL Estimate |

## UCG Gas Compositions

LLNL used weighted-averages of historical UCG tests in Wyoming and Washington states to estimate the composition of syngas. Weighting was done using the volume of coal consumed in the historical tests. It was decided that this gave compositions more rooted in empirical data than using modeling to predict

[1] Plant gate costs are defined here as the cash cost plus depreciation charges. Production cost is equal to the plant gate cost plus a charge for corporate general, sales, administration and R&D costs (GASR).

compositions. Composition and operational data was obtained from published reports on UCG testing in the U.S. [iii] As each individual tests often included both air-blown and $O_2$/steam blown phases, these phases were separated in the calculations of compositions. It was found that some purported oxygen-blown tests in fact used a combination of oxygen and air: results from these tests were excluded from calculations of syngas compositions. Sulfur and ammonia or nitrogen oxide content in the syngas was estimated based on typical sulfur content for Power River Basin coals.

After weighted-average compositions for air-blown and $O_2$-steam blown were prepared, the composition was slightly altered to account for increased methane content. The projected depth of the UCG modules in this study (480 m depth) was deeper than the UCG tests used in (most of which were conducted at 100-150 m depth). It was hypothesized that methane content would increase at depth because of the shift in equilibrium of methanation reactions towards methane product. However, it was found that the methane content only varied slightly with the depth of historical UCG tests, suggesting that methane is predominantly a result of pyrolysis reactions rather than methanation reactions. Hence, methane content was adjusted slightly (increased ~10%) and $H_2$, CO, and $CO_2$ content accordingly slightly reduced. Table 1.2 indicates the compositions used for this study.

***Table 1.2***
***UCG Dry Product Gas Composition Estimates***

| Component | Dry Gas Molar Composition, Air-Blown UCG | Dry Gas Molar Composition, Oxygen Blown UCG |
|---|---|---|
| Nitrogen & Argon | 52.1% | 1.8% |
| Oxygen | 0% | 0.0% |
| Hydrogen | 13.6% | 34.1% |
| Methane | 5.8% | 10.1% |
| Carbon Monoxide | 11.2% | 10.5% |
| Carbon Dioxide | 16% | 41.1% |
| C2+ hydrocarbons | 0.5% | 0.9% |
| Nitrogen oxides | 0.2% | 0% |
| Sulfur oxides | 0.5% | 0% |
| Ammonia | 0% | 1.2% |
| Hydrogen sulfide | 0% | 0.3% |

## UCG Module Design

LLNL decided to assess the case of Linear Continual Retractable Injection Point (linear CRIP) for the UCG module design. LLNL and ExxonMobil agreed that a minimum depth of 1,000 feet would be considered. We assessed costs and product compositions based on a hypothetical 480 m deep, >10 m thick seam located in the Powder River Basin, Wyoming (e.g., the Big G seam).[iv]

We assessed a 480 m deep production well with a 480 m horizontal run to be reasonable, and assumed a ~12 m thick coal seam. At this depth, we assessed an extraction percentage of 25-35% would be feasible without fracturing potentially extending upward into aquifers: the unextracted coal would form "pillars" between the CRIP modules supporting the overburden. We assessed that the length of the horizontal run would require three injection wells over the lifetime of the CRIP module. Four instrumentation wells were also included in the design. Design parameters for the UCG modules are summarized in Table 1.3 below.

Each UCG cavity was envisioned as a roughly teardrop-shaped cavity 24 m wide, with the final shape before a subsequent CRIP maneuver of a semicircular section of 24 m diameter and a roughly trapezoidal section 24 m wide tapering to 6 m wide over a 30 m length.  This gave roughly 11 CRIP maneuvers possible in a 480 m length run. We assumed that an average 10 m of the 12 m thickness of the seam would be extracted, with the remaining 2 m remaining as char. Figures 1.1 and 1.2 give conceptual plan and side views of the UCG module.

*Figure 1.1*
*Conceptual-level  Plan View of UCG CRIP Module*

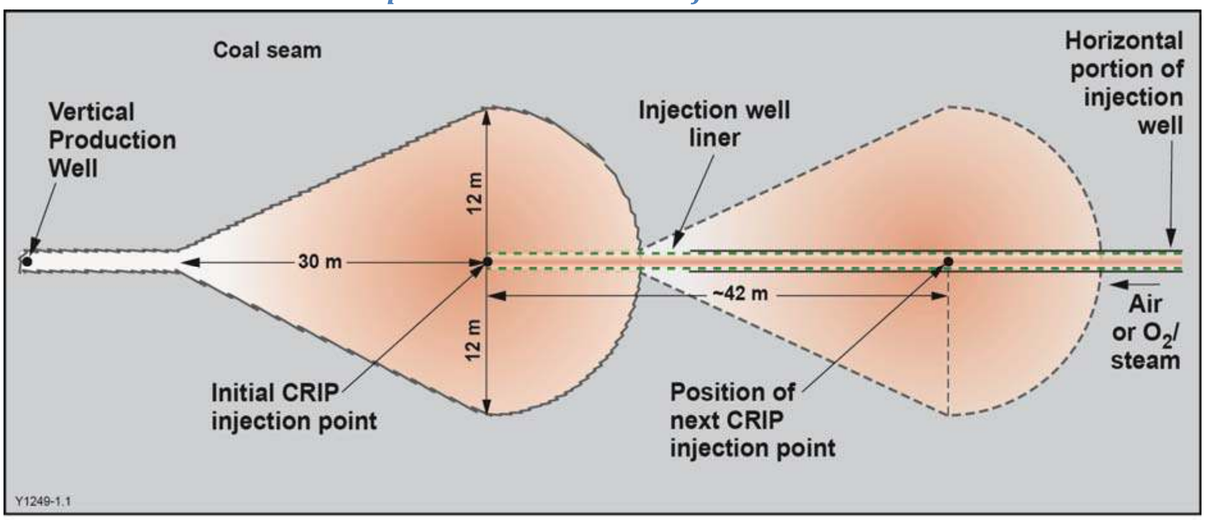
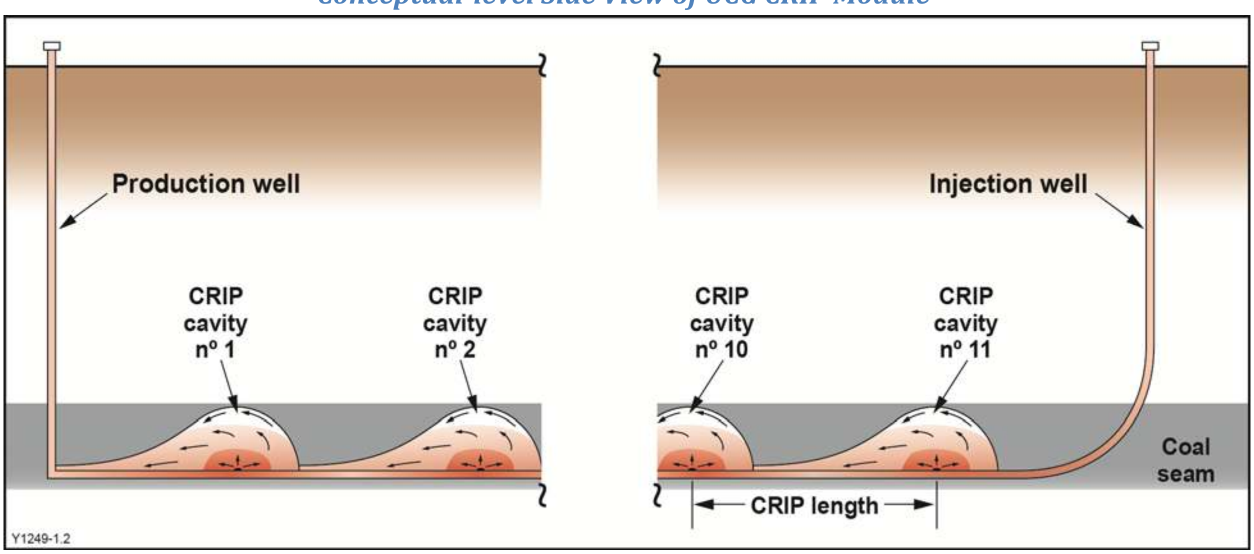



*Figure 1.1*
*Conceptual-level Side View of UCG CRIP Module*



Produced gas pressure was assumed to be 45 atm, the hydrostatic pressure of the cavity at 480 m below ground surface (bgs) with a water table of 20-30 m bgs. The pressure difference between injection and production was assumed to be ~1 atm, based on historical data from the Rocky Mountain Linear CRIP UCG tests.

***Table 1.3***
***UCG CRIP Module Design Parameters***

| Parameter | Value Used | Comments |
|---|---|---|
| | | |
| Depth to Bottom of Seam | 480 m | |
| Seam thickness | 12 m | |
| Module Length | 480 m | |
| UCG Module Geometry | Linear CRIP | |
| Injection Cavity Length | 42 m | |
| Maximum Cavity Width | 24 m | |
| Depth of Char remaining | 2 m | |
| Number of Injection Wells per CRIP module | 3 | |
| Number of instrumentation wells per CRIP module | 4 | |
| Distance between center of CRIP Modules | 60-90 m | |
| Assumed Lifetime of one CRIP Module | ~1.2 years | Assuming a ~1.12 m/day progression of cavity growth |
| Estimated Output per CRIP Module | 43,000 tons coal | |
| Produced gas Pressure | 45 atm | Assumed to be slightly less than the hydrostatic pressure of the UCG cavity |
| | | |

## Case 1: Power Generation

### Process Discussion

The power production flowsheet can be conceptually divided into two subsystems:

1. Raw syngas cleanup sub-system comprising
    a. Particulate removal equipment
    b. Waste heat recovery heat exchangers, wherein the sensible heat of the syngas is used to make steam
    c. Acid gas removal units, comprising absorbers and scrubbers

d. A Claus unit that converts the $H_2S$ in the syngas to elemental sulfur

2. Power generation subsystem, comprising

    a. gas turbines and air compressors for combustion air

    b. Waste heat recovery heat exchangers wherein the sensible heat of the turbine exhaust is used to make steam

    c. Steam turbines

### Process Description

The process description is split into two sections, one for the gas cleanup section and one for the combined-cycle power generation system. Major equipment items are listed in Table 2.1.

***Table 2.1***
***Power Generation from UCG***
***Major Process Equipment List***

| Item Label in Process Flow Diagram (PFD) | Size | Description | Comments |
|---|---|---|---|
| *Gas Cleanup Section* | | | |
| **Reactors** | | | |
| Water Gas Shift Reactor [Not Shown] | 300 L | Packed Bed Multitube Reactor | 304 SS |
| **Columns** | | | |
| RECTABS | 14 x 5 m | Rectisol Absorber | 304 SS: 20 sieve trays |
| RECTSTR | 7.5 x 3.3 m | Rectisol Stripper | 304 SS: 10 sieve trays |
| **Pressure Vessels** | | | |
| SYNFLSH1 | 12 x 4 m | Knockout Vessel for cooled syngas | C.S. |
| SYNFLSH2 | 10.8 x 3.6 m | Knockout Vessel for cooled syngas | C.S. |
| SYNFLSH3 | 10.8 x 3.6 m | Knockout Vessel for chilled syngas | C.S. |
| STRFLSH | 4.5 x 1.5 m | Knockout Vessel from Stripper for Acid Gas | 304 S.S. |
| **Heat Exchangers** | | | |
| WHBSYN | 23 x 1000 $m^2$ | Steam recovery from hot UCG gas | C.S.<br>Heat Duty:<br>280 MW BFW |
| WGSCOOL | 3 x 1000 $m^2$ | Syngas cooler | C.S.<br>65 MW Cooling Water |
| WGSCRYO | 2 x 1000 $m^2$ | Syngas Economizer before Rectisol Absorption | C.S.<br>13 MW |
| RECTHTX | 3 x 800 $m^2$ | pre-Rectisol Stripper Methanol Economizer | C.S.<br>11 MW |
| RECTCRY | 800 $m^2$ | Methanol Chiller | 304 SS |

| Item Label in Process Flow Diagram (PFD) | Size | Description | Comments |
|---|---|---|---|
| | | | Heat Duty :12 MW<br>Refrigerant |
| RECTCOOL | 375 $m^2$ | Methanol Cooler | 304 SS<br>Heat Duty 20 MW<br>Cooling Water |
| STREBOIL | 375 $m^2$ | Rectisol Stripper Reboiler | 304 SS<br>Heat Duty: 30 MW |
| **Compressors** | | | |
| COMP1 | 3 x 20 MW | 3 Serial Air Compressors to supply<br>UCG Modules | Intake flow<br>240,000 scf/min<br>(400,000 $m^3$/hour)<br>Outlet pressure:<br>46.5 atm<br>Not shown on flow diagram |
| **Miscellaneous Equipment** | | | |
| DEASHER | | Cyclone<br>Electrostatic precipitator<br>Ceramic filter | Misc. |
| | | | |
| **Power Generation Section (Priced as Package Unit)** | | | |
| | | | |
| COMP1 | 48 MW | Air Compressors for Gas Turbine | Intake flow<br>600,000 scf.min<br>(1,000,000 $m^3$/hour)<br>Outlet pressure 3.6 atm |
| COMP2 | 50 MW | Air Compressors for Gas Turbine | Outlet pressure 12.6 atm |
| COMP3 | 50 MW | Air Compressors for Gas Turbine | Outlet pressure 12.6 atm |
| TURB1 | 580 MW | Gas Turbine | Misc. |
| STMTURB1 | 52 MW | Condensing Steam Turbine | Misc. |
| STMTURB2 | 42 MW | Condensing Steam Turbine | Misc. |
| STMTURB3 | 36 MW | Condensing Steam Turbine | Misc. |
| STMGEN1 | 17,250 $m^2$ | Steam Drum | Misc. |
| COMPCLR1 | | Intercooler for Air Compression | C.S. |
| COMPCLR2 | | Intercooler for Air Compression | C.S. |
| TRBFLSH1 | 20 $m^3$ | Condensate Separator | C.S. |
| TRBFLSH2 | 20 $m^3$ | Condensate Separator | C.S |
| CONDCOOL | 15,000 $m^2$ | Condenser: 300 MW | C.S.<br>300 MW Heat duty |
| [COMBRXR] | | Combustor | |
| **Tankage** | | | |

| Item Label in Process Flow Diagram (PFD) | Size | Description | Comments |
|---|---|---|---|
| Methanol Day Tanks | 2 x 800 $m^3$ | | |
| Methanol Surge Tanks | 4 x 100 $m^3$ | | |
| **Other** | | | |
| Claus Unit [Not shown] | 40 tons/day | Package Unit | Misc. |
| **Utilities** | | | |
| Refrigeration | 12 MW | | |
| Boiler Feed Water | 105 tonnes/hr | | |
| Cooling Water | 42,000 tonnes/hr | | |

A process flowsheet showing most, but not all, of these equipment items is given in Appendix A as Figure A.1. A stream table of process flows is given in Table B.1

### *Raw Syngas Cleanup Section*

A combination of cyclones, ceramic filters and electrostatic precipitators are used in our design to remove particulates from the raw syngas .[v] The combination of these is noted with the symbol DEASHER in the process flowsheet, with an assumed 100% removal efficiency. The units were costed based on total gas flow treated.

The particle-free syngas stream, SYNNOASH is sent to the heat exchange WHBSYN, where it exchanges heat with the boiler feed water stream BFW1. The resultant steam stream WHBSTM is sent to the flow splitter unit, STMSPLT, where it is split into two streams, MPSTEAM1, and MPSTEAM2. The cooled syngas stream, SYNMHOT, passes through a knock-out vessel, SYNFLSH1, to remove condensate as wastewater. The dry gas is cooled further in the heat exchanger unit WGSCOOL using cooling water, CW1, and then passes through a second knock-out vessel, SYNFLSH2 . The cooled syngas stream, WGHPRDC, is further cooled in the heat exchanger WGSCRYO to cryogenic temperature, using cold syngas (BALSYNC) exiting the Rectisol absorber, RECTABS. The cold syngas, WGSPRDCC, is flashed in SYNFLSH3 to remove condensate and ice (SYNCOND). The dry cold syngas BALDSYN is introduced into RECTABS, wherein cold methanol, L1CL, is used as the solvent, to remove the acid gas $H_2S$. The clean syngas, BALSYNC, exchanges heat with WGHPRDC stream mentioned earlier in the heat exchanger WGSCRYO, and is then sent to the gas turbine.

The rich cold methanol stream, L1CR, exits the bottom of the Rectisol absorber unit, RECTABS, and exchanges heat, in the heat exchanger RECTHTX with the lean hot methanol stream L1HL, exiting the bottom of the Rectisol stripper unit, RECTSTR. The warm rich methanol stream L1HR is sent to the Rectisol stripper RECTSTR, where the acid gas $H_2S$ is stripped from the rich methanol stream. The now lean methanol stream, L1HL exchanges heat with the cold rich methanol stream in RECTHTX. The steam stream MPSTEAM1, generated earlier, is used to provide the heat for the reboiler (STREBOIL) of the stripping column. The warm lean methanol stream, L1WL, is sent to a cryogenic cooler (not shown in process flow diagram A-1) to produce the cold methanol for recycle. The cold methanol stream, L1CRYOI, is used as the refrigerant to cool the solvent methanol stream, MAKEUPL1, to produce L1CL, which is introduced into RECTABS as the Rectisol solvent. The warmed L1CRYOO is sent to a refrigeration system (not shown) to regenerate L1CRYOI.

The acid gas stream from the Rectisol stripper, RECTSTRP, is sent to a Claus unit (not shown) to recover elemental sulfur.

### *Power Generation Subsystem*

Aspen does not have a gas turbine simulation unit, so we have had to approximate it using a combination of an adiabatic stoichiometric combustion reactor, and a reverse compressor.

Combustion air, COMBAIR1, is compressed in a series of isentropic compressors, COMP1, COMP2 and COMP3, with intermediate coolers, COMPCLR1 and COMPCLR2, to produce the compressed air stream, COMPAIR3. It is mixed with the clean syngas from the unit WGSCRYO, and sent to the reactor COMBRXR, wherein all the fuel from the syngas ($H_2$, CO, $CH_4$ and higher hydrocarbons, represented by $C_2H_6$) are completely oxidized. The hot pressurized syngas is sent to the reverse compressor unit, TURB1, connected to a generator, not shown, to produce power.

The hot exhaust from TURB1 is sent to the heat exchanger STMGEN1, where steam is generated from the boiler feed water stream BFW4STRB. The resultant steam stream, STM4TRB, is mixed with the steam stream MPSTEAM2, from the syngas waste heat boiler, and sent to a series of steam turbines STMTURB1, STMTURB2 and STMTURB3 to produce more power. Table 2.2 summarizes the projected power generation and consumption at the plant.

***Table 2.2***
***Power Generation from UCG***
***Electrical Power Generation and Consumption***

| Item Label in Process Flow Diagram (PFD) | Function | Power Generated (Consumed), MW | Comments |
|---|---|---|---|
| | | | |
| COMP1 | 50 MW Combustion Air Compressor | (48) | |
| COMP2 | 50 MW Combustion Air Compressor | (50) | |
| COMP3 | 50 MW Combustion Air Compressor | (50) | |
| | | | |
| UCGCOMP1 | 20 MW Air Compressor for UCG Modules | (20) | Not shown in Flow Diagram |
| UCGCOMP2 | 20 MW Air Compressor for UCG Modules | (20) | Not shown in Flow Diagram |
| UCGCOMP3 | 20 MW Air Compressor for UCG Modules | (20) | Not shown in Flow Diagram |
| TURB1 | 580 MW Gas Turbine | 580 | |

| Item Label in Process Flow Diagram (PFD) | Function | Power Generated (Consumed), MW | Comments |
|---|---|---|---|
| STMTURB1 | 52 MW Steam Turbine | 52 | |
| STMTURB2 | 42 MW Steam Turbine | 42 | |
| STMTURB3 | 36 MW Steam Turbine | 36 | |
| | Refrigeration | (5) | |
| | Other Estimated Electrical Power Demands (e.g. pumping) | (12) | |
| | | | |
| | ***Net Power Output, MW*** | **485** | |

### *Materials of Construction*

We do not envision excessively corrosive conditions in the process, hence we envisioned that most of the gas cleanup process equipment would be carbon steel, with the exception of the rectisol absorber/stripper loop, where 304 Stainless steel was projected. Power generation equipment would be a mixture of different materials, but again we do not envision more severe conditions than would be normal for IGCC or NGCC power plants.

### Process Discussion

The flowsheet simulated here is has not been fully optimized for heat integration. A number of improvements are possible:

- A more thorough heat integration for in-process heat exchange between hot and cold streams is likely to reduce utility consumption (cooling water, steam and refrigeration)
- A better utilization of steam is possible. For example, all the steam generated in the syngas waste heat boiler can be sent to the first two steam turbines, and a slip stream from the exhaust of the second steam turbine can be used to provide the heat to the Rectisol stripper reboiler.
- Heat from the Claus unit, not simulated here, can be used to preheat the combustion air after the last compressor to improve the efficiency of the gas turbine.
- Specific unit operations for removal of volatile metals such as mercury

We have not completely converged the recycle loop involving the recycle of the solvent. This is done for two reasons:

- The amount of the solvent flowing through the absorber/stripper system can be independently set by the designer/operator
- Calculation of the exact composition of the circulating solvent does not significantly affect the design of the process, yet creates numerical instabilities in Aspen, thus making such calculations difficult

Instead, we show that the amounts of the methanol in and out, including the makeup methanol, are in mass balance.

Likewise, we have not shown the recycle of steam, showing, instead, the steam balance.

## Capital and Operating Cost

Equipment sizes were estimated using ASPEN and according to general rules of thumb for process engineering. Table 2.1 above lists the major process equipment items. Variable costs, including estimated annual utility consumptions, are listed in Table B.2. Annual drilling costs are given in Table B.3

The capital cost of the power generation section was estimated using a rule of thumb of $1,000/kW net power (i.e. power less power loss for compression of combustion air) given by GE Power.[vi] As the power needed for 480 net power from the UCG/Power Plant Operation would be 550 MW (because of 60 MW required to compress air for the UCG modules, 8 MW refrigeration and ~2 MW other power demands), we estimated an installed cost for the power generation island of $550 million.

Capital costs for the gas cleanup process equipment were estimated using Peters & Timmerhaus.[vii] Costs were inflated from 2002 to 2010 costs using the *Chemical Engineering* plant cost index. Installation costs factors ranging from 0.9-1.8 (depending on equipment type) of purchased equipment costs, were used to include construction, electrical and instrumentation, and piping costs. Utility investment costs were also estimated using Peters & Timmerhaus, using an installation cost factor of 0.4. Certain elements (the power generation island and the Claus desulfurization unit) were treated as a package unit with installation costs included. Power generation island costs were obtained from GE Power, and Claus desulfurization package unit costs were obtained from publications by Lurgi.[viii] It was found, as would be expected, that the capital cost of the gas cleanup section was much smaller than the power generation section.

Drilling costs, being incurred throughout the plant lifetime as UCG modules are expended, were treated as an annual operating expense. Cost estimates for drilling were obtained from Mitchell Group of Queensland, Australia.[ix]

Labor costs were estimated using May 2009 hourly wage rates for manufacturing labor in Wyoming from the Bureau of Labor Statistics. We estimated 13 field operators per shift for the UCG production field and six operators for the above-ground process (approx. one operator for every 3 UCG modules , 4 operators per shift for the power generation section and 2 for the gas cleanup section.)

### *Discussion of Capital & Operating Costs*

Total Fixed Capital for the Gas Cleanup and Power Generating Sections are given in Table 2.4. The total fixed capital cost was estimated at $886 million. (For a net power output of 485 MW, this works out at $1,760/kW generation capacity.) Working capital of 3 months of operating cash costs was estimated at $27 million, for a total capital investment of $913 million. Investment in the inventory of methanol kept on-site was not included.

Operating expenses, including return on investment and plant depreciation over a 7-year period, were estimated at $360 million, as shown in Table B.5, with variable expenses shown in Table B.4 and Annual drilling expenses in Table B.3. Excluding depreciation, the operating costs, including return on investment, are $233 million. These give a cost of $93/MWh during the depreciation period and $60/MWh post-depreciation.

## Case 2: Synthetic Natural Gas

### Process Review

For gas cleanup prior to methanation, the Rectisol process was used because of its ability to remove $H_2S$ which would poison the methanation catalyst. However, as most of the $CO_2$ needs to be removed to meet pipeline specifications, three absorbers were used: a $H_2S$ absorber, a $CO_2$ absorber, and a polishing absorber to remove $CO_2$ resulting from the methanation reaction.

### Process Description

The SNG production flowsheet can be conceptually divided into two subsystems:

3. Raw syngas cleanup sub-system comprising
    a. Particulate removal equipment
    b. Waste heat recovery heat exchangers, wherein the sensible heat of the syngas is used to make steam
    c. Acid gas removal units, comprising absorbers and scrubbers
    d. A Claus unit (not shown) that converts the $H_2S$ in the syngas to elemental sulfur
4. SNG generation subsystem, comprising
    a. Methanation reactor
    b. $CO_2$ absorber
    c. $CO_2$ stripper and solvent regenerator (shared with the acid gas removal system, mentioned under the acid gas removal system)

The description of each subsystem in detail follows.

Table 3.1 gives the major process equipment items for the SNG scenario.

***Table 3.1***
***Synthetic Natural Gas from UCG***
***Major Process Equipment List***

| Item Label in Process Flow Diagram (PFD) | Size | Description | Comments |
|---|---|---|---|
| *Gas Cleanup Section* | | | |
| **Reactors** | | | |
| WGSEQ | 300 L | Water Gas Shift Reactor<br>Packed Bed Multitube Reactor | 304 SS |
| METHRXR | | 3 x Pack Bed Multitube Reactor | Misc |
| **Columns** | | | |
| H2SABS | 10 x 7 m dia | Rectisol Absorber (Hydrogen Sulfide) | 304 SS |
| CO2ABS | 5.5 x 18 m dia | Rectisol Absorber (Carbon Dioxide) | 304 SS. Fluor-Daniel is constructing $CO_2$ Absorber/Strippers of up to 20 m diameter |
| H2SSTRP | 5.5 x 5 m dia | Rectisol Stripper ($H_2S$) | |
| CO2STRP | 5.5 x 20 m dia | Rectisol Stripper ($CO_2$) | 304 SS. Fluor-Daniel is constructing $CO_2$ Absorber/Strippers of up to 20 m diameter |
| SNGRECT | 10 x 6 m dia | Polishing Absorber | 304 SS |
| **Pressure Vessels** | | | |
| SYNFLSH1 | 20 x 5 m | Knockout Vessel for syngas | C.S. |
| SYNFLSH2 | 20 x 5 m | Knockout Vessel for cooled syngas | C.S. |
| LTFLASH | 8 x 2.5 m | Flash Vessel for $CO_2$ absorber bottoms | 304 S.S. |
| METHCOND | 8 x 2.5 m | Knockout Vessel for cooled SNG product gas | 304 S.S. |
| METHRCVR | 6.5 x 2 m | Knockout Vessel for cooled feed to Claus Unit | 304 S.S. Not shown on flow diagram |
| **Heat Exchangers** | | | |
| C1FDHTR | 1,100 $m^2$ | Heater for Methanation Input. | Misc.<br>73 MW High-Pressure Steam |
| L1CRYO1 | 13 x 1000 $m^2$<br>1 x 500 $m^2$ | Cryogenic Cooler | 304 S.S. tubes<br>143 MW Refrigerant |
| L2CRYO2 | 76 x 1000 m2 | Cryogenic Heat exchanger | 304 S.S. tubes<br>122 MW<br>Not shown on flow diagram |
| L3CRYO3 | 4 x 925 $m^2$ | Cryogenic Heat exchanger | 304 S.S. tubes<br>41 MW<br>Not shown on flow diagram |
| RECTHTX1 | 2 x 720 m2 | Heat Exchanger w/ Steam | 304 S.S. tubes<br>53 MW |
| RECTHTX2 | 7 x 1,000 $m^2$ | Heat Exchanger w/ CW | 304 S.S. tubes<br>72 MW |

| Item Label in Process Flow Diagram (PFD) | Size | Description | Comments |
|---|---|---|---|
| SYNCRY1 | 27 x 1000 $m^2$ | Cryogenic Cooler | 304 S.S. tubes |
| SYNCRY2 | 3 x 800 $m^2$ | Cryogenic HX | 304 S.S. tubes<br>Not shown on flow diagram |
| SYNCRY3 | 6 x 1,000 $m^2$ | Cryogenic HX | 304 S.S. tubes<br>Not shown on flow diagram |
| SYNCRY4 | 6 x 1,000 $m^2$ | Cryogenic HX | 304 S.S. tubes<br>Not shown on flow diagram |
| WGSCOOL | 9 x 1000 $m^2$ | Cooler pre-$H_2S$ absorption | C.S.<br>33 MW CW |
| WHBSYN | 41 x 1000 $m^2$ | Steam recovery from hot UCG gas | C.S.<br>590 MW BFW |
| WHBWGS | 31 x 1000 $m^2$ | Steam recovery from hot UCG gas | |
| [Not shown] | 2 x 900 $m^2$ | CO2STRP Reboiler | 304 S.S.<br>177 MW Steam |
| [Not shown] | 1 x 1200 $m^2$ | H2STSRP Condenser | 304 S.S.<br>7 MW Refrigerant |
| [Not shown] | 1 x 200 $m^2$ | H2SSTRP Reboiler | 304 S.S.<br>20 MW Steam |
| [Not shown] | 6 x 1,100 $m^2$ | Methanol Condenser from Claus feed | 304 S.S.<br>10 MW Refrigeration |
| | | | |
| **Tankage** | | | |
| Methanol Day Tanks | 2 x 1,000 m3 | | |
| Methanol Surge Tanks | 5 x 100 m3 | | |
| | | | |
| **Miscellaneous Equipment** | | | |
| DEASHER | | Cyclone<br>Electrostatic precipitator<br>Ceramic filter | Misc. |
| **Other** | | | |
| Claus Unit [Not shown] | 105 tonnes/day | Package Unit | Misc. |
| **Utilities** | | | |
| Refrigeration | 100 MW | | |
| Boiler Feed Water | 2,000 tonnes/hr | | |
| Cooling Water | 20,000 tonnes/hr | | |

Figure A.2 in Appendix A is a process flow diagram showing most of the major process equipment. Table C.1 in Appendix C is a stream table for the process with streams corresponding to the streams shown in Figure A.2.

Note that the stream table contains an erroneous value of too much $CO_2$ in the product stream (7%), due to a slight undersupply of methanol to the product polishing column SNGRECT and imperfections in ASPEN's property methods for methanol in Rectisol processes. However, we judge this error would not affect the accuracy of our cost estimates. We have verified that a slight increase (15%) in input methanol flow to SNGRECT would give CO2 in the product gas of <0.5%. Because of project time constraints, we were unable to integrate that correction in the full process. However, we judge that such a minor change would not make a material difference to the capital and operating cost of the SNG process, given that the small size of SNGRECT to other columns in the process. We also have confidence, based on published studies, that with better property data, that our design could meet $CO_2$ specifications. [2,x,xi]

### *Raw Syngas Cleanup Subsystem*

A combination of many units is needed to remove particulates from the raw syngas. These include cyclones, baghouse filters, venture scrubbers and electrostatic precipitators.[xii] The amount of information needed to rigorously design and size these various units is beyond the scope of this study, so we have lumped all these into a composite unit called DEASHER in the flowsheet, with 100% particle removal efficiency, and costed them based on their gas throughput.

The particle-free syngas stream, SYNNOASH is sent to the heat exchanger WHBSYN, where it exchanges heat with the boiler feed water stream BFW1. The resultant steam stream MPSTEAM0 is sent to s flow splitter unit, STMSPL1, where it is split into two streams, MPSTEAM2, and MPSTEAM3. The warm syngas stream, SYNMHOT, is flashed in the unit SYNFLSH1 to remove condensate, which is sent to a wastewater treatment unit. The dry gas is mixed with MPSTEAM3 and a portion of it is passed through the water gas shift reactor, WGSEQ. The product stream WGSPRDH is mixed with the portion not passed through the reactor to produced the balanced syngas stream BALSYN1. The hot BALSYN1 is used to generate more steam, MPSTEAM1, in the waste heat boiler WHBWGS. The warm syngas from WHBWGS is cooled further in the heat exchanger unit WGSCOOL using cooling water, CW1. The cooled syngas is sent to the flash drum SYNFLSH2 to remove condensed water, and is further cooled in the heat exchanger SYNCRY2 (not shown on flow diagram) with the cold stream from the top of the CO2ABS, and then to cryogenic temperature in the cryogenic cooler SYNCRY1. The cold syngas, SYN2SABS, is introduced into H2SABS, wherein cold methanol, L1TOSABS, is used as the solvent, to remove the acid gas $H_2S$. The $H_2S$-free syngas, BALSYNC, is sent to CO2ABS where the $CO_2$ remaining in the syngas is removed using cold

[2] Published studies indicate that with the right thermodynamic package, a more accurate Rectisol model can be developed, and that the Rectisol system is capable of producing high purity syngas and SNG. Weiss describes a 5-column Rectisol scheme used to purify syngas wherein he feeds a syngas containing 34% $CO_2$ to the Rectisol system and gets a clean gas containing 10 ppm $CO_2$.and $H_2S$ content of 0.24 % to 0.1 ppm. Preston has modeled a six-column Rectisol system using the SRK thermodynamic model that was modified by specifying the binary interaction parameters for all the important binary pairs from measured data. With the use of this model, she was able to get excellent agreement with field data, lowering the $CO_2$ concentration to <2.5 % in a column with less than ten theoretical stages.

methanol stream, L1TOCABS. The rich liquid stream from CO2ABS is flashed in LTFLSH to remove dissolved light gases $H_2$, CO and $CH_4$. The gas stream from LTFLSH is mixed with BALSYN2, the gas stream from CO2ABS, and the combined stream, TOC1RXR, exchanges heat with WGHPRDC2 stream mentioned earlier in the heat exchanger SYNCRY2 (not shown) and is then sent to the methanator reactor METHRXR after passing through the fired heater C1FDHTR.

The $H_2S$-rich rich methanol stream is heated in the heater RECTHTX1 and then sent to the $H_2S$ stripper H2SSTRP. The top product from the stripper containing $H_2S$ is cooled to -40 and flashed to remove methanol (not shown on flowsheet) and then mixed with air/oxygen and sent to a Claus unit (not shown). Likewise, the cold bottom product of the LTFLSH, stream L1TOCST2, is mixed with the cold bottom stream from another Rectisol unit, SNGRECT (described later), and the combined cold stream L1CO2RCH is used to cool the recycle methanol stream further, in the heat exchanger L1CRYO2 (not shown in flow diagram). The now warm rich stream is sent to the $CO_2$ stripper CO2STRP where the $CO_2$ is stripped out from the liquid. The bottoms products of the two strippers, namely, L1WL and LEANL1 are mixed and recycled back to the front of the process where a cryogenic cooler L1CRYO1 (L1CRYO3, not shown in flow diagram) lowers the temperature of the recycle stream to the design temperature of the Rectisol unit. The top of the $CO_2$ absorber can be disposed of as tail gas, or sent to sequestration after further processing.

### *SNG Generation Subsystem*

The heated balanced gas stream from C1FDHTR is sent to the methanation reactor METHRXR, simulated as an equilibrium reactor. The product of the reactor is cooled and flashed in the flash drum METHCOND to remove the condensate formed during cooling. The dry stream is sent to the Rectisol column SNGRECT to remove $CO_2$ from the raw product. The bottom stream from SNGRECT is mixed with the liquid stream from LTFLSH mentioned earlier to form the cold stream L1CO2RCH, which, after passing through the heat exchanger L1CRYO2 (not shown on flow diagram), is sent to CO2STRP where the $CO_2$ is stripped out, thus regenerating the solvent. The top product from SNGRECT is HPPRDSNG, high pressure SNG.

## Process Discussion

The heating value of the SNG product is below the acceptable pipeline minimum of 950 BTU/scft (Foss, 2004).[xiii] A major reason for this is that it contains ~8% $N_2$, even though the raw syngas fed to the process has only about 1.2% $N_2$.[3] This indicates that the quality of the oxygen used as an oxidant in the upstream UCG process needs to be very high, and that minor intrusions of nitrogen (e.g. nitrogen in the coal being converted to nitrogen gas, or intrusions of air into the UCG chamber) into the product will cause great difficulty in meeting pipeline specification.

It should be further noted that the flowsheet simulated here is has not been optimized. A number of improvements are possible:

[3] For the product gas with 89% methane, 8% nitrogen and ~3% other gases (~1% each of ethane, hydrogen and CO2), we estimate the HHV would be ~920 BTU/scf.

- A more thorough heat integration for in-process heat exchange between hot and cold streams is likely to reduce utility consumption (cooling water, steam and refrigeration)

- We have not modeled a use for exported steam. For example, any excess steam can be used to generate power before being used as a heat source, thus reducing electrical power consumption in the cryogenic systems.

- Instead of using methanol as the stripping agent in the $CO_2$ stripper, nitrogen from the air separation unit can be used to reduce energy consumption, in scenario where the $CO_2$ stream can be released to the atmosphere.

- Heat from the Claus unit, not simulated here, can be used to preheat the combustion air after the last compressor to improve the efficiency of the gas turbine.

- We have not modeled purification and liquefaction of the $CO_2$ stream to carbon capture and storage quality. As this $CO_2$ stream contains some methane, purification of the $CO_2$ stream would likely have a beneficial effect on the economics.

- We have assumed that oxygen is delivered from the toll air separation unit (ASU) at the required pressure of ~45 atm.

We have avoided, on purpose, closing of the recycle loop involving the recycle of the solvent. This is done for two reasons:

- The amount of the solvent flowing through the absorber/stripper system can be independently set by the designer/operator

- Calculation of the exact composition of the circulating solvent does not significantly affect the design of the process, yet creates numerical instabilities in Aspen, thus making such calculations difficult.

Instead, we show that the amounts of the methanol in and out, including the makeup methanol, are in mass balance.

Likewise, we have not shown the recycle of steam, showing, instead, the steam balance.

### *Materials of Construction*

As with the power generation option, we do not envision excessively corrosive conditions in the process, hence we envisioned that most of the gas cleanup process equipment would be carbon steel, with the exception of the rectisol absorber/stripper loop, where 304 Stainless steel was projected.

## Capital and Operating Cost

Equipment sizes were estimated using ASPEN and according to general rules of thumb for process engineering. Table 3.1 lists the major process equipment items. Variable costs, including estimated annual utility consumptions, are listed in Table C.2.

Capital costs for the gas cleanup process equipment were estimated using Peters & Timmerhaus.[xiv] Costs were inflated from 2002 to 2010 costs using the *Chemical Engineering* plant cost index. Installation costs factors ranging from 0.6-1.5 (depending on equipment type) of purchased equipment costs, were used to include construction, electrical and instrumentation, and piping costs. Utility investment costs were also estimated using Peters & Timmerhaus, using an installation cost factor of 0.4. Certain elements (the Claus desulfurization unit) were treated as a package unit with installation costs included. The methanation and water-gas shift reactors were costed using correlations for heat exchangers with a multiplier for complexity of construction.

Drilling costs, being incurred throughout the plant lifetime as UCG modules are expended, were treated as an annual operating expense. Cost estimates for drilling were obtained from Mitchell Group of Queensland, Australia.[xv] Drilling cost estimates for the SNG scenario are given in Table C.3

Labor costs were estimated using May 2009 hourly wage rates for manufacturing labor in Wyoming from the Bureau of Labor Statistics. We estimated one operator for every 3 UCG modules , and 9 operators per shift for the gas cleanup and methanation plant.

### *Discussion of Capital & Operating Costs*

Total Fixed Capital for the Gas Cleanup and Power Generating Sections are given in Table C.4. The total fixed capital cost was estimated at $363 million. Working capital of 3 months of operating cash costs was estimated at $90 million, for a total capital investment of $453 million. This capital investment does not include the cost of the air separation unit (ASU) or capital investment for productive use of exported steam, or investment in the inventory of methanol kept on-site.

Annual operating expenses, including return on investment and plant depreciation over a 7-year period, were estimated at $489 million, as shown in Table C.5, with variable expenses shown in Table C.2. Excluding depreciation, the operating costs, including return on investment, are $437 million. These give a cost of $7.5/MMBTU during the depreciation period and $6.7/MWh post-depreciation.

### *Uncertainties*

For the power generation option, the greatest uncertainty is in the capital cost of the power generation island. While GE power supplied a rough cost using a rule of thumb of $1,000-1,200/kW capacity, we could not completely clarify with GE Power what assumptions underlay their cost estimate. GE Power also believed the syngas product was marginal at the combustion ratios we specified. Use of a richer syngas:air mixture would reduce the gas turbine output and adversely affect the economics.

For the SNG option, the greatest uncertainty is the price of oxygen from an air separation unit and the price of steam exported. Because of the requirement for a low percentage of nitrogen on the raw syngas from the UCG modules, cryogenic oxygen rather than pressure-swing-adsorption (PSA) oxygen would be needed. Therefore a relatively high estimate of oxygen costs was used. Also, we have assumed that excess steam not needed in the process can be exported offsite for revenue (e.g. to a co-located steam turbine electricity generation plant). A more rigorous analysis would be to include the ASU in the capital and operating costs, and inclusion of a steam turbine to consume the exported steam to supply power to the ASU and to the rest of the SNG process.

The properties method used in the ASPEN model, even between those recommended for Rectisol processes, can make a difference in the modeled performance of the absorption/stripping columns, particularly for the final polishing column in the SNG process, leading to over an order-of-magnitude difference in the percentage of $CO_2$ remaining in the product gas.

Other uncertainties are the exact volume of coal extractable from each UCG run. Larger volumes of coal extractable in a run would improve economics, especially for the SNG option where drilling costs alone are almost half of the operating expenses.

Field tests indicate that conditions (pressure, temperature, composition) of the product gas from an individual UCG module can fluctuate radically due to conditions in the subsurface (e.g. spalling of overburden into the UCG cavity, changing composition of coal burned, intrusion of groundwater into the cavity, startup/shutdown between CRIP maneuvers, etc.). As dozens of UCG modules would be operating in parallel, we have assumed that such excursions from average conditions would be largely be 'smoothed out'. However, some surge capacity in the gas cleanup may be needed to

We have costed the gas cleanup as a single-train Rectisol absorption system. However, for the SNG option, although columns of 20 m diameter have been constructed for $CO_2$/amine absorption, these may not be practical for the absorption pressures used (~45 atm), and multiple parallel absorbers may be used instead. Also, because of the large flows of methanol, separate absorption trains may be advisable for health & safety reasons. This would cause a modest increase in the capital and operating costs.

## References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[vi] Personal Communication, Joe Barry, GE Power, 27 April 2011.

[vii] M.S. Peters, K.D. Timmerhause, R.E. West, "Plant Design and Economics for Chemical Engineers, 5th Ed." 2002, McGraw-Hill

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[x] Weiss, H., "Rectisol wash for purification of partial oxidation gases", Gas Separation and Purification, Vol 2, page 171, December 1988

[xi] Preston, Rosalyn, "A computer model of the Rectisol process using the Aspen simulator", MS Thesis in Chemical Engineering, MIT, December 1981

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[xiii] Foss, Michele M., Interstate Natural Gas – Quality Specifications & Interchangeability, Center for Energy Economics, University of Texas, 2004, available at http://www.beg.utexas.edu/energyecon/lng/documents/CEE_Interstate_Natural_Gas_Quality_Specifications_and_Interchangeability.pdf, accessed 23 May 2011.

[xiv] M.S. Peters, K.D. Timmerhause, R.E. West, “Plant Design and Economics for Chemical Engineers, 5th Ed.” 2002, McGraw-Hill

[xv] Personal Communication, Jason Patterson, Mitchell Group, 3 April 2011.

# Appendix A

**Figure A.1 Process Flow Diagram Power Generation from UCG.**

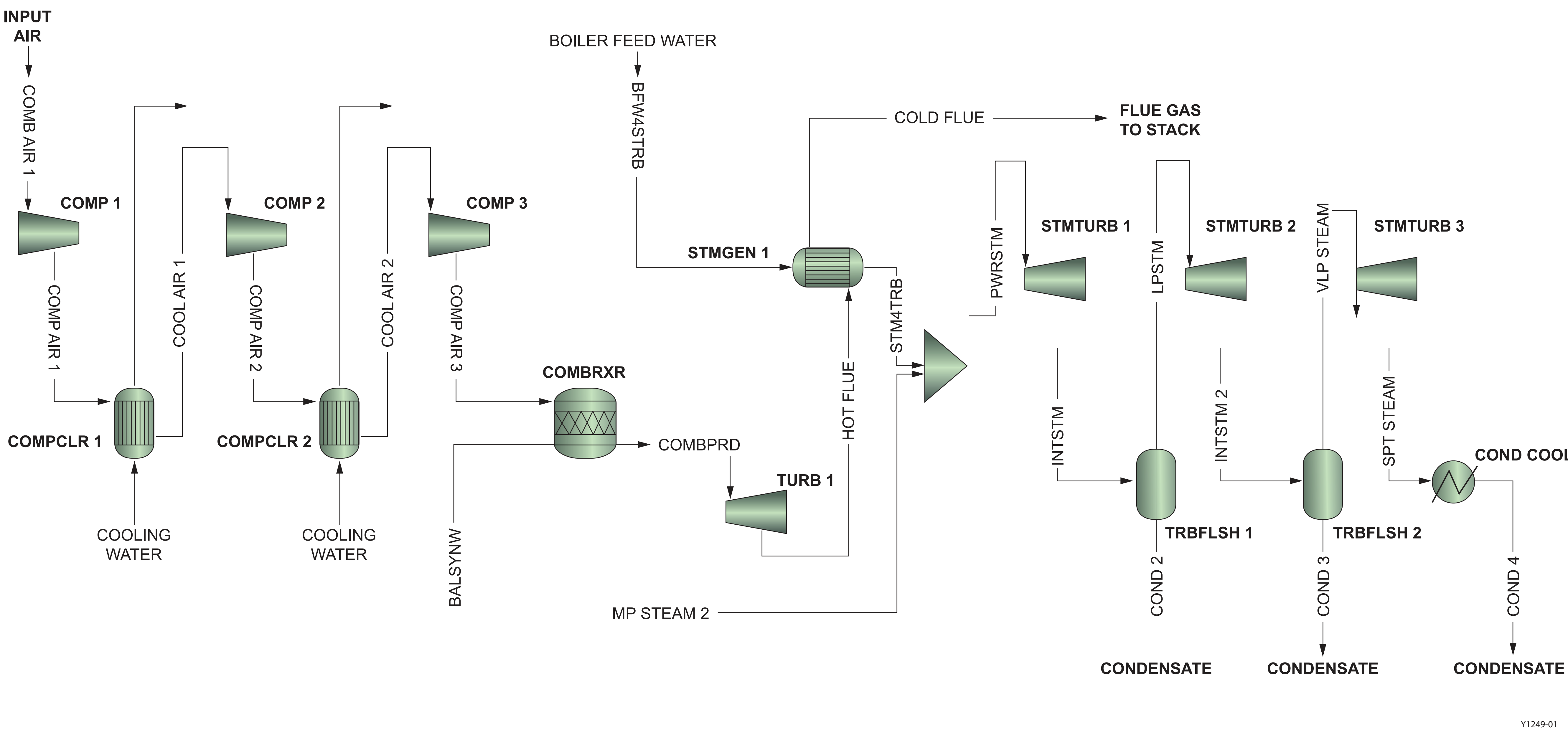


**Figure A.1 Process Flow Diagram Power Generation from UCG. (cont.)**

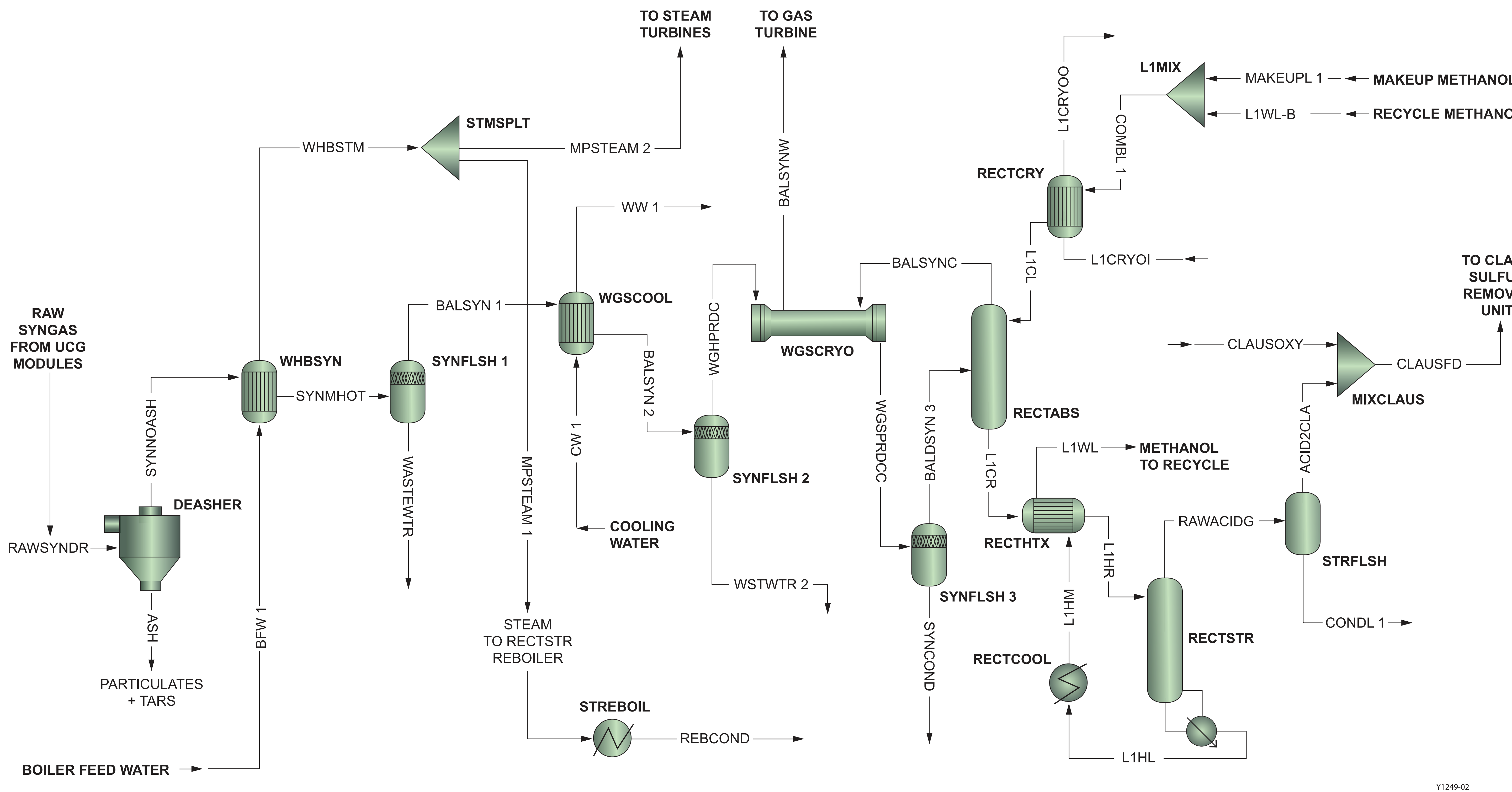
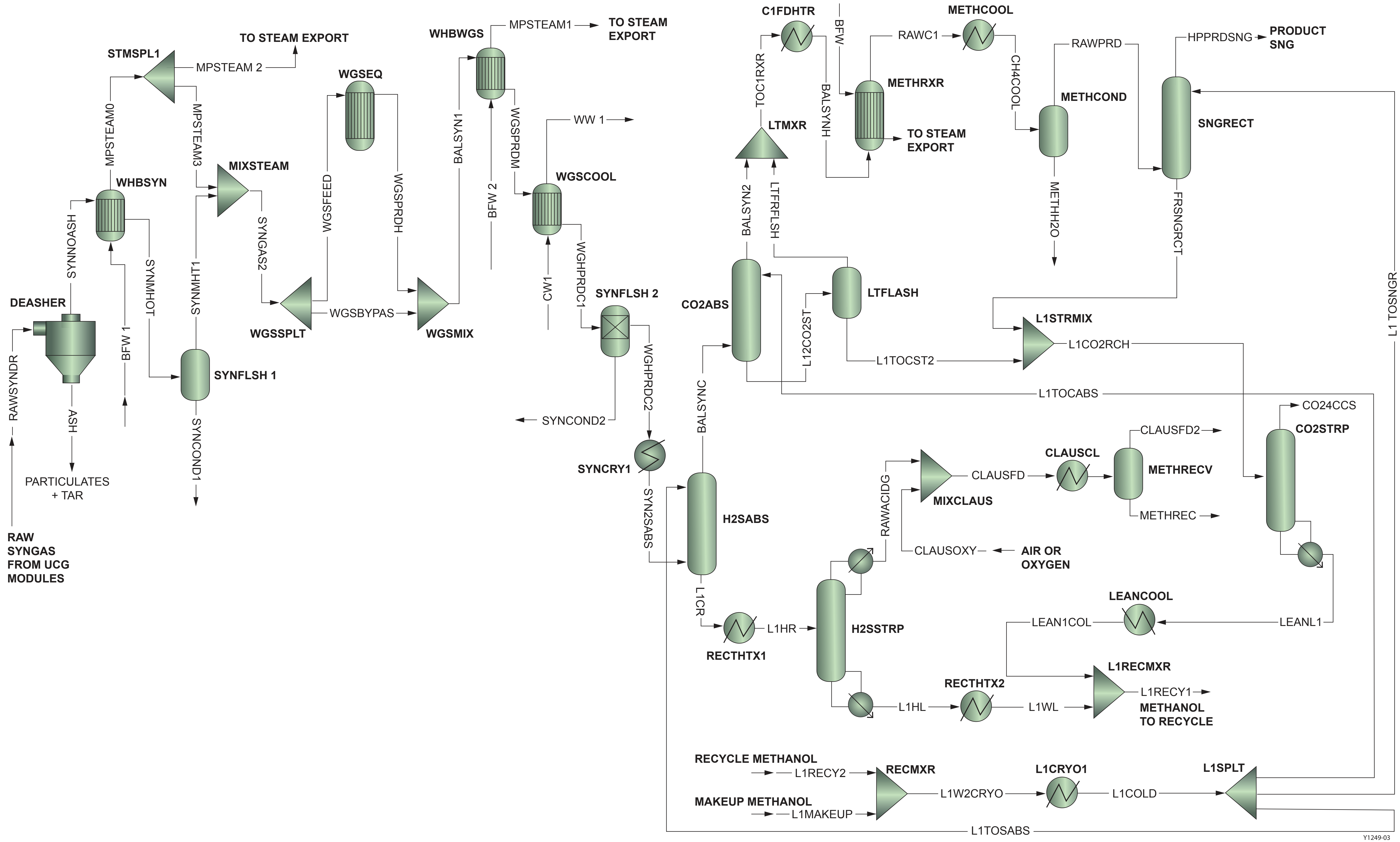


**Figure A.2 Process Flow Diagram Synthetic Natural Gas from UCG.**



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# Appendix B

**Table B-1**
**Power Generation from UCG**
**Stream Table**

| Stream Name | BALDSYN3 | BALSYN1 | BALSYNC | BALSYNW | BFW1 | BFW4STRB |
|---|---|---|---|---|---|---|
| **Temperature K** | 263 | 418 | 249 | 306 | 298 | 298 |
| **Pressure atm** | 44.7 | 44.9 | 44.7 | 44.7 | 45 | 45 |
| ***Component Mole Flow*** | | | | | | |
| ***kmol/hr*** | | | | | | |
| **H2** | 3465 | 3466 | 3450 | 3450 | -- | -- |
| **CO** | 2854 | 2854 | 2835 | 2835 | -- | -- |
| **H2O** | 4 | 3239 | Negl. | Negl. | 20000 | 15300 |
| **CO2** | 4062 | 4072 | 2881 | 2881 | -- | -- |
| **CH4** | 1478 | 1478 | 1442 | 1442 | -- | -- |
| **N2** | 13252 | 13252 | 13183 | 13183 | -- | -- |
| **C2H6** | 137 | 137 | 118 | 118 | -- | -- |
| **H2S** | 50 | 51 | Negl. | Negl. | -- | -- |
| **NH3** | 26 | 134 | Negl. | Negl. | -- | -- |
| **O2** | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | 7 | 7 | -- | -- |
| ***Component Mass Flow*** | | | | | | |
| ***kg/hr*** | | | | | | |
| **H2** | 6986 | 6986 | 6955 | 6955 | -- | -- |
| **CO** | 79943 | 79955 | 79411 | 79411 | -- | -- |
| **H2O** | 68 | 58352 | Negl. | Negl. | 360306 | 275634 |
| **CO2** | 178788 | 179192 | 126785 | 126785 | -- | -- |
| **CH4** | 23712 | 23715 | 23134 | 23134 | -- | -- |
| **N2** | 371225 | 371242 | 369304 | 369304 | -- | -- |
| **C2H6** | 4125 | 4130 | 3555 | 3555 | -- | -- |
| **H2S** | 1718 | 1727 | 7 | 7 | -- | -- |
| **NH3** | 443 | 2279 | Negl. | Negl. | -- | -- |
| **O2** | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | 233 | 233 | -- | -- |
| | | | | | | |
| ***Total Flow kmol/hr*** | 25329 | 28683 | 23917 | 23917 | 20000 | 15300 |
| ***Total Flow kg/hr*** | 667008 | 727579 | 609384 | 609384 | 360306 | 275634 |
| ***Total Flow l/min*** | 196898 | 361623 | 175585 | 223816 | 7972 | 6099 |
| | | | | | | |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 |

**Table B-1**
**Power Generation from UCG**
**Stream Table**

| Stream Name | CLAUSFD | CLAUSOXY | COLDFLUE | COMBAIR1 | COMBL1 | COMBPRD |
|---|---|---|---|---|---|---|
| **Temperature K** | 270 | 298 | 457 | 298 | 273 | 1707 |
| **Pressure atm** | 2 | 2 | 1.1 | 1 | 45 | 45 |
| ***Component Mole Flow kmol/hr*** | | | | | | |
| **H2** | 15 | -- | -- | -- | -- | -- |
| **CO** | 19 | -- | -- | -- | -- | -- |
| **H2O** | Negl. | -- | 6704 | -- | -- | 6704 |
| **CO2** | 1181 | -- | 7402 | -- | -- | 7402 |
| **CH4** | 36 | -- | -- | -- | -- | -- |
| **N2** | 69 | -- | 46020 | 32836 | -- | 46020 |
| **C2H6** | 19 | -- | -- | -- | -- | -- |
| **H2S** | 27 | -- | -- | -- | -- | -- |
| **NH3** | Negl. | -- | -- | -- | -- | -- |
| **O2** | 36 | 36 | 2277 | 8729 | -- | 2277 |
| **SO2** | -- | -- | Negl. | -- | -- | Negl. |
| **CH3OH** | 11 | -- | -- | -- | 11000 | -- |
| ***Component Mass Flow kg/hr*** | | | | | | |
| **H2** | 31 | -- | -- | -- | -- | -- |
| **CO** | 532 | -- | -- | -- | -- | -- |
| **H2O** | Negl. | -- | 120769 | -- | -- | 120769 |
| **CO2** | 51964 | -- | 325743 | -- | -- | 325743 |
| **CH4** | 578 | -- | -- | -- | -- | -- |
| **N2** | 1922 | -- | 1289170 | 919863 | -- | 1289170 |
| **C2H6** | 570 | -- | -- | -- | -- | -- |
| **H2S** | 907 | -- | -- | -- | -- | -- |
| **NH3** | 3 | -- | -- | -- | -- | -- |
| **O2** | 1167 | 1167 | 72861 | 279307 | -- | 72861 |
| **SO2** | -- | -- | 14 | -- | -- | 14 |
| **CH3OH** | 358 | -- | -- | -- | 352464 | -- |
| | | | | | | |
| ***Total Flow kmol/hr*** | 1413 | 36 | 62402 | 41565 | 11000 | 62402 |
| ***Total Flow kg/hr*** | 58031 | 1167 | 1808550 | 1199170 | 352464 | 1808550 |
| ***Total Flow l/min*** | 257841 | 7430 | 35488300 | 16949500 | 9602 | 3252330 |
| | | | | | | |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 1.00 | 0.00 | 1.00 |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 0.00 |

**Table B-1**
**Power Generation from UCG**
**Stream Table**

| Stream Name | COMPAIR1 | COMPAIR2 | COMPAIR3 | COND2 | COOLAIR1 | COOLAIR2 |
|---|---|---|---|---|---|---|
| **Temperature K** | 439 | 453 | 453 | 442 | 308 | 308 |
| **Pressure atm** | 3.56 | 12.6736 | 45 | 7.515 | 3.56 | 12.6736 |
| ***Component Mole Flow kmol/hr*** | | | | | | |
| **H2** | -- | -- | -- | -- | -- | -- |
| **CO** | -- | -- | -- | -- | -- | -- |
| **H2O** | -- | -- | -- | 3647 | -- | -- |
| **CO2** | -- | -- | -- | -- | -- | -- |
| **CH4** | -- | -- | -- | -- | -- | -- |
| **N2** | 32836 | 32836 | 32836 | -- | 32836 | 32836 |
| **C2H6** | -- | -- | -- | -- | -- | -- |
| **H2S** | -- | -- | -- | -- | -- | -- |
| **NH3** | -- | -- | -- | -- | -- | -- |
| **O2** | 8729 | 8729 | 8729 | -- | 8729 | 8729 |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | -- | -- | -- | -- |
| ***Component Mass Flow kg/hr*** | | | | | | |
| **H2** | -- | -- | -- | -- | -- | -- |
| **CO** | -- | -- | -- | -- | -- | -- |
| **H2O** | -- | -- | -- | 65703 | -- | -- |
| **CO2** | -- | -- | -- | -- | -- | -- |
| **CH4** | -- | -- | -- | -- | -- | -- |
| **N2** | 919863 | 919863 | 919863 | -- | 919863 | 919863 |
| **C2H6** | -- | -- | -- | -- | -- | -- |
| **H2S** | -- | -- | -- | -- | -- | -- |
| **NH3** | -- | -- | -- | -- | -- | -- |
| **O2** | 279307 | 279307 | 279307 | -- | 279307 | 279307 |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | -- | -- | -- | -- |
| ***Total Flow kmol/hr*** | 41565 | 41565 | 41565 | 3647 | 41565 | 41565 |
| ***Total Flow kg/hr*** | 1199170 | 1199170 | 1199170 | 65703 | 1199170 | 1199170 |
| ***Total Flow l/min*** | 7016160 | 2045820 | 585690 | 1670 | 4923190 | 1385230 |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 0.00 | 1.00 | 1.00 |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 1.00 | 0.00 | 0.00 |

**Table B-1**
**Power Generation from UCG**
**Stream Table**

| Stream Name | CW1 | HOTFLUE | INSTM2 | INTSTM | L1CL | L1CR | L1CRYOI |
|---|---|---|---|---|---|---|---|
| **Temperature K** | 298 | 827 | 380 | 442 | 228 | 259 | 193 |
| **Pressure atm** | 1 | 1.1 | 1.255005 | 7.515 | 45 | 44.7 | 10 |
| ***Component Mole Flow*** | | | | | | | |
| ***kmol/hr*** | | | | | | | |
| **H2** | -- | -- | -- | -- | -- | 15 | -- |
| **CO** | -- | -- | -- | -- | -- | 19 | -- |
| **H2O** | 3825000 | 6704 | 29653 | 33300 | -- | 4 | -- |
| **CO2** | -- | 7402 | -- | -- | -- | 1182 | -- |
| **CH4** | -- | -- | -- | -- | -- | 36 | -- |
| **N2** | -- | 46020 | -- | -- | -- | 69 | -- |
| **C2H6** | -- | -- | -- | -- | -- | 19 | -- |
| **H2S** | -- | -- | -- | -- | -- | 50 | -- |
| **NH3** | -- | -- | -- | -- | -- | 26 | -- |
| **O2** | -- | 2277 | -- | -- | -- | -- | -- |
| **SO2** | -- | Negl. | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | -- | -- | 11000 | 10993 | 100000 |
| ***Component Mass Flow*** | | | | | | | |
| ***kg/hr*** | | | | | | | |
| **H2** | -- | -- | -- | -- | -- | 31 | -- |
| **CO** | -- | -- | -- | -- | -- | 532 | -- |
| **H2O** | 68908500 | 120769 | 534205 | 599909 | -- | 68 | -- |
| **CO2** | -- | 325743 | -- | -- | -- | 52003 | -- |
| **CH4** | -- | -- | -- | -- | -- | 578 | -- |
| **N2** | -- | 1289170 | -- | -- | -- | 1922 | -- |
| **C2H6** | -- | -- | -- | -- | -- | 570 | -- |
| **H2S** | -- | -- | -- | -- | -- | 1710 | -- |
| **NH3** | -- | -- | -- | -- | -- | 443 | -- |
| **O2** | -- | 72861 | -- | -- | -- | -- | -- |
| **SO2** | -- | 14 | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | -- | -- | 352464 | 352231 | 3204220 |
| ***Total Flow kmol/hr*** | 3825000 | 62402 | 29653 | 33300 | 11000 | 12412 | 100000 |
| ***Total Flow kg/hr*** | 68908500 | 1808550 | 534205 | 599909 | 352464 | 410088 | 3204220 |
| ***Total Flow l/min*** | 1525840 | 64156500 | 11125300 | 2287930 | 9254 | 10403 | 82243 |
| **Vapor Frac** | 0.00 | 1.00 | 0.92 | 0.89 | 0.00 | 0.00 | 0.00 |
| **Liquid Frac** | 1.00 | 0.00 | 0.08 | 0.11 | 1.00 | 1.00 | 1.00 |

**Table B-1**
**Power Generation from UCG**
**Stream Table**

| Stream Name | L1CRYOO | L1HL | L1HR | L1WL | LPSTM | MAKEUPL1 | MPSTEAM1 |
|---|---|---|---|---|---|---|---|
| **Temperature K** | 198 | 383 | 295 | 274 | 442 | 318 | 531 |
| **Pressure atm** | 10 | 5 | 44.7 | 4.946598 | 7.515 | 45 | 45 |
| ***Component Mole Flow kmol/hr*** | | | | | | | |
| **H2** | -- | -- | 15 | -- | -- | -- | -- |
| **CO** | -- | -- | -- | -- | -- | -- | -- |
| **H2O** | -- | 4 | 4 | 4 | 29653 | -- | 2000 |
| **CO2** | -- | Negl. | 1182 | Negl. | -- | -- | -- |
| **CH4** | -- | Negl. | 36 | Negl. | -- | -- | -- |
| **N2** | -- | Negl. | 69 | Negl. | -- | -- | -- |
| **C2H6** | -- | Negl. | 19 | Negl. | -- | -- | -- |
| **H2S** | -- | 24 | 50 | 24 | -- | -- | -- |
| **NH3** | -- | 26 | 26 | 26 | -- | -- | -- |
| **O2** | -- | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- | -- |
| **CH3OH** | 100000 | 10967 | 10993 | 10967 | -- | 38 | -- |
| ***Component Mass Flow kg/hr*** | | | | | | | |
| **H2** | -- | -- | 31 | -- | -- | -- | -- |
| **CO** | -- | -- | 532 | -- | -- | -- | -- |
| **H2O** | -- | 68 | 68 | 68 | 534205 | -- | 36031 |
| **CO2** | -- | 5 | 52003 | 5 | -- | -- | -- |
| **CH4** | -- | Negl. | 578 | Negl. | -- | -- | -- |
| **N2** | -- | Negl. | 1922 | Negl. | -- | -- | -- |
| **C2H6** | -- | Negl. | 570 | Negl. | -- | -- | -- |
| **H2S** | -- | 801 | 1710 | 801 | -- | -- | -- |
| **NH3** | -- | 439 | 443 | 439 | -- | -- | -- |
| **O2** | -- | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- | -- |
| **CH3OH** | 3204220 | 351401 | 352231 | 351401 | -- | 1218 | -- |
| ***Total Flow kmol/hr*** | 100000 | 11020 | 12412 | 11020 | 29653 | 38 | 2000 |
| ***Total Flow kg/hr*** | 3204220 | 352714 | 410088 | 352714 | 534205 | 1218 | 36031 |
| ***Total Flow l/min*** | 82492 | 11220 | 11032 | 9628 | 2286260 | 35 | 27276 |
| **Vapor Frac** | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 0.00 | 1.00 |
| **Liquid Frac** | 1.00 | 1.00 | 1.00 | 1.00 | 0.00 | 1.00 | 0.00 |

**Table B-1**
**Power Generation from UCG**
**Stream Table**

| Stream Name | MPSTEAM2 | PWRSTM | RAWACIDG | RAWSYNDR | STM4TRB | SYNCOND |
|---|---|---|---|---|---|---|
| **Temperature K** | 531 | 534 | 287 | 873 | 536 | 263 |
| **Pressure atm** | 45 | 45 | 5 | 45 | 45 | 44.7 |
| ***Component Mole Flow kmol/hr*** | | | | | | |
| **H2** | -- | -- | 15 | 3467 | -- | -- |
| **CO** | -- | -- | 19 | 2855 | -- | -- |
| **H2O** | 18000 | 33300 | -- | 12747 | 15300 | 68 |
| **CO2** | -- | -- | 1182 | 4079 | -- | 1 |
| **CH4** | -- | -- | 36 | 1479 | -- | Negl. |
| **N2** | -- | -- | 69 | 13256 | -- | Negl. |
| **C2H6** | -- | -- | 19 | 138 | -- | Negl. |
| **H2S** | -- | -- | 27 | 51 | -- | Negl. |
| **NH3** | -- | -- | Negl. | 178 | -- | 10 |
| **O2** | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | 26 | -- | -- | -- |
| ***Component Mass Flow kg/hr*** | | | | | | |
| **H2** | -- | -- | 31 | 6989 | -- | Negl. |
| **CO** | -- | -- | 532 | 79976 | -- | 1 |
| **H2O** | 324275 | 599909 | Negl. | 229634 | 275634 | 1224 |
| **CO2** | -- | -- | 51998 | 179512 | -- | 42 |
| **CH4** | -- | -- | 578 | 23721 | -- | Negl. |
| **N2** | -- | -- | 1922 | 371360 | -- | 1 |
| **C2H6** | -- | -- | 570 | 4139 | -- | Negl. |
| **H2S** | -- | -- | 909 | 1738 | -- | 1 |
| **NH3** | -- | -- | 4 | 3039 | -- | 168 |
| **O2** | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | 830 | -- | -- | -- |
| ***Total Flow kmol/hr*** | 18000 | 33300 | 1392 | 38250 | 15300 | 79 |
| ***Total Flow kg/hr*** | 324275 | 599909 | 57374 | 900108 | 275634 | 1439 |
| ***Total Flow l/min*** | 245483 | 457450 | 106307 | 1012530 | 211963 | 32 |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 0.00 |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 |

**Table B-1**
**Power Generation from UCG**
**Stream Table**

| Stream Name | SYNMHOT | SYNNOASH | WASTEWTR | WGHPRDC | WGSPRDCC | WW1 |
|---|---|---|---|---|---|---|
| **Temperature K** | 418 | 873 | 418 | 313 | 263 | 299 |
| **Pressure atm** | 44.95 | 45 | 44.9 | 44.8 | 44.75 | 1 |
| ***Component Mole Flow kmol/hr*** | | | | | | |
| **H2** | 3467 | 3467 | 1 | 3465 | 3465 | -- |
| **CO** | 2855 | 2855 | 1 | 2854 | 2854 | -- |
| **H2O** | 12747 | 12747 | 9508 | 72 | 72 | 3825000 |
| **CO2** | 4079 | 4079 | 7 | 4063 | 4063 | -- |
| **CH4** | 1479 | 1479 | Negl. | 1478 | 1478 | -- |
| **N2** | 13256 | 13256 | 4 | 13252 | 13252 | -- |
| **C2H6** | 138 | 138 | Negl. | 137 | 137 | -- |
| **H2S** | 51 | 51 | Negl. | 50 | 50 | -- |
| **NH3** | 178 | 178 | 45 | 36 | 36 | -- |
| **O2** | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | -- | -- | -- | -- |
| ***Component Mass Flow kg/hr*** | | | | | | |
| **H2** | 6989 | 6989 | 3 | 6986 | 6986 | -- |
| **CO** | 79976 | 79976 | 22 | 79945 | 79945 | -- |
| **H2O** | 229634 | 229634 | 171282 | 1292 | 1292 | 68908500 |
| **CO2** | 179512 | 179512 | 320 | 178830 | 178830 | -- |
| **CH4** | 23721 | 23721 | 6 | 23712 | 23712 | -- |
| **N2** | 371360 | 371360 | 118 | 371226 | 371226 | -- |
| **C2H6** | 4139 | 4139 | 9 | 4125 | 4125 | -- |
| **H2S** | 1738 | 1738 | 10 | 1719 | 1719 | -- |
| **NH3** | 3039 | 3039 | 760 | 611 | 611 | -- |
| **O2** | -- | -- | -- | -- | -- | -- |
| **SO2** | -- | -- | -- | -- | -- | -- |
| **CH3OH** | -- | -- | -- | -- | -- | -- |
| ***Total Flow kmol/hr*** | 38250 | 38250 | 9567 | 25408 | 25408 | 3825000 |
| ***Total Flow kg/hr*** | 900108 | 900108 | 172529 | 668447 | 668447 | 68908500 |
| ***Total Flow l/min*** | 365490 | 1012530 | 4258 | 241129 | 196718 | 1526690 |
| **Vapor Frac** | 0.75 | 1.00 | 0.00 | 1.00 | 1.00 | 0.00 |
| **Liquid Frac** | 0.25 | 0.00 | 1.00 | 0.00 | 0.00 | 1.00 |

## Table B.2
## Power Generation from UCG
## Annual Estimated Variable Costs

*Costs in 2011 US$*

| *Materials Consumed* | *Number/year* | | *Unit Cost* | | *Costs* |
|---|---|---|---|---|---|
| Coal Royalty Costs | 1,750,000 | tonnes | $3 | per tonne | $ 5,250,000 |
| Estimated Tar By-product | 7,000 | tonnes | $ (40.00) | per tonne | $ (280,000) |
| Methanol Losses | 9590 | tonnes | $ 300 | per tonne | $ 2,877,000 |
| | | | Raw Material Costs | | $ 8,127,000 |
| | *Subtotal, Drilling Contractor Turnkey Costs* | | | | $ 11,004,000 |
| Utilities | | | | | |
| Cooling Water | 3.30E+08 | cu.m | $ 0.02 | per cu.m | $ 6,600,000 |
| Boiler Feed Water | 8.29E+05 | cu.m | $ 0.20 | per cu.m | $ 166,000 |
| | | | Utility Costs | | $ 6,766,000 |
| | | | ***Total Variable costs*** | | **$ 14,893,000** |

**Table B.3**
**Power Generation from UCG**
**Annual Estimated Drilling & Field Costs**

*Costs in 2011 thousand US$*

| | | *Number/run* | *Number/year* | | *Unit Cost* | | *Costs* |
|---|---|---|---|---|---|---|---|
| Production Wells | | 1 | 33 | wells | $ 374 | per well | $ 12,333 |
| Injection Wells | | 3 | 99 | wells | $ 173 | per well | $ 17,160 |
| Instrumentation Wells | | 4 | 132 | wells | $ 25 | per well | $ 3,300 |
| Instrument Costs | | 4 | 64 | wells | $ 10 | per well | $ 640 |
| Drill Waste Disposal | | 325 | 10725 | tonne | $ 0.05 | per tonne | $ 536 |
| | | | *Subtotal, Drilling Contractor Turnkey Costs* | | | | $ 33,969 |
| Drilling Program Contingency | 30% | | | | | | $ 10,191 |
| Direct Employees for Oversight of Drilling Contract | | | 1.5 | employees | $ 61 | each | $ 90 |
| | | | | | | ***Total drilling costs*** | **$ 44,249** |
| Site Preparation Costs | | | | | | | |
| | | *Number/run* | *Number/year* | | *Unit cost* | | |
| Land Lease Costs for Extraction | | 0.1 | 3.3 | hectares | 1.75 | per hectare | **$ 6** |
| Site Clearing and Preparation | | 0.1 | 3.3 | hectares | 4.5 | per hectare | **$ 15** |
| Utility Road Construction | | 0.4 | 13.2 | km | 8 | per km | **$ 106** |
| Field Piping & Installation | | 0.6 | 19.8 | km | 125 | per km | **$ 2,475** |
| | | | | | | ***Site Preparation Costs*** | **$ 2,601** |
| UCG Field Operation and Maintenance | | | | | | | |
| | | | Number/year | | | | |
| Decommissioning of spent wells | | | 33 | | 10 | ***each*** | **$ 330** |
| Field Piping Maintenance | | | | | | | **$ 500** |
| Monitoring Well Sampling | | | 80 | | 1.5 | ***per sample*** | **$ 120** |
| Environmental Reporting | | | 2 | | 20 | ***each*** | **$ 40** |
| | | | | | | ***Field Operation Costs*** | **$ 990** |
| ***Total Annual UCG Field Operation Costs*** | | | | | | | **$ 47,840** |

## Table B.4
## Power Generation from UCG
## <u>Fixed Capital Costs</u>

**Plant Net Capacity** **485 MW**

*Costs in 2011 thousand US$*

Gas Cleanup and Power Plant

| | | | | |
|---|---|---|---|---|
| Battery Limits Investment (BLI) | | Equipment Cost | Installation Cost | Total Cost |
| Power Plant Package Unit | | | | $ 550,000 |
| Compressors | | $ 10,000 | $ 9,000 | $ 19,000 |
| Reactors | | $ 50 | $ 90 | $ 140 |
| Columns | | $ 2,520 | $ 3,780 | $ 6,300 |
| Pressure Vessels | | $ 1,310 | $ 1,570 | $ 2,880 |
| Heat Exchangers | | $ 4,070 | $ 5,900 | $ 9,970 |
| Claus Package Unit | | | | $ 8,570 |
| Particulate Removal | | $ 730 | $ 510 | $ 1,240 |
| | | | *Subtotal* | *$ 598,100* |
| BLI Contingency | | **30%** | of Installed Equipment Costs | $ 179,430 |
| Battery Limits Investment | | | | *$ 777,530* |
| Battery Limits Investment, Gas Cleanup Only | | | | *$ 37,830* |
| Tankage | | | | |
| Methanol Storage Tanks | | | | $ 13,200 |
| Methanol Surge Tanks | | | | $ 2,600 |
| | | | | $ 15,800 |
| Utilities | | Purchased Cost | Installation Cost | Investment |
| Refrigeration | 12 MW | $ 12,700 | $ 5,080 | $ 17,780 |
| Boiler Feed Water | 105 tonnes/hr | $ 400 | $ 160 | $ 600 |
| Cooling Water | 42,000 tonnes/hr | $ 8,000 | $ 3,200 | $ 11,200 |
| | | | *Utilities Investment Subtotal* | *$ 29,600* |
| Offsite & Utility Investment Contingency | | **30%** | | $ 13,620 |
| Offsite & Utilities Investment | | | | *$ 59,020* |
| General Service Facilities | | 5% | of BLI & Utilities Investment | $ 41,830 |
| Waste Treatment | | 1% | of BLI Investment | $ 7,780 |
| Outside Battery Limits Investment | | | | $ 108,600 |
| | | | *Total Fixed Capital (TFC) Investment* | *$ 886,100* |

**Table B.5**
**Power Generation from UCG**
**Annual Estimated Operating Costs**

| | | | | |
|---|---|---|---|---|
| **Plant Net Capacity** | | | | **485 MW** |
| *Costs in 2011 thousand US$* | | | | |
| | | | | *Costs* |
| Plant Investment, Battery Limits (BLI) | | | | $ 777,530 |
| Plant Investment, Outside Battery Limits (OBLI) | | | | $ 108,600 |
| ***Total Fixed Capital (TFC)*** | | | | $ 886,130 |
| **Operating Costs, Per Year** | | | | |
| Raw Material Costs | | | | $ 8,127 |
| Utility Costs | | | | $ 6,766 |
| Variable Costs | | | | $ 14,893 |
| ***Estimated Annual Drilling Costs*** | | | | $ 47,840 |
| ***Operating Labor*** | | | | |
| | | Number/year | Unit Cost | |
| Gas Cleanup and Power Generation Personnel (3 shifts) | | 18 | $ 62 wages/year | $ 1,116 |
| UCG Field Operations Personnel (3 shifts) | | 33 | $ 62 wages/year | $ 2,046 |
| Maintenance Labor | $1.20 per GWh | 3880 GWh | | $ 4,660 |
| Control Laboratory Labor, 10% of Operating Labor | 10% of Operating Labor | | | $ 320 |
| ***Direct Labor Costs*** | | | | $ 8,140 |
| Maintenance Materials | $1.80 per GWh | 3880 GWh | | $ 6,980 |
| Operating Supplies, 12% of Operating Labor | 12% of Operating Labor | | | $ 380 |
| ***Total Direct Costs*** | | | | $ 86,380 |
| Plant Overhead | 80% of Labor Costs | | | $ 6,820 |
| Taxes and Insurance | 1.60% of TFC | | | $ 14,180 |
| ***Cash Costs*** | | | | $ 107,380 |
| Depreciation | 14.3% of TFC | | | $ 126,590 |
| ***Gate Costs*** | | | | $ 233,970 |
| General, Admin, Sales, Research | 5% of Gate Costs | | | $ 11,700 |
| ***Production Costs*** | | | | $ 245,670 |
| TFC + Estimated Working Capital | | | | $ 912,975 |
| ROI | 12.5% of Capital Investment | | | $ 114,120 |
| ***Production Cost + Cost of Capital*** | | | | $ 359,790 |
| *Production Cost + Cost of Capital without Depreciation Charge* | | | | *$ 233,200* |
| Nominal Net Capacity, MW | | | | 485 |
| Stream Factor | | | | 0.913 |
| Estimated Annual Energy Output, MWh | | | | 3,880,000 |
| **Cost including Capital Return per MWh, $** | | | | **$ 93** |
| **Cost excluding Depreciation but including Capital Return per MWh, $** | | | | **$ 60** |

# Appendix C

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | BALSYN1 | BALSYN2 | BALSYNC | BALSYNH | BFW1 |
|---|---|---|---|---|---|
| **Temperature K** | 727 | 235 | 259 | 525 | 298 |
| **Pressure atm** | 50 | 45 | 45 | 45 | 45 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| H2 | 17,072 | 16,594 | 16,940 | 16,933 | - |
| CO | 5,234 | 4,946 | 5,122 | 5,116 | - |
| H2O | 27,242 | Negl. | Negl. | Negl. | 45,100 |
| CO2 | 20,549 | 120 | 6,967 | 2,136 | - |
| CH4 | 5,055 | 4,116 | 4,736 | 4,651 | - |
| N2 | 901 | 866 | 889 | 889 | - |
| C2H6 | 451 | 53 | 291 | 161 | - |
| H2S | 150 | 1 | 3 | 2 | - |
| NH3 | 601 | Negl. | Negl. | Negl. | - |
| O2 | - | - | - | - | - |
| SO2 | - | - | - | - | - |
| S2 | - | - | - | - | - |
| S8 | - | - | - | - | - |
| CH3OH | - | 3 | 21 | 8 | - |
| ***Component Mass Flow kg/hr*** | | | | | |
| H2 | 34,415 | 33,451 | 34,149 | 34,134 | - |
| CO | 146,617 | 138,526 | 143,470 | 143,298 | - |
| H2O | 490,773 | Negl. | Negl. | Negl. | 812,489 |
| CO2 | 904,367 | 5,280 | 306,595 | 94,021 | - |
| CH4 | 81,089 | 66,034 | 75,971 | 74,610 | - |
| N2 | 25,247 | 24,272 | 24,910 | 24,893 | - |
| C2H6 | 13,550 | 1,584 | 8,735 | 4,852 | - |
| H2S | 5,119 | 33 | 115 | 77 | - |
| NH3 | 10,233 | Negl. | Negl. | Negl. | - |
| O2 | - | - | - | - | - |
| SO2 | - | - | - | - | - |
| S2 | - | - | - | - | - |
| S8 | - | - | - | - | - |
| CH3OH | - | 82 | 689 | 248 | - |
| ***Total Flow kmol/hr*** | 77,255 | 26,698 | 34,969 | 29,896 | 45,100 |
| ***Total Flow kg/hr*** | 1,711,410 | 269,261 | 594,634 | 376,133 | 812,489 |
| ***Total Flow l/min*** | 1,519,300 | 194,573 | 271,313 | 487,237 | 17,978 |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 1.00 | 0.00 |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | BFW2 | CH4COOL | CLAUSFD | CLAUSFD2 | CLAUSOXY |
|---|---|---|---|---|---|
| **Temperature K** | 298 | 313 | 285 | 243 | 298 |
| **Pressure atm** | 2 | 44.9 | 2 | 2 | 2 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| H2 | - | 98 | 132 | 132 | - |
| CO | - | 1 | 112 | 112 | - |
| H2O | 30,000 | 5,860 | Negl. | Negl. | - |
| CO2 | - | 1,764 | 13,258 | 13,237 | - |
| CH4 | - | 10,138 | 319 | 319 | - |
| N2 | - | 889 | 12 | 12 | - |
| C2H6 | - | 161 | 158 | 158 | - |
| H2S | - | 2 | 135 | 134 | - |
| NH3 | - | Negl. | Negl. | Negl. | - |
| O2 | - | - | 1 | 1 | 1 |
| SO2 | - | - | - | - | - |
| S2 | - | - | - | - | - |
| S8 | - | - | - | - | - |
| CH3OH | - | 8 | 417 | 30 | - |
| ***Component Mass Flow kg/hr*** | | | | | |
| H2 | - | 198 | 266 | 266 | - |
| CO | - | 22 | 3,148 | 3,148 | - |
| H2O | 540,458 | 105,563 | 9 | Negl. | - |
| CO2 | - | 77,639 | 583,483 | 582,574 | - |
| CH4 | - | 162,643 | 5,118 | 5,117 | - |
| N2 | - | 24,893 | 337 | 337 | - |
| C2H6 | - | 4,852 | 4,744 | 4,741 | - |
| H2S | - | 77 | 4,591 | 4,562 | - |
| NH3 | - | Negl. | 7 | 1 | - |
| O2 | - | - | 46 | 46 | 46 |
| SO2 | - | - | - | - | - |
| S2 | - | - | - | - | - |
| S8 | - | - | - | - | - |
| CH3OH | - | 248 | 13,354 | 963 | - |
| ***Total Flow kmol/hr*** | 30,000 | 18,921 | 14,545 | 14,136 | 1 |
| ***Total Flow kg/hr*** | 540,458 | 376,133 | 615,102 | 601,755 | 46 |
| ***Total Flow l/min*** | 11,967 | 120,298 | 2,796,750 | 2,305,740 | 291 |
| **Vapor Frac** | 0.00 | 0.69 | 1.00 | 1.00 | 1.00 |
| **Liquid Frac** | 1.00 | 0.31 | 0.00 | 0.00 | 0.00 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | CLRSYN | CO24CCS | COLDSYN | CW1 | FRSNGRCT |
|---|---|---|---|---|---|
| **Temperature K** | 250 | 245 | 277 | 293 | 264 |
| **Pressure atm** | 45 | 1 | 45 | 1 | 25 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| **H2** | 17,091 | 8 | 17,091 | - | 1 |
| **CO** | 5,205 | 6 | 5,205 | - | Negl. |
| **H2O** | - | Negl. | - | 7,500,000 | 105 |
| **CO2** | 20,532 | 5,771 | 20,532 | - | 904 |
| **CH4** | 5,053 | 468 | 5,053 | - | 383 |
| **N2** | 901 | 8 | 901 | - | 7 |
| **C2H6** | 449 | 166 | 449 | - | 36 |
| **H2S** | 149 | 8 | 149 | - | 4 |
| **NH3** | - | Negl. | - | - | 5 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | - | 32 | - | - | 16,947 |
| ***Component Mass Flow kg/hr*** | | | | | |
| **H2** | 34,453 | 16 | 34,453 | - | 1 |
| **CO** | 145,794 | 171 | 145,794 | - | Negl. |
| **H2O** | - | Negl. | - | 135,115,000 | 1,900 |
| **CO2** | 903,609 | 253,968 | 903,609 | - | 39,788 |
| **CH4** | 81,064 | 7,512 | 81,064 | - | 6,151 |
| **N2** | 25,240 | 223 | 25,240 | - | 205 |
| **C2H6** | 13,501 | 4,979 | 13,501 | - | 1,096 |
| **H2S** | 5,078 | 269 | 5,078 | - | 137 |
| **NH3** | - | Negl. | - | - | 86 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | - | 1,038 | - | - | 543,031 |
| ***Total Flow kmol/hr*** | 49,380 | 6,467 | 49,380 | 7,500,000 | 18,394 |
| ***Total Flow kg/hr*** | 1,208,740 | 268,177 | 1,208,740 | 135,115,000 | 592,396 |
| ***Total Flow l/min*** | 337,989 | 2,148,080 | 388,911 | 2,981,560 | 15,634 |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | HPPRDSNG | L1CO2RCH | L1COLD | L1CR | L1HL |
|---|---|---|---|---|---|
| **Temperature K** | 244 | 248 | 233 | 241 | 294 |
| **Pressure atm** | 25 | 2 | 45 | 45 | 3 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| **H2** | 98 | 8 | - | 132 | Negl. |
| **CO** | 1 | 6 | - | 112 | Negl. |
| **H2O** | Negl. | 393 | 430 | 72 | 71 |
| **CO2** | 898 | 5,936 | 302 | 13,633 | 375 |
| **CH4** | 9,751 | 468 | - | 319 | Negl. |
| **N2** | 881 | 8 | - | 12 | Negl. |
| **C2H6** | 124 | 166 | - | 160 | 2 |
| **H2S** | 1 | 17 | 17 | 150 | 15 |
| **NH3** | Negl. | 26 | 31 | 5 | 5 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 4 | 86,439 | 103,798 | 17,348 | 16,931 |
| ***Component Mass Flow kg/hr*** | | | | | |
| **H2** | 197 | 16 | - | 266 | Negl. |
| **CO** | 22 | 171 | - | 3,148 | Negl. |
| **H2O** | Negl. | 7,086 | 7,747 | 1,296 | 1,287 |
| **CO2** | 39,516 | 261,258 | 13,291 | 599,996 | 16,513 |
| **CH4** | 156,439 | 7,512 | - | 5,118 | 1 |
| **N2** | 24,683 | 223 | - | 337 | Negl. |
| **C2H6** | 3,739 | 4,979 | - | 4,815 | 71 |
| **H2S** | 33 | 563 | 579 | 5,102 | 511 |
| **NH3** | Negl. | 440 | 528 | 88 | 81 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 120 | 2,769,690 | 3,325,910 | 555,867 | 542,513 |
| ***Total Flow kmol/hr*** | 11,758 | 93,467 | 104,578 | 31,944 | 17,400 |
| ***Total Flow kg/hr*** | 224,748 | 3,051,940 | 3,348,060 | 1,176,030 | 560,976 |
| ***Total Flow l/min*** | 143,786 | 604,271 | 88,021 | 24,168 | 15,423 |
| **Vapor Frac** | 1.00 | 0.03 | 0.00 | 0.00 | 0.00 |
| **Liquid Frac** | 0.00 | 0.97 | 1.00 | 1.00 | 1.00 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | L1HR | L1MAKEUP | L1RECY1 | L1RECY2 | L1TOCABS |
|---|---|---|---|---|---|
| **Temperature K** | 298 | 298 | 308 | 308 | 233 |
| **Pressure atm** | 5 | 50 | 5 | 50 | 45 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| **H2** | 132 | - | Negl. | - | - |
| **CO** | 112 | - | Negl. | - | - |
| **H2O** | 72 | - | 465 | 430 | 288 |
| **CO2** | 13,633 | - | 541 | 302 | 202 |
| **CH4** | 319 | - | Negl. | - | - |
| **N2** | 12 | - | Negl. | - | - |
| **C2H6** | 160 | - | 2 | - | - |
| **H2S** | 150 | - | 24 | 17 | 11 |
| **NH3** | 5 | - | 31 | 31 | 21 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 17,348 | 58 | 103,338 | 103,740 | 69,478 |
| ***Component Mass Flow kg/hr*** | | | | | |
| **H2** | 266 | - | Negl. | - | - |
| **CO** | 3,148 | - | Negl. | - | - |
| **H2O** | 1,296 | - | 8,372 | 7,747 | 5,185 |
| **CO2** | 599,996 | - | 23,804 | 13,291 | 8,896 |
| **CH4** | 5,118 | - | 1 | - | - |
| **N2** | 337 | - | Negl. | - | - |
| **C2H6** | 4,815 | - | 71 | - | - |
| **H2S** | 5,102 | - | 805 | 579 | 388 |
| **NH3** | 88 | - | 520 | 528 | 353 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 555,867 | 1,858 | 3,311,170 | 3,324,050 | 2,226,220 |
| ***Total Flow kmol/hr*** | 31,944 | 58 | 104,400 | 104,520 | 70,000 |
| ***Total Flow kg/hr*** | 1,176,030 | 1,858 | 3,344,740 | 3,346,200 | 2,241,050 |
| ***Total Flow l/min*** | 1,162,050 | 52 | 94,412 | 94,227 | 58,917 |
| **Vapor Frac** | 0.45 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Liquid Frac** | 0.55 | 1.00 | 1.00 | 1.00 | 1.00 |

## Table C.1
## Synthetic Natural Gas from UCG
## Stream Table

| | L1TOCST2 | L1TOSABS | L1TOSNGR | L1W2CRYO | L1WL |
|---|---|---|---|---|---|
| **Temperature K** | 250 | 233 | 233 | 308 | 308 |
| **Pressure atm** | 5 | 45 | 45 | 50 | 2 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| **H2** | 7 | - | - | - | Negl. |
| **CO** | 6 | - | - | - | Negl. |
| **H2O** | 288 | 72 | 70 | 430 | 71 |
| **CO2** | 5,032 | 51 | 49 | 302 | 375 |
| **CH4** | 85 | - | - | - | Negl. |
| **N2** | 1 | - | - | - | Negl. |
| **C2H6** | 129 | - | - | - | 2 |
| **H2S** | 12 | 3 | 3 | 17 | 15 |
| **NH3** | 21 | 5 | 5 | 31 | 5 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 69,492 | 17,369 | 16,951 | 103,798 | 16,931 |
| ***Component Mass Flow kg/hr*** | | | | | |
| **H2** | 14 | - | - | - | Negl. |
| **CO** | 171 | - | - | - | Negl. |
| **H2O** | 5,186 | 1,296 | 1,265 | 7,747 | 1,287 |
| **CO2** | 221,470 | 2,224 | 2,170 | 13,291 | 16,513 |
| **CH4** | 1,361 | - | - | - | 1 |
| **N2** | 18 | - | - | - | Negl. |
| **C2H6** | 3,883 | - | - | - | 71 |
| **H2S** | 426 | 97 | 95 | 579 | 511 |
| **NH3** | 354 | 88 | 86 | 528 | 81 |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 2,226,660 | 556,556 | 543,135 | 3,325,910 | 542,513 |
| ***Total Flow kmol/hr*** | 75,073 | 17,500 | 17,078 | 104,578 | 17,400 |
| ***Total Flow kg/hr*** | 2,459,550 | 560,261 | 546,751 | 3,348,060 | 560,976 |
| ***Total Flow l/min*** | 63,092 | 14,729 | 14,374 | 94,279 | 66,300 |
| **Vapor Frac** | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| **Liquid Frac** | 1.00 | 1.00 | 1.00 | 1.00 | 0.99 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | L12CO2ST | LEAN1COL | LEANL1 | LTFRFLSH | METHH2O |
|---|---|---|---|---|---|
| **Temperature K** | 253 | 308 | 325 | 250 | 313 |
| **Pressure atm** | 45 | 1 | 1 | 5 | 45 |
| ***Component Mole Flow*** | | | | | |
| ***kmol/hr*** | | | | | |
| **H2** | 346 | Negl. | Negl. | 339 | Negl. |
| **CO** | 176 | Negl. | Negl. | 170 | Negl. |
| **H2O** | 288 | 393 | 393 | Negl. | 5,824 |
| **CO2** | 7,049 | 166 | 166 | 2,016 | 11 |
| **CH4** | 619 | Negl. | Negl. | 535 | 3 |
| **N2** | 23 | Negl. | Negl. | 22 | Negl. |
| **C2H6** | 238 | Negl. | Negl. | 109 | 1 |
| **H2S** | 14 | 9 | 9 | 1 | Negl. |
| **NH3** | 21 | 26 | 26 | Negl. | Negl. |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 69,497 | 86,407 | 86,407 | 5 | 7 |
| ***Component Mass Flow*** | | | | | |
| ***kg/hr*** | | | | | |
| **H2** | 698 | Negl. | Negl. | 683 | Negl. |
| **CO** | 4,944 | Negl. | Negl. | 4,773 | Negl. |
| **H2O** | 5,186 | 7,085 | 7,085 | Negl. | 104,927 |
| **CO2** | 310,211 | 7,290 | 7,290 | 88,741 | 506 |
| **CH4** | 9,937 | Negl. | Negl. | 8,576 | 53 |
| **N2** | 638 | Negl. | Negl. | 621 | 4 |
| **C2H6** | 7,152 | Negl. | Negl. | 3,269 | 17 |
| **H2S** | 470 | 294 | 294 | 44 | 1 |
| **NH3** | 354 | 439 | 439 | Negl. | Negl. |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 2,226,830 | 2,768,660 | 2,768,660 | 166 | 232 |
| ***Total Flow kmol/hr*** | 78,271 | 87,000 | 87,000 | 3,198 | 5,847 |
| ***Total Flow kg/hr*** | 2,566,420 | 2,783,760 | 2,783,760 | 106,872 | 105,740 |
| ***Total Flow l/min*** | 65,224 | 78,724 | 80,349 | 212,998 | 2,363 |
| **Vapor Frac** | 0.00 | 0.00 | 0.00 | 1.00 | 0.00 |
| **Liquid Frac** | 1.00 | 1.00 | 1.00 | 0.00 | 1.00 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | METHREC | MPSTEAM0 | MPSTEAM1 | MPSTEAM2 | MPSTEAM3 | RAWACIDG |
|---|---|---|---|---|---|---|
| **Temperature K** | 243 | 398 | 398 | 398 | 398 | 286 |
| **Pressure atm** | 2 | 45 | 2 | 45 | 45 | 3 |
| ***Component Mole Flow kmol/hr*** | | | | | | |
| **H2** | Negl. | - | - | - | - | 132 |
| **CO** | Negl. | - | - | - | - | 112 |
| **H2O** | Negl. | 45,100 | 30,000 | 42,845 | 2,255 | Negl. |
| **CO2** | 21 | - | - | - | - | 13,258 |
| **CH4** | Negl. | - | - | - | - | 319 |
| **N2** | Negl. | - | - | - | - | 12 |
| **C2H6** | Negl. | - | - | - | - | 158 |
| **H2S** | 1 | - | - | - | - | 135 |
| **NH3** | Negl. | - | - | - | - | Negl. |
| **O2** | Negl. | - | - | - | - | - |
| **SO2** | - | - | - | - | - | - |
| **S2** | - | - | - | - | - | - |
| **S8** | - | - | - | - | - | - |
| **CH3OH** | 387 | - | - | - | - | 417 |
| ***Component Mass Flow kg/hr*** | | | | | | |
| **H2** | Negl. | - | - | - | - | 266 |
| **CO** | Negl. | - | - | - | - | 3,148 |
| **H2O** | 9 | 812,489 | 540,458 | 771,865 | 40,624 | 9 |
| **CO2** | 909 | - | - | - | - | 583,483 |
| **CH4** | Negl. | - | - | - | - | 5,118 |
| **N2** | Negl. | - | - | - | - | 337 |
| **C2H6** | 3 | - | - | - | - | 4,744 |
| **H2S** | 29 | - | - | - | - | 4,591 |
| **NH3** | 6 | - | - | - | - | 7 |
| **O2** | Negl. | - | - | - | - | - |
| **SO2** | - | - | - | - | - | - |
| **S2** | - | - | - | - | - | - |
| **S8** | - | - | - | - | - | - |
| **CH3OH** | 12,391 | - | - | - | - | 13,354 |
| ***Total Flow kmol/hr*** | 409 | 45,100 | 30,000 | 42,845 | 2,255 | 14,544 |
| ***Total Flow kg/hr*** | 13,348 | 812,489 | 540,458 | 771,865 | 40,624 | 615,057 |
| ***Total Flow l/min*** | 344 | 19,575 | 8,052,400 | 18,596 | 979 | 1,861,310 |
| **Vapor Frac** | 0.00 | 0.00 | 1.00 | 0.00 | 0.00 | 1.00 |
| **Liquid Frac** | 1.00 | 1.00 | 0.00 | 1.00 | 1.00 | 0.00 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | RAWC1 | RAWPRD | RAWSYN | SYN2SABS | SYNCOND1 |
|---|---|---|---|---|---|
| **Temperature K** | 575 | 313 | 873 | 233 | |
| **Pressure atm** | 44.9 | 45 | 50 | 45 | 50 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| **H2** | 98 | 98 | 17,049 | 17,072 | - |
| **CO** | 1 | 1 | 5,257 | 5,234 | - |
| **H2O** | 5,860 | 35 | 25,010 | - | - |
| **CO2** | 1,764 | 1,753 | 20,526 | 20,549 | - |
| **CH4** | 10,138 | 10,135 | 5,055 | 5,055 | - |
| **N2** | 889 | 888 | 901 | 901 | - |
| **C2H6** | 161 | 161 | 451 | 451 | - |
| **H2S** | 2 | 2 | 150 | 150 | - |
| **NH3** | Negl. | Negl. | 601 | - | - |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 8 | Negl. | - | - | - |
| ***Component Mass Flow kg/hr*** | | | | | |
| **H2** | 198 | 198 | 34,368 | 34,415 | - |
| **CO** | 22 | 22 | 147,261 | 146,617 | - |
| **H2O** | 105,563 | 635 | 450,562 | - | - |
| **CO2** | 77,639 | 77,133 | 903,356 | 904,367 | - |
| **CH4** | 162,643 | 162,590 | 81,089 | 81,089 | - |
| **N2** | 24,893 | 24,889 | 25,247 | 25,247 | - |
| **C2H6** | 4,852 | 4,835 | 13,550 | 13,550 | - |
| **H2S** | 77 | 76 | 5,119 | 5,119 | - |
| **NH3** | Negl. | Negl. | 10,233 | - | - |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | 248 | 16 | - | - | - |
| ***Total Flow kmol/hr*** | 18,921 | 13,074 | 75,000 | 49,412 | - |
| ***Total Flow kg/hr*** | 376,133 | 270,393 | 1,670,790 | 1,210,410 | - |
| ***Total Flow l/min*** | 328,661 | 117,671 | 1,774,160 | 264,514 | - |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 0.79 | |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 0.21 | |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | SYNCOND2 | SYNGAS2 | SYNMHOT | SYNMHT1 | SYNNOASH |
|---|---|---|---|---|---|
| **Temperature K** | 298 | 727 | 760 | 760 | 873 |
| **Pressure atm** | 50 | 45 | 50 | 50 | 50 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| H2 | - | 17,049 | 17,049 | 17,049 | 17,049 |
| CO | - | 5,257 | 5,257 | 5,257 | 5,257 |
| H2O | 27,242 | 27,265 | 25,010 | 25,010 | 25,010 |
| CO2 | - | 20,526 | 20,526 | 20,526 | 20,526 |
| CH4 | - | 5,055 | 5,055 | 5,055 | 5,055 |
| N2 | - | 901 | 901 | 901 | 901 |
| C2H6 | - | 451 | 451 | 451 | 451 |
| H2S | - | 150 | 150 | 150 | 150 |
| NH3 | 601 | 601 | 601 | 601 | 601 |
| O2 | - | - | - | - | - |
| SO2 | - | - | - | - | - |
| S2 | - | - | - | - | - |
| S8 | - | - | - | - | - |
| CH3OH | - | - | - | - | - |
| ***Component Mass Flow kg/hr*** | | | | | |
| H2 | - | 34,368 | 34,368 | 34,368 | 34,368 |
| CO | - | 147,261 | 147,261 | 147,261 | 147,261 |
| H2O | 490,773 | 491,187 | 450,562 | 450,562 | 450,562 |
| CO2 | - | 903,356 | 903,356 | 903,356 | 903,356 |
| CH4 | - | 81,089 | 81,089 | 81,089 | 81,089 |
| N2 | - | 25,247 | 25,247 | 25,247 | 25,247 |
| C2H6 | - | 13,550 | 13,550 | 13,550 | 13,550 |
| H2S | - | 5,119 | 5,119 | 5,119 | 5,119 |
| NH3 | 10,233 | 10,233 | 10,233 | 10,233 | 10,233 |
| O2 | - | - | - | - | - |
| SO2 | - | - | - | - | - |
| S2 | - | - | - | - | - |
| S8 | - | - | - | - | - |
| CH3OH | - | - | - | - | - |
| ***Total Flow kmol/hr*** | 27,843 | 77,255 | 75,000 | 75,000 | 75,000 |
| ***Total Flow kg/hr*** | 501,006 | 1,711,410 | 1,670,790 | 1,670,790 | 1,670,790 |
| ***Total Flow l/min*** | 11,162 | 1,688,230 | 1,543,640 | 1,543,640 | 1,774,160 |
| **Vapor Frac** | 0.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| **Liquid Frac** | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## Table C.1
## Synthetic Natural Gas from UCG
## Stream Table

| | SYNTOCRY | TOC1RXR | TORXR | WGHPRDC1 | WGHPRDC2 |
|---|---|---|---|---|---|
| **Temperature K** | 233 | 240 | 293 | 298 | 298 |
| **Pressure atm** | 45 | 45 | 45 | 50 | 50 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| **H2** | 17,091 | 16,933 | 16,860 | 17,072 | 17,072 |
| **CO** | 5,205 | 5,116 | 5,049 | 5,234 | 5,234 |
| **H2O** | - | Negl. | - | 27,242 | - |
| **CO2** | 20,532 | 2,136 | 831 | 20,549 | 20,549 |
| **CH4** | 5,053 | 4,651 | 4,460 | 5,055 | 5,055 |
| **N2** | 901 | 889 | 883 | 901 | 901 |
| **C2H6** | 449 | 161 | 96 | 451 | 451 |
| **H2S** | 149 | 2 | 2 | 150 | 150 |
| **NH3** | - | Negl. | - | 601 | - |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | - | 8 | 4 | - | - |
| ***Component Mass Flow kg/hr*** | | | | | |
| **H2** | 34,453 | 34,134 | 33,988 | 34,415 | 34,415 |
| **CO** | 145,794 | 143,298 | 141,425 | 146,617 | 146,617 |
| **H2O** | - | Negl. | - | 490,773 | - |
| **CO2** | 903,609 | 94,021 | 36,572 | 904,367 | 904,367 |
| **CH4** | 81,064 | 74,610 | 71,551 | 81,089 | 81,089 |
| **N2** | 25,240 | 24,893 | 24,736 | 25,247 | 25,247 |
| **C2H6** | 13,501 | 4,852 | 2,887 | 13,550 | 13,550 |
| **H2S** | 5,078 | 77 | 68 | 5,119 | 5,119 |
| **NH3** | - | Negl. | - | 10,233 | - |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | - | 248 | 128 | - | - |
| ***Total Flow kmol/hr*** | 49,380 | 29,896 | 28,185 | 77,255 | 49,412 |
| ***Total Flow kg/hr*** | 1,208,740 | 376,133 | 311,354 | 1,711,410 | 1,210,410 |
| ***Total Flow l/min*** | 263,827 | 219,170 | 258,037 | 392,356 | 382,645 |
| **Vapor Frac** | 0.79 | 1.00 | 1.00 | 0.64 | 1.00 |
| **Liquid Frac** | 0.21 | 0.00 | 0.00 | 0.36 | 0.00 |

**Table C.1**
**Synthetic Natural Gas from UCG**
**Stream Table**

| | WGSBYPAS | WGSFEED | WGSPRDH | WGSPRDM | WW1 |
|---|---|---|---|---|---|
| **Temperature K** | 727 | 727 | 753 | 446 | 295 |
| **Pressure atm** | 45 | 45 | 50 | 50 | 1 |
| ***Component Mole Flow kmol/hr*** | | | | | |
| **H2** | 16,878 | 170 | 193 | 17,072 | - |
| **CO** | 5,205 | 53 | 30 | 5,234 | - |
| **H2O** | 26,992 | 273 | 250 | 27,242 | 7,500,000 |
| **CO2** | 20,321 | 205 | 228 | 20,549 | - |
| **CH4** | 5,004 | 51 | 51 | 5,055 | - |
| **N2** | 892 | 9 | 9 | 901 | - |
| **C2H6** | 446 | 5 | 5 | 451 | - |
| **H2S** | 149 | 2 | 2 | 150 | - |
| **NH3** | 595 | 6 | 6 | 601 | - |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | - | - | - | - | - |
| ***Component Mass Flow kg/hr*** | | | | | |
| **H2** | 34,025 | 344 | 390 | 34,415 | - |
| **CO** | 145,788 | 1,473 | 829 | 146,617 | - |
| **H2O** | 486,275 | 4,912 | 4,498 | 490,773 | 135,115,000 |
| **CO2** | 894,322 | 9,034 | 10,045 | 904,367 | - |
| **CH4** | 80,278 | 811 | 811 | 81,089 | - |
| **N2** | 24,995 | 252 | 252 | 25,247 | - |
| **C2H6** | 13,415 | 136 | 136 | 13,550 | - |
| **H2S** | 5,068 | 51 | 51 | 5,119 | - |
| **NH3** | 10,130 | 102 | 102 | 10,233 | - |
| **O2** | - | - | - | - | - |
| **SO2** | - | - | - | - | - |
| **S2** | - | - | - | - | - |
| **S8** | - | - | - | - | - |
| **CH3OH** | - | - | - | - | - |
| ***Total Flow kmol/hr*** | 76,482 | 773 | 773 | 77,255 | 7,500,000 |
| ***Total Flow kg/hr*** | 1,694,300 | 17,114 | 17,114 | 1,711,410 | 135,115,000 |
| ***Total Flow l/min*** | 1,671,350 | 16,882 | 15,750 | 727,843 | 2,985,260 |
| **Vapor Frac** | 1.00 | 1.00 | 1.00 | 0.81 | 0.00 |
| **Liquid Frac** | 0.00 | 0.00 | 0.00 | 0.19 | 1.00 |

## Table C.2
## Synthetic Natural Gas (SNG) from UCG
## Annual Estimated Variable Costs

*Costs in 2011 US$*

| *Materials Consumed* | *Number/year* | | *Unit Cost* | | *Costs* |
|---|---|---|---|---|---|
| Coal Royalty Costs | 6,100,000 | tonnes | $3 | per tonne | $ 18,300,000 |
| Oxygen Purchase | 3,215,100 | tonnes | $30 | per tonne | $ 96,453,000 |
| Estimated Tar By-product | 45,000 | tonnes | $ (40.00) | per tonne | $ (1,800,000) |
| Catalyst Losses | | | | | $ 700,000 |
| Methanol Losses | 23,990 | tonnes | $ 300 | per tonne | $ 7,197,000 |
| | | | | Raw Material Costs | $ 120,850,000 |
| | *Subtotal, Raw Material Costs* | | | | $ 120,850,000 |
| *Utilities* | | | | | |
| Steam Export | 1.35E+07 | tonnes | $ (2.00) | per tonne | $ (26,991,051) |
| Cooling Water | 1.56E+08 | cu.m | $ 0.02 | per cu.m | $ 3,123,400 |
| Electricity | 4.80E+05 | MWh | $ 50.00 | per MWh | $ 23,993,640 |
| Boiler Feed Water | 1.59E+07 | tonnes | $ 0.20 | per tonne | $ 3,173,152 |
| | | | | Utility Costs | $ 3,299,142 |
| | | | | ***Total Variable costs*** | **$ 124,149,142** |

**Table C.3**
**Synthetic Natural Gas (SNG) from UCG**
**<u>Annual Estimated Drilling Costs</u>**

*Costs in 2011 thousand US$*

| | | *Number/run* | *Number/year* | | *Unit Cost* | | | *Costs* |
|---|---|---|---|---|---|---|---|---|
| Production Wells | | 1 | 124 | wells | $ | 374 | per well | $ 46,341 |
| Injection Wells | | 3 | 372 | wells | $ | 173 | per well | $ 64,480 |
| Instrumentation Wells | | 4 | 496 | wells | $ | 25 | per well | $ 12,400 |
| Instrument Costs | | 4 | 496 | wells | $ | 10 | per well | $ 4,960 |
| Drill Waste Disposal | | 325 | 40300 | tonne | $ | 0.05 | per tonne | $ 2,015 |
| | | | *Subtotal, Drilling Contractor Turnkey Costs* | | | | | $ 130,196 |
| Drilling Program Contingency | 30% | | | | | | | $ 39,059 |
| Direct Employees for Oversight of Drilling Contract | | | 5 | employees | $ | 61 | each | $ 310 |
| | | | | | | | ***Total drilling costs*** | **$ 169,564** |
| Site Preparation Costs | | | | | | | | |
| | | Number/run | Number/year | | Unit cost | | | |
| Land Lease Costs for Extraction | | 0.1 | 12.4 | hectares | | 1.75 | per hectare | **$ 22** |
| Site Clearing and Preparation | | 0.1 | 12.4 | hectares | | 4.5 | per hectare | **$ 56** |
| Utility Road Construction | | 0.4 | 49.6 | km | | 8 | per km | **$ 397** |
| Field Piping & Installation | | 0.6 | 74.4 | km | | 125 | per km | **$ 9,300** |
| | | | | | | | ***Site Preparation Costs*** | **$ 9,774** |
| UCG Field Operation and Maintenance | | | | | | | | |
| | | | Number/year | | | | | |
| Decommissioning of spent wells | | | 124 | | | 10 | ***each*** | **$ 1,240** |
| Field Piping Maintenance | | | | | | | | **$ 1,860** |
| Monitoring Well Sampling | | | 80 | | | 1.5 | ***per sample*** | **$ 120** |
| Environmental Reporting | | | 2 | | | 20 | ***each*** | **$ 40** |
| | | | | | | | ***Field Operation Costs*** | **$ 3,260** |
| ***Total Annual UCG Field Operation Costs*** | | | | | | | | **$ 182,600** |

## Table C.4
## Synthetic Natural Gas (SNG) from UCG
## Estimated Fixed Capital Costs

**Plant Net Capacity** — **66 Trillion BTU/yr (34,500 BoPD Equivalent)**

*Costs in 2011 thousand US$*

Gas Cleanup and Power Plant

| | | | | |
|---|---|---|---|---|
| Battery Limits Investment (BLI) | Equipment Cost | | Installation Cost | Total Cost |
| Reactors | $ 3,630 | | $ 9,076 | $ 12,706 |
| Catalyst Cost | | | | $ 2,100 |
| Columns | $ 14,870 | | $ 23,800 | $ 38,670 |
| Pressure Vessels | $ 1,200 | | $ 720 | $ 1,920 |
| Heat Exchangers | $ 41,260 | | $ 45,400 | $ 86,660 |
| Claus Package Unit | | | | $ 17,420 |
| Particulate Removal | $ 480 | | $ 960 | $ 1,440 |
| | | | *Subtotal* | *$ 160,916* |
| BLI Contingency | **30%** | of Installed Equipment Costs | | $ 48,270 |
| Battery Limits Investment | | | | $ 209,186 |
| Tankage | | | | |
| Methanol Storage Tanks | | | | $ 15,840 |
| Methanol Surge Tanks | | | | $ 3,300 |
| | | | | $ 19,140 |
| Utilities | Purchased Cost | | Installation Cost | Investment |
| Refrigeration | $ 20,300 | | $ 8,120 | $ 28,420 |
| Boiler Feed Water | $ 3,260 | | $ 1,300 | $ 4,560 |
| Cooling Water | $ 2,900 | | $ 1,160 | $ 4,060 |
| | | | *Utilities Investment Subtotal* | *$ 37,000* |
| Offsites & Utility Investment Contingency | **30%** | | | $ 16,842 |
| Offsite & Utilities Investment | | | | *$ 72,982* |
| General Service Facilities | 25% | of BLI & Utilities Investment | | $ 70,540 |
| Waste Treatment | 5% | of BLI Investment | | $ 10,460 |
| Outside Battery Limits Investment | | | | $ 154,000 |
| | | | *Total Fixed Capital (TFC) Investment* | *$ 363,200* |

**Table C.5**
**Synthetic Natural Gas (SNG) from UCG**
**Annual Estimated Operating Costs**

| | | | | |
|---|---|---|---|---|
| **Plant Net Capacity** | | | **66 Trillion BTU/yr (34,500 BoPD Equivalent)** | |
| *Costs in 2011 thousand US$* | | | | |
| | | | | *Costs* |
| Plant Investment, Battery Limits (BLI) | | | | $ 209,200 |
| Plant Investment, Outside Battery Limits (OBLI) | | | | $ 154,000 |
| ***Total Fixed Capital (TFM)*** | | | | $ 363,200 |
| **Operating Costs, Per Year** | | | | |
| Raw Material Costs (net) | | | | $ 120,850 |
| Utility Costs (net) | | | | $ 3,299 |
| Variable Costs | | | | $ 124,149 |
| ***Estimated Annual Drilling Costs*** | | | | $ 182,600 |
| ***Labor Costs*** | | | | |
| Operating Labor, Gas Cleanup Personnel (3 shifts) | | 27 | $ 62 wages/year | $ 1,674 |
| Operating Labor, UCG Field Operations Personnel (3 shifts) | | 124 | $ 62 wages/year | $ 7,688 |
| Maintenance Labor | 2.40% of BLI | | | $ 5,021 |
| Control Laboratory Labor, 10% of Operating Labor | 10% of Operating Labor | | | $ 940 |
| ***Direct Labor Costs*** | | | | $ 15,320 |
| Maintenance Materials | 1.60% of BLI | | | $ 3,347 |
| Operating Supplies, 12% of Operating Labor | 12% of Operating Labor | | | $ 1,120 |
| ***Total Direct Costs*** | | | | $ 341,860 |
| Plant Overhead | 80% of Direct Labor Costs | | | $ 12,260 |
| Taxes and Insurance | 1.60% of TFC | | | $ 5,810 |
| ***Cash Costs*** | | | | $ 359,930 |
| Depreciation | 14.3% of TFC | | | $ 51,890 |
| ***Gate Costs*** | | | | $ 411,820 |
| General, Admin, Sales, Research | 5% of Gate Costs | | | $ 20,590 |
| ***Production Costs*** | | | | $ 432,410 |
| TFC + Estimated Working Capital | | | | $ 453,183 |
| ROI | 12.5% of Capital Investment | | | $ 56,650 |
| ***Production Cost + Cost of Capital*** | | | | $ 489,060 |
| *Production Cost + Cost of Capital without Depreciation Charge* | | | | *$ 437,170* |
| *Stream Factor* | | | | 0.913 |
| Estimated Natural Gas Output, moles methane | | | | 7.78E+10 |
| Estimated Natural Gas Output, MJ HHV | | | | 6.92E+10 |
| Estimated Natural Gas Output, MMBTU HHV | | | | 6.55E+07 |
| **Production Cost including Capital Return per GJ, $** | | | | **$ 7.1** |
| **Production Cost including Capital Return per MMBTU, $** | | | | **$ 7.5** |
| **Production Cost including Capital Return per Barrel Oil Equivalent Energy, $** | | | | **$ 43.1** |
| **Cost excluding Depreciation but including Capital Return per MMBTU, $** | | | | **$ 6.7** |